RESOLUTION NO. 155 - 25

A RESOLUTION SETTING CERTAIN ELECTRIC RATES WITHIN THE SERVICE AREA OF COLORADO SPRINGS UTILITIES AND REGARDING CERTAIN CHANGES TO THE ELECTRIC RATE SCHEDULES

WHEREAS, Colorado Springs Utilities ("Utilities") has evaluated and found that existing rate schedules do not adequately address the resource adequacy, infrastructure requirements, risks, and costs of providing service to large industrial loads; and

WHEREAS, Utilities, proposed to freeze participation in the Industrial Service – Time-of-Day Transmission Voltage ("ETX") Rate Schedule; and

WHEREAS, Utilities proposed to implement the addition of Industrial Service – Large Load ("ELL") Rate Schedule applicable to industrial customers with loads greater than 10MW; and

WHEREAS, Utilities proposed revising the Contract Service – Military Wheeling ("ECW") Rate Schedule to shift transmission expense recovery from the Open Access Transmission Tariff ("OATT") to ECW non-fuel rates, reflecting costs for transmission wheeling service as Utilities will no longer maintain its independent OATT in conjunction with planned membership in joining the Southwest Power Pool Regional Transmission Organization; and

WHEREAS, Utilities proposed administrative changes removing the Fixed Seasonal Options ("ETR-F", "ECS-F") as exceptions to availability under the Community Solar Garden Program and updating the reference lettering order to reflect those exception removals; and

WHEREAS, Utilities proposed to make other clerical modifications; and

WHEREAS, Utilities proposed to make the Electric Rate Schedule and tariff changes effective January 1, 2026, and April 1, 2026.

WHEREAS, the details of the changes noted above are reflected in Utilities' 2026 Rate Case; and

WHEREAS, the City Council finds Utilities' proposed modifications prudent; and

WHEREAS, the City Council finds that the proposed modifications to the Electric Rate Schedules and tariffs are just, reasonable, sufficient and not unduly discriminatory and allow Utilities to collect revenues that enable Utilities to continue to operate in the best interest of all of its customers; and

WHEREAS, Utilities provided public notice of the proposed changes and has complied with the requirements of the City Code for changing its electric schedules; and

WHEREAS, specific rates, policy changes, and changes to any terms and conditions of service are set out in the attached tariffs for adoption with the final City Council Decision and Order in this case.

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

Section 1. That Colorado Springs Utilities Tariff, City Council Volume No. 6, Electric Rate Schedules shall be revised as follows:

Effective January 1, 2026

City Council Vol. No. 6		
Sheet No.	**Title**	**Cancels Sheet No.**
Sixth Revised Sheet No.1	TABLE OF CONTENTS	Fifth Revised Sheet No.1
Fourth Revised Sheet No. 2.17	RATE TABLE	Third Revised Sheet No. 2.17
Fourth Revised Sheet No. 2.18	RATE TABLE	Third Revised Sheet No. 2.18
Second Revised Sheet No. 2.19	RATE TABLE	First Revised Sheet No. 2.19
Second Revised Sheet No. 2.20	RATE TABLE	First Revised Sheet No. 2.20
Original Sheet No. 2.21	RATE TABLE	
Original Sheet No. 2.22	RATE TABLE	
Original Sheet No. 2.23	RATE TABLE	
Fourth Revised Sheet No. 3	GENERAL	Third Revised Sheet No. 3
Fourth Revised Sheet No. 3.1	GENERAL	Third Revised Sheet No. 3.1
First Revised Sheet No. 5.2	COMMERCIAL SERVICE – SMALL (ECS, ECS-P, ECS-F)	Original Sheet No. 5.2
Second Revised Sheet No. 9	INDUSTRIAL SERVICE – 4,000 kW MINIMUM (E8S, E8S-P)	First Revised Sheet 9
Third Revised Sheet No. 10	INDUSTRIAL SERVICE – LARGE POWER AND LIGHT (ELG, ELG-P)	Second Revised Sheet No. 10
First Revised Sheet No. 11	FROZEN INDUSTRIAL SERVICE – TIME-OF-DAY TRANSMISSION VOLTAGE (ETX)	Original Sheet No. 11
Second Revised Sheet No. 23	COMMUNITY SOLAR GARDEN PROGRAM	First Revised Sheet No. 23
Second Revised Sheet No. 26	INTERRUPTIBLE SERVICE	First Revised Sheet No. 26
Original Sheet No. 27	INDUSTRIAL SERVICE – LARGE LOAD (ELL)	
Original Sheet No. 27.1	INDUSTRIAL SERVICE – LARGE LOAD (ELL)	
Original Sheet No. 27.2	INDUSTRIAL SERVICE – LARGE LOAD (ELL)	
Original Sheet No. 27.3	INDUSTRIAL SERVICE – LARGE LOAD (ELL)	
Original Sheet No. 27.4	INDUSTRIAL SERVICE – LARGE LOAD (ELL)	

Effective April 1, 2026

City Council Vol. No. 6		
Sheet No.	**Title**	**Cancels Sheet No.**
Second Revised Sheet No. 2.13	RATE TABLE	First Revised Sheet No. 2.13
Second Revised Sheet No. 13	CONTRACT SERVICE – MILITARY WHEELING (ECW)	First Revised Sheet No. 13
First Revised Sheet No. 13.1	CONTRACT SERVICE – MILITARY WHEELING (ECW)	Original Sheet No. 13.1

Section 2. The attached sheets of the Colorado Springs Utilities Tariff, 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

Electric

Final Tariff Sheets

Effective January 1, 2026

ELECTRIC RATE SCHEDULES

TABLE OF CONTENTS

DESCRIPTION **SHEET NO.**

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates
Electric Cost Adjustment (ECA) – Sheet No. 16	
Fixed ECA, per kWh (E1R, ETR-F, E1C, ENM, ECS-F, E2C, ETLO, ETLW, ELG, E2T, E7SL, ELL)	$0.0263
Energy-Wise Standard Time-of-Day ECA (ETR, ECS, ETC, ECM, ECL, ETX, ETL, EIS, E8T, E8S, ETX, ECD)	
On-Peak, per kWh	$0.0464
Off-Peak, per kWh	$0.0232
Energy-Wise Plus Time-of-Day Option ECA (ETR-P, ECS-P, ECM-P, ECL-P, EIS-P, E8T-P, E8S-P, ELG-P, ECD-P)	
On-Peak, per kWh	$0.0564
Off-Peak, per kWh	$0.0225
Off-Peak Saver, per kWh	$0.0180
Green Power Service – Time-of-Day – Sheet No. 24	
The rate applicable to each kilowatt hour subscribed under this rate schedule	$0.0323

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates
Electric Capacity Charge (ECC) – Sheet No. 16	
Residential Service – (E1R, ETR, ETR-P, ETR-F), per kWh	$0.0066
Commercial Service – Small (E1C), per kWh	$0.0066
Commercial Service – Non-Metered (ENM), per kWh	$0.0066
Commercial Service – Small (ECS, ECS-P, ECS-F), per kWh	$0.0066
Commercial Service – General (E2C, ETC), per kWh	$0.0056
Commercial Service – Medium 10 kW Minimum (ECM, ECM-P), per kWh	$0.0056
Commercial Service – Large 50 kW Minimum (ECL, ECL-P), per kWh	$0.0056
Industrial Service – 1,000 kWh/Day Min (ETL, ETLO, ETLW), per kWh	$0.0048
Industrial Service – 100 kW Minimum (EIS, EIS-P), per kWh	$0.0048
Industrial Service – 500 kW Minimum (E8T, E8T-P), per kWh	$0.0045
Industrial Service – 4,000 kW Minimum (E8S, E8S-P), per kWh	$0.0053
Industrial Service – Large Power and Light (ELG, ELG-P), per kWh	$0.0036
Industrial Service – Transmission Voltage (ETX), per kWh	$0.0034
Contract Service – Military (ECD, ECD-P), per kWh	$0.0046
Contract Service – Traffic Signals (E2T), per kWh	$0.0032
Contract Service – Street Lighting (E7SL), per kWh	$0.0032
Industrial Service – Large Load (ELL)	$0.0036

