BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

RE: IN THE MATTER OF ADVICE	**)**
LETTER NO. 1712-ELECTRIC FILED BY	**)**
PUBLIC SERVICE COMPANY OF	**)**
COLORADO TO REPLACE COLORADO	**) PROCEEDING NO. 16AL-________E**
PUC NO. 7-ELECTRIC TARIFF WITH	**)**
COLORADO PUC NO. 8-ELECTRIC	**)**
TARIFF	**)**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF ALICE K. JACKSON</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

January 25, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

*** * * * ***

RE: IN THE MATTER OF ADVICE	**)**
LETTER NO. 1712-ELECTRIC FILED BY	**)**
PUBLIC SERVICE COMPANY OF	**)**
COLORADO TO REPLACE COLORADO	**) PROCEEDING NO. 16AL-________E**
PUC NO. 7-ELECTRIC TARIFF WITH	**)**
COLORADO PUC NO. 8-ELECTRIC	**)**
TARIFF	**)**

SUMMARY OF THE DIRECT TESTIMONY OF ALICE K. JACKSON

Ms. Alice K. Jackson is Regional Vice President, Rates and Regulatory Affairs of Xcel Energy Services Inc. In this position she is responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service Company of Colorado ("Public Service" or "Company"), one of four utility operating company subsidiaries of Xcel Energy Inc. Her duties include, among other things, the design and implementation of Public Service's regulatory strategy and programs, and directing and supervising Public Service's regulatory activities, including oversight of rate cases.

In her testimony, Ms. Jackson presents an overview of this case as well as lays out the longer-term rate design that the Company is developing and will implement in response to the rapidly changing environment in which we operate. We believe this longer-term rate design addresses how we should be assessing the costs of the electric system to our customers in light of the changes to customer consumption due to evolving technology -- including customer-owned distributed generation and increasing customer options and choices -- that we and third parties may offer. She explains why it is important to begin to make changes today to achieve that longer-term rate design. The longer-term approach envisioned will not be achieved in this Phase II Rate Case alone. It will be shaped and implemented through a variety of filings, close examination, and careful communications with affected customers - as well as with the Colorado Public Utilities Commission (“Commission”), Staff of the Commission (“Staff”), the Office of Consumer Counsel (“OCC”), and other stakeholders over the next several years.

Imagine a day when a customer has the option to interconnect with Public Service and that customer has the ability to select amongst a variety of options of how they may receive service. Would they like solar? Then their options are rooftop – here’s the vendors in our service territory; or community solar – here are the gardens, owners and contact information; or purchase solar from the utility through programs like Solar*Connect®. Does the customer have an electric vehicle (“EV”)? If so, assist them with identifying how and when their charging of the EV may affect their bill because of time of use rates or a time specific demand charge. Does the customer have a battery? If so, can the utility contract with that customer to use that battery a certain number of times a year to help defray the cost of other infrastructure, not unlike Saver’s Switch®. Today, these types of conversations are difficult to have because the existing rates do not send the right price signals for those types of products and activities. In this Phase II Rate Case, Ms. Jackson identifies the need to consistently apply long-standing rate design principles that the Commission has utilized for decades to expand the price signals already sent to larger customers to those customers at lower service levels such as Residential and Small Commercial. This allows for these (1) customers to control not only their usage, but also have more control over their electricity costs; (2) customers to more efficiently use the system; and (3) for the utility to provide the type of environment discussed above for all customers on its system to ensure customers are fairly assessed the costs of the system and the utility can recover those costs.

The future described above cannot be achieved overnight and will take time to implement. One of the more significant items that needs to be addressed is the metering available for these smaller customers. This is not the proceeding to address that issue; thus, to achieve this future, other proceedings will be necessary. The Company is committed to providing a total package financial overlay to show cost impacts to customers when each of the filings has been made with the Commission. We believe the pertinent filings to be made are: this Phase II Rate Case, the Renewable Energy Plan, a grid intelligence and security request for a certificate of public convenience and necessity ("Grid CPCN"), and the Electric Resource Plan ("ERP"). We are not asking for approval of the complete package in this proceeding and believe there is a path to approve each of the filings independently and clearly delineate where costs may come in and may be evaluated. Ms. Jackson lays this bigger picture out in her Direct Testimony.

In addition to laying this larger framework, Ms. Jackson addresses the following in her Direct Testimony:

- *Principles of Rate Design and Resulting Conclusions:* In this section of her testimony, she outlines the basic principles of rate design, maps those principles to the actual changing environment, and provides the recommendations the Company is making at this time to modify historical rate design to maintain these long-standing principles. She also outlines why it is important to take the principles and the changes we have seen in customer consumption and policy initiatives over the past decade into account in the decision to modify how to assess costs to customers. In this she shows that there is an existing deficiency in the current tariffs due to these market changes and policy modifications that drive us towards the preliminary steps taken in this filing.

- *Summary of Public Service's Request in this Proceeding:* This section will detail the results of the Class Cost of Service Study ("CCOSS") as well as summarize the proposed changes to the rate design for each of the rate classes. It also summarizes the overhaul that is proposed to the Electric Tariff that results in either (1) closing tariffs; (2) initiating new tariffs; or (3) modifying tariffs. Many modifications are proposed simply to clean up the Electric Tariff to eliminate inconsistencies that have accumulated over two decades. But other changes are more significant.

- *Timeline and Outreach:* In this section she describes the timeline under which we believe it is reasonable to implement the recommendations made and outlines future filings with the Commission that will allow this transition to take place.

- *Rate Case Expenses:* Finally, Ms. Jackson provides the estimated rate case expenses to be incurred during the preparation and processing of this Phase II rate case. She also lays out the Company's proposal to defer recovery of these rate case expenses until the next Phase I electric rate case through the use of a deferred accounting asset.

Ms. Jackson recommends that the Commission approve the following Company proposals:

- Instituting Grid Use Charges to recover distribution costs for customers served under Residential Service ("Schedule R") and Commercial Service ("Schedule C"). For both Schedules R and C, the Company proposes to assess graduated charges that will increase with a customer's average use over the past 12 billing periods. Solar*Rewards® customers, who are net metered as of December 31, 2016, will have the option of remaining on the current two-part rate design that does not include a Grid Use Charge.

- Instituting an optional Residential Demand – Time-of-Use Service ("Schedule RD–TOU"). This service would be available to a maximum of 10,000 residential customers in 2017, 14,000 residential customers in 2018, and 18,000 residential customers in 2019.
- Revising the rate differential between summer and winter rates for Schedule C.
- Instituting an on-peak Demand Charge for customers on Primary General Service ("Schedule PG") and Transmission General Service ("Schedule TG") to recover generation and transmission costs. This charge would be assessed on a customer's peak load during non-holiday weekdays from 2:00 p.m. through 6:00 p.m.
- Instituting a Critical Peak Pricing option (Schedules "SG-CPP", "PG-CPP" and "TG-CPP") for large Commercial and Industrial ("C&I") customers. This service would be offered on a pilot basis, and total participation would be capped at 30 megawatts ("MW").
- Offering a Supplemental Service within Secondary General Service ("Schedule SG"), Schedule PG and Schedule TG. This service would be available to C&I customers whose on-site generation does not operate as frequently and predictably as the generators for whom Standby Service is intended. The Company is also proposing to introduce the concept of Auxiliary Service for customers with on-site electric storage applications operating in parallel with the Company.
- Revising the differential between summer and winter demand charges for the following service schedules: SG, PG, and TG.
- Lowering the required maximum demand used to determine whether Schedule SG customers are eligible for the Time-of-Use Electric Commodity Adjustment ("TOU ECA") from 300 kW to 100 kW.
- Eliminating or closing to new customers some existing service options that are rendered obsolete by or do not complement the Company's proposed long-term rate design.

The Company also requests approval to replace the existing Colorado P.U.C. No. 7 – Electric Tariff with Colorado P.U.C. No. 8 – Electric Tariff as described by Company witness Mr. Steven Wishart and other Company witnesses. The primary revisions to the Electric Tariff include the following:

- Institute a new General Definitions section, which will define terms used throughout the tariff in one section. The purpose of this section is to clarify and standardize the meanings of terms found throughout the different sections of the Electric Tariff. Definitions that are specific to certain sections of the tariff will remain in that section.
- Reorganize the Rules and Regulations section to group together similar sections, include provisions for the measurement of service if customers have multiple meters, and address responsibility for damage to the system.
- Revise the Rules and Regulations applicable to Street Lighting Service to address the relocation and removal of lights and attachments to street lighting poles.
- Specify that customers taking service under Schedules R and C who have on-site renewable energy generation operating in parallel with the Company and are not net-metered will be subject to a buy-all, sell-all arrangement.
- Add a Production Meter Charge applicable to customers on various service schedules with on-site generation.
- Update the Customer list for Schedule TG.
- Modify the Secondary General Standby ("Schedule SST"), Primary General Standby (Schedule PST") and Transmission General Standby (Schedule TST") services by adding a Production Meter Charge and basing the annual grace energy period on a calendar year.
- Modify the Street Lighting Service to incorporate the new LED options.
- Revise the Parking Lot Lighting Service ("Schedule PLL") to differentiate this lighting from Commercial Area Lighting Service.

Ms. Jackson concludes her testimony by discussing rate case expenses and requests approval of the Company's proposal to defer recovery of these rate case expenses until the next Phase I electric rate case through the use of a deferred accounting asset.

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

* * * * *

RE: IN THE MATTER OF ADVICE	**)**	
LETTER NO. 1712-ELECTRIC FILED BY	**)**	
PUBLIC SERVICE COMPANY OF	**)**	
COLORADO TO REPLACE COLORADO	**)**	**PROCEEDING NO. 16AL-________E**
PUC NO. 7-ELECTRIC TARIFF WITH	**)**	
COLORADO PUC NO. 8-ELECTRIC	**)**	
TARIFF	**)**	

INDEX

SECTION **PAGE**

LIST OF ATTACHMENTS

Attachment AKJ-1	Colorado Rate Design Mini-Groups Qualitative Research Report
Attachment AKJ-2	Rate Case Expense Overview

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2009 Electric Phase II Rate Case	2009 Electric Phase II Rate Case, Docket No. 09AL-299E
2014 Electric Phase I Rate Case	2014 Electric Phase I Rate Case, Proceeding No. 14AL-0660E
C&I	Commercial and Industrial
CACJA	Clean Air - Clean Jobs Act
CCOSS	Class Cost of Service Study
CEC	Colorado Energy Consumers
CEO	Colorado Energy Office
Commission	Public Utilities Commission
CP	Coincident Peak
CPCN	Certificate of Public Convenience and Necessity
CPP	Critical Peak Pricing
DSMCA	Demand-Side Management Cost Adjustment
ECA	Electric Commodity Adjustment
EE	Energy Efficiency
ERP	Electric Resource Plan
EV	Electric vehicle
G&T	Generation and Transmission

Grid CPCN	Grid Intelligence and Security Certificate of Public Convenience and Necessity
GRSA	General Rate Schedule Adjustment
IBR	Inverted Block Rate
kWh	Kilowatt Hour
MW	Megawatt
Navigant Report	Navigant Research Report “Electric Vehicle Geographic Forecasts”
NCP	Noncoincident Peak
OCC	Office of Consumer Counsel
O&M	Operations and Maintenance
PCCA	Purchased Capacity Cost Adjustment
Public Service or Company	Public Service Company of Colorado
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
S&F	Service and Facilities
Schedule C	Commercial Service
Schedule PG	Primary General Service
Schedule PG-CPP	Primary General Critical Peak Pricing
Schedule PLL	Parking Lot Lighting Service
Schedule R	Residential Service
Schedule RAL	Residential Outdoor Lighting

Schedule RD	Residential Demand Service
Schedule RD-TOU	Residential Demand Time-of-Use service
Schedule SG	Secondary General Service
Schedule SG-CPP	Secondary General Critical Peak Pricing
Schedule TG	Transmission General Service
Schedule TG-CPP	Transmission General Critical Peak Pricing Service
Schedule TOU-ECA	Time-of-Use Electric Commodity Adjustment
Staff	Staff of the Commission
TCA	Transmission Cost Adjustment
TOU	Time-of-Use
XES	Xcel Energy Services Inc.
Schedule SST	Secondary General Standby Service
Schedule PST	Primary General Standby Service
Schedule TST	Transmission General Standby Service

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

RE: IN THE MATTER OF ADVICE	**)**	
LETTER NO. 1712-ELECTRIC FILED BY	**)**	
PUBLIC SERVICE COMPANY OF	**)**	
COLORADO TO REPLACE COLORADO	**)**	**PROCEEDING NO. 16AL-________E**
PUC NO. 7-ELECTRIC TARIFF WITH	**)**	
COLORADO PUC NO. 8-ELECTRIC	**)**	
TARIFF	**)**	

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Alice K. Jackson. My business address is 1800 Larimer Street, Suite 1400, Denver, CO 80202.

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

A. I am employed by Xcel Energy Services Inc. (“XES”) as Regional Vice President, Rates and Regulatory Affairs. XES is a wholly-owned subsidiary of Xcel Energy Inc. (“Xcel Energy”), and provides an array of support services to Public Service Company of Colorado (“Public Service” or “Company”) and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

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. As the Regional Vice President of Rates and Regulatory Affairs, I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service. My duties include the design and implementation of Public Service's regulatory strategy and programs, and directing and supervising Public Service's regulatory activities, including oversight of rate cases, administration of regulatory tariffs, rules and forms, regulatory case direction and administration, compliance reporting, and complaint response. I frequently testify in proceedings before the Colorado Public Utilities Commission ("Commission") as the Company's policy witness. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to present an overview of this case, as well as lay out the longer-term rate design that the Company is developing and recommends to be implemented in response to the rapidly changing environment in which we operate. We believe this longer-term rate design addresses how we should be assessing the costs of the electric system to our customers in light of evolving technology - including customer-owned distributed generation and increasing customer options and choices that we and third parties may offer. I explain why it is important to begin to make changes today to achieve that longer-term rate design. The longer-term approach we envision will not be achieved in this Phase II rate case alone. It will be shaped and implemented through a variety of filings, close examination, and careful communications with our affected customers -- as well as with the Commission, the Staff of the Commission ("Staff"), the Office of Consumer Counsel ("OCC") and other stakeholders, over the next several years.

