BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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IN THE MATTER OF THE APPLICATION
OF PUBLIC SERVICE COMPANY OF COLORADO FOR AUTHORIZATION TO IMPLEMENT A REVENUE DECOUPLING ADJUSTMENT MECHANISM AS A PART OF ITS COLORADO P.U.C. NO. 7-ELECTRIC TARIFF.

DIRECT TESTIMONY OF ALICE K. JACKSON
ON BEHALF OF PUBLIC SERVICE COMPANY OF COLORADO

July 13, 2016
IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AUTHORIZATION TO IMPLEMENT A REVENUE DECOUPLING ADJUSTMENT MECHANISM AS A PART OF ITS COLORADO P.U.C. NO. 7-ELECTRIC TARIFF.

SUMMARY OF THE DIRECT TESTIMONY OF ALICE K. JACKSON

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

In her Direct Testimony, Ms. Jackson describes the Company’s proposed revenue decoupling adjustment (“RDA”) and how it will align the interests of the Company, various interest groups, and customers. Public Service had proposed revenue decoupling in its last electric Phase I rate case in Proceeding No. 14AL-0660E
(“2014 Rate Case”), but the Colorado Public Utilities Commission (“Commission”) decided that the issue would best be addressed in a separate docket that would “enable the Commission to consider the broad implications of a fundamental change for Colorado in rate regulation.”¹ Ms. Jackson presents the Company’s proposal for a similar revenue decoupling mechanism here and identifies several policy matters that the proposed mechanism will address.

Because the Company recovers a significant portion of its fixed costs through the energy charge component of its rates, any reduction in the average use per customer will detrimentally affect the Company’s ability to recover its approved fixed costs. As a result of (1) various policies that reduce annual sales, (2) the Company’s proposal for new energy saving technologies, (3) its proposed Residential Demand-Time of Use (“RD-TOU”) pilot rate,² and (4) the proliferation of distributed generation, the Company’s ability to recover its approved fixed costs will continue to erode. Public Service supports energy efficiency and distributed generation and through this proposal seeks to align its interests with those of its customers and various interest groups. However, without a mechanism to “decouple” the Company’s fixed cost recovery from its sales, the Company will continue to have an economic incentive to increase sales, which is inconsistent with this support and the interests of its customers and the state.

Ms. Jackson explains that the proposed revenue decoupling adjustment will account for changes in the weather-normalized average use per customer and will

¹ Decision No. C14-1331-I, Interim Decision Dismissing Public Service Company’s Proposed Decoupling Mechanism from the Proceeding and Requiring Filing of Corrected Testimony, ¶ 9, pp. 4-5.
² Proposed in the Company’s current Phase II electric rate case, Proceeding No. 16AL-0048E.
result in either a credit or surcharge on customers’ bills to compensate for the Company’s over-recovery or under-recovery of the fixed costs embedded in its approved base rates. Based on recent forecasts, the Company expects that this will amount to less than a 2.2 percent impact on customer bills. Further reductions in average use per customer are likely to result from the deployment of Integrated Volt Var Optimization (“IVVO”), the continued growth of distributed generation, federal efficiency standards, and other societal changes. Company-run conservation programs also impact average use per customer, but the Company proposes to exclude the effect of these programs from the decoupling adjustments. This will be accomplished by subtracting the Commission-approved Demand-Side Management (“DSM”) disincentive offset from any revenue decoupling amounts that would be recovered through the RDA. The RDA will also include an adjustment associated with the Company’s proposed RD-TOU pilot program. The RD-TOU pilot is a voluntary program and is not yet in place. Nonetheless, there is uncertainty associated with the amount of fixed cost recovery that would be realized through the RD-TOU service. The decoupling mechanism will true up any over or under-recovery associated with this pilot program.

The Company’s RDA proposal is limited in scope. Ms. Jackson explains that it will be applied only to the Residential and Small Commercial classes, will not include the impact of weather on customer usage and its application will sunset on December 31, 2022 with residual “true up” occurring through 2023. Although the overall size of the RDA is small, it will fundamentally change Public Service’s economic model and will
allow the Company to continue to support conservation and distributed generation. Furthermore, it will potentially delay future Phase I rate cases.

Ms. Jackson recommends the approval of the Company’s proposed RDA tariff that is included as Attachment SWW-1 to Company witness Mr. Steven W. Wishart’s Direct Testimony.
BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF THE APPLICATION )
OF PUBLIC SERVICE COMPANY OF )
COLORADO FOR AUTHORIZATION TO )
IMPLEMENT A REVENUE DECOUPLING ) PROCEEDING NO. 16A-XXXXE
ADJUSTMENT MECHANISM AS A PART )
OF ITS COLORADO P.U.C. NO. 7- )
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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
PUC NO. 7-ELECTRIC TARIFF WITH
COLORADO PUC NO. 8-ELECTRIC
TARIFF

DIRECT TESTIMONY OF ALICE K. JACKSON

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

3 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

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

13 A. I am testifying on behalf of Public Service.
Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

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

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is tri-fold. First, I provide an overview of revenue decoupling, including what revenue decoupling is, the public policy justification for implementing a revenue decoupling mechanism, and whether such mechanisms have been adopted by other public utility commissions in the United States (“U.S.”), as well as by the Colorado Commission.

Second, I describe our proposed Revenue Decoupling Adjustment (“RDA”) and explain how the proposal helps support customer-focused programs. Features of the proposed mechanism include:
• an adjustment for the level of fixed cost recovery for changes in the
weather-normalized average use per customer ("UPC");
• a symmetrical design that would allow the Company to recoup the
lost fixed cost revenues if UPC declines, and require the Company
to refund excess fixed cost revenues back to customers if UPC
increases;
• an adjustment to account for variations in fixed cost recovery
associated with the Company’s Residential Demand – Time of Use
("RD-TOU") pilot that is proposed in our Phase II electric rate case,
Proceeding No. 16AL-0048E ("2016 Phase II");
• the removal of the impact of weather, as its inclusion could lead to
rate impacts that are unacceptably large from year to year; and
• the sunset of the rider on May 31, 2023.