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Totalization Service – Sheet No. 18					
For each meter totalized, per meter, per day	$8.0000				
Enhanced Power Service – Sheet No. 19					
Reserved Capacity Charge:					
The greater of On-Peak or Off-Peak Billing Demand or projected peak demand, per kW, per day	$0.0333	$0.0355	$0.0378	$0.0403	$0.0429
Operations & Maintenance Charge:					
See *Line Extension and Service Standards* for Electric for calculation.					

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES
RATE TABLE

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ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Small Power Producers and Cogeneration Service – Sheet No. 21					
On-Peak, per kWh	$0.0195				
Off-Peak, per kWh	$0.0180				
Community Solar Garden Bill Credit (Pilot Program) – Sheet No. 22					
The rate applicable to each kilowatt hour under the Bill Credit section of this rate schedule	$0.1080	$0.1150	$0.1225	$0.1305	$0.1390
Community Solar Garden Program – Sheet No. 23					
Customer Rate Class – Credit, per kWh					
Residential Service (E1R, ETR, ETR-F)	$0.0654	$0.0697	$0.0742	$0.0790	$0.0841
Commercial Service – Small (E1C)	$0.0585	$0.0623	$0.0663	$0.0706	$0.0752
Commercial Service – Small (ECS, ECS-F)	$0.0591	$0.0629	$0.0670	$0.0714	$0.0760
Commercial Service – General (E2C)	$0.0586	$0.0624	$0.0665	$0.0708	$0.0754
Commercial Service – General Time-of-Day Option (ETC)	$0.0586	$0.0624	$0.0665	$0.0708	$0.0754
Commercial Service – Medium 10 kW Minimum (ECM)	$0.0585	$0.0623	$0.0663	$0.0706	$0.0752
Commercial Service – Large 50 kW Minimum (ECL)	$0.0564	$0.0601	$0.0640	$0.0682	$0.0726
Industrial Service – 1,000 kWh/Day Minimum (ETL)	$0.0541	$0.0576	$0.0613	$0.0653	$0.0695
Industrial Service – 100 kW Minimum (EIS)	$0.0549	$0.0585	$0.0623	$0.0663	$0.0706
Industrial Service – 500 kW Minimum (E8T)	$0.0514	$0.0547	$0.0583	$0.0621	$0.0661
Industrial Service – 4,000 kW Minimum (E8S)	$0.0507	$0.0540	$0.0575	$0.0612	$0.0652
Industrial Service – Large Power and Light (ELG)	$0.0443	$0.0472	$0.0503	$0.0536	$0.0571
Industrial Service – Time-of-Day Transmission Voltage (ETX)	$0.0578	$0.0616	$0.0656	$0.0699	$0.0744
Contract Service – Military (ECD)	$0.0517	$0.0551	$0.0587	$0.0625	$0.0666

Approval Date: October 28, 2025
Effective Date: January 1, 2026
Resolution No.

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Electric Vehicle Public Charging Service – Time-of-Day – Sheet No. 25					
Level 2					
On-Peak, per kWh	$0.3600	$0.3800	$0.4000	$0.4300	$0.4600
Off-Peak, per kWh	$0.1300	$0.1400	$0.1500	$0.1600	$0.1700
Idle Rate, per minute	$0.1100	$0.1200	$0.1300	$0.1400	$0.1500
Idle rate is applicable beginning 15 minutes after charge is complete.					
Direct Current Fast Charger (DCFC)					
On-Peak, per kWh	$0.5800	$0.6200	$0.6600	$0.7000	$0.7500
Off-Peak, per kWh	$0.2000	$0.2100	$0.2200	$0.2300	$0.2400
Idle Rate, per minute	$0.3200	$0.3400	$0.3600	$0.3800	$0.4000
Idle rate is applicable beginning 15 minutes after charge is complete.					
Interruptible Service – Sheet No. 26					
Demand Credit, per kW, per day	$0.1233				
Energy Credit, per kWh	$0.4500				

Note: 2025 rates are effective October 1, 2025. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)			
	2026	2027	2028	2029
Industrial Service – Large Load (ELL) – Sheet No. 27				
Access and Facilities Charge, per day	$8.9065	$9.9664	$11.1524	$12.4795
Demand Charge Secondary, per kW, per day	$0.8593	$0.9616	$1.0760	$1.2040
System Support Charge, per kW, per day	$0.0859	$0.0962	$0.1076	$0.1204
Resource Adequacy Charge, per kW, per day	$0.4110	$0.4377	$0.4662	$0.4965
Purchased Energy Charge, per kWh	By Contract			
Purchased Capacity Charge, per kW, per day	By Contract			
Electric Cost Adjustment (ECA), per kWh	Sheet No. 2.17			
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18			

Note: All rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES

GENERAL

DEMAND DETERMINATIONS

Commercial Service (ECM, ECM-P, ECL, ECL-P)

Maximum Demand and/or Billing Demand:

Greatest 15-minute load during any block of time in the billing period.

Industrial and Contract Service

Maximum Demand (ETL, EIS, EIS-P, E8T, E8T-P, E8S, E8S-P, ELG, ELG-P, ETX, ECD, ECD-P, ELL)

Maximum Demand is the greatest 15-minute load during any time in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Billing Demand

Energy-Wise Standard Time-of-Day Option (ETL, EIS, E8T, E8S, ELG, ETX, ECD)

On-Peak:

The greatest 15-minute load during On-Peak hours in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Off-Peak: either A or B, whichever is greater.

A. The greatest 15-minute load during Off-Peak hours in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading, minus the
On-Peak Billing Demand. Such demand will not be less than zero.

B. 68% of the Maximum Demand during the last 12 billing periods, minus the On-Peak Billing Demand. Such demand will not be less than zero. Part B of Off-Peak Billing Demand is not applicable to Industrial Service – Transmission Voltage (ETX).

Energy-Wise Plus Time-of-Day Peak Option (EIS-P, E8T-P, E8S-P, ELG-P, ECD-P)

Demand:

The greatest 15-minute load during any time in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading.

Industrial Service – Large Load (ELL) see Sheet No. 27.1

Approval Date: October 28, 2025
Effective Date: January 1, 2026
Resolution No.

TRANSMISSION AND PRIMARY SERVICE DEMAND CHARGE CREDIT

Transmission Service Demand Charge Credit

A Transmission Service Demand Charge Credit of $0.2738 per kW, per day will be applied to the Demand Charge Secondary for Customers receiving electric transmission service under the Industrial Service – Large Load (ELL) Rate Schedule. The credit is not applicable to all other kW, per day charges.

Primary Service Demand Charge Credit

A Primary Service Demand Charge Credit of $0.0118 per kW, per day will be applied to all applicable Demand Charges for Customers receiving electric primary service.