In addition to laying this larger framework, I will address the following:

- *Principles of Rate Design and Resulting Conclusions:* In this section of my testimony I will outline the basic principles of rate design, map those principles to our changing environment and provide the recommendations the Company is making at this time to modify our historical rate design to maintain these long-standing principles. I will outline why it is important to take the principles and the changes we have seen in customer consumption and policy initiatives over the past decade into account in the decision to modify how we are assessing costs to our customers. I will show that there is an existing deficiency in our current tariffs due to these developing customer options and policy modifications that drive us towards the preliminary steps we are taking in this filing.

- *Summary of Public Service's Request in this Proceeding:* This section will detail the results of the Class Cost of Service Study ("CCOSS") as well as summarize the proposed changes to the rate design for each of the rate classes. I will also summarize the overhaul that we are proposing to our Electric Tariff that results in either: (1) closing tariffs; (2) initiating new tariffs; or (3) modifying tariffs. Many modifications are proposed simply to clean up the Electric Tariff to eliminate inconsistencies that have accumulated over two decades. But other changes are more significant.

- *Timeline and Outreach:* In this section of my testimony I will describe the timeline under which we believe it is reasonable to implement the recommendations made by the Company and outline future filings with the Commission that will allow this transition to take place.

- *Rate Case Expenses:* Finally, I will provide the estimated rate case expenses we will incur during the preparation and processing of this Phase II Rate Case. I will also lay out the Company's proposal to defer recovery of these rate case expenses until the next Phase I electric rate case through the use of a deferred accounting asset.

Q. WHY IS THE COMPANY PRESENTING RATE DESIGN CHANGES IN THIS PROCEEDING?

A. We have been hearing from our customers and communities over the past several years that they would like different options from us as compared to the past. Thus, we have worked to build a longer-term vision to meet those customer and community interests. So, imagine a day when a customer has the option to interconnect with Public Service and that customer has the ability to select amongst a variety of options for receiving service. Would they like solar? Then their options are rooftop – here are the vendors in our service territory; or community solar – here are the gardens, owners and contact information; or purchase solar from the utility through programs like Solar*Connect®. Does the customer have an electric vehicle ("EV")? If so, assist them with identifying how and when their charging of the EV may affect their bill because of time of use rates or a time specific demand charge. Does the customer have a battery? If so, can the utility contract with that customer to use that battery a certain number of times a year to help defray the cost of other infrastructure, not unlike Saver's Switch®. Today, these types of conversations are difficult to have because the existing rates do not send the right price signals for those types of products and activities. In this Phase II Rate Case I identify the need to consistently apply long-standing rate design principles that the Commission has utilized for decades to expand the price signals already sent to large customers to smaller customers such as residential and small commercial customers. This allows for: (1)

customers to control not only their usage but also their electricity costs, (2) customers to more efficiently use the system, and (3) the utility to provide the type of environment discussed above for all customers on its system to ensure customers are fairly assessed the costs of the system and the utility can recover those costs. I lay this bigger picture out in my Direct Testimony.

Q. ARE OTHER COMPANY WITNESSES SUPPORTING THIS PHASE II ELECTRIC RATE CASE FILING?

A. Yes. In addition to my Direct Testimony, five Public Service witnesses are also providing Direct Testimony and accompanying attachments in this proceeding. Those witnesses and their respective topics are as follows:

Witness	**Area of Testimony**
Dolores Basquez	• Presents the CCOSS results. • Provides a description of and support for the methodology utilized by Public Service to conduct the CCOSS. • Discusses the Functionalization, Classification and Allocation of costs. • Presents the results of the analysis required from the 2009 Electric Phase II Rate Case in regards to an alternative CCOSS utilizing stratification.

Witness	Area of Testimony
Scott Brockett	• Presents the various customer class rate design methodologies and justification as well as the resulting rate levels. • Presents and supports new or updated service tariffs for: Standby Service, Supplemental Service, Auxiliary Service, a Critical Peak Pricing option, and Residential Demand Time-of-Use. • Explains and supports certain Terms and Conditions of service.
Robert Osborn	• Presents modifications to the Street Lighting Schedule.
Donald Garretson	• Presents evidence and results regarding the impact of tiered rates from 2010 through 2013. • Explains the impacts of time of use rates on customer use. • Details the impacts of the distribution demand ratchet during the 2013 Test Year. • Presents the Company's bill frequency distribution study and how it was utilized to develop the tiered distribution charges for Residential and Schedules.
Steven Wishart	• Explains how the Company's proposed rates were developed. • Presents the Company's revenue proof to establish the fair recovery of the approved revenue requirement. • Presents the stratification study and the results of the study. • Provides the bill impacts of the Company's proposed rate design. • Sponsors the Colorado P.U.C. No. 8-Electric Tariff, which replaces the existing Colorado P.U.C. No. 7-Electric Tariff.

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

A. Yes, I am sponsoring Attachments AKJ-1 and AKJ-2. Attachment AKJ-2 was prepared by me or under my direct supervision. Attachment AKJ-1 is the result of surveys conducted or requested by the Company and address topics in this proceeding.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A. Public Service recommends that the Commission approve the following:

- Instituting Grid Use Charges to recover distribution costs for customers served under Residential Service ("Schedule R") and Commercial Service ("Schedule C"). For both Schedules R and C, the Company proposes to assess graduated charges that will increase with a customer's average use over the past 12 billing periods. Solar*Rewards® customers, who are net metered as of December 31, 2016, will have the option of remaining on the current two-part rate design that does not include a Grid Use Charge.
- Instituting an optional Residential Demand – Time-of-Use Service ("Schedule RD-TOU"). This service would be available to a maximum of 10,000 residential customers in 2017, 14,000 residential customers in 2018, and 18,000 residential customers in 2019.
- Revising the rate differential between summer and winter rates for Schedule C.
- Instituting an on-peak Demand Charge for customers on Primary General Service ("Schedule PG") and Transmission General Service (Schedule TG) to recover generation and transmission costs. This charge would be assessed on a customer's peak load during non-holiday weekdays from 2:00 p.m. through 6:00 p.m.
- Instituting a Critical Peak Pricing option (Schedules "SG-CPP", "PG-CPP" and "TG-CPP") for large Commercial and Industrial ("C&I") customers. This service would be offered on a pilot basis, and total participation would be capped at 30 megawatts ("MW").

- Offering a Supplemental Service within Secondary General Service ("Schedule SG"), Schedule PG and Schedule TG. This service would be available to C&I customers whose on-site generation does not operate as frequently and predictably as the generators for whom Standby Service is intended. The Company is also proposing to introduce the concept of Auxiliary Service for customers with on-site electric storage applications operating in parallel with the Company.
- Revising the differential between summer and winter demand charges for the following service schedules: SG, PG, and TG.
- Lowering the required maximum demand used to determine whether Schedule SG customers are eligible for the TOU ECA from 300 kW to 100 kW.
- Eliminating or closing to new customers some existing service options that are rendered obsolete by or do not complement the Company's proposed long-term rate design.

The Company also requests approval to replace the existing Colorado P.U.C. No. 7 – Electric Tariff with Colorado P.U.C. No. 8 – Electric Tariff as described by Company witness Mr. Steven Wishart and other Company witnesses. The primary revisions to the Electric Tariff include the following:

- Institute a new General Definitions section, which will define terms used throughout the tariff in one section. The purpose of this section is to clarify and standardize the meanings of terms found throughout the different sections of the Electric Tariff. Definitions that are specific to certain sections of the tariff will remain in that section.
- Reorganize the Rules and Regulations section to group together similar sections, include provisions for the measurement of service if customers have multiple meters, and address responsibility for damage to the system.
- Revise the Rules and Regulations applicable to Street Lighting Service to address the relocation and removal of lights and attachments to street lighting poles.
- Specify that customers taking service under Schedules R and C who have on-site renewable energy generation operating in parallel with the Company and are not net-metered will be subject to a buy-all, sell-all arrangement.

- Add a Production Meter Charge applicable to customers on various schedules with on-site generation.
- Update the Customer list for Schedule TG.
- Modify the Secondary General Standby (Secondary SST"), Primary General Standby ("Schedule PST") and Transmission General Standby ("Schedule TST") services by adding a Production Meter Charge and basing the annual grace energy period on a calendar year.
- Modify the Street Lighting Service to incorporate the new LED options.
- Revise the Parking Lot Lighting Service ("Schedule PLL") to differentiate this lighting from Commercial Area Lighting Service.

The Company also requests approval to defer recovery of the Current Phase II Electric Rate Case expenses until the next Phase I Electric Rate Case through the use of a deferred accounting asset.

II. PRINCIPLES OF RATE DESIGN AND RESULTING CONCLUSIONS

Q. WHAT WILL YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. To provide a framework for our proposals in this case, I will first address the basic principles of utility rate design that have been in existence for decades and how generally the industry got to the current rate design methodology. Then I will discuss significant changes and developments in our business that have occurred since our last Phase II Electric Rate Case six years ago in Docket No. 09AL-299E ("2009 Electric Phase II Rate Case"). It is these changes that have led us to many of the recommendations we are making in this proceeding ("Current Phase II"). Similar to our 2009 Electric Phase II Rate Case, we are proposing a step towards achieving a longer-term rate design objective.

Q. WHAT DO YOU BELIEVE ARE THE BASIC PRINCIPLES OF UTILITY RATE DESIGN?

A. A number of texts and position papers have been written over the past sixty plus years regarding the principles of utility rate design, typically with those texts or position papers becoming more numerous and prominent at times of change or prompted by problems that indicate a need for a modification to past practice. One text that I believe clearly lays out the principles of utility rate design that has been largely unchanged and relied upon by many regulators and utilities alike over the years is that primarily authored by James C. Bonbright. While the Second Edition of the Principles of Public Utility Rates was published after his death, it has maintained the attributes of sound rate structures (i.e., “principles”) that he laid out in the first printing (1961) as follows[1]:

Revenue-related Attributes:

1. *Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.*
2. *Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.*
3. *Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity. (Compare “The best tax is an old tax.”)*

Cost-related Attributes:

4. *Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:*
    a. *In the control of the total amounts of service supplied by the company;*
    b. *In the control of the relative uses of alternative types of service to ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).*
5. *Reflection of all of the present and future private and social costs and benefits occasioned by a service’s provision (i.e., all internalities and externalities).*
6. *Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three dimensions: (1) horizontal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer’s demands can be diverted away uneconomically from an incumbent by a potential entrant).*

[1] J.C. Bonbright, A.L. Danielsen, and D.R. Kamerschen, Principles of Public Utility Rates, Public Utilities Reports, Inc., 1988. Pages 383-384

7. *Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).*

8. *Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.*

<u>Practical-related Attributes</u>:

9. *The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.*

10. *Freedom from controversies as to proper implementation.*

Q. CAN THESE TEN ATTRIBUTES BE SUMMARIZED INTO SIMPLER CONCEPTS OR GOALS?

A. Yes. Paraphrased from the text, these attributes balanced together and at times in conflict attempt to highlight the pillars of utility rate design described as: (1) the provision of adequate, stable, and, predictable rates for the utility; (2) the balancing of cost, efficiency, and equity considerations; and finally, (3) consideration of matters of practicality and acceptability.

Q. WILL THESE GOALS AT TIMES COMPETE WITH ONE ANOTHER?

A. Yes. For example, the recovery of costs equitably from the various customer classes and customers in each of those classes will inherently compete with the goal to offer services and rates that are easy to understand and administer. As Bonbright says, "…the wise choice must be that of wise compromise…" However, the text goes on to give some further direction in that it states "…the ratemaker should utilize the cost standard as a benchmark, with assessments of the efficiency advantages (or disadvantages) of particular rate structures playing a subsidiary role; social and fairness standards also may be appropriate within the limits of authority that a regulating body may be able to exercise."

Q. ARE THESE RATE DESIGN PRINCIPLES REFLECTED IN THE PUBLIC UTILITIES LAW?

A. I believe so, but to be clear, I am not a lawyer. I would note in particular the anti-discrimination section of the Colorado Public Utilities Law, 40 C.F.R § 40-3-106(1)(a). This and similar provisions provide the basis to understand the service characteristics of customer and customer classes so that rates can be properly established.

Q. DO YOU BELIEVE THAT THE COMPANY AND THE COMMISSION HAVE APPLIED AND BALANCED THESE PRINCIPLES OVER RECENT HISTORY?

A. Yes. I believe that rates resulting from the 2009 Electric Phase II Rate Case and those preceding the 2009 Electric Phase II Rate Case have adhered to these principles and balanced the demands and conflicts between them.

Q. DO YOU BELIEVE THAT THE COMMISSION AND THE COMPANY SHOULD CONTINUE TO ADHERE TO THESE PRINCIPLES?

A. Yes. Just as these principles were applicable when first outlined in the 1960s they are applicable today. As outlined by Mr. Brockett, the pricing principles that he has relied upon in his rate design included in this Current Phase II are as follows:

- recover costs equitably from customer classes based on the costs they impose;

- send accurate price signals that encourage efficient energy use;
- afford the Company a reasonable opportunity to recover the Commission-approved revenue requirement;
- offer services and rates that are easy to understand and administer;
- prevent extremely large rate impacts; and
- provide sufficient pricing and service flexibility to allow Public Service to compete effectively with alternative providers of energy services.