Finally, I will also address the relationship between revenue decoupling
and the rate of return that the Commission has established for Public Service.

Q. ARE OTHER COMPANY WITNESSES SUPPORTING THE COMPANY’S
PROPOSAL TO IMPLEMENT A REVENUE DECOUPLING MECHANISM IN
THIS PROCEEDING?
A. Yes. In addition to myself, Mr. Steven W. Wishart, Manager of Pricing and
Planning for Public Service, is submitting testimony in which he details the
Company’s proposed RDA tariff. He provides examples of how the adjustments
will be calculated and provides a forecast of future adjustments under the RDA based on the Company’s current forecast of average use per customer.

Ms. Jannell E. Marks, Director of Energy and Demand Forecasting for XES, is providing testimony in which she reviews the historical trends in average use per customer and presents a forecast of how that usage is expected to change in the coming years. Ms. Marks also discusses the weather normalization calculations that will be applied to annual energy usage in order to calculate the RDA.

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

A. No.

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

A. I recommend that the Commission grant our Application for authorization to implement the RDA tariff. The adoption of the RDA will allow Public Service to break the link between energy sales and fixed cost recovery and will align Public Service’s economic interests with the interests of our customers and Colorado’s public policy goal of supporting the development of distributed generation. While revenue decoupling is indeed a fundamental change in our economic model, the expected customer impact is anticipated to be quite small, less than 2.2 percent under our current forecast. This modest rate impact is achieved by limiting the
scope of our proposal to changes in weather-normalized average use per customer.

Many state public utility commissions have used revenue decoupling to align utility and customer interests, and approval of a revenue decoupling mechanism would make Public Service financially indifferent to changes in average use per customer and remove the disincentive associated with programs or policies that reduce sales to our customers. This includes the Company's soon to be proposed Integrated Volt Var Optimization ("IVVO") project and the promotion of distributed generation under the Colorado net metering policies.

Finally, I recommend that the Commission find that the Company's proposed revenue decoupling adjustment does not impact our Commission authorized Return on Equity ("ROE"). The design of the Company's proposed RDA, such as its symmetrical nature, mitigates any impact of the RDA as a factor to be considered in evaluating the appropriate ROE in future rate cases. Further, because the proposed RDA removes the impact of weather from the decoupling adjustment, the majority of sales volume risk remains with the Company and, consequently, there should be little change in the Company's overall risk profile. If the Commission disagrees, I recommend that this issue be addressed in Public Service's next Phase I rate case.
II. BACKGROUND OF APPLICATION AND RELATIONSHIP TO OTHER PROCEEDINGS

Q. MS. JACKSON, WHY IS THE COMPANY FILING ITS DECOUPLING PROPOSAL AS A STAND-ALONE APPLICATION, RATHER THAN AS PART OF A COMPREHENSIVE RATE CASE?

A. Public Service had proposed revenue decoupling in its last electric Phase I rate case in Proceeding No. 14AL-0660E (“2014 Rate Case”), but the Commission decided that the issue would best be addressed in a separate docket that would “enable the Commission to consider the broad implications of a fundamental change for Colorado in rate regulation.”

Q. IS THE COMPANY PROPOSING THE SAME REVENUE DECOUPLING MECHANISM IN THIS APPLICATION AS IT DID IN THE 2014 RATE CASE?

A. The decoupling mechanism proposed in this Application is similar in many respects, but not identical, to the decoupling mechanism we proposed in the 2014 Rate Case. Like to the revenue decoupling mechanism proposed in the 2014 Rate Case, which was presented through the direct testimony of Company witness Mr. Scott B. Brockett, we are proposing the revenue decoupling mechanism here to apply only to Residential (Schedule R) and small Commercial (Schedule C) customers. Under both proposals, annual adjustments to collect or return revenues would be made as necessary to assure the Company’s recovery of fixed costs underlying its approved base energy charges, calculated based on

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the change in the weather-normalized average use per customer applicable to residential and small commercial customer classes. Based on this annual change, the resulting under- or over-recovery of the approved level of fixed costs included in the energy component of the Company’s base rates would be used to develop either a surcharge to collect the under-recovered amounts from customers or a credit to return the over-recovered amounts to customers. Under the particular decoupling mechanism proposed in the 2014 Rate case, the decoupling adjustment surcharge or credit to base rates was to be made through the General Rate Schedule Adjustment (“GRSA”), rather than through a separate rate rider.

Q, WHY DID THE COMMISSION DISMISS THE COMPANY’S DECOUPLING PROPOSAL FROM THE 2014 RATE CASE?

A. In Decision No. C14-1331-I issued November 5, 2014 in the 2014 Rate Case, the Commission recognized that it could consider the Company’s decoupling proposal in the context of that Phase I rate case, but found that “the record in this proceeding shows that there are different approaches to implementing revenue decoupling and the choice of a decoupling mechanism depends on the state’s broader policy goals.” The Commission concluded as follows:

9. Therefore, we find that Public Service’s suggestion of a separate proceeding to address decoupling is reasonable and efficient based on these circumstances, including the statements of the parties that implementing a decoupling mechanism will have broad policy implications. By considering decoupling in a separate proceeding, the
Commission and interested parties will have an opportunity to address policy objectives for a decoupling mechanism before engaging in a discussion about the merits of the design of a particular decoupling mechanism. We find that, in this instance, considering a decoupling mechanism in a separate proceeding will serve the public interest and enable the Commission to consider the broad implications of a fundamental change for Colorado in rate regulation, including, without limitation, the effects of revenue decoupling on related proceedings.

Decision No. C14-1331-I, pp. 4-5.

Q. DID THE COMMISSION DIRECT THE COMPANY TO PROVIDE ANY SPECIFIC INFORMATION IN THE EVENT IT CHOSE TO FILE A SEPARATE APPLICATION?

