BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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RE: IN THE MATTER OF ADVICE LETTER NO. 1672-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 7-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE JULY 18, 2014.	)	**PROCEEDING NO. 14AL-________E**

<u>DIRECT TESTIMONY AND EXHIBITS OF SCOTT B. BROCKETT</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

June 17, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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SUMMARY OF DIRECT TESTIMONY OF SCOTT B. BROCKETT

Mr. Scott B. Brockett is Director, Regulatory Administration and Compliance, of Xcel Energy Services Inc. In this position Mr. Brockett is responsible for the coordination of various regulatory filings and the economic analyses supporting these filings. Mr. Brockett primarily works on matters related to Public Service Company of Colorado ("Public Service" or "Company").

In his testimony Mr. Brockett supports the Company's request to implement a new rider to recover the incremental costs, i.e., costs over test-year levels, of projects undertaken in compliance with the Clean Air Clean Jobs Act ("CACJA"). Mr. Brockett also supports and explains the Company's proposal to implement a revenue decoupling mechanism, under which the Company would charge or credit customers based on changes to the weather-normalized use per customer of customers on the Residential ("R") and Commercial service schedules. The Company proposes to collect the revenue decoupling adjustment through the General Rate Schedule Adjustment ("GRSA").

Mr. Brockett also sponsors changes to multiple tariffs to reflect the Company's proposals in this proceeding.

The Electric Commodity Adjustment ("ECA") tariff is being revised to incorporate the proposed Equivalent Availability Factor Performance Mechanism ("EAFPM") supported by Company witnesses Alice K. Jackson and Mark A. Fox in their Direct Testimony.

The GRSA tariff is being revised to capture both the base rate deficiency that Company witness Deborah A. Blair supports in her Direct Testimony, and the institution of different GRSAs for R customers, C customers, and all other customers to incorporate the impacts of the proposed revenue decoupling mechanism.

The Transmission Cost Adjustment ("TCA") tariff is being revised to: capture the propose plant balances that will be used to derive future TCA rates; and update the TCA rates to reflect the transfer of cost recovery from the TCA to base rates as a result of this proceeding.

Mr. Brockett is also updating the charges for non-routine street lighting maintenance services and various services provided upon request or as needed.

Finally, Mr. Brockett sponsors a variety of bill impacts on the typical customer served under each of the Company's five major service schedules. These impacts capture both the bill impacts directly related to the Company's proposals in this proceeding and the all-in bill impacts that incorporate other projected rate changes.

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DIRECT TESTIMONY AND EXHIBITS OF SCOTT B. BROCKETT

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
AFUDC	Allowance for Funds Used During Construction
C	Commercial
CACJA Rider	Clean Air Clean Jobs Act Rider
Commission	Colorado Public Utilities Commission
CWIP	Construction Work in Progress
DSM	Demand Side Management
DSMCA	Demand Side Management Cost Adjustment
EAPFM	Equivalent Availability Factor Performance Mechanism
ECA	Electric Commodity Adjustment
GRSA	General Rate Schedule Adjustment
O&M	Operations & Maintenance
PCCA	Purchased Capacity Cost Adjustment
PRDA	Partial Revenue Decoupling Adjustment
PDRR	Partial Decoupling Revenue Requirement
PG	Primary General
Public Service, or Company	Public Service Company of Colorado
PSIA	Pipeline System Integrity Adjustment
R	Residential

Acronym/Defined Term	Meaning
RD	Residential Demand
ROE	Return on Equity
SG	Secondary General
TCA	Transmission Cost Adjustment
TG	Transmission General
UPC	Use Per Customer
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

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DIRECT TESTIMONY AND EXHIBITS OF SCOTT B. BROCKETT

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Scott Brockett. My business address is 1800 Larimer Street, Denver, Colorado 80202.

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

A. I am employed by Xcel Energy Services Inc. ("XES") as Director, Regulatory Administration and Compliance. XES is a wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), and provides an array of support services to Public Service Company of Colorado ("Public Service" or "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

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

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. I am responsible for overseeing various economic analyses and filings. A description of my qualifications, duties and responsibilities is included as Attachment A.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to:

- sponsor the Company's tariff governing the Company's proposed Clean Air Clean Jobs Act Rider ("CACJA Rider");
- support the Company's proposal to institute a new partial revenue decoupling mechanism and sponsor the implementing Partial Decoupling Revenue Requirement ("PDRR") tariff;
- sponsor the Company's proposed revisions to the General Rate Schedule Adjustment ("GRSA") tariff, Transmission Cost Adjustment ("TCA") tariff, Electric Commodity Adjustment ("ECA") tariff; Maintenance Charges for Street Lighting Service tariff, and Schedule of Charges for Rendering Service tariff; and
- sponsor various bill impacts in 2015, 2016 and 2017 as a result of the Company's proposals in this proceeding and other projected changes to riders.

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

A. Yes. I am sponsoring Exhibit Nos. SBB-1 through SBB-21. These exhibits were prepared by me or under my direct supervision.

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR TESTIMONY?

A. I recommend that the Colorado Public Utilities Commission ("Commission") approve:

- the Company's proposed CACJA Rider that is supported in my testimony and the testimony of Company witnesses Ms. Alice K. Jackson and Mr. Mark R. Fox;
- the Company's proposed PDRR tariff that is supported in my testimony;
- the Company's proposed revision to the GRSA percentage to reflect the increase to the base cost of service supported in the testimony of Ms. Jackson and Company witness Ms. Deborah A. Blair;
- the Company's proposed revisions to the GRSA tariff to allow for the collection of the annual PDRR through adjustments to the GRSA applied to the residential and Commercial rate schedules as supported in my testimony;
- the Company's proposed revisions to the ECA to implement the proposed Equivalent Availability Factor Performance Mechanism ("EAFPM") supported by Ms. Jackson and Mr. Fox;

- the Company’s proposal to modify the TCA tariff both to reflect the changes to the terms and conditions supported by Ms. Blair in their testimony and to reflect the partial transfer of cost responsibility from the TCA to base rates as supported by Ms. Blair in her testimony; and
- the Company’s proposal to modify the schedule of charges in both the Maintenance Charges for Street Lighting Service and the Schedule of Charges for Rendering Service tariffs.

II. <u>CLEAN AIR CLEAN JOBS ACT RIDER</u>

Q. WHAT IS THE BASIS FOR THIS RIDER?

A. Company witness Ms. Jackson provides the policy basis for this rider in her Direct Testimony. I will cover the elements of the proposed CACJA Rider and how it will be implemented.

Q. ARE YOU ATTACHING THE PROPOSED TARIFF TO YOUR DIRECT TESTIMONY?

A. Yes. The proposed tariff is attached as Exhibit No. SBB-1. Since this is a new tariff, I am attaching only a clean version.

Q. WHAT IS THE PROPOSED EFFECTIVE DATE OF THE NEW TARIFF?

A. The Company proposes an effective date coincident with the Commission's Final Decision in this proceeding. While the Company proposes a rate of $0 for calendar-year 2015, the tariff needs to become effective in early 2015 to allow for a true-up of 2015 costs (based on actual 2015 costs minus the allowed base-rate recovery of such costs) under the terms of the rider.

Q. PLEASE EXPLAIN THE TIMING OF THE CACJA RIDER FILINGS AND HOW THE ANNUAL RIDER AMOUNT WOULD BE DETERMINED.

A. The Company would submit our first annual Advice Letter no later than November 1, 2015, with a proposed implementation date of January 1, 2016. The following costs would be recovered through the 2016 CACJA rider:

Projected 2016 capital and O&M costs of our CACJA initiatives ("Eligible CACJA Projects") minus the dollar level of Test Year costs approved for Eligible CACJA Projects and recovered through base rates.

The second filing would be submitted no later than November 1, 2016, for implementation on January 1, 2017. The following costs would be recovered through the 2017 CACJA Rider:

Projected 2017 capital and Operations & Maintenance ("O&M") costs of Eligible CACJA Projects minus the dollar level of Test Year costs approved for Eligible CACJA Projects and recovered through base rates minus/plus the over-collection or under-collection of costs through the CACJA Rider in 2015.

As Ms. Jackson explains, the Company does not envision a need for this rider after the date on which the Company implements base rates which include the costs of the CACJA projects. These new rates will probably be implemented sometime in 2017 pursuant to certain statutory requirements regarding this recovery mechanism, as explained by Ms. Jackson. However, the CACJA Rider would need to remain in the Company's electric tariff until the true-ups for previous years' over-collections or under-collections were completed.

Q. GIVEN THAT THE COMPANY ENVISIONS ONLY A TEMPORARY NEED FOR THE CACJA RIDER, ARE YOU PROPOSING TO INCLUDE A TERMINATION DATE?

A. No. Because we do not know the timing of the next Phase I proceeding, we do not propose any specific termination date. The timing and conditions of the rider's termination can be addressed easily as part of the next Phase I proceeding.

Q. WHICH TYPES OF COSTS WOULD BE ELIGIBLE FOR COST RECOVERY?

A. The Company proposes to recover both the capital and O&M costs associated with Eligible CACJA Projects. The Eligible CACJA Projects are listed in the proposed tariff. They are: the new combined cycle plant being constructed at Cherokee Station, including the interconnection equipment; the selective catalytic reduction equipment and particulate scrubber being installed at Pawnee Station; and the selective catalytic reduction equipment being installed on Hayden Station Units 1 and 2.

Q. WHAT TYPES OF O&M EXPENSES WOULD BE ELIGIBLE FOR RECOVERY UNDER THE CACJA RIDER?

A. As Mr. Fox explains in his Direct Testimony in greater detail, the combined-cycle facility at the Cherokee station and the emissions-control projects at the Hayden and Pawnee stations will increase the use and costs of chemicals and water. This cost increase will be partially offset by the reduction to chemicals and water costs when Cherokee 3 is retired in 2016. The CACJA Rider would collect or credit customers for these net changes to variable O&M expenses from their approved Test Year levels. We are not requesting to recover fixed O&M expenses through the CACJA Rider.

Q. HOW WOULD THE COMPANY ESTIMATE THE GROSS AND NET PLANT BALANCES USED TO DERIVE THE ANNUAL CACJA REVENUE REQUIREMENTS?

A. The Company would use the forecasted average 13-month plant balances. For example, the projected 2016 CACJA revenue requirement would be based on the average monthly plant balances from December 2015 through December 2016.

Q. WOULD THE CAPITAL COSTS INCLUDE A RETURN ON CONSTRUCTION WORK IN PROGRESS ("CWIP")?

A. Yes. As Ms. Jackson and Ms. Blair explain in more detail in their Direct Testimony, the annual CACJA Rider revenue requirement would include a return on CWIP for any construction work incurred after December 31, 2014. The applied return would be the Company's weighted average cost of capital. Consistent with this recovery, the gross and net plant balances of eligible CACJA initiatives would include no Allowance for Funds Used During Construction ("AFUDC") component for construction expenditures incurred after December 31, 2014.

Construction work incurred from May 2012 through the end of 2014 will accumulate AFUDC. The AFUDC rate applied to such capital expenditures will be the weighted average cost of capital – consistent with the provisions of the Settlement Agreement approved in the Company's last electric rate proceeding (Proceeding No. 11AL-947E). The accumulated AFUDC associated with these 2012-2014 capital expenditures would ultimately be included in the gross and net plant balances of the eligible CACJA initiatives.

The projected current and deferred federal and state income taxes included in the annual CACJA revenue requirement would reflect this treatment of capital expenditures.

Q. HOW WOULD THE WEIGHTED AVERAGE COST OF CAPITAL BE DETERMINED?

A. In each November filing the Company would forecast the cost of debt and capital structure for the upcoming calendar year. The Company would use the cost of equity approved by the Commission in this proceeding – unless this allowed return was modified in a subsequent proceeding.

Q. WHAT DEPRECIATION RATE WOULD THE COMPANY APPLY TO THE CACJA PLANT BALANCES?

A. We would use the depreciation rates that the Commission approves in this proceeding — unless they were modified in a subsequent proceeding while the rider was in effect.

Q. WOULD THE ANNUAL REVENUE REQUIREMENT OF CACJA INITIATIVES INCLUDE ASSOCIATED PROPERTY TAXES?

A. No. The Company is not seeking to recover through the CACJA rider any incremental property taxes attributable to the incremental CACJA investments. The Company would continue to recover the approved Test Year level of property taxes through base rates.

Q. HOW WOULD UNDER-COLLECTIONS OR OVER-COLLECTIONS BE TRUED-UP?

A. I will use 2016 costs as an example. Let's assume that the projected 2016 CACJA cost was $90 million and the approved test year recovery of projects eligible for cost recovery through the CACJA rider was $80 million. Under this scenario, the 2016 CACJA revenue requirement would be $10 million ($90 million - $80 million). Let's further suppose that our total actual collections through the 2016 CACJA rider were $9 million, and that actual 2016 CACJA Rider costs were $89.5 million. We would then propose to collect from customers the under-recovery of $0.5 million ($90 million - $89.5 million + $9 million - $10 million) through the true-up component of the 2018 CACJA Rider.

Q. WHY WOULD THE TRUE-UP OF 2016 COST RECOVERIES BE DEFERRED UNTIL 2018?

A. The Company cannot calculate its under-collections or over-collections in any given year until early in the next year. Consequently, if 2016 over-collections or under-collections are calculated in early 2017, the earliest the Company can reflect this true-up is in the November 2017 filing for the 2018 CACJA Rider.

Q. IS THE COMPANY PROPOSING TO APPLY CARRYING CHARGES TO ANY OVER-RECOVERY OR UNDER-RECOVERY?

A. No. The Company does not assess carrying charges on under-collections or over-collections of Pipeline System Integrity Adjustment ("PSIA") costs.

Likewise, we propose to apply no carrying charges to CACJA Rider over-collections or under-collections.

Q. HAVE YOU PREPARED AN EXHIBIT OUTLINING THE COSTS TO BE COLLECTED THROUGH THE CACJA RIDER, THE TIMING OF THE CACJA RIDER FILINGS, AND THE IMPLEMENTATION DATES BASED ON THE APPROACH YOU DESCRIBED ABOVE?

A. Yes. Exhibit No. SBB-2 illustrates the types of costs to be recovered, the timing of the CACJA Rider filings, and their implementation for the years 2015 through 2019.

Q. WHY ARE YOU PROVIDING AN ILLUSTRATIVE EXAMPLE OF CACJA RIDER REVENUE REQUIREMENTS THROUGH 2019, SINCE THE COMPANY DOES NOT ANTICIPATE A NEED FOR RIDER RECOVERY PAST 2017?

A. The CACJA Rider would need to be in effect two years beyond the final year of collection to either credit customers or charge customers for over-collections or under-collections in that final year of collection.

Q. WOULD THE COMPANY BE WILLING TO PROVIDE SUPPORT ANNUALLY FOR THE PROJECTED COSTS FOR WHICH IT SEEKS RECOVERY THROUGH THE CACJA RIDER?

A. Yes. The Company's November Advice Letter would include support for the capital and O&M costs associated with each project. In addition, the Company would be willing to meet with the Commission Staff and other interested interveners each year in November or early December to answer questions about our CACJA Rider filing.