Q. SO THEN, IN YOUR OPINION DOES THE RESULTING RATE DESIGN TODAY HAVE TO LOOK LARGELY THE SAME AS IN THE 1960s OR EVEN IN THE 2009 ELECTRIC PHASE II RATE CASE?

A. No, to the contrary. Rate design may vary from one utility to another based on their customer compositions (e.g., how much individual load the utility might have). Likewise, over time changes in a utility's customer types and consumption patterns will result in rate design changes. As we have seen since the 1960s, utility rate design has not remained constant. There have been triggers in time that result in changes in the utility rate design without change to the underlying principles outlined above. I believe we are at another trigger in Colorado that raises the question of making a change in rate design for certain classes of customers. It is also important to understand that Public Service is not requesting a radical change in rate design. We are simply recommending that the Commission expand its past practices of rate design for our Schedule PG and Schedule TG customers to lower service levels because of changes in customer behavior and options. Even in our 2009 Electric Phase II Rate Case we mentioned that the move we were making at that time to an Inverted Block Rate ("IBR") proposal was a step to a more time of use ("TOU") based rate design but by no means the end of the road per se.[2]

Q. PLEASE PROVIDE A FEW EXAMPLES OF HISTORICAL TRIGGERS THAT HAVE CHANGED UTILITY RATE DESIGN.

A. One such trigger is the 1970s Energy Crisis, which resulted in significant changes to rate design particularly for larger customers through TOU rates and rate designs that promoted more energy efficiency than those previously in place. Not long after the first Energy Crisis, another trigger occurred when Congress passed the Public Utility Regulatory Policies Act ("PURPA") in 1978. Not only did PURPA encourage further energy efficiency and push for further differentiated rates based on customer types, it also created the concept of a Qualifying Facility ("QF").[3] Next, the concept of deregulation started in the 1980s and continued through the early 2000s. This trigger resulted in many deregulated states unbundling services and caused significant changes in rate design. Moving into the early 2000s an increased interest in demand response, previously provided through interruptible rates in a bundled state, caused another change in rate designs. And finally, I would argue the implementation of advanced meters has and is continuing to facilitate further changes in rate design.

[2] Docket 09AL-299E, Direct Test. & Exs. of Scott B. Brockett, p. 16 (filed May 1, 2009).
[3] QF Defn. FERC website reference.

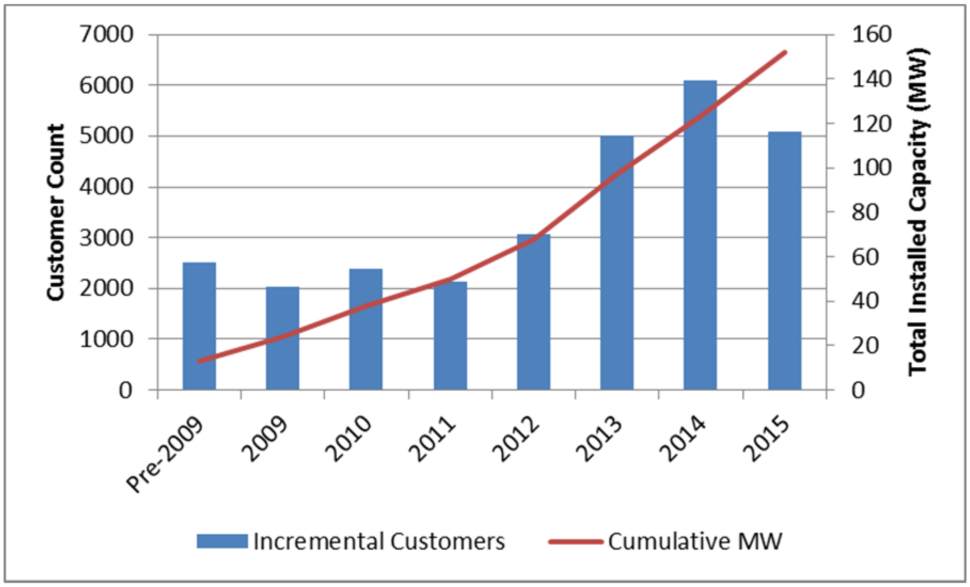
Q. YOU MENTIONED THAT YOU BELIEVE COLORADO IS AT ANOTHER TRIGGER FOR A RATE DESIGN CHANGE. PLEASE EXPLAIN.

A. Changes and advancements in technology on the customer side of the meter are and will continue to affect rate design for the next decade if not longer. We can clearly see in the Public Service territory that a change in technology adoption has occurred since our 2009 Electric Phase II Rate Case and the Current Phase II. Two technologies have advanced since our 2009 Electric Phase II Rate Case, rooftop solar and EV adoption. Other initiatives that have advanced as well are energy efficiency ("EE") and demand side management ("DSM"), which also affect utility cost recovery. However, I will not discuss these impacts here because they are better addressed in our DSM strategic issues and plan proceedings if a rate design change is undertaken.

Q. PLEASE DESCRIBE THE CHANGE PUBLIC SERVICE IS EXPERIENCING IN ROOFTOP SOLAR TECHNOLOGY ADVANCEMENT.

A. Chart AKJ-1 below reflects the number of rooftop solar installations per year under our small Solar*Rewards® program, which roughly translates to our Residential service schedule, from 2009 through 2015 at year end as well as the total MW of installed capacity.

Chart AKJ-1: 2009 – 2015 Residential Rooftop Solar
Annual Incremental Customers and Total Installed Capacity (MW)



As can be seen by the detail of this chart, a significant influx of rooftop solar installations has occurred since 2009. To directly compare the bases for the 2009 Electric Phase II Rate Case and the Current Phase II rate cases, the periods that were utilized as the pertinent periods for each are calendar year 2010 and calendar year 2013. Since the end of 2010 through the end of 2013, Public Service has seen an additional 10,202 rooftop solar installations in the Residential service schedule, an increase of 147 percent. This has added an incremental 59 MW of capacity over this period, an increase of 155 percent in Residential rooftop solar capacity. As is depicted in the chart the incremental customer installations in calendar years 2014 and 2015 are larger than those in 2013, so the trend is continuing. Additionally of note is that while customer count installations in 2015 were less than those in 2014, the incremental capacity installed still increased between the two years.

Q. HOW DOES THIS IMPACT THE CURRENT PHASE II RESULTS?

A. As discussed by Company witness Ms. Dolores Basquez, the allocators in this Current Phase II rate case are based upon calendar year 2013 billing determinants and utilized to set the rates to be assessed. This is because the Phase I revenue requirement, approved in Proceeding No. 14AL-0660E/14A-0680E ("2014 Electric Phase I Rate Case"), being recovered through this Current Phase II Rate Case is based on a historical test year ending December 31, 2013. Effectively the results of the 2014 Electric Phase I Rate Case eliminated any revenue gap that the utility was experiencing due to degradation in kilowatt hour ("kWh") sales. This Current Phase II reapportions those costs associated with infrastructure to other customers either within the rate class or to another rate class.

Q. WHAT IS THE IMPACT TO PUBLIC SERVICE?

A. Fixed costs are costs that are unavoidable regardless of the amount of energy consumed (kWh); thus, additional rooftop solar installations in the Residential or Small Commercial classes (after rates have been set) erode revenue recovery. Theoretically, the impact is nothing in year one (i.e., 2013) because rates have been reset to capture any of the lost kWh and revenue collections. However, all else being equal, each time a new rooftop solar customer is added, this is not the case. To answer the impact of incremental customers, two items need to be identified. Those two items are (1) the total fixed costs allocated to the Residential rate class and (2) the kWh over which those costs are being spread so that the rate of collection ($/kWh) is known. The following are the fixed costs allocated to the Residential rate class in the Current Phase II CCOSS and recommended to be recovered through the customer's energy charge:

Production:	$219,683,574
Transmission:	71,547,308
DSM:	37,000,918
Total Fixed Costs:	**$328,231,800**

The Residential retail sales that these costs are spread over to determine the rate is 8,880,334,513 kWh. This translates into a rate of $0.03696/kWh.

If we assume the rates resulting from the Current Phase II had been implemented on January 1, 2014 we could now look at the impacts of the incremental customers in calendar years 2014 and 2015 to see the estimated impact on Public Service's revenues from these customer choices. Table AKJ-1 below lays out a conservative estimate of the impacts in 2014 and 2015 under these assumptions of additional rooftop solar on Public Service's base rate revenue recovery.

Table AKJ-1: Estimated Lost Revenue Recovery 2014 & 2015

Year	Incremental New Customer Installations	Average Annual Energy Production	Lost Fixed Cost Recovery ($/kWh)	Incremental Lost Fixed Cost Recovery
2014	6,095	6,133 kWh	$0.03696	$1,381,588
2015	5,092			$1,154,233
Total	CY 2014 x 2 + CY 2015			$3,917,409

The reason that I say that this is a conservative estimate is during these years the lost fixed cost recovery would have been higher because fixed cost recovery during this period through the base energy (kWh) charge for these customers also included distribution system fixed costs. The rate included in this analysis does not include the costs for the distribution system, since we are recommending to move those costs to the Grid Use Charge as explained later in my testimony.

Q. IF YOU WERE TO APPLY THIS SAME THEORY TO 2010 THROUGH 2013, CAN YOU ESTIMATE HOW MUCH LOST FIXED COST RECOVERY OCCURRED?

A. Yes. Once again as a conservative estimate of lost revenues, using the same lost fixed cost recovery rate from 2010 through 2013, is $6.1 million. As illustrated in the table above, each year compounds with the next, since the additions are incremental year-over-year. Also recall that these amounts are for the Residential rate class only. The same type of fixed cost recovery erosion exists for the Small Commercial rate class as well.

Q. IS THE IMPACT OF ROOFTOP SOLAR ON FIXED COST RECOVERY LIMITED TO BASE RATE IMPACTS?

A. No. The table above depicts base rate fixed cost recovery, but the Company also recovers some fixed costs through riders - namely through the Clean Air - Clean Jobs Act ("CACJA") rider, the Purchased Capacity Cost Adjustment ("PCCA") rider, the Transmission Cost Adjustment ("TCA") rider and the Demand-Side Management Cost Adjustment ("DSMCA") rider. These riders are listed below and reflect additional incremental fixed cost revenues that would not be recovered. I have provided this analysis assuming ongoing incremental additions of 5,000 customers per year in Table AKJ-2.

Table AKJ-2: Annual Lost Rider Revenue Recovery

Rider	Number of New Customer Installations	Average Annual Energy Production (kWh)	Lost Fixed Cost Recovery ($/kWh)	Annual Lost Fixed Cost Recovery
CACJA	5,000	6.133	$0.00401	$122,967
PCCA			$0.00551	168,964
TCA			$0.00081	24,839
DSMCA			$0.00123	37,718
Total Annual			**$0.01156**	**$354,487**

It is more difficult to do longer than an annual analysis of this lost fixed cost recovery, because these riders are updated on an annual basis and some of them also recover costs based on rates derived by using forecasted billing determinants.

This rider-related loss in fixed cost recovery does not affect Public Service, because we true up for any under-collections. But this loss in fixed cost recover does result in costs being shifted to other customers.

Q. LOGICALLY WHAT DOES THIS MEAN FOR THE RATE DESIGN CURRENTLY IN PLACE FOR THE RESIDENTIAL RATE CLASS?

A. Because (1) the Residential rate class' costs are largely assessed through their energy (kWh) charge; and, (2) through policy implemented over the years, Residential customers are billed for fixed costs through a kWh rate and rooftop solar customers are allowed to offset kWh for kWh their energy charge by produced kWh from their rooftop solar, I reach the conclusion that fixed cost recovery is potentially being impacted by this technology change. Thus, the first principle outlined above is potentially being stressed.

Q. IF THE FIXED COSTS ARE NOT GOING AWAY, WHAT HAPPENS TO THESE COSTS WHEN PUBLIC SERVICE FILES A PHASE II RATE CASE?

A. These costs are moved either inside of a rate class to other customers in that rate class or they are moved to a different rate class due to changes in allocators.

Q. IS THIS SOMETHING EASILY QUANTIFIED?

A. Not easily, but possibly indirectly. In a conservative exercise utilizing 2015 Residential customer information, we attempted to calculate the costs that otherwise have to be collected from non-rooftop solar customers after the avoided energy and capacity are taken into account. The result of this analysis is an estimated $9.8 million impact for the Residential rate class. If you divide this cost recovery shift by the number of customers in the Residential rate class as of December 2013 that do not have rooftop solar, that means each non-rooftop solar customer is paying on average $7.94 per year.

To further expand on this, the $9.8 million shift is spread over approximately 25,000 Residential rooftop solar customers, and on average we are also adding between 4,500 and 5,000 more rooftop solar customers in the Residential rate class each year. As a rough estimate, if this shift translates into $391 per customer per year ($9.8 million / 25,000 customers), then the $9.8 million is incrementally increasing by approximately $1.8 million per year ($391 per customer per year * 4,500 customers).

Q. YOU SAY THE EXERCISE THAT YOU PERFORMED IS CONSERVATIVE. HOW SO?

A. Due to the iterations of rooftop solar installation, we do not have 100 percent of the Residential rooftop solar installations metered with production meters. In our exercise we used actual metered production, so it results in a conservative estimate. If all of the Residential rooftop installations were production metered, the total rooftop kWh generated would have been greater.

Q. WILL THIS TRANSLATE INTO A UTILITY UNDER RECOVERING ITS REVENUE REQUIREMENT?

A. Not necessarily. Just as rate design is complex, so is revenue requirement recovery. Under recovery of the revenue requirement is dependent on many factors such as load growth, weather, force majeure events, etc. What this does is reduce the reasonable opportunity for the utility to recover its approved revenue requirement.

Q. BECAUSE OF THE BEHIND THE METER TECHNOLOGY ADVANCEMENT TRIGGER, DO YOU BELIEVE THAT THE PRINCIPLES THAT YOU PRESENTED ABOVE ARE BEING CHALLENGED?