A. Yes. The Commission provided the following directives in paragraph 12 of Decision C14-1331-I:

12. We do not require Public Service to file an application to implement revenue decoupling by this Decision. However, an application must account for regulatory mechanisms and rate structures affected by revenue decoupling. By way of example, Public Service should consider whether the application should be filed before the Company’s next Electric Resource Plan filing. An application to implement a revenue decoupling mechanism must address how and whether the mechanism will affect current and upcoming proceedings.

Q. HOW DOES THIS APPLICATION IMPACT OTHER PROCEEDINGS?

A. This Application has one significant impact upon another proceeding. One of the factors that are driving our revenue decoupling Application is the loss of sales that will result from the Integrated Volt Var Optimization (“IVVO”) program that is part of the Advanced Grid Intelligence and Security (“AGIS”) Certificate of Public
Convenience and Necessity ("CPCN") that will be filed shortly after this Application. As I explain later in my testimony, in the event that our Application for revenue decoupling is denied, Public Service would no longer pursue the IVVO project due to its negative impact on the Company’s financial returns. Without revenue decoupling, IVVO will lower annual revenue and significantly decrease our opportunity to earn our Commission authorized rate of return. The result of this Application is not expected to have a significant impact on any of our other current or near term proceedings.

Conversely there is one case that can significantly impact this proceeding. Our current Phase II Rate Case, Proceeding No. 16AL-0048E, includes a proposal for a Residential Demand Time of Use ("RD-TOU") rate. The effect of that proposed pilot rate is included in our proposed calculation for the revenue decoupling adjustment. To the extent that proposed pilot rate is denied or an additional pilot rate is approved, Public Service would seek to amend this Application to ensure that any Residential or Small Commercial pilot rates that may result in either under or over recovery of its approved fixed cost revenues are included in the revenue decoupling adjustment.
III. OVERVIEW OF REVENUE DECOUPLING

Q. WHAT IS REVENUE DECOUPLING?

A. Revenue decoupling is a regulatory tool that breaks or reduces the link between the quantity of energy that a utility sells and the amount of net revenue that it collects. By breaking or reducing this link, a utility’s recovery of fixed costs is no longer tied or is less tied to its volumetric throughput. A decoupling mechanism will typically identify a target level of revenues or sales for a utility. The target level may be an absolute dollar level, an average energy use per customer from which a revenue impact is derived, or an alternative target that is based on pre-established parameters or calculations. Then, actual revenues are compared to the target levels to calculate the over- or under-collection for the period. The under-collection is recovered from customers, or the over-collection is refunded to customers, in a subsequent period through a decoupling surcharge or credit. The result is that the decoupling mechanism makes the utility whole with respect to its recovery of the target level of revenues and, therefore, more indifferent to the changes in the level of volumetric sales.

Q. WHAT ARE SOME OF THE PUBLIC POLICY REASONS FOR ADOPTION OF A REVENUE DECOUPLING MECHANISM?

A. Public utilities are just like any other business in that, when sales increase, so do potential profits.\(^4\) This creates an incentive for utilities to maximize sales, an

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\(^4\) In the context of regulated public utilities, the term "profits" means that portion of the utility's revenues that exceeds the level required for the utility to cover all of its operating expenses, service its debt, and earn its authorized return on equity.
activity that is typically recognized to not be in the public interest. Consequently, utilities are financially discouraged from providing customer programs that may result in lower sales. Utilities are also economically harmed by state and federal energy efficiency standards that reduce average energy use by customers. This situation is a natural result of the economic structure of regulated utilities. Unfortunately, it sometimes puts the utility’s economic interest at odds with customer preferences and, at times, public policy.

With the more recent technological advancements in combination with existing rate design, this energy efficiency type issue has expanded to another area. To the extent that the public policy of a state is to encourage adoption and integration of distributed energy resources, the utility is also seeing a decline in recovery of its fixed costs. Thus, a utility’s economic interest is also at odds with adoption of these technologies.

A decoupling mechanism addresses this paradox by breaking or reducing the link between energy sales and fixed cost recovery. With a decoupling mechanism, the regulating authority can identify the appropriate level of cost recovery and ensure that the utility has a fair opportunity to achieve that level of recovery and avoid subsequent rate case proceedings to the extent revenues lag below the target level.

Q. IS DECOUPLING THE ONLY WAY OF FIXING THIS RELATIONSHIP?

A. Yes and no. A customer’s rate design also assists with some of the utility’s economic disincentive for technology adoption but at the same time, making a
change to rate design across an entire system is another key opportunity to utilize a decoupling mechanism. However, for energy efficiency adoption, between rate cases, decoupling or a disincentive offset of some sort is necessary.

Q. HOW DO YOU DEFINE FIXED COSTS IN THE CONTEXT OF REVENUE DECOUPLING?

A. Here, I use the term fixed costs to refer to costs that do not vary as a result of customer usage in the one- to five-year time frame. This encompasses fixed distribution costs, transmission costs, and production costs. In the longer term, distribution, transmission, and production costs may indeed change in response to customer peak loads but in the short term, these costs are generally accepted to be fixed. Fuel and non-fuel variable Operations and Maintenance ("O&M") costs, on the other hand, are variable costs that vary directly with changes in customer energy usage.

Q. HOW DOES PUBLIC SERVICE RECOVER ITS FIXED COSTS?

A. We recover our fixed costs through a combination of fixed monthly service and facilities ("S&F") charges, cents per kilowatt hour ("kWh") energy charges, and dollar per kW-month demand charges. For Residential and Small Commercial customers, fixed costs are primarily recovered through the kWh energy charge. For Commercial and Industrial customers, fixed costs are recovered through either kilowatt ("kW") demand charges or S&F charges.
From the perspective of charging customers for the costs they impose and sending proper price signals, it is somewhat counter-intuitive that utilities recover some of their fixed costs through variable charges. For example, Figure AKJ-1 below illustrates that approximately 83 percent of the total allocated costs in base rates for Residential and Small Commercial customers are fixed, while only 6 percent of total costs are recovered through fixed charges.

