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

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IN THE MATTER OF ADVICE NO. 1923-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8 – ELECTRIC TARIFF TO RESET THE GENERAL RATE SCHEDULE ADJUSTMENTS, TO PLACE INTO EFFECT REVISED BASE RATES, AND TO IMPLEMENT OTHER PHASE II TARIFF PROPOSALS TO BECOME EFFECTIVE JUNE 15, 2023	**)**	**PROCEEDING NO. 23AL-XXXXE**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF JEFFREY R. KNIGHTEN</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

May 15, 2023

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

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<u>DIRECT TESTIMONY AND ATTACHMENTS OF JEFFREY R. KNIGHTEN</u>

I. <u>INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeffrey R. Knighten. My business address is 1800 Larimer, Suite 1100, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Public Service Company of Colorado (“Public Service” or the “Company”) as a Pricing Consultant in the Rates & Regulatory Affairs department.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. I am responsible for the development of new rate design proposals or modifications to existing rates to ensure effective pricing structures, increased options for customers, and compliance with regulatory requirements. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my Direct Testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I am the Company's primary policy witness in this Phase II rate case, which is intended to revise the Company's base rates to recover the revenue requirement being established in Proceeding No. 22AL-0530E (the "2022 Phase I"). I provide a general overview of the Company's proposed cost allocation, class revenue distribution and rate design, and introduce the Company's Phase II witnesses. I also sponsor the Company's proposed class revenue distribution, rate structure and rate levels, and I present a revenue proof associated with the Company's recommended rates.

My Direct Testimony also presents a Time-of-Use ("TOU") rates study required by Decision No. C22-0398 in Proceeding No. 22AL-0143E (the "SG-TOU Proceeding"). In light of the continued deployment of Advanced Meters[1] to the Company's customers, I propose a change to the cost recovery of certain costs related to Integrated Volt-Var Optimization ("IVVO") associated with the Advanced Meter deployment. I also support the Company's request to defer expenses

[1] An "Advanced Meter" as the term is used in my Direct Testimony includes Advanced Metering Infrastructure ("AMI") and interval data meters. A customer opting out of AMI would receive an interval data meter.

associated with this proceeding for future cost recovery and sponsor revisions to the Company's Electric Tariff.[2]

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes. I am sponsoring the following attachments:

- Attachment JRK-1 – Proposed Revisions to Public Service's PUC No. 8 Electric Tariff (Redline);
- Attachment JRK-2 – Proposed Revisions to Public Service's PUC No. 8 Electric Tariff (Clean);
- Attachment JRK-3 – Time-of-Use Study;
- Attachment JRK-4 – Test Year Billing Determinants;
- Attachment JRK-5 – Lighting Rates;
- Attachment JRK-6 – Revenue Proof; and
- Attachment JRK-7 – Rate Case Expense Detail.

Q. ARE OTHER WITNESSES PROVIDING TESTIMONY ON BEHALF OF THE COMPANY IN THIS PROCEEDING?

A. Yes, two additional witnesses provide Direct Testimony in support of the Company's requests in this Phase II proceeding. Company witness Mr. Steven W. Wishart supports certain policy issues, including the use of the Probability of Dispatch – Peak Hours ("POD-PH") allocation methodology in the Company's class cost of service study ("CCOSS") and importance of demand charges in rate design. Mr. Wishart also provides an update to the marginal cost analysis used in calculation of the Company's Economic Development Rate ("EDR"), and he

[2] Colo. PUC No. 8 Electric Tariff ("Electric Tariff" or "Tariff").

provides an analysis of the Small Commercial demand threshold required by Decision No. C21-0536 (the “2020 Phase II Decision”) in Proceeding No. 20AL-0432E (the “2020 Phase II”). Finally, he calculates bill impacts of the Company’s proposals in this proceeding, including an affordability analysis consistent with his Supplement Direct Testimony in the 2022 Phase I.

Company witness Mr. Derek S. Klingeman presents and supports the CCOSS, which forms the basis of the Company’s proposed class revenue distribution and rate design.

II. PHASE II OVERVIEW, SUMMARY AND RECOMMENDATIONS

Q. WHAT ARE THE MAIN COMPONENTS OF A RATE CASE?

A. At the highest level, a rate case does two things: (1) establishes the utility's authorized revenue requirement based on the cost of providing service during a particular period (the test year); and (2) designs rates that yield that revenue requirement when applied to test year billing determinants. The portion focused on establishing the amount of revenues that the Company is authorized to recover through rates is referred to as a Phase I, while the cost allocation and rate design portion is referred to as a Phase II. The Phase I and Phase II portions of a rate case can be conducted as part of the same proceeding or in separate proceedings. This Phase II is being filed separately from the associated Phase I, which is ongoing in Proceeding No. 22AL-0530E.

Q. WHY IS THE COMPANY FILING THIS PHASE II WHILE THE PHASE I IS ONGOING IN A SEPARATE PROCEEDING?

A. The cadence of this filing, with the Phase II being filed before the conclusion of the Phase I, was approved by the Commission in Decision No. C22-0724.[3] The Company requested the ability to stagger the Phase I and Phase II portions of the rate case after working with stakeholders, including the parties to the Company's 2021 Electric Phase I Settlement.[4] The staggered approach was intended to

[3] Proceeding No. 21AL-0317E, Decision No. C22-0724 at p. 3, ¶ 10 (Mailed Date: November 15, 2022).

[4] Proceeding No. 21AL-0317E, Decision No. C22-0178 (Mailed Date: March 24, 2022) approved the Unopposed and Comprehensive Settlement Agreement (Except as to One Issue) (the "2021 Electric Phase I Settlement"). As part of that approval, the Commission required the Company to file a Phase II rate case no later than six months following the effective date of Decision No. C22-0178. Decision No. C22-0178 at p. 32, Ordering Paragraph 7. In Decision No. C22-0278, the Commission clarified the Company was obligated to file a Phase II rate case no later than six months following the effective date of

enable robust consideration of both Phase I and Phase II matters without compressing timelines within a single combined Phase I and Phase II rate case proceeding. This staggered approach allows the final rate design in a Phase II to follow shortly behind that incorporates the test year revenue requirement and billing determinants (ultimately from the final decision in the preceding Phase I rate case), permits stakeholders to better allocate resources to the Phase I and Phase II filings, and alleviates other resource constraints, while not significantly extending the period a General Rate Schedule Adjustment ("GRSA") remains in place following conclusion of the Phase I. The Commission approved the Company's request to make a staggered Phase II filing, with the filing required no later than May 15, 2023.[5]

Q. HAS THE COMPANY USED THIS APPROACH IN PRIOR RATE CASES?

A. Yes. The Company used a staggered Phase I / Phase II approach in its 2010/2011 natural gas rate cases,[6] including the filing of the Phase II based on the Company's Phase I Direct Testimony revenue requirement.

Q. HOW WILL THE STAGGERED FILING WORK IN THIS CASE?

A. The Commission directed "Public Service to work with the parties to its upcoming Phase I and Phase II rate cases to account for in the procedural schedules for both proceedings a supplemental filing in the Phase II rate case that would address the

its General Rate Schedule Adjustment True-Up. Proceeding No. 21AL-0317E, Decision No. C22-0278 at p. 6, ¶ 24 (Mailed Date: May 4, 2022). The General Rate Schedule Adjustment True-Up became effective July 1, 2022. *See* Amended Advice No. 1887 in Proceeding No. 22AL-0229E (Filed June 1, 2022). Therefore, the Company was required to file a new Phase II rate case on or before December 31, 2022. That obligation was modified in Decision No. C22-0724. Proceeding No. 21AL-0317E, Decision No. C22-0724 at p. 4, Ordering Point 2.

[5] Proceeding No. 21AL-0317E, Decision No. C22-0724 at p. 3, ¶10.

[6] Proceeding Nos. 10AL-963G (Phase I) and 11AL-151G (Phase II).

outcomes of the Phase I rate case."[7] Thus, the base rates approved in this case ultimately will be designed to recover the authorized 2022 Phase I revenue requirement. With the Phase I still pending, however, the Company's Direct Testimony in this Phase II reflects the Company's proposed Test Year revenue requirement and billing determinants from the Phase I Direct Testimony.[8] Based on the Phase I procedural schedule, a Commission final decision is expected on or before September 7, 2023. Once a final decision in the Phase I proceeding is reached and the base rate revenue requirement is determined, the Company will update the CCOSS and rate design to incorporate the approved Phase I revenue requirements and billing determinants, in accord with the procedural schedule to be determined herein.[9]

Q. IS THE COMPANY PROPOSING ANY MAJOR STRUCTURAL CHANGES TO ITS PRINCIPAL BASE RATE SCHEDULES?

A. No. Except for modifying the Schedule SG demand charge to be time-differentiated, the Company is not proposing any major structural changes to its principal base rate schedules (*i.e.*, Schedules RE-TOU, R, R-OO, C-TOU, C, SG,

[7] Proceeding No. 21AL-0317E, Decision No. C22-0724 at p. 3, ¶11.

[8] For purposes of this proceeding (and in the 2022 Phase I), the "Test Year" consists of the period ending December 31, 2023. The Test Year revenue requirement reflects rate base using a 13-month average convention for the period ending December 31, 2023, with actual plant additions through June 31, 2022 plus forecasted additions through December 31, 2023. The Test Year also consists of forecasted sales revenue for 2023 and actual O&M expense for the 12 months ended June 30, 2022 with certain known and measurable adjustments and inflationary increases. The Company received answer testimony in the Phase I proceeding on May 3, 2023 and is scheduled to file its rebuttal testimony on May 31, 2023. Due to the time needed to work through the cost allocation and rate design process, the Company has utilized the Phase I Direct Testimony Test Year revenue requirement and billing determinants for its filing in this Proceeding.

[9] The Company anticipates being able to update the CCOSS and rate design models within 30 days of the advice letter compliance filings required under a Commission final decision in the 2022 Phase I. Additional details regarding the update to incorporate the 2022 Phase I decisions can be developed as part of the creation of a procedural schedule for this proceeding.

PG, and TG). Rather, most of the rate schedule revisions in this proceeding merely reflect revised rate levels due to changes to cost allocation and the Company's overall base rate revenue requirement.

Q. IS THE COMPANY PROPOSING ANY MAJOR CHANGES TO HOW IT ALLOCATES COSTS?

A. Yes. In the 2020 Phase II, the Commission noted that the Company's generation fleet is undergoing a transformation, supporting a fresh consideration of cost allocation methodologies:[10]

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

In his Direct Testimony, Mr. Wishart explains that in response to the Commission's direction, the Company recommends production, transmission, and distribution substation costs be allocated using the new, POD-PH methodology.

Q. HAS THE COMMISSION ORDERED THE COMPANY TO ASSESS OTHER ISSUES AS PART OF THIS PROCEEDING?

A. Yes. The Commission also ordered the Company to address several rate design issues, including: (1) the role of demand charges in Secondary General ("SG") rate design;[11] (2) the demand threshold for the Small Commercial class, including

[10] Proceeding No. 20AL-0432E, Decision No. C21-0536, at p. 20, ¶47 (Mailed Date: September 2, 2021).
[11] *Id*. at pp. 9-10, ¶ 21.

whether the threshold should be raised above 50 kilowatts ("kW") and whether the threshold presents a barrier to electrification;[12] and (3) a detailed analysis on the time periods used for the TOU rates in light of increasing amounts of renewable generation on the Company's system.[13] Mr. Wishart addresses issues (1) and (2) in his Direct Testimony, while I address item (3), below.

Q. IS THE COMPANY PROPOSING ANY NEW RATE OPTIONS IN THIS PROCEEDING?

A. Yes. While the Company is generally maintaining the structure of its principal base rate schedules (*i.e.*, Schedules RE-TOU, R, R-OO, C-TOU, C, SG, PG, and TG), we are proposing to add certain rate options to the Electric Tariff. Specifically, the Company proposes to add new electric vehicle ("EV") rate options for customers taking service at the Primary distribution level. These new rate schedules are similar to the existing EV and EV – Critical Peak Pricing ("CPP") rates available to customers taking service at the Secondary distribution level. These rate options are being made available in response to customer interest, and they support both the Commission's and the Company's goals of clean transportation and electrification.

Q. WHAT ARE THE COMPANY'S PHASE II RECOMMENDATIONS?

A. As described in my testimony below, as well as in the testimony of Mr. Wishart and Mr. Klingeman, the Company recommends the Commission:

- Approve the Company's proposed cost allocation as presented in the CCOSS, including use of the POD-PH allocator;

[12] *Id*. at pp. 17-18, ¶ 39.
[13] Proceeding No. 22AL-0143E, Decision No. C22-0398 at p. 2, ¶ 5 (Mailed Date: June 30, 2022).

- Approve the resulting revenue distribution;

- Approve the Company's proposed rate design and authorize implementation of the Company's proposed new base rates and other rates and charges, including:
  - Addition of time-differentiated demand charges for Schedules SG and SG-CPP;
  - Implementation of new Schedule P-EV and Schedule P-EV-CPP rate options for customers taking service at the Primary distribution level; and
  - Adjusting the Primary General Critical Peak Pricing and Secondary Photovoltaic Time-of-Use Service Section B time-differentiated demand charges to be based on demand measured between 2 p.m. and 7 p.m. on non-holiday weekdays to align with the Company's other time-differentiated demand calculations.

- Maintain the Schedule C and Schedule C-TOU demand threshold at 50kW;

- Maintain the existing TOU energy periods for all rate schedules;

- Maintain current Economic Development Rate discounts in Schedule EDR;

- Terminate the recovery of lost revenue associated with IVVO-related energy reductions if the Company's proposed Test Year is approved;

- Authorize deferred accounting treatment for expenses that have been incurred or are expected to be incurred as related to this Phase II Rate Case for potential recovery in the Company's next Phase I electric rate case; and

- Approve the Company's proposed rate and other changes to its Electric Tariff, as described herein and in the accompanying Advice Letter, and included as redlined and clean versions in Attachments JRK-1 and JRK-2 to my Direct Testimony.

Q. DO THE COMPANY'S PHASE II RECOMMENDATIONS RESULT IN REASONABLE RATES ACROSS CUSTOMER CLASSES?

A. Yes. The 2022 Phase I will determine the Company's authorized level of base rate revenue. As shown in Table JRK-D-1 and as discussed in more detail later in my Direct Testimony, the Company's cost allocation and rate design recommendations in this Phase II result in reasonable bill impacts across customer classes.

TABLE JRK-D-1
Impact of Phase II Cost Allocation & Rate Design

	Phase I Bill	Phase II Bill	Monthly $ Change	Monthly % Change
Residential - RE-TOU	$94.52	$95.31	$0.78	0.8%
Small Commercial - C	$140.66	$134.08	($6.58)	-4.7%
Secondary General - SG	$2,637.93	$2,636.96	($0.97)	0.0%
Primary General - PG	$44,853.13	$43,337.10	($1,516.03)	-3.4%
Transmission General - TG	$552,973.56	$558,130.32	$5,156.76	0.9%

III. COST ALLOCATION AND RATE DESIGN POLICY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. The purpose of this Section of my Direct Testimony is to present factors considered by the Company in conducting its cost allocation and rate design analyses.

Q. WHAT IS THE FIRST STEP IN THE COST ALLOCATION AND RATE DESIGN PROCESS?

A. The first step is development of a CCOSS. The CCOSS allocates the test year revenue requirement to the various customer classes based on cost causation principles. Mr. Klingeman discusses the development of the CCOSS in this case in his Direct Testimony.

Q. WHAT IS THE NEXT STEP IN THE PROCESS?

A. The next step is to establish class revenue responsibilities, *i.e.*, the amount of base rate revenue to be recovered from each class. As discussed below, the Company recommends that class revenue responsibilities be equal to the class cost responsibilities determined in the CCOSS.

Q. WHAT IS THE FINAL STEP?

A. In the final step, rates are designed to yield those class revenue responsibilities when applied to test year billing determinants, and ultimately the authorized base rate revenue requirement.

A. Cost Allocation and Class Revenue Responsibilities

Q. HOW IS THE COST ALLOCATION ANALYSIS PERFORMED?

A. Cost allocation generally consists of four steps: functionalization, classification, allocation, and direct assignment. The classification, allocation, and direct assignment steps all occur in the CCOSS, while functionalization generally occurs in Phase I proceedings.[14]

Q. HOW IS THE CCOSS USED IN THE RATE DESIGN PROCESS?

A. The CCOSS serves two purposes: (1) informing class revenue responsibilities; and (2) guiding development of individual rate components.

Q. PLEASE EXPLAIN HOW THE CCOSS IS USED IN THE DEVELOPMENT OF CLASS REVENUE RESPONSIBILITIES.

A. The CCOSS allocates the authorized revenue requirement among customer classes, resulting in class-specific revenue requirements. Those allocations consider each major customer class's overall energy use, contribution to system coincident peaks, individual class peaks, and individual customer demand quantities.

The sum of each class's revenue requirement equals the overall revenue requirement. Therefore, the results of the CCOSS can be thought of as distributing the revenue responsibility among the customer classes, producing a "revenue distribution" based on class cost responsibilities. As discussed below, the Company recommends a cost-based revenue distribution in this proceeding.

[14] Mr. Klingeman explains in his Direct Testimony that the CCOSS reflects the functionalized revenue requirements study sponsored by Company witness Mr. Arthur P. Freitas in the 2022 Phase I (Proceeding No. 22AL-0530E, Hrg. Ex. 120, Attachment APF-1 (Freitas Direct)), with one minor modification sponsored and discussed by Mr. Klingeman.

Q. HOW DOES THE CCOSS ASSIST IN THE DEVELOPMENT OF INDIVIDUAL RATE COMPONENTS?

A. The CCOSS develops classified costs (*i.e.*, energy-related, capacity-related or demand-related, and customer-related costs). Those classified costs are used to develop individual rate components (monthly fixed services and facilities ("S&F") charges, energy charges (per kilowatt hour ("kWh")) and, for certain rate schedules, demand charges (per kW).

Q. IS THE COMPANY RECOMMENDING ANY CHANGES TO ITS COST ALLOCATION METHODOLOGIES IN THIS PROCEEDING?

A. Yes. As discussed above, through the POD-PH methodology, the Company is proposing to change how it allocates production, transmission, and distribution substation costs in response to the Commission's direction that the Company develop an allocation methodology that can apply to all of the Company's production plant costs, regardless of the fuel source for the underlying generating facilities.[15] At a high level, the POD-PH methodology analyzes expected generation commitment and dispatch and customer class load shapes and allocates fixed production costs based on generation and class loads in the top 1,000 hours of the test year. The Company also is recommending a change to

[15] Proceeding No. 20AL-0432E, Decision No. C21-0536, p. 20, ¶ 47 ("We also find that Staff's request is reasonable and appropriate. While the Rush Creek Wind Farm provides primarily energy benefits to the grid, it represents the beginning of likely future generation asset investment. We agree that Public Service should develop mechanisms to allocate generation assets on a consistent basis. As a result, we direct the Company to file, as part of its next Phase II rate case, an alternative CCOSS methodology with the goal of applying more consistent allocation treatment across all electric generation and storage assets").

how it allocates service lateral costs. Mr. Klingeman discusses these changes in his Direct Testimony.

Q. WHAT FACTORS INFLUENCE COST ALLOCATION METHODOLOGIES?

A. The Company strives to measure cost-causation as accurately as possible, but we consider other factors too. For example, we endeavor to utilize cost allocation methodologies that are stable. And we are concerned with issues of fairness among customer classes. Both of these considerations inform our cost allocation and rate design recommendations.