RATE OPTIONS

Residential and Commercial Service – Small (ETR-F, ETR-P, ECS-F, ECS-P)

Rate options will be for a minimum twelve (12) consecutive billing periods.

All Other Rate Schedules

Customers may elect a rate option as more fully set forth on subsequent Electric Rate Schedules subject to any applicable separate eligibility and contract requirements as noted. Unless otherwise noted, the initial contract period is from the rate option service start date to December 31st. Unless otherwise stated and as long as the Customer continues to meet the eligibility requirements, the rate option service contract shall be automatically renewed for an additional 12-month contract period each January 1st unless Customer provides advance written notice to Utilities not less than 30 days prior to the January 1st renewal date that Customer elects not to renew for the upcoming rate option contract year. Customers will be evaluated periodically to ensure they continue to meet the specified rate option eligibility requirements. In the event that a Customer is no longer eligible, the contract for rate option service shall not be renewed and shall automatically terminate at the end of the 12-month contract period on December 31st. Upon termination, Customer shall be required to move to the rate schedule to which they are eligible upon the end of the contract period.

TIME-OF-DAY PERIODS

On-Peak Periods are Monday through Friday excluding the holidays as defined below. Unless otherwise provided On-Peak periods are as follows:

On-Peak Periods (excluding ETC, ETL)

January through December: 5:00 p.m. to 9:00 p.m.

Frozen Time-of-Day Service On-Peak Periods (ETC, ETL)

Winter (October through March): 4:00 p.m. to 10:00 p.m.
Summer (April through September): 11:00 a.m. to 6:00 p.m.

ELECTRIC RATE SCHEDULES
COMMERCIAL SERVICE – SMALL (ECS, ECS-P, ECS-F)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for any establishment engaged in the operation of a business or an institution, whether or not for profit, whose Maximum Demand is less than 10 kW in each of the last 12 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (ECS)
Service under this option is not available to Customers who receive service under the Renewable Energy Net Metering Rate Schedule.

B. Energy-Wise Plus Time-of-Day Option (ECS-P)
Service under this option is not available to Customers who: (a) receive service under the Renewable Energy Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

C. Fixed Seasonal Option (ECS-F)
Service under this option is not available to customers receiving service under the Renewable Energy Net Metering Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES
INDUSTRIAL SERVICE – 4,000 kW MINIMUM (E8S, E8S-P)

AVAILABILITY

As provided in the Energy-Wise, Energy-Wise Plus, and Fixed Seasonal Transition Terms and Conditions of these Electric Rate Schedules, service under this rate schedule is available in Utilities' electric service territory for Customers whose Maximum Demand equals or exceeds 4,000 kW in any of the last 12 billing periods. Service is not available under this rate schedule for any Customer whose Maximum Demand equals or exceeds 10,000 kW in any of the last 12 billing periods or whose Maximum Demand is reasonably expected to equal or exceed 10,000 kW in any billing period in the next 120 billing periods.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Time-of-Day Option (E8S)

B. Energy-Wise Plus Time-of-Day Option (E8S-P)
   Service under this option is not available to Customers who: (a) receive service under the Renewable Energy Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

INDUSTRIAL SERVICE – LARGE POWER AND LIGHT (ELG, ELG-P)

AVAILABILITY

Available by contract in Utilities' electric service territory for the Customers whose aggregated Maximum Demand equals or exceeds 4,000 kW in any of the last 12 billing periods. Service is not available under this rate schedule for any Customer whose Maximum Demand equals or exceeds 10,000 kW in any of the last 12 billing periods or whose Maximum Demand is reasonably expected to equal or exceed 10,000 kW in any billing period in the next 120 billing periods. Demand aggregation may only be performed for contiguous service properties on a Customer campus setting. Customers must maintain an annual load factor of 75% or greater.

Annual load factor is derived by multiplying the annual kWh in the period by 100 and dividing by the product of the maximum real demand (prior to power factor correction) in kW and the number of hours in the period. Annual reviews will be conducted by Utilities at the end of the Customer's annual contract period. Annual kWh will be adjusted for Customers receiving service under the Interruptible Service Rate Schedule.

Customers who select this service will be required to provide a suitable location for the aggregation equipment. Totalization charges do not apply to this offering.

RATE OPTIONS

Customers may choose between the following:

A. Energy-Wise Standard Option (ELG)

B. Energy-Wise Plus Time-of-Day Option (ELG-P)
Service under this option is not available to Customers who: (a) receive service under the Renewable Energy Net Metering Rate Schedule; (b) receive service under the Community Solar Garden Bill Credit (Pilot Program) Rate Schedule, or (c) receive service under the Community Solar Garden Program Rate Schedule.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

FROZEN INDUSTRIAL SERVICE – TIME-OF-DAY TRANSMISSION VOLTAGE (ETX)

AVAILABILITY

Available in Utilities' electric service territory for any Customer who has provided, installed, and maintains transformer(s) to receive three-phase, 60-hertz, alternating current electrical service at a nominal potential of 115,000 or 230,000 volts on the Customer's Premise. The Customer may be required to execute a contract with additional terms and conditions should service to the Customer under this rate schedule require any material change to Utilities' plant in service or operations. Unless Utilities determines temporarily establishing service under this rate schedule is in the best interest of Utilities, service under this rate schedule is frozen to new participation.

The Customer will provide, install, and maintain necessary switches, cutouts, protection equipment and the necessary wiring on the primary and secondary sides of the transformer(s). All equipment required to receive service that is installed and maintained by the Customer will be subject to approval by Utilities prior to installation and inspection or testing thereafter.

RATE

See Rate Table for applicable charges.

ELECTRIC RATE SCHEDULES

COMMUNITY SOLAR GARDEN PROGRAM

AVAILABILITY

The Community Solar Garden Program (Program) is available under the terms and conditions of this rate schedule to all Customers taking service under Utilities' Electric Rate Schedules with the following exceptions: (a) Energy-Wise Plus Time-of-Day Peak Options (ETR-P, ECS-P, ECM-P, ECL-P, EIS-P, E8T-P, E8S-P, ELG-P, ECD-P), (b) Commercial Service – Non-Metered (ENM), (c) Contract Service – Military Wheeling (ECW), (d) Contract Service – Traffic Signals (E2T), (e) Contract Service – Street Lighting (E7SL), (f) Electric Cost Adjustment (ECA), (g) Electric Capacity Charge (ECC), (h) Totalization Service, (i) Enhanced Power Service, (j) Renewable Energy Net Metering, (k) Small Power Producers & Cogeneration Service, and (l) Community Solar Garden Bill Credit (Pilot Program). All Customers that participate under this rate schedule must hold evidence of ownership to, a subscription as evidence of beneficial use of, or an entitlement to the electric generating capacity of a Community Solar Garden Facility (Customer Solar Garden Interest). Customers may choose any Community Solar Garden Facility that conforms to this rate schedule.

The choice of a Community Solar Garden Facility and the purchase of a Customer Solar Garden Interest is solely the responsibility of the Customer and are undertaken at the Customer's risk. Utilities makes no representations or warranties concerning the Community Solar Garden Facility and its operation and maintenance and its financial viability or the continued usefulness of any Customer Solar Garden Interest.

