Q. Please state your name, business address and present position with PacifiCorp dba Rocky Mountain Power ("the Company").

A. My name is Joelle R. Steward. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Director of Pricing, Cost of Service, and Regulatory Operations in the Regulation Department.

Qualifications

Q. Please briefly describe your education and business experience.

A. I have a Bachelor of Arts degree in Political Science from the University of Oregon and a Masters of Public Affairs from the Hubert Humphrey Institute of Public Policy at the University of Minnesota. Between 1999 and March 2007, I was employed as a Regulatory Analyst with the Washington Utilities and Transportation Commission. I joined the Company in March 2007 as the Regulatory Manager responsible for all regulatory filings and proceedings in Oregon. I assumed my current position in February 2012, in which I direct the work of the cost of service, pricing, and regulatory operations groups.

Q. What are your responsibilities?

A. I am responsible for regulated retail rates, cost of service analysis, and regulatory filings and documentation in the Company's six state service territory.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have testified in regulatory proceedings in Idaho, Oregon, Utah, Wyoming, and Washington.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I present the Company's functionalized class cost of service ("COS") study based on the 12 month forecast test period ending June 30, 2015. I also address the Company's proposed rate spread and rate changes for the affected rate schedules.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- First, I present the results of the COS study, including a description of changes in the COS since the last general rate case in Docket No. 11-035-200, and procedures used in the preparation of the study.
- Second, I present the Company's proposed rate spread, which is the allocation of the rate increase to the major customer rate schedules.
- Third, I describe and present the Company's proposed rate changes for the major customer rate schedules.
- Next, I describe and present the Company's proposed Net Metering Facilities Charge for residential net metering customers on Schedule 135.
- Lastly, I present the Company's proposal for a 15 percent increase to the Low Income Lifeline Credit.

Q. What are the Company's objectives in this case in regards to allocating costs and designing rates?

A. The Company's objectives in this case are to implement the proposed rate increase while reflecting cost causation, equity, economic efficiency, revenue adequacy, and minimizing customer impacts. As noted in the Direct Testimony of

Mr. A. Richard Walje, the growth of customer generation and declining usage per customer present challenges to several of these objectives. To address these challenges the Company believes it is necessary to confront the current inconsistency between rate design and the capital-intensive nature of electric utilities, i.e., the fixed infrastructure that is necessary for customers to take service regardless of usage. As discussed later in my testimony, I present proposals that recognize this changing nature of the industry and help achieve the objectives noted above.

Class Cost of Service Study

Q. What are the results from the COS study?

A. Exhibit RMP___(JRS-1) shows the summary of results from the embedded COS study for the State of Utah. It is based on the Company's revenue requirement presented in the testimony and exhibits of Mr. Steven R. McDougal. It summarizes, both by customer group and function, the results of the class cost of service study for the 12 months ending June 30, 2015. Page 1 of Exhibit RMP___(JRS-1) presents results at the Company's June 2013 rate of return assuming current rate levels. Page 2 shows results using the target rate of return based on the requested $76.3 million revenue requirement increase.

Exhibit RMP___(JRS-2) shows the cost of service results in more detail by class and by function. Page 1 summarizes the total COS summary by class; pages 2 through 6 contain a summary by class for each major function; pages 7 through 9 contain a summary by class and major function on a unit cost basis.

The complete functionalized results of operations and embedded class cost of service detail are included as Exhibit RMP___(JRS-3). Also included is a detailed narrative describing the Company's functionalization, classification and allocation procedures.

Changes in Cost of Service Study

Q. Are there any differences between this COS study and the study filed with the Utah Public Service Commission ("Commission") in Docket No. 11-035-200?

A. Yes. The Company has incorporated changes in response to the questions raised regarding consistency between the Company's jurisdictional allocation model ("JAM") and COS study. In the Commission's May 17, 2012 action request in Docket No. 11-035-200, the Commission asked the Division of Public Utilities ("DPU") to investigate the following three items for inconsistencies between the JAM and COS models:

- Relations among cash working capital, interest expense, and income taxes.
- Determination of state income taxes.
- Use of the income to revenue multiplier.