Q. HOW ARE YOU PROPOSING TO ALLOCATE THE ANNUAL CACJA REVENUE REQUIREMENT TO CUSTOMER CLASSES?

A. The Company proposes to apply the same allocator used to allocate production costs in our most recent Phase 2 rate proceeding (Proceeding No. 09AL-299E). This same allocator is also used to allocate Purchased Capacity Cost Adjustment ("PCCA") and Demand Side Management Cost Adjustment ("DSMCA") costs to customer classes. I believe this allocator is appropriate, because the costs eligible for recovery through the CACJA Rider are almost entirely production costs.

Q. HOW DOES THE COMPANY PROPOSE TO COLLECT THE COSTS ALLOCATED TO EACH CLASS?

A. The costs would be collected through a separate charge assessed on projected usage for customers who are not assessed demand charges, and on projected billing demands for customers who are assessed demand charges. The structure of these charges is provided in the proposed tariff, attached as Exhibit No. SBB-1.

Q. HAVE YOU PREPARED ESTIMATED BILL IMPACTS OF THE CACJA RIDER ON TYPICAL CUSTOMERS BY CLASS?

A. Yes. I have prepared such bill impacts for 2016 and 2017, and will address them in the "Bill Impacts" section of my Direct Testimony.

Q. WOULD THE COMPANY BE WILLING TO SUBMIT AN ANNUAL FILING DOCUMENTING THE CACJA ACTIVITIES AND REVENUE REQUIREMENTS FROM THE PREVIOUS CALENDAR YEAR?

A. Yes. The Company is proposing to submit an annual filing by April 15 that would explain the types of activities and associated costs related to Eligible CACJA Projects during the previous calendar year. The Company would also identify deviations between the projected and actual costs and explain material deviations. This approach is similar to that approved for the annual PSIA reports.

Q. WOULD THERE BE ANY OPPORTUNITY TO CONTEST THE PRUDENCE OF CACJA ACTIVITIES UNDERTAKEN BY THE COMPANY?

A. To the extent that a party wished to challenge the Company's prudent administration of the CACJA projects, that challenge could be raised following the Company's annual April 15 filing.

III. REVENUE DECOUPLING

A. OVERVIEW

Q. PLEASE EXPLAIN THE TERM "REVENUE DECOUPLING."

A. Revenue decoupling is a mechanism that partially or entirely severs the link between customer use and the utility's return on equity. Most utilities, including Public Service, recover a portion of their fixed costs of service through volumetric charges. By "fixed" I am not suggesting that the levels of these costs cannot change over a long period as old assets are retired and new assets added, but that these costs are relatively invariant to variations in customer use over the short term – such as the period between rate cases. For example, the Company cannot practically lower the costs of its service drops, transformers, and secondary feeders in response to reduced customer usage.

A revenue decoupling mechanism adjusts the utility's revenues for changes in customer use between rate cases. In other words, the utility credits or charges customers for changes to the level of the utility's fixed-cost recovery in a prior period attributable to changes in customer use. These billing determinants are usually therms or cubic feet for gas utilities or kilowatt-hours for electric utilities.

The decoupling charge or credit is usually derived by multiplying the change to the level of sales (such as therms or kWh) from an established base period by the fixed costs recovered per unit of sales. (Some mechanisms adjust for the entire revenue gain or loss, instead of only the impact on fixed cost recovery. For purposes of this discussion I will assume the goal is to true up only for changes in fixed-cost recovery.)

For example, if the utility sold 1000 kWh less energy in a given period compared to the base period, and the utility recovered $0.05 of fixed costs for each kWh sold, then the decoupling charge would recover $50 (1000 X $0.05). If the utility's sales increased by 1000 kWh from the base period level, then the utility would provide a credit to customers of $50. Since fixed-cost recovery varies significantly among customer classes, this derivation is usually performed separately for each class to which the revenue decoupling mechanism applies.

Q. ARE ALL REVENUE DECOUPLING MECHANISMS DESIGNED IDENTICALLY?

A. No. Many permutations are possible within the general framework described above. These design alternatives include the following:

- The revenue decoupling mechanism can be calibrated to true up for changes to either total use for a customer class or use per customer ("UPC") for a customer class.
- The revenue decoupling mechanism may be applied to all customer classes or a subset of customer classes. In general, revenue decoupling mechanisms are more likely to be applied to small customer classes – such as the residential or small business class. The reason is that energy charges applied to such classes usually

recover more fixed costs than the energy charges applied to large customer classes.

- The decoupling mechanism can be applied to true up for all changes to sales from a base period or only changes to weather-normalized sales. In other words, decoupling mechanisms can be structured to either eliminate or retain the utility's exposure to weather-related risks to profitability.
- The decoupling mechanism can be assessed such that the adjustment derived for a given class is charged to or recovered from that specific class. Alternatively, the net amount of the adjustments attributable to all classes can be combined into a single dollar amount and recovered from 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.

The list above is not intended to be comprehensive, but highlights some of the key decisions involved with designing a revenue decoupling mechanism. In addition to these basic design decisions, there are a number of second-level implementation issues to address.

Q. WHAT CRITERIA SHOULD BE USED TO SELECT A SPECIFIC REVENUE DECOUPLING MECHANISM FROM THE VARIOUS OPTIONS DISCUSSED ABOVE?

A. The guiding principle for the design of the revenue decoupling mechanism should be the specific policy objective(s). In other words, the revenue decoupling mechanism should be consistent with the policy decision as to which risks and impacts should be mitigated and which should continue to be borne by the utility. After this high-level policy decision is reached, the remaining policy and implementation issues should be informed by the balancing of other goals -- including accuracy, customer equity, administrative ease, transparency, and the avoidance of extreme rate impacts.

Q. DID PUBLIC SERVICE FOLLOW THIS BASIC APPROACH WHEN DESIGNING ITS PROPOSED REVENUE DECOUPLING MECHANISM?

A. Yes. We first identified the basic policy objective(s) underlying our request to implement revenue decoupling. We then addressed the remaining policy and implementation issues based on the other considerations mentioned above. The remainder of this section of my Direct Testimony will detail the Company’s evaluation and the resulting revenue decoupling mechanism we are proposing in this proceeding. In the course of this discussion I will also provide a summary of revenue decoupling activity across the nation.

B. POLICY BASIS

Q. WHY IS THE COMPANY PROPOSING A REVENUE DECOUPLING MECHANISM AT THIS TIME?

A. Our main objective is to meet the objective set in statute by the Colorado General Assembly that the utility have an opportunity to profit from the provision of demand-side management programs. Public Service currently collects a large percentage of its fixed costs through the base energy charges assessed under the Residential and Commercial rate schedules. Energy-efficiency programs, by definition, directly reduce customer use. To the extent that we recover our fixed costs through usage charges, each kWh of savings from an energy-efficiency program has a direct and easily quantifiable impact on gross revenues and after-tax earnings. This financial loss significantly impairs Public Service's opportunity to meet the statutory profitability standard.

This loss of fixed-cost recovery and its impact on earnings is particularly important now, since we have aggressive energy savings goals in Colorado. In fact, our current annual savings goal is about 400 GWh per year. Programs of that scale unquestionably erode earnings.

While this basic financial dilemma is not debated seriously anymore, not everyone agrees on the policy response. The Company has previously sought the direct recovery of these identifiable impacts on net revenue through our Demand Side Management ("DSM") financial incentive mechanism, but the Commission has denied this request. The Company believes that the more general revenue decoupling mechanism we propose in this proceeding can accomplish a similar goal without requiring the tracking and direct recovery of financial losses due to utility-sponsored programs only. While the Company's revenues would be trued up for impacts other than energy-efficiency programs, i.e., a broader decoupling mechanism is not as well targeted as the direct recovery of lost margins due solely to utility-sponsored DSM initiatives, the scope of a broader decoupling mechanism can still be reasonably limited.

Q. PLEASE EXPLAIN HOW THE DECOUPLING MECHANISM CAN BE LIMITED IN LIGHT OF THE SPECIFIC GOAL OF ENCOURAGING THE PROVISION OF ENERGY-EFFICIENCY PROGRAMS.

A. The Company proposes several limits. First, as I mentioned previously, a decoupling mechanism can true up total usage revenues for a class or usage revenues per customer. The Company is proposing to derive the decoupling adjustment based on changes in use per customer. It is this per-customer use that is affected by energy-efficiency programs – not the total use of a class.

Second, the Company proposes that the decoupling mechanism be calibrated to changes in weather-normalized use per customer – not gross use per customer. The Company would continue to assume the weather risk it currently faces.

Third, the Company proposes to limit the decoupling mechanism to the Residential and Commercial service schedules, which excludes the residential Demand ("RD") service schedule. The base energy charge assessed on small customers is designed to collect the majority of the fixed costs allocated to their respective customer classes, since these customers are not assessed a demand charge. In contrast, the base energy charges currently assessed on demand-metered customers -- primarily Secondary General ("SG"), Primary General ("PG") and Transmission General ("TG") customers -- recover only variable non-fuel Operations and Maintenance expenses. As a result, the base revenue the Company loses from lower sales to these customers is roughly offset by the avoidance of O&M expenses.

Q. YOU HAVE MENTIONED THE EARNINGS LOSSES FROM REDUCTIONS TO BASE USAGE REVENUE. BUT DON'T ENERGY-EFFICIENCY PROGRAMS ALSO REDUCE REVENUES FROM THE BASE DEMAND CHARGES ASSESSED ON LARGE CUSTOMERS?

A. Yes. In fact, the revenue losses attributable to reduced billing demands may well exceed the losses due to reduced kWh sales to R and C customers. Nonetheless, the Company is not proposing to extend the revenue decoupling mechanism to demand-metered customers at this time. Incorporating changes to demand billing determinants poses unique challenges, since demand billing determinants per customer can fluctuate significantly with changes in average customer size and customer mix. Consequently, we would like to start with the R and C classes that are billed on an energy-only basis. If we can resolve the issues with incorporating demand billing determinants into the decoupling mechanism, we may seek to extend decoupling to more customers in the future.

Q. GIVEN THESE RESTRICTIONS, FOR WHICH REVENUE AND EARNINGS IMPACTS WOULD THE COMPANY'S PROPOSED DECOUPLING MECHANISM ACCOUNT?

A. The Company's proposed mechanism would primarily capture increased or decreased usage due to utility-sponsored energy-efficiency programs, customer-initiated actions, appliance efficiency standards, and changes to general economic conditions. In addition, the Company's proposed revenue decoupling mechanism would eliminate any incentive for the utility to actively *increase* per-customer use. The elimination of this incentive to increase sales is a reasonable analog to the goal of reducing the utility's disincentive to reduce sales.

Q. WOULD THE POTENTIAL FOR RATE INCREASES AS A RESULT OF IMPLEMENTING A REVENUE DECOUPLING MECHANISM DISCOURAGE CUSTOMERS FROM REDUCING THEIR USAGE?

A. No. That concern would be unfounded. A residential customer who reduces usage by 100 kWh per month in 2015 would save about $132.96 for the entire year. Given that the Company currently serves about 1.2 million residential customers, the impact of a $132.96 loss in net revenue would probably have no impact on even the last digit of any future rate adjustment. Consequently, the implementation of a decoupling rate adjustment should not affect an individual customer's financial benefit from reducing usage.

Q. IS THE COMPANY'S PROPOSAL CONSISTENT WITH TRENDS EXPERIENCED ACROSS THE COUNTRY?

A. Yes. While the concept of revenue decoupling dates to the 1980s, there appears to be a recent resurgence of interest. One study prepared by Pamela Morgan of Graceful Systems LLC concluded that, between May 2009 and May 2013, the number of gas distribution utilities with decoupling mechanisms increased from 28 to 50, and the number of electric utilities with decoupling mechanisms increased from 12 to 27. I have attached that study as Exhibit No. SBB-3, as it provides a good summary of utility decoupling mechanisms.

Q. CAN YOU SUMMARIZE THE ATTRIBUTES OF THE REVENUE DECOUPLING MECHANISMS FOR ELECTRIC UTILITIES?

A. Yes. Mr. Daniel G. Hansen, a vice president at Christensen Associates Energy Consulting, recently sponsored testimony on behalf on Northern States Power Company supporting the utility's proposed revenue decoupling mechanism. Based on his review of two studies[1], Mr. Hansen identified 25 electric utilities with decoupling mechanisms. He prepared a table summarizing some key attributes of these mechanisms, which I have reproduced as Exhibit No. SBB-4.

The "RPDC" column indicates whether the decoupling adjustment rate is based on revenue per customer. Where "no" is indicated, the utility trues up revenues to a pre-specified *total* revenue amount. The "Include Weather

[1] The list of decoupled utilities Mr. Hansen used was developed using the previously cited Graceful Systems LLC study and the following study: *State Electric Efficiency Regulatory Framework*, Institute for Electric Efficiency, July 2013

Effects" column indicates whether the effects of weather are included in the decoupling adjustment. The "EE Performance Incentive" column indicates whether the utility has a separate energy efficiency incentive program in place in addition to its decoupling mechanism. The "Cap on Deferral" column indicates whether the decoupling rate adjustment is capped at a certain percentage or level. The "CAP Level" column indicates the amount of the cap, if applicable. The "Soft or Hard Cap" column indicates whether deferrals in excess of the cap amount are carried into subsequent periods or lost forever.

Q. DO YOU WISH TO OFFER ANY GENERAL OBSERVATIONS ABOUT THIS SUMMARY OF REVENUE DECOUPLING MECHANISMS?

A. Yes. The attributes of revenue decoupling mechanisms vary considerably among jurisdictions. This diversity suggests that states (and the District of Columbia) have tailored their revenue decoupling mechanisms to meet their specific goals and needs – which again highlights the need for specifying policy objectives. I will return to this report later in my testimony.

Q. HAS THE COLORADO PUBLIC SERVICE COMMISSION EVER APPROVED A REVENUE DECOUPLING MECHANISM FOR PUBLIC SERVICE?

A. Yes. In Proceeding No. 06S-656G, the Commission approved a Partial Revenue Decoupling Adjustment ("PRDA") for the Company's gas department. That mechanism never led to any rate adjustment and the Company received permission to terminate it in a subsequent Phase I rate proceeding (Proceeding No. 10AL-963G). But the design of the mechanism was similar to the Company's proposal in this proceeding, in that the adjustment was to be calculated based on changes to weather-normalized UPC times the fixed-cost component of the base usage charge effective during the month times the number of monthly bills. The design of this former gas mechanism was different in that no negative adjustment was authorized (customers could never be credited based on increases to weather-normalized UPC) and the mechanism was limited to the Residential class.

In contrast, I am proposing a symmetric mechanism that allows customers to receive a credit if UPC increases. In addition, I am proposing to apply the mechanism to both residential and small commercial customers – instead of residential customers only.

Q. YOU HAVE EXPLAINED HOW THE COMPANY'S PROPOSED REVENUE DECOUPLING MECHANISM ADVANCES THE BASIC POLICY GOAL OF ALLOWING PUBLIC SERVICE TO PROTECT ITSELF FROM THE REDUCED FIXED COST RECOVERY RESULTING FROM ENERGY-EFFICIENCY PROGRAMS. HOW DID THE COMPANY EVALUATE HOW TO COLLECT OR CREDIT ANY ADJUSTMENT RESULTING FROM YOUR PROPOSED MECHANISM?