COMMUNITY SOLAR GARDEN FACILITY

A Community Solar Garden Facility for purposes of this rate schedule is a photovoltaic electric generating installation having a nameplate rating of not less than 0.5 megawatts Alternating Current (MWAC) and not more than 2.0 MWAC in electric generating capacity and the owning entity that has executed an Interconnection Agreement with Utilities. If the Interconnection Agreement is extended, Utilities will retain the Renewable Energy Credits through the extension period at no additional cost. The physical location of any Community Solar Garden Facility under this rate schedule shall be within the electric service territory of Utilities and any electric power produced by the Community Solar Garden Facility shall be consumed within the electric service territory of Utilities. All costs of interconnection for the Community Solar Garden Facility shall be borne and paid by the legal owner of the Community Solar Garden Facility.

This Program will allow for up to 2.0 MWAC of electric generating capacity to be added to Utilities' portfolio of Distributed Generation resources.

ELECTRIC RATE SCHEDULES

INTERRUPTIBLE SERVICE

AVAILABILITY

Available by contract in Utilities' electric service territory for Customers whose Maximum Demand equals or exceeds 4,000 kW in any of the last 12 billing periods. Service under this rate schedule is subordinate to all other services and is conditioned upon availability of Utilities' capacity, resources, and assets without detriment or disadvantage to existing Customers.

INTERRUPTION

Customers receiving service under this rate schedule agree to allow Utilities to completely interrupt electric service at the Customer's facility. Utilities may completely interrupt electric service for any reason and without notice up to 100 hours per year. As specified by contract, Customers may agree to be subject to additional hours of interruption in excess of 100 hours per year.

Notwithstanding any provision to the contrary herein, Utilities may fully or partially reduce applicable service when, in the Utilities option, reduction or interruption is necessary to protect the delivery of applicable service to Customers with higher priority uses, or to protect the integrity of its system. Interruption of service related to the following noneconomic reasons will not count towards the total number of interruption hours including emergency repairs, incidents, occurrences, accidents, strikes, force majeure or other circumstances beyond Utilities' control.

Customers are required to provide 24 hours advance notice to Utilities when changes in load of 5 MW or greater are expected.

CREDIT DETERMINATIONS

For Customers receiving service under Industrial Service – Time-of-Day rate schedules, the Interruptible Service Demand Credit will be based on the On-Peak Billing Demand for the billing period. For Customers receiving service under the Industrial Service – Large Power and Light (ELG) or the Industrial Service – Large Load (ELL) Rate Schedules, the Interruptible Service Demand Credit will be based on the higher of the Maximum Demand of the billing period or 68% of the Maximum Demand during the last 12 billing periods.

Interruptible Service Energy Credits will be based on the Customers' 15-minute kW demand preceding the interruption event, minus the Customers' average of 5-minute kW demands recorded during the interruption, multiplied by the duration of the interruption event measured in hours.

ELECTRIC RATE SCHEDULES

INDUSTRIAL SERVICE – LARGE LOAD (ELL)

AVAILABILITY

Available by contract in Utilities' electric service territory for any Customer whose Maximum Demand equals or exceeds 10,000 kW in any of the last 12 billing periods, or whose Maximum Demand is reasonably expected to equal or exceed 10,000 kW in any billing period in the next 120 billing periods. If aggregation of loads is permitted by Utilities pursuant to the terms provided in this rate schedule, the Maximum Demand used for the purpose of determining availability under this rate schedule will be based on the aggregated Maximum Demand. Customers with common owner(s) or parent companies operating within a contiguous site will have loads aggregated for determining the Maximum Demand for the purposes of determining availability under this rate schedule.

SERVICE CONSIDERATIONS

A. Customers must submit a completed signed Large Load Service Agreement (LLSA) and pay all applicable fees and charges in order to qualify for service under this rate schedule. The LLSA shall specify provisions of service including the following but not limited to: annual load and energy requirements, load characteristics, construction related terms, operating procedures, the date of service availability, and administrative terms and conditions. The initial term of the LLSA will be established in the agreement but not be less than 10 years. Customers meeting the collateral waiver requirements as provided in this Rate Schedule are deemed to have completed the initial LLSA term.

B. Upon Utilities joining a Regional Transmission Organization (RTO), service under this rate schedule will be contingent upon and subject to the RTO's tariff provisions, and the Customer will be responsible for any cost incurred related to studies, interconnection, and service of the Customer's load.

C. Availability and terms of service are subject to Utilities and any applicable RTO study results and requirements. Interim service may be contingent upon the Customer being subject to interruption or curtailment under any applicable Utilities and/or RTO tariffs.

D. If extension or modification of Utilities' transmission system is required to provide service, the Customer shall be responsible for the cost of required extensions or modifications as set forth in Utilities' Rules and Regulations.

E. Customers must provide, install, and maintain transformer(s) to receive three-phase, 60-hertz, alternating current electrical service at nominal potential of 115,000 or 230,000 volts on the Customer Premise. Alternatively, where Utilities determines serving Customers through Utilities' substation facilities is in the best interest, Customers shall pay the applicable Substation Facility Fees as set forth in Utilities' Rules and Regulations. Customers paying the Substation Facility Fees must provide, install, and maintain equipment to receive Primary or Secondary Service as provided in Utilities' Rules and Regulations and in accordance with the *Line Extension and Service Standards* for Electric.

F. Service will generally be provided through one meter unless Utilities, in its sole discretion, determines additional meters and aggregation is warranted. The aggregation terms and conditions set forth in the Industrial Service – Large Power and Light (ELG) Rate Schedule will apply.

G. If in Utilities determination, the Customers load cannot be served by Utilities existing capabilities, the Customer will be served on an interim basis through market agreement(s) for capacity and energy requirements for a period of time not to exceed the 10-year term of the initial LLSA. In lieu of ECA or Green Power Service if selected, and ECC charges, Utilities will bill the Customer the full costs of the market agreement(s) through charges as set forth in the LLSA and these Electric Rate Schedules.

H. Except for Customers whose collateral requirements have been waived pursuant to the terms provided in this rate schedule below, Customers will be subject to the Resource Adequacy Charge and the System Support Charge, as set forth in these Electric Rate Schedules, for each billing period in the initial 10-year term of the LLSA.

I. If at any time the Customer's actual maximum demand exceeds the contracted annual load requirements, the Customer shall provide an updated annual load requirement and the LLSA shall be updated to reflect the higher demand.

J. Utilities has no obligation to serve loads in excess of the contracted demand for the calendar year as provided in the LLSA.

DEMAND AND ENERGY DETERMINATIONS

A. During the initial 10-year LLSA period, Billing Demand will be the highest of (1) the greatest 15-minute load in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading, (2) 100% of the Maximum Demand occurring during the last 12 billing periods, or (3) 100% of the contracted demand for the calendar year as provided in the LLSA.

B. After the initial 10-year LLSA period, Billing Demand will be the highest of the greatest 15-minute load in the billing period adjusted upward by 1% for each 1% that the power factor of Customer is below 95% lagging or leading, or 68% of the Maximum Demand occurring during the last 12 billing periods.

C. During the initial 10-year LLSA period, Billing Energy will be the higher of metered energy for the billing period, or contracted monthly energy as set forth in market agreement and the LLSA.

D. After the initial 10-year LLSA period, Billing Energy will be equal to the metered energy for the billing period.

MINIMUM MONTHLY BILL

The Minimum Monthly Bill will be the sum of applicable Access and Facilities, Demand, Generation Capacity Charge, System Support Charge, market agreement charges, ECA, ECC, and all other applicable charges calculated using the Billing Demand, Billing Energy, and other applicable billing determinates as defined in these Electric Rate Schedules, Utilities' Rules and Regulations, and the LLSA.