A technical conference was held with interested parties on June 4, 2012 to discuss the questions in the action request, along with a follow-up settlement telephone conference on June 18, 2012. Based on these discussions and its investigation, DPU recommended that the Company modify the class COS study to be consistent with the JAM on these items.[1] Consistent with this recommendation, the Company has modified the COS model to treat the three items noted above in a manner consistent with the JAM.

[1] *See* Docket No. 11-035-200, Pre-filed Direct Testimony for Mr. Artie Powell, June 22, 2012, p. 35.

Description of Cost of Service Study Procedures

Q. Please explain how the COS study was developed.

A. The COS study uses the results from Mr. McDougal's Exhibit RMP___(SRM-3) and employs a three-step process referred to as functionalization, classification, and allocation. These three steps recognize the way a utility provides electrical service and assigns cost responsibility to the groups of customers for whom those costs were incurred.

Q. Please describe functionalization and how it is employed in the COS study.

A. Functionalization is the process of separating expenses and rate base items according to five utility functions--production, transmission, distribution, retail and miscellaneous.

- The production function consists of the costs associated with power generation, including coal mining, and wholesale purchases.
- The transmission function includes the costs associated with the high voltage system utilized for the bulk transmission of power from the generation source to the load centers.
- The distribution function includes the costs associated with all the facilities that are necessary to connect individual customers to the transmission system. This includes distribution substations, poles and wires, line transformers, service drops and meters.
- The retail services function includes the costs of meter reading, billing, collections and customer service.
- The miscellaneous function includes costs associated with demand-side

management, franchise taxes, regulatory expenses, and other miscellaneous expenses.

Q. Describe classification and explain how it is used by the Company in the COS study.

A. Classification identifies the component of utility service being provided. The Company provides and customers purchase service that includes at least three different cost components: demand-related, energy-related, and customer-related. Demand-related costs are incurred by the Company to meet the maximum demand imposed on generating units, transmission lines, and distribution facilities. Energy-related costs vary with the output of a kWh of electricity. Customer-related costs are driven by the number of customers served.

Q. How does PacifiCorp determine cost responsibility between customer groups?

A. After the costs have been functionalized and classified, the next step is to allocate them among the customer classes or rate schedules. This is achieved by using allocation factors that specify each class' share of a particular cost driver such as system peak demand, energy consumed, or number of customers. The appropriate allocation factor is then applied to the respective cost element to determine each class' share of cost. A detailed description of the Company's functionalization, classification and allocation procedures and the supporting calculations for the allocation factors is contained in my workpapers. To the extent possible and consistent with prior Commission direction, the COS study treats and allocates costs among customer classes on a consistent basis with the way the Company's shared system costs are allocated to each state in the jurisdictional allocation model.

Q. How are generation and transmission costs apportioned among customer classes?

A. The Company classifies production and transmission plant and non-fuel expenses as 75 percent demand-related and 25 percent energy-related. The demand-related portion is allocated using 12-monthly peaks coincident with the Company's total system firm peak. The energy-related portion is allocated using annual class MWh adjusted for losses at the generation level.

Q. How are distribution costs classified and allocated?

A. Distribution costs are classified as either demand-related or customer-related. In this study, only meters and services are considered customer-related with all other costs considered demand-related. Distribution substations and primary lines are allocated using the weighted monthly coincident distribution peaks. Distribution line transformers and secondary lines are allocated using the weighted non-coincidental peak method. The meter allocation factor is developed using the installed costs of new metering equipment for different types of customers.

Q. Please explain how customer accounting, customer service, and sales expenses are allocated.

A. Customer accounting expenses are allocated to classes using weighted customer factors. The weightings reflect the resources required to perform such activities as meter reading, billing, and collections for different types of customers. Customer service expenses are allocated on the number of customers in each class.

Q. How are administrative & general expenses, general plant and intangible plant allocated?

A. Most general plant, intangible plant, and administrative and general expenses are functionalized and allocated to classes based on generation, transmission, and distribution plant. Costs that have been identified as supporting customer systems are considered part of the retail services function and have been allocated using customer factors. Coal mine plant costs are allocated using the energy factor.

Q. How has the Company reflected the allocation of the deferred depreciation expense, pursuant to paragraph 45 in the Stipulation in Docket No. 11-035-200?

A. The deferred depreciation expense in Account 407, which is explained in Mr. McDougal's testimony, has been allocated on factor F151. This factor is derived from total depreciation expenses for each customer rate schedule.