Q. HOW DOES STABILITY INFLUENCE THE COMPANY'S COST ALLOCATION RECOMMENDATIONS?

A. There are two ways stability influences the Company's cost allocation recommendations. First, we are interested in using cost allocation methodologies that do not produce dramatic changes in cost responsibilities based on small changes in underlying usage. Second, we are interested in using cost allocation methodologies that can gradually accommodate changes in underlying usage or system characteristics, resulting in more stable bills for customers.

Q. PLEASE DISCUSS THE FIRST WAY STABILITY INFLUENCES THE COMPANY'S COST ALLOCATION RECOMMENDATIONS.

A. In the Company's 2020 Phase II, the system peak hour moved from the 3:00 p.m.--4:00 p.m. hour to the 4:00 p.m.-to-5:00 p.m. hour, which accounted for an approximate $30 million change in Residential class cost responsibility.[16] Mr.

[16] Proceeding No. 20AL-0432E, Hrg. Ex. 101 at 45:10-17, 46:7-11 (Trammell Direct).

Wishart and Mr. Klingeman explain the POD-PH allocator considers customers' usage during the top 1,000 hours of a year (approximately equal to all on-peak hours, as defined in Schedules RE-TOU and C-TOU), as compared to the 4CP-AED[17] allocation factor previously used to allocate production, transmission, and distribution substation costs to customer classes, which was highly sensitive to usage patterns in only four hours of a year.

Q. PLEASE DISCUSS THE SECOND WAY STABILITY INFLUENCES THE COMPANY'S COST ALLOCATION RECOMMENDATIONS.

A. As discussed in the 2020 Phase II Decision, the Company's generation fleet is evolving to incorporate different kinds of generating resources. Further, customers' usage is likely to change over time through increased electrification of the building and transportation sectors of our economy. The POD-PH allocator can accommodate both of these phenomena and will do so gradually without abrupt changes to class cost responsibilities.

Q. HOW DOES THE COMPANY CONSIDER FAIRNESS IN THE COST ALLOCATION PROCESS?

A. We try to use cost allocation methodologies that produce allocations that reflect how customers cause costs to be incurred. As a corollary, we want to make sure customers that use the system pay for that use.

[17] 4CP-AED stands for 4 Coincident Peak ("CP") – Average and Excess Demand ("AED").

Q. DO THE COMPANY'S COST ALLOCATION RECOMMENDATIONS IN THIS PROCEEDING SATISFY THE ABOVE CONSIDERATIONS?

A. Yes. Transitioning to the POD-PH methodology not only promotes stability and fairness, but also meets the Commission's directive that the Company reconsider its classification and allocation of fixed production plant in this case. That directive was influenced by the fact the Company's generation mix is undergoing a significant transformation, incorporating more renewable and intermittent resources. Further, as noted in the SG-TOU Proceeding and discussed in more detail below, the Company has gained additional insights into the hours that contribute most to the cost of providing service. All of these factors contribute to the Company's recommendation that fixed production plant, transmission and distribution substation costs be allocated using the POD-PH methodology, rather than the 4CP-AED methodology used in prior cases.

B. Rate Design

Q. HAS THE COMPANY'S RATE DESIGN UNDERGONE SIGNIFICANT CHANGES OVER THE PAST SEVERAL YEARS?

A. Yes. In Proceeding No. 19AL-0687E (the "Residential TOU Proceeding"), the Company, Commission, and stakeholders worked to migrate the Residential class to a default TOU rate following deployment of Advanced Meters. TOU offerings were expanded to Small Commercial customers in the 2020 Phase II,[18] which also initiated a new Schedule SG-TOU Pilot.[19]

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[18] Proceeding No. 20AL-0432E, Decision No. R21-0400, at p. 44, ¶ 103.
[19] Proceeding No. 20AL-0432E, Decision No. C21-0536, at p. 10, ¶ 22.

The Company also has received approval for new commercial electric vehicle charging rates,[20] and a permanent critical peak pricing rate.[21] Some older rate options have been terminated either by policy decision of the Commission or with the expiration of certain pilot rates. These include the Residential Demand – Time Differentiated Rate ("RD-TDR") which was terminated on January 1, 2022, as ordered by the Commission in the 2020 Phase II,[22] and the Secondary Time-of-Use Service ("STOU"), and Primary Time-of-Use Service ("PTOU") pilot rates, which expired on January 1, 2023.

Q. ARE THERE IMPORTANT CONSIDERATIONS ASSOCIATED WITH THESE AND OTHER EXPANDED RATE OPTIONS?

A. Yes. As discussed above, rates are designed so that when they are applied to test year billing determinants, they result in the test year revenue requirement. Actual billing determinants almost certainly will deviate from test year amounts, resulting in the Company collecting more or less than the authorized revenue requirement. Those deviations are expected and are a natural part of utility regulation.

The addition of rate options introduces a factor that can contribute to the deviations between actual billing determinants and the billing determinants used to design rates, and therefore utility cost recovery. If more customers choose a particular rate option than was expected, that could contribute to over- or under-collection.

[20] Proceeding No. 19AL-0290E.
[21] Proceeding No. 21AL-0091E.
[22] Proceeding No. 20AL-0432E, Decision No. C21-0536 at 22, ¶ 55.

Q. IS THIS A PROBLEM?

A. Not necessarily. First, providing customers with additional options may improve overall satisfaction with their service, as the offering can be better matched to the customers' particular needs or desires. Second, rate offerings, if well designed, can help influence behaviors that are desirable from an economic perspective, a policy perspective, or both.

Q. WHY IS IT IMPORTANT THAT THE RATE OFFERINGS BE WELL DESIGNED?

A. As discussed above, any deviation from test year billing determinants will result in over- or under-collection. If the deviation is one that results in under-collection, but the deviation also results in equivalent system savings, then on net, the utility is not harmed. It is therefore important that rate offerings be focused on producing behaviors that result in system savings or other policy goals.

Q. WHAT HAPPENS IF RATE OFFERINGS ARE NOT WELL DESIGNED?

A. If the overall suite of rate options is not well designed, it can result in customers self-selecting into the most advantageous rate to gain bill savings without commensurate changes in usage and therefore system costs. In the short-term, this results in under-collection by the utility. It ultimately can accelerate the need to file a rate case, and results in cost increases for other customers (*i.e.*, those that do not engage in inappropriate rate arbitrage).

Q. CAN YOU PROVIDE EXAMPLES OF INAPPROPRIATE RATE ARBITRAGE?

A. Yes. The Company established three TOU pilot rates for Commercial and Industrial ("C&I") customers in 2010: STOU (for C&I-Secondary customers), PTOU (for C&I-Primary customers), and TTOU (for C&I-Transmission customers) (collectively, the "2010 C&I TOU Pilots"). These pilots resulted in over $1 million annual revenue erosion from just four pilot participants.[23] The participating customers had much higher percentage of off-peak energy use than typical C&I-Secondary customers, indicating the participating customers likely achieved theses bill savings without any change in behavior.[24]

Q. HOW DOES THIS EXPERIENCE AND THE COMPANY'S OVERALL VIEW ON RATE OPTIONS INFLUENCE YOUR RECOMMENDATIONS IN THIS PROCEEDING?

A. We have tried to direct our recommendations at: (1) designing rates that reflect cost causation (as accurately as possible); and (2) making sure rates and rate options are designed to drive desirable behavioral changes that ultimately reduce costs, promote public policy, or both.

Q. ARE THERE ANY RECOMMENDATIONS THAT ARE PARTICULARLY DRIVEN BY THESE CONCERNS?

A. Yes. As discussed in more detail by Mr. Wishart in his Direct Testimony, modifying Schedule SG from a demand charge based on a customer's peak demand no matter what time it occurs to a time-differentiated demand charge results in a rate that better reflects cost causation and is designed to promote desirable behavioral changes, like electrification during off-peak hours. And as Mr. Wishart discusses, maintaining the Small Commercial demand cap at 50 kW avoids creation of rate

[23] Proceeding No. 16AL-0048E, Hrg. Ex. 105 at 32, Table DEG-4 (Garretson Direct).
[24] Proceeding No. 16AL-0048E, Hrg. Ex. 105 at 30:16-31:15 (Garretson Direct).

arbitrage opportunities that do not pair reduced bills with corresponding behavioral changes (and therefore reduced system costs).

IV. CLASS REVENUE DISTRIBUTION

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. The purpose of this Section of my Direct Testimony is to present the Company's proposed class revenue distribution.

Q. WHAT IS THE CLASS REVENUE DISTRIBUTION?

A. The CCOSS allocates the authorized revenue requirement among customer classes and the result is a class-specific revenue requirement. The sum of each class's revenue requirement equals the overall approved revenue requirement. Therefore, the results of the CCOSS can be thought of as distributing the revenue responsibility among the customer classes, producing a "revenue distribution" among the Company's major customer classes. Rates are then designed to yield each class's assigned revenue target when applied to test year billing determinants.

Q. IS THE COMPANY RECOMMENDING A COST-BASED REVENUE DISTRIBUTION IN THIS PROCEEDING?

A. Yes. The Company recommends that the revenue distribution should be equal to class cost responsibilities, as determined by the CCOSS. This results in the following class revenue distribution.

Table JRK-D-2: Proposed Revenue Distribution[25]

Class	Phase I Rate Revenue Responsibility*		Phase II Rate Revenue Responsibility	
	Dollars	Percentage	Dollars	Percentage
Residential	$1,084,746,840	44.0%	$1,098,688,161	44.6%
Small Commercial	$131,789,619	5.3%	$122,878,532	5.0%
C&I Secondary	$900,839,338	36.6%	$905,171,575	36.7%
C&I Primary	$208,424,113	8.5%	$201,058,345	8.2%
C&I Transmission	$89,866,271	3.6%	$91,108,993	3.7%
Street and Area Lighting	$47,070,502	1.9%	$43,831,160	1.8%
Traffic Signal Lighting	$1,460,003	0.1%	$1,459,919	0.1%
Total	$2,464,196,686	100.0%	$2,464,196,686	100.0%

*Reflects 2022 Phase I Proposed GRSA and GRSA-E

Q. WHY DOES THE COMPANY SUPPORT A COST-BASED REVENUE DISTRIBUTION?

A. Cost-based revenue distribution is fair (in that it results in customers contributing toward the costs they cause), encourages the efficient use of resources, and affords the Company a reasonable opportunity to earn its authorized revenue requirement.

Q. DO THE COMPANY'S EXISTING BASE RATES REFLECT A COST-BASED REVENUE DISTRIBUTION?

A. No. Certain parties to the Company's 2020 Phase II entered into a Stipulation and Settlement Agreement (the "2020 Phase II Partial Stipulation") that provided for a $15 million reduction to class revenue responsibility (from the cost-based level) for the Residential class and $0.8 million reduction to class revenue responsibility

[25] Excludes Electric Affordability Program ("EAP").

(from the cost-based level) for the Small Commercial class. These reductions were approved in the 2020 Phase II and became part of approved rates.[26]

Q. SHOULD DEVIATIONS FROM COST-BASED REVENUE DISTRIBUTIONS BE PERMANENT?

A. No. The Company acknowledges that the Commission has deviated from a cost-based revenue distribution in different cases for policy reasons based on particular facts and circumstances. But the Company believes those deviations should be just that – deviations from the norm of setting class revenue responsibility equal to class cost responsibility, as measured in the CCOSS. Therefore, the Company recommends a cost-based revenue distribution in this case and uses that cost-based revenue distribution in the proposed rate design.

[26] Proceeding No. 20AL-0432E, Decision No. 21R-0400, pp. 26-32, ¶¶57-73 (Mailed Date: July 12, 2021).

V. TIME OF USE RATES STUDY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. The purpose of this Section of my Direct Testimony is to present the TOU rates study performed by the Company in response to Decision No. C22-0398 in the SG-TOU Proceeding.

Q. PLEASE DESCRIBE THE COMMISSION'S DIRECTIVE FROM DECISION NO. C22-0398.

A. In Decision No. C22-0398, the Commission expressed concern that the on-peak, shoulder, and off-peak periods of the proposed Schedule SG-TOU Pilot rate did not optimally reflect current and future usage patterns. The Commission stated that:[27]

> expected increases in solar generation and storage suggest that the on-peak period should begin later than 3:00 p.m. and end later than 7:00 p.m. Such a change would encourage increased electric usage such as electric vehicle charging during hours of abundant solar generation, rather than discouraging usage during those hours through higher pricing.

Q. DID THE COMMISSION REQUIRE THE COMPANY TO PERFORM AN ANALYSIS OF THE ON-PEAK, OFF-PEAK, AND SHOULDER PERIODS OF THE COMPANY'S TOU RATES?

A. Yes. The Commission requested the Company prepare "a comprehensive, data-driven analysis of whether the on-peak, shoulder, and off-peak periods of [the Company's] various rate schedules with a TOU component reflect the realities of today's system and what we know about where that system is headed."[28]

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[27] SG-TOU Proceeding, Decision No. C22-0398 at 2, ¶ 4 (Mailed Date: June 30, 2022).
[28] SG-TOU Proceeding, Decision No. C22-0398 at 2, ¶ 5.

Q. DID THE COMMISSION PROVIDE ANY ADDITIONAL GUIDANCE?

A. Yes. The Commission stated the analysis "should include the most up-to-date forecasting of hourly load net of renewable generation and storage, and account for the actual generation the Company expects through 2030."[29]

Q. DID THE COMPANY PREPARE THE ANALYSIS REQUESTED BY THE COMMISSION?

A. Yes. Attachment JRK-3 provides the analysis requested by the Commission.

Q. PLEASE DESCRIBE THE TOU ANALYSIS.

A. The TOU analysis included in Attachment JRK-3 studies the Company's hourly system load net of renewable generation for the years 2022 (actual), 2025 (forecasted), and 2030 (forecasted). I prepared the analysis by first subtracting the total renewable generation in a given hour, including wind, solar, and hydro, from the total system load in that hour to determine the hourly load net of renewable generation. Then, I determined the highest 1,000 load hours (net of renewable generation) in each year and determined in which hours of the day those 1,000 hours occur. I focused on the top 1,000 hours because the Company's TOU rates are designed with approximately 1,000 on-peak hours per year. As described in Attachment JRK-3, the forecasted load and generation portfolios are based on information included in the Company's 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP") in Proceeding No. 21A-0141E.

[29] SG-TOU Proceeding, Decision No. C22-0398 at 2, ¶ 5.

Attachment JRK-3 provides more detail on the TOU analysis, including modeling assumptions used in the forecasting.

Q. HOW DID YOU ACCOUNT FOR ENERGY STORAGE RESOURCES IN THE ANALYSIS?

A. The majority of the data presented in Attachment JRK-3 and in this Section of my Direct Testimony does not include the effects of energy storage resources. I believe the best way to set TOU rates is based on system load net of renewable generation *without* considering the effects of storage. System load net of renewable generation is a measure of the load that is needed to be served by dispatchable generation resources. For purposes of this analysis, and in setting TOU rates, I consider energy storage resources to be more akin to traditional dispatchable generation resources – tools that can be used to help serve this changing load net of intermittent or non-dispatchable generation. By excluding the effects of storage from this analysis, we more effectively separate the problem to be solved (net load) from the solution (dispatchable generation resources, including storage). However, Attachment JRK-3 does show how including storage in the 2025 analysis changes the results.

Q. HOW IS LOAD NET OF RENEWABLE GENERATION DATA USED IN TOU RATE DESIGN?

A. Generally, TOU rates are designed to incentivize customers to shift electric usage from higher-cost periods to lower-cost periods. Load net of renewable generation is a good indicator of the relative costs that can be avoided if load is shifted out of a particular hour. In other words, the more dispatchable generation that is needed in an hour, the more beneficial it would be to reduce load in that hour and reduce use of the higher cost dispatchable generation that is needed during periods of high load net of renewable generation. For this reason, the Company designs its TOU rates with price signals to reduce usage during periods of high load net of renewable generation.

Q. WHAT ARE THE CURRENT TOU PERIODS USED IN THE COMPANY'S TOU RATES?

A. Generally, the Company's TOU rates use an on-peak period of 3 p.m. to 7 p.m. on non-holiday weekdays, with a two-hour shoulder period both before and after the on-peak period, from 1 p.m. to 3 p.m. and from 7 p.m. to 9 p.m. All other hours, including all hours on holidays and weekends, are classified as off-peak. These TOU periods apply to the Company's Schedule RE-TOU, C-TOU, and SG-TOU Pilot rates, except that the Schedule RE-TOU rate does not include an evening shoulder period and instead reverts to off-peak pricing after 7 p.m.[30]

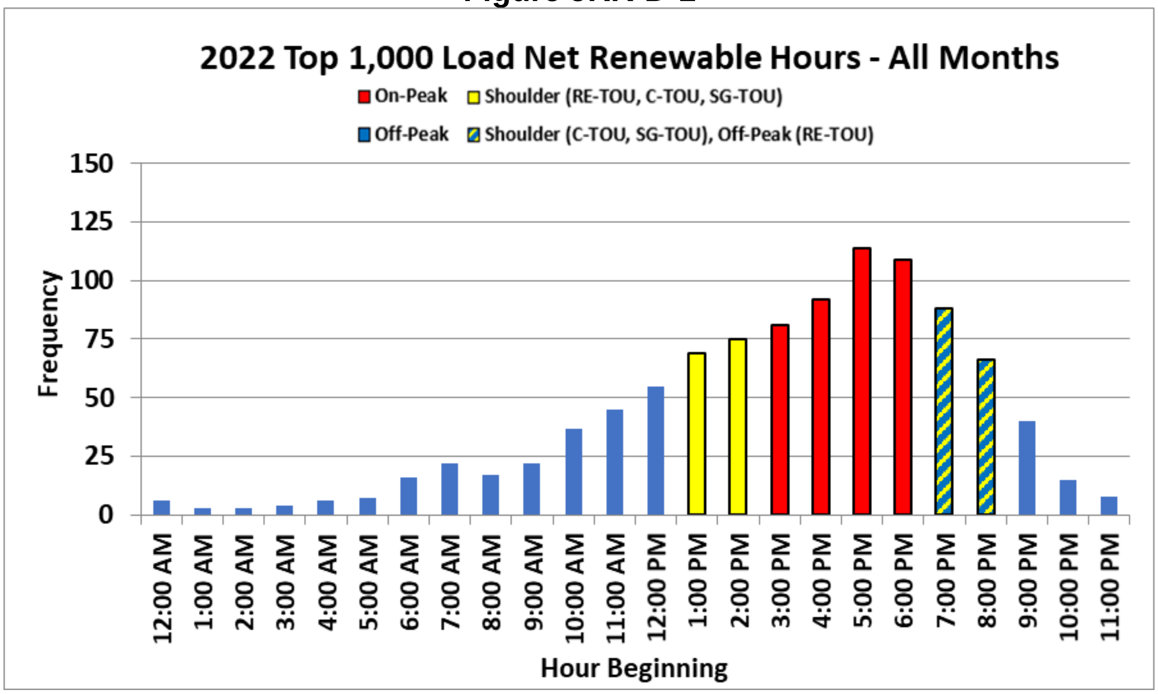
Q. HOW WERE THE TOP 1,000 HOURS OF LOAD NET OF RENEWABLES DISTRIBUTED IN 2022?