**Figure AKJ-1 – Residential and Small Commercial Cost and Cost Recovery**

Q. **ARE THERE DIFFERENT WAYS IN WHICH A REVENUE DECOUPLING MECHANISM MAY BE DESIGNED?**

A. Yes. A revenue decoupling mechanism can be designed in various ways based on the objectives and policy goals that it is intended to address. These design alternatives include the following:

- The revenue decoupling mechanism can target either a specific revenue level or a level of energy sales.
• If a sales target is selected, the mechanism can be calibrated for changes in total energy use for a customer class or energy UPC within the class.

• The revenue decoupling mechanism may be applied to all customer classes or a subset of customer classes.

• The decoupling mechanism can be applied to all changes in actual sales during a base period or only changes in weather-normalized sales.

• The decoupling mechanism can be assessed such that the adjustment derived for a given class is charged to or recovered from that specific customer class. Alternatively, the net dollar amount from all customer classes can be combined into a single adjustment and billed or credited to all classes more or less uniformly.

• The magnitude of the revenue decoupling rate adjustment can be unlimited or capped at a certain threshold.

• Such a cap can allow for the amounts above the established threshold to be deferred for recovery in a future year (soft cap) or not allow for any such deferred recovery (hard cap).

In addition to these basic design decisions, there are a number of second-level implementation issues to address.
Q. **HOW COMMON ARE REVENUE DECOUPLING MECHANISMS?**

A. While the concept of revenue decoupling dates to the 1980s, there appears to be a recent resurgence of interest among gas and electric utilities. One study prepared by Pamela Morgan of Graceful Systems LLC concluded that, between 2009 and 2012, the number of gas distribution utilities with decoupling mechanisms increased from 28 to 52, and the number of electric utilities with decoupling mechanisms increased from 12 to 25.

In 2014, the National Resource Defense Council produced the following map (Figure AKJ-2) of the U.S. indicating states that have approved revenue decoupling mechanisms for electric utilities. The map shows that at the time 17 states had approved some type of revenue decoupling for electric utilities.

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5 Colorado is shown as having pending electric decoupling in September of 2014. Presumably, this is related to Public Service’s decoupling proposal in its 2014 Phase I Rate Case in Proceeding No. 14AL-0660E, which was subsequently dismissed by the Commission. Minnesota is also shown as having pending revenue decoupling. This was a decoupling mechanism proposed by Northern States Power Company, a subsidiary of Xcel Energy, which was subsequently approved by the Minnesota Public Utilities Commission in Docket No. E002/GR-13-868 in August 2015.
Q. HAS THE COMMISSION EVER APPROVED A REVENUE DECOUPLING MECHANISM FOR PUBLIC SERVICE?

A. Yes. In Docket No. 06S-656G, the Company’s 2006 Phase I Gas Rate Case, the Commission approved a Partial Decoupling Rate Adjustment (“PDRA”) tariff for the Company’s gas department applicable to residential gas customers. In Decision No. C07-0568 in that proceeding, the Commission modified the PDRA mechanism that had been agreed to among the parties to the settlement entered in that case. Due in part to those modifications, the resulting mechanism never
led to any actual rate adjustments and the Company was permitted to terminate it in a subsequent Phase I Gas Rate Case, Proceeding No. 10AL-963G.

The Commission also considered decoupling in the context of Public Service’s proposed implementation of DSM programs in a proceeding established for that purpose 25 years ago. In Docket No. 91A-480EG, and continuing into proceeding in Docket No. 93I-199EG, the Commission recognized that Public Service’s financial incentives under traditional regulation were inconsistent with its promotion of cost-effective DSM programs and that a decoupling mechanism offered a potential solution to reduce underlying disincentives. The Commission examined three different types of decoupling mechanisms in Docket No. 93I-199EG, but ultimately found insufficient support to adopt any of them.

Q. **DO ANY OF XCEL ENERGY’S OTHER OPERATING COMPANIES HAVE ELECTRIC DECOUPLING MECHANISMS?**

A. Yes. Public Service’s sister utility in Minnesota, Northern States Power Company (“NSP”), was authorized to place into effect a three-year decoupling pilot mechanism that adjusts for the over- or under-recovery of non-fuel costs for Residential and Small Commercial customers in their Minnesota jurisdiction. The NSP decoupling mechanism is similar to Public Service’s proposal in that the adjustment is based on average use per customer. However, the NSP mechanism is different in that it does not use weather normalized data. Instead the impact of weather is included in the revenue decoupling adjustment, which
can lead to much bigger impacts on customers. The NSP mechanism is also similar in that the over- or under-recovered amount is collected or refunded in the following year as a cents per kWh rider applied to the residential and small commercial classes.
IV. PUBLIC SERVICE’S PROPOSED REVENUE DECOUPLING MECHANISM

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. In this section of my testimony I explain the Company’s RDA and then I discuss the reasons why Public Service is proposing such a mechanism at this time.

A. THE REVENUE DECOUPLING PROPOSAL

Q. PLEASE SUMMARIZE THE COMPANY’S REVENUE DECOUPLING PROPOSAL.

A. The Company’s proposed RDA tariff provides for separate revenue decoupling adjustments for two rate classes; one for the Residential class and another for the Small Commercial class. The Residential decoupling adjustment will have two components. The first accounts for changes in the weather-normalized average use per customer for customers on our base Residential rate (Schedule R). The second component accounts for the RD-TOU pilot that was proposed in our 2016 Phase II. This adjustment reconciles the fixed costs collected through the new RD-TOU rate with what the fixed cost recovery from the RD-TOU customers would have been under the standard Residential (“Schedule R”) tariff. These two adjustments are combined for a total, and then the DSM disincentive offset is subtracted from that total. The remaining net amount is passed through the Schedule R and RD-TOU rates in the form of a surcharge or credit in the subsequent year.
The Small Commercial ("Schedule C") decoupling adjustment also accounts for changes in weather-normalized average UPC and is reduced by the class's share of the DSM disincentive offset. This revenue decoupling surcharge or credit is applied only to the Schedule C class.

Company witness Steve Wishart provides additional details on how the proposed RDA will be calculated and other details related to the implementation of the RDA and administration of the tariff.

