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	**)**	

DIRECT TESTIMONY AND ATTACHMENTS OF SCOTT B. BROCKETT

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 SCOTT B. BROCKETT

Mr. Scott B. Brockett is Director, Regulatory Administration, for Xcel Energy Services Inc. In this capacity he provides strategic direction, oversees compliance with regulatory requirements, directs the preparation of filings and the subsequent processes related to these filings, and collaborates with external stakeholders in the regulatory process. He focuses primarily on Public Service Company of Colorado ("Public Service" or "Company"), one of four utility operating company subsidiaries of Xcel Energy Inc.

In his Direct Testimony Mr. Brockett presents many of the Company's pricing recommendations, the Company's pricing goals, and a wide variety of studies and analyses the Company has conducted to support this filing. He also presents many of the Company's recommendations for adding, restricting or eliminating services. In some cases, he sponsors specific rates. In other cases, he sponsors rate relationships

or principles that Company witness Steven W. Wishart incorporates into the specific rates he sponsors as part of the revenue proof attached to his Direct Testimony.

Mr. Brockett concludes that the Company's proposed rates balance the Company's pricing goals and incorporate important improvements to our current rates. These pricing goals reflect closely the traditional pricing goals commonly cited in regulatory proceedings. Mr. Brockett also supports some terms and conditions of service, but he is not sponsoring any of the specific service schedules that the Company proposes to include in its Electric Tariff. Company witness Steven W. Wishart sponsors the Company's proposed Electric Tariff.

Mr. Brockett recommends that the Commission approve the Company's proposed rate design for our existing services. One important rate-design change he recommends is the institution of fixed Grid Use Charges to recover the distribution costs imposed by residential and small commercial customers. This rate-design modification will better prepare customers for the long-term rate design that Company witness Alice K. Jackson discusses in her Direct Testimony. Mr. Brockett also sponsors the Company's recommendation to establish a new basis for assessing Generation and Transmission ("G&T") Demand Charges on customers served at primary and transmission voltages to better recognize the loads that drive G&T capacity costs.

In addition, Mr. Brockett recommends that the Commission approve the Company's proposals to institute: an optional three-part, time-of-use ("TOU") service for residential customers, a Critical Peak Pricing service option for large customers, and Supplemental and Auxiliary Services for customers with on-site generation or storage applications.

Finally, Mr. Brockett recommends that the Commission approve the Company's proposals to phase out some existing service schedules. He recommends closing the Residential Demand service to new customers as of January 1, 2017, and transitioning them to the new three-part residential tariff when it is implemented. He also recommends closing to new customers as of January 1, 2017, and eliminating as of January 1, 2020, the Secondary TOU Service and Primary TOU Service. Mr. Brockett further recommends eliminating the Transmission TOU Service as of January 1, 2017 – as no customers are currently served under this schedule. Finally, Mr. Brockett recommends closing the Secondary Photovoltaic Time of Use Service to new customers as of January 1, 2017, but allowing existing customers on the schedule to remain on it until they move or their contracts expire.

Mr. Brockett's proposals to modify the rate design for existing services, phase out some existing services, and add services are all designed in light of the more far-reaching rate-design changes that Ms. Jackson recommends for future implementation. In his Direct Testimony Mr. Brockett explains how the most significant initiatives he proposes advance or complement the Company's long-term pricing strategy.

In addition to the pricing and service proposals explained above, Mr. Brockett also introduces a recent study of energy and demand losses that the Company has applied in its proposed CCOSS.

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**

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS 12

II. OVERVIEW 16

III. RESIDENTIAL SERVICE 26

- **A. Overview 26**
- **B. Grid Use Charge 27**
- **C. Residential Schedule R Energy And S&F Charges 38**
- **D. Alternative Rate Design Under Schedule R 44**
- **E. Residential Demand Service 46**
- **F. Optional Residential Three-Part, TOU Service 48**

IV. SMALL COMMERCIAL SERVICE 54

V. LARGE COMMERCIAL AND INDUSTRIAL SERVICE 58

- **A. Overview 58**
- **B. Secondary General 60**
- **C. Primary General 65**
- **D. Transmission General 71**

E. Critical Peak Pricing Service Option **74**

F. Optional TOU Services **97**

G. Demand Ratchet **101**

H. Time Of Use ECA **104**

VI. UPDATED LOSS STUDY **107**

LIST OF ATTACHMENTS

Attachment SBB-1	Summary of Short-Term Phase II Implementation Costs
Attachment SBB-2	Grid Use Charge
Attachment SBB-3	Summer_Winter Peak Summary
Attachment SBB-4	Marginal Summer Generation & Transmission Costs
Attachment SBB-5	RD-TOU S&F Charge Adder
Attachment SBB-6	Critical Peak Pricing (CPP) Rates
Attachment SBB-7	Rate Schedule Applicability Table
Attachment SBB-8	Siemens Industry, Inc. “Electric System Loss Analysis”

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 14AL-0660E
4CP-AED	Four Coincident Peak-Average and Excess Demand
BFD	Bill Frequency Demand
Black Hills	Black Hills/Colorado Electric Company, LP
C&I	Commercial and Industrial
CACJA Rider	Clean Air Clean Jobs Act Rider
CCOSS	Class Cost of Service Study
Coincident peak load	Customer's energy requirements during the hours of the year when total customer/system demand is at its highest.
Commission	Public Utility Commission of Colorado
Company	Public Service Company of Colorado
CPP	Critical Peak Pricing
Critical Peak	Period when Company experiences high system loads as a percentage of available generation capacity.
Distribution Fee	Distribution Standby Capacity Fee
DSM	Demand Side Management
DSMCA	Demand Side Management Cost Adjustment

Acronym/Defined Term	**Meaning**
ECA	Electric Commodity Adjustment
G&T	Generation and Transmission
G&T Fee	Standby Capacity Reservation Fee
GRSA	General Rate Schedule Adjustment
HTY	Historical Test Year
ISOC	Interruptible Service Option Credit
kW	Kilowatt
kWh	Kilowatt hour
LOLP	Loss of Load Probability
MW	Megawatts
Noncoincident peak load	Customer's highest or peak energy requirements, regardless of whether the system is experiencing a high level of customer demand
O&M	Operations & Maintenance
PCCA	Purchased Capacity Cost Adjustment
Peak Chasing	Customer's change usage patterns such that they move the system peak to an hour outside of the 2:00 p.m. – 6:00 p.m. window.
PTR	Peak Time Rebate
Public Service	Public Service Company of Colorado
Reservation Fee	G&T Standby Capacity Reservation Fee
S&F	Service and Facility Charge
Schedule C	Small Commercial Service

Acronym/Defined Term	**Meaning**
Schedule NM	Net Metering Service
Schedule PG	Large demand-metered customers served at primary voltage
Schedule PST	Primary Standby Service
Schedule PTOU	Primary Time-of-Use Service
Schedule R	Residential General Service
Schedule RAL	Residential Outdoor Area Lighting Service
Schedule RD	Residential Demand Service
Schedule RD-TOU	Residential Demand Time-of-Use Service
Schedule SG	Secondary General Service
Schedule SGL	Secondary General Low-Load Factor Service
Schedule SPVTOU	Secondary Photovoltaic Time-of-Use Service
Schedule SST	Secondary Standby Service
Schedule STOU	Secondary Time-of-Use Service
Schedule TG	Transmission General Service
Schedule TST	Transmission Standby Service
Schedule TTOU	Transmission Time-of-Use Service
TCA	Transmission Cost Adjustment
TOU	Time Of Use
Usage Demand Charge	Usage Demand Charge: Demand Charge
Usage Energy Charge	Monthly Usage Charge: Energy Charge
Xcel Energy	Xcel Energy Inc.

Acronym/Defined Term	**Meaning**
XES	Xcel Energy Services, Inc.

**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 Scott B. Brockett. My business address is 1800 Larimer Street, Suite 1400, Denver, Colorado 80202.

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

A. I am employed by Xcel Energy Services Inc. (“XES”) as Director, Regulatory Administration. 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 Director, Regulatory Administration, I am responsible for the preparation of most of the Company's regulatory filings. In this capacity I provide strategic direction; oversee compliance with regulatory requirements; direct the preparation of filings and the subsequent processes related to these filings; and collaborate with external stakeholders in the regulatory process. 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 Direct Testimony is to support the rate design the Company proposes to implement in this proceeding. This rate design is based on the Company's pricing goals and is informed by a wide variety of studies and analyses the Company has conducted to support this filing. I will discuss this foundation for the Company's pricing recommendations later in my testimony.

I will also sponsor the Company's proposals regarding Standby Service, Supplemental Service and Auxiliary Service, a Critical Peak Pricing ("CPP") service option for large customers, and a three-part, time-of-use ("TOU") service option for residential customers. In addition, I sponsor the Company's proposals to phase out some existing service schedules.

In some cases I will sponsor and support specific rates. In other cases I will sponsor rate relationships or principles that Mr. Wishart will incorporate into the specific rates he sponsors as part of the revenue proof attached to his Direct Testimony as Attachment SWW-2.

In addition to sponsoring pricing recommendations, I will also explain and support some terms and conditions of service. But I am not sponsoring any of the specific service schedules that the Company proposes to include in our Electric Tariff. Mr. Wishart sponsors the Company's Electric Tariff - which reflects both his own proposals and the proposals of other Company witnesses - in Attachments SWW-5 and SWW-6, the clean and redlined Electric Tariff, respectively.

Finally, I will introduce a revised study of line losses that the Company has applied in its Class Cost of Service Study ("CCOSS").

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

A. Yes. I am sponsoring Attachments SBB-1 through SBB-8, which were prepared by me or under my direct supervision. Attachment SBB-1 breaks down the estimated incremental costs attributable to each of the Company's proposed initiatives in this proceeding into three categories: Marketing, Communications and Administration; IT/Billing; and Metering. Attachment SBB-2 lists the Grid Use Charges the Company is proposing and the estimated "worst-case" bill impacts. Attachment SBB-3 provides the levels and timing of the Company's historical system peak demands, as well as the results of a Loss of Load Probability ("LOLP") Study the Company recently conducted. Attachment SBB-4 provides a derivation of marginal summer Generation & Transmission ("G&T") costs. Attachment SBB-5 includes the derivation of the incremental fixed charge for the optional three-part, TOU residential service the Company proposes. Attachment SBB-6 provides the derivation of the CPP rates. Attachment SBB-7 lists the applicability of the Company's various service schedules to Standby, Supplemental and Auxiliary services. Attachment SBB-8 is the loss study.

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

A. I recommend that the Public Utility Commission of Colorado ("Commission") approve my rate-design recommendations and proposed additions and modifications to the Company's existing services.

II. OVERVIEW

Q. WHAT ARE THE COMPANY'S PRICING GOALS?

A. When developing rates for regulated services the Company's primary goals are to:

- 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. ARE THESE COMPANY PRICING GOALS LISTED ABOVE UNIQUE?

A. No. In my experience these goals are fairly typical of the pricing goals that utilities subject to economic regulation and regulatory commissions have traditionally espoused. While industry technology, trends and challenges have evolved over the past 35 years, the basic pricing goals have not materially changed and are still relevant in this proceeding. While different practitioners of utility ratemaking may express the goals differently, they usually stress the same fundamental pricing goals.

Q. ARE THESE PRICING OBJECTIVES ALWAYS COMPLEMENTARY?

A. No. The development of rates often requires a consideration of competing objectives. The resulting rate design does not fully advance each pricing objective; instead, it strikes a balance among the objectives. For example, one of the best ways to encourage efficient energy use is to price services at marginal cost. But setting prices at marginal cost is not necessarily consistent with a CCOSS that is based on embedded costs.

Similarly, eliminating all subsidies among customers in a class would result in a complex rate design that would be extremely difficult to administer.

Striking the appropriate balance of applicable objectives requires the exercise of informed judgment. Public Service has used its best informed judgment to balance these objectives in designing its proposed rates. We believe that the end result best promotes all of the applicable objectives. Consequently, the proposed rates are equitable, just and reasonable.

Q. PLEASE ELABORATE ON YOUR FIRST AND THIRD PRICING GOALS.

A. The Company seeks to develop rates that provide us with a fair opportunity to recover our cost of service on a reasonably stable basis, and to recover those costs in an equitable manner from each customer. In some respects, these goals are related, and both goals can be advanced by adhering to traditional cost-of-service ratemaking.

In other words, by examining closely how costs are incurred and reflecting those costs in rates, the Company can both ensure a reasonably stable revenue flow and promote equitable rates.

Q. WHY ARE COST-BASED RATES EQUITABLE?

A. If customers are responsible for the costs they impose on the system, then cross-subsidization among customer classes, and among customers within the same class, is minimized. Charging customers for the costs they impose is - at a minimum - a good starting point for setting rates. The incorporation of other pricing considerations may result in rates that do not exactly mirror how costs are incurred. But the Commission should, to the extent practical, strive to set cost-based rates.

Q. HOW CAN THIS GOAL OF SETTING COST-BASED RATES BE ACHIEVED?

A. Among the most important steps in developing cost-based rates is to properly classify costs. The cost of providing electric service is typically broken down into three components: customer-related costs, capacity-related or demand-related costs, and energy-related or usage-related costs. Company witness Dolores R. Basquez explains how she classifies costs in her CCOSS.

Ideally, a separate rate or rates would recover each of these three types of costs. A fixed monthly charge would recover all customer-related costs, an energy charge or charges would recover all usage-related costs, and a demand charge or charges would recover all capacity-related costs.

Q. IS THIS "IDEAL" APPROACH REFLECTED IN THE COMPANY'S CURRENT RATE DESIGN?

A. To a large extent the Company's current rates do reflect this preferred approach. But one significant exception should be emphasized for purposes of this proceeding and the Company's long-term pricing strategy.

Q. PLEASE IDENTIFY THIS EXCEPTION.

A. Public Service's current rate design provides for the recovery of a large percentage of fixed capacity-related costs imposed by small customers through usage charges. In other words, the Company does not assess demand charges on most small customers.

The rate design for small customers has historically been simplified for practical reasons. But as Company witness Alice K. Jackson explains in her Direct Testimony, developments over the past few years have led the Company to propose a more robust three-part, TOU rate design for small customers in the future. Until these more robust rates are implemented, most of the Company's residential and small commercial customers will not be assessed a demand charge.

Q. SINCE YOU HAVE HIGHLIGHTED THIS LACK OF DEMAND CHARGES FOR SMALL CUSTOMERS, PLEASE BRIEFLY EXPLAIN HOW DEMAND CHARGES ARE TYPICALLY DESIGNED.

A. Demand charges are usually designed to recover the costs the Company incurs to ensure reliable service during periods when customer use – either the customer's individual use or total system use - is at its greatest. Therefore, the rate is assessed on some measure of the customer's contractually established peak requirement or actual peak load. Since a customer's contractually established or actual peak load usually varies less from month to month than a customer's energy usage, demand charges usually result in a more consistent revenue flow to the utility and less variation in a customer's bill from month to month. Most customers prefer more predictable, stable bills.

As an interim step before the implementation of a demand charge, the Company is proposing to add a fixed, monthly Grid Use Charge to recover our distribution costs, and adjust the base usage charge to eliminate any recovery of distribution costs. This modification will allow us to recover customer-related costs and distribution costs through fixed charges. I will explain the proposed Grid Use Charges for residential and small commercial customers later in my testimony.

Q. CAN TARIFFS BE DESIGNED THAT PERFECTLY REFLECT THE COSTS OF PROVIDING SERVICE TO CUSTOMERS?

A. No. Even the robust tariffs the Company proposes for large customers in this proceeding – and hopes to extend to small customers in the future – will not precisely capture the costs various customers impose. But this rate design will represent a significant improvement over the current rates.