A. Yes, to a degree. I believe we are seeing the start of a significant change in how customers are placing demands on the Company's provision of service and thus challenging how utility rate design can continue to adhere to the first, second, sixth and eighth principles that I discussed above.

Q. PLEASE ELABORATE.

A. The first principle goes to the recovery of the approved revenue requirement. In my testimony above, it is clear that the recovery of the approved revenue requirement is eroded, all else being equal. This was true to some extent with Company-promoted DSM. In that instance, we have adjusted not the current rate design, but instead utilized another mechanism for recovery.

The second principle goes to revenue stability and predictability. Utilities do not control the rate at which customers are choosing to adopt the new technology. When the technology is adopted it clearly has an impact on the revenue recovery of the utility. Thus revenue stability and predictability are impacted.

The sixth principle goes to the fairness of the rate between different ratepayers so that there is equity among those ratepayers. As the rate design stands today for Residential customers, the fairness of the fixed cost recovery inside the rate class bears revisiting. While policy decisions in the past have been found to be just and reasonable, resulting in the Residential rate we have today, we are facing changes that precipitate revisiting these decisions. In my opinion, while the dollar impact amount may be small today, it is growing each year.

The eighth principle takes into account the fact that the rate design should provide dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns. Currently the Residential rate design does not promote innovation and the adoption of new technologies in an economically efficient manner. Because the appropriate indicative price signal is not being translated to the consumer, choices are being made that do not promote long-term efficiencies and appropriate technology adoption.

Q. YOU ALSO MENTIONED ELECTRIC VEHICLES AS ANOTHER POTENTIAL TRIGGER. PLEASE EXPLAIN.

A. EV is another technological advancement that we are seeing in more prevalence since the 2009 Electric Phase II Rate Case. While the numbers are statewide metrics, data that we have indicates that electric vehicles in the State of Colorado have doubled between 2014 and 2015. We have also had conversations with certain stakeholder groups that raise EV concerns with our existing rate design.

Q. WHAT IS THE EV CUSTOMER'S PRIMARY CONCERN WITH THE COMPANY'S EXISTING RATE DESIGN AS YOU UNDERSTAND IT?

A. Primarily it revolves around the Residential rate design's IBR structure, which lacks a TOU component. In theory, an EV customer primarily charges their vehicle at night when that customer is home from work. However, under energy rates without TOU components -- such as our existing IBR rate during the summer months and the flat winter energy charge -- all energy consumption is treated as the same. Thus, this customer is potentially penalized unduly. The IBR operates such that the first 500 kWh is assessed at a lower cost than any energy incrementally consumed above that first 500 kWh. IBR rates are utilized, particularly during the summer months, to promote efficient use of energy during peak system periods. An EV is electric intensive. But if the concept holds that it is being charged at night, the energy consumption of the EV is not contributing to the system peak. This logical phenomenon indicates that the existing Residential rate design is not sending sufficiently detailed enough price signals to this customer type and could potentially be assessing costs on the customer in a non-equitable manner. In other words, principle six that I described above is being impugned.

Q. IS IT REASONABLE TO BELIEVE THAT THIS EV ISSUE WILL ONLY EXPAND IN THE FUTURE AND SHOULD BE CONSIDERED IN THE EVALUATION OF A LONGER-TERM SOLUTION?

A. Yes. The Company purchased a study and forecast assembled by Navigant Research entitled *Electric Vehicle Geographic Forecasts* and its underlying data (“Navigant Report”). Near the same time, the Colorado Energy Office (“CEO”) also published a forecast and report regarding EV adoption in the State of Colorado. Both reports are on a statewide basis versus breaking the customer-owned EVs into electric utility service territories. But, since Public Service serves roughly 60 percent of the State and the majority of the metropolitan areas, we believe it is a safe assumption that the majority of the EVs will reside in our service territory. The Navigant Report forecasts that the number of EV’s in Colorado in 2015 will increase five times by 2020. The CEO report forecasts that they will increase by 2.7 times over the same time period. Both of these variables were taken from each report’s conservative forecast. Suffice it to say the forecast is varied, but the anticipated penetration is significant enough to keep this technology trigger in mind when developing these rates.

Q. ARE THERE OTHER TRIGGERS THAT MAY BE ON THE HORIZON OR ARE CURRENTLY AFFECTING ADHERENCE TO LONG-STANDING RATE DESIGN PRINCIPLES?

A. Yes. While we do not know the timing of adoption with a high degree of certainty, battery technology is advancing and the costs to install are coming down. This will be another technology that, while it provides utilities new opportunities and solutions on the grid, if adopted by customers could impact cost recovery and rate design even more.

Q. WITH THESE TRIGGERS IN MIND, WHAT DO YOU RECOMMEND?

A. After much thought and consideration, we recommend moving virtually all rate classes and service schedules to a common platform of rate design. As we move to satisfying our customer's desires for more choices and integrating more technological advancements that our customers' choose, it is essential that we are able to do so while adhering to long-standing rate design and pricing principles. At the forefront we need to provide cost recovery of the approved revenue requirement and we need to ensure that customers are not cross subsidizing one another due to independent customer choices.

Q. WHAT OPTIONS DID THE COMPANY CONSIDER IN MOVING TO A COMMON PLATFORM OF RATE DESIGN?

A. We identified a couple of options in addressing the triggers outlined above. One option was to provide a tariff for each permutation of customer choice that was made – e.g., maybe an EV tariff, maybe a rooftop solar tariff, maybe a battery tariff, etc. But this quickly got out of hand when we started contemplating stacked customer choices. For example, would we then also have to construct an EV + battery tariff, an EV + rooftop solar + battery tariff, a rooftop solar + battery tariff, and then iterate again for any other technology or choice a customer would have to make. The administrative burden associated with managing a wide swath of tariffs to enable the technologies and customer choices was overwhelming and concerning from a cost recovery perspective.

The second option was to build a rate design that adhered to the Bonbright principles that I discussed earlier in my testimony, would last through additional innovative technological advancements, and provide customers with more clarity despite the increase in complexity. We are recommending the second option that we explored. Additionally, this rate design may be complemented with targeted demand response options.

Q. WHAT IS THE RESULTING RATE DESIGN RECOMMENDATION FOR THE SECOND OPTION?

A. In adhering to cost-causation principles we delved into how we incur costs and thus how should we translate those costs into rates. Much of our logic can be gleaned from the method of developing the CCOSS through functionalization, classification, and allocation.

First, functionalization consists of the sorting of plant investment and expenses by system component, such as production, transmission, distribution or customer operations. Second, classification moves beyond the accounting records and identifies the primary driver of each cost. There drivers fall into basically three categories: (1) energy-related; (2) capacity-related; and (3) customer-related. And, finally, in the allocation step we utilize class load data to apportion the classified costs to the rate classes that have caused those costs to be incurred. Ms. Basquez further defines and expands upon each of these steps in her testimony.

Once these three steps are performed the deciding factor becomes how do we take the identified costs in their allocated buckets and translate that into the rate design. We recommend that the common platform provide for: (1) recovery of fuel and purchased energy costs through a TOU energy charge – most likely assessed as a rider; (2) recovery of fixed generation and transmission ("G&T") costs through a time limited demand charge; (3) recovery of distribution costs through a non-time limited demand charge; (4) recovery of non-fuel variable energy costs through a flat energy charge; and, (5) recovery of customer specific costs through a customer charge.

Q. PLEASE DESCRIBE THE TOU ENERGY CHARGE.

A. The TOU energy charge would recover variable fuel and purchased energy costs through a time-differentiated energy charge. The kWh rate applied in each time period will be differentiated based on the variable costs associated with the units providing the energy during that time. This will include the fuel component -- and possibly the non-fuel variable operating and maintenance ("O&M") expenses. However, the kWh rate will not include any fixed costs associated with transmission, distribution, and generation. The TOU energy charge is an important element of the proposed common platform, because TOU pricing sends customers a more accurate signal as to how energy costs vary depending on the season, day of the week and time of the day. TOU rates can range from extremely granular and interactive with the market, such as real time pricing, to very generalized, such as two time periods, On Peak and Off Peak. They can also be differentiated based on season or other attributes, such as Critical Peak Pricing ("CPP"). We expect the level of granularity and complexity to vary based on local circumstance and analysis of load profiles.

Q. PLEASE DESCRIBE THE TIME LIMITED G&T DEMAND CHARGE.

A. The Generation and Transmission ("G&T") demand charge will recover fixed costs related to generation and transmission. Because generation and transmission investments are primarily driven by system peak (or coincident peak) requirements, the proposed common platform of rate design more closely aligns the customer's billing demand based on the customer's peak load with when the Company experiences its highest load or system peak. However, to simplify the rate design and provide a more predictable charge to the customer, the Company proposes that the customer's billing peak will be set monthly based on the customer's demand during a specified, fixed weekday, non-holiday time period consistent with when the system typically peaks but not directly tied to it. For example, as further discussed by Mr. Brockett, we are proposing a window of 2:00 p.m. to 6:00 p.m. on non-holiday weekdays for certain customers. The customer's monthly G&T demand charge would be calculated based on the highest demand during that window. In more technical terms, the customer would be billed on a non-coincident peak ("NCP") basis, but within the time-limited window.

We propose this method for every month of the year, such that monthly demand charges are based on the customer's NCP demand during a specified measurement window.

While the measurement method and window may not change during the year, the rate applied to the billing demand could vary by season, specifically by summer and winter, as the most expensive days to deliver power to customers are during the summer. Consistent with the principles that I discussed earlier in my testimony, the actual kW rate should be set to align the types of costs and charges the utility can or cannot avoid with the customer rate components that can or cannot be avoided. In other words, ideally the charges a customer can avoid by reducing demand should reflect the types of costs the utility can avoid. In this scenario, the utility would be relatively indifferent to customer actions to reduce demand.

This will be a major change for the Residential and Small Commercial classes, which have not previously had a demand component on their bills. While the concept may be confusing initially for those unfamiliar with demand charges, we believe education can overcome this hurdle and eventually automation tools can make the change nearly invisible to the customer. Furthermore, much like the TOU energy charge, the proposed G&T demand charge sends price signals to customers indicating that loads during the established non-holiday weekday window drive G&T capacity costs as opposed to loads outside this window.

Q. PLEASE DESCRIBE THE NON-TIME LIMITED DISTRIBUTION CHARGE.

A. The proposed non-time limited distribution charge will recover fixed distribution costs through a charge that is assessed on a customer's monthly or rolling 12-month averages of measured non-coincident peak demands. The supporting logic is that the Company's distribution investments are largely driven by and sized to meet localized peak demand, and the costs are typically proportional to this demand. An analogy that may help is to think of the difference between building a reservoir for the flood versus the river. If the reservoir were built only to be able to take the run of river, when the flood came there would be a serious problem. Our distribution system cannot be built for the run of river level of consumption; it has to be built for the flood level of consumption. For the distribution system, think of each feeder as a river, its size is dependent on how many inputs on the river similar to the fact that each feeder's characteristics are specific to the quantities and types of customers interconnected to the feeder in question.

Q. PLEASE DESCRIBE THE NON-FUEL VARIABLE ENERGY CHARGE.

A. The non-fuel variable energy charge will recover non-fuel energy-related costs, such as chemicals or water that are incurred and dependent on the amount of facility usage. This charge will be assessed on a customer's metered monthly kWh energy consumption. This is an appropriate method because these costs are directly proportional to energy generated and consumed. The more energy consumed, the higher the cost. I also mention above that this cost could potentially be collected through the variable TOU rate, which would potentially help with simplifying a customer’s bill.

Q. PLEASE DESCRIBE THE CUSTOMER CHARGE.

A. We are not proposing any changes to the current method under which we recover our customer-specific charges through our Service and Facilities (“S&F”) charge.

Q. IS IT POSSIBLE TO ACHIEVE THIS COMMON RATE DESIGN PLATFORM IN THIS CURRENT PHASE II RATE CASE?

A. For some rate classes, yes; for others, no. The limiting factor is the metering available to measure a customer’s consumption. Specifically, this suggested rate design is remarkably similar to that which already exists for our larger rate classes such as Schedules PG and TG.

Q. BECAUSE METERING CANNOT BE REPLACED OVERNIGHT, WHAT ARE YOU PROPOSING TO DO IN THIS FILING?

A. As described by Mr. Brockett, we recommend moving the Schedules PG and TG rate classes to the time limited G&T demand charge. Additionally, we are recommending taking a step forward for our Residential and Small Commercial rate classes by recovering distribution system costs through a tiered Grid Use Charge based on a customer’s monthly average energy consumption based on a rolling twelve months of usage. Finally, we are requesting the Commission allow us to establish a new voluntary Residential Demand TOU tariff for a limited number of customers so that we may test the contemplated final rate design and work with the customers that opt into this service over the near-term to learn pros and cons.

Q. HOW DOES THE FINAL RATE DESIGN ADDRESS THE ISSUES OUTLINED ABOVE WITH THE TRIGGERS YOU ARE FACING TODAY?

A. This final rate design allows the Company to measure an individual customer's impact on the system. Those that demand and use more of the system would be appropriately billed. Additionally, we anticipate that this improved rate design will address not only current technological advancements, but also address longer-term, unknown technologies that may impact our industry. Finally, in the event there is long-term interest in a more integrated distribution system, the final rate design would enable that type of interaction. So for reasons of cost recovery, efficient use of the system and equal treatment of customers, the final rate design appropriately applies the long-standing principles of rate design presented by Bonbright and utilized by this Commission.

Q. HOW DOES THE STEP PROPOSED IN THE CURRENT PHASE II ADDRESS THE ISSUES OUTLINED ABOVE WITH THE TRIGGERS YOU ARE FACING TODAY?