A. The top 1,000 load net of renewable generation hours most frequently occurred during the current on-peak period of 3 p.m. to 7 p.m., though the hour of 7 p.m. to

[30] Other Company rate schedules include time-based elements that differ from the TOU periods discussed in this paragraph. For example, Schedule PG utilizes a time-differentiated demand charge based on measured demands between 2 p.m. and 7 p.m. Schedules SPVTOU-A and SPVTOU-B use an on-peak energy period of 12 p.m. to 8 p.m. Schedules S-EV and S-EV-CPP use an on-peak period of 2 p.m. to 10 p.m. The Electric Commodity Adjustment ("ECA") includes some TOU rate options with an on-peak period of 9 a.m. to 9 p.m. These rate schedules were designed with different goals (*e.g.*, avoiding higher energy cost hours in the ECA), and it may not be appropriate to align all TOU periods across all rate schedules.

8 p.m. also contained many of the top 1,000 hours as shown below in Figure JRK-D-1.

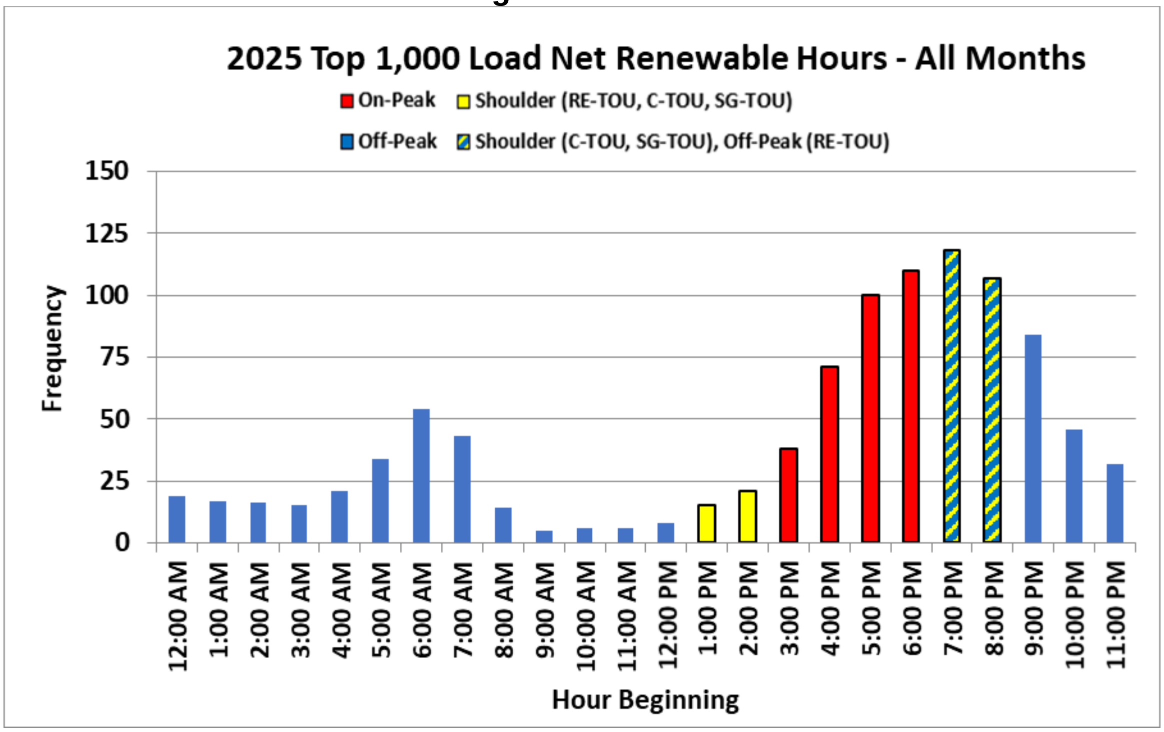
Figure JRK-D-1



Q. HOW IS THE DISTRIBUTION OF THE TOP 1,000 HOURS OF LOAD NET OF RENEWABLE GENERATION EXPECTED TO CHANGE IN THE FUTURE?

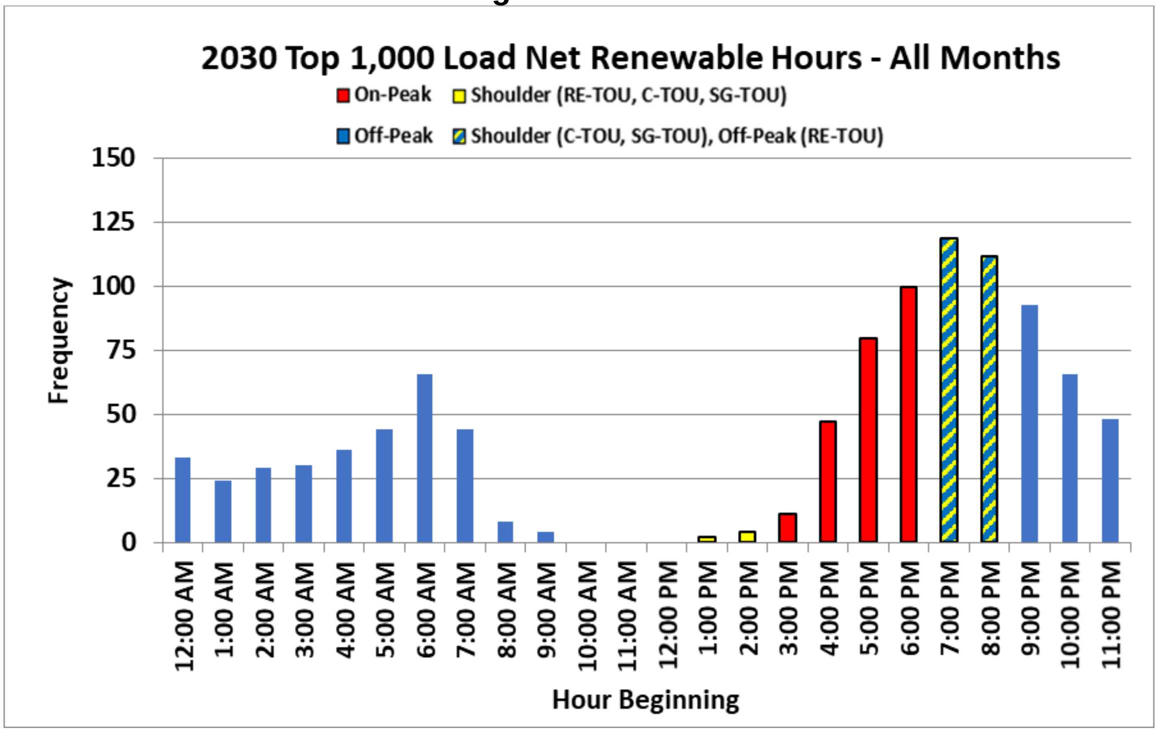
A. The Company’s forecast for 2025 shows fewer instances of the top 1,000 hours of load net of renewable generation occurring during the afternoon shoulder (*i.e.*, 1 p.m. through 3 p.m.) and the first two hours of the on-peak period, and more instances of the top 1,000 hours occurring during the evening shoulder period of 7 p.m. to 9 p.m., with the hour from 7 p.m. to 8 p.m. having the most instances of high load net of renewable generation. This is shown in Figure JRK-D-2 below.

Figure JRK-D-2



The Company's forecast for 2030 shows similar results to 2025, with the most instances of high load net of renewable generation from 7 p.m. to 9 p.m., as shown below in Figure JRK-D-3.

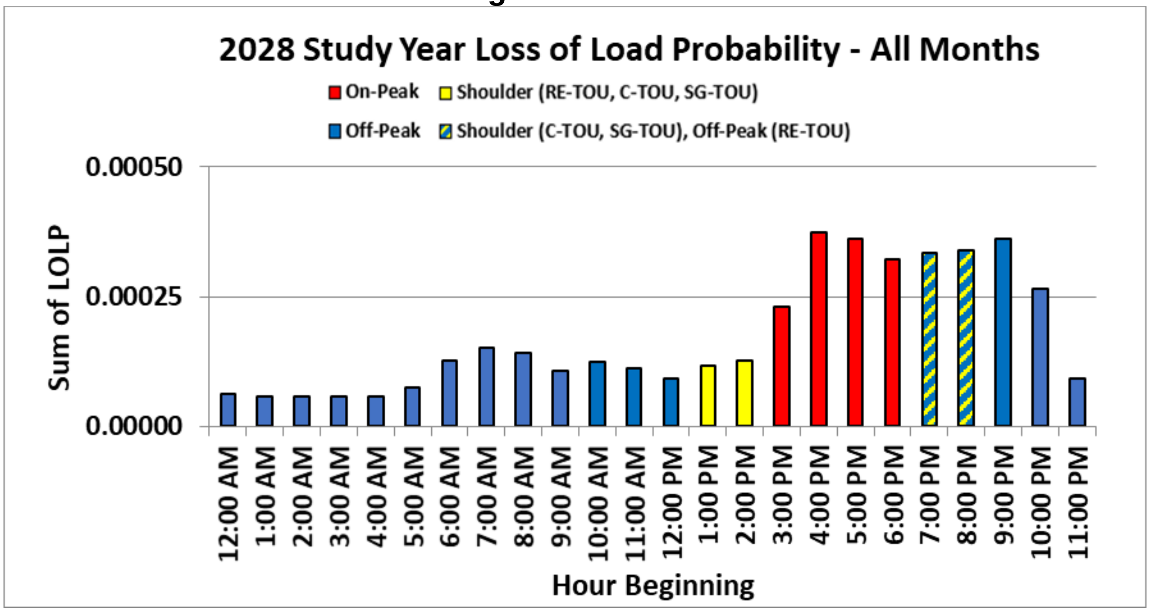
Figure JRK-D-3



Q. DID YOU INCLUDE A LOSS OF LOAD PROBABILITY EVALUATION IN THE TOU ANALYSIS?

A. Yes. Loss of Load Probability ("LOLP") is a metric used to measure resource adequacy and is analyzed as part of the Company's 2021 ERP & CEP. LOLP generally measures the likelihood of being unable to serve the full load requirement in a given hour. Attachment JRK-3 also includes an hourly LOLP analysis for 2028, which is the final year that new resources will be considered within the current 2021 ERP & CEP. The hourly LOLP values for 2028 are also presented in Figure JRK-D-4 below.

Figure JRK-D-4



Q. WHAT CONCLUSIONS CAN BE DRAWN FROM THE 2028 LOLP DATA?

A. The LOLP data generally agrees with the load net of renewable generation analysis. This is not surprising, as hours with high load net of renewable generation require more dispatchable generation to meet the load need and therefore have less reserve generation available in the event of a generator outage. Although the LOLP and load net of renewable generation histograms do not perfectly align, both support the importance of the evening on-peak period and show that hours after 7 p.m. may become more critical as the Company's resource portfolio adds more renewable generation. Additional information on the LOLP study is available in Attachment JRK-3.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS TOU PERIODS AT THIS TIME?

A. No. The current TOU periods are a good match for current system conditions (based on 2022 data), and it is premature to alter the TOU periods for any of the affected rate schedules at this time.

Q. WHY IS IT PREMATURE TO ALTER THE TOU PERIODS IN THIS PROCEEDING?

A. There are two broad reasons: practical considerations and quantitative support.

Q. PLEASE DESCRIBE THE PRACTICAL CONSIDERATIONS THAT SUPPORT MAINTAINING THE EXISTING TOU PERIODS.

A. First, as discussed above, the Company's TOU periods generally are consistent across all TOU rates (*i.e.*, Schedules RE-TOU, C-TOU, and SG-TOU Pilot), with Schedule RE-TOU being the largest TOU rate schedule (by both number of customers and revenues).

Second, under the terms of the Unanimous and Comprehensive Stipulation and Settlement Agreement ("Residential TOU Settlement") in the Residential TOU Proceeding,[31] the structure of Schedule RE-TOU may only be modified prior to April 1, 2025 for two reasons: (1) if needed to maintain revenue neutrality between Schedules RE-TOU, R-OO, and R; and (2) to add an evening shoulder period if at least 22 of the top 100 load net of renewables hours occur between 7 p.m. and 9 p.m.[32] As discussed below, neither of these provisions have been triggered,

[31] The Residential TOU Settlement was approved in Decision No. R20-0642 (Mailed Date: September 11, 2020), which thereafter became the decision of the Commission by operation of law.
[32] Residential TOU Settlement at 17-20, ¶ 26.

meaning the Schedule RE-TOU periods cannot be modified at this time. While only Schedule RE-TOU is subject to the Residential TOU Settlement restrictions, we prefer to maintain consistent TOU periods between the various TOU rate schedules in order to reinforce customer understanding (or conversely, avoid customer confusion), particularly since Schedule C-TOU has only been in place for a short period of time, and the Schedule SG-TOU Pilot is just getting underway.

Q. ARE THERE OTHER PRACTICAL CONSIDERATIONS THAT SUPPORT MAINTAINING TOU PERIODS AT THIS TIME?

A. Yes. Customers are just starting to move to a TOU rate construct, which is intended to incentivize customers to change behaviors. Those behavioral changes, in turn, are predicated on customers having familiarity with and understanding of the TOU periods. The Company has undertaken a significant effort to educate Residential and Small Commercial customers about TOU rates generally and the existing TOU periods specifically, as an integral component of the Advanced Meter rollout and education campaign. This education is ongoing as customers continue to receive advanced meters and switch over to TOU rates, with the transition to TOU rates not scheduled to be completed for Residential and Small Commercial customers until April 2025.

Q. PLEASE ELABORATE.

A. The customer education strategies for both the meter rollout and transition to TOU rates for Residential and Small Commercial customers have been addressed in several proceedings, including the Residential TOU Proceeding, and are the subject of ongoing stakeholder meetings, with authorized cost recovery for those efforts.[33]

At a high level, there are three phases to the customer education strategy. The first phase includes raising awareness through an introductory and wide-reaching effort to inform customers about Advanced Meter installations and educate them on the overall benefits of grid intelligence. The second phase supports successful meter installations by targeting affected customers in geographic areas to educate and minimize confusion, and introductory information about the TOU rates are provided in this communication. The third phase involves customer engagement, which will continue post Advanced Meter installation, so that customers can take full advantage of Advanced Meter features and opportunities to save money with TOU rates. The strategies are being executed across multiple communications channels including, but not limited to, website updates, stakeholder outreach meetings, media outreach, social media, blogs, direct mail, e-mail, outbound calls, door hangers, community events, bill onserts, targeted advertising, fact sheets, video, and customer testimonials. Much has been invested in this process, and the successful transition to Residential and Small Commercial TOU rates.

[33] *See, e.g.*, Decision No. R20-0642 at ¶ 127 in the Residential TOU Proceeding authorizing deferral of costs associated with the Residential transition plan, for billing and programming work, and the customer education outreach and communications plan, then estimated at approximately $5.1 million. *See also* Decision No. R21-0400 at ¶ 157 authorizing deferred accounting for incremental educational and communications-related costs to help our Small Commercial customers with the transition to Schedule C-TOU, as well as billing and programming costs to implement the rate.

Altering the TOU periods now would require a new (or significantly modified) educational program and we are concerned that the conflicting messages around TOU periods before the originally contemplated transition is complete would result in customer dissatisfaction, decreased understanding of TOU periods (and therefore electiveness of TOU rates) or both. Therefore, the existing awareness and education campaign should continue as designed and scheduled until some period of time after customer transition has been completed in the Spring of 2025, and new TOU periods should not be implemented prematurely as it is important that the transition be successful.

Q. WHAT ARE THE QUANTITATIVE REASONS TO MAINTAIN THE EXISTING TOU PERIODS?

A. Figure JRK-D-1 above shows that current TOU periods are a good match for current system conditions (based on 2022 data). Further, the Company performed the revenue neutrality and evening shoulder analyses discussed in the Residential TOU Settlement and neither supported changes to the Schedule RE-TOU periods in this Proceeding.

Q. PLEASE SUMMARIZE THE COMPANY'S RE-TOU REVENUE NEUTRALITY ANALYSIS.

A. On February 28, 2023, the Company filed its RE-TOU Revenue Neutrality Report in the Residential TOU Proceeding.[34] That report showed that through December 31, 2022, Schedules RE-TOU, R, and R-OO base rate revenues received were

[34] Proceeding No. 19AL-0687E, RE-TOU Revenue Neutrality Report (filed Feb. 28, 2023).

within 1.9 percent of the baseline, which is less than the three percent threshold. The rate is performing extremely well, so no change was required to maintain revenue neutrality.

Q. WHAT DOES THE RESIDENTIAL TOU SETTLEMENT REQUIRE WITH RESPECT TO ADDING AN EVENING SHOULDER?

A. The Residential TOU Settlement provides as follows, at Paragraph 26:

> In addition, if the Company finds, based on observable data, that hours after 7 pm are demonstrating significant increased loads, the Company may file an advice letter prior to April 1, 2025 to propose to modify the RE-TOU rate design by adding an evening shoulder period. In order to bring forward such a modification, the Company must demonstrate in its advice letter filing that there have been significant increased net loads in the hours between 7pm-9pm. For that advice letter, the Settling Parties agree that a threshold of 22 out of the top 100 load net of renewable hours between 7pm and 9pm in one year is permissible criteria to warrant filing for an evening shoulder period of one or more hours. The Parties reserve the right to take any position in response to such an advice letter filing.[35]

This was a negotiated provision of the aforementioned settlement that reflects consensus among the parties and was approved by the Commission.

Q. PLEASE DESCRIBE THE ANALYSIS UNDERTAKEN IN ORDER TO DETERMINE WHETHER AN RE-TOU EVENING SHOULDER COULD BE ADDED.

A. Similar to the load net of renewable generation analyses described above, I determined the hourly load net of renewable generation for calendar year 2022 by subtracting the total renewable generation in a given hour from the hourly system load. Then, I determined the highest 100 load hours (net of renewable generation)

[35] Residential TOU Settlement at p. 19, ¶ 26.

and determined in which hours of the day those top 100 hours occurred. For calendar year 2022, only six of the top 100 load net of renewable hours occurred between 7 p.m. and 9 p.m. This is short of the Residential TOU Settlement 22-hour threshold, so the Company has not proposed to add an evening shoulder for Schedule RE-TOU in this Proceeding.

Q. WILL THE ISSUE OF TOU PERIODS CONTINUE TO BE EVALUATED GOING FORWARD?

A. Yes. The Company is required to make certain periodic filings under the terms of the Residential TOU Settlement. These include revenue neutrality reports on December 31, 2023 and March 1, 2025 and annual reports on November 1, 2023, and November 1, 2024. More importantly, Company is required to file an Advice Letter on April 1, 2025, addressing the future of Schedule RE-TOU:[36]

> The Company will engage with parties to this proceeding in 2025 in a collaborative stakeholder environment to review the information reported to date and discuss any potential revisions to Modified Schedule RE-TOU that may need to be made. The Company agrees to file an Advice Letter on April 1, 2025, proposing to either modify or maintain Schedule RE-TOU, which may include, but is not limited to, rate structures, price ratios, time periods of on-peak, off-peak, or shoulder periods, to address revenue neutrality or in consideration of reporting provided to parties in Paragraph 22.

Q. HOW DOES THIS CADENCE OF FILINGS RELATE TO THE TIMING FOR CHANGING TOU PERIODS?

A. The Residential TOU Settlement created a thoughtful, thorough plan for implementing TOU rates for a vast majority (by number) of the Company's

[36] Residential TOU Settlement at p. 19, ¶ 26.

customers. It had the broad support of many stakeholders, including the Company, Commission Trial Staff, the Colorado Office of Consumer Counsel (now known as the Colorado Office of the Utility Consumer Advocate), the City of Boulder, the Colorado Solar and Storage Association, the Solar Energy Industry Association, Energy Outreach Colorado, Vote Solar, the Southwest Energy Efficiency Project, and Western Resource Advocates. That plan provides for a period of initial TOU roll out and customer education, followed by a comprehensive reassessment in 2025, which is to include a collaborative stakeholder process.