Q. SHOULD COST-BASED RATES ALWAYS BE BASED STRICTLY ON AN EMBEDDED CCOSS?

A. No. It is important to recognize that pricing is not a rote, mechanical exercise. Pricing is part art and part science, and even the application of the "scientific" aspects can vary between practitioners. For example, in my discussion above, I have equated cost-based rates with rates designed solely to recover embedded costs. But in some cases, charges may be set above or below the levels suggested by a CCOSS to better reflect price signals based on marginal costs or market conditions. While the scientific aspect of the Company's proposed pricing in this proceeding is based primarily on embedded costs, our pricing is also informed by marginal costs. The extent to which the Company uses marginal cost depends on the specific pricing application.

Q. YOU HAVE DISCUSSED THE IMPORTANCE OF COST-BASED RATES. HOW DOES YOUR GOAL OF PREVENTING EXTREMELY LARGE BILLING IMPACTS DOVETAIL WITH THIS GOAL?

A. I believe cost-based rates are usually a good long-term goal. In some cases the Company can propose such rates without affecting customer bills significantly. But in other cases, an immediate transition to cost-based rates could result in unacceptably high billing impacts. The Company's approach to developing rates is to first derive prices based on embedded or marginal costs. We then evaluate whether rates should be increased or reduced from their cost-based levels (set between current and cost-based levels) to mitigate billing impacts. As explained in more detail below, this approach has resulted in some rates based strictly on costs, and other rates set below or above cost to moderate billing impacts.

Q. WHEN YOU REFER TO DEPARTURES FROM COST-BASED RATES, ARE YOU REFERRING TO RATES THAT IN TOTAL DO NOT GENERATE THE CLASS'S EMBEDDED COST RESPONSIBILITY FROM THE CCOSS?

A. No. The Company's proposed rates are designed to recover from each broad customer class - in total - 100 percent of the class's test-year cost responsibility from the CCOSS. But the specific rate design and rates for a class may be calibrated to moderate billing impacts on certain customers within the class.

Q. GIVEN THESE GOALS, WHAT CHANGES DOES THE COMPANY PROPOSE TO ITS RATE DESIGN?

A. The Company's overall goal is to retain the positive features of the current design and propose changes that would offer the most significant improvements. For example, I believe the Company's current rate design is relatively straightforward and easy to understand. This important benefit should not be sacrificed. The current design also provides some seasonal differentials. Moreover, the current rates are (or at least were when they were designed) cost-based, meaning they were designed to collect in total the test-year embedded costs imposed by each class without inter-class subsidies. The avoidance of inter-class subsidies based on embedded costs is a laudable feature of the current rates that should be retained.

With this background in mind, our first initiative is to update the embedded cost study. The Company's current rates are based on class cost allocations for a 2010 test year. Obviously, class load characteristics and relative cost responsibilities have changed since 2010. Our updated CCOSS and resulting revenue apportionment have been updated to reflect these changes.

The second initiative is to institute a Grid Use Charge for customers served under Schedule R and Schedule C. This refinement will help customers transition to the more robust long-term rate design that Ms. Jackson explains.

The third initiative is to reflect the marginal cost of service in rates where warranted. For example, the Company's proposed tiered rates and TOU Electric Commodity Adjustment ("ECA") incorporate price signals based on marginal costs.

The fourth initiative is to offer mandatory or optional tariffs that better reflect variations in cost by time-of-use. Our proposed on-peak demand charges for customers on the Primary General ("Schedule PG") and Transmission General ("Schedule TG") service schedules, our optional three-part TOU tariff for residential customers, and our proposed CPP service all advance this goal.

The fifth initiative is to better reflect the fact that not all customers who install generation facilities behind the meter are good candidates for Standby Service. The Company proposes to offer Supplemental Service to accommodate customers whose on-site generation is often unavailable or is inherently intermittent – unlike the generators for whom standby service is intended. The

Company also proposes to introduce the concept of Auxiliary Service for customers with on-site storage applications.

The sixth initiative is to close to new customers or eliminate some existing service options that are rendered obsolete by or do not complement the Company's long-term rate design.

The Company believes that accomplishing these limited, but important, objectives would be a good outcome for this proceeding.

Q. HOW DO YOU ORGANIZE YOUR TESTIMONY TO DISCUSS EACH OF THE PRICING ISSUES YOU SUMMARIZE ABOVE?

A. I will organize my testimony by broad customer class: residential, small commercial, and large commercial and industrial ("C&I"). In both the residential and large C&I sections I will discuss multiple service schedules that are applicable to the broad class.

Q. CAN YOU PROVIDE A MAP OF WHICH SERVICES ARE BEING ADDED, ELIMINATED OR CLOSED?

A. Yes. Table 1 below indicates the service additions, eliminations or closures for all services but lighting and traffic signals. (Mr. Wishart and Company witness Robert J. Osborn discusses the Company's lighting and traffic signal services in their Direct Testimony.) This table covers all of the service schedules I discuss in the remainder of my Direct Testimony.

Table SBB-1

Schedule	Existing or New	Maintained or Eliminated	Closed to New Customers?
R	Existing	Maintained	No
RD	Existing	Maintained	Yes
RAL	Existing	Maintained	No
RD-TOU	New	Not Applicable	No
C	Existing	Maintained	No
NMTR	Existing	Maintained	No
SG	Existing	Maintained	No
SGL	Existing	Maintained	No
SST	Existing	Maintained	No
STOU	Existing	Maintained	Yes
SPVTOU	Existing	Maintained	Yes
SG-CPP	New	Not Applicable	No
PG	Existing	Maintained	No
PST	Existing	Maintained	No
PTOU	Existing	Maintained	Yes
PG-CPP	New	Not Applicable	No
TG	Existing	Maintained	No
TST	Existing	Maintained	No
TTOU	Existing	Eliminated	Yes
TG-CPP	New	Not Applicable	No

III. RESIDENTIAL SERVICE

A. Overview

Q. IS THE COMPANY PROPOSING SIGNIFICANT CHANGES TO ITS RESIDENTIAL SERVICE SCHEDULES?

A. As Ms. Jackson explains, the Company proposes to implement the most significant changes in a later proceeding. Until that time, the Company proposes to retain the summer tiered Energy Charges in the Residential Schedule ("Schedule R"). Nonetheless, the Company is proposing one important change to Schedule R: the addition of Grid Use Charges to recover distribution costs. I will explain how the Company developed the Grid Use Charges, as well as the differentials between the two base usage charges assessed under Schedule R. I will refer to these two usage charges as the Tier 1 Energy Charge and Tier 2 Energy Charge. Mr. Wishart will reflect these proposals in his revenue proof.

Q. WILL ALL CUSTOMERS BE REQUIRED TO TAKE SERVICE UNDER THIS MODIFIED SCHEDULE R?

A. No. The majority of our residential customers will receive service under Schedule R, which I will discuss below. But the Company is also proposing to add or retain three additional residential service schedules: The Residential Demand Time-of-Use ("Schedule RD–TOU"), Residential Demand Schedule ("Schedule RD), and Residential Outdoor Area Lighting ("Schedule RAL"). Each of these three schedules will be available only to a small subset of our existing residential customer base. Later in my testimony, I will explain the availability of and pricing parameters for all of the residential schedules, except Schedule RAL. Mr. Wishart and Mr. Osborn will sponsor all Company recommendations regarding Schedule RAL.

Finally, within Schedule R, the Company proposes an alternative rate design available only to Solar*Rewards® customers as of December 31, 2016.

B. Grid Use Charge

Q. WHAT IS THE PURPOSE OF THE GRID USE CHARGE?

A. The Schedule R Grid Use Charge will recover all distribution costs through a fixed monthly charge assessed on each residential customer. The Tier 1 and Tier 2 Energy Charges will then be adjusted to remove any recovery of distribution costs.

The Company proposes to implement this Grid Use Charge on an interim basis to:

- provide a more stable revenue source that clearly distinguishes (or unbundles) the charge for distribution services,
- signal to customers that distribution costs are fixed costs, and
- acclimate customers to the future rate design that Ms. Jackson describes, which also includes a separate charge for recovering distribution costs that is not assessed on kilowatt-hour ("kWh") usage.

Moreover, this Grid Use Charge can be applied to our broad residential customer base at a modest cost.

Q. WHY DO YOU CONCLUDE THAT THE COSTS ARE MODEST?

A. The assessment of an additional fixed monthly charge does not require more sophisticated metering; the current meters can be retained. The incremental costs of assessing the Grid Use Charge are limited to customer education and some IT/billing costs. These costs are identified in Attachment SBB-1.

Q. ATTACHMENT SBB-1 APPEARS TO COVER A WIDE VARIETY OF COSTS ASSOCIATED WITH THIS PHASE II PROCEEDING. SINCE THIS IS YOUR FIRST REFERENCE TO ATTACHMENT SBB-1, PLEASE DESCRIBE ITS PURPOSE AND CONTENT.

A. Attachment SBB-1 sets forth the estimated incremental costs attributable to each of the Company's proposed initiatives in this proceeding (regardless of which witness sponsors the initiative). The costs of each initiative are broken into three categories: Marketing, Communications and Administration; IT/Billing; and Metering. Each cost is also designated as either one-time or ongoing, and as either a capital expenditure or operations and maintenance ("O&M") expense. Finally, the Company's proposed treatment or recovery of each cost is also designated in Attachment SBB-1. I will also refer to this attachment later in my testimony when explaining other initiatives.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE COSTS OF ASSESSING THE GRID USE CHARGE?

A. The primary costs are for customer education, programming and testing the billing system, and conducting focus groups with residential customers to gather their input on Grid Use Charges and the Company's long-term rate design. These expenses are all Phase II rate case expenses for which the Company seeks recovery. Ms. Jackson discusses the Company's proposal for recovering the expenses attributable to this proceeding.

Q. YOU MENTIONED THAT THE GRID USE CHARGE IS DESIGNED TO RECOVER DISTRIBUTION COSTS. WHAT ARE DISTRIBUTION COSTS?

A. Distribution costs are the cost of planning, constructing, operating and maintaining our primary and secondary distribution systems. We use the primary and secondary distribution network to deliver energy from our bulk-power (transmission) system to end-use customers served at primary or secondary voltage. The distribution network comprises substations, poles, underground and overhead conduit, transformers, etc. When I discuss distribution costs in this section of my testimony, I will exclude the costs of customer-specific investments such as services and meters. These costs are considered to be customer-related costs and are collected through the Service and Facility ("S&F") Charge.

Q. WHAT CUSTOMER LOADS DRIVE DISTRIBUTION COSTS?

A. In her Direct Testimony Ms. Basquez discusses the drivers of distribution costs in more detail. She explains that distribution investments and costs reflect increasing levels of diversity as we move upstream. Nonetheless, a high percentage of the distribution costs a customer imposes are either driven by, or are positively correlated with, the customer's noncoincident peak load.

By "noncoincident peak load" I am referring to a customer's highest or "peak" energy requirements during the year, regardless of whether the system as a whole is experiencing a high level of customer demand during that same period. This customer peak load is usually measured over a short period – such as 15 minutes or 60 minutes.

Of course, coincident peak loads are also important drivers of some distribution costs – such as the cost of upstream distribution facilities located relatively close to the transmission or bulk-power grid. By "coincident peak load," I am referring to a customer's energy requirements during the hours or hours of the year when total customer demand – or system demand – is at its highest.

Finally, some distribution costs are arguably driven not only by peak loads, but also by the number of customers the utility serves and the extent of the utility's footprint. The number of customers and their dispersion are important cost drivers because a utility must extend its distribution system to establish a physical connection with each customer. This connection must be established regardless of how much energy customers require or when they require this energy. The costs of establishing this connection are not limited to the costs of meters and services that the Company has traditionally classified as customer-related costs, but also include a portion of the costs of distribution poles, conductors, and supporting facilities upstream from the customer's overhead or underground service line.

Q. HAS THE COMMISSION EVER APPROVED THE IMPUTATION OF A MINIMUM SYSTEM FOR PURPOSES OF CLASSIFYING DISTRIBUTION COSTS?

A. Yes. In 2004 the Commission approved a minimum-intercept method for Aquila, Inc., the predecessor of Black Hills/Colorado Electric Company, LP ("Black Hills")[1]. This zero-intercept method is a widely recognized approach to classifying distribution costs as either customer-related or capacity-related. Black Hills was then allowed to adjust its S&F Charge to recognize these additional customer-related costs. In Proceeding No. 12AL-1052E, the Commission again approved a zero-intercept method for Black Hills.

While Public Service has not conducted a similar study, i.e., we classify all such costs as capacity-related costs, it is important to remember that our estimates of customer-related costs (which are the only costs collected through the S&F Charge) are conservative.

Q. GIVEN THESE CONSIDERATIONS, HOW SHOULD DISTRIBUTION COSTS BE RECOVERED THROUGH RATES?

A. Regardless of whether distribution costs are driven by the number of customers, noncoincident peak loads or coincident peak loads, these costs would – ideally – not be collected through a usage charge. Instead, these costs would be collected through a combination of fixed monthly charges and demand charges. The Company's proposed rate design for its large demand-metered customers

[1] Black Hills acquired Aquila, Inc.'s Colorado electric assets in July 2008.

served at primary voltage ("Schedule PG") will largely accomplish this goal. The Company proposes to extend this rate design to smaller customers in the future.

But until that superior rate design can be implemented for small customers, the Company still faces the challenge of collecting distribution costs from customers not subject to demand charges. One positive interim step the Company can take in this proceeding is to begin collecting distribution costs through a fixed charge. This fixed charge will mirror more closely the distribution demand charge customers will face in the future. That demand charge – while not part of the fixed S&F Charge – will be assessed on billing determinants that are more stable than monthly kWh use. Moreover, as mentioned previously, some upstream distribution costs could arguably be classified as customer-related costs. If so, then they should be collected through fixed monthly charges.

Q. WILL ALL CUSTOMERS PAY THE SAME MONTHLY GRID USE CHARGE?

A. No. A uniform charge might make sense if distribution costs were driven entirely by the number of customers. But peak loads still drive a significant percentage of distribution costs. In the absence of any direct measurement of a customer's peak load(s), it is reasonable to recognize in some manner the probability that large customers impose higher peak loads and higher levels of distribution costs than small customers. Consequently, the Company proposes to assess Grid Use Charges that increase with a customer's size.

Q. HOW IS THE CUSTOMER'S SIZE DETERMINED WHEN BILLING THE GRID USE CHARGE?

A. The Company proposes to use the customer's average monthly use over the past 12 months as a proxy for a customer's size. Depending on this average use, the customer will be charged one of five Grid Use Charges. These charges are provided in Attachment SBB-2, and are summarized in Table SBB-2 below:

Table SBB-2

Average Monthly Use (kWh)	Residential Grid Use Charge
0 – 200	$2.62
201 – 500	$7.76
501 – 1000	$14.56
1001 – 1400	$25.69
> 1400	$44.79

Q. HOW WILL THE AVERAGE MONTHLY USE BE ESTABLISHED FOR CUSTOMERS WITH LESS THAN 12 MONTHS OF BILL HISTORY AT A PREMISE?

A. The average monthly use for customers with less than 12 months of bill history will be the average monthly use for the prior months for which the Company has billing data for the customer.

For new customers with no prior bill history, the Company will apply the lowest Grid Use Charge for the first billing month. The Grid Use Charge for the second billing month will be based on the Customer's average usage in the first and second months. This process will continue until the Customer has accumulated 12 consecutive billing months of data. At that point, the Company will base the Grid Use Charge on the customer's average monthly use for the most recent 12 months.