Q. How are costs and revenues associated with wholesale contracts and other electric revenues treated in the COS study?

A. No costs are assigned to wholesale contracts and other electric revenues. The revenues from these transactions are treated as revenue credits and are allocated to customer groups using appropriate allocation factors. Revenue credits reduce the revenue requirement that is to be collected from firm retail customers. This is consistent with treatment of these revenues in the inter-jurisdictional results of operations.

Q. Have you included cost of service results for the Utah special contracts?

A. Yes. Consistent with the 2010 Protocol, the loads and revenues associated with service to special contract customers are included as part of the jurisdictional allocation and included in the revenue requirement. The loads and revenues for special contract customers are also included in the COS study.

Q. Does the COS study include results for partial requirements, back-up service and electric furnace customers?

A. No. Cost of service results were not calculated for these categories of customers, which include one special contract customer and those customers taking service on Schedule 21 and Schedule 31.

Q. Why are these customers removed from the COS study?

A. Partial requirements service and electric furnace customers are not included in the embedded COS study because they do not lend themselves well to this type of analysis. These customers usually have very sporadic loads from year-to-year producing volatile cost of service results depending on whether or not service is required during the hour of monthly system peak. It is the Company's practice to derive prices for partial requirements service from the prices and costs for full requirements service.

Proposed Allocation of Revenue Requirement Increase to Customer Classes

Q. How does the Company propose to allocate the increase across customer classes?

A. The Company proposes to rely on the results of the COS study at the target return on rate base (Exhibit RMP___(JRS-1, page 2 of 2) to guide the allocation of the rate increase to tariff customers.

Q. Please describe Exhibit RMP___(JRS-4).

A. Exhibit RMP___(JRS-4) details the Company's proposed changes to class revenues to be implemented in this case. Based on the forecast 12 month test period ending June 2015, this proposal would result in an overall increase of 4.0 percent to tariff customers in Utah.

Q. Please describe the Company's proposal for the allocation of the revenue requirement.

A. The Company proposes the following allocation of the rate increase for the major customer classes.

Customer Class	Proposed Rate Change
Residential	5.1%
General Service	
Schedule 23	3.1%
Schedule 6	2.1%
Schedule 8	4.1%
Schedule 9	6.1%
Irrigation	6.1%

Q. Please explain the proposed rate spread.

A. The proposed rate spread is designed to reflect cost of service results while balancing the impact of the rate change across customer classes. In order to achieve the revenue requirement target, the proposed rate spread midpoint was set at 4.1 percent. The midpoint is set based on the revenue increase to the rate schedules to which the proposed increase is being applied.

The Company proposes the rate spread midpoint amount for Schedule 8 customers based on their cost of service results which are less than two percentage points from the rate spread midpoint.

For residential customers, the cost of service results indicate that they should receive an increase about four percentage points more than the rate spread midpoint. Based on these results, the Company proposes an increase one percentage point more than the rate spread midpoint, roughly one-fourth of their cost of service percentage difference from the rate spread midpoint.

For Schedule 6, the cost of service results indicate that they should receive an increase about eight percentage points less than the rate spread midpoint. Based on these results, the Company proposes an increase two percentage points less than the rate spread midpoint, roughly one-fourth of their cost of service percentage difference from the rate spread midpoint.

For Schedule 23, the cost of service results indicate that they should receive an increase about five percentage points less than the rate spread midpoint. Based on these results, the Company proposes an increase one percentage point less than the rate spread midpoint, or roughly one-fourth of the cost of service percentage difference from the rate spread midpoint.

For Schedule 9 and Schedule 10, the cost of service results indicate that they should receive an increase about seven to eight percentage points more than the rate spread midpoint respectively. Based on these results, the Company proposes an increase two percentage points higher than the rate spread midpoint, or roughly one-fourth of the cost of service percentage difference from the rate spread midpoint.

For the public streetlighting schedules, based on the cost of service results the Company is not proposing an increase except for traffic signal systems on Schedule 15.

Overall, the Company believes that the proposed rate spread makes appropriate movement to cost of service while mitigating customer impacts.

Q. How has the Company treated special contract customer price changes in this case?

A. For Contract 1, the percentage rate change is set at the overall average increase of 4.05 percent for Utah customers, consistent with terms of the contract.