A. There are several aspects to this decision, including:

- the assignment or allocation of the dollar amounts (to be recovered or credited) to customer classes;

- the specific rider through which the rate adjustment is reflected; and
- the basis on which the rider is assessed.

Many different allocations and rate designs would be consistent with the fundamental policy goal. Consequently, these design issues must be resolved on the basis of other policy considerations. I will explain the basis of the Company's position on each issue below.

Q. HOW DOES THE COMPANY PROPOSE TO ASSIGN OR ALLOCATE THE DECOUPLING RATE ADJUSTMENT TO CUSTOMER CLASSES?

A. We propose to directly assign the decoupling rate adjustments to the responsible customer class. In other words, the net revenue impact attributable to changes in Residential UPC would be recovered from or credited to the Residential service schedule. Likewise, the net revenue impact attributable to changes in Commercial UPC would be recovered from or credited to the Commercial service schedule..

Q. WHAT IS THE BASIS OF THIS PROPOSAL?

A. The net revenue impacts we are targeting are limited to the Residential and Commercial classes. Since the usage changes of demand-metered customers have no impact on the rate adjustment, these same customers should not be afforded the benefit of any negative rate adjustment or share the burden of any positive rate adjustment.

Q. IS THE COMPANY PROPOSING A SEPARATE RIDER FOR THE REVENUE DECOUPLING ADJUSTMENT?

A. No. The Company proposes to implement this adjustment through an existing rider -- the GRSA.

Q. WHY IS THE COMPANY PROPOSING TO USE THE GRSA?

A. We are sensitive to the goal of limiting the number of riders – particularly the number of riders separately identified on customer bills. We are already asking in this proceeding to implement a CACJA Rider. Adding two additional riders to the bill could be confusing to customers. By reflecting revenue decoupling through the GRSA, the Company need add only one new rider to the bill for electric service. Moreover, since the CACJA Rider is intended as a short-term cost-recovery bridge, the Company's proposals in this proceeding would probably require no additional line items on bills after 2019.

In addition, the revenue decoupling rate adjustment the Company proposes captures base-rate revenue impacts only. Consequently, a rider applied to the base components of the customer's bill would seem to be a reasonable approach.

I will discuss the mechanics of the GRSA changes later in my testimony.

Q. ON WHAT BASIS WOULD THE DECOUPLING RATE ADJUSTMENT BE ASSESSED?

A. Since the Company proposes to use the GRSA instead of a new rider, the issue is settled; the rate adjustment would be assessed on the base components of a customer's bill. As I explained above, this approach is reasonable given that the decoupling rate adjustments are a function of changes to base revenue.

Q. IS THE COMPANY PROPOSING A CAP ON THE DECOUPLING RATE ADJUSTMENT?

A. Yes. The Company proposes a cap each year of 5 percent of the total revenue generated from the R or C service schedule during the same historical calendar year for which the decoupling rate adjustment is being derived.

Q. WOULD THIS CAP BE A "HARD" CAP OR "SOFT" CAP?

A. The Company proposes a soft cap. Stated differently, the Company proposes that any positive difference between the unadjusted amount in a given year and the cap would be deferred with the possibility of collection in future years. This collection in a future year would be contingent on the total adjustment not exceeding the 5 percent cap applied in that future year.

C. <u>IMPLEMENTATION</u>

Q. PLEASE EXPLAIN HOW THE COMPANY WOULD TRACK THE AMOUNT OF THE DECOUPLING ADJUSTMENT?

A. The Company would begin tracking the net revenue impact of changes in Residential and Commercial UPC on a monthly basis, beginning with the first calendar month after a Commission Final Decision in this proceeding. The Company would calculate this UPC on a billing-month basis, consistent with the derivation of test-year revenues in this proceeding. This UPC would then be compared with the UPC for the same month underlying the approved test year. (For the illustrations in this section of my testimony, I will assume that the Commission approves the Company's proposed test year, which is based on projected 2015 sales and customer numbers.) The change in UPC would then be multiplied by the adjusted energy charge(s) in effect during that month. Finally, this product would be multiplied by the actual number of bills to derive the dollar amount of the decoupling adjustment for that month.

Q. HOW WOULD THE MONTHLY ADJUSTED ENERGY CHARGE(S) BE DERIVED?

A. The Company would first calculate the base energy rate minus the DSM component of the base energy rate minus the component of the base energy rate earmarked for the recovery of variable O&M expenses. The resulting net energy rate represents the portion of the base energy charge that recovers fixed costs.

Using the R service schedule as an example, this net energy charge would then be then be multiplied by the following:

1.0 + (R GRSA minus decoupling component of R GRSA)

The resulting net rate per kWh would be the adjusted energy charge used to determine the monthly decoupling adjustment.

These monthly amounts would be tracked separately for the Residential and Commercial service schedules. A cumulative balance would be identified at the end of each calendar year. These end-of-year balances would then be used to derive the positive or negative GRSA components for the two service schedules.

Q. OVER WHAT PERIOD WOULD THESE BALANCES BE COLLECTED?

A. The balances as of December 31 of each year would be credited or collected over the 12 months beginning April 1 of the next year. This schedule would allow sufficient time to calculate the balances, prepare a filing, and have it reviewed for compliance with the approved tariff.

Q. WHAT TYPE OF FILING WOULD THE COMPANY SUBMIT AND WHEN WOULD IT BE SUBMITTED?

A. The Company would file an Advice Letter each year on or around March 1 for implementation on April 1. These GRSA adjustments would be in effect from April 1 to March 31 of the next calendar year.

Q. HOW WOULD THE COMPANY TRACK THE MONTHLY BALANCES IN 2015 IF THE COMMISSION'S FINAL DECISION IN THIS PROCEEDING ISN'T EFFECTIVE UNTIL SOMETIME AFTER JANUARY 1, 2015?

A. The Company would begin tracking the monthly balances as of the first calendar month after the Commission issued a Final Decision in this proceeding. For example, if the Commission issued its Final Decision on February 15, 2015, the Company would begin tracking monthly balances in March 2015. In that case, the revenue decoupling adjustment implemented on April 1, 2016, would be based on changes to UPC for the 10 calendar months of March 2015 through December 2015.

Q. WOULD THE COMPANY ACCRUE INTEREST OR CARRYING CHARGES ON THE POSITIVE OR NEGATIVE BALANCES IN THE TRACKER ACCOUNTS?

A. No. The Company does not propose to accrue any interest on these balances.

Q. WHY IS THE COMPANY NOT PROPOSING TO ACCRUE INTEREST OR CARRYING CHARGES?

A. One of our primary goals is to simplify the mechanism whenever possible to facilitate the development and review of the rate adjustments. While the recovery or crediting of the revenue decoupling adjustments will lag the period in which they are incurred, the lag will be relatively limited. Specifically, the midpoint of the performance year will lag the midpoint of the recovery year by 15 months. This lag would impose little disincentive to the Company to offer energy-efficiency projects.

Q. WOULD THE COMPANY PROPOSE TO TRUE UP ANY OVER-COLLECTIONS OR UNDER-COLLECTIONS FROM THE PREVIOUS APPLICATIONS OF THE GRSA?

A. No. Again, the Company's goal is to minimize the complexity of the mechanism. The risk of over-collections or under-collections would remain with the Company, because that risk imposes little disincentive to the Company to offer energy-efficiency projects. Moreover, unlike the PSIA or proposed CACJA Rider, there are no revenue requirement variances to true up. In the case of revenue decoupling, the source of over-collections or under-collections would be limited to differences between actual and forecasted billing determinants and base rates.

Q. CAN YOU PROVIDE AN ILLUSTRATIVE EXAMPLE OF HOW THE COMPANY'S REVENUE DECOUPLING MECHANISM WOULD BE ADMINISTERED?

A. Yes. Exhibit No. SBB-5 provides illustrative examples of the monthly entries into the tracker account and the resulting decoupling adjustments for the Residential and Commercial service schedules. I provide these examples under 8 difference scenarios for changes in monthly UPC: a reduction of 1 percent, a reduction of 3 percent, a reduction of 5 percent; a reduction of 10 percent; an increase of 1 percent; an increase of 3 percent; an increase of 5 percent; and an increase of 10 percent. These reductions are applied to the 2015 projected UPC underlying the Company's proposed test year.

In this same exhibit I have also provided estimated R and C bill impacts under each scenario. While the actual bill impacts would depend on the actual changes to UPC, these scenarios provide a reasonable range of bill impacts.

Q. IS THE COMPANY PROPOSING A REVENUE DECOUPLING TARIFF TO DOCUMENT THE PROCEDURES OUTLINED ABOVE?

A. Yes. The proposed PDRR tariff is included as Exhibit No. SBB-6. This tariff explain the applicability and limits of the proposed revenue decoupling mechanism consistent with the discussion above. The PDRR tariff also explains how monthly balances would be computed and specifies the monthly

UPC for the Residential and Commercial service schedules against which the actual UPC would be compared. If the Commission approved a test year in this proceeding that assumed different UPC than what the Company proposes in our direct case, then the Company would substitute the Commission-approved monthly UPC.

I will explain the changes to the GRSA tariff necessary to implement the recovery of the annual PDRR by service schedule in a subsequent section of my Direct Testimony.

D. <u>IMPACT ON REQUIRED ROE</u>

Q. HAVE YOU REVIEWED ANY DATA REGARDING THE RELATIONSHIP BETWEEN REVENUE DECOUPLING MECHANISMS AND THE REQUIRED Return on Equity ("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, offering some data regarding the comparable group used by the Company's ROE witness, 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 mechanism. The affected service schedules provide less than 50 percent of the Company's base revenues, so the Company would continue to assume a 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 would 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. On Pages 95-97 of the study authored by Pamela Morgan for Graceful Systems, which I attached as Exhibit No. SBB-3, 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. DO ANY OF THE UTILITIES IN COMPANY WITNESS MR. ROBERT HEVERT'S COMPARABLE GROUPS HAVE APPROVED REVENUE DECOUPLING MECHANISMS?

A. Yes. We identified seven utilities in Mr. Hevert's Combination Comparable Group and Electric Comparable Group that currently have some form of revenue decoupling mechanism. Exhibit No. SBB-7 provides the data supporting this conclusion.

Q. HAVE ANY OF THESE UTILITIES BEEN SUBJECT TO A NEGATIVE ROE ADJUSTMENT AS A RESULT OF THEIR DECOUPLING MECHANISM(S)?

A. In only one of these seven instances did the regulatory commission order a corresponding reduction to the utility's ROE. That one reduction was 10 basis points.

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.[2] In the "Conclusion" section of this study the authors state the following:

> Our statistical tests do <u>not</u> 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

[2] Michael Vilbert, Joseph Wharton, Charles Gibbons "The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Emperical Investigation". *The Energy Foundation.* (2014)

> 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 he 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.]

Q. PLEASE SUMMARIZE YOUR REVIEW OF RECENT STUDIES AND THE COMPANY'S COMPARABLE GROUP?

A. Many utilities across the country have revenue decoupling mechanisms, including some of the utilities in Mr. Hevert's comparable group. Explicit reductions to the utility's ROE appear to be the exception rather than the rule – both across the nation and for the specific utilities in the comparable group. Finally, 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.

IV. <u>TCA TARIFF CHANGES</u>

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED CHANGES TO THE TCA TARIFF.

A. The Company proposes changes to the both the terms and conditions of the TCA tariff and the TCA rates. Regarding the TCA terms and conditions, the Company proposes to change the bases for identifying the net plant and CWIP balances used to derive the annual TCA rates. The Company also proposes to change the TCA rates to reflect the roll-in of transmission costs into base rates in this proceeding. The proposed TCA rates after this adjustment would recover only a return on CWIP for capital expenditures that will not be included in plant in service until after 2015. Ms. Blair explains the bases for these changes to the TCA terms, conditions and rates in more detail in her Direct Testimony.

Q. ARE YOU ATTACHING REDLINED AND CLEAN VERSIONS OF THE TCA TARIFF TO YOUR TESTIMONY?

A. Yes. Redlined and clean versions are attached as Exhibit Nos. SBB-8 and SBB-9.

V. ECA TARIFF CHANGES

Q. PLEASE SUMMARIZE THE CHANGES TO THE ECA TARIFF THAT YOU ARE SPONSORING?

A. The Company proposes only one change to the ECA tariff: the addition of a proposed performance benchmarking mechanism -- the Equivalent Availability Factor Performance Mechanism. Redlined and clean versions of the tariff are attached as Exhibit Nos. SBB-10 and SBB-11. Ms. Jackson and Mr. Fox explain the basis for and design of the plan in more detail in their Direct Testimony.

VI. <u>GRSA TARIFF CHANGES</u>

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED CHANGES TO THE GRSA TARIFF.

A. The Company proposes two changes. First, the Company proposes to designate separate GRSAs for the Residential service schedule, the Commercial service schedule, and all other service schedules. This tariff modification is necessary to implement the revenue decoupling mechanism described above. Second, the Company proposes to revise the current GRSA that applies to all electric customers to reflect our proposed base revenue increase in this proceeding. Ms. Blair explains the derivation of this GRSA in more detail in her Direct Testimony.

Q. ARE YOU ATTACHING REDLINED AND CLEAN VERSIONS OF THE GRSA TARIFF TO YOUR TESTIMONY?

A. Yes. Redlined and clean versions are attached as Exhibit Nos. SBB-12 and SBB-13. Since there would be no revenue decoupling component of the R or C GRSA until April 1, 2016, the proposed GRSAs are the same for all service schedules.

VII. <u>CHANGES TO STREET LIGHTING MAINTENANCE AND MISCELLANEOUS CHARGE TARIFFS</u>

Q. DOES THE COMPANY CURRENTLY HAVE TARIFFS GOVERNING CHARGES FOR NON-ROUTINE STREET LIGHTING MAINTENANCE AND OTHER CHARGES FOR RENDERING NON-ROUTINE SERVICE?

A. Yes. The Company offers street lighting maintenance services over and above the services provided under the Street Lighting Service Schedule (Schedule SL). We then bill for these services on a time and materials basis. The "Maintenance Charge for Street Lighting Service" tariff provides the rates under which such non-routine services are offered, while Schedule SL governs the terms and conditions under which such non-routine services are offered.

Similarly, the Company provides a wide variety of services upon request or as needed – including instituting or reinstituting service, transferring service from one customer to another, performing work outside of normal hours, etc. The rates for these services are listed in the "Schedule of Charges for Rendering Service."

Q. WHAT CHANGES DOES THE COMPANY PROPOSE TO THESE TARIFFS?

A. We are proposing no changes to the terms and conditions in Schedule SL. But we are changing the majority of the rates in both the Maintenance Charge for Street Lighting Service and Schedule of Charges for Rendering Service tariffs to reflect updated analyses of our labor and vehicle expenses.

Q. HAVE YOU ATTACHED REDLINED AND CLEAN TARIFFS REFLECTING THESE CHANGES?

A. Yes. The redlined and clean tariffs for street lighting maintenance charges are attached as Exhibit Nos. SBB-14 and SBB-15. The redlined and clean tariffs for non-routine service charges are attached as Exhibit Nos. SBB-16 and SBB-17.