A. The step proposed in the Current Phase II proceeding starts to mitigate some of the issues regarding the recovery of fixed distribution costs and starts to send a better price signal to customers regarding the costs of the system that they rely upon and benefit from. As Mr. Brockett also mentions, this is not the ultimate design and is not perfect – there is a balancing that goes on in any rate design.

However, it is a good step for the Company to take, and we believe it positions us well for the future changes in the industry that we are expecting. This step will also assist in further educating customers on their electricity costs.

III. CURRENT PHASE II REQUEST SUMMARY

Q. WHAT WILL YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony I will:

(1) provide a high level history of the 2009 Electric Phase II Rate Case as well as remaining obligations from that proceeding;

(2) detail the results of the current CCOSS;

(3) summarize our proposed changes to the rate design for each of the rate classes; and,

(4) outline the overhaul that we are proposing to our Electric Tariff that results in either: (i) closing tariffs; (iii) initiating new tariffs; or (iii) modifying existing tariffs or terms of service.

Q. WHAT IS PUBLIC SERVICE REQUESTING IN THIS CURRENT PHASE II FILING?

A. We are requesting that the Commission approve the updated cost allocation and rate design as presented in the Direct Testimony of the Company's witnesses. We are requesting that rates resulting from this Current Phase II rate request be implemented on January 1, 2017. The filing includes modifications to various base service schedules as well as the introduction and elimination of various service schedules. Some elements of note in this Current Phase II filing are as follows:

- The CCOSS has been updated to reflect the 2014 Phase I utilizing almost all of the principles approved in the Company's 2009 Electric

Phase II Rate Case and reflecting allocators based on 2013 class loads.

- A modification to the Schedule R and Schedule C service schedules to reflect transferring the distribution system costs out of the energy components of the tariffs into the “Grid Use Charge.”
- Introduction of a new voluntary Schedule RD-TOU service schedule to address certain customer concerns and provide an avenue for learning.
- Modification of the Schedule PG and Schedule TG service schedules to assess the G&T demand charge on customer peak loads from 2:00 p.m. to 6:00 p.m. versus the around the clock methodology employed today.
- Introduction of a CPP service schedule available on a limited basis to SG, PG, and TG customers.
- A comprehensive review of and update to our tariffs to ensure consistency, clarity and effective organization.

Q. YOU MENTIONED THAT THE COMPANY IS REQUESTING THE RESULTING RATES FROM THIS CURRENT PHASE II RATE CASE BE EFFECTIVE ON JANUARY 1, 2017. WHY?

A. The Company recognizes that the changes it is proposing are impactful to the various rate classes and harken back to the changes made with the 2009 Electric Phase II Rate Case in which summer inverted block rates were established, a demand ratchet was reinstated, and seasonal differences in charges were increased. Thus, we believe that attention and time needs to be taken to educate customers on the changes prior to their effectiveness. I will discuss this further in Section IV of my Direct Testimony.

A. <u>Public Service Phase II History</u>

Q. WHEN WAS THE COMPANY'S 2009 ELECTRIC PHASE II RATE CASE FILED?

A. Public Service filed the 2009 Electric Phase II Rate Case on May 1, 2009. The 2009 Electric Phase II Rate Case was resolved through a litigated decision, and a settlement with Colorado Energy Consumers Group ("CEC") on limited issues relating to one customer. It was approved by the Commission in March 2010. The Phase I and Phase II were filed together in this docket, but the Commission bifurcated the hearing into two sections, the first one to hear Phase I revenue requirements and Electric Commodity Adjustment ("ECA") issues and the second to hear Phase II rate design issues. The 2009 Electric Phase II Rate Case implemented rates based on 2010 billing determinants. Rates as a result of the

2009 Electric Phase II Rate Case went into effect on June 1, 2010. Thus it has been approximately 5.5 years since Public Service has revised its base rate tariffs through a Phase II filing. If these rates become effective on January 1, 2017, as requested by the Company, it will have been approximately 6.5 years since the last base rate update.

Q. IN DECISION NO. C10-0268 IN THE 2009 ELECTRIC PHASE II RATE CASE, DID THE COMMISSION DIRECT PUBLIC SERVICE TO PROVIDE CERTAIN DATA AND/OR ANALYSES IN OUR NEXT PHASE II FILING?

A. Yes. In Decision No. C10-0286, the Commission directed Public Service to include the following data and/or analyses in our next Phase II rate case:

- A CCOSS that includes a stratification adjustment in addition to the Company's proposed CCOSS. This stratification CCOSS should also contain a comparison sheet that maps its results to the results of the Company's proposed CCOSS. (Decision No. C10-0286, ¶34)
- The impacts of the 50 percent demand ratchet rate mechanism approved by the Commission in the 2009 Electric Phase II Rate Case. (Decision No. C10-0286, ¶58)
- Examine the consequences of the IBR rate structure approved in the 2009 Electric Phase II Rate Case. (Decision No. C10-0286, ¶97)

While not a directive, the Commission also encouraged Public Service to develop TOU rates for large, demand metered customers beyond the pilot program approved in the 2009 Electric Phase II Rate Case and to make the rates a permanent part of its tariff as soon as possible or in its next Phase II rate case. (Decision No. C10-0286, ¶65)

Q. HAS PUBLIC SERVICE ADDRESSED THESE COMMISSION DIRECTIVES IN THIS ELECTRIC PHASE II FILING?

A. Yes. Company witnesses Mr. Steven Wishart and Ms. Dolores Basquez together provide a CCOSS that includes a stratification adjustment and a comparison sheet that maps its results to the results of the Company's proposed CCOSS. Specifically, Mr. Wishart sponsors the stratification study and Ms. Basquez sponsors a CCOSS with a stratification adjustment and requested comparison sheet. Company witness Mr. Donald Garretson provides the requested analyses regarding the demand ratchet and the IBR rate structure. Mr. Garretson also provides an analysis of the TOU rates that were approved in the 2009 Electric Phase II Rate Case for large, demand metered customers. Mr. Brockett discusses the types of TOU and demand response rate designs that make most sense on an ongoing basis given the Company's proposed long-term pricing platform.

Q. IS THE COMPANY SUPPORTING THE CLASSIFICATION OF ALL FIXED PRODUCTION COSTS AS CAPACITY-RELATED COSTS, RATHER THAN STRATIFYING THESE COSTS INTO ENERGY-RELATED AND CAPACITY-RELATED COMPONENTS?

A. Yes.

Q. WHY DOES THE COMPANY OBJECT TO STRATIFYING FIXED PRODUCTION COSTS?

A. The primary reason is precedent; the Commission approved the Company's proposed classification of fixed production costs in the Company's 2009 Electric Phase II Rate Case. While a wide variety of approaches to classifying and allocating costs can be used in a CCOSS, there is no compelling reason to depart from Commission precedent. Moreover, the stratification methodology – as explained and implemented by Ms. Basquez and Mr. Wishart -- suffers from several deficiencies.

Q. PLEASE EXPLAIN.

A. First, the stratification methodology assumes that the cost of having sufficient capacity to serve customers' needs is the hypothetical cost of having a generation portfolio consisting entirely of the least-cost capacity resource (such as gas-fired peaking units). If a utility's fixed production costs exceed the fixed production costs of such a hypothetical system -- primarily because the utility has added intermediate and baseload units to its generation mix --then these additional costs are assumed to be incurred to lower system energy costs.

But that assumption is questionable. Generating plants provide a number of ancillary services – such as voltage control and reactive power – that are clearly not related to lowering system energy costs. Consequently, the assumption that any fixed production costs above the costs of a least-cost capacity resource are attributable to lowering energy costs is misplaced.

Second, the stratification methodology is premised on the substitution of capital costs for fuel costs. By definition, this substitution must apply in both directions. If a utility can incur higher capital costs to lower fuel costs, then the utility can also incur higher fuel costs to lower capital costs. If so, the same logic by which capital costs are demonstrated to be energy-related can be extended to conclude that the higher fuel costs attributable to peaking and intermediate units should be classified as capacity-related costs.

Third, the corollary of adopting capital substitution is that some "fixed energy-related costs" should be collected through energy charges. This result would perpetuate the problems with the recovery of fixed costs that utilities across the nation are facing. While rate design can depart from the results of a CCOSS, there is no reason to purposely and needlessly introduce a significant schism.

Q. DO YOU WISH TO OFFER ANY OTHER OBSERVATIONS REGARDING THE TREATMENT OF FIXED PRODUCTION COSTS IN THE COMPANY'S CCOSS?

A. Yes. Although the Company classifies 100 percent of our fixed production costs as capacity-related, the allocation factor we apply to these costs is not based strictly on system peak loads. As Ms. Basquez explains, the four coincident peak-average and excess demand ("4CP-AED") allocator considers both peak loads and average loads. Consequently, fixed production costs are not allocated to customer classes solely on the basis of their contributions to system peak demands during the summer.

B. <u>CCOSS Results</u>

Q. WHAT ARE THE HIGH LEVEL RESULTS OF THE CCOSS?

A. One way to look at the results of the Current Phase II CCOSS is to compare the results to those that came out of the 2009 Electric Phase II Rate Case. This comparison reasonably depicts how cost responsibilities have moved between classes since the 2009 Electric Phase II Rate Case. These cost movements are caused by a variety of factors, such as where incremental investment has been made on the system or changes in consumption (energy or demand) by each of the rate classes.

Q. PLEASE PROVIDE DETAILS REGARDING THE RESULTS OF THE 2009 ELECTRIC PHASE II RATE CASE CCOSS VERSUS THE CURRENT PHASE II CCOSS.

A. When compared to the outcome of the 2009 Electric Phase II Rate Case, the following Table AKJ-3 reflects the change in revenues collected from each of the rate classes under the Current Phase II CCOSS.

Table AKJ-3: CCOSS Results 2009 Electric Phase II Rate Case vs. Current Phase II

			Total Change	
Rate Class	**2009 Phase II**	**2015 Phase II**	**$**	**%**
Residential	$545,626,246	$644,533,804	$98,907,558	18.1%
Small Commercial	$83,010,943	$89,583,237	$6,572,294	7.9%
C&I Secondary	$530,110,179	$605,105,094	$74,994,915	14.1%
C&I Primary	$106,591,428	$118,785,831	$12,194,403	11.4%
C&I Transmission	$50,226,631	$62,801,229	$12,574,598	25.0%
Lighting	$40,464,158	$41,217,303	$753,145	1.9%
CPUC Total	$1,356,029,588	$1,562,026,497	$205,996,909	15.2%

Q. ARE THERE ANY AREAS OF NOTE IN THIS COMPARISON?

A. Yes. It is clear from this comparison that there is a larger change in costs for the Residential and C&I Transmission rate classes than the other rate classes. It is also clear that the Lighting and Small Commercial rate classes are receiving a substantially smaller percentage impact from the Current Phase II CCOSS results than other rate classes.

Q. WHY DO YOU BELIEVE SOME OF THE RATE CLASSES ARE HAVING A DIFFERENT IMPACT VERSUS ALL OF THE RATE CLASSES RECEIVING THE SAME IMPACT?

A. As I mentioned before, a variety of factors can impact the differences in costs from one Phase II to the next. In this instance, we first need to look at any changes in billing determinants. Table AKJ-4 shows the energy or kWh billing determinants by rate class in the 2009 Electric Phase II Rate Case versus the Current Phase II kWh billing determinants.

Table AKJ-4: Energy (kWh) Billing Determinants – 2009 Electric Phase II Rate Case vs. Current Phase II

			Total Change	
Rate Class	**2009 Phase II**	**2015 Phase II**	**kWh**	**%**
Residential	8,686,119,054	8,880,334,514	194,215,460	2.2%
Small Commercial	1,447,913,039	1,320,501,548	(127,411,491)	-8.8%
C&I Secondary	12,265,600,678	11,797,929,988	(467,670,690)	-3.8%
C&I Primary	3,394,569,762	3,462,312,254	67,742,492	2.0%
C&I Transmission	2,504,114,618	2,612,222,396	108,107,778	4.3%
Lighting	200,185,789	202,658,899	2,473,110	1.2%
CPUC Total	28,498,502,940	28,275,959,599	(222,543,341)	-0.8%

Q. WILL THESE RATE CLASSES FEEL THE FULL IMPACT OF THE CHANGE IN COST RESPONSIBILITY SHOWN IN TABLE AKJ-3?

A. No. These rate classes have already been assessed rates higher than those reflected in the 2009 Electric Phase II Rate Case due to two Phase I rate cases that adjusted the Phase II rates through the application of a General Rate Schedule Adjustment ("GRSA"). The GRSA mechanism applies a fixed percentage increase to each variable in a base service schedule to reflect the change in revenue requirements approved in a Phase I rate case. Thus, the rate impact on each of the rate schedules above is moderated when going through a Phase II rate case.

Q. PLEASE SHOW THE EXPECTED PERCENTAGE IMPACT ON EACH RATE CLASS OF THIS PHASE II RATE CASE AS COMPARED TO CURRENTLY COLLECTED RATES.

A. Table AKJ-5 reflects the expected percentage impact in total revenues for each rate class resulting from this Phase II versus what they are currently being assessed under the GRSA mechanism.