COLLATERAL REQUIREMENT DETERMINATION

A. The collateral requirement under this rate schedule is in place of the Electric portion of deposits for starting service under Utilities' Rules and Regulations. Deposits relating to starting service for Natural Gas, Water, and Wastewater services provided by Utilities shall apply as provided in Utilities' Rules and Regulations and Utilities' Tariffs.

B. The collateral requirement is equal to the highest 36 months of estimated Minimum Monthly Bills occurring during the LLSA term. Estimation of the highest 36 monthly bills will be calculated using the demand and energy requirements as provided in the LLSA.

C. If during the LLSA term the annual load or energy requirements increase from those provided in the initial agreement, additional collateral will be required such that the total collateral requirement equals the highest 36 months of estimated bills for the service contract based on the updated annual load and energy requirements.

D. The Customer must provide the collateral requirement in one or more of the following forms:
   1. Cash for the full collateral requirement. Interest will not be accrued on cash collateral; or

   2. A standby irrevocable Letter of Credit (LOC) for the full collateral requirement. The LOC must be issued by a U.S. bank or the U.S. branch of a foreign bank, which is not affiliated with the

Customer, with a credit rating of at least A- from Standard & Poor's (S&P) and A3 from Moody's, as well as a minimum capitalization of at least $250 million. Such security must be issued for a minimum term of 360 days. The Customer must cause the renewal or extension of the security for additional consecutive terms of 360 days or more no later than 30 days prior to each expiration date of the security through the entire service contract term and provide Utilities written notice of such renewal. If the security is not renewed or extended as required herein, Utilities will have the right to draw immediately upon the LOC and be entitled to hold the amounts so drawn as security. The LOC must be in a format acceptable to and approved by Utilities.

E. Utilities may waive collateral requirements for Customers who have maintained service under an Industrial Service Rate Schedule for the preceding 120 billing periods, and each of the following conditions apply:

1. The Customer has not had any delinquency within the preceding 120 billing periods; and

2. The Customer's maximum rolling 12-month load to rolling 12-month average load ratio has not exceeded 1.20 in any month in the preceding 120 billing periods; and

3. The Customer's load is not expected to increase by more than 5 MW within the next 120 billing periods; and

4. In the event of merger, acquisition, or legal transfer of interest or other event causing a change in the Customer name and/or identification, the Customer demonstrates successorship in interest from the predecessor to the successor entity.

5. If circumstances related to Utilities' prior waiver of collateral requirements change and are no longer applicable, the collateral requirement will be immediately due.

TERMS AND CONDITIONS

A. During the term of the LLSA the Customer may terminate service by providing written notice to Utilities no less than 36 months prior to the requested service end date. The LLSA will automatically renew for an additional 36 months at the end of each LLSA term unless Customer provides advance written notice of termination no less than 36 months prior to expiration.

ELECTRIC RATE SCHEDULES
INDUSTRIAL SERVICE – LARGE LOAD (ELL)

B. Upon termination the Customer is responsible for paying a LLSA Termination Fee equal to the estimated Minimum Monthly Bills remaining in the LLSA term or the highest 36 months of estimated Minimum Monthly Bills occurring during the LLSA, whichever is greater.

C. 36 months prior to LLSA renewal, Utilities or the Customer may request modification of the load and energy requirement.

RATE

See Rate Table for applicable charges.

PAYMENT

Payment of billing statements is due and payable by the date indicated in the billing statement. If full payment of charges is not made on or prior to the due date, a late payment fee of 1.5% per month will be assessed on the overdue balance. Collateral requirements will be called when Utilities initiates Discontinuance of Service by Utilities for Failure to Pay When Due as provided in Utilities Rules and Regulations.

Electric

Final Tariff Sheets

Effective April 1, 2026

ELECTRIC RATE SCHEDULES

RATE TABLE

Description	Rates (Note)				
	2025	2026	2027	2028	2029
Summer (June – September), per kW, per day	$0.0366	$0.0390	$0.0415	$0.0442	$0.0471
Access and Facilities Charge:					
Winter (October – May) On-Peak, per kWh	$0.0407	$0.0433	$0.0461	$0.0491	$0.0523
Winter (October – May) Off-Peak, per kWh	$0.0276	$0.0294	$0.0313	$0.0333	$0.0355
Winter (October – May) Off-Peak Saver, per kWh	$0.0114	$0.0121	$0.0129	$0.0137	$0.0146
Summer (June – September) On-Peak, per kWh	$0.1293	$0.1377	$0.1467	$0.1562	$0.1664
Summer (June – September) Off-Peak, per kWh	$0.0276	$0.0294	$0.0313	$0.0333	$0.0355
Summer (June – September) Off-Peak Saver, per kWh	$0.0142	$0.0151	$0.0161	$0.0171	$0.0182
Critical Peak Period (During Event Hours), per kWh	$0.4578	$0.4876	$0.5193	$0.5531	$0.5891
Electric Cost Adjustment (ECA):					
On-Peak, per kWh	Sheet No. 2.17				
Off-Peak, per kWh	Sheet No. 2.17				
Off-Peak Saver, per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				
Optional Service (EHYDPWR, EINFPRS)					
See rate and charge detail in tariff					
Contract Service – Military Wheeling (ECW) – Sheet No. 13					
Required Services					
Wheeling Demand Charge, per kW, per day	$0.0806	$0.2009	$0.2140	$0.2279	$0.2427
Contract Service – Traffic Signals (E2T) – Sheet No. 14					
Access and Facilities Charge, per day	$0.5135	$0.5613	$0.6135	$0.6706	$0.7330
Access and Facilities Charge, per kWh	$0.0949	$0.1037	$0.1133	$0.1238	$0.1353
Electric Cost Adjustment (ECA), per kWh	Sheet No. 2.17				
Electric Capacity Charge (ECC), per kWh	Sheet No. 2.18				

Approval Date: October 28, 2025
Effective Date: April 1, 2026
Resolution No.

Note: 2025 rates are effective October 1, 2025. 2026 ECW rate is effective starting April 1, 2026. All other rates are effective January 1st of the respective year shown. Rates effective 2029 will remain effective until superseded by City Council.

ELECTRIC RATE SCHEDULES
CONTRACT SERVICE – MILITARY WHEELING (ECW)

AVAILABILITY

Available by contract in Utilities' electric service territory to the United States of America at the Peterson Space Force Base, the Cheyenne Mountain Space Force Station, the United States Air Force Academy and the Fort Carson Military Installation. Service under this rate schedule is not available to any other Customer or entity.

Service is offered at the request of Customer so that Customer may purchase an allocated portion of its power and energy requirements from the Western Area Power Administration (Western). Service is also offered at the request of Customer to allow the Fort Carson Military Installation (Fort Carson) to purchase a portion of its power and energy requirements from Utilities under Contract Service – Military (EHYDPWR) (Hydro Power tariff). These Customer purchases from Western or from Utilities will be under a long-term contract for firm capacity and associated energy. Utilities will wheel (transport), subject to available capacity, such energy over Utilities' transmission and distribution systems to Customer's facility. Electric requirements of the Customer in excess of its allocation from Western or in excess of its purchases under the Hydro Power tariff will be supplied by Utilities as supplemental power and energy.