VIII. <u>BILL IMPACTS</u>

Q. HAS THE COMPANY ESTIMATED THE IMPACTS OF ITS PROPOSED REQUESTS IN THIS PROCEEDING ON TYPICAL CUSTOMER BILLS?

A. Yes. The impacts on typical R, C, SG, PG and TG customers are provided in Exhibit No. SBB-18. Specifically, I have compared 2014 monthly bills with 2015 monthly bills. To isolate the impacts of our request in this proceeding, I changed only the levels of the GRSA and TCA riders between 2014 and 2015; I maintained the other riders at their 2014 levels. For simplicity I assume the new rates resulting from this proceeding would be implemented on January 1, 2015.

Q. PLEASE SUMMARIZE THESE IMPACTS.

A. The monthly dollar and percentage bill impacts on the typical customer in each class are provided below:

Class	Monthly $ Change	Monthly % Change
R	$3.96	5.32%
C	$6.35	5.07%
SG	$110	4.39%
PG	$1,427	3.81%
TG	$23,069	2.88%

The percentage bill impacts decrease consistently with the size of the typical customer. This result is not surprising, since the most significant impact on customer bills is the higher GRSA. Base rates and the GRSA applied to base rates account for a larger percentage of the bills of small customers than the bills of large customers. By extension, changes to riders such as the ECA have a greater percentage impact on the bills of large customers.

Q. WOULD THESE BILL IMPACTS CHANGE SIGNIFICANTLY IF YOU ACCOUNTED FOR THE PROJECTED CHANGES TO ALL RIDERS?

A. No. In Exhibit No. SBB-19 I have modified the projected bills to typical customers in 2014 and 2015 to capture the projected changes to all riders between 2014 and 2015. The bill impacts under this scenario are provided below.

Class	Monthly $ Change	Monthly % Change
R	$4.12	5.53%
C	$6.62	5.28%
SG	$112	4.45%
PG	$1,318	3.51%
TG	$18,579	2.32%

Changes to riders other than the GRSA and TCA (i.e., the rates directly affected by this proceeding) slightly increase the bills of typical R, C and SG customers, and decrease the bills of typical PG and TG customers. These disparate impacts are attributable to the fact that two of these riders -- the DSMCA and PCCA -- are higher in 2015 than in 2014, while the ECA is lower. The PCCA and DSMCA constitute a relatively low percentage of the typical customer bill for all five classes. But since large customers benefit relatively more from a lower ECA than small customers, the modest reduction to the ECA in 2015 -- even when netted against the higher PCCA and DSMCA -- results in a decrease to PG and TG bills.

Q. HAVE YOU PREPARED ESTIMATED BILL IMPACTS OF THE CACJA RIDER ON TYPICAL CUSTOMERS BY CLASS?

A. Yes. Exhibit No. SBB-20 provides these impacts for 2016 and 2017. I first derive the estimated 2016 and 2017 revenue requirements based on anticipated capital and O&M costs for the eligible CACJA initiatives. I then subtract from each of these annual revenue requirements the total test-year revenue requirements for these same initiatives that the Company proposes in this proceeding. I then allocate the resulting net costs to each customer class. Finally, I develop the bill impact on a typical customer in each class based on the revenue requirements allocated to that class and the forecasted billing determinants used to collect these revenue requirements. The impacts are summarized below:

Class	2015 – 2016 Monthly $ Change	2015 - 2016 Monthly % Change
R	$1.06	1.35%
C	$1.85	1.40%
SG	$39	1.49%
PG	$520	1.34%
TG	$11,399	1.39%

Class	2016 – 2017 Monthly $ Change	2016 - 2017 Monthly % Change
R	$(0.12)	(0.15)%
C	$(0.19)	(0.14)%
SG	$(4.35)	(0.16)%
PG	$(53)	(0.14)%
TG	$(1,238.99)	(0.15)%

The projected bill impacts are expected to be negative in 2017, because the revenue requirement of the Eligible CACJA Projects is expected to decline from 2016 to 2017. The percentage bill impacts attributable to the CACJA Rider do not vary significantly among classes.

Q. ARE YOU SPONSORING ANY ADDITIONAL BILL IMPACTS?

A. Yes. The last set of bill impacts I am sponsoring is the projected changes to typical customer bills between 2015 and 2016 in Exhibit No. SBB-21. These bill impacts capture all projected changes to riders, including the proposed CACJA rider, and are summarized below:

Class	Monthly $ Change	Monthly % Change
R	$0.80	1.02%
C	$1.36	1.03%
SG	$31	1.17%
PG	$436	1.12%
TG	$9,967	1.22%

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Attachment A

Statement of Qualifications

Scott B. Brockett

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

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

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

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

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

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

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

I joined Xcel Energy as Manager, Gas Pricing and Planning, in July 2004. I assumed my current position in 2008. During my tenure with Xcel Energy I have testified on pricing issues in six general rate cases (Proceeding Nos. 05S-264G, 06S-656G, 08S-146G, 09AL-299E, 10AL-963G, and 11AL-947E), on policy issues in proceedings involving electric interruptible rates and electric Demand Side Management cost recovery and incentives, and on cost recovery issues involving the implementation of the Clean Air Clean Jobs Act, the acquisition of various generating units, and distributed generation.

PUBLIC SERVICE COMPANY OF COLORADO

ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER N

APPLICABILITY

All rate schedules for electric service are subject to a Clean-Air Clean-Jobs Act Rider (CACJA Rider) designed to recover both the capital and operations and maintenance costs associated with Eligible Clean-Air Clean-Jobs Act Projects.

The CACJA Rider for all applicable rate schedules is as set forth on Sheet No. 112D. The CACJA Rider shall be calculated for each service schedule and for customers subscribing for Standby Service.

DEFINITIONS

Clean-Air Clean-Jobs Act (CACJA)
House Bill HB10-1365 required Public Service to work with the Colorado Department of Public Health and Environment to submit a plan to the Public Utilities Commission to reduce nitrogen oxide emissions at Front Range coal plants by 70 to 80 percent by December 31, 2017. The plan, which was approved by the Commission in 2010, includes the retirement of five aging coal plant, their replacement with a new natural gas combined cycle plant, the addition of pollution control equipment at three other coal plants, and the conversion of one coal plant to a natural gas fuel source.

Eligible CACJA Projects
The approved projects included in this CACJA Rider are as follows:
1. Cherokee 5, 6, and 7 -- a natural gas combined cycle (CC) plant, including interconnection equipment.
2. Pawnee selective catalytic reduction and particulate scrubber.
3. Hayden 1 selective catalytic reduction.
4. Hayden 2 selective catalytic reduction.

CACJA Revenue Requirement
The forecasted or actual costs associated with Eligible CACJA Projects, including the following:
1. Variable non-fuel Operation and Maintenance (O&M) expenses, including chemical and water expenses. The 2015 CACJA Base Costs will include the variable non-fuel O&M for the existing Cherokee 3 coal unit. After that unit is retired at the end of 2015, subsequent CACJA rider calculations will reflect the variable O&M savings from Cherokee 3's retirement.
2. Depreciation expense.

(Continued on Sheet No. 112A)

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ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER N

DEFINITIONS – Cont'd

CACJA Revenue Requirement – Cont'd

3. State and federal current and deferred income tax expense.
4. Return on net plant for projects that have been placed into service, including the accumulated allowance for funds used during construction (AFUDC) for capital expenditures incurred before January 1, 2015.
5. Return on construction work in progress (CWIP) for capital expenditures incurred on or after January 1, 2015.

CACJA Forecasted Revenue Requirements (FRR)

Forecast of the CACJA Revenue Requirement for the subsequent calendar year, based on the best available estimates of capital expenditures, O&M expenses, taxes, and the cost of capital.

CACJA Actual Revenue Requirements (ARR)

The actual CACJA Revenue Requirement for the previous calendar year.

CACJA Base Costs (BC)

The portion of CACJA Revenue Requirements that has been approved by the Commission to be collected through the Company's base rates. This amount is currently $94,217,018, and will be adjusted to reflect any future Commission-approved changes to the base-rate recovery of Eligible CACJA Costs.

CACAJA Rider Revenues (RR)

The actual amount collected from customers in a given year through the CACJA Rider.

Allowance for Funds Used During Construction (AFUDC)

An account that tracks the accumulating costs to the Company to fund large construction projects. The account includes the financing cost of the capital invested in the construction project. These costs are tracked until the project is placed into service, at which point the accumulated AFUDC is included as part of the gross plant placed in service.

Construction Work In Progress (CWIP)

The capital expenditures the Company incurs for a project prior to its in-service date.

Return on CWIP

The Return on CWIP will be the Company's weighted average cost of capital (WACC) times the average monthly CWIP balance for the relevant period.

(Continued on Sheet No. 112B)

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 112B

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Cancels
Sheet No.

ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER N

DEFINITIONS – Cont'd

Weighted Average Cost of Capital (WACC)
The costs of debt and common equity weighted by the relative proportions of each in the Company's balance sheet. For the purpose of developing the FRR, a forecast of the debt cost and capital structure for the following calendar year will be used. For the purpose of developing both the FRR and ARR, the return on equity shall be the latest return on equity approved by the Commission for the Company's electric department.

CACJA Rider True-up
The over-recovery or under-recovery of CACJA costs from two years previous. In 2015 and 2016 the CACJA Rider True-up value shall be $0. The CACJA Rider True-up consists of two components. The first is an adjustment that reconciles the difference between the forecasted revenue requirements (FRR) and the actual revenue requirements (ARR) from two years prior. The second component accounts for the difference between the revenues the rider was designed to recover from customers and the actual dollars collected.

CLEAN AIR CLEAN JOBS ACT RIDER AMOUNT

The CACJA Rider Amount shall consist of the current year's Forecasted Revenue Requirement less the CACJA Base Costs, plus the CACJA Rider True-up.

The following formula is used to determine the total annual costs to be collected through the CACJA Rider.

$$\text{CACJA Rider} = \text{Current Year Rev.Req.} + \text{True-up}_1 + \text{True-up}_2$$
$$= (FRR_y - BC) + (ARR_{y-2} - FRR_{y-2}) + (FRR_{y-2} - RR_{y-2} - BC)$$

- FRR_y = Forecasted CACJA revenue requirements in year 'y', the current year
- BC = Amount of CACJA Base Costs that included in the Company's base rates
- FRR_{y-2} = Forecasted CACJA revenue requirements in year 'y-2', two years previous
- ARR_{y-2} = Actual revenue requirements for CACAJA projects in year 'y-2', two years previous
- RR_{y-2} = Actual revenues collected through the CACJA Rider in year 'y-2', two years previous

(Continued on Sheet No. 112C)

ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER N

CLEAN-AIR CLEAN-JOBS ACT RIDER AMOUNT – Cont'd

RATE DESIGN

The costs of approved Clean-Air Clean-Job initiatives will be allocated to rate classes based on the production demand allocator approved in the Company's latest Phase II rate case. The allocation factors will be updated based on a projection of energy use by customer class for the forecast year. Rates shall be designed by dividing the costs allocated to each class by the projected class billing determinants. Residential Demand, Secondary General, Primary General, Transmission General, Special Contracts and Standby customers shall be billed the CACJA Rider on a demand basis; all other customers will be billed on an energy basis.

INFORMATION TO BE FILED WITH THE PUBLIC UTILITIES COMMISSION

Each revision to the CACJA Rider will be accomplished by filing an advice letter no later than November 1st of each year to take effect on the next January 1 and will be accompanied by such supporting data and information as the Commission may require.

The Company shall submit an additional annual filing on or around April 15, starting in 2016. In this filing the Company will: discuss the types and levels of expenditures incurred for Eligible CACJA Projects during the previous calendar year; and compare the FRR and ARR for the previous calendar year and explain material deviations.

(Continued on Sheet No. 112D)

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 112D

P.O. Box 840
Denver, CO 80201-0840

Cancels
Sheet No.

ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER N

RATE TABLE

Rate Schedule	Applicable Charge	Monthly Rider Rate
Residential Service		
R, RTOU, RPTR, RCPP	Energy Charge	$0.00000/kWh
RD	Demand Charge	0.00/kW-Mo
Small Commercial Service		
C	Energy Charge	0.00000/kWh
NMTR	Energy Charge	0.00000/kWh
Commercial & Industrial General Service		
SGL	Energy Charge	0.00000/kWh
SG, STOU, SPVTOU	Demand Charge	0.00/kW-Mo
PG, PTOU	Demand Charge	0.00/kW-Mo
TG, TTOU	Demand Charge	0.00/kW-Mo
Special Contract Service		
SCS-7	Production Demand Charge	0.00/kW-Mo
Standby Service		
SST	Gen & Trans Standby Capacity Reservation Fee	0.00/kW-Mo
	Usage Demand Charge	0.00/kW-Mo
PST	Gen & Trans Standby Capacity Reservation Fee	0.00/kW-Mo
	Usage Demand Charge	0.00/kW-Mo
TST	Gen & Trans Standby Capacity Reservation Fee	0.00/kW-Mo
	Usage Demand Charge	0.00/kW-Mo
Lighting Service		
RAL, CAL, PLL, MSL, ESL, SL, SSL, COL, SLU	Energy Charge	0.00000/kWh
TSL, MI	Energy Charge	0.00000/kWh

ADVICE LETTER NUMBER

ISSUE DATE

DECISION NUMBER

VICE PRESIDENT,
Rates & Regulatory Affairs

EFFECTIVE DATE

ILLUSTRATIVE DEVELOPMENT OF 2016/2017 CACJA RIDER REVENUE REQUIREMENTS

DEVELOPMENT OF 2015 CACJA RIDER		
Projected 2015 COSTS		
Cherokee Combined Cycle Revenue Requirements (1)	$	48,848,000
Pawnee SCR and Scrubber Revenue Requitrements	$	38,729,000
Hayden 1 SCR Revenue Requirements	$	5,379,000
Hayden 2 SCR Revenue Requirements	$	1,384,000
SUM	$	94,340,000
Approved Test Year Costs	$	94,340,000
Incremental 2015 Costs (Projected 2015 Minus Test Year)	$	-
True-Up of Under (Over) Recovery in 2013	$	-
Total 2015 CACJA Rider Revenue Requirements	**$**	**-**
Filing Date		1-Jun-14
Implementation Date		1-Jan-15
Actual 2015 CACJA Revenue Requirements	$	95,340,000
Actual 2015 CACJA Rider Recovery	$	94,840,000

DEVELOPMENT OF 2016 CACJA RIDER		
Projected 2016 COSTS		
Cherokee Combined Cycle Revenue Requirements (1)	$	85,918,000
Pawnee SCR and Scrubber Revenue Requitrements	$	37,457,000
Hayden 1 SCR Revenue requirements	$	8,648,000
Hayden 2 SCR Revenue Requirements	$	3,394,000
SUM	$	135,417,000
Approved Test Year Costs	$	94,340,000
Incremental 2016 Costs (Projected 2016 Minus Test Year)	$	41,077,000
True-Up of Under (Over) Recovery in 2014	$	-
Total 2016 CACJA Rider Revenue Requirements	**$**	**41,077,000**
Filing Date		1-Nov-15
Implementation Date		1-Jan-16
Actual 2016 CACJA Revenue Requirements	$	134,417,000
Actual 2016 CACJA Rider Recovery	$	134,917,000