Q. WILL THE AVERAGE MONTHLY USE OF CUSTOMERS ELIGIBLE FOR NET METERING BE BASED ON GROSS CUSTOMER MONTHLY USE OR NET CUSTOMER MONTHLY USE?

A. The Company will average 12 months of net customer use. But during months when the customer generates more energy than the customer uses, i.e., the customer's net use is negative, the Company will set the customer's net use during that month at 0 kWh. This imputation of 0 kWh will be used only to derive the Grid Use Charge.

Q. WHAT GOALS OR CRITERIA DID THE COMPANY USE WHEN DEVELOPING THE NUMBER OF USAGE INTERVALS AND THE CHARGE ASSOCIATED WITH EACH USAGE INTERVAL?

A. The Company balanced the following, sometimes competing, goals:

- Set the Grid Use Charges to allow the Company a fair opportunity to recover 100 percent of the distribution costs allocated to the residential class.
- Reflect meaningful differences in monthly charges based on customer size.

- Avoid customer confusion and promote ease of administration by limiting the number of usage intervals.
- Allow customers a reasonable opportunity to lower their Grid Use Charges by lowering their monthly use over time.
- Avoid frequent fluctuations in customers' monthly Grid Use Charges, to prepare customers for the future rate design under which such fluctuations will be smaller.
- Avoid extreme bill impacts.

Q. DO THE PROPOSED RATES MEET THE GOAL OF RECOVERING 100 PERCENT OF THE DISTRIBUTION COSTS?

A. Yes. The five charges are set to generate revenues equal to 100 percent of the distribution costs allocated to the residential customer class (net of distribution cost recovery generated from the other residential tariffs). The Company derived these charges by reviewing bill frequency distribution ("BFD") data for the residential class data for calendar-year 2013. The Company chose calendar-year 2013 because it coincides with the Historical Test Year ("HTY") in the Company's last Phase I Electric Rate Case (Proceeding No. 14AL-0660E) to which this Phase II proceeding is calibrated. Multiplying each rate by the number of annual bills subject to that charge yields the revenue from that charge. The sum of the revenues from the five charges equals the distribution costs allocated to the residential class in the CCOSS (net of the distribution cost recovery through both Schedule RD and the optional rate design for grandfathered net metered customers in Schedule R.)

Q. DO THE PROPOSED CHARGES MEET THE GOAL OF REFLECTING MEANINGFUL DIFFERENCES IN CHARGES BASED ON CUSTOMER SIZE?

A. Yes. The ratios of the charges are based on the average customer use within each interval. For example, the average monthly use of residential customers in the interval of 501 kWh to 1,000 kWh is 668 kWh. The average use for residential customers in the interval of 201 kWh to 500 kWh is 356 kWh. The ratio of these average uses is 1.88:1.0. The charges for the same two tiers are $14.56 and $7.76, respectively. The ratio of these charges is also 1.88:1.00. Each of the five charges reflects this same correspondence, as illustrated in Attachment SBB-2.

This approach results in charges that are equitably escalated with a customer's size, and result in meaningful differences in charges for small and large customers.

Q. HAS THE COMPANY ADEQUATELY ADDRESSED THE OTHER FOUR GOALS AS WELL?

A. Again, I believe so. It is important to recognize that these goals are competing. For example, the goals of limiting customer confusion, promoting ease of administration and limiting frequent changes to a customer's Grid Use Charge from month to month are best realized by limiting the number of charges. But the goals of allowing customers the opportunity to reduce their charges and avoiding extreme rate impacts are best realized by increasing the number of usage intervals and charges.

The Company exercised informed judgment to balance these goals, but did employ one firm constraint; the monthly bill increase to any one residential customer could not exceed 15 percent. Establishing five different charges allowed us to meet this goal (see Attachment SBB-2), while balancing the other goals as well.

Q. DO THE GRID USE CHARGES RESULTING FROM YOUR BALANCING OF THESE GOALS RESULT IN AN INCENTIVE FOR CUSTOMERS TO REDUCE ENERGY USE?

A. Yes. The tiered structure encourages customers to reduce their monthly usage so that they can be assessed a lower Grid Use Charge.

Q. WILL ALL CUSTOMERS BE SUBJECT TO THE GRID USE CHARGES IN SCHEDULE R?

A. No. Any residential Solar*Rewards® customer with on-site generation who is net metered before January 1, 2017, will be eligible for the Optional Energy Charge specified in Schedule R. That rate design does not include a Grid Use Charge.

In addition, customers served under Schedule RD will pay for distribution costs through the demand charge applicable to that tariff. Consequently, these customers will not be subject to a Grid Use Charge.

But customers on the optional Schedule RD–TOU service schedule will be assessed the Grid Use Charge.

I will discuss the pricing of these three alternative residential schedules later in my Direct Testimony.

C. <u>Residential Schedule R Energy And S&F Charges</u>

Q. WHEN DID THE COMPANY INSTITUTE TIERED SUMMER ENERGY CHARGES FOR SCHEDULE R AND HOW ARE THESE CHARGES APPLIED?

A. The Company instituted the tiered charges on June 1, 2010. They are assessed only during the summer months of June, July, August and September. The first 500 kWh of a customer's use during each of the four months are billed at the lower Tier 1 Energy Charge. All energy in excess of 500 kWh is billed at the higher Tier 2 Energy Charge.

Q. HAS THE COMPANY ESTIMATED THE IMPACTS OF TIERED RATES ON THE SUMMER USE OF RESIDENTIAL CUSTOMERS?

A. Yes. In his Direct Testimony Company witness Mr. Donald E. Garretson discusses the estimated impacts of tiered rates since their inception in June 2010 through the summer of 2013. He concludes that the rates have reduced summer use to roughly the same extent that the Company projected in our most recent Phase II electric proceeding, Docket No. 09AL-299E ("2009 Electric Phase II Rate Case").

Q. IS THE COMPANY PROPOSING TO RETAIN THE TIER 1 AND TIER 2 ENERGY CHARGES IN THE PROPOSED SCHEDULE R?

A. Yes. The original objective of the tiered charges was to recognize that the Company's cost of providing service is markedly higher in the summer, and to better reflect these higher costs in residential customers' marginal summer prices. Summer loads still drive most of our G&T capacity costs. Until the Company can implement TOU demand charges, there is still a basis for continuing to reflect these seasonal differences through summer tiered rates. The institution of a Grid Use Charge to recover distribution costs has no bearing on the justification for or levels of tiered energy charges.

But once the Company implements the long-term rate design that Ms. Jackson discusses, there will be no need for tiered Energy Charges. A demand charge assessed on peak loads during weekday afternoons will recover G&T fixed costs more accurately than the current tiered rates. The base usage charge – similar to the base usage charge currently assessed on large demand-metered customers – can then be limited to recovering non-fuel variable O&M expenses.

Q. YOU STATE THAT SUMMER LOADS STILL DRIVE MOST OF THE COMPANY'S G&T CAPACITY COSTS. WHAT ANALYSES DID YOU CONDUCT TO SUPPORT THIS CONCLUSION?

A. The Company reviewed the month and time of day when our annual system peak hour occurred during the past 10 years. On each occasion the system peak occurred in the summer, and this system peak demand was – on average – 943 megawatts ("MW") higher than the system peak demand during any of the eight non-summer months.

The Company also conducted an LOLP Study to determine when there might be insufficient generation capacity to serve projected loads – given generation maintenance schedules, projected customer loads, and forced outage probabilities. This analysis suggests that about 99 percent of our LOLP is attributable to the summer season.

Based on our historical experience and this LOLP Study, I conclude that most of the G&T capacity costs are attributable to the summer season. Likewise, this analysis supports the Company's proposal to use a Four Coincident Peak – Average and Excess Demand ("4CP-AED") allocator to allocate production and transmission costs. (See the Direct Testimony of Ms. Basquez.)

Q. HAVE YOU INCLUDED SUMMARIES OF THESE STUDIES AS AN ATTACHMENT TO YOUR DIRECT TESTIMONY?

A. Yes. These summaries are provided in Attachment SBB-3. I will also refer to this attachment when discussing the pricing of non-residential services.

Q. IS THE COMPANY PROPOSING TO MODIFY THE TIERED RATE STRUCTURE IN THIS PROCEEDING?

A. The Company is not proposing any changes to the structure; the Company proposes to continue to assess Tier 1 and Tier 2 Energy Charges during the summer and a single Energy Charge during the winter equal to the summer Tier 1 Energy Charge. But I have evaluated the need to modify the differential between the Tier 1 and Tier 2 Energy Charges. I conclude that the differential should not be materially modified.

Q. PLEASE EXPLAIN THE CRITERIA YOU USE TO EVALUATE THIS DIFFERENTIAL.

A. I start with establishing a cap on the Tier 2 Energy Charge at the estimated long-run marginal G&T cost per kWh – net of the riders earmarked for the recovery of G&T costs. This net amount of $0.1036 per kWh is derived in Attachment SBB-4.

Q. WHY DOES THIS AMOUNT REPRESENT AN APPROPRIATE CAP?

A. It is important to send price signals to small customers who are often faced with making long-term investment decisions that reflect or are informed by long-run marginal costs. These signals could be adjusted to reflect a utility's generation reserve margins and/or other factors, but the long-run marginal cost is a reasonable cap. The rate can then be lowered from this cap to meet other goals.

Q. IS THE CURRENT TIER 2 ENERGY CHARGE ABOVE OR BELOW THIS LONG-RUN MARGINAL COST?

A. The current Tier 2 Energy Charge is $.09000 per kWh. Adding the General Rate Schedule Adjustment ("GRSA") of 14.19 percent yields a total Tier 2 Charge of $0.10277 per kWh, which is very close to the adjusted long-run marginal cost of $0.1036 per kWh.

Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

A. The current Tier 2 Energy Charge is only slightly below the cap of $0.1036 per kWh. But it is important to remember that the current Tier 1 and Tier 2 Energy Charges recover distribution costs, while the proposed Tier 1 and Tier 2 Energy

Charges would not. When the component of the current Tier 2 Energy Charge that recovers distribution costs is removed, then the adjusted charge will be below the long-run marginal cost.

Q. WHAT OTHER FACTORS, ASIDE FROM IMPOSING A CAP AT THE LONG-RUN MARGINAL COST, DID YOU CONSIDER WHEN EVALUATING THE APPROPRIATE LEVEL OF THE TIER 2 RATE?

A. I do not recommend any significant charges to the relationship between the Tier 1 and Tier 2 Energy Charges to limit the potential for extreme bill impacts on low-use or high-use customers. I believe this restraint is particularly important given the impact of the Grid Use Charge.

Moreover, the Company proposes to replace the Schedule R tariff proposed in this proceeding with a more robust tariff in a few years. There is little compelling reason to subject customers to significant changes in the tiered rate structure or rate differentials if tiered rates will be eliminated in a few years.

Q. SHOULD THE DIFFERENTIAL BETWEEN THE TIERED RATES BE REDUCED TO PREPARE CUSTOMERS FOR THE ULTIMATE ELIMINATION OF TIERED ENERGY CHARGES?

A. No. The Company proposes to replace the price signal provided by the current tiered rate design with the equally pronounced (and arguably more pronounced) signal provided by on-peak demand charges. Muting the price signal currently provided through tiered usage charges would not better prepare residential customers for the proposed long-term rate design.

Q. BASED ON THIS ANALYSIS, WHAT RATE DIFFERENTIAL DO YOU RECOMMEND?

A. I recommend that the difference between the Tier 1 and Tier 2 Energy Charges be set at $0.045 per kWh, which is slightly less than the current differential after the application of the GRSA.

Q. HOW SHOULD THE RESIDENTIAL S&F CHARGE BE ESTABLISHED?

A. The Company's proposed S&F Charge should be set to recover 100 percent of the embedded customer-related costs allocated to the residential class in the CCOSS. While this approach of recovering only embedded customer-related costs without the imputation of a minimum system would normally yield a fixed charge that is too low from the Company's perspective, the institution of the Grid Use Charge will help compensate for this low S&F Charge. Without the Grid Use Charge, the Company would recommend a higher S&F Charge for Schedule R.

Q. WHY DO YOU BELIEVE THE S&F CHARGE WOULD BE TOO LOW IN THE ABSENCE OF THE GRID USE CHARGE?

A. There are two reasons – both of which I have mentioned previously. First, the Company's decision to classify all distribution costs as capacity-related results in a conservative estimate of customer-related costs. Second, setting the Schedule R S&F Charge to recover only embedded customer-related costs results in the recovery of most fixed costs allocated to the residential class through usage charges. There is no compelling conceptual reason for this rate design – other than historical practice. I am not suggesting that all fixed capacity-related costs should be recovered through the fixed monthly charge rather than the usage charge under two-part tariffs. But I believe splitting the recovery of fixed capacity-related costs between the two rate components has merit. The result of applying this split would be an S&F Charge higher than an S&F Charge earmarked solely for the recovery of embedded customer-related costs.

D. <u>Alternative Rate Design Under Schedule R</u>

Q. WHAT ALTERNATIVE RATE DESIGN DOES THE COMPANY PROPOSE FOR SCHEDULE R AND TO WHICH CUSTOMERS WOULD THIS RATE DESIGN BE AVAILABLE?

A. As an alternative to the proposed rate design described above, the Company proposes to continue offering the current Schedule R rate design to customers who participate in the Company's Solar*Rewards® program and are net metered as of December 31, 2016. Under this alternative rate design customers will pay an S&F Charge, summer tiered Energy Charges, and a flat winter Energy Charge. All distribution costs will be collected through the Energy Charges; no Grid Use Charge will be assessed.

Of course, the proposed S&F Charges and Energy Charges have been adjusted from their current levels to reflect the results of the CCOSS. Mr. Wishart sponsors the specific rates applicable to this alternative rate design.

Q. WHY IS THE COMPANY PROPOSING THIS ALTERNATIVE RATE DESIGN?

A. Most customers who are net metered assessed the economic viability of their on-site generation based on their projected bill credits under the current rate design.

Certainly utilities are always free to propose (and should propose) rate-design changes over time. The proliferation of on-site generation should in no way be construed as precluding such changes. But the Company also recognizes that some existing net metered customers may have assumed that service under the current Schedule R rate design would be available for some time. The Company proposes the alternative rate design to allow existing Solar*Rewards® customers who are net metered to realize bill savings more in line with their original estimates.

Q. HAS THE COMPANY EXPLAINED TO SOME NET METERED CUSTOMERS THAT REGULATORY CHANGES CAN CHANGE THE ECONOMIC VALUE OF THEIR ON-SITE SOLAR?

A. Yes. In both 2014 and 2015 the Company submitted letters to customers who expressed interest in net metering outside of the Solar*Rewards® Program.

In the letter submitted to customers in 2014, the Company referenced the then ongoing Commission investigation into distributed generation. The Company explained that "if in the future the Colorado Public Utilities Commission makes a decision on net metering, the benefits that net metering currently offers for your solar generating system may be eliminated, or substantially reduced."

The Commission closed the investigatory proceeding by the time the Company submitted the 2015 version of the letter to customers interested in net metering outside of the Solar*Rewards® Program. Nonetheless, in this 2015 letter the Company reminded customers that "[w]e offer net metering under our

Public Utilities Commission approved tariff service, which is subject to change from time to time."

Although neither letter was sent to customers requesting enrollment in the Solar*Rewards® Program, the letters demonstrate the Company's efforts to alert customers to the possibility of regulatory changes that could affect the value of on-site solar.