Table AKJ-5: 2009 Electric Phase II Rate Case Revenues with GRSA vs. Current Phase II Revenue Requirement

Rate Class	2009 Phase II	2009-2013 Change in Sales	GRSA	Total Baseline Revenues	2015 Phase II	Total Change $	Total Change %
Residential	$545,626,246	$26,940,106	14.19%	$653,813,518	$644,533,804	($9,279,714)	-1.7%
Small Commercial	$83,010,943	($5,738,777)	14.19%	$88,237,087	$89,583,237	$1,346,150	1.6%
C&I Secondary	$530,110,179	($10,189,735)	14.19%	$593,697,155	$605,105,094	$11,407,939	2.2%
C&I Primary	$106,591,428	($143,059)	14.19%	$121,553,392	$118,785,831	($2,767,561)	-2.6%
C&I Transmission	$50,226,631	$2,915,619	14.19%	$60,683,136	$62,284,509	$1,601,373	3.2%
Lighting	$40,464,158	($1,431,859)	14.19%	$44,570,982	$41,217,303	($3,353,679)	-8.3%
CPUC Total	$1,356,029,588	$12,352,295	14.19%	$1,562,555,273	$1,562,026,497	($528,776)	-0.04%

Q. PLEASE SUMMARIZE THE BILL IMPACTS A CUSTOMER WOULD EXPECT TO SEE AS A RESULT OF THE PROPOSED RATE DESIGN.

A. An average Residential customer using 628 kWh per month will see an average monthly bill increase of $0.18 or 0.25 percent. An average Commercial customer using 24,981 kWh per month will see a bill increase of $24.70 or 1.11 percent per month. While these values are important to evaluate, it is also important to look at the bill impacts on other customers inside of the rate class that are not at average consumption. Mr. Steven Wishart provides Attachment SWW-3 detailing multiple views of the customer impacts at various levels. Later in my testimony I will address some other specific customer types and their potential experience under our proposed rate design modifications.

Q. DO YOU HAVE ANY VISUAL DEPICTIONS OF HOW THE CHANGES IN RATE DESIGN WILL IMPACT THE RESIDENTIAL CUSTOMERS ON THE SYSTEM WHEN LOOKING AT THEIR ACTUAL USAGE?

A. Yes. I found it helpful to have my team construct the following charts for a visual examination of the impacts to the Residential rate class of the proposed rate design changes in this proceeding. Chart AKJ-2 depicts the distribution of Residential customers' average monthly usage as calculated over a 12 month period. Additionally the vertical lines depict where the Grid Usage Charge tiers are delineated.

Chart AKJ-2: Residential Customer Distribution of Average Monthly Consumption

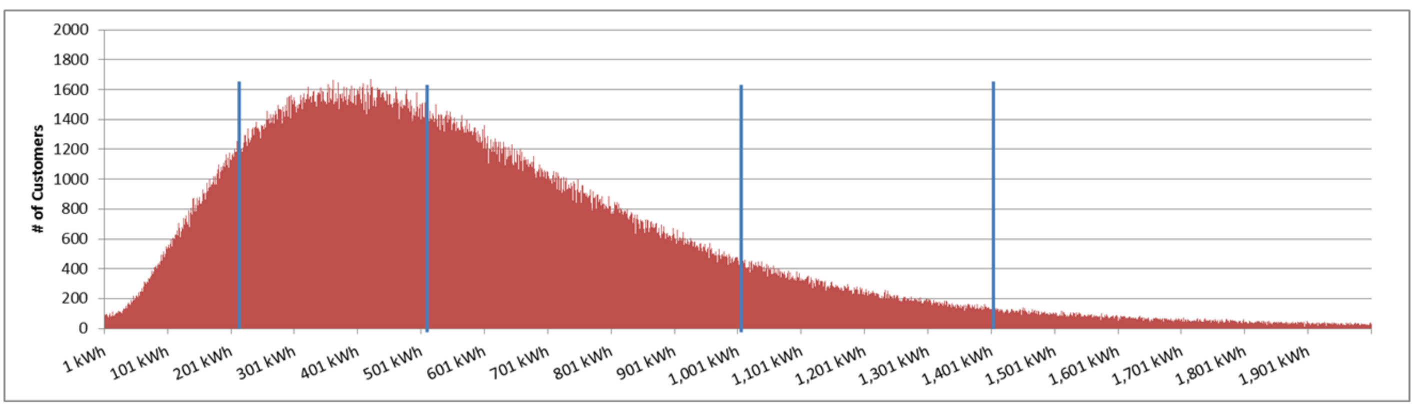
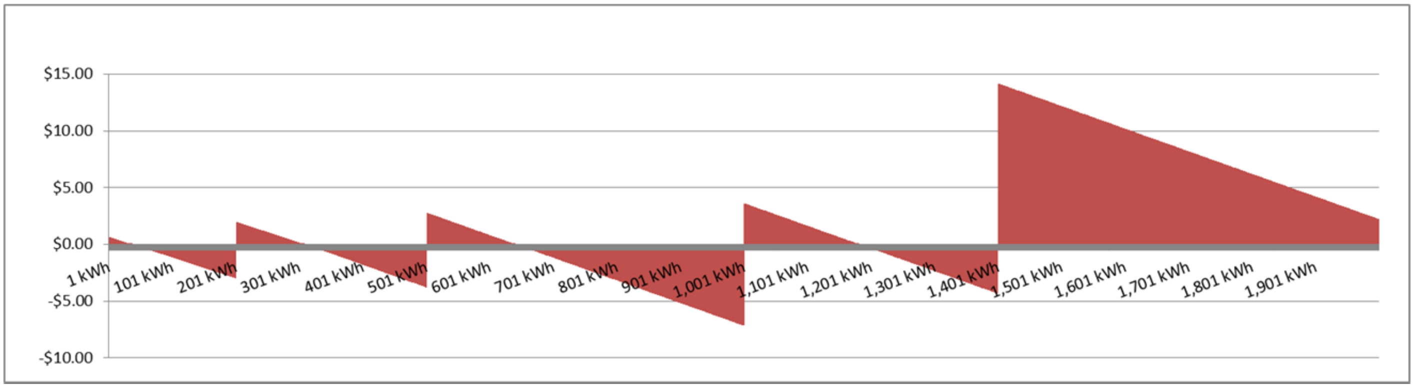


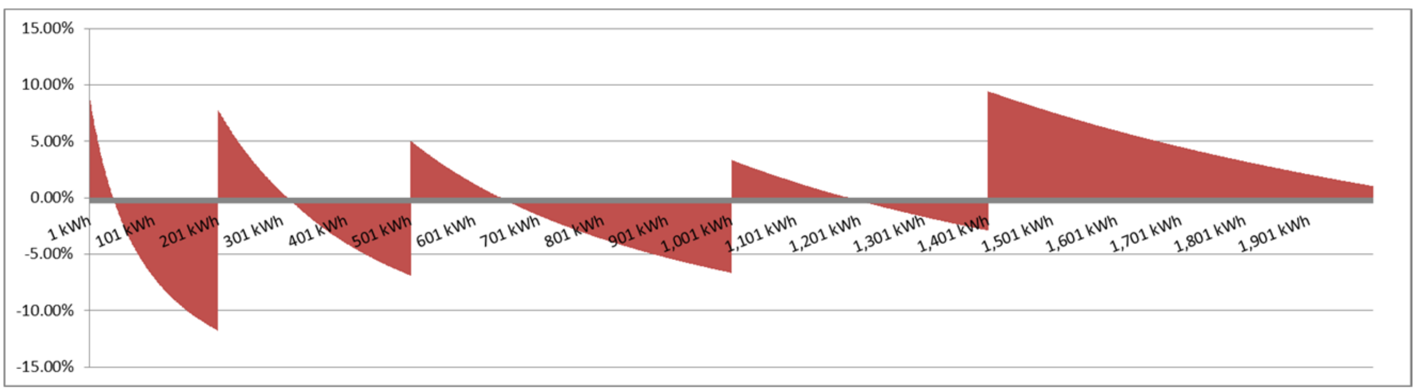
Chart AKJ-3 below shows the anticipated monthly dollar impact per month for each of these same customers.

Chart AKJ-3: Monthly Dollar Impact per Customer



Finally, Chart AKJ-4 depicts the monthly percentage impact per customer of the Current Phase II costs and rate design.

Chart AKJ-4: Residential Monthly Percentage Impact per Customer



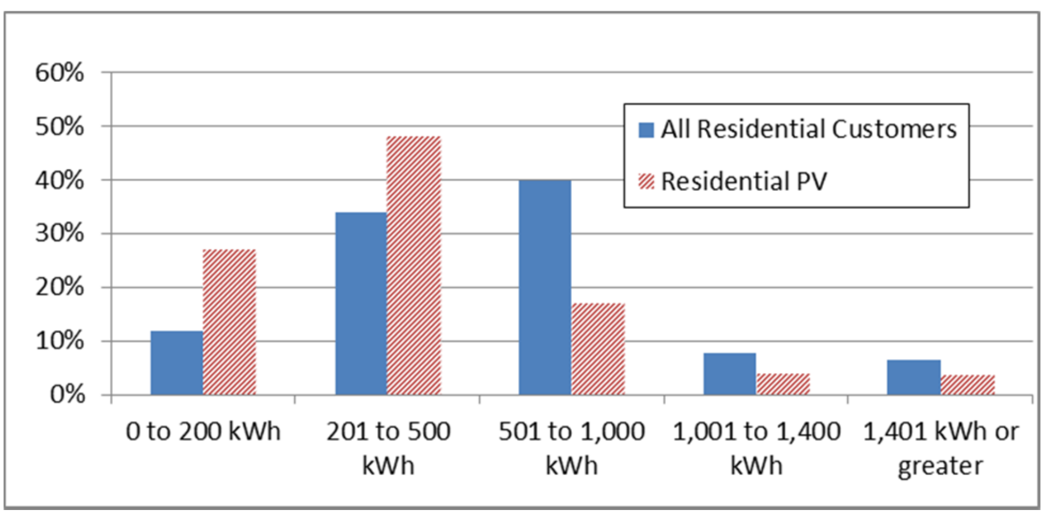
Q. DID YOU NOTICE ANYTHING WHEN LOOKING AT THESE CHARTS?

A. Yes. As a result of these charts, I noticed that more customers in the Residential rate class will experience a rate decrease than a rate increase. This is what is anticipated as evidenced by past bill history. Of our 1.17 million Residential customers, approximately 736,000 of them will receive a bill decrease. This translates to 63 percent of the Residential customers should expect a bill decrease.

Q. WHEN YOU IMPLEMENT THE GRID USE CHARGES, IN WHICH TIER IS IT ANTICIPATED THAT RESIDENTIAL CUSTOMERS THAT ADD DISTRIBUTED SOLAR TO THEIR PREMISES AFTER JANUARY 1, 2017 WOULD RESIDE?

A. It depends on the size of the customer and the size of the solar installation. When looking at our distribution of existing solar customers, it appears that these customers would predominantly fall into the two lowest tiers. Chart AKJ-5 below depicts the tier that (1) all customers would fall into for their Grid Use Charge; and (2) where it is expected the existing solar customers would reside if they were not exempt. It is expected that new rooftop solar customers would similarly fall into the lower tiers of the Grid Use Charge consistent with the data we have for existing customers.

Chart AKJ-5: Residential Grid Use Charge Distribution



C. Rate Design Modifications

Q. WHAT RATE DESIGN MODIFICATIONS ARE YOU PROPOSING FOR THE RESIDENTIAL RATE CLASS?

A. As supported by Mr. Scott Brockett, Mr. Steven Wishart and Mr. Robert Osborn, the Company is proposing a few modifications for the Residential rate class. First, Schedule R will be modified to move the distribution system costs from the Schedule R energy charge to a new tiered Grid Use Charge to more accurately reflect the variety of customers we have on the system as well as prepare customers for the anticipated long-term rate design that I present later in my testimony.

Second, we are establishing a special rate option for customers that have signed a contract under the Company's Solar*Rewards® program prior to January 1, 2017, so that these customers are not financially impacted by the proposed Grid Use Charge. Using a popular phrase, this effectively "grandfathers" these customers under the prior rate design methodology.

Third, the Company is proposing to add or retain three additional residential service schedules: RD–TOU, Schedule RD, and Schedule RAL. Each of these three schedules will be available only to a small subset of our residential customer base. Schedule RD-TOU will reflect the Company's anticipated preferred long-term rate design. It is an opportunity to test the rate design with a subset of customers prior to rolling it out to all customers. I will discuss this later in my testimony. Schedule RD is being maintained in its former status, but is being closed to any additional applicants.

Q. WHAT RATE DESIGN MODIFICATIONS ARE YOU PROPOSING FOR THE SMALL COMMERCIAL RATE CLASS?

A. As supported by Mr. Brockett, Schedule C will be modified, similar to Schedule R, to move the distribution system costs from the Schedule C energy charge to a tiered Grid Use Charge to prepare customers for the anticipated long-term rate design that I present later in my testimony. Additionally, Mr. Brockett presents a modest modification to the seasonal energy charge differential for this rate class.

Q. WHAT RATE DESIGN MODIFICATIONS ARE YOU PROPOSING FOR THE SECONDARY GENERAL RATE CLASS?

A. As supported by Mr. Scott Brockett, Schedule SG's rate design will remain unchanged at this time; the Company is simply updating the applicable rates under the existing rate design. The seasonal energy charge differential has been evaluated, and the Company is proposing a modest modification also as described and supported by Mr. Brockett.

Q. WHAT RATE DESIGN MODIFICATIONS ARE YOU PROPOSING FOR THE LARGE C&I RATE CLASSES?

A. As supported by Mr. Brockett, Schedules PG and TG are being modified in a number of ways. First, we are proposing to modify the assessment of Generation and Transmission demand charges to peak loads during a fixed number of hours -- non-holiday weekdays from 2:00 p.m. to 6:00 p.m. Second, the Company proposes to offer a CPP service on a limited basis to large C&I customers. Third, the Company proposes to better differentiate among the services we provide to customers with on-site generators or storage applications. Finally, we are proposing to extend the TOU ECA to more Schedule SG customers.

D. <u>Electric Tariff Changes</u>

Q. IS THE COMPANY PROPOSING CHANGES TO ITS ELECTRIC TARIFF ASIDE FROM UPDATING RATES OR ADDING NEW SERVICES AS OUTLINED ABOVE?