Q. WHY IS PUBLIC SERVICE NOT PROPOSING REVENUE DECOUPLING FOR LARGE COMMERCIAL AND INDUSTRIAL CUSTOMER CLASSES?

A. We have not identified the same issues related to the Company's fixed cost recovery within our Commercial and Industrial rate classes. Rates for these customers are based on demand charges, and demand billing determinants do not face the same erosion applicable to average use per customer for the Residential and small Commercial classes. Also, as I discuss further below, rooftop solar does not have a significant impact on fixed cost recovery for large customers who are on tariffs with demand charges. Finally, Public Service is not planning any significant changes to the rate design for these customers. Thus, we are not facing significant revenue uncertainty like we anticipate with residential customers migrating to from tariffs without demand charges to tariffs with demand charges. Issues may arise in the future that call for revenue decoupling of large commercial and industrial customers. But at this time, Public Service is not including these customer classes in our proposal.
Q. WHAT IS THE PROPOSED TERM FOR THE RDA?

A. We are proposing an initial term of five years, with adjustments being based on UPC and fixed cost recovery data for the years 2017 through the end of 2021. In light of the proposed changes in our 2016 Phase II Rate Case, as explained in more detail below, this time period represents the transition between our existing rate structures for the Residential and Small Commercial classes and the potential future rate design. During this period, Public Service will continue to risk under-recovery of fixed costs as a result of programs and policies that reduce the average use per customer. In the event that implementation of the future Residential and Small Commercial rates is delayed or significantly modified, the Company may seek to extend the effective period of the RDA.

We are proposing that the first year of the RDA be 2017. Based on a 2017 base year, we will calculate the change in actual weather normalized average use per customer at the end of that year and implement the 2017 credit or surcharge from mid-2018 through mid-2019. This process would continue on an annual basis until the RDA for the final base year is calculated at the end of 2021 and applied to customers' bills from mid-2022 through mid-2023.
Q. IS THE PROPOSED RDA SYMMETRICAL?

A. Yes. If average use per customer falls from one year to the next, the RDA will allow the Company to collect the shortfall in fixed cost recovery in the following year. Likewise, if average use per customer increases, a credit will be given to customers. We believe this symmetry is an important aspect of revenue decoupling. The goal is not to enrich the Company, but rather to ensure that we recover the Commission’s approved level of fixed costs. This goal applies to all scenarios, whether we under-recover or over-recover those costs.

Q. WHY IS THE COMPANY’S RDA PROPOSAL BASED ON WEATHER-NORMALIZED AVERAGE USE PER CUSTOMER?

A. We believe that excluding the impact of weather from the RDA is a very important aspect of our proposal. Energy usage is highly dependent upon weather. Including the effects of weather in the RDA may lead to unacceptably large rate impacts. Weather-related variation in sales has been a part of our business risk for a long time. The Company is well versed in management of this risk and is willing to accept weather risk because of its symmetric nature (i.e., cooler-than-normal weather and warmer-than-normal weather are evenly distributed.) The RDA is needed to neutralize the negative economic effects of specific programs and policies that would otherwise interfere with the Company’s opportunity to recover our Commission-approved fixed costs.
B. SUPPORT FOR A DECOUPLING MECHANISM

Q. WHY IS PUBLIC SERVICE PROPOSING A REVENUE DECOUPLING MECHANISM AT THIS TIME?

A. The Company is proposing revenue decoupling for Residential and Small Commercial for the following reasons:

- Revenue decoupling will align the Company’s interests with the preferences of our customers.
- Average usage per customer is declining, which diminishes Public Service’s opportunity to recover its Commission authorized fixed costs.
- Through our Advanced Grid Intelligence and Security (“AGIS”) proposal, the Company proposes to deploy IVVO infrastructure that has the potential to significantly decrease customers’ energy usage.
- The RD-TOU pilot rate for residential customers and the Company’s proposal long-term to move all residential customers to a different rate design than what is in place today, as discussed in our 2016 Phase II, creates new and significant uncertainty regarding fixed cost recovery.
- Net metering rules diminish the opportunity for fixed cost recovery for customers who are billed primarily on the basis of kWh usage.
- Energy efficiency standards, technology advancement, and consumer behavior combine to create a natural trend in energy conservation that I refer to Natural DSM, which has eroded and will continue to erode the Company’s opportunity to recover fixed costs.
A properly designed decoupling adjustment will not replace, the current DSM disincentive offset by truing up fixed cost recovery for actual decreases in customer use. The revenue decoupling adjustment will be reduced by the authorized DSM disincentive offset.

A decoupling mechanism can help avoid or delay future Phase I rate cases.

Except for the first reason, which I discuss in Section II of my Direct Testimony, I will address each of the reasons supporting why the Company is filing for approval of a revenue decoupling mechanism at this time below.

1. **Declining Average Use per Customer**

Q. **WHY IS AVERAGE UPC ON PUBLIC SERVICE’S ELECTRIC SYSTEM DECLINING?**

A. Average UPC is falling as a result of rooftop solar, energy efficiency standards, Company-run DSM programs, and changes in consumer behavior. Company witness Jannell Marks provides additional details on this topic. But the cause of falling average UPC is not particularly relevant. Regardless of the reason, Public Service is collecting less revenue to serve each customer every year. The following graphs illustrate how our weather-normalized average UPC for Residential and Small Commercial customers has fallen since 2009 and how this trend is expected to continue.
Figure AKJ-3 – Residential Average Use Per Customer 2009-2020

Figure AKJ-4 – Small Commercial Average Use Per Customer 2009-2020
2. The AGIS Proposal

Q. WHAT IS AGIS AND HOW MIGHT IT IMPACT AVERAGE ENERGY USE OF PUBLIC SERVICE’S CUSTOMERS?

A. Advanced Grid Intelligence and Security, or AGIS, will lead to a more modern, intelligent electric distribution system that provides advanced sensors, monitoring and control technology, additional information on customer load, and communications to improve grid performance that will support a wider array of additional services to customers and communities. The proposed project will include the deployment of advanced meters for all customers, distribution infrastructure to improve reliability, and computer systems to support and share all of the new data that will be accumulated. AGIS will also include IVVO infrastructure. IVVO changes the way the voltage is managed and optimizes the operation of the distribution system. IVVO will lower the amount of energy that everyday appliances use and subsequently will lower overall energy use by our customers.