For Contract 3, rates are set at Schedule 31/Schedule 9 equivalent rates. The dollar and percentage rate changes indicated in this case for this customer reflect their usage at the proposed applicable tariff rates.

For Contract 2, its 2014 prices have been calculated per the terms of the contract and assumed in the present revenues in this case.

Residential Rate Design

Q. What is the Company's proposed residential rate design?

A. The Company proposes to increase the current Customer Charge from $5.00 to $8.00 per month. The Company proposes to collect the balance of the residential price change through proportional increases to the energy charges. The Company also proposes to increase the minimum bill for residential customers from $7.00 per month to $15.00 per month.

Q. Please provide a brief history of the Company's residential customer charge.

A. In 1985, in Docket No. 84-035-01, the Commission developed a policy regarding what costs should be included in the residential customer charge. These included some of the customer-based costs, such as meters, service drops, meter reading, collections and billing. Under this policy the Company's residential customer charge in Utah has consistently been the lowest of the Company's residential customer charge across its six state system. It was set at $1.00 per month in 1985 and is currently $5.00.

Q. What costs should be reflected in the customer charge?

A. The costs that do not vary with usage are appropriate costs to include in determining the level of the residential monthly customer charge. Specifically, at this time the Company proposes that, at a minimum, the customer charge should be determined by taking into consideration the costs functionalized in the embedded COS study that are specified as distribution and retail. As shown on Exhibits RMP **___**(JRS-2) and (JRS-8), the COS study supports a monthly customer charge of $25.00 for these costs. This does not include fixed costs related to transmission and generation, which would increase this amount by an additional approximate $31 per month.

The distribution function includes the radial system that connects the customer to the transmission system. This includes distribution substations, poles and wires, line transformers, service drops and meters. The retail function includes the retail activities associated with customer service, including meter reading, customer accounting, and customer service activities.

While the COS study supports a much higher customer charge, the Company is proposing an increase of only $3.00 in this case, resulting in an $8.00 monthly customer charge, which is a reasonable and a balanced step that takes into account the Company’s pricing objectives identified earlier. The proposed residential customer charge is supported by cost, and helps reduce intra-class cross subsidies while minimizing customer bill impacts.

Q. Why is it important that the customer charge recover a significant portion of the fixed costs of serving customers?

A. In today's environment where we encourage reductions in usage where possible and attempt to achieve efficient usage in all circumstances, it is not appropriate to achieve the recovery of fixed costs through the variable energy components of rates. Doing so creates a conflict for the utility and unclear price signals for customers.

For the utility, when recovery of fixed costs is predominantly through energy rates, as is the case in Utah, the utility has an incentive to sell more kWh in order to recover its fixed costs and is more dependent on weather and changes in usage for recovery of these costs; particularly when a steeply inverted tier rate structure is in place, as in Utah. As discussed in the direct testimony of Ms. Kelcey A. Brown, the Company has seen a drop in usage per customer, which is expected to continue in the future as a result of changing demographics and adoption of more energy efficient technology. This drop in residential usage is a significant contributor to the requested increase in the case, and in particular to the residential class.

While reduced energy usage will directly influence the need for variable resources, such as fuel, and potentially slow the need for new infrastructure, a drop in energy usage results in fewer kWh over which to recover the fixed costs that have been incurred and are necessary to serve customers. For example, distribution system components--substations, primary feeders, secondary lines, line transformers, and service drops--are facilities required to provide a residential customer access to electric service regardless of how much energy is used. The expenses related to maintenance of these facilities are also necessary in order to provide reliable service for any energy user, regardless of size. Additionally, retail service costs, which include the cost of reading meters, answering customer service phone calls, sending customer statements, processing customer payments, and providing online access to customers' accounts are clearly unrelated to usage and are a necessary part of doing business. These costs do not go away when usage levels decrease, whether the decrease is related to weather, behavioral changes or the adoption of energy efficient technology.

For customers, recovery of a significant portion of fixed costs in volumetric energy charges distorts price signals and inequitably places a larger burden of fixed cost recovery on larger users.