APPLICABILITY

Service under this rate schedule will be provided only if a contract for such service is in effect between Customer and Utilities. Services other than distribution wheeling provided to Customer by Utilities are limited to services set forth within this rate schedule and separately contracted for by Customer. Services provided by Utilities under this rate schedule are strictly limited to power and energy requirements of each Customer within its boundaries. Under no circumstances will Customer resell any power and/or energy provided under this rate schedule, or use in any way such power or energy outside the confines of Customer's facility.

REQUIRED SERVICES

Customer must contract for the following services:

A. Wheeling

B. Supplemental Power and Energy

ELECTRIC RATE SCHEDULES

CONTRACT SERVICE – MILITARY WHEELING (ECW)

Wheeling

Wheeling is defined as the transporting of power and energy over Utilities' transmission and distribution system for redelivery of Customer's allocated portion of its power and energy from Western or for Customer's purchase of power and energy from Utilities under the Hydro Power tariff. This rate schedule pertains to wheeling over Utilities' transmission and distribution system. Customer must furnish to Utilities copies of contracts and/or agreements between Customer and Western, and between Customer and any intermediate wheeling source. Utilities will maintain copies of Customer's purchases under the Hydro Power tariff. Wheeling availability is always subject to capacity constraints of Utilities' transmission and distribution system and any intermediate wheeling parties' transmission limitations. When Utilities identifies a transmission capacity constraint, Utilities agrees to provide notice to the Customer and to work with the Customer in developing an alternative transmission arrangement.

This service is contingent upon the availability of a transmission and distribution wheeling path from the point of interconnection to Customer's facility. Wheeling will be provided if and when capacity is available above the needs of Utilities' firm Customers.

This service is available to Customer for power and energy purchased from Western and delivered to Utilities' points of interconnection pursuant to a contract between Customer and Utilities. This service is also available to Customer for power and energy purchases from Utilities under the Hydro Power tariff and delivered to Customer. Absent physical or safety constraints, Utilities will redeliver all of Customer's power and energy scheduled and delivered from Western (or purchased by Customer from Utilities under the Hydro Power tariff) to Utilities' points of interconnection with Customer. Utilities shall not be liable for failing to deliver power to Customer either because of interruption of scheduled deliveries from Western (or interruption of deliveries under the Hydro Power tariff) or malfunctions within Utilities' transmission and distribution system or interruptions of wheeling service by intermediate wheeling parties.

BEFORE THE CITY COUNCIL OF
THE CITY OF COLORADO SPRINGS

IN THE MATTER OF THE REVISION	)	
OF THE ELECTRIC TARIFF OF	)	DECISION & ORDER 25-02 (E)
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"), provides electric utility service within the City and within its Colorado Public Utilities Commission-certificated service territory outside of the City.

2. Utilities submitted the 2026 Rate Case, which proposes changes to the Electric Rate Schedules, Utilities Rules and Regulations ("URR"), the Open Access Transmission Tariff ("OATT"), completion of a Public Utility Regulatory Policy Act ("PURPA") evaluation, and proposes a Transmission Owner 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 Transmission Owner Formula Rate Tables with full details.

3. Utilities engages in the production, purchase, and distribution of electricity. These activities incur fuel related (production and purchases) and non-fuel related (production and distribution) expenditures. Fuel related expenditures are currently recovered through the Electric Cost Adjustment ("ECA") and Electric Capacity Charge ("ECC"). Non-fuel related expenditures are recovered through Access and Facilities Charges and Demand Charges. Utilities' filing proposes changes to the Electric Rate Schedules. Utilities' filing does not include any changes to the Electric base rates.

4. Utilities proposed Electric Rate Schedules changes and actions as follows:

    a) **Industrial Service – Large Load Tariff** –

        i. Electric demands from prospective large load customers present significant challenges for Utilities' infrastructure, resources, planning, and financial position. Utilities proposes the addition of a new large load rate schedule applicable to industrial customers with loads greater than 10 MW to advance and balance the principles of: (1) Supporting economic development and rate competitiveness; (2) Ensuring resource and infrastructure adequacy; (3) Minimize cost shifting to existing customers; (4) Mitigate stranded cost risk; and (5) Protect Utilities' financial health.

        ii. Utilities coordinated with an industry leading firm to survey and analyze electric utility trends in large load tariff and rate design development. Utilities' proposed rate schedule incorporates best practices including, but not limited to, the following considerations:

1. A minimum 10-year initial contract period;
2. Customer responsibility for the cost of infrastructure extension and/or modifications;
    a. Service subject to applicable studies, conditions, and resulting costs to Utilities and any Regional Transmission Organization
3. Interim service through purchase power agreements ("PPA") until resource adequacy is obtained;
    a. Bill components including: (a) Access and Facilities, per day; (b) Demand Charge; (c) System Support Charge; (d) Resource Adequacy Charge; (e) Pass through PPA charges; (f) ECA; (g) ECC; and (h) All other applicable charges
4. Minimum Monthly Bill based on all applicable bill components and the highest of:
    a. Billing period maximum demand and energy, or
    b. Contracted demand and energy requirements, or
    c. 100% of maximum 12-month demand and billing period energy
5. Collateral requirement of cash or letter of credit equal to 36-months of estimated Minimum Monthly Bills;
6. Automatic Customer contract renewal for additional 36-month periods, unless customer provides notice to request termination; and
7. Late payment fee of 1.5% per month will be assessed on overdue balances.

iii. For this proposed rate, Utilities proposed establishing the Access and Facilities, per day, and the Demand Charge, per kW, per day, equal to the Industrial Service – Large Power and Light (ELG) charges as supported by the 2025 Electric Cost of Service Study included in the 2025 Rate case approved by City Council on November 12, 2024.

iv. Utilities' ability to provide service to large loads may require interim service through PPAs. If PPAs are required for interim service, the full cost of PPA energy, capacity, and deliverability will be passed through to the Customer as specified by contract in lieu of ECA and ECC charges. When interim service through PPAs is no longer necessary, the ECA and ECC will be applicable.

v. When interim service through PPAs is required, Customers will be subject to the System Support Charge and the Resource Adequacy Charge for a period of ten (10) years. The proposed System Support Charge is designed to mitigate risk associated with serving large loads and to insulate existing customers from potential added costs. The System Support Charge is calculated at 10% of the Demand Charge, per kW, per day. The proposed Resource Adequacy Charge, per kW, per day, is based on preliminary projections of the Cost Of New Energy ("CONE") as part of Utilities' Electric Integrated Resource Plan currently in progress. The 10-year period of applicability for the System Support Charge and Resource Adequacy Charge provides a reasonable period of marginal cost recovery for Utilities to plan and acquire adequate resources to service the large load Customer while mitigating risk to existing customers.

b) **Renewable Energy Net Metering (Net Metering)** – Utilities' proposed changes to Net Metering were updated in Utilities' October 1, 2025, Supplemental Filing. The following includes Utilities' original proposal as modified by the Supplemental Filing.

   i. Utilities worked over the past few years to assess its resource portfolio with respect to energy regulations, customer growth, and system efficiency. Utilities sees customer growth and increased demand on its system and generation portfolio. To meet the increasing number of stringent state requirements and the needs of a growing community, Utilities initiated the development of an Electric rate design strategy in 2018.

   ii. Over the course of the last eight years, this strategy was developed with Utilities Board guidance and coordinated with Utilities' energy vision workshops, integrated resource planning efforts, and major metering and billing system project implementation. Utilities' draft proposal builds upon the Energy Wise rates strategy to improve alignment of customer demand with the cost of providing service.