DEVELOPMENT OF 2017 CACJA RIDER		
Projected 2017 COSTS		
Cherokee Combined Cycle Revenue Requirements (1)	$	82,345,000
Pawnee SCR and Scrubber Revenue Requitrements	$	36,146,000
Hayden 1 SCR Revenue requirements	$	8,281,000
Hayden 2 SCR Revenue Requirements	$	4,616,000
SUM	$	131,388,000
Approved Test Year Costs	$	94,340,000
Incremental 2017 Costs (Projected 2017 Minus Test Year)	$	37,048,000
True-Up of Under (Over) Recovery in 2015	$	500,000
Total 2017 CACJA Rider Revenue Requirements	**$**	**37,548,000**
Filing Date		1-Nov-16
Implementation Date		1-Jan-17
Actual 2015 CACJA Revenue Requirements	$	131,388,000
Actual 2015 CACJA Rider Recovery	$	129,888,000

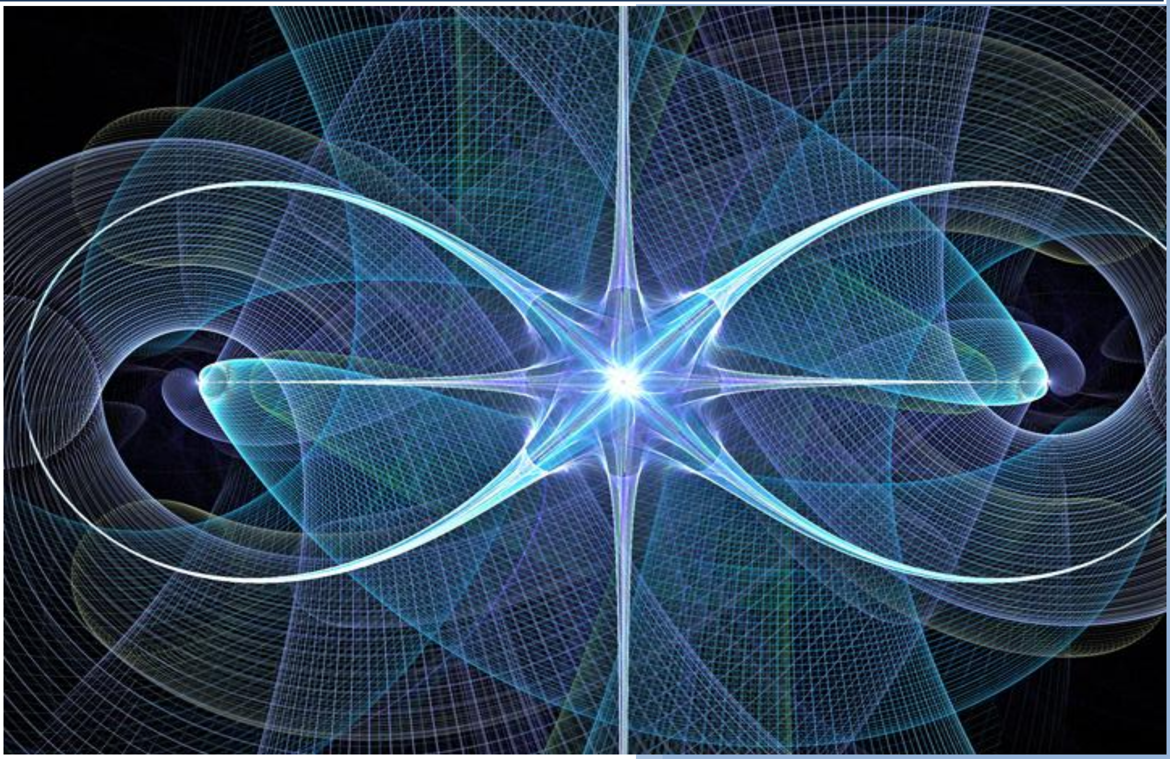
DEVELOPMENT OF 2018 CACJA RIDER		
Incremental 2017 Costs (Projected 2017 Minus Test Year)		Not Eligible for Recovery
True-Up of Under (Over) Recovery in 2016	$	(500,000)
Total 2018 CACJA Rider Revenue Requirements	**$**	**(500,000)**

DEVELOPMENT OF 2019 CACJA RIDER		
Incremental 2018 Costs (Projected 2018 Minus Test Year)		Not Eligible for Recovery
True-Up of Under (Over) Recovery in 2017	$	1,500,000
Total 2019 CACJA Rider Revenue Requirements	**$**	**1,500,000**

NO CACJA RIDER IN 2020

(1) Includes the variable O&M expense attributable to Cherokee 3.

A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations



Pamela Morgan

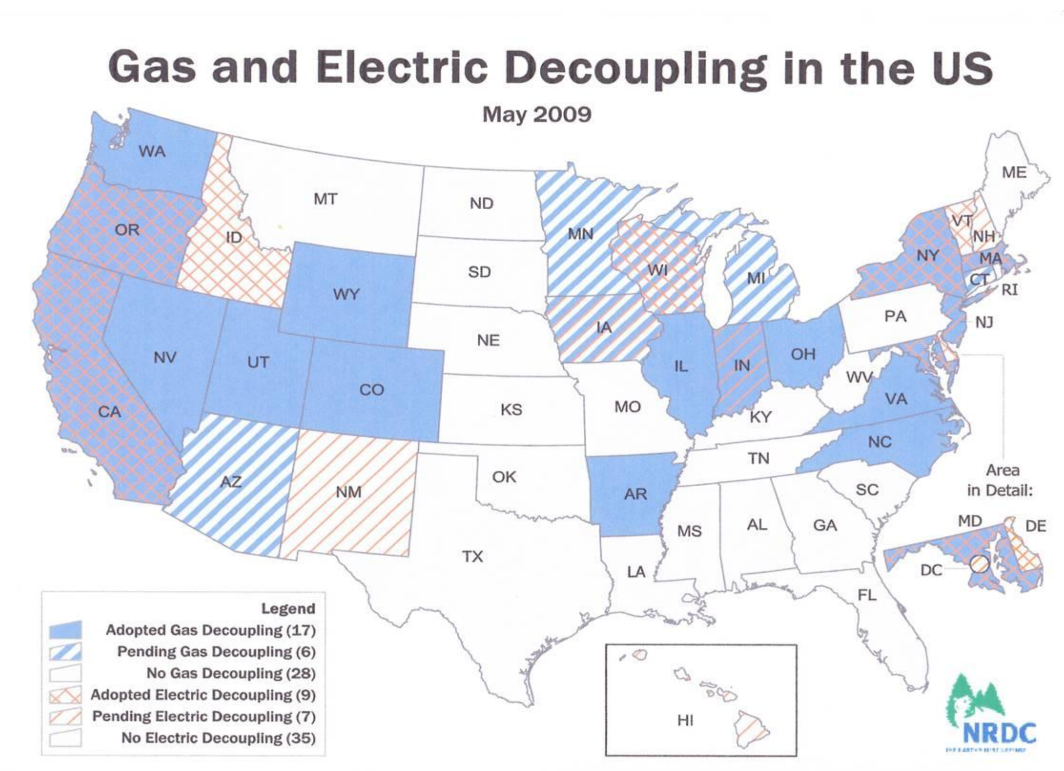
Graceful Systems LLC

Revised February 2013

Summary

With the turn of the century and its many energy-related events – the western power market crisis, record and unexpected natural gas prices, slowing (electricity) or falling (natural gas) demand, growing concern about climate change – energy utility funding for energy efficiency programs revived after the 1990s lull. Along with renewed funding, that spanned both types of energy utilities and restructured as well as vertically integrated markets, came a serious look at decoupling. Decoupling is a regulatory tool that first appeared in the 1980s as a means of helping utilities overcome the throughput incentive; i.e., the contribution to gross income that occurs with every energy unit sold because the unit (variable) price recovers some of a utility's fixed costs. A decoupling mechanism separates a utility's revenues from its unit sales volumes without affecting the design of customer rates.[1] In other words, utility customers continue to pay for service primarily according to the amount of energy they use. The utility's revenue is based on a formula approved by its regulator.

This report builds on a 2009 report, which summarized the designs and rate impacts associated with the decoupling mechanisms of 28 local natural gas distribution utilities (LDCs) and 12 electric utilities, across 17 states. Much has happened in the three intervening years. This was the map the 2009 report addressed:



[1] Some also use the term "decoupling" to describe rate design changes, such as straight fixed-variable rates that recover all utility fixed costs in a fixed price per billing period and all variable costs according to usage. While these approaches achieve the similar results for utilities as decoupling mechanisms described above, they often do so with significant impact to customers. These impacts include shifting cost recovery within a customer class and weakening incentives to invest in energy efficiency and distributed generation. Moreover, the result can be rigid rate designs that may send wholly inadequate price signals and permit little experimentation. This report addresses only decoupling mechanisms that operate at the regulatory level, leaving rate design largely untouched.

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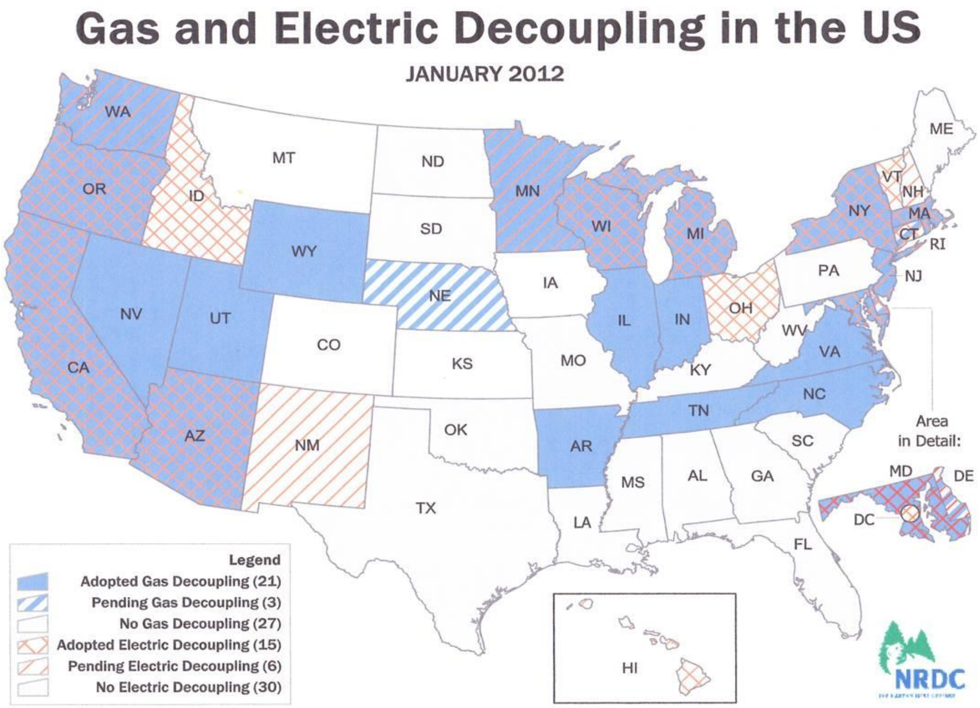
Now covering 25 states, including 52 LDCs and 25 electric utilities,[2] this is the map that this report addresses:



This report[3] summarizes the decoupling mechanism designs these utilities use and the rate adjustments they have made under those mechanisms. Some of these utilities make decoupling adjustments monthly; some semi-annually; some annually; and others on an as-needed basis. In total, this report estimates the retail rate impacts of 1269 decoupling mechanism adjustments since 2005.

With respect to decoupling rate adjustments, even though jurisdictions around the U.S. have now performed a vastly greater number of adjustments, the primary conclusions of the prior study remain valid based on this updated and expanded research:

- **Decoupling rate adjustments are mostly small – within plus or minus two percent of retail rates.** Across the total of all utilities and rate adjustment frequencies, 64% of all adjustments are within plus or minus 2% of the retail rate. This amounts to about \$2.30 per month for the average electric customer, and about \$1.40 per month for the average natural gas customer.[4]

[2] Indication on the map that a given state has adopted decoupling for its gas or electric utilities, or both, does not necessarily mean that every utility in the state has a decoupling mechanism. The detailed state reports that appear after this summary indicate clearly which utilities in each of the states indicated on the map has a decoupling mechanism and whether that mechanism is currently active or has expired.

[3] This report is a corrected version of the report dated December 2012. That report inadvertently omitted four decoupling mechanisms in Michigan: three for natural gas utilities and one for an electric utility. This report includes those mechanisms in all tables and the Michigan-specific detail is now correct.

[4] The electric calculation uses an average monthly consumption of 1000 kWh and the 2010 annual average residential price of 11.54¢/kWh from the Energy Information Administration (EIA). An average monthly consumption does not make as much sense for natural gas customers because usage is seasonal. EIA's 2010 report on Trends in U.S. Residential Natural Gas Consumption reported a 2009 average annual use of 74 Mcf for

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About 80% are within plus or minus 3%. The primary distinction on size variation exists between mechanisms that adjust monthly and those that adjust on some other basis, most commonly annually. For natural gas mechanisms that adjust monthly, the adjustments are within plus or minus 2% only half of the time; for electric monthly decoupling mechanisms, this is 65% of the time. Electric decoupling mechanisms that adjust other than monthly have been within plus or minus 2% most of the time – 85%. Gas mechanisms that adjust other than monthly have stayed within this range 75% of the time. In other words, the more frequent adjustments yield more volatile rate changes.

- **Decoupling mechanism adjustments yield both refunds and surcharges.[5]** Across all electric and gas utilities and all adjustment frequencies, 63% were surcharges and 37% were refunds. There are many reasons that actual revenues can deviate from the revenues assumed in ratemaking. Most of the mechanisms do not adjust revenues to remove, or normalize, the effects of weather.[6] If the mechanism does not normalize weather, the primary cause of greater and lower sales volumes, particularly on a monthly basis or for residential rate schedules, is usually weather effects. Other causes include energy efficiency, programmatic and otherwise, customer conservation, price elasticity, and economic conditions. Regardless of the particular combination of causes for any given adjustment, no pattern of either rate increases or decreases emerges.

Figure 1, below, summarizes the distribution of rate adjustments due to decoupling from 2005 to 2011,[7] followed by the table[8] that supports the chart.

---

residential customers. Spreading this over 12 months is 6.16 Mcf, which when multiplied by the 2010 average annual rate of $11.39/Mcf is about $70.

[5] The calculations are not the actual rate changes that occurred because this is usually impossible to determine unless the decoupling adjustment is occurring by itself and the utility calculates the rate change in its filing. Otherwise, the actual rate change depends on what rate adjustments might be ending (including a prior decoupling adjustment) and what new ones other than decoupling might be starting. See the section on methodology for more information.

[6] For natural gas utilities, it is common that a separate mechanism adjusts rates for weather variations for the winter heating season months only.

[7] This chart and table show "All" adjustments as a percentage of retail rates, regardless whether gas or electric, monthly or annual. Adjustments done either just for residential customers or for the entire customer base appear under the category of "Residential/All." The "Commercial" category captures the customer class often referred to as general service or small general service. "Other" includes the few decoupling mechanism adjustments found that applied to industrial or larger commercial customers. For some utilities, the study recorded only the residential and general service or small commercial adjustments, even though the mechanisms applied to other rate schedules. This was done to keep the number somewhat manageable and because retail rate detail at that level is not available.