E. Residential Demand Service

Q. PLEASE PROVIDE SOME BACKGROUND ON THE CURRENT SCHEDULE RD.

A. Schedule RD is an optional three-part service schedule that is available to any residential customer on an optional basis. Schedule RD includes a higher S&F Charge than the Schedule R S&F Charge to recover the additional metering costs. The tariff also includes summer and winter Demand Charges assessed on a customer's noncoincident peak demand during the billing period and a flat Energy Charge applied to all use during the year. Customers on this tariff pay a flat ECA; they are not eligible for the TOU ECA.

This service is most attractive to residential customers who use a large amount of energy on an annual basis and/or have a high load factor. My understanding is that it was originally designed primarily for electric space-heating customers. There are currently about 1,200 customers on the schedule – or about 0.1 percent of the total residential customer base.

Q. HOW DOES THE CURRENT SCHEDULE RD FIT INTO THE COMPANY'S LONG-TERM PRICING STRATEGY?

A. It does not fit; the Company believes the three-part TOU tariff that Ms. Jackson describes would send better price signals and recover costs more equitably than does Schedule RD. Residential customers on both Schedule R and Schedule RD would ultimately migrate to the tariff Ms. Jackson describes.

Q. DOES THE COMPANY PROPOSE TO ELIMINATE SCHEDULE RD IN THIS PROCEEDING?

A. No. The Company proposes to close the tariff to new customers beginning January 1, 2017. Existing Schedule RD customers as of that date can remain on Schedule RD until the date on which they are ultimately transitioned to the new three-part tariff. This "grandfathering" of the service will reduce the potential for extreme rate impacts on current Schedule RD customers.

Of course, the Company is also proposing to implement the three-part tariff that Ms. Jackson describes on a limited and optional basis. Within the constraint of the participation limits, customers on Schedule RD could also choose to take service under the new three-part tariff on or after January 1, 2017.

Q. WHAT IS THE COMPANY'S GOAL REGARDING THE PRICING OF SCHEDULE RD IN THIS PROCEEDING?

A. The Company's goal is to maintain roughly the current relationship between Schedule R and Schedule RD rates. Mr. Wishart sponsors the Company's proposed pricing for this service.

F. <u>Optional Residential Three-Part, TOU Service</u>

Q. YOU MENTIONED THAT THE COMPANY PROPOSES TO IMPLEMENT THE RATE DESIGN THAT MS. JACKSON DISCUSSES ON A LIMITED BASIS AS OF JANUARY 1, 2017. PLEASE DISCUSS THIS OFFERING IN MORE DETAIL.

A. The rate design will be identical to that which Ms. Jackson discusses, except that the schedule will recover distribution costs through Grid Use Charges rather than a Distribution Demand Charge. These Grid Use Charges will be identical to the Grid Use Charges the Company proposes for Schedule R. The Company proposes this modification from the preferred long-term rate design to facilitate early implementation and eliminate the costs of two demand readings. In all other respects, the Schedule RD-TOU rate design – including the summer and winter G&T Demand Charges, the Base Energy Charge and the TOU ECA – will be identical to the long-term rate design.

The S&F Charge is designed to recover the additional metering and IT/Billing costs required to implement the service. The estimated incremental capital expenditure for each meter is $133. Since the metering may not be compatible with the Company's long-term infrastructure and metering plans, this S&F Charge is designed to recover the meter's capital costs over five years. The Company will also incur a one-time O&M expense of about $330,000 for billing and programming. As with the meter costs, the Company proposes to recover this expense over five years – assuming on average the Company bills 7,000 customers. This amount represents 50 percent of the average of the annual program caps in 2017, 2018 and 2019. I derive the resulting incremental S&F Charge of $3.75 in Attachment SBB-5.

The proposed winter G&T Demand Charge is set at 67 percent of the summer G&T Demand Charge. The base Energy Charge is designed to collect non-fuel variable O&M expenses at secondary voltage. Since these expenses per kWh are the same for all customers served at secondary voltage, the same base Energy Charge will be applied to both Schedule RD–TOU and Schedule SG customers.

The service will be designated in the Company's electric tariff as Schedule RD–TOU and will be initiated on January 1, 2017. In 2017 it will be open to a maximum of 10,000 customers on a first-come, first-served basis. In 2018 the participation limit will be raised to 14,000 customers, and in 2019 the limit will be raised to 18,000 customers.

There will be no termination date for the tariff, as the specific schedule for transitioning customers to the ultimate long-term tariff is unknown at this time.

Q. WHY DO YOU PROPOSE TO SET THE WINTER DEMAND CHARGE AT 67 PERCENT OF THE SUMMER DEMAND CHARGE?

A. Based on the studies summarized in Attachment SBB-3 and the long-run marginal G&T capacity costs derived in Attachment SBB-4, there is a cost basis for proposing a high seasonal rate differential without exceeding the long-run marginal cost of service in the summer. But when evaluating seasonal rate differentials the Company considers not only costs, but also the need to mitigate extreme billing impacts, customers' preference for stable bills, and the stability of the Company's revenue stream. These non-cost goals militate against extreme differences between summer and winter rates. Any rate design based entirely on cost considerations would require customers to cope with very extreme bill fluctuations during the course of a year and destabilize the Company's revenues.

In recognition of both cost considerations and non-cost pricing goals, the Company proposes to set the winter G&T Demand Charge at 67 percent of the summer G&T Demand Charge. For a customer who imposes equal monthly peak demands over the course of a year, the Company's proposed seasonal Demand Charges would collect the same revenue during the four summer months as during the eight winter months.

Q. WHY DID YOU DEVELOP THE BILLING AND PROGRAMMING COMPONENT OF THE PROPOSED S&F CHARGE ASSUMING 7,000 CUSTOMERS WILL OPT FOR THE SERVICE?

A. The Company plans to educate customers about this service and encourage customer participation when it makes economic sense. But we are not proposing to track and recover these costs on a dollar-for-dollar basis. The proposed S&F Charge provides us with an incentive to enroll customers - because we will not recover our programming and billing costs unless we enroll on average 7,000 customers per year. I selected 7,000 customers because that participation level is 50 percent of our average participation cap in 2017, 2018 and 2019. If we achieve additional participation, we can begin defraying the costs of our customer education and outreach. Of course, we have no assurance of recovering completely any of these costs. But if we are successful, then we should receive a modest financial incentive commensurate with our risk of cost recovery.

Q. WHAT TYPES OF CUSTOMERS WOULD BE MOST INTERESTED IN THIS SERVICE?

A. I suspect that the service would be most attractive to large customers with disproportionately high off-peak or winter use. For example, space-heating customers, customers with batteries, or customers with electric vehicles might be good candidates. Large families in large homes may also benefit from the service, depending on their usage patterns.

Q. ASIDE FROM OFFERING CUSTOMERS A MORE ROBUST RATE DESIGN IMMEDIATELY, ARE THERE OTHER BENEFITS OF IMPLEMENTING THIS SCHEDULE?

A. Yes. The Company plans to monitor customer loads before and after they opt for service under the schedule. This data will provide valuable information regarding the potential impacts of our proposed long-term rate design on the residential class's coincident and noncoincident peak demands, annual energy use, and revenues. Admittedly, the sample of up to 18,000 customers – while reasonably large - will not be representative of the class as a whole, since participants will tend to be larger and have relatively more off-peak electric use than typical residential customers. But the data will still be valuable even if we need to be careful when drawing inferences for the class as a whole.

Q. WILL THIS OPTIONAL SCHEDULE AFFECT THE COMPANY'S REVENUE?

A. Yes. I suspect it will reduce the Company's revenue, since customers will presumably opt for the tariff only if they can reduce their bills.

Q. IS THE COMPANY PROPOSING TO COMPENSATE FOR THIS REVENUE LOSS?

A. The Company is not proposing any compensation mechanism - such as the elasticity adjustment that the Commission approved in the 2009 Electric Phase II Rate Case to account for the impact of tiered rates - in this proceeding. Moreover, Mr. Wishart imputes no billing determinants for this service in his revenue proof. But if the Company later proposes a revenue decoupling mechanism, we might ask to incorporate base revenue impacts from this service into the mechanism.

IV. SMALL COMMERCIAL SERVICE

Q. WHAT SMALL COMMERCIAL SERVICE SCHEDULES WILL YOU DISCUSS?

A. I will focus on Schedule C, as most small commercial customers are served under this schedule. Schedule C is limited to non-residential customers who impose an annual noncoincident peak demand of less than 25 kilowatts ("kW").

Q. PLEASE DESCRIBE THE CURRENT SCHEDULE C RATE DESIGN.

A. The current rate design for Schedule C is similar to the current Schedule R rate design, in that both schedules include an S&F Charge and a seasonally differentiated base Energy Charge. The salient difference is that the Schedule C summer Energy Charge is not tiered; one charge applies to all summer usage.

Q. IS THE COMPANY PROPOSING TO MODIFY THIS RATE DESIGN?

A. Yes. The Company proposes to add a Grid Use Charge to the Small Commercial Service ("Schedule C"), which will recover 100 percent of the distribution costs allocated to the class. We propose to set the S&F Charge to recover 100 percent of the customer-related costs allocated to the class in the embedded CCOSS. The base Energy Charges will then recover the remaining costs allocated to the class – primarily transmission costs, fixed generation costs, and variable (non-fuel) generation costs.

Q. REGARDING THE GRID USE CHARGE, HOW DID YOU ESTABLISH THE NUMBER OF USAGE INTERVALS AND THE MONTHLY CHARGE APPLIED TO EACH INTERVAL?

A. The Company applied the same criteria that we used to develop the Schedule R Grid Use Charges, and I will not repeat that discussion here. To balance our various goals, the Company proposes five Grid Use Charges for Schedule C, which will be applied to customers based on their average use over the most recent 12 billing periods. The specific usage intervals and associated charges are provided in Attachment SBB-2.

One of our important goals in developing the charges was to limit bill impacts to 15 percent. The proposed charges meet this goal for all customers except those using no (or virtually no) energy - as demonstrated in Attachment SBB-2. While the monthly bill increase to a customer using no energy will be 18.60 percent, the associated dollar impact will be very small ($2.33). The Company believes a bill increase of above 15 percent is justified if the associated dollar increase is relatively small.

Q. DOES THE COMPANY PROPOSE AN ALTERNATIVE RATE DESIGN FOR SCHEDULE C CUSTOMERS WHO PARTICIPATE IN THE SOLAR*REWARDS® PROGRAM AND ARE NET METERED AS OF DECEMBER 31, 2016?

A. Yes. The Company proposes a similar alternative for Schedule C customers as I explained earlier for Schedule R customers. Under this alternative rate design customers will pay an S&F Charge and seasonally differentiated Energy Charges. All distribution costs will be collected through the Energy Charges; no Grid Use Charge will be assessed. Mr. Wishart sponsors the specific rates applicable to this alternative rate design in Schedule C.

Q. ARE THERE ANY ADDITIONAL MARKETING, COMMUNICATIONS, ADMINISTRATION OR IT/BILLING COSTS ASSOCIATED WITH EXTENDING THE GRID USE CHARGE TO SCHEDULE C AS WELL AS SCHEDULE R?

A. No. The costs provided in Attachment SBB-1 assume the Grid Use Charges are applied to both residential and small commercial customers.

Q. WHAT SEASONAL ENERGY CHARGE DIFFERENTIAL DOES THE COMPANY PROPOSE?

A. The current summer and winter Energy Charges after the application of the GRSA are $0.07365 per kWh and $0.04476 per kWh, respectively. Stated differently, the winter charge is about 61 percent of the summer charge. The difference between the summer and winter Energy Charges was increased in the 2009 Electric Phase II Rate Case. While from a cost standpoint there is justification for increasing the differential (see Attachment SBB-3), the Company proposes only a modest reduction to 50 percent for several reasons.

First, the institution of the Grid Use Charge will affect some customers' bills by a significant percentage. The Company has no reason to believe that modifying seasonal rate differentials would adversely affect the same customers disproportionately affected by the Grid Use Charges. Nonetheless, there may be unintended, compounded impacts on these same customers.

Second, as I explained earlier in my testimony, the Company does not endorse the collection of virtually all base revenue in the summer months regardless of cost considerations. Such a rate design would require customers to cope with very extreme bill fluctuations during the course of a year and destabilize the Company's revenues.

Third, the elimination of the distribution cost component from the two Energy Charges means that the percentage difference will be calibrated from a lower base. As a result, the percentage differential can be increased without increasing the absolute differential.

After considering all of these factors, the Company proposes to set the Winter Energy Charge at 50 percent of the Summer Energy Charge. This percentage represents a modest increase in the seasonal differential to reflect cost differences more accurately, but prevents any extreme bill impacts or revenue instability.

Q. SOME SMALL COMMERCIAL LOADS TAKE SERVICE UNDER THE NON METERED SERVICE SCHEDULE. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THIS SERVICE?

A. No. Mr. Wishart will sponsor the Company's proposed rates and terms and conditions applicable to this service.

V. LARGE COMMERCIAL AND INDUSTRIAL SERVICE

A. Overview

Q. PLEASE SUMMARIZE THE MODIFICATIONS THE COMPANY IS PROPOSING IN THIS PROCEEDING REGARDING SERVICES TO LARGE C&I CUSTOMERS.

A. We propose several important changes.

First, the Company proposes to modify its assessment of G&T Demand Charges on customers served at primary and transmission service voltage (customers served on Schedules PG and TG). Specifically, the Company proposes to determine a customer's billing demand based on the customer's peak load during weekday afternoons – the period during which the Company experiences its highest loads.

Second, the Company proposes to offer a CPP service on a limited basis to large Commercial and Industrial ("C&I") customers.

Third, the Company proposes to better differentiate among the services we provide to customers with on-site generators or storage applications.

Aside from these fundamental changes, the Company has also re-evaluated the appropriate differential between summer and winter demand charges and the appropriate on- and off-peak periods for the TOU ECA.

Q. HOW DO THE THREE MAJOR INITIATIVES YOU MENTION ABOVE ADVANCE OR COMPLEMENT THE COMPANY'S LONG-TERM STRATEGIC PRICING PLAN?

A. I will start with the Company's proposal to implement on-peak demand charges to recover G&T capacity costs. The Company's proposed CCOSS indicates that generation and transmission capacity costs account for about 50 percent of the Company's base cost of service. Consequently, no rate design can be effective if it does not properly charge for these costs. The revision I am sponsoring will allow the Company to implement immediately the long-term rate design that Ms. Jackson proposes for all of our major service schedules.

The offering of a CPP service helps fill an important gap in the Company's pricing by encouraging load relief when most needed. I will discuss this strategic value in more detail later in my testimony.

The differentiation of the services provided to customers with behind-the-meter generators or storage applications recognizes the increasing importance of these options. On-site generation is growing not only in magnitude, but also in diversity. One challenge for utilities is to recognize that not all customers with on-site generation require typical standby service; some customers require a higher level of service. Behind-the meter storage applications are currently rare, but could proliferate in the future.

In other words, these three initiatives advance or complement the long-term rate design that Ms. Jackson discusses. With all of these initiatives the

Company's primary goals are to send good price signals and recover costs equitably from the customers who impose these costs.

B. <u>Secondary General</u>

Q. PLEASE DESCRIBE THE CURRENT RATE DESIGN FOR SCHEDULE SG.

A. The Secondary General ("Schedule SG") tariff includes the following base charges: a monthly S&F Charge, a Distribution Demand Charge, G&T Demand Charges, and an Energy Charge. The S&F Charge is designed to recover the customer-related costs imposed by the class. The flat base Energy Charge is applied to all usage during the billing period and recovers variable O&M expenses. The Distribution Demand Charge is assessed on a customer's peak demand during the billing period, unless applying the 50 percent demand ratchet yields a higher billing demand. The G&T Demand Charge is also assessed on a customer's peak load during the month, but is not subject to a demand ratchet.