Q. HOW WILL IVVO IMPACT THE COMPANY’S OPPORTUNITY TO RECOVER COMMISSION APPROVED FIXED COSTS?

A. IVVO is expected to decrease the average use of Residential and Small Commercial customers by 1.4 percent by 2022. The total expected savings for the Residential and Small Commercial classes is approximately 141 million kWh per year. Public Service’s current average fixed cost recovery rate for these two classes is 5.8 cents per kWh. This means that the deployment of IVVO will result
in lost fixed cost recovery of approximately $8.2 million per year. Without revenue decoupling, the Company would absorb this loss and Public Service would not have an opportunity to reduce these losses until it completes another Phase I rate case. Revenue decoupling will remove the financial disincentive associated with IVVO and subsequent infrastructure programs that may also reduce our customers’ energy usage.

3. The Impact of the Proposed RD-TOU Pilot

Q. HOW DO THE COMPANY’S PLANS TO MIGRATE RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS TO A DIFFERENT RATE DESIGN IMPACT FIXED COST RECOVERY?

A. Because the Company does not have detailed metering information for the population of the Residential and small Commercial customers, a level of uncertainty about recovery of fixed costs exists during a rate design transition. If the change to the small customer’s rate design is set appropriately, there will be no impact on fixed cost recovery. However, there is enough uncertainty regarding the peak demands of Residential and Small Commercial customers and, consequently, how much revenue will be collected from these customers. If we knew the level of billed demand with certainty, then the Company could design rates to exactly recover all of the Commission-approved fixed costs. However, without an adequate history of Residential demand billing, it is much harder to predict what the billed demands will be in the future. In this case,
revenue decoupling will provide symmetrical protection for both the Company and our customers. This is also the reason that the Company has proposed to conduct the RD-TOU pilot, to gain this information to inform any future long-term rate design proposal. This decoupling proposal will not solve the issue of uncertain demand for Residential and Small Commercial customers in the long term. Nevertheless, the RDA will address the uncertainty associated with our proposed RD-TOU pilot rate.

Q. HOW DID THE COMPANY DESIGN THE DEMAND RATE FOR ITS PROPOSED RD-TOU PILOT RATE, WHICH HAS BEEN PROPOSED IN THE 2016 PHASE II?

A. Public Service designed the RD-TOU demand charge to recover the fixed transmission and generation costs allocated to the Residential class. The design was also intended to be revenue neutral if applied to all residential customers, such that an average customer would pay the same total monthly bill regardless of whether the customer was on our standard Residential (Schedule R) service or on the RD-TOU pilot. We estimated what the billing demands would be based on sample hourly data from over 200 Residential customers. Based on this data, the average billed demand per customer was 3.7 kW per month -- with an average monthly load factor of 24 percent. However, there is no guarantee that the actual billing demands of customers on the RD-TOU pilot will match the averages derived from the sample. In fact, it is our expectation that the customers who choose to enroll in the RD-TOU pilot will be those customers who
will realize the largest savings from the new rate. We refer to this as “self-
selection bias,” meaning that the customers enrolled in the RD-TOU pilot will
likely not be a representative random sample of our entire Residential class.
While the opportunity to save on monthly bills is one of the positive aspects of the
RD-TOU pilot, the result is lower fixed costs recovery for Public Service. This
“self-selection bias” will also impact the risk to the Company by presumably
adversely increasing the risk due to the self-selection of customers to benefit.

Q. HOW CAN REVENUE DECOUPLING SOLVE THE UNCERTAINTY
ASSOCIATED WITH THE RD-TOU PILOT?

A. In our revenue decoupling proposal, we recommend a revenue target for
RD-TOU that is equal to the revenue that would have been collected under
Schedule R. This will ensure that there will be no loss of fixed cost recovery as a
result of customers moving to the RD-TOU pilot rates. The Company likewise
will not earn extra revenue from RD-TOU if the RD-TOU revenues are higher
than expected. A similar target could be set for the entire Residential and Small
Commercial classes if they are eventually moved to demand-based rates or
another rate design, although the Company is not proposing to set those targets
at this time.
Q. IN THE EVENT THE COMMISSION ALTERS THE COMPANY’S PROPOSED
RD-TOU PILOT, WILL AN ADJUSTMENT NEED TO BE MADE TO THE
DECOUPLING MECHANISM IN ORDER TO ACCOUNT FOR THIS
MODIFICATION?

A. Possibly. If the modification to the RD-TOU pilot impacts the fixed cost recovery, yes. If the Commission institutes multiple pilots or rejects the RD-TOU pilot, then that modification would need to be made as well. The Company anticipates that it will be able to adjust for these eventualities prior to hearing or via a compliance filing.

4. Net Metering

Q. HOW DO NET METERING RULES DIMINISH THE OPPORTUNITY FOR FIXED
COST RECOVERY FROM CUSTOMERS WHO ARE NOT ASSESSED
DEMAND CHARGES?

A. Net metering rules specify that for every kWh produced by customer-sited generation, the customer receives a credit equal to a kWh per kWh offset. This means that if a customer installs sufficient rooftop solar to offset 100 percent of the customer’s energy usage, that customer will be contributing nothing to the Company’s fixed costs for distribution, transmission, and generation, aside from the fixed costs associated with services collected through the S&F charge. However, because solar, wind, and other renewables are intermittent, customers utilizing these resources still depend on Public Service’s distribution,
transmission, and generation infrastructure, even though they may not be contributing to the cost of that infrastructure.

Net metering rules do not have the same impact on customers from whom we collect fixed costs through demand charges, because rooftop solar has minimal impact on customers’ monthly peak demands. Therefore, large Commercial and Industrial customers with on-site solar generation still make their cost based contributions to the fixed costs associated with distribution, transmission, and generation infrastructure.