   iii. Energy Wise rates better reflect Utilities' time-varying cost of providing service while offering both system and customer benefits. Energy Wise rates are expected to play a significant role in helping reduce high demand and delay the need to build additional sources of electric generation. With the Energy Wise rates, most customers will pay different rates for the electricity based on the time of day it is used. This approach more equitably recovers the cost to provide service, while also playing a significant role in incentivizing customers to shift electric use to periods when demand is lower and the cost of providing electricity is cheaper. These rates give customers more control over their bill since they can shift electricity use to less costly time periods. Shifting some electric use to non-peak hours also supports Utilities' sustainable energy transition. Recent investment in smart meters and customer information systems enable Utilities to make Energy Wise rate options available to most customers.

   iv. In 2024, Utilities proposed Energy Wise rate changes effective October 1, 2025. Utilities expects to transition all existing customers to Energy Wise rates by early 2026. Due to the unique interaction Net Metering customers have with Utilities' electric system, the Energy Wise rates available to most customers do not adequately reflect the cost of providing service to customers with solar behind the meter. As such, Net Metering customers were not included in the 2025 transition to the Energy Wise rates. Through 2024 and into 2025, Utilities continued its evaluation and analysis of the most appropriate and fair rate design for Net Metering customers.

v. In 2004, Colorado adopted renewable energy Net Metering standards through Colorado Revised Statues § 40-2-124. C.R.S. § 40-2-124 establishes Net Metering standards for municipal utilities, which include: (a) Treatment of excess monthly and annual generation in kWh; (b) Nondiscriminatory rate requirements; (c) Interconnection standards; and (d) Size specifications for Customer system.

vi. Utilities first established Net Metering service in 2005 as a pilot program with availability limited to 50 residential customers. In 2007, the limitation on the number of participating customers was removed and the service became available as a regular service option to residential and commercial customers. Since the service's inception, the number of Net Metering interconnections has steadily increased, with more than approximately 1,000 new interconnections per year in recent years and more than 9,000 total customers' electric service being Net Metered in 2025.

vii. The decrease in photovoltaic cost has also supported Utilities in integrating renewable energy resources to its energy portfolio, including the Pike Solar array which features 175 MW of solar energy. After adding Pike Solar to the existing solar, wind and hydroelectric power resources, renewable energy is estimated to represent about 27% of Utilities' energy portfolio.

viii. As defined in statute, energy generated by Customer solar systems under Net Metering service is netted against Customer consumption on a monthly billing period basis. Additionally, if monthly solar generation exceeds the Customer's monthly consumption, the excess generation credits are rolled forward to the subsequent months and offset future consumption. Netting Customer generation and Customer consumption on a monthly basis under-quantifies the amount of energy the Customer is consuming from Utilities' system and under-quantifies the amount of energy the Customer pushes onto Utilities' system.

ix. Specifically, for a typical Net Metering Customer, Customer consumption exceeds Customer generation during the early morning hours, resulting in consumption from the Utilities' system (imports). During the middle of the day, when solar generation is highest, Customer generation exceeds consumption and energy is pushed back onto Utilities' system (exports). As Customer consumption increases in the afternoon and into the evening and Customer generation decreases, Customer consumption once again exceeds

Customer generation resulting from additional consumption, or imports, from the Utilities' system.

x. Current rate designs applicable to residential and commercial Net Metering Customers recover capacity cost through energy charges, which compounds the cost shifting to non-Net Metering Customers. Although some level of intraclass cross subsidization is a reality with any rate design, for non-Net Metering Customers, recovery of capacity cost through energy charges can reasonably reflect the cost of providing service.

xi. Further analysis to quantify the Net Metering subsidy related to Utilities Net Metering customers was conducted using the cost-of-service approach. Based on the cost-of-service analysis, the median customer subsidy for a Utilities Net Metering customer is approximately $600 annually or $50 per month. This level of subsidy is consistent with results of similar studies across the United States, with subsidies ranging from $20 to $100 per month. All Net Metering customers are unique in terms of usage and system size, and therefore the $600 is not reflective of every customer. However, the median customer is representative of a typical Net Metering customer and can be used to estimate overall subsidy levels. Utilizing the $600 median subsidy, when attributed to over 9,000 Net Metering customers, the total cost shift from Net Metering customers to non-Net Metering customers is estimated to exceed $5,500,000 annually.

xii. To promote fair and equitable cost recovery and to align rates with the cost of providing service in the transformed electric landscape, Utilities proposes the addition of Renewable Energy Net Metering Rate Options applicable to residential and commercial Customer Net Metering Customers, effective January 1, 2027. The proposed rates are supported by the 2025 Electric Cost of Service Study included in the 2025 Rate case approved by City Council on November 12, 2024. The proposed rate options include:

1. Access and Facilities, per day charges based on costs classified and allocated as Customer cost in the Line – Secondary, Electric Service, Meters and Installations, and Customer functions;

2. Access and Facilities, per kWh charges based on costs classified and allocated as Energy cost in the Generation Non-Fuel, Transmission, and Surplus Payments to the City functions and a portion of costs classified and allocated as Demand cost in the Generation Non-Fuel, Transmission, Substation, Line – Primary, and Line – Secondary functions;

3. Demand Charge, per kW, per day charge based on a portion of costs classified and allocated as Demand cost in the Generation Non-Fuel, Transmission, Substation, Line – Primary, and Line – Secondary

functions. The demand determination for the proposed Demand Charge is the average of each daily greatest 15-minute net load during the On-Peak hours in the billing period;

4. ECA, per kWh; and

5. ECC, per kWh.

xiii. Utilities proposes to migrate all residential and commercial Net Metering Customers from Frozen Rate Options ("Frozen") to the new Renewable Energy Net Metering Rate Options effective January 1, 2027. Industrial and Contract Service Energy Wise Rate Options currently include appropriate demand charges. As a result, additional Net Metering options are not necessary for Industrial and Contract Service Net Metering Customers. Utilities proposes to migrate any Industrial Net Metering Customers receiving service under Frozen to the Energy Wise Standard Rate Options effective January 1, 2027.

xiv. The proposed Net Metering rate options are designed to be consistent with C.R.S. § 40-2-124. Utilities proposed rate options have a rational nexus to the cost of providing service to Net Metering Customers, meet the requirements of the State statute, and as a result are just, reasonable, and non-discriminatory.

c) **Contract Service – Military Wheeling (ECW) –**

i. The Department of Defense ("DoD") receives retail service for the majority of its loads under Utilities' Contract Service – Military (ECD) Rate Schedule. The Contract Service – Military Wheeling (ECW) Rate Schedule is available to the DoD for the purpose of wheeling hydroelectric power from the Western Area Power Administration ("WAPA") and the Southeastern Colorado Water Conservancy District over Utilities distribution system. The DoD load served under the ECW Rate Schedule represents less than 14% of the overall average DoD monthly load. Historically, the wheeling service over Utilities transmission system has been billed under Utilities' OATT rates and wheeling through Utilities' distribution system has been billed under the ECW rates.

ii. Utilities anticipates joining the SPP RTO and upon approved membership into the RTO, Utilities OATT will be withdrawn in its entirety and utilization of Utilities transmission system will be administered under the SPP RTO's OATT based on Utilities' Transmission Owner Filing materials to SPP.

iii. As a retail Customer of Utilities, the DoD expressed interest in maintaining Utilities' billing treatment for loads served by WAPA energy rather than being considered a transmission Customer under SPP's OATT. In support of DoD's position, Utilities anticipates successfully demonstrating to interested parties including, but not limited to, DoD, WAPA, and SPP, that DoD's WAPA energy becomes part of Utilities network load to self under SPP's OATT, and as such is appropriately billed to the DoD under Utilities' proposed ECW rate as described below. Furthermore, if additional transfer of ownership or other administrative action is necessary to demonstrate the appropriateness of retail treatment, Utilities will participate in discussions to develop mutual agreements or transfers to facilitate appropriate treatment under Utilities' Rate Schedules.

iv. To appropriately recover cost of providing wheeling service over both Utilities' transmission and distribution systems, Utilities proposes to modify the ECW rate to include transmission and distribution allocations as supported by the 2025 Electric Cost of Service Study included in the 2025 Rate case approved by City Council on November 12, 2024. The proposed rates result in billing treatment approximately equal to current charges under the current ECW and Utilities' OATT, but consolidate the charges into a single rate component under the ECW Rate Schedule.

d) **Other Rate Schedule Clerical Changes or Corrections** – Utilities proposed several clerical changes to the Electric Rate Schedules to add clarity and/or make administrative corrections. The full detail of proposed changes is found in Utilities' proposed resolution and tariff sheets.