If the electric system develops consistent with current expectations, then it may be reasonable and appropriate to alter the Company's TOU periods as part of that comprehensive reassessment.[37] By the time the Company files the 2025 Advice Letter filing required by the Residential TOU Settlement, it is possible that results from 2023 and 2024 will show that the top load net of renewables hours are occurring later in the day. Further, that filing will have additional information to help identify whether the movement is expected to continue beyond 2025 (as shown in Figure JRK-D-2, above) or whether there is an expectation that system peaks will stabilize around a more defined set of hours. In the meantime, the Company will continue to provide the Commission with information through its periodic, required Residential TOU Settlement filings so that parties are well prepared for the April 2025 Advice Letter filing.

[37] While the Residential TOU Settlement was focused on Residential rates, the Company anticipates that the April 2025 Advice Letter will more broadly address the TOU periods for the Company's other TOU rate schedules.

VI. SUMMARY OF RATES AND RATE CHANGES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this Section of my Direct Testimony, I provide an overview of each of our seven major customer classes, which include:

- Residential;
- Small Commercial;
- C&I Secondary;
- C&I Primary;
- C&I Transmission;
- Street and Area Lighting; and
- Traffic Signal Lighting.

I then describe the major rate schedules within each customer class, present any changes to the structure of those rates and proposed new rate levels.[38]

A. Residential

Q. PLEASE PROVIDE AN OVERVIEW OF THE RESIDENTIAL CUSTOMER CLASS.

A. The Residential class is the largest major customer class in terms of number of customers and second largest in terms of sales volumes. In the Test Year, Public

[38] Throughout this Section III of my Direct Testimony, I make recommendations to adjust S&F charges for various rate schedules. Unless otherwise noted, all referenced S&F charges are inclusive of the Company's EAP charge. The Company notes that the Commission, in its weekly meeting on May 10, 2023, approved a request from the Company to increase its EAP charges as set forth in Proceeding No. 23AL-0176E. As the new rates do not go into effect until May 14, 2023, there was not sufficient time to incorporate them into this filing. Thus, whenever I reference the EAP charge in my Direct Testimony, I am referring to the EAP charges in effect prior to May 14, 2023.

Service's Residential class is projected to have approximately 1.34 million customers and account for approximately 34 percent of retail electric sales.

Q. DO RESIDENTIAL CUSTOMERS HAVE CHOICES IN THEIR RATE SCHEDULE?

A. Yes. Customers who have received an Advanced Meter are placed on Schedule RE-TOU by default, although they have the option to opt out of time-of-use pricing and pay a seasonal flat energy rate on Schedule R-OO. Residential Customers without an Advanced Meter generally take service under Schedule R. Certain Residential customers may also qualify for a Medical Exemption Program ("MEP") discount to their energy rate in the summer. Lastly, some Residential customers take service under Schedule RD, which includes a demand charge and a lower energy charge (as compared to Schedules RE-TOU, R-OO, and R). Schedule RD has been closed to new business as of December 31, 2016 but remains in effect for customers already on the rate.

1. Schedule RE-TOU

Q. PLEASE DESCRIBE SCHEDULE RE-TOU.

A. About 64 percent of Residential customers are projected to take service under Schedule RE-TOU during the Test Year, making it the largest Residential rate schedule (in terms of customers) in the Test Year. The predominance of Schedule RE-TOU reflects the ongoing process of Schedule RE-TOU becoming the default Residential rate after the deployment of Advanced Meters. Schedule RE-TOU is a kWh-based rate with on-peak, off-peak, and shoulder energy charges that vary by season. It also includes a monthly S&F charge.

Q. ARE YOU PROPOSING ANY CHANGES TO THE STRUCTURE OF SCHEDULE RE-TOU?

A. No. The Residential TOU Settlement established a general rate design for Residential TOU rates, including defined on-peak, off-peak, and shoulder hours, and seasonal on-peak to off-peak price ratios. As discussed above, the Residential TOU Settlement generally provides for the Schedule RE-TOU structure to remain unchanged until April 1, 2025.[39]

Q. HAS THE COMPANY ANALYZED THE PERFORMANCE OF SCHEDULE RE-TOU TO DATE?

A. Yes. The Company has assessed customers' usage patterns on Schedule RE-TOU and bill impacts when on the Schedule RE-TOU rate.

Q. PLEASE DESCRIBE THE ANALYSIS OF CUSTOMERS' USAGE PATTERNS ON SCHEDULE RE-TOU.

A. Approximately 640,000 Residential customers migrated to Schedule RE-TOU in 2022-2023.[40] The migration occurred geographically based on the deployment of Advanced Meters and therefore the migrated customers do not represent a random statistical sample of the Residential class. For example, the Company observed that the initial group of Schedule RE-TOU customers generally had average usage that was lower than the general Residential customer population.

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[39] As discussed in Section V, above, the Residential TOU Settlement does allow for the addition of an evening shoulder period if at least 22 of the top 100 load net of renewables hours occur between 7 p.m. and 9 p.m. That condition has not occurred, and the Company is not recommending the addition of an evening shoulder period in this Proceeding.

[40] This migration occurred in three tranches, the first involving approximately 310,000 in April 2022, another 210,000 in October of 2022 and another 130,000 in April 2023.

As a result, a simple comparison of peak load of Schedule RE-TOU customers to Schedule R customers could be misleading.

To provide a more accurate estimate of the peak demand reduction associated with Schedule RE-TOU, the Company unitized the load shapes of the Schedule RE-TOU customers that migrated to the Schedule in April 2022 and all Schedule R customers so they were more comparable. The results provided in the table below show that Schedule RE-TOU customers' on-peak usage during the Company's peak summer day in 2022 was 3 to 5 percent lower than Schedule R customers' on-peak usage.

Table JRK-D-3
Estimate of Schedule RE-TOU Peak Demand Reduction

	Average Usage (kWh)		Percent Daily Usage		
Hour Beginning	R	RE-TOU	R	RE-TOU	% Delta
8/11/22 12:00 AM	1.2	1.14	3.4%	3.8%	9.1%
8/11/22 1:00 AM	1.08	1.01	3.1%	3.3%	7.4%
8/11/22 2:00 AM	0.96	0.91	2.8%	3.0%	8.9%
8/11/22 3:00 AM	0.88	0.83	2.5%	2.7%	8.3%
8/11/22 4:00 AM	0.8	0.77	2.3%	2.5%	10.6%
8/11/22 5:00 AM	0.77	0.73	2.2%	2.4%	8.9%
8/11/22 6:00 AM	0.77	0.72	2.2%	2.4%	7.4%
8/11/22 7:00 AM	0.83	0.75	2.4%	2.5%	3.8%
8/11/22 8:00 AM	0.93	0.83	2.7%	2.7%	2.5%
8/11/22 9:00 AM	1.06	0.91	3.0%	3.0%	-1.4%
8/11/22 10:00 AM	1.21	1.02	3.5%	3.4%	-3.2%
8/11/22 11:00 AM	1.38	1.15	4.0%	3.8%	-4.3%
8/11/22 12:00 PM	1.56	1.3	4.5%	4.3%	-4.3%
8/11/22 1:00 PM	1.73	1.44	5.0%	4.7%	-4.4%
8/11/22 2:00 PM	1.9	1.58	5.5%	5.2%	-4.5%
8/11/22 3:00 PM	2.04	1.69	5.9%	5.6%	-4.8%
8/11/22 4:00 PM	2.17	1.78	6.2%	5.9%	-5.8%
8/11/22 5:00 PM	2.24	1.84	6.4%	6.1%	-5.6%
8/11/22 6:00 PM	2.23	1.88	6.4%	6.2%	-3.2%
8/11/22 7:00 PM	2.12	1.82	6.1%	6.0%	-1.4%
8/11/22 8:00 PM	1.99	1.75	5.7%	5.8%	1.0%
8/11/22 9:00 PM	1.87	1.66	5.4%	5.5%	2.0%
8/11/22 10:00 PM	1.67	1.5	4.8%	4.9%	3.2%
8/11/22 11:00 PM	1.44	1.31	4.1%	4.3%	4.5%
Total	34.83	30.32	100%	100.0%	

Q. ARE THE RESULTS SHOWN IN THE TABLE ABOVE ENCOURAGING?

A. Yes. The preliminary data suggests that customers are responding to the new rate structure and shifting load. The results, however, are only for a subset of customers that is not statistically representative of the entire customer population. It is therefore premature to make any definitive conclusions.

Q. HOW HAVE CUSTOMER BILLS BEEN IMPACTED BY THE MIGRATION TO SCHEDULE RE-TOU?

A. As discussed above, the RE-TOU Revenue Neutrality Report showed that Schedule RE-TOU, R, and R-OO base rate revenues received were well within a +/- three percent threshold of the baseline comparison. We separately performed a more focused analysis of the bills of customers that migrated to Schedule RE-TOU in April 2022 for this case. That analysis showed the average bill impact of migrating to Schedule RE-TOU was quite small.

Q. WHY DID YOU FOCUS ON THE CUSTOMERS THAT MIGRATED TO SCHEDULE RE-TOU IN APRIL 2022 IN THIS ANALYSIS?

A. This group of customers had a full year of billing data on Schedule RE-TOU, which is important because the Schedule RE-TOU rate was designed to be revenue neutral on an annual basis but not necessarily on a seasonal basis.

Q. PLEASE DESCRIBE THE BILL ANALYSIS.

A. The analysis assessed monthly bills for approximately 310,000 customers that were on Schedule RE-TOU from April 2022 to March 2023, comparing their bills under Schedule RE-TOU to what their bill would have been if priced under Schedule R-OO.

Q. WHAT WERE THE RESULTS OF THE ANALYSIS?

A. The analysis showed that overall, the average bill impact of migrating to Schedule RE-TOU was quite small. For the customers analyzed, the average monthly bill under Schedule RE-TOU was $67.53; if they had been priced under Schedule R-OO, the average monthly bill would have been $67.32, a difference of only $0.21

or 0.3% per month. This result indicates that rates were designed accurately, and that the rate design of Schedule RE-TOU is working as expected in terms of customer bill impacts.

Q. DID YOU ALSO ASSESS THE DISTRIBUTION OF BILL IMPACTS OF THE CUSTOMERS THAT MIGRATED TO SCHEDULE RE-TOU IN APRIL 2022?

A. Yes. The Company also investigated the distribution of bill impacts for the customers that migrated to Schedule RE-TOU in April 2022. The results showed that average monthly bill impacts were tightly clustered within +/- $5.00, with 96 percent of customers falling within this range.

Figure JRK-D-5
Distribution of Average Monthly Bill Impacts:
Schedule RE-TOU vs Schedule R-OO

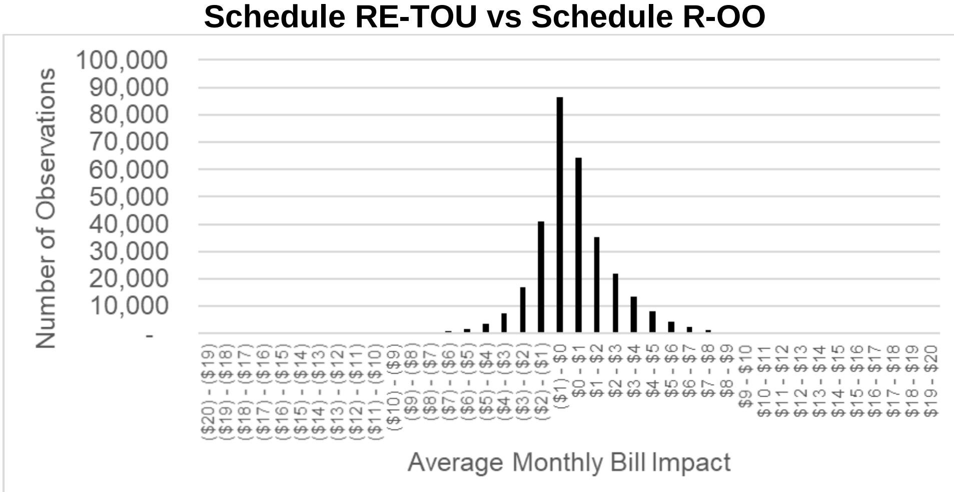
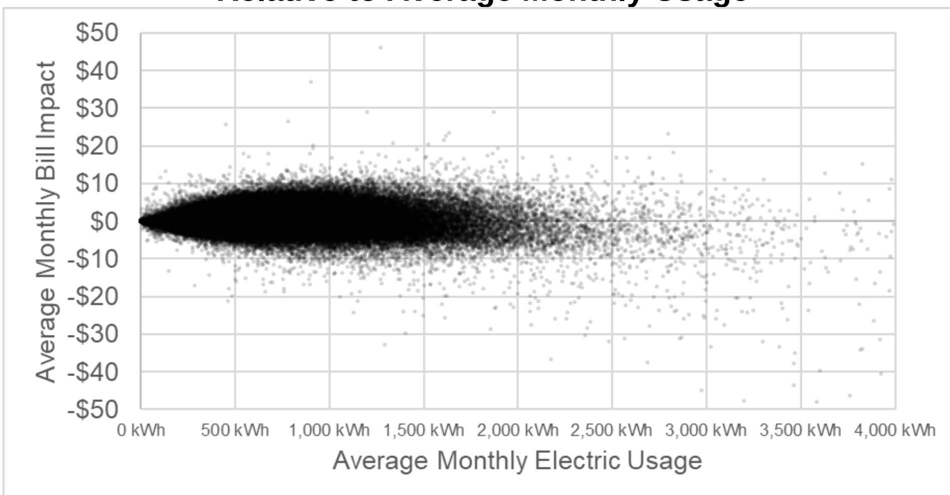


Figure JRK-D-6
Average Monthly Bill Impacts:
Schedule RE-TOU vs Schedule R-OO
Relative to Average Monthly Usage



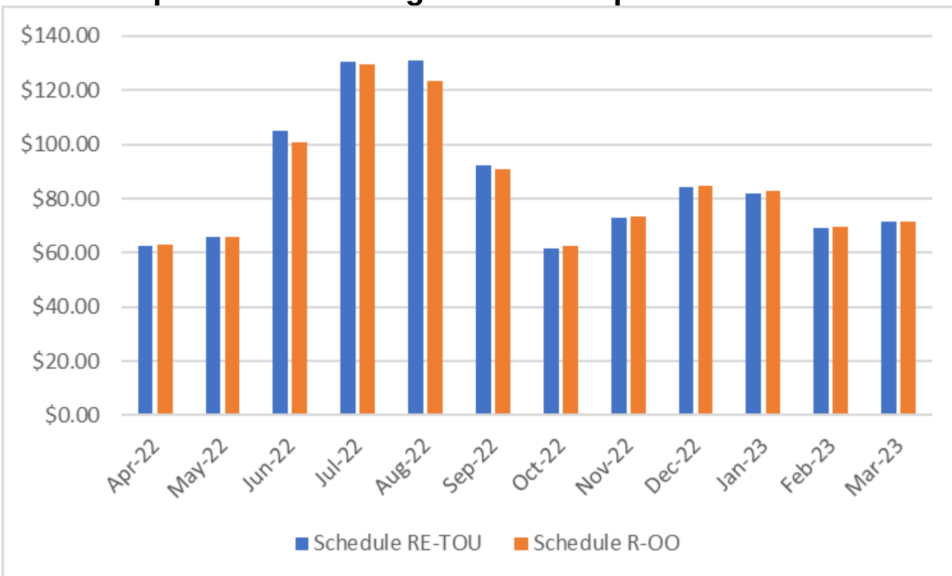
Q. HOW MANY CUSTOMERS HAVE OPTED OUT OF SCHEDULE RE-TOU?

A. About 7,800 (approximately 1.1 percent) of Residential customers that were to be migrated to Schedule RE-TOU have opted out in favor of Schedule R-OO.

Q. DO THE CUSTOMERS THAT HAVE OPTED OUT OF SCHEDULE RE-TOU HAVE SUBSTANTIALLY SIMILAR USAGE PATTERNS TO THOSE UNDER SCHEDULE RE-TOU?

A. Yes. Customers who chose to opt out of Schedule RE-TOU have substantially the same time-of-use patterns as those who have not elected to opt out. Our analysis showed that in some months their bills were lower, but in several months their bills ended up being higher under Schedule R-OO. Over the twelve-month period of April 2022 to March 2023, the average bills for Schedule R-OO customers were $0.85 lower than they would have been under Schedule RE-TOU. The following figure compares the monthly bills under each Schedule.

Figure JRK-D-7
Comparison of Average Bills For Opt-Out Customers



Q. WHAT DOES THE PERFORMANCE OF SCHEDULE RE-TOU TO DATE MEAN FOR THE DESIGN OF SCHEDULE RE-TOU IN THIS PROCEEDING?

A. As discussed above, the Residential TOU Settlement established a structure for Schedule RE-TOU and provides for that structure to remain in place until April 1, 2025. The fact that Schedule RE-TOU seems to be performing well reinforces the wisdom of allowing the process outlined in the Residential TOU Settlement to continue and reinforces the decision to maintain the structure of Schedule RE-TOU in this proceeding.

Q. HOW WERE SCHEDULE RE-TOU RATES DEVELOPED?

A. Schedule RE-TOU rates have been designed to recover the entire revenue requirement allocated to the Residential class, approximately $1,099 million, as shown in the Company's CCOSS. This ensures that the Schedule RE-TOU rates are revenue neutral to Schedules R-OO and R for the average Residential customer. The number of retail customers and total energy sales in kilowatt-hours are taken from Attachment JRK-4 to my Direct Testimony, and these kilowatt-hours were divided into the on-peak, off-peak, and shoulder periods based on the Residential class load shape used in development of the CCOSS. The Schedule RE-TOU energy rates were then developed consistent with the rate design specified in the TOU settlement, including:

- On-Peak to Off-Peak price ratio of 2.7 to 1 in the Summer (June 1 through September 30) and 1.7 to 1 in the Winter (October 1 through May 31);
- Off-Peak prices equal in both Winter and Summer;
- Shoulder prices for Winter and Summer set as the midpoint between the On-Peak and Off-Peak prices for each season; and
- TOU periods defined as:
  - On-Peak period defined as 3:00 p.m. to 7:00 p.m. on non-holiday weekdays;
  - Shoulder period defined as 1:00 p.m. to 3:00 p.m. on non-holiday weekdays; and
  - Off-peak period as all other hours.

Q. HOW DID YOU DEVELOP THE MONTHLY S&F CHARGE?

A. The monthly S&F charge was developed by dividing the customer costs allocated to the Residential class in the CCOSS by the total number of Residential class customers during the Test Year. This monthly S&F charge is calculated based on costs and billing determinants for the entire Residential class, except for Schedule

RD, and I recommend using the same S&F charge for Schedules RE-TOU, R-OO, and R.