A revenue decoupling mechanism is not a perfect solution to the net metering issue. Decoupling will effectively pass on the costs that are not paid by net-metered customers to the rest of the rate class. A better solution is to have net-metered customers pay for the distribution, transmission, and production resources that they actually use. Nonetheless, revenue decoupling will help prevent the chronic under-recovery of fixed costs due to net metering rules and make the Company more economically indifferent to the continued adoption of rooftop solar.

5. **Natural DSM**

**Q. WHAT IS NATURAL DSM?**

**A.** Natural DSM includes energy conservation improvements that occur outside the scope of conservation programs run by Public Service. Federal, state, and local energy efficiency codes, technological advancements, and changes in consumer
behavior all contribute to Natural DSM. It is difficult, if not impossible, to identify and quantify all of the sources of Natural DSM that impact energy sales. Higher energy efficiency standards lower customers’ energy usage and result in environmental benefits. However, in the short term, Natural DSM reduces our opportunity to recover the fixed costs that the Commission approved in our last Phase I proceeding.

Q. HOW DOES REVENUE DECOUPLING ADDRESS NATURAL DSM?

A. In our previous DSM proceedings before the Commission, Public Service has been awarded a DSM disincentive offset to account for the lost revenue impacts of Company-run DSM programs. However, erosion in average use per customer from Natural DSM, which was not addressed by the DSM disincentive offset, will continue to be a problem. Our revenue decoupling proposal adjusts the Company’s revenue collection to account for decreases in average use per customer without specifically identifying the causes, such as Natural DSM.

Q. IS PUBLIC SERVICE’S REVENUE DECOUPLING PROPOSAL A REPLACEMENT FOR THE EXISTING DSM DISINCENTIVE OFFSET?

A. No. Our proposal retains the existing DSM disincentive offset and takes that reimbursement into account in the calculation of the decoupling adjustment. The Company is not proposing to alter the current DSM disincentive offset approved by the Commission for Company-run DSM programs. However, this disincentive offset does not account for the host of other issues that impact the Company’s fixed cost recovery and resulting economic disincentives. Company witness
Steve Wishart explains how the existing DSM disincentive offset is incorporated into the RDA calculation.

6. The Need for Future Rate Cases

Q. WILL REVENUE RECOUPLING ELIMINATE THE NEED FOR FUTURE RATE CASES?

A. No. Periodic rate cases will still be necessary to establish revised base rates to reflect changes in the Company’s investments, revenues, and expenses. However, revenue decoupling will help delay the timing of future Phase I rate cases if the revenue loss associated with declining average UPC is one of the factors that erodes the Company’s opportunity to recover fixed costs and causes us to request a rate adjustment. Revenue decoupling will address this issue, but other drivers, such as increased taxes, capital investments, inflation, and changes in O&M expenses, will still create the need for future rate cases. Company witness Steve Wishart provides a forecast of the expected RDA adjustments during the five-year effective period, peaking at $23 million for 2021. While this is not large in comparison to Public Service’s total annual base rate revenues of $1.6 billion, it is large enough that it may delay a Phase I rate case for a few years.
V. REVENUE DECOUPLING AND RETURN ON EQUITY

Q. SHOULD THE COMPANY’S ROE BE ADJUSTED TO ACCOUNT FOR THE ADOPTION OF REVENUE DECOUPLING?

A. No, I do not believe that the Company’s ROE should be adjusted as a result of our RDA proposal. I do not view our decoupling proposal as a way to reduce our corporate risk. I view it as a means to address the increasing risks associated with our opportunity to recover our fixed costs, and keep the Company’s risk profile status quo. In fact, any perceived reduction in risk from implementation of revenue decoupling simply offsets the additional risk the Company faces from the promulgation of net metering rules, new energy efficiently standards, and the new IVVO and RD-TOU pilot programs.

Furthermore, our proposed RDA is symmetrical, giving ratepayers a refund should average use per customer increase. This means that our shareholders will be foregoing an opportunity for higher returns in some circumstances, which balances against the lower sales volume risk that may result from the RDA. Consideration of all the risk factors facing the Company is best done in the context of a comprehensive Phase I rate case, where parties are specifically focused on the question of ROE, when all new developments can be considered, and when ROE experts will be on hand to provide their perspectives.
Q. HOW DOES THE PROPOSED RDA ADDRESS NEW BUSINESS RISKS FOR PUBLIC SERVICE?

A. The business model of public utilities is changing rapidly. For decades, utilities provided reliable energy to customers at reasonable rates and could rely on growing energy consumption as new end uses for electricity continued to be invented. Times have changed, however. Distributed generation and energy efficiency gains have significantly altered the certainty associated with energy sales. We have never before faced an environment where thousands of customers a year are installing their own generation. As I discussed earlier, we have voluntarily accepted the cost recovery risk associated with the RD-TOU pilot to give our Residential customers another choice when it comes to their rate structure. We expect that this is just a first step and our customers will continue to show interest in new rate structures and programs that may impact our ability to recover our fixed costs of operations. The RDA will allow the Company to maintain the same opportunity to recover its Commission-approved fixed costs even while these new business risks continue to grow.

This is not an uncommon phenomenon. The gas industry has experienced declining use per customer for many years. As a result of this declining UPC, many gas utilities have received decoupling mechanisms to offset this decline. Now that the electric utility industry is beginning to see some of this same occurrence, it should be no surprise and pose no new policy concern to implement it here as well.
Q. **HOW DO YOU THINK A WALL STREET INVESTOR WOULD REACT TO THE COMPANY’S IVVO PROPOSAL?**

A. If we explained to an investor that we planned to invest over $140 million with the sole purpose of reducing sales and revenues, I believe that the investor would think that this was not a prudent business strategy. Businesses do not invest millions of dollars on programs designed to reduce their sales. IVVO is a new business risk that we are taking on in the interest of our customers and the public good. It runs counter to any conventional business strategy and undeniably increases our risk of not fully recovering our costs of operations. Revenue decoupling will not reduce our corporate risks; it will simply address some new risks that the Company is facing.