A. Yes. As supported in detail by Mr. Steven Wishart, the Company has undertaken an overhaul of its Electric Tariff. The Company filed P.U.C. No. 7-Electric Tariff cancelling P.U.C. Nos. 6 and 10 with Advice Letter No. 1257 on April 2, 1996, to become effective May 5, 1996. Over the last nearly 20 years, the Company has filed approximately 450 Advice Letters altering the Tariff, a handful of sheets at a time. The Company decided that this proceeding provides a good opportunity to evaluate the entire Electric Tariff. Based on this evaluation we are proposing to re-arrange sections of the Electric Tariff, and add to or delete other sections. Our goal is to generate a more consistent, transparent document that our customers and business area counterparts can easily use. We are also striving to generate administrative efficiencies to better manage filing requirements as we move forward. Mr. Wishart goes on to classify the changes into three categories: (1) new services; (2) substantive changes to existing Terms and Conditions; and (3) non-substantive changes such as formatting, tariff arrangement, deletions, additions, grammar/syntax, and other miscellaneous items. Mr. Wishart provides a roadmap in Attachment SWW-7 for all of the proposed changes. Either he or another Company witness provides support for each of the new services or substantive tariff changes that the Company proposes.

IV. TIMELINE AND OUTREACH

Q. WHAT WILL YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section I will address the Company's proposed plans for implementation of the recommended rate design and customer and stakeholder outreach. I also provide a subsection in this section of my testimony to outline the bigger picture timeframe and explain how decisions in each will allow for a final review of the financials before those decisions are made.

A. Current Phase II Proposed Rate Design Implementation

Q. YOU PREVIOUSLY MENTIONED THE NEED FOR CUSTOMER OUTREACH AND EDUCATION. PLEASE ELABORATE ON THAT TOPIC.

A. As we did following the change in rate design from the 2009 Electric Phase II Rate Case, we believe it is important to take the time to talk to customers about the rate design changes resulting from the outcome of the Current Phase II. We anticipate the following timeframe:

Filing Date: January 25, 2016
Anticipated Commission Decision: late September 2016
Initial Customer Outreach: mid-October through year-end

In the timeframe that I outline, I mention "initial customer outreach." We believe that customer outreach will continue on past this timeframe, especially if we are anticipating changes to metering infrastructure and subsequent rate design changes.

Q. HAVE YOU ALREADY DONE ANY CUSTOMER OUTREACH REGARDING THESE LONG-TERM AND SHORT-TERM RATE DESIGN CHANGES?

A. Yes. In November 2015 we took part in a customer focus group regarding both the short-term and long-term rate designs for the Residential customers. Attachment AKJ-1 to my testimony is the final evaluation slide deck that was provided by the research organization that conducted the focus group. In this report, on slide 6, it is stated that "[c]ustomers expect multiple communications about the Grid Use Charge to explain it and to address their concerns before, during and after introduction."

Q. HOW ARE YOU RESPONDING TO THIS FEEDBACK?

A. We anticipate providing not only notice to our customers of this proceeding, but also, at the outset, communications with customers that may be more concerned with the impacts of this rate design -- such as existing rooftop solar customers. Following the filing's conclusion and prior to rate implementation we anticipate communicating with our customers about this change in multiple forums. Examples could include, but would not be limited to: direct mail, bill onserts, website communications, short video links, newspaper, and email.

Q. WILL YOU ALSO EDUCATE THE RESIDENTIAL CUSTOMERS ABOUT THE OPPORTUNITY TO PARTICIPATE IN THE RD-TOU TARIFF?

A. Yes. Not only will we directly communicate this message, we would like to engage with our special interest stakeholder groups to communicate about this opportunity as well. This would be particularly useful for those that promote technology such as EVs.

Q. WILL YOU ALSO BE REACHING OUT TO YOUR LARGER CUSTOMERS?

A. Yes. Not only will we inform them of the change to how their demand charge will be assessed, we also want to make sure they know about the proposed pilot for Critical Peak Pricing, as well as the changes regarding Supplemental and Auxiliary services. This outreach will be conducted by our Accounts Management team and could also be effected through other vehicles such as those described above.

Q. HAVE YOU CONDUCTED ANY OTHER CUSTOMER SURVEYS OR OTHER MARKET RESEARCH?

A. Yes. Another national survey was conducted by E Source to assess a number of items, one of which was the openness to changes in rate design.

B. <u>Long-Term Implementation Plan</u>

Q. YOU MENTIONED IN SECTION II OF YOUR TESTIMONY THAT YOU CANNOT ACHIEVE THE FINAL RATE DESIGN IN THIS CURRENT PHASE II. PLEASE ELABORATE.

A. As mentioned previously, in order to implement the final rate design for the Residential and Small Commercial classes, the meters that the customers currently have need to be replaced. We did not believe it appropriate to request the change-out meters in a Phase II proceeding. Also, in looking at the horizon of the actions the Company will be taking to provide service, there are a number of filings that interplay. We expect that the Commission will want to evaluate the financial impacts of the filings in their totality. I discuss below how we envision the next few filings to interplay to not only achieve the final rate design, but also build on our already successful renewable energy plans and work towards meeting new requirements that the Company has to consider, such as the Clean Power Plan.

Q. WHAT ARE THE "NEXT FEW FILINGS" THAT YOU ARE REFERRING TO?

A. The filings that I believe are related and for which we will need to clearly provide some level of consolidated information to the Commission are as follows:

(1) Current Phase II – lays out the longer term rate design for all rate classes and takes steps to move towards that longer term design.

(2) Renewable Energy Plan ("RE Plan") – provides an avenue for multiple types of solar growth and presents the health and availability of the Renewable Energy Standard Adjustment, fondly known as the RESA.

(3) Grid Intelligence and Security Certificate of Public Convenience and Necessity ("Grid CPCN") – presents the costs and benefits of investments necessary on the grid to provide for the future state described in this filing.

(4) Electric Resource Plan ("ERP") – will examine options during the resource acquisition period to satisfy any resource needs, as well as present options and potential opportunities available to manage the cost of energy for customers.

Q. PLEASE DISCUSS HOW YOU ENVISION THE INTERPLAY OF EACH OF THESE FILINGS.

A. This Current Phase II filing lays out the longer term rate design, but does not ask for approval of this design. However, it is clear that to even move to a rate design that contains TOU type attributes, we will need to make an investment in metering technology. Thus the Grid CPCN presents that technology move. The Grid CPCN will also present the technology and communications that will allow for the future state of interaction with customers and fully embrace two-way power flows.

The Renewable Energy ("RE") Plan will show the availability of the RESA to support continued expansion of the renewable programs already offered by

Public Service and will layer on to the proposed rate design changes by necessity.

Finally, the ERP overlays options to meet the capacity needs of the future -- with present day opportunities to invest in renewables guided by recent rule changes at the federal level. The collection of these initiatives and plans has a cost. I believe that cost should be identified at key steps along the way to ensure that since the implementation of these plans will happen at the same time, there is a clear picture for the Commission and stakeholders to evaluate these initiatives and impacts fairly.

Q. PLEASE EXPLAIN WHAT REQUESTS FOR APPROVAL YOU WILL BE MAKING IN EACH FILING AND WHEN YOU ENVISION THIS FINANCIAL IMPACT OVERLAY TO BE PERTINENT?

A. Table AKJ-6 below summarizes the anticipated requests of the Commission and when we will provide materials we anticipate the Commission and stakeholders would like to see.

Table AKJ-6: Filing Requests and Presentation of Materials

Filing	Date (Filing / Est. Decision)	Incremental Total Bill Financial Impact	Cost/Benefit Analysis
Current Phase II	Jan. 2016 / Sept. 2016	Only on voluntary tariffs	None necessary
RE Plan	Feb. 2016 / Oct. 2016	Yes	Yes
Grid CPCN	Apr. 2016 / Dec. 2016	Yes	Yes

Filing	Date (Filing / Est. Decision)	Incremental Total Bill Financial Impact	Cost/Benefit Analysis
ERP	Jun. 2016[4] / Feb. 2017	Yes	Yes

For the Current Phase II, the financial impacts of the proposed rate designs are fully contained within that filing. For example, establishing the RD-TOU tariff, the metering investment has been captured in the calculation of the Service and Facilities charge as well as the information technology ("IT") costs that are necessary to implement the billing. Because the tariff is voluntary and self-contained, we believe no residual impacts would be included in ongoing costs. No costs for the longer term rate design are presented in the Current Phase II because we are not asking for approval of the longer term rate design at this point in time.

The Grid CPCN will present and address not only the need for changes to the existing infrastructure, but also the cost and benefit analysis for customers of making those investments. This presentation will lay out the cost of the investment but also the anticipated total bill impact to customers over the next several years. This filing is not anticipated to include a request or plan to implement the longer term rate design. We anticipate the AMI infrastructure will take up to five years to install following any approvals received from the Commission. Thus, we have some time to gather data and test the proposed

[4] The Company has or will shortly file a request of the Commission to delay the filing of the ERP to on or before June 1, 2016. This table presumes that request is approved.

final rate design, through pilot tariffs such as the proposed RD-TOU tariff prior to final implementation. We have not made a final decision but anticipate filing an application to implement the longer term rate design with the Commission after knowing the outcome of the Grid CPCN as well as some time to evaluate the RD-TOU tariff and the TOU G&T Demand Charges assessed on PG and TG customers.

The RE Plan and ERP also have an impact on a customer's total bill, thus in evaluating the RESA and any presented resource options, a financial impact analysis for customer's total bills will be presented.

As shown in the chart above, the timing of these cases leads to an opportunity for each to have decisions made with the necessary information. This first decision regarding the Current Phase II rate case does not bind the Commission to the presented longer term rate design. That decision will come later after better information is available. The Company is committed to providing a bigger picture analysis of each of these steps impacts on a customer's total bill. However, we firmly believe that information is better developed and more appropriate with the successive and later filings.

Q. WHEN DO YOU ANTICIPATE FILING FOR THE IMPLEMENTATION OF THE LONGER TERM RATE DESIGN?

A. The date is uncertain at this time. However, if the timeline above is implemented we would anticipate a filing in mid to late 2017. This would allow the time for the processing of the listed proceedings as well as some time to evaluate the RD-TOU tariff.

V. RATE CASE EXPENSES

Q. WILL PUBLIC SERVICE INCUR RATE CASE EXPENSES TO PREPARE AND PROSECUTE THIS RATE CASE?

A. Yes. Public Service has already incurred rate case expenses to prepare the rate case filing and will continue to incur rate case expenses to perform the other tasks attendant to filing and litigating a rate case before the Commission. Public Service expects to incur additional rate case expenses as the case progresses.

Q. IS PUBLIC SERVICE PROPOSING TO RECOVER THESE RATE CASE EXPENSES IN THIS CASE?

A. No. The Company proposes the Commission defer the review, approval and recovery of these electric Phase II rate case expenses to the next electric Phase I rate case. As part of the 2014 Phase I settlement, the Company agreed not to change base rates for electric service prior to the 2017 Rate Case, which will not go into effect earlier than January 1, 2018.

The Phase II Electric Rate Case expenses would be deferred into a deferred accounting asset without interest until they are included in the next electric Phase I rate case cost of service request for recovery, along with the estimated Phase I rate case expenses for that case. The amortization of the electric Phase I and Phase II rate case expenses would be determined in that proceeding.

Q. WHETHER THERE IS RECOVERY IN THIS PROCEEDING OR THE NEXT ELECTRIC PHASE I RATE CASE, WHY IS IT APPROPRIATE FOR PUBLIC SERVICE TO INCLUDE RATE CASE EXPENSES AS A RECOVERABLE ITEM IN THE COST OF SERVICE?

A. Most businesses have the flexibility to set their prices based on their assessment of the market and the demand for their products. Utilities that are subject to cost of service regulation do not have this same flexibility, but rather must make rate filings and obtain public utility commission authorization to establish new rates. Accordingly, it is my understanding that it has been the long-standing practice of this Commission to treat reasonable rate case expenses as a necessary cost of doing business and, after review, to allow recovery of rate case expenses through mechanisms established in a rate case proceeding.

In light of the 2014 Phase I Settlement, in this instance, it is appropriate to defer the recovery of the Current Phase II rate case expenses to the next electric Phase I Rate Case where the cost of service or level of overall cost recovery is at issue.

Q. WHAT AMOUNT OF RATE CASE EXPENSES IS PUBLIC SERVICE SEEKING TO DEFER FOR THIS CURRENT PHASE II?

A. The total cost for legal counsel, customer noticing and education, and other expenses associated with this rate case is estimated to be $1,165,885, assuming a fully litigated case with a hearing, post-hearing briefing, exceptions and replies to exceptions, and motions for rehearing and replies. Please refer to Attachment

AKJ-2 for a summary of the Current Phase II rate case expenses by major category of expected rate case expenses, along with detail by major category. Below I will explain the major categories of the rate case expenses.

Q. PLEASE LIST AND GENERALLY DESCRIBE THE MAJOR RATE CASE EXPENSE CATEGORIES YOU ARE PRESENTING FOR THIS CURRENT PHASE II.

A. The major categories of rate case expenses included in my Attachment AKJ-2 include the following areas:

<u>Transcripts/Hearing Costs:</u> During the course of the case, a court reporter may be necessary to transcribe depositions and hearings before the Commission or administrative law judge ("ALJ"). To have those court reporters record and then transcribe these proceedings, there is a cost. This fee increases or decreases based upon the timeframe by which the reporter must turn over the transcript.

<u>Legal Counsel:</u> Not unlike our operations departments, the Company does not staff up its legal department assuming continuous ongoing rate cases. Additionally, the expertise to file a comprehensive rate case is not always in-house for all topics; thus, outside legal assistance is necessary. Therefore, outside legal assistance in developing, processing, and litigating a case is a valid rate case expense.

<u>Customer Noticing:</u> Pursuant to Rule 1210, the Company must provide a notice to its customers regarding the rate request. Historically this meant

sending out a mailing to all customers at a substantial cost. During the 2014 Phase I, we reached an agreement on noticing and filed that alternative form of notice with the Commission. We are proposing to utilize that same procedure here.