Q. DOES THE COMPANY PROPOSE ANY SIGNIFICANT CHANGES TO THE RATE DESIGN FOR SCHEDULE SG?

A. No. The Company is not requesting any changes to the rate design – only the rate levels.

Q. WHY IS THE COMPANY NOT PROPOSING TO ASSESS THE G&T DEMAND CHARGE ON PEAK LOADS DURING WEEKDAY AFTERNOONS – SIMILAR TO YOUR PROPOSAL FOR THE PG AND TG SERVICE SCHEDULES?

A. As Ms. Jackson explains, over the next few years the Company plans to institute this on-peak demand charge for all of the major service schedules - Schedules R, C, SG, PG and TG.

However, the Company believes that it is important to roll out this rate design carefully. The TG and PG service schedules are applicable mostly to relatively large customers whose billing determinants under various rate designs - at least before customer response to the price signal is accounted for - can be estimated with a reasonable degree of accuracy. In contrast, Schedule SG comprises a large number of customers with disparate load characteristics. Also, while the current meters deployed for PG and TG customers can accommodate the new rate design, the current meters used to bill SG customers often cannot. Immediately changing out SG meters would add to the cost of the transition.

Consequently, before transitioning SG customers to the new rate design, the Company proposes to analyze carefully the potential impacts of this transition. The impact of the new rate design on PG and TG customers will inform this analysis.

Q. HAS THE COMPANY ANALYZED WHETHER THE DIFFERENTIAL BETWEEN THE SUMMER AND WINTER DEMAND CHARGES SHOULD BE ADJUSTED?

A. Yes. The current summer and winter Demand Charges, after the application of the GRSA, are $12.51 per kW-Month and $9.13 per kW-Month, respectively. In other words, the winter Demand Charge is about 73 percent of the summer Demand Charge.

As explained previously, when evaluating seasonal rate differentials the Company considers seasonal cost differences, marginal costs, the need to mitigate extreme billing impacts, customers' preference for stable bills, and the stability of the Company's revenue stream. Based on the studies summarized in Attachment SBB-3 and the long-run marginal G&T capacity costs derived in Attachment SBB-4, there is a cost basis for increasing the seasonal rate differential without exceeding the long-run marginal cost of service in the summer. But the other goals militate against any significant increase in the differential. In recognition of these goals, the Company proposes to increase the differential modestly – such that the winter G&T Demand Charge is 70 percent of the summer G&T Demand Charge.

Q. IS THE COMPANY PROPOSING ANY ADDITIONAL CHANGES TO THE SG RATE DESIGN OR RELATIONSHIPS?

A. No. Of course, the rate levels themselves must be adjusted to reflect the new test-year costs and billing determinants. In his revenue proof Mr. Wishart demonstrates that the Company has developed compensatory rates for the SG Schedule.

Q. ARE ANY OTHER SERVICE SCHEDULES APPLICABLE TO LARGE C&I CUSTOMERS SERVED AT SECONDARY VOLTAGE?

A. Yes. Four additional service schedules are currently applicable: Secondary General Low-Load Factor ("Schedule SGL"), Secondary Standby Service ("Schedule SST"), Secondary Time-of-Use Service ("Schedule STOU"), and Secondary Photovoltaic Time-of-Use Service ("Schedule SPVTOU"). In addition, the Company is proposing in this proceeding a new CPP program that will be open to large customers served at secondary voltage.

Q. WILL YOU DISCUSS ANY OF THESE SERVICE SCHEDULES?

A. Yes. Since TOU, CPP and standby services are applicable to demand-metered customers served at secondary, primary and transmission voltage, I will devote a separate section of my testimony to each of these services that addresses all three service voltages.

I am recommending one change to the terms and conditions in Schedule SGL. Mr. Wishart sponsors the Company's proposed rate design and rates for this service.

Q. WHAT CHANGE TO THE SCHEDULE SGL TERMS AND CONDITIONS IS THE COMPANY RECOMMENDING?

A. We recommend closing this service to customers requiring Supplemental Service, Auxiliary Service or net metering, except for customers who operate generators connected in parallel with the Company and receive service under both Schedule SGL and Net Metering Service ("Schedule NM") as of December 31, 2016.

Q. WHAT IS THE BASIS FOR THIS RECOMMENDATION?

A. I discuss the particulars of Supplemental Service and Auxiliary Service later in my testimony. But one of the Company's goals in this proceeding is to provide services to customers with behind-the-meter generation or storage that reflect the actual services they require and the costs they impose. The purpose of Schedule SGL is to cap the per-kWh cost to customers who by virtue of their loads use energy at a very low capacity factor. Schedule SGL is not intended to allow customers with more typical end uses – who would normally be subject to a G&T Demand Charge under the standard Schedule SG - to avoid paying for their fair share of fixed G&T costs by installing on-site generation and opting for Schedule SGL. The Company has other service options for customers with on-site generation.

Q. WHY IS THE COMPANY PROPOSING TO ALLOW CUSTOMERS CURRENTLY RECEIVING SERVICE ON SCHEDULES SGL AND NM TO REMAIN ON BOTH SCHEDULES?

A. Customers on both schedules may have assumed that Schedule SGL would be offered to them indefinitely when evaluating the bill savings attributable to their on-site generation. The Company proposes to help preserve this assumed economic benefit for existing net-metered customers.

C. Primary General

Q. PLEASE DESCRIBE THE CURRENT RATE DESIGN FOR SCHEDULE PG?

A. The current Schedule PG rate design is identical to the Schedule SG rate design that I described earlier. Customers on Schedule PG are assessed an S&F Charge, a Distribution Demand Charge, seasonal G&T Demand Charges, and a base Energy Charge.

Q. DOES THE COMPANY RECOMMEND ANY SIGNIFICANT CHANGES TO THE SCHEDULE PG RATE DESIGN?

A. The Company recommends one significant change. The current G&T Demand Charge is assessed on a customer's highest 15-minute demand during the billing period, regardless of when that peak load occurs. As I mentioned previously, the Company proposes, as of January 1, 2017, to assess the G&T Demand Charge on a customer's peak load from 2:00 p.m. to 6:00 p.m. on non-holiday weekdays.

Q. WHY IS THE COMPANY PROPOSING THIS MODIFICATION?

A. Earlier in my testimony, I explained that some capacity costs are driven by noncoincident peak loads, while other costs are driven by system (coincident) peak loads. In the case of G&T costs, the cost driver is coincident peak loads. The Company must secure enough generation capacity – either through owned generation or firm capacity purchases - to meet our projected system peak loads. As I explained previously, these peak loads occur primarily during summer weekday afternoons, and a customer's contribution to these system peak loads is the relevant metric in terms of determining the costs that customer imposes. If a customer uses even more energy during off-peak hours, such as 10:00 p.m. on a November weekend, those higher loads do not increase the amount of required generation capacity. In other words, these higher off-peak loads do not impose any additional generation capacity costs.

For this same reason, the Company allocates fixed G&T costs on the basis of summer coincident peak loads – through the 4CP-AED allocator that Ms. Basquez discusses.

Consequently, it makes sense to send a price signal that loads during weekday afternoons drive G&T capacity costs, while loads outside of this period do not. The Company proposes to send this price signal by limiting the assessment of the G&T Demand Charge to non-holiday weekday afternoons.

Q. WHY DID THE COMPANY SELECT THE PERIOD OF 2 P.M. THROUGH 6 P.M.?

A. Earlier in my testimony, I introduced Attachment SBB-3 to demonstrate that our historical system peak demands have occurred during the summer, and that our projected probability of having insufficient generation resources to serve load is also concentrated in the summer. (The latter was established through a LOLP Study.) But the implications of these studies go beyond establishing the importance of summer loads in general. Both our historical peak loads and LOLP Study indicate that the loads that truly drive G&T costs are summer weekday afternoon hours. Each of the historical annual system peak hours during the past 10 years occurred during a summer non-holiday weekday during the window of 2 p.m. to 6 p.m. In addition, about 82 percent of the annual LOLP is attributable to these same summer weekday hours.

Q. WILL A NARROW WINDOW OF FOUR HOURS POSE A RISK OF SIMPLY MOVING THE SYSTEM PEAK TO AN HOUR OUTSIDE OF THIS WINDOW – SUCH AS 1:00 P.M. OR 7:00 P.M.?

A. There is some risk, since 18 percent of the annual LOLP falls outside of the proposed window. Specifically, as is the case with many TOU rates, there is some risk that the proposed price signal could result in "peak chasing." In other words, customers might change their usage patterns such that they move the system peak to an hour outside of the 2:00 p.m. to 6:00 p.m. window.

Q. WHY DOESN'T THE COMPANY SIMPLY PROPOSE A BROADER WINDOW FOR DETERMINING THE G&T BILLING DEMAND?

A. There is no question that a broader period could virtually eliminate the potential for peak chasing. But another goal is to provide customers a reasonable opportunity to reduce their peak loads during the critical period. The narrower the window, the more opportunity customers have for reducing their billing demands. The designated period for determining billing demands must strike a balance between capturing the critical hours - even after accounting for customer response to the price signal - and providing customers with a reasonable opportunity to financially benefit from their responses. In the Company's judgment, the four-hour window strikes a reasonable balance.

Q. IS THERE AN OPPORTUNITY TO ADJUST THE WINDOW IN SUBSEQUENT ELECTRIC PHASE II PROCEEDINGS?

A. Yes. In fact, one advantage of excluding Schedule SG from the on-peak G&T Demand Charge is that the Company can first monitor the response of PG and TG customers before implementing the on-peak charge on a broader basis. If that experience suggests a material potential for peak chasing when the rate design is applied to all customers, then the window can be extended to include additional hours.

Q. WILL THE ASSESSMENT OF THE G&T DEMAND CHARGE ON CUSTOMER PEAK LOADS DURING A NARROW WINDOW OF THE BILLING PERIOD AFFECT THE SCHEDULE PG TEST-YEAR BILLING DEMANDS?

A. Yes. The G&T billing demands will decrease from their actual 2013 test-year levels, because some customers' maximum 15-minute loads during the entire billing period will exceed their maximum 15-minute loads during the period from 2 p.m. to 6 p.m. on non-holiday weekdays.

Q. HAS THE COMPANY ADJUSTED THE SCHEDULE PG TEST-YEAR BILLING DEMANDS TO REFLECT THIS DECREASE?

A. Yes. In his revenue proof Mr. Wishart imputes a lower level of Schedule PG billing demands. This adjustment is based on interval data for Schedule PG customers. Of course, a reduction to class billing demands requires a higher G&T Demand Charge to recover the costs allocated to the Primary C&I class in the Company's CCOSS.

Q. WOULD A SCHEDULE PG CUSTOMER'S G&T BILLING DEMAND AS DESCRIBED ABOVE ALSO BE USED FOR PURPOSES OF ASSESSING ANY DEMAND-BASED RIDERS OR COST ADJUSTMENTS?

A. Yes. As of January 1, 2017, the demand-based riders would be assessed on the same billing demands applied to the base G&T Demand Charge described above. The demand-based riders applicable to schedule PG customers are the Purchased Capacity Cost Adjustment ("PCCA"), Transmission Cost Adjustment ("TCA"), Demand Side Management Cost Adjustment ("DSMCA") and Clean Air - Clean Jobs Act Rider ("CACJA Rider"). Accordingly, the Company will develop the Schedule PG charges for these riders based on the same billing determinants.

Q. HAS THE COMPANY ANALYZED WHETHER THE DIFFERENTIAL BETWEEN THE SUMMER AND WINTER DEMAND CHARGES SHOULD BE ADJUSTED?

A. Yes. The current summer and winter Demand Charges, after the application of the GRSA, are $11.46 per kW-Month and $8.03 per kW-Month, respectively. In other words, the winter Demand Charge is about 70 percent of the summer Demand Charge.

As explained previously, when evaluating seasonal rate differentials, the Company considers seasonal cost differences, marginal costs, the need to mitigate extreme billing impacts, customers' preference for stable bills, and the stability of the Company's revenue stream. Based on the studies summarized in Attachment SBB-3 and the long-run marginal G&T capacity costs derived in

Attachment SBB-4, there is a cost basis for increasing the seasonal rate differential without exceeding the long-run marginal cost of service in the summer. But the other goals militate against any significant increase in the differential. In recognition of these goals, the Company proposes to increase the differential modestly – such that the winter G&T Demand Charge is 67 percent of the summer G&T Demand Charge. For a customer who imposes equal monthly peak demands over the course of a year, this design would collect the same demand revenue during the four summer months as during the eight winter months.

Q. IS THE COMPANY PROPOSING ANY ADDITIONAL CHANGES TO THE PG RATE DESIGN OR RELATIONSHIPS?

A. No. Of course, the rate levels themselves must be adjusted to reflect the new test-year costs and billing determinants. In his revenue proof Mr. Wishart demonstrates that the Company has developed compensatory rates for the PG Schedule.

Q. ARE ANY OTHER SERVICE SCHEDULES APPLICABLE TO THE LARGE C&I CUSTOMERS SERVED AT PRIMARY VOLTAGE?

A. Yes. Two additional service schedules are currently applicable: Primary Standby Service (“Schedule PST”) and Primary Time-of-Use Service (“Schedule PTOU”). In addition, the Company is proposing in this proceeding a new Critical Peak Pricing program that will be open to customers served at primary voltage.

Q. WILL YOU DISCUSS ANY OF THESE SERVICE SCHEDULES?

A. Yes. Since TOU, standby and CPP services are applicable to demand-metered customers served at secondary, primary and transmission voltage, I will devote a separate section of my testimony to each of these services that addresses all three service voltages.

D. Transmission General

Q. PLEASE DESCRIBE THE CURRENT RATE DESIGN FOR SCHEDULE TG.

A. The current Schedule TG rate design is similar to the Schedule PG rate design that I described earlier, except that TG customers do not pay a Distribution Demand Charge. Customers on Schedule TG are assessed an S&F Charge, seasonal G&T Demand Charges, and a base Energy Charge.

Q. DOES THE COMPANY RECOMMEND ANY SIGNIFICANT CHANGES TO THE SCHEDULE TG RATE DESIGN?

A. The Company recommends one significant change, which is the same as the change to the Schedule PG rate design that I described earlier. The current G&T Demand Charge is assessed on a customer's highest 15-minute demand during the billing period, regardless of when that peak load occurs. The Company proposes, as of January 1, 2017, to assess the G&T Demand Charge on a customer's peak load from 2:00 p.m. to 6:00 p.m. on non-holiday weekdays.

Q. IS THE BASIS FOR THIS CHANGE THE SAME AS THE BASIS FOR THE CHANGE TO THE SCHEDULE PG RATE DESIGN?

A. Yes.

Q. ARE THE SCHEDULE TG TEST-YEAR BILLING DEMANDS AND DEMAND CHARGES ADJUSTED IN THE SAME MANNER AS YOU DESCRIBED ABOVE FOR SCHEDULE PG?

A. Yes.

Q. WOULD A SCHEDULE TG CUSTOMER'S G&T BILLING DEMAND ALSO BE USED FOR PURPOSES OF ASSESSING ANY DEMAND-BASED RIDERS OR COST ADJUSTMENTS, IN THE SAME MANNER AS YOU DESCRIBED ABOVE FOR SCHEDULE PG?

A. Yes.

Q. HAS THE COMPANY ANALYZED WHETHER THE DIFFERENTIAL BETWEEN THE SUMMER AND WINTER DEMAND CHARGES SHOULD BE ADJUSTED?

A. Yes. The current summer and winter Demand Charges, after the application of the GRSA, are $11.05 per kW-Month and $7.63 per kW-Month, respectively. In other words, the winter Demand Charge is about 69 percent of the summer Demand Charge.