Q. Will the proposed increase in the residential customer charge dampen customers' price signals for conservation?

A. No. Even with the proposed increase in the residential customer charge, 90 percent of residential revenue will be recovered through energy rates. This compares to the cost of service that shows that 30 percent of costs are energy related. For an average customer using approximate 700 kWh per month, at the proposed rates 90 percent of the bill is related to energy charges. For a small user half the size of an average user, 80 percent of the bill is related to energy charges; and a high user twice the size of an average user will have 95 percent of the bill related to energy charges. Therefore, all residential customers--and high use customers in particular--will continue to have a strong motivation to conserve or pursue energy efficient technology.

Q. Why does the Company propose to increase the minimum bill to $15 for residential customers in this case?

A. The Company had proposed eliminating the minimum bill in the past few general rate case because the Company believes that the customer charge is the appropriate mechanism to recover fixed costs. However, the minimum bill has been supported by both the Office of Consumer Services ("OCS") and the Salt Lake Community Action Program ("SLCAP") on that basis that it helps the Company recover fixed costs from very low use customers. As a result, the Company is proposing to retain the minimum bill as a reasonable compromise at this time for fixed cost recovery from low use customers rather than a higher customer charge for all residential customers.

In the calculation of a minimum bill, volumetric usage is included. At current rates, the minimum bill is only applied to customers whose monthly usage is at or below approximately 23 kWh for single phase service, and most customers never pay a minimum bill. For the most recent historic period available (12 month period ended June 30, 2013), approximately one percent of all residential customer bills were minimum bills. The proposed minimum bill of $15 helps recover a portion of the fixed costs incurred and necessary to provide service to very low usage customers.

Q. Does the Company propose any changes to the current optional, experimental residential time of day tariff rider, Schedule 2?

A. The Company proposes no change to both the on-peak charge and the off-peak credit for the optional, experimental time of day tariff rider for residential customers.

Low Income Lifeline Credit

Q. Is the Company proposing to increase the Low Income Lifeline Credit on Schedule 3?

A. Yes. The Company is proposing a $1.60 increase in the Low Income Lifeline Credit. This will increase the current credit from $11.00 per month to $12.60 per month, and is shown in Exhibit RMP___(JRS-5). Since the credit level has not been changed since 2009, the Company believes the proposed change to the credit is reasonable to reflect changes in residential rates over time and the proposed increase in this case.

Q. How many customers currently receive the Low Income Lifeline Credit?

A. While the number fluctuates monthly, on average approximately 30,000 customers receive the credit.

Q. Is the Company proposing an increase to Schedule 91, Surcharge to Fund Low Income Residential Lifeline Program, at this time?

A. No. Based on the current collection balance for Schedule 91, an increase in the collection level is not necessary at this time. The Company will continue to monitor the balance and propose revisions in the future as necessary.

General Service & Irrigation Rates

Q. Please generally describe the Company's proposed rate design changes for commercial, industrial, and irrigation customers.

A. Consistent with the Company's proposal in recent general rate cases, the Company does not propose any structural changes to its general service rates. Generally, the Company proposes to apply a uniform percentage change to the billing components in each schedule. The proposed rates are in Exhibit RMP___(JRS-5).

Q. What changes does the Company propose for customers on Schedule 6, General Service - Distribution Voltage?

A. The Company proposes to apply the proposed revenue requirement change by applying a uniform percentage to demand charges and energy charges. We also propose to increase the Customer Service Charge.

Q. What does the Company propose for Schedule 8, Large General Service - 1,000 kW and Over - Distribution Voltage, and Schedule 9, General Service - High Voltage?

A. The Company proposes to increase uniformly the facility, demand and energy charges to reflect the proposed revenue requirement change. We also propose to increase the monthly Customer Service Charge for Schedule 8 and Schedule 9.

Q. What does the Company propose for the optional time of use Schedule 9A, General Service - High Voltage Energy Time of Day Option currently in effect?

A. Schedule 9A is closed to new service. These customers have the ability to shift to

Schedule 9 if they desire. The Company proposes to increase Schedule 9A charges consistent with the proposed changes to Schedule 9.

Q. Is the Company proposing changes to Schedule 31, Back-up, Maintenance, and Supplementary Power?

A. The Company has proposed changes to the applicability and methodology for the calculation of rates in Schedule 31 in Docket No. 13-035-196. The Company is proposing to implement any changes adopted in that proceeding in the compliance filing for this general rate case. This filing includes updated proposed Schedule 31 rates consistent with the proposed methodology in Docket No. 13-035-196 and updated for the proposed revenue requirement increase and rates in this proceeding.