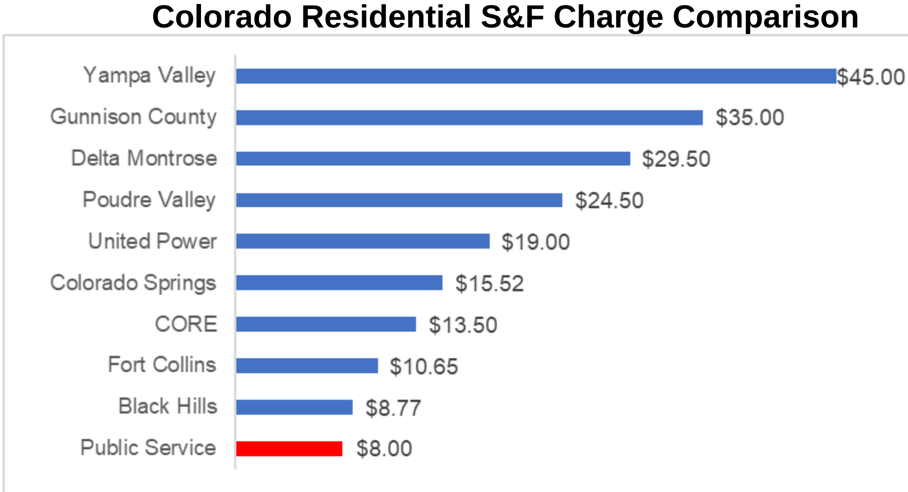
Q. ARE CUSTOMER-RELATED COSTS GREATER THAN THEY WERE IN THE 2020 PHASE II?

A. Yes. Mr. Klingeman explains that investment in customer-related assets outpaced all other investments between the test year ended August 31, 2019 (the "August 2019 Test Year"), which was the basis of the 2020 Phase II, and the Test Year. As a result, the S&F charge for Residential rate schedules is increasing.

Q. HOW DOES THE PROPOSED S&F CHARGE COMPARE TO SIMILAR CHARGES OF OTHER COLORADO ENERGY PROVIDERS?

A. Even at the proposed level of $8.00 per month, Public Service will still have the lowest S&F charge in the state. The following figure compares the Company's proposal to the standard Residential S&F charges of nine other electric service providers in the state.

Figure JRK-D-8
Colorado Residential S&F Charge Comparison



Q. WHAT ARE THE RESULTING PROPOSED NEW SCHEDULE RE-TOU RATES?

A. The new Schedule RE-TOU rates, compared to current rates are set forth below.

Table JRK-D-4

Schedule RE-TOU Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$5.60/Mo.	$8.00/Mo.
Energy Charge:		
On-peak - Summer	$0.17246/kWh	$0.22701/kWh
Shoulder - Summer	$0.11816/kWh	$0.15566/kWh
Off-peak - Summer	$0.06387/kWh	$0.08431/kWh
On-peak - Winter	$0.10858/kWh	$0.14307/kWh
Shoulder - Winter	$0.08623/kWh	$0.11369/kWh
Off-peak - Winter	$0.06387/kWh	$0.08431/kWh

2. Schedule R and R-OO

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF SCHEDULES R AND R-OO.

A. Schedules R and R-OO are identical in terms of rate design and specific charges. Schedule R is the default rate schedule for Residential customers prior to receiving an Advanced Meter. After receiving an Advanced Meter, a customer is switched to Schedule RE-TOU, consistent with the transition schedule included in the Residential TOU Settlement. If the customer chooses to opt out of TOU rates, then they will take service under Schedule R-OO. Approximately 35 percent of Residential customers are projected to take service under Schedule R during the Test Year, and less than 1 percent are projected to take service under Schedule R-OO.

Q. ARE YOU PROPOSING ANY CHANGES TO THE STRUCTURE OF SCHEDULES R-OO AND R?

A. No. Consistent with the Residential TOU Settlement, Public Service is not recommending any changes to the structure of Schedule R-OO from what was agreed to in the Residential TOU Proceeding and approved by the Commission.[41] And, consistent with the 2020 Phase II Decision,[42] we are maintaining the structure of Schedule R as a seasonal flat rate, with parity between Schedules R-OO and R.

Q. HOW ARE SCHEDULES R AND R-OO DESIGNED?

A. Schedules R and R-OO utilize seasonally differentiated flat energy rates. The winter and summer energy rates are designed to be revenue neutral to Schedule RE-TOU energy rates, and the overall rate design is revenue neutral to Schedule RE-TOU. In other words, for the average Residential customer, the energy rates for Schedules R and R-OO are the average of the on-peak, off-peak, and shoulder energy rates for Schedule RE-TOU, weighted by usage for the average customer. These rate schedules also include a monthly S&F charge, which is identical to that of Schedule RE-TOU.

[41] Residential TOU Settlement at pp. 52-54, ¶¶ 117-118; p. 69, ¶1 54; p. 80, Ordering Point 3.
[42] 2020 Phase II Decision, at pp. 32-33, ¶¶ 80-85.

Q. WHAT IS THE COMPANY'S PROPOSED S&F CHARGE FOR SCHEDULE R-OO?

A. As mentioned earlier, the Company proposes that the S&F charges for Schedules RE-TOU, R-OO, and R be set at the same level. I therefore recommend a $8.00 per month S&F charge for Schedules R-OO and R.

Q. WHAT ARE THE RESULTING PROPOSED NEW RATES FOR SCHEDULES R-OO AND R?

A. The new rates for Schedules R-OO and R, compared to current rates, are set forth in the table below.

Table JRK-D-5

Schedule R and Schedule R-OO Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$5.60/Mo.	$8.00/Mo.
Summer	$0.08356/kWh	$0.11254/kWh
Winter	$0.07136/kWh	$0.09311/kWh

3. Medical Exemption Program Discount

Q. HOW IS THE MEP DISCOUNTED RATE CALCULATED?

A. The MEP rate is calculated by dividing the total dollars recovered through energy charges for the Residential class by the total kilowatt-hours of the Residential class. In other words, it is the average energy charge for Schedule RE-TOU assuming the average customer distribution of energy usage across all seasons and TOU periods. And because Schedules R, RE-TOU, and R-OO are all revenue neutral to each other, it would also be the average of the flat seasonal energy charges for Schedules R and R-OO, again assuming average customer energy usage across the summer and winter seasons.

Q. HOW DOES THE MEP DISCOUNTED RATE BENEFIT QUALIFYING CUSTOMERS?

A. During the winter season, MEP-qualifying customers are billed standard rates under Schedule RE-TOU, R-OO, or R. During the summer, they are instead billed the MEP discounted rate, which allows them to bypass higher summer seasonal energy charges (for Schedules R and R-OO) and higher shoulder and on-peak TOU energy charges (for Schedule RE-TOU).

Q. WHAT IS THE RESULTING MEP ENERGY RATE?

A. The new MEP energy rate, compared to the current rate is shown below.

Table JRK-D-6

Medical Exemption Rate		
Rate Component	**Current**	**Proposed**
Energy Charge	$0.07596/kWh	$0.10035/kWh

4. Schedule RD

Q. PLEASE DESCRIBE SCHEDULE RD.

A. Schedule RD has summer and winter demand charges and a modest energy charge that is constant throughout the year. As stated in the Electric Tariff and mentioned above, Schedule RD was closed to new participants as of December 31, 2016.

Q. HOW MANY CUSTOMERS ARE ON SCHEDULE RD?

A. There are approximately 1,000 customers projected to take service under Schedule RD during the Test Year, which represents approximately 0.1% of the Residential class.

Q. WHAT IS YOUR RECOMMENDATION REGARDING SCHEDULE RD?

A. I recommend no structural changes to the rate design of Schedule RD, but I do recommend updated rate levels.

Q. HOW DID YOU CALCULATE THE UPDATED SCHEDULE RD RATE LEVELS?

A. Customer-related costs are recovered through the monthly S&F charge. The remaining costs are split between the energy charge and seasonal demand charges. I calculated the energy charge by increasing it by the percentage change in the average energy charge for Schedules RE-TOU, R-OO, and R between the 2020 Phase II and the proposed rates in this Proceeding. I then calculated the summer and winter demand charges to recover the remaining revenue requirement. The resulting total rate is revenue neutral to the other Residential rates (Schedules RE-TOU, R-OO, R) for the average customer taking service under Schedule RD and so that the winter to summer demand charge ratio is equal to 77 percent.

Q. HOW DID YOU CALCULATE THE MONTHLY S&F CHARGE FOR SCHEDULE RD?

A. Schedule RD historically had a higher monthly S&F charge than the other Residential rate schedules because of the more complicated billing and metering required for Schedule RD compared to the other Residential rate schedules which have no demand component. I updated the monthly S&F charge for Schedule RD by escalating the current charge by the increase in the monthly S&F charge for Schedules RE-TOU, R-OO, and R from the 2020 Phase II to the rates proposed in this Proceeding.

Q. WHAT ARE THE RESULTING SCHEDULE RD RATES?

A. The new Schedule RD rates, compared to current rates, are set forth below.

Table JRK-D-7

Schedule RD Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$12.02/Mo.	$17.26/Mo.
Demand Charge - Summer	$14.12/kW-Mo.	$18.63/kW-Mo.
Demand Charge - Winter	$10.87/kW-Mo.	$14.34/kW-Mo.
Energy Charge	$0.01958/kWh	$0.02614/kWh

5. Revenue Proof Adjustment

Q. WAS A REVENUE PROOF ADJUSTMENT INCLUDED IN THE PROPOSED RATES FOR THE RESIDENTIAL CLASS?

A. Yes. The proposed rates include a revenue proof adjustment to the monthly S&F charges of + $0.05 per month and an adjustment to the monthly energy charges of $0.00037 per kWh.

B. Small Commercial

Q. PLEASE PROVIDE AN OVERVIEW OF THE SMALL COMMERCIAL CLASS.

A. The Small Commercial class consists of approximately 120,000 commercial customers with peak loads of 50 kW or less, and accounts for approximately 4.5 percent of total projected retail sales in the Test Year.

Q. DO SMALL COMMERCIAL CUSTOMERS HAVE CHOICES IN THEIR RATE SCHEDULE?

A. Yes. Similar to Residential customers, Small Commercial customers have rate options depending on whether they have an Advanced Meter. After a Small Commercial customer receives an Advanced Meter, they move to Schedule C-TOU by default. Customers who have not moved to Schedule C-TOU, and customers who opt out of the TOU rate, take service under the standard Schedule C. Certain non-fluctuating loads may take service under Schedule NMTR, which uses the same seasonal energy prices as Schedule C.

Q. ARE YOU RECOMMENDING ANY CHANGES TO THE RATE OPTIONS AVAILABLE FOR SMALL COMMERCIAL CUSTOMERS?

A. No. Public Service is updating rate levels for the latest revenue requirement, class allocation, and billing determinants, but is making no structural changes to Small Commercial rates.

1. Schedule C-TOU

Q. PLEASE DESCRIBE SCHEDULE C-TOU.

A. Schedule C-TOU is similar in design to Schedule RE-TOU. Schedule C-TOU uses seasonally differentiated off-peak, shoulder, and on-peak energy charges, along with a monthly S&F charge.

Q. HOW WERE SCHEDULE C-TOU RATES DEVELOPED?

A. Schedule C-TOU rates have been designed to recover the entire revenue requirement allocated to the Small Commercial class, approximately $123 million, as shown in the Company's CCOSS. This ensures that the Schedule C-TOU rates are revenue neutral to Schedules C and NMTR for the average Small Commercial customer. The number of retail customers and total energy sales in kWh are taken from Attachment JRK-4 to my Direct Testimony, and these kWh were divided into the on-peak, off-peak, and shoulder periods based on the Small Commercial class load shape used in development of the CCOSS. The Schedule C-TOU rates were then developed with similar rate design parameters as Schedule RE-TOU, including:

- On-Peak to Off-Peak price ratio of 2.7 to 1 in the Summer (June 1 through September 30) and 1.7 to 1 in the Winter (October 1 through May 31);
- Off-Peak prices equal in both Winter and Summer;
- Shoulder prices for Winter and Summer set as the midpoint between the On-Peak and Off-Peak prices for each season; and
- TOU periods defined as:
    - On-Peak period defined as 3:00 to 7:00 p.m. on non-holiday weekdays;
    - Shoulder period defined as 1:00 to 3:00 p.m. and 7:00 p.m. to 9:00 p.m. on non-holiday weekdays; and
    - Off-Peak period defined as all other hours.

Q. HOW DID YOU CALCULATE THE SCHEDULE C-TOU S&F CHARGE?

A. The monthly S&F charge was developed by dividing the customer-related costs allocated to the Small Commercial class in the CCOSS by the total number of Small Commercial class customers during the Test Year, with an adjustment to account for revenues associated with the Schedule NMTR monthly S&F charge. The monthly S&F charge for Schedules C-TOU and C is calculated based on costs and billing determinants for the entire Small Commercial class, except for Schedule NMTR, and I recommend using the same S&F charge for Schedules C-TOU and C.

Q. WHAT ARE THE RESULTING PROPOSED NEW SCHEDULE C-TOU RATES?

A. The new Schedule C-TOU rates, compared to current rates are set forth below.

Table JRK-D-8

Schedule C-TOU Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$10.68/Mo.	$10.50/Mo.
Energy Charge - On-peak - Summer	$0.14352/kWh	$0.18164/kWh
Energy Charge - Shoulder - Summer	$0.09834/kWh	$0.12464/kWh
Energy Charge - Off-peak - Summer	$0.05315/kWh	$0.06764/kWh
Energy Charge - On-peak - Winter	$0.09036/kWh	$0.11458/kWh
Energy Charge - Shoulder - Winter	$0.07176/kWh	$0.09111/kWh
Energy Charge - Off-peak - Winter	$0.05315/kWh	$0.06764/kWh

2. Schedule C and NMTR

Q. PLEASE DESCRIBE SCHEDULE C.

A. Schedule C is a kWh-based rate and includes a monthly S&F charge. The energy charge differs by seasons, with a higher energy price in the summer months.

Q. PLEASE DESCRIBE SCHEDULE NMTR.

A. Schedule NMTR is non-metered service available to municipal, county, state and federal governments, quasi-governmental entities, and other utilities that take electric service at secondary voltage. Schedule NMTR is only available in those instances where the customer’s usage does not fluctuate, or if having a meter would be hazardous to the public, and/or Company personnel requiring access to a meter installation or service requirements with extremely low usage, and/or where it may not be economical to install and read a meter. Customers wishing to take service under Schedule NMTR must specifically enter into a service agreement with the Company. Schedule NMTR is identical to Schedule C in terms of rate design and pricing.

Q. HOW WERE SCHEDULES C AND NMTR RATES DEVELOPED?

A. Like Schedule C-TOU, Schedules C and NMTR energy rates are designed based on the entire revenue requirement allocated to the Small Commercial class and the entire Small Commercial class billing determinants. This ensures that the Schedule C and NMTR rates are revenue neutral to Schedule C-TOU for the average Small Commercial customer. The Schedule C and NMTR energy rates are calculated using a 60% winter to summer energy price ratio.

As discussed above, I propose a monthly S&F charge for Schedule C identical to that of Schedule C-TOU. Schedule NMTR has a lower monthly S&F charge because no meter costs are associated with that service. To calculate the monthly S&F charge for Schedule NMTR, I adjusted the current monthly S&F charge for Schedule NMTR by the change in monthly S&F charges for Schedules C and C-TOU from the 2020 Phase II to the rates proposed in this Proceeding.

Q. WHAT ARE THE RESULTING RATES FOR SCHEDULES C AND NMTR?

A. The new rates for Schedules C and NMTR, compared to current rates are shown below.

Table JRK-D-9

Schedule C Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$10.68/Mo.	$10.50/Mo.
Energy Charge - Summer	$0.08852/kWh	$0.11313/kWh
Energy Charge - Winter	$0.05314/kWh	$0.06811/kWh
Schedule NMTR Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$3.02/Mo.	$3.03/Mo.
Energy Charge - Summer	$0.08852/kWh	$0.11313/kWh
Energy Charge - Winter	$0.05314/kWh	$0.06811/kWh

3. Revenue Proof Adjustment

Q. WAS A REVENUE PROOF ADJUSTMENT INCLUDED IN THE PROPOSED RATES FOR THE SMALL COMMERCIAL CLASS?

A. Yes. The proposed rates include a revenue proof adjustment to monthly S&F charges of + $0.08 per month and an adjustment to the monthly energy charges of $0.00058 per kWh.

C. C&I Secondary

Q. PLEASE PROVIDE AN OVERVIEW OF THE C&I SECONDARY CLASS.

A. The C&I Secondary class is the Company’s largest customer class in terms of sales volumes. The class is made up of about 44,000 C&I customers that interconnect to Public Service’s system at secondary distribution voltage of 120 or 277 volts.

Q. HOW MANY RATE OPTIONS ARE THERE FOR SECONDARY VOLTAGE C&I CUSTOMERS?

A. There are several different rate schedules for C&I customers taking service at secondary voltage. These schedules include: Schedule SG, Schedule SGL, Schedule SPVTOU, Schedule SG-CPP, Schedule SST, Schedule SG-TOU Pilot, Schedule S-EV and Schedule S-EV-CPP.

Q. DO YOU ADDRESS THE RATE DEVELOPMENT FOR ALL C&I SECONDARY RATE SCHEDULES IN THIS SECTION OF YOUR DIRECT TESTIMONY?

A. No. Because of similarities in rate design between CPP, standby service, Special Contract Service, and Recycled Energy Service rate schedules across the C&I Secondary, C&I Primary, and C&I Transmission classes, I will address each of these rate categories in a later section of my Direct Testimony.

Q. ARE YOU PROPOSING ANY STRUCTURAL CHANGES TO C&I SECONDARY RATE SCHEDULES?

A. Yes. As discussed in more detail below, I propose to amend Schedule SG and Schedule SG-CPP to include time-differentiated generation and transmission ("G&T") demand charges, in which G&T demand charges are assessed based on demand measured between the hours of 2 p.m. to 7 p.m. on non-holiday weekdays. Additionally, I propose to update the time-differentiated G&T demand charge currently used in Schedule SPVTOU-B to be based on demand measured between the hours of 2 p.m. to 7 p.m. to match the proposed rates for Schedule SG and Schedule SG-CPP.[43] There are no other changes to the structure of the C&I Secondary rate schedules, though rate levels are updated for the latest revenue requirement, class allocation, and billing determinants.

[43] Schedule SPVTOU-B currently uses a time-differentiated G&T demand charge based on demand measured between 2 p.m. to 6 p.m. on non-holiday weekdays.

1. Schedule SG

Q. PLEASE DESCRIBE SCHEDULE SG.

A. Approximately 40 percent of the Company's total sales volume occurs under Schedule SG, making it the Company's largest individual rate schedule by sales volume. Schedule SG consists of a monthly S&F charge, a distribution demand charge that utilizes a 50 percent ratchet,[44] a seasonally differentiated G&T demand charge, and a modest energy charge that accounts for Company-owned wind energy resources and variable operations and maintenance ("O&M") expenses on Public Service's system.

Q. WHAT CHANGES ARE YOU RECOMMENDING FOR SCHEDULE SG?

A. As discussed above, I propose to modify the G&T demand charge for Schedule SG to only account for measured demands during the hours of 2 p.m. to 7 p.m. on non-holiday weekdays. This will better align the G&T demand charge with cost causation, as system loads outside of those peak hours are typically lower and can be served at a lower cost than demands within the 2 p.m. to 7 p.m. window. The time-differentiated G&T demand charge would send a similar price signal as TOU energy rates to shift usage outside of those peak hours and into lower cost hours, but as discussed by Mr. Wishart, they also encourage customers to flatten their load profile. I propose similar changes to Schedule SG-CPP in the CPP rate design section of my Direct Testimony.

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[44] The demand ratchet specifies that the billing demand for the distribution charge will be the greater of the actual measured demand or 50 percent of the highest measured demand over the preceding 12 months.