[8] In all of these tables, the positive number ranges mean that customers received surcharges while the negative number ranges mean that customers received refunds.

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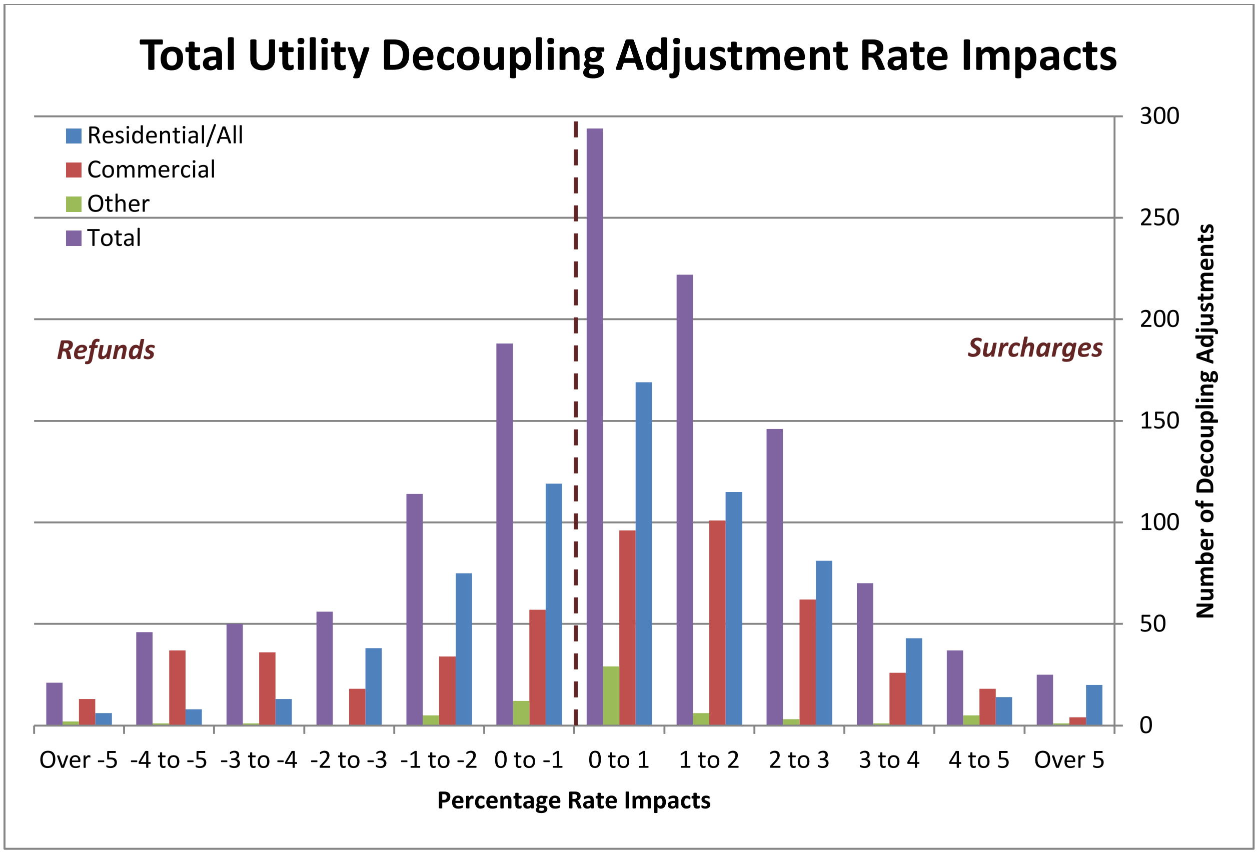

Adjustment Amount	Residential/All	Commercial	Other	Total
Over 5	20	4	1	25
4 to 5	14	18	5	37
3 to 4	43	26	1	70
2 to 3	81	62	3	146
1 to 2	115	101	6	222
0 to 1	169	96	29	294
0 to -1	119	57	12	188
-1 to -2	75	34	5	114
-2 to -3	38	18		56
-3 to -4	13	36	1	50
-4 to -5	8	37	1	46
Over -5	6	13	2	21

In addition, this report updates the summary of the features various states and utilities have used in constructing their decoupling mechanisms. Although there are interesting variations, a notable similarity has emerged in designs, with differentiation depending on the utility's status as either a distribution only utility or a vertically integrated[9] electric utility. This report also reviews state decisions whether or not to reduce a utility's authorized return on common equity (ROE) in conjunction with the

[9] For purposes of this report, vertically-integrated utility refers to any utility that owns at least some of the generation it uses to provide retail service, whether or not it owns a majority or all. Thus, the report considers the California utilities vertically integrated even though they purchase a significant amount of generation.

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adoption of decoupling for that utility, the amount of any such reduction and the reasons why and why not. The conclusion discusses observations made on the topic of decoupling during the preparation of this report.

Immediately below is a brief explanation of "decoupling" [10] as used in this report, followed by a short description of the methodology used to calculate rate adjustments and a summary of the findings. The discussions of features and ROE follow, with the conclusion. Decoupling information on a state-by-state basis is attached, along with the table showing the ROE reduction made, if any, in each of the cases in which a commission adopted a decoupling mechanism.

Decoupling

Decoupling, as used in this study, is a regulatory mechanism that adjusts rates periodically to ensure that the amount a utility books as revenue for fixed cost recovery is no more and no less than the amount of revenue authorized by the regulator for that cost coverage. Under traditional ratemaking methodologies, a utility's revenues result from the combination of its customer accounts, customer energy use (in therms or kilowatt-hours) and customer demand (this usually applies only to commercial customers with larger usage and industrial customers) and the rates the regulator has approved. For residential and smaller-usage commercial customers, most of the utility's revenue will derive from energy use. This is what causes the throughput incentive: the more energy customers use, the more revenue the utility collects and, to the extent this revenue exceeds variable costs, the better its financial performance.

Decoupling changes the driver of revenue from energy use to a basis approved by the regulator in the decoupling mechanism design. Some mechanisms use the revenue authorized in the utility's last general rate case; others adjust that for specific cost changes or according to a formula, and still others calculate revenue on a per-customer account basis rather than as a single dollar amount.

A decoupling mechanism does not affect the design of customer utility rates. For example, most states design rates for customers with relatively low levels of use such that the biggest driver of a customer's bill is the amount of energy they use. Such a design provides the best incentive for customers to conserve or use energy more efficiently because the reduced consumption translates directly into a reduced bill.

On some regular basis, a decoupling mechanism causes a rate adjustment to ensure that customers, in effect, receive refunds or pay surcharges based on whether the revenues the utility actually received from customers were less or greater than the revenues the mechanism calculates. This difference can occur for many reasons, primary among which are weather, economic conditions, energy efficiency programs and incentives, and customer behavior that cause the use of electricity or natural gas to differ from amounts assumed in the ratemaking process.

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[10] For a more in-depth explanation of decoupling and decoupling mechanisms, see Regulatory Assistance Project, *Revenue Regulation and Decoupling: A Guide to Theory and Application,* June 2011, www.raponline.org/document/download/id/902; National Action Plan for Energy Efficiency, *Aligning Utility Incentives with Investments in Energy Efficiency*, November 2007, www.epa.gov/cleanenergy/energy-programs/suca/resources.html; Natural Resources Defense Council, *Removing Disincentives to Utility Energy Efficiency Efforts,* May 2012, www.nrdc.org/energy/decoupling/; Sullivan, D., D. Wang and D. Bennett, "Essential to Energy Efficiency but Easy to Explain: Frequently Asked Questions about Decoupling," *The Electricity Journal,* Vol 24, Issue 8, October 2011.

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The overwhelming majority of decoupling mechanisms cover only a utility's fixed costs associated with local delivery of natural gas or electricity.[11] Seven electric utility decoupling mechanisms, however, include the fixed costs associated with generating plants owned by the utility or other supply-related fixed costs.[12]

Methodology

Rate adjustments made pursuant to decoupling mechanisms are reported here as a percentage of retail rates. For a few utilities, as noted in footnotes, this percentage rate change was either specified in the adjustment filing or provided by the utility for purposes of this study. For most of the adjustments, however, utility filings provided with the adjustment but not the retail rate. To estimate the rate impact, the report uses data from the Energy Information Administration (EIA). For gas utilities, the data is generally the appropriate class (residential, commercial or industrial) for the year of the adjustment. 2012 is an average of the months to date. For gas utilities that make monthly decoupling adjustments, the study used monthly EIA gas prices. For months that did not have a retail price, the study uses the price from the month before. For electric utilities, utility specific retail prices are available for years before 2011. For 2011 and 2012 adjustments, the study uses statewide data except as noted. All data on the adjustments are from utility filings, with any additional calculations noted. The resulting adjustment percentages should not be viewed as precise; these are estimates that are correct in general magnitude, not tenths or hundredths of a percentage point.

Moreover, regardless of whether the rate impact is from the utility or calculated from EIA data, the percentage shown is not necessarily what customers experienced. Experienced rate changes would vary depending on whether the prior decoupling adjustment was more or less than the adjustment being put into place. For example, if the prior adjustment was a refund of 0.02 cents per kWh and the new adjustment is a refund of 0.01 cents per kWh, customers will experience a rate increase, even though the adjustment is negative because the prior adjustment terminates. Experienced rate changes may also depend on whether the utility was changing rates for any other adjustment clauses at the time, as is often the case.

Summary Tables and Charts

Below are chart/table sets for gas utilities that make decoupling adjustments monthly and those that make decoupling adjustments annually or on some frequency other than monthly, and the same two sets for electric utilities. Overall, the charts reveal some differences in the distribution of surcharges and refunds and the overall rate impacts between (1) gas utilities and electric utilities; and (2) decoupling mechanisms that make monthly rate adjustments and those that make adjustments on some other basis. The table below summarizes these differences:

	Gas Utilities		Electric Utilities	
Frequency Of	Surcharges	Refunds	Surcharges	Refunds
Mechanisms Adjusting Monthly	49%	51%	66%	34%
Mechanisms Adjusting "Other"	65%	30%	64%	36%

[11] For natural gas utilities, these fixed costs are virtually all of their fixed costs, although some pipeline-related fixed costs may flow through purchased gas cost adjustment clauses. For electric utilities, the limitation to distribution fixed costs stems from state retail market restructuring, which resulted in electric utilities that do not own generation or, if they do so, do not include such generation in revenue requirement in a traditional sense.
[12] This could include the fixed costs of transmission as well.

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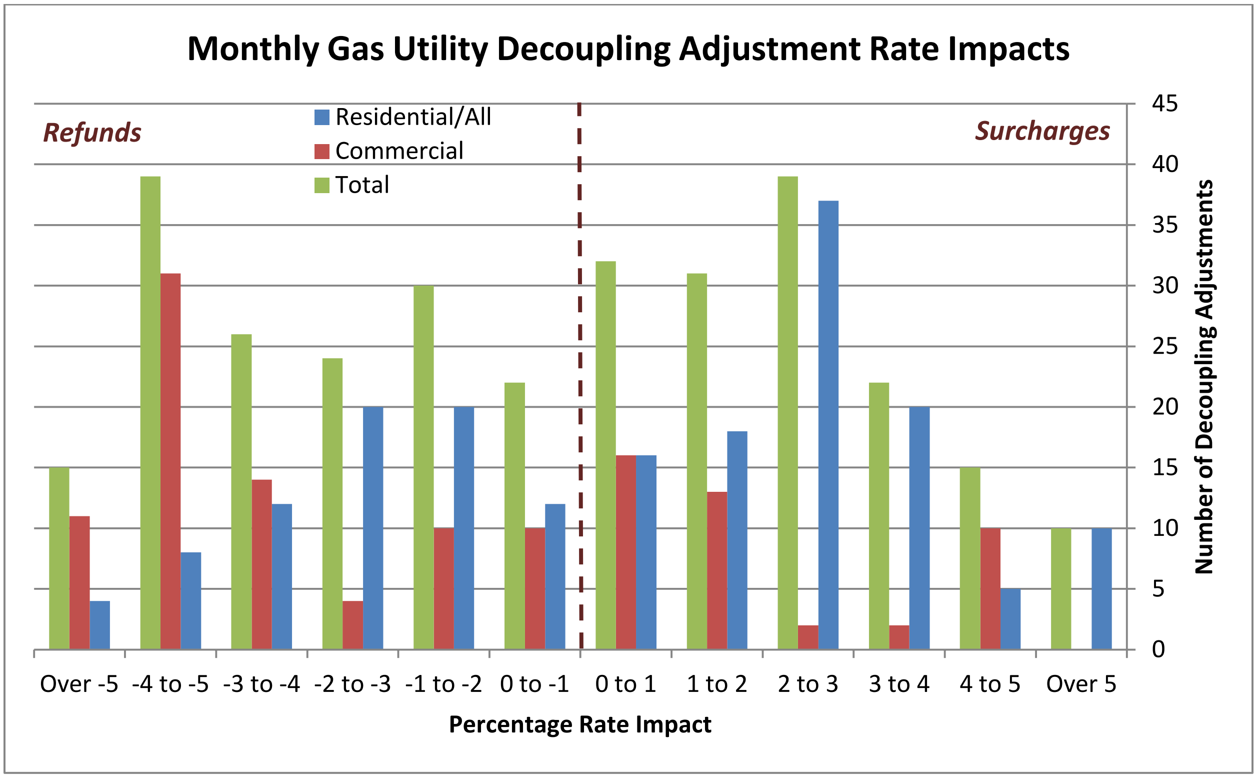
The charts and tables below follow this order:

- Monthly gas utility decoupling mechanisms
- Annual and other gas utility decoupling mechanisms
- Monthly electric utility decoupling mechanisms
- Annual and other electric utility decoupling mechanisms



Adjustment Amount %	Residential/All	Commercial	Total
Over 5	10		
4 to 5	5	10	15
3 to 4	20	2	22
2 to 3	37	2	39
1 to 2	18	13	31
0 to 1	16	16	32
0 to -1	12	10	22
-1 to -2	20	10	30
-2 to -3	20	4	24
-3 to -4	12	14	26
-4 to -5	8	31	39
Over -5	4	11	15