Postage: This category is fairly self-explanatory. In order to provide case materials to intervenors (e.g. Company testimonies, discovery responses, etc.) at times we must mail those items.

Duplicating and Office Supplies: This category of costs reflects the printing of our filings for internal and external use, as well as other rate case necessary materials.

Miscellaneous Expenses: This category captures a variety of items, including customer education, market research, Grid Use Charge - IT and Billing programming and testing, and regulatory support from temporary or hourly employees for the preparation and processing of the case.

Q. DOES YOUR ESTIMATE OF RATE CASE EXPENSES INCLUDE ANY CONSULTANT AND OUTSIDE WITNESS COSTS?

A. No, it does not.

Q. PLEASE DISCUSS THE TRANSCRIPT AND HEARING COSTS THAT THE COMPANY IS PROJECTING TO INCUR FOR THIS CURRENT PHASE II.

A. Costs the Company anticipates to incur for the purchase of transcripts of the hearings and other hearing costs are $21,300.

Q. PLEASE DISCUSS THE OUTSIDE LEGAL FEES THAT THE COMPANY IS PROJECTING TO INCUR FOR THIS CURRENT PHASE II.

A. Outside Legal costs are estimated to be $525,000 for the firm Armstrong Teasdale that we have hired for specific assistance for our rate case filing. This firm was retained for its expertise in utility regulation and its reasonable rates. The firm provided, or will provide, assistance in assembling testimony and attachments, witness preparation, advice on strategy, responding to discovery, and generally processing the case.

Q. WHY WAS IT NECESSARY TO RETAIN OUTSIDE COUNSEL FOR THIS PROCEEDING?

A. Outside legal services were retained in order to supplement the Company's in-house legal staff's current and projected case load. There are in-house attorneys leading and supporting this case in addition to handling other cases; however, the Company does not have the resources to dedicate the necessary resources to this case. The Company's in-house legal department is currently understaffed due to the recent departure of an experienced attorney and all the attorneys have a full case load.

Q. PLEASE DESCRIBE THE COSTS INCURRED TO MEET THE NOTICE REQUIREMENTS OF THE COMMISSION.

A. Pursuant to Commission Rule 1210, the Company must provide notice to our customers of the proposed rate change and the impacts on the customer. The costs estimated for completing this requirement are $55,525. This cost can be broken down into two major categories, bill onsert and newspaper. The bill onsert component of this category of rate case expense is $30,000 for the costs associated with printing the notice on a customer’s bill, and mailing it to customers during their normal billing cycle. The newspaper component of this category of rate case expense is $24,025. This expense is to fulfill the requirement that we post the notice of our filing in a newspaper of general circulation for two consecutive Sundays. The remaining $1,500 is for social media outreach and to email customers with online view and pay that would not otherwise receive notice because they opt to not receive paper bills mailed from the Company.

The Commission granted a request for a waiver of Rule 1210 in order for the Company to provide an alternative form of notice in the 2014 Phase I and 2015 Gas Rate Case, Proceeding No. 15AL-0135G, and the approval of this waiver has allowed the Company to provide less expensive notice for these cases and will do so here as well. We worked with external parties in the 2015 Gas Rate Case to ensure that the waiver notice includes the information necessary for the customers to be aware of a pending rate case and their ability to comment during the proceeding. By moving to this alternative form of notice, the Company and customers have realized significant savings.

Q. PLEASE DISCUSS THE POSTAGE COSTS THAT THE COMPANY IS PROJECTING TO INCUR FOR THIS CURRENT PHASE II.

A. We are estimating that we will incur approximately $2,000 in postage expenses throughout the case. These are costs associated with providing materials such as discovery responses to intervening parties through the United States Postal Service delivery or direct shipping (e.g., FedEx). In the event that materials need to be mailed to an intervenor, the Company's preference is to utilize the United States Postal Service delivery; however, in tight timeframes the only means of timely delivery may be direct shipping.

Q. PLEASE DESCRIBE THE PROJECTED COSTS ASSOCIATED WITH PRINTING AND PROVISION OF HARD COPIES OF CASE MATERIALS.

A. Both at the initial onset of the case and throughout the case, the Company will provide paper copies to various parties as well as to Company witnesses. The costs incurred with duplicating (e.g., copying) the case and the associated office supplies are estimated to be $6,500. This expense is further subdivided into the following categories and amounts: for duplication - $4,500; and, for supplies - $2,000.

Q. PLEASE DISCUSS THE MISCELLANEOUS EXPENSES THAT THE COMPANY IS PROJECTING TO INCUR FOR THIS CURRENT PHASE II.

A. The total amount requested for the Miscellaneous Expense category is $555,560 and is subdivided as listed below:

Communications – Webinar	$ 2,000
Electronic Collateral	500
Postage for Collateral	300
Account Management Fact Sheets, Leave Behind Info	1,000
PG/TG Demand Billing	15,000
Customer Education	100,000
Market Research	75,000
Grid Use Charge - IT and Billing Programming and Testing	340,000
Regulatory Support	21,760
Total	$555,560

The most significant subcategories in this major cost category are Customer Education, Market Research, Grid Use Charge, and Regulatory Support. The Customer Education category includes a series of three bill onserts which make up the majority of these costs, as well as web resources/online tools, social media and collateral printing costs to inform customers about the tariff and rate changes, including an infographic intended to help customers understand their new bill. The Market Research costs are for conducting Focus Groups with residential customers to gather their input on Grid Use Charges and the Company's long-term rate design. The Grid Use Charge and the PG/TG Demand Billing costs are for programming and testing the billing system. These costs are further explained in Mr. Brockett's Direct Testimony.

The Regulatory Support is for the incremental labor that the Company has contracted for eight months to support the case full time. The Regulatory Support includes supporting the SharePoint site permissions, tracking Discovery requests and responses, and other administrative tasks necessary to managing the case timely and accurately.

Q. WHY IS CUSTOMER EDUCATION IMPORTANT FOR THIS CASE?

A. As discussed in my testimony above, the Company is requesting a number of tariff and rate changes as part of this case and it is very important for our customers to understand why the changes are being made and how they can impact their bills for there to be effective price signals. The Company did outreach to possible intervenors and market research with customers prior to filing the case and the need for customer education was communicated to be very important to both customers and intervenors.

In addition, the Company was required to develop a robust education campaign that reached out to residential customers to educate them on the Company's Residential IBR approved in the Company's last 2009 Electric Phase II Rate Case.[5] The Company believes that customer education was critical for a relatively smooth implementation of these rates.

[5] Decision No. C10-0286 Docket No. 09AL-299E, Paragraph 95.

Q. WILL THE COMPANY'S REQUEST FOR RATE CASE EXPENSE RECOVERY IN THE NEXT ELECTRIC PHASE I RATE CASE EXACTLY MIRROR THE ESTIMATE PROVIDED IN THIS CASE?

A. The Company is committed to ensuring the rate case expense estimate is reasonable and the rate case is managed efficiently to control costs; however this is an estimate, and in the event that the volume of discovery is greater than anticipated, or an extraordinary amount of motion practice is required, or the hearings are longer than anticipated, or the Commission requires more customer education than what is projected, these factors can all cause the actual rate case expenses to deviate from the original estimate. If that occurs, we will update the rate case expense request at the time of filing our next Phase 1 Electric Rate Case.

VI. CONCLUSION

Q. PLEASE SUMMARIZE THE REQUESTS THE COMPANY IS MAKING OF THE COMMISSION IN THIS CURRENT PHASE II RATE CASE.

A. The Company is requesting the Commission approve the following:

- Instituting Grid Use Charges to recover distribution costs for customers served under Residential Service (Schedule R) and Commercial Service (Schedule C). For both Schedules R and C, the Company proposes to assess graduated charges that will increase with a customer's average use over the past 12 billing periods. Solar*Rewards® customers, who are net metered as of December 31, 2016, will have the option of remaining on the current two-part rate design that does not include a Grid Use Charge.
- Instituting an optional Residential Demand – Time-of-Use Service (Schedule RD - TOU). This service would be available to a maximum of 10,000 residential customers in 2017, 14,000 residential customers in 2018, and 18,000 residential customers in 2019.
- Revising the rate differential between summer and winter rates for Schedule C.
- Instituting an on-peak Demand Charge for customers on Primary General Service (Schedule PG) and Transmission General Service (Schedule TG) to recover generation and transmission costs. This charge would be assessed on a customer's peak load during non-holiday weekdays from 2:00 p.m. through 6:00 p.m.
- Instituting a Critical Peak Pricing option (Schedules SG-CPP, PG-CPP and TG-CPP) for large C&I customers. This service would be offered on a pilot basis, and total participation would be capped at 30 megawatts ("MW").
- Offering a Supplemental Service within Secondary General Service (Schedule SG), Schedule PG and Schedule TG. This service would be available to C&I customers whose on-site generation does not operate as frequently and predictably as the generators for whom standby service is intended. The Company is also proposing to introduce the concept of Auxiliary Service for customers with on-site electric storage applications operating in parallel with the Company.
- Revising the rate differential between summer and winter demand charges for the following service schedules: SG, PG, and TG.

- Lowering the required maximum demand used to determine whether Schedule SG customers are eligible for the TOU ECA from 300 kW to 100 kW.
- Eliminating or closing to new customers some existing service options that are rendered obsolete by or do not complement the Company's proposed long-term rate design.

The Company also requests approval of replacing the existing Colorado P.U.C. No. 7 – Electric Tariff with Colorado P.U.C. No. 8 – Electric Tariff as described by Company witness Mr. Steven Wishart and other Company witnesses. The primary revisions to the Electric Tariff include the following:

- Institute a new General Definitions section, which will define terms used throughout the tariff in one section. The purpose of this section is to clarify and standardize the meanings of terms found throughout the different sections of the Electric Tariff. Definitions that are specific to certain sections of the tariff will remain in that section.
- Reorganize the Rules and Regulations section to group together similar sections, include provisions for the measurement of service if customers have multiple meters, and address responsibility for damage to the system.
- Revise the Rules and Regulations applicable to Street Lighting Service to address the relocation and removal of lights and attachments to street lighting poles.
- Specify that customers taking service under Schedules R and C who have on-site renewable energy generation operating in parallel with the Company and are not net-metered will be subject to a buy-all, sell-all arrangement.
- Add a Production Meter Charge applicable to customers on various service schedules with on-site generation.
- Update the Customer list for Schedule TG.
- Modify the Secondary General Standby, Primary General Standby and Transmission General Standby services (Schedules SST, PST, and TST) by adding a Production Meter Charge and basing the annual grace energy period on a calendar year.
- Modify the Street Lighting Service to incorporate the new LED options.
- Revise the Parking Lot Lighting Service (Schedule PLL) to differentiate this lighting from Commercial Area Lighting Service.

The Company also requests approval to defer recovery of the Current Phase II rate case expenses until the next Phase I electric rate case through the use of a deferred accounting asset.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Alice K. Jackson

As the Regional Vice President of Rates and Regulatory Affairs, I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service Company of Colorado ("Public Service"). My duties include the design and implementation of Public Service's regulatory strategy and programs, and directing and supervising Public Service's regulatory activities, including oversight of rate case. Those duties include: administration of regulatory tariffs, rules, and forms; regulatory case direction and administration; compliance reporting; complaint response; and working with regulatory staffs and agencies.

I accepted the RVP position with Public Service in November 2013 after holding the same position in another Xcel Energy Inc. ("Xcel Energy") subsidiary, Southwestern Public Service Company, for two and a half years. Prior to my employment with Xcel Energy, I had been employed in the energy industry for over 10 years. In 2001, I was employed by Enron Energy Services, where I provided software application design and support to a variety of departments within that company.

In December 2001, I began working as a contract employee for Oxy Services, Inc., a subsidiary of Occidental Petroleum Corporation ("Oxy"), and transitioned to permanent employee status in January 2002. I held positions of increasing responsibility as a software programmer supporting Occidental Energy Marketing, Inc., the trading organization within Oxy, where I designed, developed and implemented an application used by Oxy for the operations of their Retail Electric Provider ("REP") in the Electric Reliability Council of Texas ("ERCOT").

In June of 2004, I accepted a promotion to work for Occidental Energy Ventures Corp. ("OEVC") as Manager, Texas REP. In this position I was responsible for front office (procurement, monitoring, and regulatory), mid office (data processing and billing) and back office (accounting and reporting) operations of Oxy's wholly owned REP in the ERCOT region. In 2010, I became Director Energy for OEVC and was responsible for the regulatory activities of Oxy's facilities located within the New York Independent System Operator, the Southwest Power Pool ("SPP"), and ERCOT. My responsibilities for these jurisdictions included: (1) direction of Oxy's participation in utility cases at both state and federal levels; (2) direction and participation in federal initiatives impacting Oxy's business (*e.g.*, FERC Notices of Proposed Rulemaking); (3) maintenance of regulatory filings required of Oxy's REP and generation assets at the state and federal level; (4) administration of Occidental Power Marketing, L.P. as a registered North American Electric Reliability Corporation Load Serving Entity in the SPP; and (5) evaluation of, and participation in, rule and protocol updates, revisions and additions before State Commissions, Regional Independent System Operators, and Regional Transmission Organizations ("RTOs"). In May 2011, I accepted a position with Xcel Energy Services Inc. ("XES") as Director, Regulatory Administration, and the position was transferred to SPS effective January 1, 2012. I was subsequently promoted to

Regional Vice-President, Rates and Regulatory Affairs, and in that capacity I devote my time to regulatory issues in SPS's Texas, New Mexico, and FERC jurisdictions.

I graduated from Texas A&M University in 2001, receiving a Bachelor of Business Administration degree with a major in information and operations management. I have testified before this Commission and the New Mexico Public Regulation Commission and provided written testimony a number of times before the Public Utility Commission of Texas.