As explained previously, when evaluating seasonal rate differentials, the Company considers seasonal cost differences, marginal costs, the need to mitigate extreme billing impacts, customers' preference for stable bills, and the stability of the Company's revenue stream. Based on the studies summarized in Attachment SBB-3 and the long-run marginal G&T capacity costs derived in Attachment SBB-4, there is a cost basis for increasing the seasonal rate differential without exceeding the long-run marginal cost of service in the summer. But the other goals militate against any significant increase in the differential. In recognition of these goals the Company proposes to increase the differential modestly – such that the winter G&T Demand Charge is 67 percent of the summer G&T Demand Charge.

Q. IS THE COMPANY PROPOSING ANY ADDITIONAL CHANGES TO THE TG RATE DESIGN OR RELATIONSHIPS?

A. No. Of course, the rate levels themselves must be adjusted to reflect the new test-year costs and billing determinants. In his revenue proof, Mr. Wishart demonstrates that the Company has developed compensatory rates for the TG Schedule.

Q. ARE ANY OTHER SERVICE SCHEDULES APPLICABLE TO THE LARGE C&I CUSTOMERS SERVED AT TRANSMISSION VOLTAGE?

A. Yes. Two additional service schedules are currently applicable: Transmission Standby Service ("Schedule TST") and Transmission Time-of-Use Service ("Schedule TTOU"). In addition, the Company is proposing to institute in this proceeding a new CPP program that will be open to customers served at transmission voltage.

Q. WILL YOU DISCUSS ANY OF THESE SERVICE SCHEDULES?

A. Yes. Since TOU, standby and CPP services are applicable to demand-metered customers served at secondary, primary and transmission voltage, I will devote a separate section of my testimony to each of these services that addresses all three service voltages.

E. <u>Critical Peak Pricing Service Option</u>

Q. PLEASE DESCRIBE THE CONCEPT OF CPP.

A. A CPP program or tariff attempts to strongly encourage – rather than require – customers to reduce their usage during periods when the Company is actually experiencing high system loads as a percentage of available generation capacity. The nomenclature "critical peak" is a reference to such periods. The term "pricing" indicates that, rather than *requiring* load reductions, the Company will charge a high price for usage during these hours that will *encourage* customers to reduce their usage.

There are many different ways to design CPP rates. But the basic idea is to assess a very high charge during the critical periods, and much lower charges for usage during the other hours.

Q. OF THE VARIOUS POTENTIAL DEMAND RESPONSE PROGRAMS OR TARIFFS THE COMPANY COULD POTENTIALLY OFFER, WHY IS THE COMPANY PROPOSING CPP?

A. There are two primary reasons. First, CPP offers promise as a cost-effective service option. Second, CPP complements well the Company's long-term rate design and current direct control programs.

Q. WHY DOES THE COMPANY BELIEVE THAT CPP IS A RELATIVELY COST-EFFECTIVE OPTION?

A. In 2013 the Company engaged The Brattle Group to study demand response potential in the Company's service territory. On June 4, 2013, The Brattle Group issued a report summarizing its research and findings entitled *Estimating PSC's Demand Response Potential*. A few interruptible or direct control programs were estimated to be cost-effective. The non-curtailable options studied were CPP, TOU tariffs and Peak Time Rebate ("PTR") tariffs. These options were broken down by both market segment (Residential, Small C&I, Medium C&I and Large C&I) and choice architecture (opt-in and opt-out program designs). Under the opt-in option, customers are not placed on the tariff unless they affirmatively enroll. Under the opt-out option, customers are placed on the tariff unless they affirmatively choose an alternative service.

At this time, the Company plans on offering demand response tariffs as alternatives to the long-term rate design that Ms. Jackson explains and that we propose to implement for Schedule PG and TG customers as of January 1, 2017. Consequently, the Company is more focused on opt-in alternatives. The Brattle Group found that the only opt-in options with a benefit-cost ratio exceeding 1.0 were CPP for the Medium C&I and Large C&I market segments. The Medium C&I segment consists of all Schedule SG and PG customers, while the Large C&I segment consists of Schedule TG customers.

Based on this analysis, the Company believes a CPP option for medium and large C&I customers is a promising service option.

Q. WHY DOES THE COMPANY BELIEVE THAT CPP COMPLEMENTS THE COMPANY'S OTHER SERVICES AND PROGRAMS?

A Once the long-term rate design is implemented for most customers, the Company will charge rates that send sound price signals to customers based on *expected* loads and costs during different seasons, times of day, etc. But it is important to remember that these rates will be applied during pre-specified periods regardless of whether the actual loads and cost pressures during any particular hour comport with these expectations.

For example, the Company proposes to ultimately assess a G&T demand charge on a customer's peak load during the weekday hours of 2 p.m. through 6 p.m. But load conditions even during that fairly narrowly defined period will probably fluctuate significantly. For example, the system load during a relatively cool and cloudy summer afternoon will probably be much less than the load during a hot, sunny afternoon in the summer. While system loads and costs will differ between the two summer afternoons, the price signal to customers will be the same.

This is by no means an indictment of three-part, TOU tariffs – as they generally send very good price signals under the constraint of pre-determined prices during predetermined periods. But there is also room for complementary services or programs that target load reductions during periods when *actual* loads are highest, reliability concerns the greatest, and/or energy costs are at their highest levels. These programs that target real-time critical conditions can require or offer load relief when it is most needed. While the Company offers curtailable or interruptible programs that target these periods – such as the Interruptible Service Option Credit ("ISOC") and Saver's Switch® programs - we do not currently offer voluntary programs that encourage reductions. The Company proposes to fill this niche with a potentially cost-effective CPP service.

Q. WHICH CUSTOMERS WILL BE ELIGIBLE FOR THE CPP SERVICE?

A. The Company proposes to offer the service to any Schedule PG or TG customer with a load factor of 30 percent or greater for each of the previous 12 months and whose average monthly noncoincident peak demand in the summer is equal to or greater than the customer's average monthly noncoincident peak demand in the winter. The service will also be open to secondary customers at or above 25 kW who meet these two conditions, as long as the customer has interval data recording metering. The three proposed service schedules are designated as Schedule SG–CPP, Schedule PG–CPP and Schedule TG–CPP for customers served at secondary, primary and transmission voltage, respectively.

Q. DOES THE COMPANY PROPOSE ANY LIMITS ON PROGRAM PARTICIPATION?

A. Yes. The Company proposes a limit on total program capacity of 30 MW.

Q. WHY ARE YOU PROPOSING THIS LIMIT?

A. The Company proposes to study the impacts of CPP on system peak demands and base revenues before extending it more broadly. This is the same approach the Company proposed – and the Commission approved – in the 2009 Electric

Phase II Rate Case for the offering of TOU tariffs to Schedule SG, PG and TG customers.

Q. GIVEN THIS NEED TO EVALUATE THE IMPACTS OF CPP, IS THE COMPANY PROPOSING THE SERVICE ON A PILOT BASIS?

A. Yes. The Company proposes a termination date of December 31, 2019, unless the Commission expressly extends the service availability beyond that date. This approach would allow the Company an opportunity to evaluate program impacts and propose to extend as is, modify or eliminate the CPP service.

Q. PLEASE DESCRIBE THE RATE DESIGN FOR THE CPP SERVICE?

A. To a large extent the proposed CPP pricing mirrors the pricing for the standard tariffs. The CPP service will feature a three-part rate design consisting of an S&F Charge, a Distribution Demand Charge (except for Schedule TG customers), a G&T Demand Charge and two Energy Charges – a Non-CPP Energy Charge and a CPP Energy Charge. The proposed S&F Charges and Distribution Demand Charges for Schedules SG-CPP and PG–CPP are equal to the corresponding charges in Schedules SG and PG, respectively. Schedule TG–CPP customers will continue to be assessed their individually determined S&F Charges specified in Schedule TG. Likewise, the Non-CPP Energy Charge, which applies to all energy used during hours when the Company has not called a critical period, is set at the Energy Charge in the corresponding standard tariff.

Q. HOW ARE THE RATES FOR CPP SERVICE DIFFERENT FROM THE RATES IN THE STANDARD TARIFFS?

A. In the standard tariffs 100 percent of the G&T capacity costs are collected through the seasonal Demand Charges. For the CPP services the Company proposes to split the collection of G&T capacity costs between the G&T Demand Charge and the CPP Energy Charge.

Q. HOW WAS THIS SPLIT DETERMINED?

A. The proposed split is not based on any targeted percentage breakdown between the Demand Charges and the CPP Energy Charges. Instead, at each service voltage the Company fixed the CPP Energy Charge at the level where we believe customers would have a strong incentive to reduce their usage during critical periods. In other words, the levels of the CPP Energy Charges were set to afford customers the opportunity to realize significant bill reductions by responding to the price signals. This goal necessitated setting the CPP Energy Charges, which are applied for only a few hours each year, at relatively high levels.

Since the CPP rates as a whole are designed to be revenue neutral for the average customer on Schedule SG, PG or TG, the inherent financial risk to customers signing up for the CPP rate is limited. The Company believes we can effectively explain our proposed rate design and rate levels to customers, and that some customers will conclude that the CPP rates offer an attractive value proposition.

Q. HAVE YOU PREPARED AN ATTACHMENT PROVIDING THE DEVELOPMENT OF THESE RATES?

A. Yes. Attachment SBB-6 provides the derivations of the rates – based on the approach I describe above. The resulting breakdown of G&T capacity costs between the G&T Demand Charge and CPP Energy Charge is also provided by service voltage in Attachment SBB-6.

Q. WHY ARE YOU PROPOSING THIS PARTICULAR RATE DESIGN?

A. The goal is to send program participants a strong price signal that G&T capacity costs are driven by the need to provide service when system loads and capacity constraints are the highest. As explained previously, these hours are concentrated in summer weekday afternoons – although capacity constraints can occur in other periods if there is an unusually high incidence of forced outages. By responding to these price signals, customers reduce their loads during periods most critical to the Company.

In contrast, customer-related costs, distribution costs and non-fuel variable costs are largely not driven by loads during the CPP critical periods. The recovery of these costs should mirror their recovery in the standard tariffs.

Q. HOW MANY HOURS WOULD POTENTIALLY BE SUBJECT TO THE CPP ENERGY CHARGE?

A. The Company proposes to charge the CPP Energy Charge for a maximum of 15 days during a year and for no more than 4 hours during any given day. Consequently, the CPP Energy Charge will be applied for no more than 60 hours in any given year. The four hours during any given day must be consecutive and all fall within the eight-hour period of 12:00 p.m. to 8:00 p.m. CPP days are limited to non-holiday weekdays. As illustrated in Attachment SBB-3, this proposed window captures about 99 percent of the annual LOLP.

Q. WILL THE 60-HOUR LIMIT ON ANNUAL CPP HOURS ADEQUATELY COVER THE PERIODS WHEN CAPACITY CONSTRAINTS ARE POTENTIALLY CRITICAL?

A. Yes. The Company's annual LOLP tends to be concentrated during a relatively few hours during the year when loads are the highest.

Q. HOW DOES THE COMPANY PROPOSE TO NOTIFY PARTICIPATING CUSTOMERS OF CRITICAL PEAK PERIODS?

A. Customers who decide to take CPP service can request to be notified via phone, email or text – or through some combination of the three. Customers must provide the Company with the appropriate contact information. The Company will notify customers at least 22 hours prior to a CPP period.

Q. WOULD THIS SERVICE REFLECT DIFFERENCES IN ENERGY COSTS DURING DIFFERENT PERIODS?

A. Yes. All customers would be subject to the same TOU ECA implemented on a mandatory basis for Schedule PG and TG customers.

At some point, there may be a compelling reason to reflect differences in energy costs with more precision. This enhancement could be effected by calling CPP hours for economic reasons (high fuel or purchased energy costs) or by offering traditional Real Time Pricing programs. But with gas prices at relatively low levels, there is relatively less need to focus on energy-related cost differences.

Q. DO THE PROPOSED SCHEDULES SG–CPP, PG–CPP and TG–CPP THAT MR. WISHART SPONSORS REFLECT THE SERVICE PARAMETERS DESCRIBED ABOVE?

A. Yes.

Q. WILL THE COMPANY INCUR ANY MARKETING, COMMUNICATIONS AND ADMINISTRATION, OR IT/BILLING COSTS FOR THIS PROGRAM?

A. Yes. The Company estimates $30,000 of one-time marketing, communications and program administration expenses, $83,000 of annual program administration expenses, and $32,000 of one-time IT/Billing expenses. These expenses are itemized in Attachment SBB-1.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THESE COSTS?

A. The Company believes CPP qualifies as a demand response program within our broader Demand Side Management ("DSM") portfolio. CPP would help the Company achieve our Demand Response Goals (which are expressed as annual MW reductions to system peak demand) that the Commission has established for the Company in 2017 and beyond. Consequently, the Company proposes to track and defer the one-time costs associated with CPP, and ultimately collect them through the Demand Side Management Cost Adjustment ("DSMCA").

Similarly, the Company proposes to collect the ongoing program administration expenses through the DSMCA.

Q. AT WHAT POINT WOULD THE COMPANY REQUEST TO INCLUDE CPP IN ITS DSM PORTFOLIO?

A. The Company plans to include CPP as a demand response program in our next Biennial DSM Plan (the 2017/2018 DSM Plan), which the Company plans to file by the end of the second quarter of 2016. The Company will estimate CPP contributions to our Demand Response Goals beginning in 2017, and will also propose a budget for CPP expenses, as itemized in Attachment SBB-1. These budgeted expenses will be recovered through the DSMCA beginning in 2017. Of course, both the inclusion of CPP in our DSM portfolio and the concomitant cost recovery are ultimately contingent on the Commission's approval of CPP in this proceeding.

Q. IF THE COMPANY PROPOSES TO TREAT CPP SERVICE AS A DEMAND RESPONSE PROGRAM WITHIN THE LARGER DSM PORTFOLIO, WHY IS THE COMPANY REQUESTING COMMISSION APPROVAL OF THE SERVICE IN A PHASE II PROCEEDING RATHER THAN A DSM PROCEEDING?

A. To answer this question we must first consider the array of initiatives included within the Company's DSM portfolio. The bulk of these initiatives are traditional energy-efficiency programs, such as programs that encourage more efficient lighting or motors. These measures are strictly DSM programs; they do not entail or require pricing changes or separate service schedules. Decisions about the array, scope and budgets of these programs clearly belong in DSM proceedings.

A second, smaller component of the Company's DSM portfolio consists of initiatives commonly referred to as "demand response" programs based on the utility's right to curtail a portion or all of a customer's load in exchange for bill credits. The Company currently offers two traditional curtailment programs, ISOC and Saver's Switch®. Again, these initiatives require mandatory load reductions during critical periods. These initiatives are not part of a broader pricing strategy to send enhanced price signals to encourage *voluntary* shifts or reductions in usage. The design and implementation of these programs are also best vetted in a DSM proceeding – or perhaps a separate proceeding dedicated to a specific program.

The third component consists of demand response initiatives that depend on pricing to encourage a more efficient use of energy. The Company currently does not offer any such voluntary pricing programs within its formal DSM portfolio. But this absence of any explicit DSM program in no way suggests that the Company has ignored this fundamental role of pricing. Most rate-design proposals we have offered in Phase II proceedings arguably have some impact on customers' usage. For example, increasing seasonal rate differentials may reduce customers' usage or peak loads during the summer and increase them during the winter. Yet regardless of their impact on customer usage, most rate-design changes are typically not deemed to be "DSM programs." In fact, utility rate-design experts and regulatory commissions considered the impacts of various prices on customer use long before states officially adopted utility-sponsored DSM or "demand response" programs.