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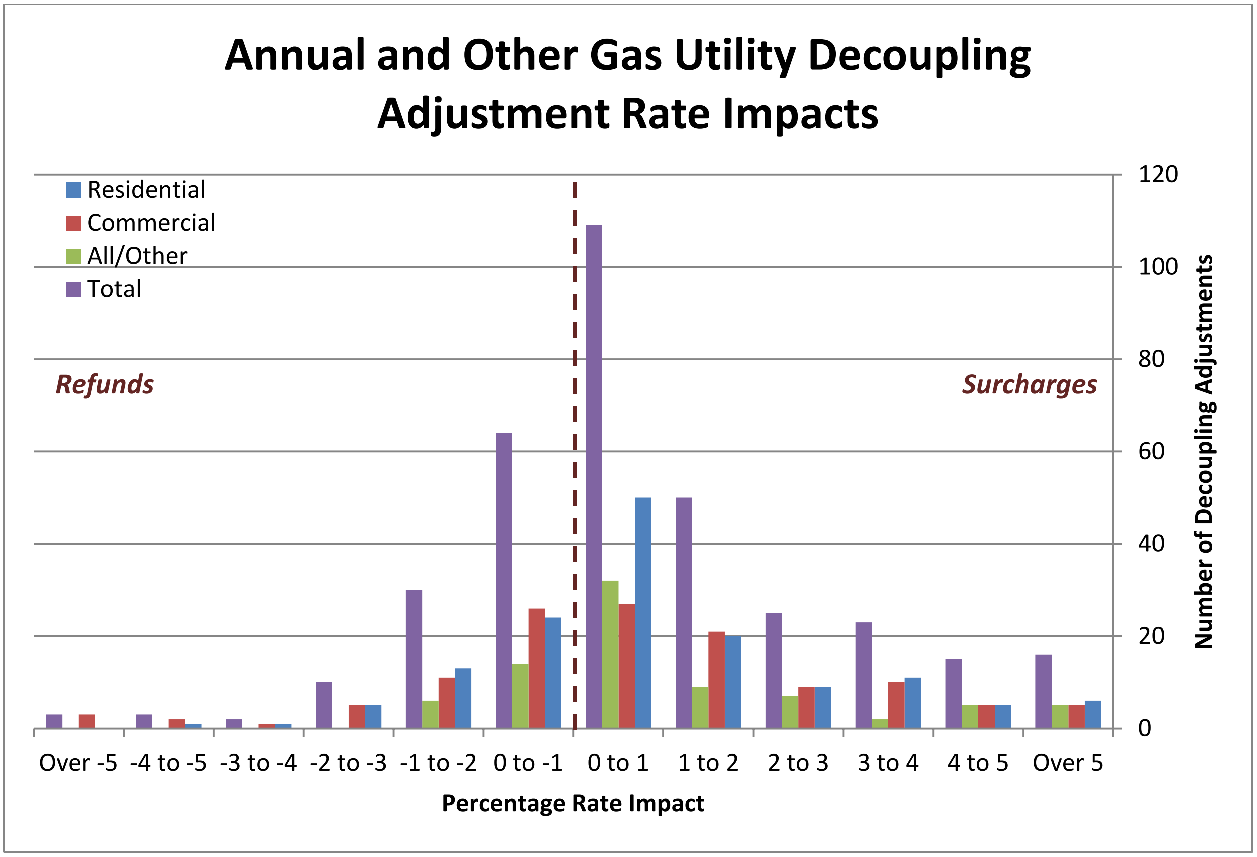

Adjustment Amount	Residential/All	Commercial	All/Other	Total
Over 5	8	4	1	13
4 to 5	6	5	5	16
3 to 4	11	11	1	23
2 to 3	15	11	3	29
1 to 2	37	25	6	68
0 to 1	88	26	10	124
0 to -1	45	25	5	75
-1 to -2	18	12	3	33
-2 to -3	5	5		10
-3 to -4		1		1
-4 to -5	1	2		3
Over -5	2	1		3

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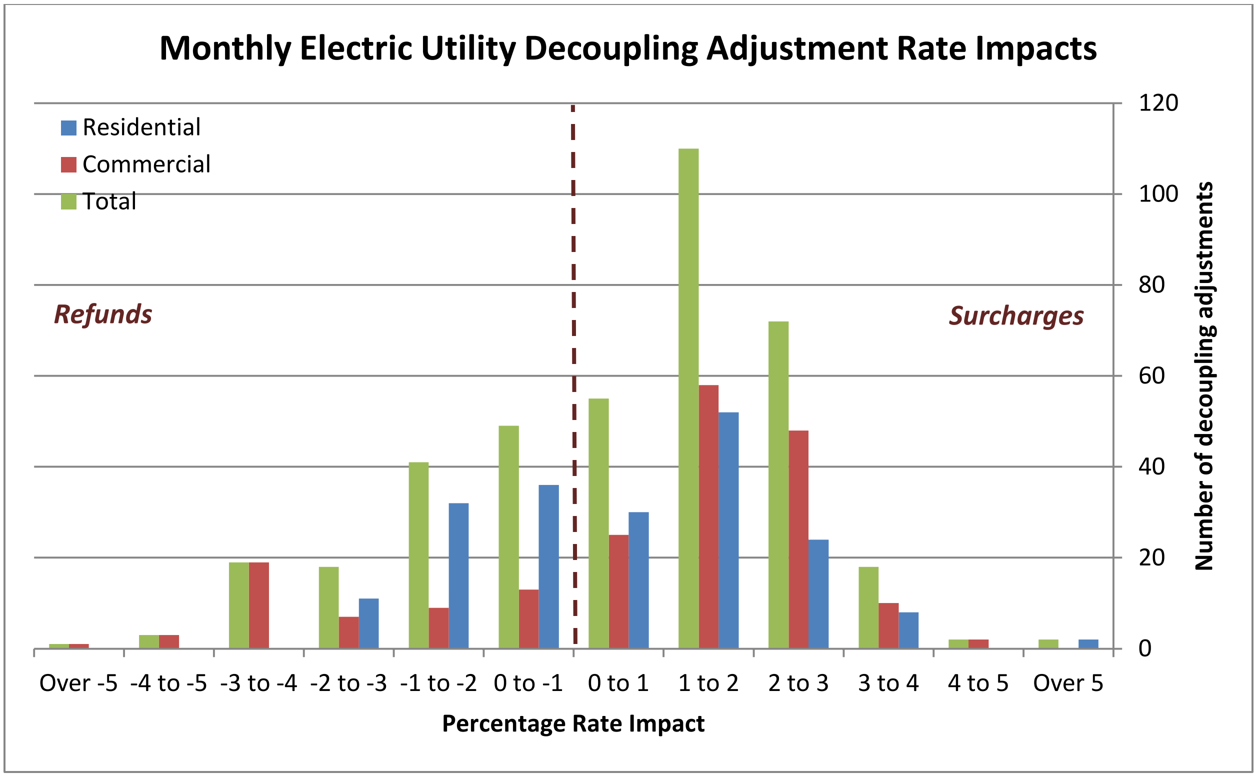

Adjustment Amount %	Residential	Commercial	Total
Over 5	2		2
4 to 5		2	2
3 to 4	8	10	18
2 to 3	24	48	72
1 to 2	52	58	110
0 to 1	30	25	55
0 to -1	36	13	49
-1 to -2	32	9	41
-2 to -3	11	7	18
-3 to -4		19	19
-4 to -5		3	3
Over -5		1	1

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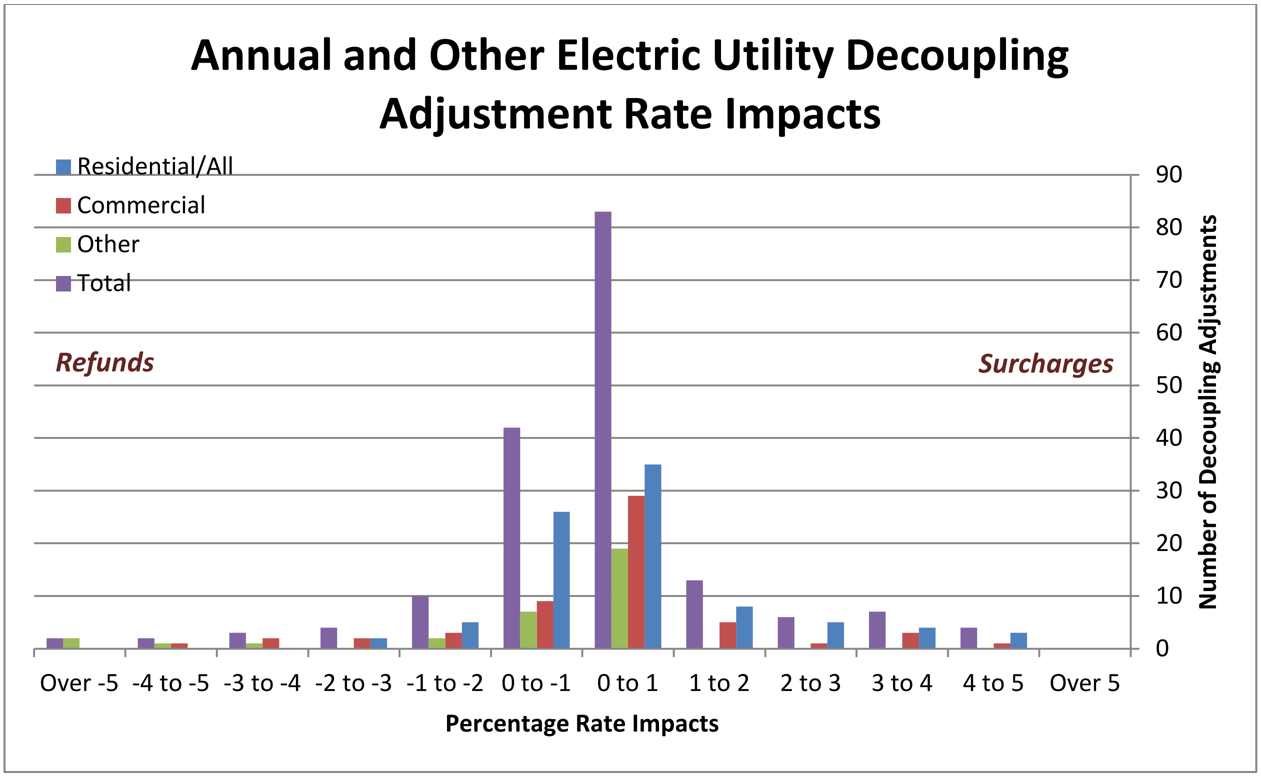

Adjustment Amount %	Residential/All	Commercial	Other	Total
Over 5				
4 to 5	3	1		4
3 to 4	4	2		6
2 to 3	5	1		6
1 to 2	7	5		12
0 to 1	34	29	19	82
0 to -1	26	9	7	42
-1 to -2	5	3	2	10
-2 to -3	2	1		3
-3 to -4		2	1	3
-4 to -5		1	1	2
Over -5			2	2

Decoupling Mechanism Design Features

Any state or utility considering decoupling must generally answer at least five questions:

- Should the authorized revenue used to calculate the decoupling adjustment (actual revenue less authorized revenue) change from year to year by any means other than a general rate case?
- How often should we make a decoupling adjustment?
- Should the actual revenues used in the mechanism be adjusted to remove the revenue effects of sales resulting from weather that is warmer or colder than the weather assumed in setting rates?

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- When we compare actual revenues to authorized revenues, should we do that on an overall utility basis or by customer class or rate schedule?
- Should there be any limits on the size of decoupling adjustments that occur and, if there are limits, what should happen to refund or surcharge amounts in excess of the limits? Should the decoupling apply to the full difference between actual and authorized revenues or only some part of it?

The table below summarizes the numbers of mechanisms that have answered these questions in different ways, sorted by electric and gas utilities. The notes following the table explain the terms used, such as "revenue-per-customer" and "attrition adjustment."

Feature	Gas Decoupling	Electric Decoupling	Comments
Revenue change between rate cases			
Revenue-per-customer[1]	46	15	Predominantly used by natural gas utilities and distribution-only electric utilities, although also vertically-integrated utilities in Idaho, Oregon, Michigan and Wisconsin.
Attrition adjustment[2]	13	11	California allows the most complete attrition adjustment but Hawaii, Massachusetts, New York, and Rhode Island allow some updating of the revenue requirement.
No change		3	
Timing of Rate True-ups			
Annual	34	19	
Semi-annual/quarterly/no set schedule	8		
Monthly	7	4	Illinois, Maryland, Virginia and Washington D.C. require monthly adjustments under their utilities' decoupling mechanisms.
Triggers[3]	6	5	New York only
Weather[4]			
Not weather-adjusted	35	21	Weather can vary considerably from the "normal" assumed in ratemaking, particularly on a monthly basis.
Weather-adjusted	14	2	
Per class calculation and adjustments[6]	40	15	
Limit on adjustments and/or dead-band[5]	14	5	

Notes to table

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1. “Revenue per customer” means that the decoupling mechanism calculates the authorized revenue to which the utility will reconcile its actual revenues by dividing the last approved fixed cost revenue requirement by the number of customer accounts assumed in that ratemaking process, and then multiplying the per-customer amount by the number of customers in the current decoupling period. For example, if the authorized fixed cost revenue requirement was $1 billion and the ratemaking number of accounts was 1 million, the fixed cost per customer amount would be $1000/year. If, during a given decoupling year, the actual number of customer accounts was 1,050,000, the utility’s authorized revenue would be $1.05 billion. To the extent actual (weather-adjusted or not) revenues exceeded this, it would refund the difference; if actual revenues were less than this, it would recover the difference.
2. “Attrition adjustment” means that the utility has some means (such as a formula) of adjusting its authorized fixed cost revenue requirement for changes other than a general rate case. Thus, the comparison of actual revenues or actual per customer revenues is to an updated “authorized” revenue amount. This may or may not occur through the decoupling mechanism.
3. “Triggers” refers to the feature included in most of the New York utilities’ decoupling mechanisms that allow and/or require that the utility file for a decoupling adjustment when the accumulated balance (positive or negative) reaches a certain threshold. This feature largely negates the need for the cap on adjustments discussed below.
4. “Weather” refers to revenue variances attributable to actual weather differing from the weather conditions assumed in the ratemaking process. If a decoupling mechanism uses actual revenues that are not weather-adjusted, that means that revenue variances attributable to weather will affect the size of the customer refund or surcharge.
5. “Per class calculation and spread of adjustments” means that the mechanism determines the difference between the authorized fixed cost revenue and the actual revenue on a per class or per rate schedule basis and refunds or surcharges the resulting amount only to that rate schedule or customer class. Included in the count are utilities for which the decoupling mechanism applies only to one customer class or rate schedule. Only eight utilities have mechanisms that spread the decoupling adjustment to all customer classes equally.
6. “Limit on adjustments or a dead-band” refers to features in a given decoupling mechanism that limit the size of any (or a cumulative set of) customer refund or surcharge, or in the case of a dead-band, exclude a certain amount of the variance (again, refund or surcharge) before calculating the positive or negative decoupling rate increment. For most of the mechanisms that have a limit on the size of decoupling adjustments, any amount not refunded or surcharged carries over to the next decoupling period. That is not always the case, however. Most mechanisms with this feature set limits in terms of a set percentage of overall revenues but a few use fixed dollar amounts.

Designing decoupling mechanism to calculate refunds or surcharges on a customer class-by-customer class basis is common. Not infrequently this design choice appears in conjunction with exempting the industrial and other large-use customer classes from the mechanism altogether. While this design choice guards against any change in customer class cost allocations between general rate cases, it requires considerable confidence in the cost allocations that exist and can result in one customer class receiving a rate increase while another receives a decrease. At least one commission spread a decoupling surcharge across all customers notwithstanding the tariff requirement of a class-by-class spread because of discomfort with the cost allocations and the disparate impacts on the customer classes covered by the mechanism.

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Fewer states or utilities have found a need to set limits or dead-bands on the effectiveness of a decoupling mechanism. For some that do, the limits are simply a rate management tool; refund or surcharge balances not included in adjustments carry forward to future periods. For others, however, this feature acts as a limit to the decoupling mechanism's effectiveness in addressing the throughput incentive. This occurs if the limits foreclose the refund or surcharge of some revenue variances, whether those fall within a dead-band, are screened away,[13] or fall outside the set limits.