5. In addition to the proposed Electric Rate Schedules revisions, Utilities' 2026 Rate Case filing also proposes changes to the OATT and the URR, completion of a PURPA evaluation, and the Transmission Owner filing.

6. The proposed effective dates for Utilities' tariff changes are November 1, 2025, January 1, 2026, April 1, 2026, and January 1, 2027.

7. 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.

8. 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.

9. 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.

10. 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.

11. 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.

12. City Council President Lynette Crow-Iverson commenced the rate hearing.

13. 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.

14. 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).

15. 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.

16. 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.

17. 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.

18. 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.

19. 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.

20. Mr. Scott Shirola, Utilities' Pricing and Rates Manager, provided the enterprise's proposals.

21. 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.

22. 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.

23. 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.

24. 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.

25. 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.

26. 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.

27. 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.

28. 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.

29. 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.

30. 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.

31. Next, Mr. Shirola presented Utilities' proposed changes to the URR.

32. 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.

33. 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.

34. 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.

35. 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.

36. 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.

37. 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.

38. 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.

39. 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.

40. 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.

41. 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.

42. 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.

43. 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.

44. 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.

45. 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.

46. 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.

47. 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.

48. 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.

49. 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.

50. City Council then took a five-minute recess.

51. 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.

52. Council Member Henjum noted that 50 MW is a substantial source of electric capacity.

53. 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.

54. 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.

55. 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.

56. 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.

57. 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.

58. 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.

59. 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.

60. 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.

61. 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.

62. Council Member Williams restated her position that the discussion should have started when far fewer customers were on the rate.

63. 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.

64. 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.

65. Council Member Leinweber commented that solar installers should change their approaches to take advantage of afternoon sun and evaluate battery options.

66. President Crow-Iverson stated that the lunch recess would be taken.

67. Upon return, Mr. Shirola reiterated the summary of Utilities' Net Metering customers' overall energy usage in relation to the energy produced.

68. 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.

69. 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.

70. 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.

71. 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.

72. Mr. Shirola noted that this type of cost shift or subsidy is comparable to many other utilities.

73. 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.

74. 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.

75. 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.

76. 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.

77. 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.

78. 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.

79. 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.

80. 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.

81. 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.

82. 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.

83. 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.

84. 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.

85. 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.

86. 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.

87. 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.

88. 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.

89. 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.

90. 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.

91. 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.

92. Council Member Rainey expressed his appreciation to Utilities for holding the open house based on his prior request to do so.

93. City Council next took a five-minute recess.

94. 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.

95. After Utilities' presentation, President Crow-Iverson opened the floor for public comment.

96. 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.

97. 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.

98. 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.

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

100. 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.

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

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

103. 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"?

104. 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?

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

106. 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.

107. 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.

108. 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.

109. 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.

110. 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.

111. 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.

112. 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.

113. 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.

114. 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.

115. 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.

116. 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.

117. 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.

118. 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.

119. 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.

120. 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.

121. 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.

122. 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.

123. Lastly, Mr. Gearhart expressed his position that the use of the word "subsidy" is appropriate in describing the cost shift seen between customers.

124. 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.

125. 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.

126. President Crow-Iverson determined that an executive session was not necessary.

127. 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.

128. Mr. Bidlack then polled City Council regarding the proposed changes to Net Metering.

129. 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.

130. 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.

131. 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.

132. 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.

133. 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.

134. 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.

135. The following are the proposed changes and the votes by City Council addressing the Electric Rate Schedules:

a) Should Utilities freeze participation in the Industrial Service – Time-of-Day Transmission Voltage (ETX) rate schedule?

   The City Council held that Utilities **shall** freeze participation in the Industrial Service – Time-of-Day Transmission Voltage (ETX) rate schedule.

b) Should Utilities implement the addition of Industrial Service – Large Load (ELL) rate schedule applicable to industrial customers with loads greater than 10 MW?

   The City Council held that Utilities **shall** implement the addition of Industrial Service – Large Load (ELL) rate schedule applicable to industrial customers with loads greater than 10 MW.

c) Should Utilities implement the Energy Wise Time-of-Day program to address changes related to energy regulations in the State of Colorado, sustainable energy transmission, Net Metering technology, and growth in the community as proposed?

   The City Council held that Utilities **shall not** implement the Energy Wise Time-of-Day program to address changes related to energy regulations in the State of Colorado, sustainable energy transmission, Net Metering technology, and growth in the community as proposed. Council President Crow-Iverson, Council President Pro Tem Brian Risley, and Council Members Donelson and Bailey supported the change. Council Members Leinweber, Williams, Rainey, Kimberly Gold, and Henjum opposed the change.

d) Should Utilities revise the Contract Service – Military Wheeling (ECW) rate schedule to shift transmission expense recovery from the Open Access Transmission Tariff (OATT) to ECW non-fuel rates, reflecting costs for transmission wheeling service as Utilities will no longer maintain its independent OATT in conjunction with planned membership in joining the Southwest Power Pool Regional Transmission Organization?

   The City Council held that Utilities **shall** revise the Contract Service – Military Wheeling (ECW) rate schedule to shift transmission expense recovery from the Open Access Transmission Tariff (OATT) to ECW non-fuel rates, reflecting costs for transmission wheeling service as Utilities will no longer maintain its independent OATT in conjunction with planned membership in joining the Southwest Power Pool Regional Transmission Organization.

e) Should Utilities make administrative changes removing the Fixed Seasonal Options (ETR-F, ECS-F) as exceptions to availability under the Community Solar Garden Program and updating the reference lettering order to reflect those exception removals?

   The City Council held that Utilities **shall** make administrative changes removing the Fixed Seasonal Options (ETR-F, ECS-F) as exceptions to availability under the Community Solar Garden Program and updating the reference lettering order to reflect those exception removals.

f) Should Utilities make clerical corrections as proposed?

   The City Council held that Utilities **shall** make clerical corrections as proposed.

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

ORDER

THEREFORE, IT IS HEREBY ORDERED that:

The Electric Tariff sheets as attached to the Resolution are adopted and will be effective on and after January 1, 2026, and April 1, 2026, as applicable. Such tariff sheets shall be published and held open for public review and shall remain effective until changed by subsequent Resolution duly adopted by the City Council.

Dated this 28th day of October, 2025.

CITY OF COLORADO SPRINGS

Council President

ATTEST:

City Clerk

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