Q. DO ALL SCHEDULE SG CUSTOMERS HAVE THE METERING NECESSARY TO IMPLEMENT TIME-DIFFERENTIATED DEMAND CHARGES?

A. Not at this time. Some C&I Secondary customers do not have the interval metering necessary for the calculation and billing of time-differentiated demand charges. However, Advanced Meters will make these time-differentiated demand charges possible for C&I Secondary customers who do not currently have interval meters. Because of this, the proposed Schedule SG rates include both time-differentiated and standard G&T demand charges. After Schedule SG customers receive an Advanced Meter, they will be transitioned from the standard G&T demand charges to the time-differentiated G&T demand charges.

Q. WHEN WILL SCHEDULE SG CUSTOMERS BE TRANSITIONED TO TIME-DIFFERENTIATED G&T DEMAND CHARGES?

A. I propose a transition schedule based on when the customer receives their Advanced Meter, similar to the transition of Residential and Small Commercial customers from flat energy rates to TOU rates. This schedule is included in the proposed Schedule SG tariff language. Specifically, the Company proposes to transition any customer who receives their Advanced Meter by December 31, 2024, on the billing cycle that includes April 1, 2025. Any customers who receive their Advanced Meter on or after January 1, 2025, will be transitioned to time-differentiated demand charges with the billing cycle that includes April 1 of the year following their receipt of an Advanced Meter.

Q. HOW WERE SCHEDULE SG RATES DEVELOPED?

A. I developed the Schedule SG rates based on class costs presented in the CCOSS and billing determinants from Attachment JRK-4. The S&F charge is designed to recover all of the customer-related costs from the CCOSS, and I propose to use the same monthly S&F charge for all C&I Secondary rate schedules. The distribution demand charge recovers all distribution costs and is based on the distribution billing demands in Attachment JRK-4, which include the 50 percent demand ratchet. The standard G&T demand charge is designed to recover transmission and production costs from the CCOSS based on demand billing determinants from Attachment JRK-4. To calculate the time-differentiated G&T demand charge, I converted these demand billing determinants, which are based on demand measured in any hour, to demand billing determinants for only the hours of 2 p.m. to 7 p.m. on weekdays based on 15-minute load data for a sample of the C&I Secondary class.

Q. WHAT ARE THE RESULTING PROPOSED SCHEDULE SG RATES?

A. The proposed Schedule SG rates, compared to current rates, are set forth below.

Table JRK-D-10

Schedule SG Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$41.13/Mo.	$70.28/Mo.
Demand Charge - Distribution	$6.17/kW-Mo.	$9.85/kW-Mo.
Demand Charge - G&T Summer	$15.15/kW-Mo.	$18.26/kW-Mo.
Demand Charge - G&T Winter	$9.09/kW-Mo.	$10.99/kW-Mo.
Energy Charge	$0.00791/kWh	$0.00939/kWh
Time-Differentiated G&T Demand Charges		
Time-Diff. G&T Summer	--	$19.86/kW-Mo.
Time-Diff. G&T Winter	--	$11.95/kW-Mo.

2. Schedule SGL

Q. PLEASE DESCRIBE SCHEDULE SGL.

A. There are about 500 customers taking service on Schedule SGL, which accounts for 0.03 percent of Public Service’s total retail sales. The rate is designed such that a customer with a load factor of 11 percent or less would benefit by switching from Schedule SG to Schedule SGL. This is accomplished by replacing the G&T demand charge included in Schedule SG with kWh-based winter and summer energy charges. The winter energy charge is set at 70 percent of the summer energy charge. SGL utilizes the same monthly S&F charge and distribution demand charge as Schedule SG described above.

Q. WHAT ARE THE RESULTING SCHEDULE SGL RATES?

A. The proposed Schedule SGL rates and a comparison to present rates are presented below.

Table JRK-D-11

Schedule SGL Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$41.13/Mo.	$70.28/Mo.
Demand Charge - Distribution	$6.17/kW-Mo.	$9.85/kW-Mo.
Energy Charge - Summer	$0.17884/kWh	$0.20509/kWh
Energy Charge - Winter	$0.12519/kWh	$0.14356/kWh

3. Schedule SPVTOU

Q. PLEASE DESCRIBE SCHEDULE SPVTOU.

A. Schedule SPVTOU is intended to make solar net metering more financially viable for commercial customers. This rate has two options, Schedule Secondary Photovoltaic Time-of-Use Service Rate – Option A ("SPVTOU-A") and Schedule Secondary Photovoltaic Time-of-Use Service Rate – Option B ("Schedule SPVTOU-B"). Schedule SPVTOU-A has approximately 150 customers, and accounts for 0.25 percent of total retail sales. Public Service launched Schedule SPVTOU-B in 2017, and currently has about 75 participants.

Q. WHY ARE THERE TWO OPTIONS UNDER SCHEDULE SPVTOU?

A. SPVTOU-B was introduced and approved in the Company's 2016 Phase II (Proceeding No. 16AL-0048E) as a replacement to SPVTOU-A. Specifically, the Three-Case Settlement therein provided that customers on Schedule SPVTOU as of December 31, 2016 would remain eligible for service under that schedule (which became SPVTOU-A), as would customers awarded capacity in calendar year 2016, but did not have their PV system online prior to the end of 2016.[45] All other

[45] Proceeding No. 16AL-0048E, Non-Unanimous Comprehensive Settlement Agreement, p. 22 (Filed August 15, 2016).

customers would take service under a revised Schedule SPVTOU (which became SPVTOU-B). At this point, based on the Applicability provision in Schedule SPVTOU, SPVTOU-A is effectively closed to new participants.

Q. PLEASE DESCRIBE THE STRUCTURE OF SCHEDULE SPVTOU.

A. The rate has the same distribution demand charge and monthly S&F charge as Schedule SG, but the G&T demand charges are much lower. The lower G&T demand charges are offset by on-peak and off-peak energy charges that are higher than the energy charges under Schedule SG. The rate under Schedule SPVTOU-B is structured such that 75 percent of cost recovery is removed from the G&T demand charges and added to the energy charges. Additionally, the G&T demand charge for Schedule SPVTOU-B is time-differentiated, with charges assessed only for demands measured between 2 p.m. and 6 p.m. on non-holiday weekdays.

Q. DO YOU PROPOSE ANY STRUCTURAL CHANGES TO SCHEDULE SPVTOU?

A. For Schedule SPVTOU-B, I propose to update the demand measurement window for the time-differentiated G&T demand charge from 2 p.m. - 6 p.m. to 2 p.m. - 7 p.m. This will align the SPVTOU-B G&T demand charge calculation with the proposed demand charge calculations for Schedule SG and with Schedule PG, so that all time-differentiated G&T demand charges have the same demand measurement window. To accomplish this, I used the same adjustment to the billing determinants described above for Schedule SG to convert to 2 p.m. to 7 p.m. demands. Otherwise, I simply adjusted the rate levels for Schedules

SPVTOU-A and SPVTOU-B for the updated revenue requirement, CCOSS allocations, and billing determinants.

Q. WHAT ARE THE RESULTING SCHEDULE SPVTOU RATES?

A. The rates for Schedules SPTOU-A and SPVTOU-B, as compared to present rates, are shown below.

Table JRK-D-12

Schedule SPVTOU-Section A Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$41.13/Mo.	$70.28/Mo.
Demand Charge - Distribution	$6.17/kW-Mo.	$9.85/kW-Mo.
On-Peak Energy Charge	$0.14636/kWh	$0.17861/kWh
Off-Peak Energy Charge	$0.02590/kWh	$0.03160/kWh
Schedule SPVTOU-Section B Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$41.13/Mo.	$70.28/Mo.
Demand Charge - Distribution	$6.17/kW-Mo.	$9.85/kW-Mo.
Demand Charge - G&T Summer	$2.99/kW-Mo.	$4.65/kW-Mo.
Demand Charge - G&T Winter	$2.10/kW-Mo.	$3.28/kW-Mo.
Energy Charge – On-Peak	$0.12038/kWh	$0.14148/kWh
Energy Charge – Off-Peak	$0.02130/kWh	$0.02503/kWh

4. Schedule S-EV and S-EV-CPP

Q. PLEASE DESCRIBE SCHEDULES S-EV AND S-EV-CPP.

A. Schedules S-EV and S-EV-CPP are optional services available to C&I customers for charging their own EVs or providing charging services to third parties for a fee. Schedule S-EV-CPP (then called Schedule S-EV) was authorized in the Company’s S-EV TOU Electrical Vehicle Service tariff filing, Proceeding No. 19AL-0290E. In Proceeding No. 21AL-0494E (the “2021 S-EV Proceeding”), the Company re-named S-EV as S-EV-CPP and updated the rate based on actual EV customer usage data. In the 2021 S-EV Proceeding, the Company also created a new Schedule S-EV rate without CPP pricing. These rate designs were recently approved by the Commission in Decision No. C22-0590 (mailed August 15, 2022).

Q. HOW DID YOU CALCULATE UPDATED RATES FOR SCHEDULES S-EV AND S-EV-CPP?

A. I maintained the price ratios established in the 2021 S-EV Proceeding and updated the rate levels for the latest revenue requirement, class allocation, and billing determinants. I did this by increasing the distribution demand charges for Schedules S-EV and S-EV-CPP by the percent change in the distribution demand charge for Schedule SG from the 2020 Phase II to the rates proposed in this Proceeding. Similarly, I increased the seasonal on and off-peak energy charges by the percent change in the energy charge for Schedule SG from the 2020 Phase II to the rates proposed in this Proceeding. Similar to the Company's other CPP rates, I propose no change to the CPP Energy Charge component of S-EV-CPP. Finally, I propose to use the Schedule SG monthly S&F charge for both C&I Secondary EV rates.

Q. WHAT ARE THE RESULTING RATES FOR S-EV AND S-EV-CPP?

A. The table below presents the proposed rates for both rate schedules along with a comparison to present rates.

Table JRK-D-13

Schedule S-EV Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$41.13/Mo.	$70.28/Mo.
Demand Charge - Distribution	$3.01/kW-Mo.	$4.85/kW-Mo.
Energy Charge – Summer On-Peak	$0.13024/kWh	$0.15476/kWh
Energy Charge – Summer Off-Peak	$0.02605/kWh	$0.03095/kWh
Energy Charge – Winter On-Peak	$0.06512/kWh	$0.07738/kWh
Energy Charge – Winter Off-Peak	$0.01302/kWh	$0.01546/kWh

Schedule S-EV-CPP Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$41.13/Mo.	$70.28/Mo.
Demand Charge - Distribution	$3.01/kW-Mo.	$4.85/kW-Mo.
Energy Charge – Summer On-Peak	$0.06935/kWh	$0.08240/kWh
Energy Charge – Summer Off-Peak	$0.01387/kWh	$0.01647/kWh
Energy Charge – Winter On-Peak	$0.03467/kWh	$0.04119/kWh
Energy Charge – Winter Off-Peak	$0.00693/kWh	$0.00823/kWh
CPP - Energy Charge	$1.44/kWh	$1.44/kWh

5. Schedule SG-TOU Pilot

Q. PLEASE DESCRIBE SCHEDULE SG-TOU.

A. Schedule SG-TOU is a rate pilot available to certain C&I Secondary customers after they receive an Advanced Meter. The SG-TOU pilot rate utilizes a monthly S&F charge, a small distribution demand charge, and seasonal TOU energy rates, with the design being the result of a stakeholder process coming out of the 2020 Phase II. The pilot rate was made available to eligible C&I Secondary customers on July 1, 2022.

Q. HOW LONG WILL THE SCHEDULE SG-TOU PILOT BE AVAILABLE?

A. Decision No. R21-0040 in the 2020 Phase II specified that the SG-TOU pilot rate should be made available for the duration of the Company's Advanced Meter rollout. The decision also requires the Company to file an advice letter in the last quarter of 2024 to report on the results of the SG-TOU pilot and to include a proposal to continue, terminate, or amend the SG-TOU pilot.

Q. HAVE ANY CUSTOMERS BEGUN PARTICIPATION IN THE SG-TOU PILOT?

A. No, not yet. However, the Company is conducting outreach to C&I Secondary customers as they receive their Advanced Meters and expects participation to begin as more customers receive their Advanced Meters and become eligible for the pilot. In the SG-TOU Proceeding, the Company agreed to continued stakeholder meetings to report on the progress of the pilot and to prepare for the 2024 advice letter filing.

Q. HOW WERE SCHEDULE SG-TOU RATES DEVELOPED?

A. Schedule SG-TOU rates are designed to recover the entire revenue requirement allocated to the C&I Secondary class in the CCOSS and using the C&I Secondary class billing determinants taken from Attachment JRK-4. A small distribution demand charge is calculated to recover all secondary voltage distribution costs allocated to C&I Secondary customers in the CCOSS. Then, the remainder of the C&I Secondary costs, except for customer-related costs, are recovered through a seasonal TOU energy charge, with on-peak, off-peak, and shoulder periods equal to those used in Schedule C-TOU. Price ratios between on-peak, off-peak, and shoulder energy charges were determined in the 2020 Phase II, and I propose to continue to use those price ratios. Schedule SG-TOU uses the same monthly S&F charge as Schedule SG to recover customer-related costs.

Q. WHAT ARE THE RESULTING SCHEDULE SG-TOU RATES?

A. The proposed Schedule SG-TOU rates are presented in the table, along with a comparison to present rates.

Table JRK-D-14

Schedule SG-TOU Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$41.13/Mo.	$70.28/Mo.
Demand Charge - Distribution	$1.01/kW-Mo.	$1.68/kW-Mo.
Energy Charge - On-peak - Summer	$0.15634/kWh	$0.20306/kWh
Energy Charge - Shoulder - Summer	$0.06642/kWh	$0.08626/kWh
Energy Charge - Off-peak - Summer	$0.04044/kWh	$0.05252/kWh
Energy Charge - On-peak - Winter	$0.09521/kWh	$0.12366/kWh
Energy Charge - Shoulder - Winter	$0.05117/kWh	$0.06646/kWh
Energy Charge - Off-peak - Winter	$0.04044/kWh	$0.05252/kWh

6. Revenue Proof Adjustment

Q. WAS A REVENUE PROOF ADJUSTMENT INCLUDED IN THE PROPOSED RATES FOR THE C&I SECONDARY CLASS?

A. Yes. The proposed rates include a revenue proof adjustment to monthly S&F charges of +$0.05 per month, an adjustment to the monthly demand charges of +$0.09 per kW-month, and an adjustment to the energy charges of -$0.00001 per kWh.

D. C&I Primary

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S C&I PRIMARY CLASS.

A. The C&I Primary class is made up of about 700 large C&I customers that interconnect to the Company's system at primary distribution voltage.

Q. HOW MANY RATE OPTIONS ARE THERE FOR C&I PRIMARY CUSTOMERS?

A. There are several different rate schedules for C&I customers taking service at primary voltage. These schedules include: Schedule PG, Schedule PST and Schedule PG-CPP. Schedule SCS-7 is a customer-specific for service at primary voltage. Further, the Company proposes to add two new EV service options for customers at primary voltage in this Proceeding – one with TOU energy charges and another with an added CPP rate component. These new options are modeled after the Schedules S-EV and S-EV-CPP currently available to C&I Secondary customers.

Q. DO YOU ADDRESS THE DEVELOPMENT OF ALL C&I PRIMARY RATE SCHEDULES IN THIS SECTION OF YOUR DIRECT TESTIMONY?

A. No. Because of similarities in rate design between CPP, standby service, Special Contract Service, and Recycled Energy Service rate schedules between C&I Secondary, C&I Primary, and C&I Transmission, I will address each of these rate categories in a later section of my Direct Testimony.

Q. IS THE COMPANY RECOMMENDING ANY STRUCTURAL CHANGES TO EXISTING RATES IN THE C&I PRIMARY CLASS?

A. I propose to amend the time-differentiated demand charge for Schedule PG-CPP, which is currently based on demand measured between 2 p.m. and 6 p.m. on non-holiday weekdays, to instead be based on demand measured between 2 p.m. and 7 p.m. on non-holiday weekdays. This will align the demand calculation for Schedule PG-CPP with Schedule PG. Schedule PG-CPP will be discussed in more detail in a later section of my Direct Testimony. I recommend no other structural changes for any of the existing C&I Primary rates. Instead, I simply update the rates to incorporate the latest CCOSS and test year billing determinants.

1. Schedule PG

Q. PLEASE DESCRIBE SCHEDULE PG.

A. Schedule PG is the largest C&I Primary rate schedule, and it accounts for 13 percent of the Company's total sales volume. Schedule PG consists of a monthly S&F charge, a distribution demand charge that utilizes a 50 percent ratchet,[46] a time-differentiated G&T demand charge with a winter / summer ratio of 67 percent, and a modest energy charge that accounts for Company-owned wind energy resources and variable O&M expenses on the Company's system. The time-differentiated G&T demand charge for Schedule PG is measured only from 2:00 p.m. to 7:00 p.m. weekdays, excluding holidays.

Q. HOW WERE SCHEDULE PG RATES DEVELOPED?

A. I developed the Schedule PG rates based on class costs presented in the CCOSS and billing determinants from Attachment JRK-4. The S&F charge is designed to recover all of the customer-related costs from the CCOSS, and I propose to use the same monthly S&F charge for all C&I Primary rate schedules. The distribution demand charge recovers all distribution costs and is based on the distribution billing demands in Attachment JRK-4, which include the 50 percent demand ratchet. The time-differentiated G&T demand charge is designed to recover

[46] The demand ratchet specifies that the billing demand for the distribution charge will be the greater of the actual measured demand for 50 percent of the highest measured demand over the preceding twelve months.

transmission and production costs from the CCOSS based on demand billing determinants from Attachment JRK-4.

Q. WHAT ARE THE RESULTING RATES FOR SCHEDULE PG?

A. Proposed Schedule PG rates, along with a comparison to present rates, are shown below.

Table JRK-D-15

Schedule PG Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$432.31/Mo.	$655.77/Mo.
Demand Charge - Distribution	$4.23/kW-Mo.	$6.41/kW-Mo.
Demand Charge - G&T Summer	$14.97/kW-Mo.	$19.35/kW-Mo.
Demand Charge - G&T Winter	$10.03/kW-Mo.	$12.89/kW-Mo.
Energy Charge	$0.00778/kWh	$0.00753/kWh

2. Schedules P-EV and P-EV-CPP

Q. PLEASE DESCRIBE THE NEWLY PROPOSED EV RATE OPTIONS FOR C&I PRIMARY CUSTOMERS.

A. Schedules P-EV and P-EV-CPP are modeled after the existing Schedules S-EV and S-EV-CPP, respectively. Both rate options use the same monthly S&F charge as Schedule PG. Both rates include a small distribution demand charge that is approximately 50 percent of the Schedule PG distribution demand charge. For Schedule P-EV, the remainder of the allocated costs are recovered through seasonal TOU energy charges, with on-peak pricing from 2 p.m. to 10 p.m. on non-holiday weekdays and off-peak pricing in all other hours. Schedule P-EV-CPP has a similar TOU energy rate structure but also includes a high CPP energy charge that applies during CPP events. Because of the high CPP charge, the TOU energy rates for Schedule P-EV-CPP are lower than those of Schedule P-EV.

Q. HOW WERE RATES DEVELOPED FOR SCHEDULES P-EV AND P-EV-CPP?

A. Schedules P-EV and P-EV-CPP rates are based on the design of Schedules S-EV and S-EV-CPP, respectively. As described earlier in my Direct Testimony, these rates were recently approved in the 2021 S-EV Proceeding. To calculate the distribution demand charges, I applied the ratio between the distribution demand charges of Schedule S-EV and S-EV-CPP and that of Schedule SG. I similarly calculated TOU energy rates by applying the ratio of Schedule S-EV and S-EV-CPP energy rates to Schedule SG energy rate to the Schedule PG energy rate. The CPP energy rate for Schedule P-EV-CPP matches the CPP energy rate for PG-CPP. Because Schedules SG and PG have identical rate design for distribution demand charges and energy charges, this derivation of Schedule P-EV and P-EV-CPP rates essentially applies all of the rate design assumptions developed in the 2021 S-EV Proceeding to these new EV rates for C&I Primary customers.