Consequently, it is sometimes difficult to determine whether a pricing proposal should be considered part and parcel of a typical Phase II proceeding, considered solely in DSM proceedings, or considered in both.

The Company's proposed CPP service is a good example. A CPP service is a promising vehicle for reducing use during system peak periods, i.e., if implemented properly it should have a direct and pronounced demand response impact. In this respect it falls under the demand response component of a DSM portfolio. But CPP service is also an alternative rate design for utility service. In this respect the service should not be assessed solely on the basis of likely impacts on customer usage. Instead, the service should be evaluated in light of the multiple pricing goals I outlined earlier in my Direct Testimony.

Consequently, I believe the need for CPP is a strategic pricing issue that should be evaluated first in light of the overall pricing strategy that we are articulating in this proceeding and approved or ejected based on whether the Commission agrees with this strategy and CPP's role within it. The more tactical issue of how aggressively CPP should be promoted or pursued can then be evaluated in specific DSM proceedings - considering both overall program budgets and DSM savings goals.

F. Services To Customers With Behind-The Meter Generation And Storage Applications

Q. PLEASE DESCRIBE THE ON-SITE GENERATORS CUSTOMERS HAVE HISTORICALLY INSTALLED.

A. On-site generation in the Company's service territory was historically dominated by relatively large, dispatchable generators operating at relatively high capacity factors. These generators usually supplied service to all or part of a customer's load for most hours of the year. The Company then served the customer's load on the rare occasions when the customer's generation was down for scheduled maintenance or experienced a forced outage.

It is these applications for which Public Service designed our traditional standby service. As the term "standby" connotes, this service was predicated on the assumption that the Company would actually serve the load typically served by the customer's generator on relatively rare occasions. Public Service would be truly standing by - similar to how a peaking unit might stand by to operate during a few critical hours of the year. The rates, terms and conditions in our standby service schedules recognized this assumption of occasional utility service.

Q. HAVE CUSTOMERS RECENTLY BEEN INSTALLING DIFFERENT TYPES OF ON-SITE GENERATION?

A. Yes. While the more traditional generators described above are still with us, to an increasing degree customers are installing behind-the-meter generation that is markedly different. Solar panels are the salient example. On an annual basis, they provide energy at a much lower capacity factor. Moreover, solar panels cannot be effectively dispatched; their production is determined by factors – such as cloud cover and time of day – outside of the owner’s control.

Customers with solar panels do not require traditional backup service. Instead, they require the utility to provide a significant share of their electrical service. Stated differently, they usually require the utility to generate and deliver electricity to them during at least some hours every day. This utility service cannot be properly construed as “standby” service. Instead, the utility is working hand-in-hand with, or “supplementing” on a continual basis, the service provided by the customer’s solar panels.

Of course, there are other potential types of on-site generation such as biomass or hydro-electric applications. The reliability and capacity factors of these generators can vary significantly. In some cases customers with this generation require traditional standby service, while in other cases customers require service on a more frequent or supplemental basis.

Q. ARE THERE OTHER EXAMPLES OF BEHIND-THE METER APPLICATIONS THAT NEED TO BE CONSIDERED WHEN DEVELOPING THE RATES, TERMS AND CONDITIONS OF UTILITY SERVICE?

A. Yes. Batteries and other storage applications are technologies that will probably be deployed more broadly in the future. Behind-the-meter storage applications are not generators in the traditional sense; they essentially optimize - or at least increase the value of - the output of true on-site generation. Nonetheless, customers who install storage applications and operate in parallel with Public Service require different services.

Q. DO THE COMPANY'S CURRENT TARIFFS RECOGNIZE THESE DIFFERENCES IN BEHIND-THE–METER APPLICATIONS?

A. No. The Company currently provides two options. Customers with generators operating in parallel with the Company who are eligible for net metering can be served under Schedule NM and the applicable standard tariff. Customers not eligible for net metering must take service under the standby tariff. This standby requirement applies regardless of whether the customer's generator is dispatchable or generates energy at a relatively low or relatively high capacity factor. As a result, the rates, terms and conditions in the standby schedule can be mis-applied to customers who require a fundamentally different service.

Q. IS THE COMPANY PROPOSING TARIFF MODIFICATIONS TO ADDRESS THIS DEFICIENCY?

A. Yes. While the Company's proposals are by no means a panacea, they will help significantly.

Q. PLEASE DESCRIBE THESE PROPOSALS.

A. First, the Company proposes to differentiate among and define three separate types of services: Standby Service for customers with the more traditional, reliable generators; Supplemental Service for customers with on-site generation who require more continual, complementary service from the utility; and Auxiliary Service for customers with on-site storage who operate in parallel with the

Company's system. Definitions of these services are included in the *General Definitions* section of the proposed Electric Tariff.

Second, the Company proposes to delineate the service schedules available to each service. The Company will offer Supplemental Service under the standard or optional three-part service schedules – to the extent customers are either required to or opt to take service under such schedules. Customers who are not net metered and choose not to take service under a service schedule with a three-part rate design must enter into a "buy-all, sell-all" arrangement with the Company. The Company will serve the customer's entire load under an applicable service schedule. The Company will then separately meter and purchase at our avoided cost any capacity or energy from the customer's generator. Customers can either opt for the standard buyback rates for Qualifying Facilities specified in our Purchase Payment Amount Table or individually negotiate buyback rates.

Q. HOW DOES THE COMPANY PROPOSE TO DETERMINE ELIGIBILITY FOR STANDBY SERVICE?

A. Eligibility will be limited to generators that are not intermittent and are expected to operate at capacity factors of at least 50 percent. Customers with on-site generation not meeting these criteria will be deemed to require Supplemental Service and must take service under the conditions I described above.

Q. WHY DOES THE COMPANY PROPOSE THAT STANDBY SERVICE BE LIMITED TO CUSTOMERS WITH GENERATORS THAT ARE NOT INTERMITTENT AND OPERATE AT CAPACITY FACTORS OF AT LEAST 50 PERCENT?

A. The utility is truly providing “standby service” as explained above only if the customer has some control over the on-site generator and the generator provides energy for a reasonably high number of hours during the year. A minimum capacity factor of 50 percent assures that the generator is operating at least as often as it is not operating. This threshold may be too liberal, i.e., a higher capacity factor threshold could be justified. But a 50 percent threshold seems to be a reasonable, if conservative, means of ensuring that the service is used as intended.

Q. IS THE COMPANY PROPOSING ANY SIGNIFICANT CHANGES TO THE STANDBY SERVICE RATE DESIGN?

A. No. The Company proposes to maintain the basic structure of a monthly G&T Standby Capacity Reservation Fee (“G&T Fee”), a Distribution Standby Capacity Fee (“Distribution Fee”) for service at secondary or primary voltage, a Monthly Usage Demand Charge: Demand Charge (“Usage Demand Charge”), and a Monthly Usage Charge: Energy Charge (“Usage Energy Charge”). Each G&T Fee will be set at 12 percent of the G&T Demand Charge in the comparable full-service schedule and applied to the Contract Standby Capacity. Each Distribution Fee will be set at the Demand Distribution Charge in the comparable full-service tariff and applied to the Contract Standby Capacity. The Usage Energy Charge will be set at the base Energy Charge in the comparable full-service tariff. Finally, the Annual Grace Energy allotment – which establishes when the Monthly Usage Charges apply – will remain at 1,051 hours. All of these proposals mirror the currently approved rate design and billing determinants for standby service.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE TERMS AND CONDITIONS OF STANDBY SERVICE?

A. Yes. The Company proposes two refinements to recover Production Meter Costs and track grace energy on a calendar-year basis. Neither of these refinements affects the basic rate design for standby service. I will address the addition of a Production Meter Charge later in my Direct Testimony, as it is not limited to standby service. I discuss the proposed change related to grace energy below.

Q. WHAT ANNUAL GRACE ENERGY PERIOD IS CURRENTLY SPECIFIED IN SCHEDULES SST, PST AND TST?

A. The Annual Grace Energy Period begins on October 1 of each year and is tracked for 12 consecutive months.

Q. WHAT IS THE PROPOSED ANNUAL GRACE ENERGY PERIOD?

A. The Annual Grace Energy Period will start on January 1 and will be tracked for 12 calendar months.

Q. WHY IS THE COMPANY PROPOSING THIS CHANGE?

A. The Company is proposing this change to make the standby service easier for customers to understand and plan for production through the summer months.

Q. HOW WILL CUSTOMERS' ANNUAL GRACE ENERGY HOURS BE TRANSITIONED FROM OCTOBER 1, 2016, TO JANUARY 1, 2017, WHEN THIS CHANGE IS EFFECTIVE?

A. The Company will prorate customers' grace energy hours for October 1, 2016, to December 31, 2016, from 1,051 annual grace energy hours to 263 hours (1,051*3/12). Once the 263/hours of grace energy have been used in 2016, the customer will be charged for Monthly Usage Demand. Starting on January 1, 2017, the customer will be allocated 1,051 hours of annual grace energy for the calendar year.

Q. WILL THE PROPOSED DISTINCTION BETWEEN STANDBY AND SUPPLEMENTAL SERVICE DISADVANTAGE CUSTOMERS WITH INTERMITTENT OR UNRELIABLE GENERATION?

A. No. It is important to remember that standby service is a double-edged sword in terms of pricing. On the one hand, standby customers pay a monthly G&T Standby Capacity Reservation Fee ("Reservation Fee") that is a small fraction of the G&T Demand Charge they would pay under Schedule SG, PG or TG. But the standby service schedules also impose a Usage Demand Charge on customers who rely more on the utility's service than recognized in the development of the G&T Fee. At some point standby service becomes uneconomical for customers with intermittent generators or generators that operate at poor capacity factors. In contrast, customers who truly require standby service will be able to minimize the occasions on which they are subject to the Usage Demand Charge.

Q. PLEASE EXPLAIN THE COMPANY'S DEFINITION OF AUXILIARY SERVICE.

A. In the *General Definitions* section of our proposed Electric Tariff, the Company defines Auxiliary Service as service to an energy storage resource that is connected in parallel with the Company's electric system.

Q. DOES THE PROVISION OF AUXILIARY SERVICES POSE CHALLENGES?

A. Yes. Consider a customer operating both on-site generation and a battery in parallel with the Company's system. At times the battery may be charging. Either the on-site generator or the utility could be charging the battery. At other times the battery may be discharging energy. This energy from the battery may either serve the customer's load or be exported to the utility system. The various permutations of energy flows and their implications in terms of the required nature and cost of utility service pose a significant challenge.

Q. HOW DOES THE COMPANY PROPOSE TO ADDRESS THIS SERVICE?

A. In the current proceeding the Company proposes only to define Auxiliary Service and designate the terms, conditions and rates under which we will provide the service. Specifically, the Company proposes to place customers requiring Auxiliary Service on ether one of the three standby tariffs or Schedule RD–TOU. Standby service seems to be the best fit for auxiliary customers at this point, since they can presumably control to some extent when the output from their on-site generation is effectively used on-site or delivered to the utility. Since there is no residential standby service, the RD–TOU service is the best alternative for residential customers – as its rate design is sufficiently robust to recover costs reasonably well from a wide variety of customers.

Q. DOES THE COMPANY ENVISION MODIFYING ITS TERMS, CONDITIONS AND RATES FOR AUXILIARY SERVICES IN THE FUTURE?

A. Yes. The Company is still in the early stages of addressing the provision of Auxiliary Service. I anticipate adapting our service over time as we gather more data and conduct additional analyses.

Q. HAVE YOU PREPARED AN ATTACHMENT THAT SUMMARIZES THE APPLICABILITY OF THE COMPANY'S VARIOUS SERVICE SCHEDULES TO STANDBY, SUPPLEMENTAL AND AUXILIARY SERVICES?

A. Yes. Attachment SBB-7 is a matrix of which services (as described above) are available under which service schedules.

Q. ARE THERE ANY OBSERVATIONS YOU WISH TO OFFER REGARDING THIS MATRIX OF SERVICES?

A. Yes. I should emphasize that the Company's proposals in this proceeding regarding Supplemental Service, Auxiliary Service and buy-all, sell-all arrangements in no way diminish a customer's right to net metering. Residential and small commercial customers eligible for net metering can still receive service under Schedule R or Schedule C; they are not required to be on a three-part tariff or take standby service. Likewise, large customers eligible for net metering can take service under Schedules SG, PG or TG.

The Company's proposals are intended to apply only to customers with on-site generation who are ineligible for net metering (or choose for some reason not to be net metered) and require various levels of service from the Company. While such applications may be relatively rare now, they may become more common in the future.

Q. YOU MENTIONED EARLIER THAT THE COMPANY PROPOSES TO ASSESS A PRODUCTION METER CHARGE ON CUSTOMERS WITH BEHIND-THE-METER GENERATION. WHY IS THE COMPANY PROPOSING SUCH A CHARGE?

A. The Commission has determined that the Company can bill customers with Renewable Resources for production meters installed on or after March 21, 2015. This determination is memorialized in Decision Nos. R12-0261 and C12-0606 in the 2012 Renewable Energy Standard ("RES") Compliance Plan (Docket No. 11A-418E) and Decision Nos. R14-0902, C14-1505 and C15-0142 in the 2014 RES Compliance Plan (Proceeding No. 13A-0836E). To maintain consistency and avoid discriminatory treatment of customers that install other types of generation resources connected in parallel with the Company's electric system, the Company is proposing to assess a Production Meter Charge on customers with generators that are not Renewable Resources.

Q. HOW ARE THE PRODUCTION METER CHARGES ASSESSED?

A. The Production Meter Charges are fixed charges billed on a monthly basis.

Q. WHAT COSTS DO THE PRODUCTION METER CHARGES RECOVER?

A. The Production Meter Charges recover the average embedded costs of meters that are dedicated to measuring the output of customers' generators and that the Company owns, maintains, and reads. [2]

Q. FOR WHICH SERVICE SCHEDULES DOES THE COMPANY PROPOSE TO ADD A PRODUCTION METER CHARGE AND WHAT ARE THE LEVELS OF THESE CHARGES?

A. Table SBB-3 below lists the proposed Production Meter Charges by service schedule.

Table SBB-3

Service Schedule	Production Meter Charge ($/Month)
Residential	
Schedule R	1.15
Schedule RD	3.65
Schedule RD-TOU	3.65
Small Commercial	2.55
Large C&I Secondary	9.30
Large C&I Primary	192.00
Large C&I Transmission	*See Note

*Note: for C&I Transmission customers the production meter cost will vary by service voltage and the number of meters. Production meter charges will be calculated individually for each customer when applicable.

[2] Decision No. R12-0261 at ¶33, Proceeding No. 11A-418E (2012 RES Plan).

F. Optional TOU Services

1. Overview

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT TOU SERVICE OFFERINGS.

A. In the 2009 Electric Phase II Rate Case, the Commission approved four pilot TOU service schedules. I have referred to three of these schedules previously. They are designated as Schedule STOU, Schedule PTOU and Schedule TTOU, and are essentially analogues to the standard SG, PG and TG services. These TOU schedules feature similar rate designs. The total load under the three tariffs is limited to 20 MW, and the schedules are offered on a first-come, first-served basis. The schedules were originally set to expire at the end of 2012, but have been subsequently extended. They are currently set to expire at the end of 2016.

The fourth schedule is open to secondary customers with on-site solar facilities between 10 kW and 500 kW. It is designated as Schedule SPVTOU. The incremental load each year is capped at MW levels specified in the tariff. This offering was not approved as a pilot, so it has no termination date.