Q. How does the Company propose to implement the rate change for Schedule 23, General Service - Distribution Voltage - Small Customer?

A. The Company proposes to implement the rate change for Schedule 23 uniformly to demand and energy charges, along with an increase to the Customer Charge.

Q. How does the Company propose to implement the rate change for Schedule 10, Irrigation and Soil Drainage Pumping Power Service?

A. The Company proposes to implement the rate change for Schedule 10 uniformly to demand and energy charges and to increase the Customer Service charges.

Q. How does the Company propose to implement the rate change for lighting customers?

A. Based on the cost of service results, the Company does not propose an increase for most lighting customers; however, it does propose an increase for traffic signals. For those customers, the Company designed the rate change by applying a percentage increase to the current rate to achieve the proposed overall revenue change.

Q. Does the Company propose any tariff revisions to lighting schedules?

A. Yes, the Company proposes to revise the burn hours from 3,940 to 4,167 for non-listed luminaries in Schedule 12, Street Lighting, Customer-Owned System. The number of burn hours is an estimate of how long the light burns, and is affected by a number of factors such as visibility to the horizon, photocell operation, and latitude and longitude (location). Based on analysis, the Company has determined that 4,167 burn hours is more accurate than the current 3,940 hours. This results in an increase of approximately 5.8 percent for these customers.

Q. Are there any other tariff changes that the Company proposes?

A. Yes. The Company proposes to cancel Schedule 14, Temporary Service Connection Facilities (No New Service). This schedule has been closed to new service since March 1999 and there are no longer any customers currently taking service on this schedule.

Billing Determinants

Q. Please explain Exhibit RMP___(JRS-5).

A. Exhibit RMP___(JRS-5) contains a summary of present and proposed prices along with the billing determinants used in preparing the pricing proposals in this case. In accordance with R746-700-21.D.1, Exhibit RMP___(JRS-5) provides in a readily identifiable form the Company's proposed price changes for all rate schedules.

Monthly Billing Comparisons

Q. Has the Company provided estimated monthly bill impacts of its proposed rate changes?

A. Yes. Exhibit RMP___(JRS-6) details the customer impacts of the Company's proposed pricing changes. For each rate schedule, it shows the change in monthly bills for various load and usage levels.

Net Metering Facilities Charge

Q. What is the Net Metering Facilities Charge that the Company is proposing in this case?

A. The Company is proposing to implement a monthly facilities charge on Schedule 135, Net Metering Service, for residential customers participating in net metering. The facilities charge is a fixed monthly charge that is in addition to the customer charge on the applicable electric service schedule. The net metering facilities charge will recover the fixed distribution and retail costs that are incurred and necessary to serve net metering customers. For residential customers, the Company is proposing a Net Metering Facilities Charge of $4.25 per month. Exhibit RMP___(JRS-7) shows the proposed revisions to Schedule 135.

Q. Please explain the net metering program in Utah.

A. Under net metering, customers who install distributed generation facilities can offset all or part of their electricity requirements and feed back to the electric grid the electricity the customer's facility generates in excess of the customer's needs at that moment. During a billing period, any excess customer generation is credited against customer kWh usage taken from the utility, resulting in a net bill.

Any additional kWh generated in excess of customer usage during that billing period can be carried over into future billing periods to be applied against customer usage taken from the utility. In effect, under net metering the customer receives a bill credit for the excess electricity that reflects the full retail rate for energy. The Company's net metering program in Utah is offered consistent with Utah Code Ann. § 54-15-101 to 106 and R746-312.

The rate at which customers in Utah are choosing to participate in net metering has been growing dramatically over the last three years; the number of customers installing facilities and participating in net metering has grown by over 30 percent annually. As of November 30, 2013, there were 2,139 customers participating in the net metering program. The generation facilities installed by these participating customers have a total generating capacity of 14,273 kW_{DC}. For 2013 alone, as of November 30, 2013, 592 new customers installed facilities. This exceeds the total installations (453) in 2012 by over 30 percent. With the continued reduction in costs of solar equipment and the existence of the Utah Solar Incentive Program, the Company expects this trend of increased net metering activity to continue.