Q. WHAT ARE THE RESULTING RATES FOR SCHEDULES P-EV AND P-EV-CPP?

A. The proposed rates are shown below.

Table JRK-D-16

New Schedule P-EV Proposed Rates	
Rate Component	**Rate**
S&F Charge	$655.77/Mo.
Demand Charge - Distribution	$3.01/kW-Mo.
Energy Charge – Summer On-Peak	$0.12398/kWh
Energy Charge – Summer Off-Peak	$0.02480/kWh
Energy Charge – Winter On-Peak	$0.06199/kWh
Energy Charge – Winter Off-Peak	$0.01239/kWh

New Schedule P-EV-CPP Proposed Rates	
Rate Component	**Rate**
S&F Charge	$655.77/Mo.
Demand Charge - Distribution	$3.01/kW-Mo.
Energy Charge – Summer On-Peak	$0.06602/kWh
Energy Charge – Summer Off-Peak	$0.01320/kWh
Energy Charge – Winter On-Peak	$0.03300/kWh
Energy Charge – Winter Off-Peak	$0.00660/kWh
CPP - Energy Charge	$1.40/kWh

3. Revenue Proof Adjustment

Q. WAS A REVENUE PROOF ADJUSTMENT INCLUDED IN THE PROPOSED C&I PRIMARY RATES?

A. Yes. The proposed rates include a revenue proof adjustment to the monthly demand charges of -$0.22 per kW-month, and an adjustment to the monthly S&F charges of +$1.50 per month.

E. C&I Transmission

Q. PLEASE PROVIDE AN OVERVIEW OF THE C&I TRANSMISSION CLASS AND ITS RATE SCHEDULES.

A. The C&I Transmission class consists of the largest customers on Public Service's system that take service at voltages of 138,000 volts and above. These customers typically are large industrial customers and independent power producers that own generation assets interconnected with the Company's system. The main rate is Schedule TG. This rate includes about 20 customers that represent over eight percent of total retail sales.

The transmission voltage class also includes Schedule TST, which is a standby rate. There are 12 customers on Schedule TST. Generally, these customers are independent power producers that have the ability to produce energy for their own needs, but they rely on Public Service for house power during periods when their generators are not running.

The Transmission class also includes Schedule TG-CPP, which is a CPP pricing option, but no customer has chosen this pricing option to date.

Q. DO YOU ADDRESS THE DEVELOPMENT OF ALL C&I TRANSMISSION RATE SCHEDULES IN THIS SECTION OF YOUR DIRECT TESTIMONY?

A. No. Because of similarities in rate design between CPP, standby service, Special Contract Service, and Recycled Energy Service rate schedules between C&I Secondary, C&I Primary, and C&I Transmission, I will address each of these rate categories in a later section of my Direct Testimony.

Q. ARE YOU RECOMMENDING ANY STRUCTURAL CHANGES TO ANY OF THE C&I TRANSMISSION RATE SCHEDULES?

A. No. I simply update the rate levels to reflect the Company's updated revenue requirement and CCOSS results.

1. Schedule TG

Q. HOW WERE SCHEDULE TG RATES DEVELOPED?

A. The monthly S&F charges vary by individual customer depending on the metering and substation equipment at each site. Distribution costs are not allocated to C&I Transmission customers, so there is no distribution demand charge for Schedule TG. Production and transmission costs are recovered through a G&T demand charge with a winter / summer price ratio of 67 percent. The schedule also includes a modest energy charge to recover the costs of Company-owned wind energy resources and variable O&M expenses on the Company's system.

Q. WHAT ARE THE RESULTING PROPOSED SCHEDULE TG RATES?

A. Proposed rates for Schedule TG, compared with present rates, are shown in the table below.

Table JRK-D-17

Schedule TG Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	Customer Specific	Customer Specific
Demand Charge - G&T Summer	$12.68/kW-Mo.	$18.30/kW-Mo.
Demand Charge - G&T Winter	$7.60/kW-Mo.	$10.89/kW-Mo.
Energy Charge	$0.00724/kWh	$0.00932/kWh

2. Revenue Proof Adjustment

Q. WAS A REVENUE PROOF ADJUSTMENT INCLUDED IN THE PROPOSED C&I TRANSMISSION RATES?

A. Yes. The proposed rates include a revenue proof adjustment to the monthly demand charges of -$0.22 per kW-month.

F. Other C&I Rate Schedules

Q. ARE THERE ANY OTHER RATE SCHEDULES FOR C&I CUSTOMERS THAN THOSE DESCRIBED ABOVE?

A. Yes. In addition to the rate schedules presented above for C&I Secondary, C&I Primary, and C&I Transmission customers, the Company also offers standby service, CPP rates options, and Recycled Energy service for C&I customers at secondary, primary, and transmission voltages. The Company also has Special Contract Service rates for specific customers at primary and transmission voltage levels.

1. Standby Service

Q. HOW WERE STANDBY SERVICE RATES DEVELOPED?

A. Schedules SST and PST utilize the same S&F charges and distribution demand charges as Schedules SG and PG, respectively. Schedule TST customers are assessed customer-specific S&F charges specified in Schedule TST. Schedules SST, PST, and TST also utilize the same energy charges as Schedules SG, PG, and TG, respectively.

G&T standby capacity reservation fees for Schedules SST, PST, and TST are calculated to be 18.0 percent of the G&T demand charges included in Schedules SG, PG, and TG, respectively. These standby capacity reservation fees are applied to contracted standby capacity. In the 2020 Phase II, these were calculated as 16.3 percent of the base G&T demand charges, but I propose to amend this calculation to 18.0 percent to match the planning reserve margin from the Company's latest Electric Resource Plan. Lastly, Schedules SST, PST, and

TST include monthly usage charges that apply to measured demand if the "grace energy" allowed under the standby rate schedules is exceeded. These charges mirror the seasonal G&T demand charges of Schedules SG, PG, and TG.

Q. WHAT ARE THE RESULTING RATES FOR STANDBY SERVICE?

A. The resulting standby capacity reservation fee rates, compared to present rates, are presented in the table below.

Table JRK-D-18

Schedules SST, PST & TST Rate Comparison		
Rate Component	**Current**	**Proposed**
SST Standby Demand Charges:		
Distribution Demand	$6.17/kW-Mo.	$9.85/kW-Mo.
G&T Demand - Summer	$2.47/kW-Mo.	$3.36/kW-Mo.
G&T Demand - Winter	$1.49/kW-Mo.	$2.05/kW-Mo.
PST Standby Demand Charges:		
Distribution Demand	$4.23/kW-Mo.	$6.41/kW-Mo.
G&T Demand - Summer	$2.44/kW-Mo.	$3.30/kW-Mo.
G&T Demand - Winter	$1.64/kW-Mo.	$2.14/kW-Mo.
TST Standby Demand Charges:		
G&T Demand - Summer	$2.07/kW-Mo.	$3.11/kW-Mo.
G&T Demand - Winter	$1.24/kW-Mo.	$1.78/kW-Mo.

2. CPP Schedules

Q. HOW WERE CPP RATE SCHEDULES DEVELOPED?

A. The proposed CPP rate schedules are largely based on pricing for each class's main rate schedules (*i.e.*, Schedules SG, PG, and TG). The CPP rates all use the same monthly S&F charge, distribution demand charge, and energy charge as their respective class's main rate schedules. In addition to the standard energy charge, which is designed to recover energy-related costs, energy consumed during CPP events is also charged a CPP energy charge, which has been calculated based on the price of a new-build combustion turbine generator. I do not propose to change the CPP energy charges for any of the CPP rate schedules. Finally, the G&T demand charges are calculated by subtracting CPP energy charge revenues from the allocated G&T revenue requirement and dividing the remainder of the G&T costs by the G&T demand billing determinants from Attachment JRK-4.

Q. WHAT ARE THE RESULTING CPP RATES?

A. The proposed CPP rates, compared to current rates, are shown in the table below.

Table JRK-D-19

Schedules SG-CPP, PG-CPP & TG-CPP Rate Comparison		
Rate Component	**Current**	**Proposed**
SG-CPP Charges:		
Distribution Demand	$6.17/kW-Mo.	$9.85/kW-Mo.
G&T Demand	$8.03/kW-Mo.	$9.74/kW-Mo.
CPP Energy Charge	$1.44/kWh	$1.44/kWh
Non-CPP Energy Charge	$0.00791/kWh	$0.00939/kWh
PG-CPP Charges:		
Distribution Demand	$4.23/kW-Mo.	$6.41/kW-Mo.
G&T Demand	$8.06/kW-Mo.	$11.23/kW-Mo.
CPP Energy Charge	$1.40/kWh	$1.40/kWh
Non-CPP Energy Charge	$0.00778/kWh	$0.00753/kWh
TG-CPP Charges:		
G&T Demand	$6.00/kW-Mo.	$11.82/kW-Mo.
CPP Energy Charge	$1.35/kWh	$1.35/kWh
Non-CPP Energy Charge	$0.00724/kWh	$0.00932/kWh

3. Special Contract Service

Q. HOW WERE SCHEDULES SCS-7 AND SCS-8 RATES DEVELOPED?

A. Schedules SCS-7 and SCS-8, which are customer-specific rates, were designed to recover the costs allocated to their respective customer classes in the CCOSS, based on billing determinants included in Attachment JRK-4. These rates were developed using the same methodology as used in the 2020 Phase II. Schedule SCS-7, which is for a C&I Primary customer, is calculated similarly to the Schedule PG rate, except the demand costs are allocated to a seasonal production demand charge and a static transmission and distribution demand charge. Schedule SCS-8, which is for a C&I Transmission customer, is calculated similarly to the Schedule TG rate, except the demand costs are allocated to a seasonal production demand charge and a static transmission demand charge.

Q. WHAT ARE THE RESULTING RATES FOR SCHEDULES SCS-7 AND SCS-8?

A. The resulting rates for Schedules SCS-7 and SCS-8 are presented in the table below, along with a comparison to the present rates.

Table JRK-D-20

Schedule SCS-7 Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	$432.31/Mo.	$655.77/Mo.
Demand Charge - G Summer	$11.83/kW-Mo.	$13.04/kW-Mo.
Demand Charge - G Winter	$7.67/kW-Mo.	$8.38/kW-Mo.
Demand Charge - D&T	$7.41/kW-Mo.	$10.30/kW-Mo.
Energy Charge	$0.00778/kWh	$0.00753/kWh
Schedule SCS-8 Rate Comparison		
Rate Component	**Current**	**Proposed**
S&F Charge	Customer Specific	Customer Specific
Demand Charge - G Summer	$9.73/kW-Mo.	$13.09/kW-Mo.
Demand Charge - G Winter	$5.84/kW-Mo.	$7.77/kW-Mo.
Demand Charge - T	$2.24/kW-Mo.	$3.66/kW-Mo.
Energy Charge	$0.00724/kWh	$0.00932/kWh

4. Recycled Energy Service Schedule

Q. HOW HAVE RECYCLED ENERGY SERVICE SCHEDULE RATES BEEN DEVELOPED?

A. The Company proposes no structural changes to Schedule RE in this Proceeding, but simply updates the rate levels for the current revenue requirement, class cost allocation, and billing determinants. The rate design is similar to the Company's standby service rate schedules, except the G&T standby capacity reservation fee is adjusted for differences in allowed grace energy hours, and the G&T demand usage charge is converted to a charge per kW-day.

Q. WHAT ARE THE RESULTING RATES FOR RECYCLED ENERGY SERVICE?

A. Proposed rates for Schedule RE, along with a comparison to current rates, are presented in the table below.

Table JRK-D-21

Schedules RE Rate Comparison		
Rate Component	**Current**	**Proposed**
Schedule RE-SG Service		
Distribution Demand	$6.17/kW-Mo.	$9.85/kW-Mo.
G&T Demand Reservation	$0.58/kW-Mo.	$0.79/kW-Mo.
G&T Daily Demand - Summer	$0.69/kW-d.	$0.83/kW-d.
G&T Daily Demand - Winter	$0.41/kW-d.	$0.50/kW-d.
Energy Charge	$0.00791/kWh	$0.00939/kWh
Schedule RE-PG Service Charges:		
Distribution Demand	$4.23/kW-Mo.	$6.41/kW-Mo.
G&T Demand Reservation	$0.61/kW-Mo.	$0.81/kW-Mo.
G&T Daily Demand - Summer	$0.68/kW-d.	$0.88/kW-d.
G&T Daily Demand - Winter	$0.46/kW-d.	$0.59/kW-d.
Energy Charge	$0.00778/kWh	$0.00753/kWh
Schedule RE-TG Service		
G&T Demand Reservation	$0.49/kW-Mo.	$0.71/kW-Mo.
G&T Daily Demand - Summer	$0.58/kW-d.	$0.83/kW-d.
G&T Daily Demand - Winter	$0.35/kW-d.	$0.50/kW-d.
Energy Charge	$0.00724/kWh	$0.00932/kWh

G. Lighting

Q. PLEASE PROVIDE AN OVERVIEW OF PUBLIC SERVICE'S LIGHTING RATES.

A. Public Service offers numerous rate options for various forms of lighting service, including: area lighting, parking lot lighting, street lights, and traffic signals across two separate classes. Street and Area Lighting comprise one class, and Traffic Signal Lighting rates are in a separate class. The largest lighting rate is Schedule SL, which has approximately 50 different sub-rates depending on the specific type of lighting equipment used. Overall, the lighting classes account for approximately 0.6 percent of total retail sales.

Q. ARE YOU RECOMMENDING ANY CHANGES TO THE STRUCTURE OF THE LIGHTING RATES?

A. No. I simply update the rate levels to reflect the Company's updated revenue requirement, class allocations in the CCOSS, and billing determinants.

Q. HOW WERE STREET AND AREA LIGHTING RATES DEVELOPED?

A. Each of the Street and Area Lighting rate schedules are calculated from up to five cost components: (1) system capacity cost; (2) system energy costs; (3) facility cost; (4) routine maintenance cost; and (5) non-routine maintenance cost. System capacity cost and energy cost are allocated to each light type based on the estimated connected load of the individual lamp type and estimated usage. Facility costs are based on the average revenue requirement per light.

Q. WHAT ARE THE RESULTING RATES FOR STREET AND AREA LIGHTING?

A. There are approximately 160 different sub-rates in the Street and Area Lighting class, with five of those sub-rates representing approximately 60 percent of total revenues for the Street and Area Lighting class. The table below shows the proposed rates for these five rate schedules along with a comparison to present rates. The remainder of the proposed rates are included in Attachment JRK-5.

Table JRK-D-22

Street and Area Lighting - Top Five		
	Current	**Proposed**
SL-030	$11.54/Mo.	$14.46/Mo.
SL-060	$15.10/Mo.	$17.59/Mo.
SL-620	$12.38/Mo.	$16.14/Mo.
SL-640	$16.02/Mo.	$18.71/Mo.
CAL-010	$12.96/Mo.	$15.51/Mo.

Q. HOW WERE TRAFFIC SIGNAL LIGHTING RATES DEVELOPED?

A. There are two Traffic Signal Lighting rates: (1) Schedule TSL, a non-metered rate with sub-rates for flashing and non-flashing traffic signals; and (2) Schedule MI, for metered intersections. Rates are designed to recover the total costs allocated to the Traffic Signal Lighting class in the CCOSS based on kWh volumes between the two rate schedules. The Schedule TSL rate is calculated as a charge per watt of connected load. Schedule MI includes a monthly S&F charge per service meter and an energy charge per kWh. The resulting rates, compared with current rates, are presented in the table below.

Table JRK-D-23

Schedule TSL Rate Comparison		
	Current	**Proposed**
Monthly Rate per Watt	$0.01330/W	$0.01789/W
Schedule MI Rate Comparison		
	Current	**Proposed**
S&F Charge	$5.16/Mo.	$5.36/Mo.
Energy Charge	$0.03930/kWh	$0.05412/kWh

Q. WAS A REVENUE PROOF ADJUSTMENT INCLUDED IN THE LIGHTING RATES?

A. Yes. For Street and Area Lighting rates, an adjustment of +$0.06 was applied to each monthly rate per light-month. No adjustment was applied to Traffic Signal Lighting rate schedules.

H. Other Updated Charges

1. EAP Charges

Q. WHAT IS EAP?

A. EAP is a financial assistance program available to qualifying Residential customers. It is funded through EAP charges that apply to all classes.

Q. WHAT IS THE TOTAL EAP COST INCLUDED IN THE RATES PROPOSED IN THIS PROCEEDING?

A. The total EAP cost included in the proposed rates is $11,609,101. However, as noted earlier in my Direct Testimony, the Commission recently approved an increase to the Company's EAP budget at its weekly meeting on May 10, 2023, in Proceeding No. 23AL-0176E. Because of the short time between the Commission's approval and the required filing date for this Phase II, the Company was unable to incorporate the newly approved EAP budget into the proposed rates. As a result, the updated EAP charges are based on the EAP budget of $11,609,101.

Q. WILL THE COMPANY UPDATE THE EAP CHARGES LATER IN THIS PROCEEDING?

A. Yes. As discussed earlier in my Direct Testimony, once a final decision in the Phase I proceeding is reached and the base rate revenue requirement is determined, the Company will update the CCOSS and rate design to incorporate the approved Phase I revenue requirements and billing determinants, in accord with the procedural schedule to be determined herein. That update also will include EAP charges based on the newly authorized, higher EAP budget.

Q. HOW ARE THE PROPOSED EAP CHARGES CALCULATED?

A. EAP charges are allocated to each class within the CCOSS based on each class's proportional share of the total revenue requirement, consistent with Rule 3412(g)(II)(C). For each class, I divided the resulting class totals from the CCOSS by the number of bills within each class. The resulting new EAP charges are shown in the table. These charges are included in the monthly S&F charges for each rate schedule but are separately identified on Sheet No. 116E of the Company's Tariff.

Table JRK-D-24

EAP Charge $/Month		
Rate Schedule	**Current**	**Proposed**
Residential	$0.31/Mo.	$0.32/Mo.
Commercial	$0.42/Mo.	$0.41/Mo.
Secondary General	$8.30/Mo.	$8.03/Mo.
Primary General	$121.07/Mo.	$117.27/Mo.
Transmission General	$980.51/Mo.	$966.72/Mo.
Lighting	$0.07/Mo.	$0.08/Mo.

2. Production Meter and Load Meter Charges

Q. HAVE YOU PROPOSED UPDATES TO THE PRODUCTION AND LOAD METER CHARGES FOR EACH CLASS?

A. Yes. In the CCOSS, the Company determines meter charges using the cost of each meter type to allocate total investment costs and derive a revenue requirement. The assigned revenue requirement is then summarized at the class level to determine an appropriate average cost for production and load meters by class. The resulting new production and load meter charges, compared to current rates, are shown in the table below.

Table JRK-D-25

Rate Component	Current	Proposed
Residential		
S&F Charge - Production Meter	$1.55/Mo.	$3.35/Mo.
S&F Charge - Load Meter	$1.55/Mo.	$3.35/Mo.
Small Commercial		
S&F Charge - Production Meter	$3.10/Mo.	$4.60/Mo.
S&F Charge - Load Meter	$3.10/Mo.	$4.60/Mo.
C&I Secondary		
S&F Charge - Production Meter	$11.95/Mo.	$24.70/Mo.
S&F Charge - Load Meter	$11.95/Mo.	$24.70/Mo.
C&I Primary		
S&F Charge - Production Meter	$240.75/Mo.	$405.90/Mo.
S&F Charge - Load Meter	$240.75/Mo.	$405.90/Mo.