2. Schedules STOU, PTOU & TTOU

Q. HOW DOES THE RATE DESIGN FOR SCHEDULES STOU, PTOU AND TTOU DIFFER FROM THE RATE DESIGN APPLIED TO THE STANDARD SCHEDULES?

A. The same S&F Charge, base Energy Charge and Distribution Demand Charge apply to both the standard and TOU schedules. The only significant difference is that the standard schedules recover fixed G&T costs through a seasonal Demand Charge, while the TOU offerings recover these same costs through on- and off-peak Energy Charges. The on-peak Energy Charges recover more transmission and generation fixed costs per unit than the off-peak Energy Charges.

Q. HOW MANY CUSTOMERS CURRENTLY RECEIVE SERVICE UNDER THE TOU SCHEDULES?

A. Two customers are on Schedule STOU and two customers are on Schedule PTOU. No customers are on Schedule TTOU.

Q. HAS THE COMPANY ESTIMATED THE IMPACT OF THE TOU SCHEDULES ON THE COMPANY'S REVENUES?

A. Yes. Mr. Garretson sponsors and supports this analysis.

Q. DOES THE COMPANY BELIEVE THESE SCHEDULES SHOULD BE EXTENDED AND/OR EXPANDED?

A. The Company believes that the long-term rate design that Ms. Jackson explains renders these services superfluous. A G&T Demand Charge assessed during peak hours provides a better price signal than the time-differentiated energy charges in the TOU schedules. Consequently, the Company proposes to eliminate the TTOU Schedule as of January 1, 2017, and close Schedules STOU and PTOU to new customers as of January 1, 2017.

Q. IS THE COMPANY PROPOSING TO REQUIRE EXISTING TOU CUSTOMERS TO MIGRATE FROM THE TWO SCHEDULES IMMEDIATELY?

A. No. To provide customers with time to prepare for the long-term rate design, the Company proposes to offer the STOU and PTOU Schedules to existing customers through 2019.

The two customers served at primary voltage will probably migrate to the standard PG Schedule – which will already incorporate the long-term rate design the Company endorses as of January 1, 2017. Alternatively, these customers could opt for the CPP Service if they qualified, assuming the service was not fully subscribed.

The two Schedule STOU customers will migrate to the standard SG Schedule – or to the CPP Service if they qualify and the service is not fully subscribed. If Schedule SG does not yet incorporate the long-term rate design by January 1, 2020, then Schedule STOU could potentially be extended until the long-term rate design was implemented.

Q. BASED ON YOU DISCUSSION ABOVE, DO YOU BELIEVE THERE IS A COMPELLING REASON TO EXPLORE OTHER TOU RATE DESIGNS FOR LARGE CUSTOMERS?

A. One of the benefits of the long-term rate design is that it largely eliminates the justification for the types of alternative TOU tariffs. Demand-response tariffs and programs that focus on curtailing load during *actual* critical hours (such as ISOC or Saver's Switch®) or discouraging use during *actual* critical hours (such as the proposed CPP service) better complement this long-term rate design than traditional TOU tariffs.

Nonetheless, at some time there may be a compelling reason to complement the standard tariff with a TOU tariff that refines or fine-tunes the price signals. But the Company proposes no such TOU service in this proceeding.

3. Schedule SPVTOU

Q. PLEASE EXPLAIN THE SCHEDULE SPVTOU RATE DESIGN.

A. The rate design for Schedule SPVTOU is identical to the rate design for Schedule STOU that I explained previously. The only difference between the rate levels is that the SPVTOU Schedule includes a greater differential between on- and off-peak Energy Charges than the STOU Schedule.

Q. GIVEN YOUR PREVIOUS DISCUSSION OF OPTIONAL TOU SERVICES ABOVE, IS THE COMPANY PROPOSING TO ELIMINATE OR CLOSE SCHEDULE SPVTOU?

A. The Company proposes to close the service to new customers on January 1, 2017, but allow existing customers to continue receiving service under the tariff. The schedule should be closed to new customers because it serves no long-term purpose. But existing customers may have assumed the schedule would be offered indefinitely when evaluating the bill savings attributable to their PV installations. The Company proposes to help preserve this assumed economic benefit for existing customers.

G. <u>Demand Ratchet</u>

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT DEMAND RATCHET.

A. In the 2009 Electric Phase II Rate Case, the Commission approved a 50 percent demand ratchet for the Company's SG and PG Schedules, as well as several other services applicable to large customers served at secondary or primary voltage. This 50 percent ratchet is applied only for the purpose of determining the monthly billing demand subject to the Distribution Demand Charge. No ratchet is applied for purposes of determining G&T billing demands. Consequently, the demand ratchet does not affect customers served at transmission voltage.

The demand ratchet is applied by multiplying the customer's highest 15-minute demand over the past 11 months by 0.50. A customer is then billed at the higher of this “ratcheted” demand or the actual peak demand in the current billing period.

Q. CAN YOU PROVIDE EXAMPLES OF HOW THE DEMAND RATCHET WOULD OR WOULD NOT AFFECT A CUSTOMER’S BILL?

A. Yes. Assume a customer’s maximum demand in the current billing period is 100 kW, and that the customer’s highest measured demand over the past 11 months is 150 kW. For purposes of determining the customer’s billing demand, the Company would compare the highest measured demand during the billing period (100 kW) with 50 percent of the customer’s highest measured demand over the past 11 months (150 kW * 0.5 = 75 kW). Since the customer’s measured demand during the billing period exceeds the billing demand derived from applying the ratchet, the customer would be billed for 100 kW. In this case the ratchet would have no practical impact on the customer’s bill.

Now assume a customer’s maximum demand in the current billing period is 100 kW, but that the customer’s highest measured demand over the past 11 months is 250 kW. For purposes of determining the customer’s billing demand the Company would once again compare the actual measured demand during the billing period (100 kW) with 50 percent of the customer’s highest measured demand over the past 11 months (250 kW * 0.5 = 125 kW). Since the customer’s highest measured demand during the billing period is less than the billing demand derived from applying the ratchet, the customer would be billed for 125 kW. In this case the application of the demand ratchet would affect the customer's bill.

Q. IS THE COMPANY PROPOSING TO RETAIN THE CURRENT DEMAND RATCHET?

A. The Company proposes to retain the demand ratchet with one small change that I will explain later. Distribution cost recovery should be pegged in some way to a customer's annual or contractually established noncoincident peak load. Consequently, the billing demand to which the charge is applied should recognize a customer's peak load in prior months. The Company could justify a ratchet higher than 50 percent – particularly since the billing determinants to which the G&T Demand Charges are applied are not subject to any demand ratchet. But given the other issues raised in this proceeding, the Company is not proposing a higher demand ratchet.

Q. HAS THE 50 PERCENT DEMAND RATCHET SIGNIFICANTLY AFFECTED BILLING DEMANDS?

A. In his Direct Testimony Mr. Garretson discusses the impact of the ratchet on demand billing determinants and revenues. In 2013 the ratchet affected the billing demands of about 34.9 percent of Schedule SG customers for at least one month. About 11.2 percent of total Schedule SG customer bills were affected by the ratchet, and the ratchet increased the total Distribution Demand billing determinants of Schedule SG customers by about 2.2 percent. The corresponding percentages for Schedule PG customers were 31.5 percent, 10.8 percent and 2.8 percent, respectively.

Although the aggregate impact of the demand ratchet on class billing demands may be small, its application allows us to recover a reasonable share of distribution costs from customers who demonstrate significant fluctuations in their peak demands over the course of a year. In this respect, the ratchet is a valuable tool for promoting equitable cost recovery and should be retained. In fact, the Company may request to increase the ratchet in future proceedings.

Q. EARLIER YOU MENTIONED THAT THE COMPANY IS PROPOSING ONE MINOR CHANGE TO THE DEMAND RATCHET. PLEASE EXPLAIN THIS PROPOSED CHANGE.

A. When applying the demand ratchet the Company proposes to identify the customer's maximum peak load during the previous 12 months rather than the previous 11 months. This change better comports with the logic in the Company's billing system and does not disadvantage customers – given that the Company must plan for a customer's peak load even if it occurs less than once per year.

H. <u>Time Of Use ECA</u>

Q. PLEASE DESCRIBE THE CURRENT TOU ECA.

A. The TOU ECA includes on- and off-peak charges. The on-peak charge applies to all use during non-holiday weekdays from 9 a.m. to 9 p.m. The off-peak charge applies to use during all other hours. The ratio of on-peak to off-peak charges is equal to the ratio of on-peak to off-peak system marginal energy costs. This ratio is updated annually.

All Schedule PG and TG customers are assessed the TOU ECA. Schedule SG customers with measured demands of at least 300 kW can opt for the TOU ECA.

Q. AS PART OF ITS PREPARATION FOR THIS PROCEEDING, DID THE COMPANY EVALUATE THE REASONABLENESS OF THE ON-PEAK AND OFF-PEAK PERIODS USED FOR THE TOU ECA?

A. Yes. The Company evaluated whether the definition of the on-peak period should be modified by estimating hourly marginal energy costs for the years 2016 through 2020. This evaluation confirmed that the current on-peak period is appropriate.

Q. DOES THE COMPANY PROPOSE TO RETAIN THE TOU ECA?

A. Yes. Even with declining gas prices, the TOU ECA continues to send an important price signal that reflects differences in marginal energy costs between on-peak and off-peak periods. In fact, the Company envisions including a TOU ECA as part of our long-term rate design.

Q. DOES THE COMPANY PROPOSE ANY CHANGES TO THE TOU ECA TERMS AND CONDITIONS?

A. Yes. The Company proposes to lower the eligibility threshold for SG customers from 300 kW to 100 kW. The Company believes that ultimately all SG customers should be assessed the TOU ECA. Until that time, we propose to allow a greater percentage of SG customers to voluntarily opt for the TOU ECA

VI. UPDATED LOSS STUDY

Q. PLEASE EXPLAIN THE PURPOSE OF A "LOSS STUDY"?

A. I am not an engineer, but will provide a high-level explanation. Not all of the useful energy generated at a power plant is available to end-use customers. Some of this useful energy is in effect "lost" in its delivery and transformation and is unavailable to customers. Moreover, these losses are cumulative down to service voltage. In other words, fewer losses are incurred to serve a large manufacturing plant served at transmission voltage than to serve a residential customer served at secondary voltage. For example, for each 100 kWh of useful energy delivered to a large industrial customer a utility may need to generate 102 kWh. But for each 100 kWh of useful energy delivered to a residential customer, the utility may need to generate 108 kWh.

Utilities usually try to account for losses not only when developing their total cost of service, but also when allocating costs to customers at various service voltages. Public Service is no exception; we have historically recognized losses when allocating costs between wholesale and retail customers in Phase I rate cases, when developing cost adjustments or riders for retail customer at various service voltages, and when conducting a CCOSS – such as we are providing in this proceeding.

Q. HAS THE COMPANY RECENTLY CONDUCTED AN UPDATED STUDY OF ITS LINE LOSSES?

A. Yes. As a result of a proceeding before the Federal Energy Regulatory Commission involving transmission service to our wholesale customers (Docket No. ER12-1589-000), the Company agreed to conduct a study of electric system line losses. The Company engaged Siemens Industry, Inc., Siemens Power Technologies International ("Siemens") to conduct this study. The final version of this study is entitled *Electric System Loss Analysis Prepared for Public Service Company of Colorado* ("Loss Study"). This Loss Study is provided as Attachment SBB-8.

Q. IS THERE ANYTHING IN PARTICULAR YOU WISH TO POINT OUT ABOUT THIS STUDY?

A. Yes. Public Service has historically developed one set of loss factors to apply to apply to both energy-related costs – such as fuel costs – and capacity-related costs – such as the fixed costs of power plants. This set of loss factors was based on an analysis of average energy losses. But some components of system losses increase as the demands customers place on the system increase. When planning its transmission and distribution systems the Company must consider not only average losses over the course of a year, but also losses during the time when customer demand is at its highest.

Siemens recognizes this important difference in its Loss Study by deriving both "energy" and "demand" losses. The Loss Study details the derivation of these demand and energy losses.

Q. PLEASE COMPARE THE LOSSES THE COMPANY CURRENTLY USES AND THE LOSSES IT PROPOSES TO USE IN THIS PROCEEDING.

A. The table below compares the current and proposed loss factors:

Table SBB-4

Delivery Level	Current Loss Factor	Proposed Energy Loss Factor	Proposed Demand Loss Factor
Secondary	1.0259	1.0248	1.0292
Primary	1.0235	1.0207	1.0375
Transmission	1.0256	1.0170	1.0220

Q. DOES THE COMPANY PLAN TO USE THESE UPDATED LOSS FACTORS IN OTHER REGULATORY FILINGS?

A. Yes. The current loss factors are used in a wide variety of rate cases and rider filings. In each application the Company plans to substitute the updated loss factors.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Statement of Qualifications

Scott B. Brockett

I graduated from Otterbein College in 1980 with a Bachelor of Arts degree in English and Economics. I graduated from Miami University (Ohio) in 1981 with a Masters of Arts degree in Economics.

From August 1982 through February 1999 I was employed by the Minnesota Department of Public Service ("Department"), a state agency charged with developing energy policy and representing all customers in utility matters before the Minnesota Public Utilities Commission.

From August 1982 through May 1984 I was an analyst in the Computational Services Unit, where I conducted economic analyses and reviewed telecommunications depreciation filings. From June 1984 through January 1991 I worked in the Energy Unit. My major areas of responsibility were buyback rates for Qualifying Facilities, rate design, embedded cost of service and marginal cost of service.

From January 1991 to August 1994 I held two similar supervisory positions. My primary responsibility was to oversee the Department Staff's advocacy in electric utility matters including general rate proceedings, integrated resource plans, demand-side management programs, and a wide variety of other regulatory issues.

In August 1994 I was promoted to Manager of Energy Planning and Advocacy. In this capacity the responsibilities I assumed as a supervisor were expanded to include natural gas advocacy, the development of state energy policy, and testifying on energy matters before the Minnesota Legislature. In December 1998 I was appointed Acting Assistant Commissioner of Energy. I held this position until February 1999.

From February 1999 to July 2004 I was employed by Consumers Energy ("Consumers"), an investor-owned utility providing natural-gas and electric service in Michigan, as Supervisor of Pricing and Revenue Forecasting. My primary responsibilities were developing prices for Consumers' electric and natural gas services, conducting economic analyses of various service options, evaluating the impact of Michigan's electric open-access program, estimating customer bills, and forecasting natural gas and electric revenue. I also managed Consumers' voluntary Green Power Pilot Program.

During my tenure with the Department I testified on demand-side management, rate design, embedded cost of service, marginal cost of service, and the environmental costs of electric generation. During my tenure with Consumers I testified on gas pricing issues and electric stranded costs.

I joined Xcel Energy as Manager, Gas Pricing and Planning, in July 2004. I was promoted to Director, Regulatory Administration and Compliance in 2008. I assumed my current position in 2014. During my tenure with Xcel Energy I have testified on pricing issues in six general rate cases (Docket Nos. 05S-264G, 06S-656G, 08S-146G, 09AL-299E, 10AL-963G, 11AL-947E, 12AL-1268G, 12AL-1269ST and also in Proceeding Nos. 14AL-0660E and 15AL-135G), on policy issues in proceedings involving electric interruptible rates, customer service, electric Demand Side Management cost recovery and incentives, and steam service, and on cost recovery issues involving the implementation of the Clean Air - Clean Jobs Act, the acquisition of various generating units, and distributed generation.