Q. Why is the Company proposing to apply the Net Metering Facilities Charge to residential customers only?

A. The Company is proposing to apply the Net Metering Facilities Charge to net metering customers taking service under residential Schedules 1, 2 and 3 because the energy rates for these schedules recover a significant portion of fixed costs. As a result, when net metering customers are credited with the full retail energy rate, their contribution to fixed costs are reduced and therefore shifted to other customers. In contrast, for non-residential rate schedules, the demand charges provide a significant portion of distribution and retail fixed cost recovery; therefore, at this time the Company is not proposing a net metering facilities charge for non-residential net metering customers until additional analysis can be completed to evaluate cost shifting impacts by these customers.

Q. Please explain how net metering customers shift costs to other customers.

A. Net metering customers continue to have energy requirements during times when their facility is not generating electricity or when their facility is not generating enough electricity to offset their usage. The net billing process, however, credits every kWh generated by the customer facility in excess of usage (i.e., the kWh fed back onto the grid) against usage at other times during the billing period, or even future billing periods. As a result of the kWh credits, the customer may not pay for all usage they have taken from the Company. Since the full retail rate that the customer is able to offset recovers both variable energy costs along with a significant portion of fixed costs, the net metering customer is not contributing to fixed cost recovery through the usage that the customer’s excess generation is credited against. Since these fixed costs are not recovered from net metering customers, they increase the burden on other customers.

Q. Some might argue that the reduction in billed kWh for net metering customers is similar to reduced usage from energy efficiency. Do you agree?

A. No. Unlike a traditional energy efficiency measure where the load and impact on the grid will predictably be reduced by the implementation of the efficiency measure, customers that install distributed generation have the same, or in many cases an increased impact, on the local distribution facilities. Frequently the Company is required to modify the distribution network in order to effectively minimize negative impacts on the grid and accommodate the new flow of electrons from the customer to the grid. Even in cases where upgrades are not required, the flow of energy back through transformers and onto the grid causes increased wear on the equipment.

Q. What cost components are the Company proposing to include in the Net Metering Facilities Charge at this time?

A. The Company is proposing to reflect only the distribution and retail service costs in the Net Metering Facilities Charge at this time. We believe that this is a good first step in addressing this issue. While additional fixed costs related to generation and transmission are also being incurred by net metering customers and shifted to other customers, we are not proposing a charge that recovers those costs or raising other potential net metering policy implications at this time.

Q. Please explain how the Company calculated the proposed Net Metering Facilities Charge.

A. The calculation of Net Metering Facilities Charge is shown in Exhibit RMP___(JRS-8). The calculation of the residential charge starts with the same average of $25.00 per customer per month from the COS study for distribution and retail costs. This amount is reduced by the proposed customer charge and fixed costs to be recovered through the forecast energy sales to net metering customers in the test period. This results in a $4.25 per customer per month proposed Net Metering Facilities Charge. Since this calculation takes into account the Company’s proposed increase in the residential customer charge, if the customer charge is less than the proposed $8.00 per month, then the proposed Net Metering Facilities Charge will increase in order to recover the fixed costs not in the customer charge.

Q. Why is the Company proposing to implement the Net Metering Facilities Charge now?

A. With the rapid growth in net metering and customer interest in distributed generation, the Company believes it is important to put in place now an appropriate rate structure that better reflects the value of net metering and minimizes cost shifting.

Q. Please summarize your testimony.

A. Consistent with Commission direction, the Company's proposed cost of service study treats and allocates costs among customer classes on a consistent basis with the way the Company’s shared system costs are allocated to each state in the jurisdictional allocation model. The Company’s proposed allocation of the revenue requirement increase is guided by the COS study results and moves all classes towards cost of service. For residential rate design, the Company proposes an $8.00 monthly customer charge, an increase to all energy rates, and a $15.00 minimum bill. This proposed residential rate design balances cost causation, equity, revenue adequacy and customer impacts. The Company is also proposing an increase in the Low Income Lifeline Credit. For non-residential rates, the Company is generally proposing equal percentage increases to all rate components. Lastly, in order to address cost shifting the Company is proposing to implement a Net Metering Facilities Charge of $4.25 for residential customers on Schedule 135. The Net Metering Facilities Charge will recover the fixed costs for distribution and retail service.

Q. Does this conclude your direct testimony?

A. Yes, it does.