VII. REVENUE PROOF ANALYSIS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this Section of my Direct Testimony, I present the Company's Revenue Proof analysis, which demonstrates that the Company's proposed rates are designed to recover the approved revenue requirement.

Q. HOW DOES THE COMPANY ENSURE THAT ITS PROPOSED ELECTRIC RETAIL RATES WILL LEAD TO RECOVERING THE APPROVED LEVEL OF ANNUAL REVENUES?

A. As I mentioned earlier in my Direct Testimony, our proposed rates are designed to recover the Test Year revenue requirement that was proposed in the 2022 Phase I. To ensure Public Service's proposed electric retail rates recover this amount, I conducted a Revenue Proof analysis included as Attachment JRK-6 to my Direct Testimony. Rate schedules with fewer than 15 customers have been aggregated in Attachment JRK-6.

Q. PLEASE EXPLAIN HOW THE REVENUE PROOF IS CALCULATED.

A. Each proposed rate is multiplied by the corresponding billing determinant listed in Attachment JRK-3. The revenues resulting from each rate are then summed to demonstrate that the total revenue from the rate design matches the approved revenue requirement.

Q. DO THE PROPOSED ELECTRIC RETAIL RATES RESULT IN EXACTLY THE REVENUE REQUIREMENT APPROVED BY THE COMMISSION?

A. No. Despite the rigorous rate design calculations and adjustments explained above, there are still inherent and unavoidable differences between the CCOSS and the total revenue that results from our proposed rates. This is to be expected as with any Phase II rate case, but the differences are *de minimis*.

Q. PLEASE IDENTIFY THIS DIFFERENCE.

A. The CCOSS shows a total base rate revenue requirement of $2,464,335,527.[47] Attachment JRK-6 to my Direct Testimony demonstrates that the Company's proposed rates will recover $2,464,342,289, reflecting a very small difference of $7,097 or 0.0003 percent.

Q. IS THIS DIFFERENCE WITHIN AN ACCEPTABLE MARGIN OF ERROR?

A. Yes. The revenues generated from proposed rates will almost never match the target revenue requirement due to rounding. For energy charges, Public Service designs rates to one one-thousandth of a penny. That might seem very small; but with Residential and Small Commercial sales totaling over 10 billion kWh, one one-thousandth of a penny equals $100,000. For demand charges, Public Service designs rates to one penny. With over 80 million billed demand units, one penny is worth $800,000. These constraints preclude the Company from developing rates that generate the total test-year revenue requirement exactly.

[47] Hrg. Ex. 102 (Klingeman Direct), Attachment KSK-1 at Tab 20 (RR-Total), Line 18.

VIII. IVVO RECOVERY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this Section I discuss changes related to the Company's recovery of IVVO-related lost revenues through the ECA, which was provided in the Unopposed Comprehensive Settlement Agreement in Proceeding No. 16A-0588E (the "AGIS Settlement").

Q. WHAT ARE THE APPLICABLE TERMS OF THE AGIS SETTLEMENT?

A. Section D of the AGIS Settlement addresses IVVO cost recovery, including the conditional recovery of measurable decreased energy consumption attributable to IVVO. Generally, the AGIS Settlement allows the Company to recover lost revenues associated with IVVO-related energy reductions through the ECA if those lost revenues are not already accounted for in a revenue decoupling mechanism. The AGIS Settlement further requires:[48]

> In the event the Company completes a base rate case that includes any portion of the IVVO usage reductions in the forecasted or actual billing determinants, the Company shall present those anticipated reductions in a transparent manner, and propose an adjustment to the annual IVVO recovery calculation to account for changes to billing determinants in order to prevent and avoid double recovery. After all IVVO usage reductions associated with the initial deployment are captured in a base rate case, the Company will discontinue the IVVO recovery treatment provided for in this Settlement Agreement.

Q. IS THE COMPANY CURRENTLY RECOVERING LOST REVENUES ASSOCIATED WITH IVVO-RELATED ENERGY REDUCTIONS?

A. No. These reductions currently are being accounted for in the Company's Revenue Decoupling Adjustment ("RDA") pilot, which ends on December 31, 2023.

[48] AGIS Settlement at 11, §I(D)(1)(b).

After the RDA pilot ends on December 31, 2023, these lost revenues could again be included for recovery in the ECA.

Q. HAS THE COMPANY IDENTIFIED HOW MUCH OF THE IVVO-RELATED ENERGY REDUCTIONS HAVE BEEN INCORPORATED INTO THE BILLING DETERMINANTS IN THIS PROCEEDING?

A. Yes. The billing determinants used in this Proceeding are based on the sales forecast underlying the Test Year included in the Company's 2022 Phase I. In that Proceeding, Company witness Mr. David C. Mino noted in his Direct Testimony that IVVO would be fully deployed in 2023,[49] and Company witness John M. Goodenough included the kWh reduction associated with IVVO in the Test Year sales forecast.[50]

Q. WHAT DO YOU PROPOSE REGARDING IVVO RECOVERY?

A. Consistent with the AGIS Settlement, I propose to terminate the recovery of lost revenue associated with IVVO-related energy reductions. However, if the Commission approves the use of a test year other than the Company's proposed Test Year in the 2022 Phase I, then the Company will determine the IVVO reductions associated with billing determinants in that test year and amend the IVVO lost revenue recovery consistent with the terms of the AGIS Settlement.

[49] Proceeding No. 22AL-0530E, Hearing Exhibit 108 at 32.
[50] Proceeding No. 22AL-0530E, Hearing Exhibit 105 at 28.

IX. DEFERRED ACCOUNTING FOR PHASE II-RELATED EXPENSES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this Section of my Direct Testimony is to support the Company's request to defer costs associated with this proceeding for future recovery in a subsequent Phase I rate case.

Q. WILL PUBLIC SERVICE INCUR INCREMENTAL EXPENSES IN CONNECTION WITH THIS PHASE II PROCEEDING?

3. Yes. The Company will incur outside legal, customer noticing, hearing transcript, and purchasing overhead costs associated with this Phase II proceeding. In total, the Company estimates total rate case expense for this proceeding of approximately $600,000, as shown in the table below. Attachment JRK-7 provides a more detailed summary of the estimated rate case expenses by major category.

TABLE JRK-D-26
Rate Case Expenses by Category

Category	**Phase II Estimate[51]**
Legal Counsel	$550,000
Customer Noticing	$37,030
Hearing Transcripts	$11,875
Purchasing Overhead	$7,307
Total Rate Case Expenses	$606,212

[51] Assumes fully litigated case with evidentiary hearing, post-hearing briefing and applications for rehearing, reargument, and reconsideration.

Q. IS THE COMPANY SEEKING TO RECOVER THESE EXPENSES IN THIS CASE?

4. No. The Company proposes the Commission defer the review, approval, and recovery of these Phase II rate case expenses to the next Phase I electric rate case.[52]

Q. WHAT COSTS ARE INCLUDED IN THE LEGAL COUNSEL CATEGORY?

A. The legal counsel category consists of estimated fees of the outside legal resources retained by the Company to assist with this proceeding.

Q. ARE THERE ANY INTERNAL LEGAL COSTS INCLUDED IN TABLE JRK-D-26, ABOVE?

A. No, the expenses shown in Table JRK-D-26 are only external legal costs. The Company's internal legal costs are part of the O&M costs included in the Company's base rate revenue requirement.

Q. ARE OUTSIDE LEGAL COSTS FOR RATE CASES INCLUDED IN THE O&M COSTS INCLUDED IN THE COMPANY'S BASE RATE REVENUE REQUIREMENT?

A. No. The Company has adopted accounting practices that use separate work orders for outside legal services associated with certain regulatory proceedings, including rate cases. Outside legal services costs for rate cases are tracked

[52] As part of the 2022 Phase I, the Company is proposing to record and defer certain Company regulatory proceeding costs in a tracker, with prudence of regulatory proceeding costs and ultimate cost recovery to be addressed in Phase I proceedings. That request is outstanding at this time. As part of that proposal, the Company would defer and track actual regulatory proceeding costs, including the costs of this Phase II proceeding. Amounts included in the regulatory proceeding tacker would be amortized over 36-months and there would be no return on the unamortized balance. If the Company's regulatory proceedings cost tracker is not approved, the Company would place expenses incurred for this proceeding into a deferred accounting asset without interest for potential recovery in a future Phase I proceeding.

separately in a deferred account to ensure there is no double-recovery of external legal costs.

Q. IS THE COMPANY'S INTERNAL COUNSEL WORKING ON THIS RATE CASE?

A. Yes. The Company's internal legal department supports all of the Company's regulatory matters before the Commission, including this Phase II. Our internal regulatory legal team is contributing a significant amount of work to support this case, with internal counsel providing legal services throughout all aspects of the case while also managing outside legal resources. That being said, we still need to utilize outside legal resources in this proceeding due to the scope and complexity of rate cases. And doing so ultimately benefits the process due to our external attorneys having rate case expertise that helps develop a comprehensive factual record and ultimately contributes efficiencies to the process.

Q. WHAT COSTS ARE INCURRED FOR CUSTOMER NOTICING?

A. There are three costs: (1) bill onsert; (2) newspaper noticing; and (3) translation to Spanish. The bill onsert component is the cost associated with printing the notice on customers' bills and mailing it to customers during their normal billing cycles. The newspaper component consists of posting the notice of our filing in a newspaper of general circulation for two consecutive weeks. There is also a cost for translating the notice to Spanish to post on the Company's website.

Q. DO THE COMMISSION'S RULES INCLUDE NOTICE REQUIREMENTS FOR RATE CASES?

A. Yes. Rule 1210 requires the Company to notify customers regarding this rate request. Historically this meant sending out a mailing to all customers at a substantial cost. More recently, the Company has utilized an alternative form of notice that includes legal notices, bill onserts, emails, and posting to our Company website. We are proposing to use that same procedure here.

Q. PLEASE DESCRIBE THE HEARING TRANSCRIPT COSTS IN TABLE JRK-D-26.

A. This includes the costs for a Commission court reporter to transcribe hearings before the Commission and resulting transcripts. The estimate is based on a total of five hearing days for the Phase II proceeding.

Q. PLEASE DESCRIBE THE OVERHEAD COSTS IN TABLE JRK-D-26.

A. The Company is including the purchase overhead for authorized labor and nonlabor costs that are incurred to support the Company's purchasing functions that include authorized Supply Chain Company labor and benefits, Supply Chain consulting services, contract labor to support Supply Chain such as planners and buyers, license fees for evaluating credit profiles of vendors, facilities charges, employee expenses and other miscellaneous expense. These costs are collected in a cost pool and are allocated out at month-end by applying overhead charges to eligible transactions.

Q. WHY IS IT REASONABLE FOR THE COMMISSION TO AUTHORIZE DEFERRED ACCOUNTING FOR PHASE II-RELATED EXPENSES?

A. Rate cases occur due the regulated nature of the Company's business and associated expenses have been long-recognized as normal and legitimate costs of providing utility service.[53] Further, this particular filing was required by the Commission,[54] and many of the substantive issues emanate directly from prior Commission directives.[55] It is therefore reasonable to authorize deferred accounting for expenses incurred in connection with this proceeding, with ultimate recovery to be decided in a subsequent Phase I rate case**.**

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[53] *See*, *e.g.*, Decision No. R21-0400 in Proceeding No. 20AL-0432E at ¶ 151 ("The Colorado Supreme Court recognized over four decades ago that the Commission has always allowed regulated utilities to recover as a proper operating expense attorneys' fees and legal costs incurred in their rate cases litigated before the Commission. Indeed, the recovery of rate case expenses to be a normal and legitimate activity for a regulated utility. The Commission has often found that rate case expenses are a legitimate cost of providing utility service, necessitated by Commission regulation of the utility, and that Colorado regulated utilities, including Public Service, have a right to seek recovery through rates for all reasonable operating expenses, including rate case expenses" (internal quotes, footnotes and citations omitted)). Decision No. R21-0400 became the decision of the Commission pursuant to Decision No. C21-0536 except as amended by Decision No. C21-0536. This portion of Decision No. R21-0400 was not amended by Decision No. C21-0536.

[54] *See* Proceeding No. 21AL-0317E, Decision Nos. C22-0178, C22-0278 and C22-0724.

[55] Proceeding No. 20AL-0432E, Decision No. C21-0536, at pp. 9-10, ¶21, pp. 17-18, ¶39, p. 20, ¶47; Proceeding No. 22AL-0143E, Decision No. C22-0398 at p. 2, ¶5.

X. TARIFF CHANGES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this Section of my Direct Testimony, I identify changes the Company is proposing to its Electric Tariff that go beyond the rate structure or rate level changes discussed above.[56] As I stated earlier, the tariff changes I am sponsoring are reflected in Attachment JRK-1 to my Direct Testimony, in redline as compared to the currently effective tariff sheets. A clean version of those same tariff sheets is found in Attachment JRK-2 to my Direct Testimony.

Q. IS THE COMPANY PROPOSING ANY NEW TARIFFS IN THIS PROCEEDING?

A. Yes. As discussed earlier, the Company is proposing to add two new EV service options for customers at primary voltage – one with TOU energy charges and another with an added CPP rate component. These options are identified in a new Schedule P-EV tariff.

Q. PLEASE SUMMARIZE THE OTHER TARIFF CHANGES PROPOSED BY THE COMPANY IN THIS PROCEEDING.

A. The proposed non-rate design changes to the Company's Electric Tariff are summarized in the table below.

[56] This Phase II rate case will establish new base rates for all base rate schedules, meaning it will be necessary to update most tariff sheets to reflect the updated rates and charges.

Table JRK-D-27
Summary of Tariff Changes

Tariff Change	Impacted Sheet(s)
Add Schedule S-EV to the Service Lateral Extension and Distribution Line Extension Policy as it was inadvertently not included in the Tariff.	R189
Add Schedule S-EV-CPP to various sheets as it was inadvertently not included in the Tariff.	114B, 116E, 140, 141, 142, and 146
Remove Johnstown from Sheet No. 8 and place it on Sheet No. 7 to properly identify it as North Region.	7, 8
Remove Sheet Nos. 59, 60, and 82 from the Reserved for Future Filing Index and add Sheet Nos. 32, 32A, 32B, 32C, 48, 48A, 58, 58A, and 58B on Sheet No. 17.	17
Revise the monthly reporting requirement to the Commission relating to restoration of street light service to align to annual reporting requirement.	98D
Remove references to Trial RE-TOU.	33, 33A, 133 - 133F
Revise RDA tariff language to reflect implementation of Schedule RE-TOU as permanent rate, removal of rate schedules no longer in effect, and streamline provisions to reflect alignment of Residential rate schedules.	133 - 133F
Remove Schedule RD-TDR all references to this Schedule as it has expired and there are no longer any customers on this rate Schedule.	2, 17, 30, 32-32C, 33A, 109, 116E, 133-133F, R189, R210, R227, R228
Remove Schedules STOU, and PTOU and all references to these Schedules as they have expired.	2, 17, 48, 48A, 58, 58A, 58B, 116E, 140, 141, 142, 146,147, R189, R203, R227
Update the website link to Non-Standard Aggregated Data Report request form information.	R99
Update holidays, adding Francis Xavier Cabrini Day and Juneteenth and removing Columbus Day.	19
Remove Thermo Greeley LLC, Valmont & Manchief from Schedule TST	72A
Correct the reference to the Economic Development Rate (“Schedule EDR”) from Schedule SCS-9 to Schedule EDR on the Electric Tariff Index	Index

Q. WILL THE COMPANY NEED TO MAKE ANY ADDITIONAL TARIFF CHANGES NOT INCLUDED IN THE TABLE ABOVE?

A. Yes. First, if the Company's proposed P-EV and P-EV-CPP rate schedules are approved in this Proceeding, these rate schedules will need to be referenced elsewhere in the tariff. For example, they will need to be added to various non-base rate adjustments, such as the Transmission Cost Adjustment ("TCA") to indicate which TCA rate will be charged to P-EV and P-EV-CPP customers.

Additionally, when final base rates are approved by the Commission, the Company will need to update any percent-based rider charges to be based on the new base rate charges. For example, if base rate charges are increasing, the percent-based rider charges will need to decrease in order to maintain the same level of rider revenue. It is most efficient to include these tariff changes in the Company's compliance advice letter filing, after the Company receives a final Commission Decision, when implementing the new base rates approved in this Proceeding.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications

Jeffrey R. Knighten

As a Pricing Consultant in the Public Service Company of Colorado's Regulatory Affairs department, I am responsible for the development of new rate design proposals or modifications to existing rates to ensure effective pricing structures, increased options for customers, and compliance with regulatory requirements. I began working in this position in July 2021.

Prior to joining Public Service Company of Colorado, I was employed by various subsidiaries of Entergy Corporation, which is the parent company of utilities in Louisiana, Texas, Mississippi, and Arkansas ("Entergy Operating Companies"). I began my career working for Entergy Services, LLC, performing long-term generation planning studies on behalf of the Entergy Operating Companies from 2009-2010. From 2010-2012, I worked as a Power Scheduler for Entergy Services, LLC, where I was responsible for administering real-time power marketing operations, including transacting on purchases and sales of power. From 2012 through 2017, I worked in the Strategic Initiatives and Regulatory Support group of Entergy Services, LLC as a Senior Analyst, Project Manager, and Manager. In these positions, I assisted with federal and retail regulatory proceedings of the Entergy Operating Companies and also worked on various strategic initiatives of the Entergy Operating Companies. From 2017 through 2019, I was a Manager of Regulatory Affairs for Entergy Louisiana, LLC, where I managed regulatory proceedings at the Louisiana Public Service Commission. Finally, from 2019 through 2021, I was a manager and later Director of Regulatory Affairs for Entergy Texas, Inc., in which I led the company's regulatory initiatives at the Public Utility Commission of Texas.

I hold a Bachelor of Science Degree in Biomedical Engineering from Texas A&M University in College Station, Texas. I have been employed by Public Service Company of Colorado as a Pricing Consultant in the Regulatory Affairs department since July 2021. I have over fourteen years of experience at regulated utility companies with experience in long-term generation planning, market operations, and both federal and retail regulatory affairs.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * *

IN THE MATTER OF ADVICE NO. 1923-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8 – ELECTRIC TARIFF TO RESET THE GENERAL RATE SCHEDULE ADJUSTMENTS, TO PLACE INTO EFFECT REVISED BASE RATES, AND TO IMPLEMENT OTHER PHASE II TARIFF PROPOSALS TO BECOME EFFECTIVE JUNE 15, 2023	) **PROCEEDING NO. 23AL-XXXXE**

AFFIDAVIT OF JEFFREY KNIGHTEN
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Jeffrey R. Knighten, being duly sworn, state that the Direct Testimony and attachments were prepared by me or under my supervision, control, and direction; that the Direct Testimony and attachments are true and correct to the best of my information, knowledge and belief; and that I would give the same testimony orally and would present the same attachments if asked under oath.

Dated at Denver, Colorado, this 9th day of May, 2023.

Jeffrey R. Knighten
Jeffrey R. Knighten
Pricing Consultant

Subscribed and sworn to before me this 9th day of May, 2023.

GINA GARGANO-AMARI
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20164028888
MY COMMISSION EXPIRES 07/29/2024

Gina G. Amari
Notary Public

My Commission expires 07-29-2024