Q. **HAVE YOU REVIEWED ANY DATA REGARDING THE RELATIONSHIP BETWEEN REVENUE DECOUPLING MECHANISMS AND THE REQUIRED ROE?**

A. Yes. I am not an ROE expert, so I will limit my testimony to recapping the scope of the Company’s proposed decoupling mechanism and summarizing some data and findings from recent studies that might shed light on this issue.
Q. HOW WOULD YOU CHARACTERIZE THE SCOPE OF THE COMPANY’S PROPOSED DECOUPLING MECHANISM?

A. The Company is proposing a fairly modest and targeted decoupling mechanism. The affected service schedules provide less than 50 percent of the Company's base revenues, so the Company would continue to assume significant risk in terms of potential declines in the billing demands of large C&I customers. Moreover, even for the affected classes, the Company would continue to absorb weather-related revenue risks. Consequently, the impact of the Company's proposed revenue decoupling mechanism will generally be less than the impact of other decoupling mechanisms that applied to a greater cross-section of a utility’s customer base and/or applied to unadjusted changes to UPC.

Q. ARE ROE ADJUSTMENTS COMMON WHEN DECOUPLING MECHANISMS ARE APPROVED?

A. No. In the study authored by Pamela Morgan of Graceful Systems, Ms. Morgan provides a summary of such ROE adjustments. Of the 71 mechanisms included in her review, only 16 were implemented with a corresponding negative adjustment to the utility’s ROE. The consensus across the country appears to be that a revenue decoupling mechanism does not warrant an ROE adjustment.
Q. ARE YOU AWARE OF ANY RECENT STUDIES THAT TESTED FOR THE
RELATIONSHIP BETWEEN THE ADOPTION OF REVENUE DECOUPLING
AND THE UTILITY’S COST OF CAPITAL?

A. Yes. In March 2014, The Brattle Group submitted a study on the impact of
revenue decoupling on utilities’ cost of capital. In the “Conclusion” section of
this study, the authors state the following:

Our statistical tests do not support the claim that the cost of
capital is reduced by the adoption of decoupling. The results
of our models of the effects of decoupling on the cost of
capital are consistent and collectively demonstrate that there
is no statistically significant evidence of a decrease in the
cost of capital following adoption of decoupling. If decoupling
policy decreases the cost of capital, these tests strongly
suggest that the effect must be relatively small because we
are not able to detect it statistically.

As decoupling continues to grow in importance, cases will
frequently come up where interveners and commission staff
may explore the extent to which decoupling reduces
business risk and the utility’s cost of capital. To date, in a
small minority of cases in which decoupling was approved,
the utility explicitly had their allowed ROE reduced. Our
research leads us to conclude that these reductions were
implemented without reliable empirical analysis to support
the ROE reduction. The results of our analysis show that
even if such empirical analysis had been done, it is unlikely
that it would have supported even the moderate reductions
in allowed ROE that were imposed on the utilities.

[Emphasis in original.]

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6 Michael Vilbert, Joseph Wharton, Charles Gibbons, “The Impact of Revenue Decoupling on the Cost of
Q. PLEASE SUMMARIZE YOUR REVIEW OF RECENT STUDIES REGARDING THE RELATIONSHIP BETWEEN DECOUPLING MECHANISMS AND ROE?

A. Many utilities across the country have revenue decoupling mechanisms. Explicit reductions to the utility’s ROE appear to be the exception rather than the rule. In addition, a recent study that explicitly tested for the relationship between revenue decoupling and the utility’s cost of capital found no statistically significant correlation.

Q. DO THE EMPIRICAL DATA AND STUDIES YOU HAVE SUMMARIZED SUPPORT AN ROE ADJUSTMENT IF THE COMMISSION APPROVES THE COMPANY’S PROPOSED REVENUE DECOUPLING MECHANISM?

A. No.

Q. DOES THE COMMISSION NEED TO EVALUATE THE EFFECT, IF ANY, OF THE PROPOSED RDA ON THE COMPANY’S ROE IN THIS PROCEEDING?

A. No. While the topic may be discussed in this proceeding, it is more appropriate for the Commission to wait and take this issue up in a proceeding to determine the Company’s overall cost of providing service, like the next Phase I rate case. There are many other business risks that Public Service faces beyond those that are resolved by the RDA.
VI. CONCLUSION AND RECOMMENDATION

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

A. I recommend that the Commission approve our proposed RDA mechanism for Residential and Small Commercial customers. Revenue decoupling will align the interests of the Company, our customers, and the public through a periodic change to customers’ bills. The RDA will serve to eliminate new risks associated with IVVO, net metering policies and rate design transitions, essentially keeping our corporate risk profile at the status quo. The annual adjustment is anticipated to be small in context of the Company's overall risk profile, and a statistical study by The Brattle Group failed to identify any measureable relationship between revenue decoupling and the cost of capital. I recommend that any question regarding the impact of revenue decoupling on the Company’s ROE be addressed in the Company's next Phase I proceeding, where all other factors impacting ROE can also be addressed simultaneously.

Q. WHAT WOULD THE IMPACT BE IF THE COMPANY’S RDA PROPOSAL WAS REJECTED?

A. First, we would be forced to withdraw our proposal for IVVO. We have a fiduciary responsibility to our shareholders and cannot, in good faith, invest millions of dollars in infrastructure that will certainly result in the loss of millions of dollars in sales. Second, we will likely have to file more frequent Phase I rate cases with larger rate increase requests. While revenue decoupling does not
eliminate all the causes of Phase I cases, it does reduce the issue of revenue erosion from declining weather-normalized use per customer. Finally, rejection of the RDA will mean that roof top solar will continue to limit our opportunity to recover the Commission’s approved level of fixed cost recovery. Xcel Energy has been a leader in the development of renewable energy for the past 20 years, and we would like to continue to be a leader in the development of solar energy. However, our current economic model puts us at odds with net metering policies and distributed generation. Revenue decoupling can solve this problem and put Colorado on a path to be a national leader in distributed solar.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.
Statement of Qualifications

Alice K. Jackson

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

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

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

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

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