Beyond these five categorical choices, states and utilities have included unique or uncommon features in decoupling mechanisms. Four utilities have (or had – two of these mechanisms have since expired) decoupling that provides only for surcharges, not refunds. One utility makes a price elasticity adjustment along with its decoupling true-up, anticipating the effect that the commodity cost change may have on demand. Moreover, considerable variation exists among utilities in the extent to which certain of the costs included in the fixed cost revenue requirement may be subject to automatic cost recovery clauses. As with any regulatory matter, the response crafted to a given issue such as the throughput incentive will depend on the state and the utility's circumstances, history, and preferences.

The ROE Issue

Although a few exceptions exist, almost every order approving a utility decoupling mechanism addresses the argument by one or more parties that the adoption of decoupling requires a reduction in the utility's authorized ROE. At the heart of the argument are two questions: (1) does decoupling reduce a utility's business risk and, if so can one quantify this reduction? and (2) assuming one can quantify the reduction in risk, can one apply this quantification in some mechanical way to the overall determination of an appropriate ROE?

The table below summarizes the commission decisions on the ROE issue:

ROE Reduction	Number of Decisions	Result of Settlement Agreement?
None	60	29
10 basis points	9	4
25 basis points	3	1
50 basis points	4	
Total	72	33

As the table demonstrates, the large majority of decisions adopting decoupling make no ROE reduction. Of the reductions that occurred, 10 basis points[14] was the most common amount. The largest reduction – 50 basis points – is limited to the jurisdictions of Maryland and Washington D.C. Maryland, with three of these decisions, has not imposed an ROE reduction in two other cases, one of which concerned a settlement agreement and one that did not. One of the three decisions making a 25-basis point reduction concerned adoption of a settlement agreement; the other two did not. Almost half of the cases including a 10-basis point reduction were approvals of settlement agreements.

Just over half of the time a utility has adopted decoupling, it has been as the result of commission approval of multi-party settlement agreements. It is impossible to know what the settling parties

[13] Washington applies a 45% factor to the revenue variation Avista calculates to eliminate revenue variation that may relate to causes other than the utility's energy efficiency efforts.
[14] Basis points are hundredths of a percent. Thus, 9.10% is 910 basis points; 50 basis points is 0.5%.

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discussed in the course of reaching a settlement but one can conclude that the level of benefits to the utility and customers satisfied all signing parties. Settlements resolved the issue in favor of no ROE reduction in Arkansas, Colorado, Georgia, Idaho, Indiana, Maryland (for Washington Gas Light), Michigan (for Upper Peninsula Power), New Jersey, New York, North Carolina, Ohio, Oregon, Utah, Washington, and Wisconsin.[15] In virtually all these cases, the commission's consideration of the issue is limited to a determination whether the settlement in its entirety is in the public interest.

The next most common reason for the lack of an ROE reduction is Commission rejection of making such an adjustment separately from all of the other considerations that result in an ROE decision. In Massachusetts, Connecticut and Hawaii, the Commissions found that decoupling reduces the utility's business risk but declined any specific quantification and considered this along with model results, comparisons to proxy companies, and other considerations such as management quality and public policy changes in choosing an ROE within the range to which experts had testified. Related reasons against making an ROE reduction were Wyoming's finding that there was no logical basis for a specific amount, Minnesota's conclusion that the risk reduction was small, and New York's finding that decoupling mechanisms were becoming commonplace and, thus, were already factored into the ROE models.

Other reasons provided against making an ROE reduction were that:

- The decoupling mechanism was a pilot program and the Commission could address the ROE issue if and when it became permanent (Michigan)
- The Commission had already significantly limited the mechanism and the evidence offered applied only to "full" mechanisms (Washington)
- The decoupling mechanisms were considered under specific statutory authority and no party raised the ROE issue or it was not found relevant (Virginia and Rhode Island)
- Other risk changes offset the decoupling ROE effect (New York – Consolidated Edison)

Among the handful of regulatory decisions making an ROE reduction for decoupling outside of a settlement, the reasoning generally centers on a conclusion that a decoupling mechanism must reduce risk because the revenue the utility will book is now more certain. Variations of this appear in the cases listed in the table from Illinois, Maryland, New York, Oregon, Tennessee and Washington D.C. Some cases note that decoupling mechanisms are not yet widespread among the proxy group used to identify the range of reasonable ROEs for a given utility (New York), although other commissions have found comparisons to proxy groups inconclusive because of the lack of uniformity among decoupling mechanisms (Nevada) and a few cite the number of proxy companies with decoupling as a reason for declining to make an ROE reduction. Other decisions making reductions note that one or more witnesses, including witnesses for the utility, actually provided different estimates of the required ROE with and without the decoupling mechanism (Washington D.C.) or chose an ROE reduction somewhere between the amount supported by the utility and that supported by other parties (Maryland, Nevada).

The two primary findings of this study shed some light on the empirical questions involved in the ROE issue.

[15] On the other hand, settlements included an ROE reduction in Arizona, Arkansas, Maryland, and New York (for St. Lawrence Gas). In a few other states – notably California with its six decoupled utilities – it is unclear whether the adoption of decoupling occurred through a settlement.

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First, it is clear that decoupling adjustments are both surcharges for under-collections of revenues for fixed costs and refunds of over-collections of such revenues. In the refund situation, the utility has foregone the opportunity to collect more revenue (for fixed costs) than the amount authorized in its last general rate case. While opponents of decoupling tend to testify extensively about the risk reduction associated with the possibility of surcharges, acknowledgements of lost opportunity associated with possible refunds are far more infrequent. Whether these changes in risk and opportunity affect income depends on whether those fixed costs are the same, less or more than the authorized amount. Fixed costs are not necessarily stable between rate cases; they vary, just on bases other than usage. The size of a utility's construction program will affect the change in its "fixed" its interest and depreciation costs. Inflation, the presence or absence of storms and other such events will affect operations and maintenance expenses. Without looking at substantial amounts of empirical data, it is difficult to conclude that the risk of under-collecting fixed-cost revenue is greater than the lost opportunity of over-collecting fixed costs, assessed in consideration of changes between authorized and actual prudent fixed costs.

Second, regardless whether refund or surcharge, decoupling adjustments are, by and large, small. It appears that neither the under-recovery risk reduction or over-recovery lost opportunity are very significant. Given the relatively small amounts of the decoupling adjustments, however, it is not apparent that this reduction is very significant.

A number of commissions addressing the ROE issue have noted the absence of empirical evidence regarding how, it at all, decoupling changes a utility's business risk. As noted previously, there is now one empirical study concluding that decoupling may actually increase a utility's overall business risk to some extent. "The Impact of Decoupling on the Cost of Capital – An Empirical Investigation," a 2011 Discussion Paper by the Brattle Group and authored by Joseph B. Wharton, Michael J. Vilbert, Richard E. Goldberg and Tony Brown. Perhaps additional empirical work will help put the controversy to rest. In the meantime, commissions should keep in mind that:

- Decoupling adjustments will be both surcharges and refunds
- The actual adjustments are likely to be small
- Most commissions have declined to make an ROE reduction in connection with the adoption of decoupling.

Concluding Observations

The vast amount of data and number of decisions reviewed in the preparation of this report lend themselves to observations and conclusions. The most significant of these are as follows:

- **The debate over decoupling is generally not about the money.**[16] As the above summary demonstrates and the detail in this report affirms over and over again, the rate impacts of decoupling are small to miniscule. The amounts that flow through utility cost adjustment clauses, such as power cost or purchased gas adjustment clauses or trackers for capital additions, environmental remediation expenses or any of a myriad of other large costs dwarf decoupling adjustments.

[16] Some customers, of course, resist any increase in rates, regardless how small or temporary, but decoupling debates far more often center on the philosophy of the matter than the size of possible rate increases – and decreases – that may occur.

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- **If it's not about the money, it's hard to make a case that the risk reduction to utilities from decoupling requires a reduction in ROE.** This issue alone has probably consumed more pages of testimony, hours of cross-examination and commission time than any other associated with decoupling. The reductions proposed are external to the methodologies by which, along with a heavy dose of judgment, commissions usually determine ROE. The only study to date quantifying the change in capital requirements of decoupled utilities points the other way.[17]
- **By and large, we are missing what should be the real debate about decoupling.** In the best case scenario now, what accompanies a decoupling debate is identification of utility energy efficiency programs and the energy savings goals the utility must meet through those programs. While energy efficiency programs are of great importance and deserve the support of policies that affect their success or failure, such as removing the throughput incentive, this is not all that is at stake. Decoupling is a tool, a path if you will, to somewhere. What a decoupling decision asks that we consider is: where is this path going? What "utility" – in the dictionary sense of the word – is it that we want from utilities in the 21st century? Is it the sale of as much energy as they can get people to buy? Is it the highest possible use of the physical infrastructure that exists? Is it support of an infant energy services industry that may or may not blossom depending on our choices for what a utility should or shouldn't do? The controversy over rate impacts and ROE effects distracts us, unintentionally or not, from holding this vital conversation.

Decoupling is challenging in a way other regulatory adjustment clauses – such as power or purchased gas adjustments, environmental cost true-ups, and storm cost trackers – are not. Decoupling requires that we consider the utility business model: how should a utility make money in the short term?[18] It has been simple for many decades to have utilities make money according to commodity sales. This worked particularly well during the first half of the 20th century when steadily rising commodity sales helped finance the build-out of universal electric service and widespread natural gas service. Grounding the business model in commodity sales came under fire when the cost of new commodity supply began to exceed the historical or embedded cost. New sales now held the potential of raising costs for everyone[19] Although numerous regulatory policies were put in place to adjust to the new reality, however, the fundamental business tie between selling more and greater profitability remained.

For some, this was proper because rising commodity sales signaled to them that the utility was "competitive." For others, rising sales (or the potential thereof) enabled comfort that the utility's rates were just and reasonable. Given these beliefs, it is no wonder this regulatory tool causes discomfort. The hope of many urging adoption of decoupling is that sales will fall, not rise, preferably because of widespread adoption of cost-effective energy efficiency measures. How, then, will we know whether a utility is competitive or has reasonable rates? We will need different indicators of competitiveness and reasonableness. And, indeed, we do. That is precisely the point. Considering adoption of decoupling is an invitation to think and converse about what success should mean for a utility in the next several decades. What results will tell us that the utility is competitive and that what it charges for the services

[17] See "The Impact of Decoupling on the Cost of Capital – An Empirical Investigation," a 2011 Discussion Paper by the Brattle Group and authored by Joseph B. Wharton, Michael J. Vilbert, Richard E. Goldberg and Tony Brown.
[18] Decoupling does not address the long-term business model, which determines the size and duration of the income opportunity that a utility will have as a result of selling electricity or natural gas commodities at regulated rates.
[19] For electric utilities, whether the potential was realized depended on how long a utility could avoid adding new supplies. If it had a significant amount of excess generation, the new sales – in the short term – lowered costs for everyone. For natural gas, the effect of increasing sales on cost depended on an increasingly volatile market.

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it offers – which may be far more than just the sale of kWh or therms – is reasonable? Perhaps the next decoupling report will describe the results of such thinking and conversation.

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A State-By-State Look At Decoupling

Arizona

Arizona presently has decoupling in place for one gas utility. On January 6, 2012, the Arizona Corporation Commission (ACC) adopted decoupling for Southwest Gas Company in Docket No. G-01551A-10-0458, decision # 72723, approving a stipulation containing the mechanism. The terms of the Stipulation indicate that Southwest Gas agreed to a 25 basis point reduction in its authorized return on common equity (ROE) as part of the settlement, along with a one-time $2.3 million revenue requirement reduction.

The decoupling mechanism appears in Arizona Gas Tariff No. 7, sheet 92 as the "Energy Efficiency Enabling Provision." For November through April, the mechanism includes a weather adjustment, calculating the per-customer margin revenue differences of actual versus normal (rate case" temperatures and making a volume adjustment on each customer's bill. The decoupling component applies year-round and calculates, per rate schedule, the difference between actual billed margin per customer and authorized margin per customer (stated in the tariff). The utility may not recover any surcharges that would raise its earnings above the authorized ROE, and there is a 5 percent cap on adjustments in any one year, with any balance carried forward to future years without interest.
The first adjustment filing under this tariff will not occur until 2013.

For one of its major electric utilities – Arizona Public Service Company – and another gas utility – UNS Gas Company, the ACC instead approved lost revenue recovery mechanisms that account only for margins lost as a result of compliance with Arizona's energy efficiency and distributed generation standards. APS Docket No. E-01345A-11-0224; UNS Gas Docket No. G-04204A-11-0158.

Arkansas

Beginning in 2007, Arkansas' three natural gas utilities put in place decoupling tariffs known as Billing Determinant Adjustments for a three-year trial period. Arkansas Oklahoma – Case No. 07-026-U, Order No. 7 (November 2007) (by settlement agreement; 10 basis point ROE reduction included); Arkansas Western – Case No. 06-124-U, Order No. 6 (July 2007) (by settlement agreement; 25 basis point ROE reduction included); CenterPoint Energy Resources – Case No. 06-161-U, Order No. 6 (October 2007) (by settlement agreement; 10 basis point ROE reduction included). Arkansas Oklahoma's tariff has now expired. Arkansas Western's Billing Determinant Adjustment Tariff, Rider No. 3.6 expires December 31, 2013. CenterPoint Energy Resources' Billing Determinant Adjustment Tariff, Rider No. 6 extends through March 31. 2015. Both tariffs reconcile actual weather-adjusted revenues to rate case revenues for the residential and small business classes only and authorize a surcharge, specific to each class, for under-recovery (net across all schedules). There is no refund for over-recovery.

In 2010, the Commission approved lost revenue recovery for all utilities as part of an order on energy efficiency. Docket No. 08-137-U, Order No. 14. The Order modified the existing BDA's for gas utilities to ensure that these riders did not double-collect. See, e.g. Docket No. 07-078-TF for Arkansas Western Gas Company, Order No. 26, June 30, 2011.

Neither Arkansas Oklahoma nor Arkansas Western made any adjustments because the amounts accrued under their mechanisms would have resulted in refunds, rather than surcharges. The table below shows the adjustments for CenterPoint Energy Resources.

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CenterPoint Energy Resources			
	Adjustment $/ Ccf	Retail Price $ per Mcf	Adjustment %
2008			
Residential	0		
Small Commercial	0		
2009			
Residential	0.003014[20]	13.39	0.23
Small Commercial	0.002555	10.72	0.24
2010			
Residential	0.025905	11.53	2.25
Small Commercial	0	8.89	0
2011			
Residential	0.003923	13.15	0.30
Small Commercial	0		

California

California has had decoupling in place for its electric and gas utilities for many years, both prior to and after the state's utility market restructuring efforts of the late 1990s. For all of the utilities except Southwest Gas, the decoupling mechanism is not a separate tariff but, rather, part of the broader true-up processes that occur under comprehensive regulatory frameworks. Southwest Gas has the Core Fixed Cost Adjustment Mechanism, which appears as a line item in the cost of gas.
The orders adopting decoupling for the various utilities post-restructuring are in the following cases:

- Pacific Gas & Electric (electric): Case A.02-11-017 et al.
- Pacific Gas & Electric (gas): Case A.02-11-017 et al.
- Southern California Edison: Case A.93-120-29
- San Diego Gas & Electric (electric): Case A.02-12-027
- San Diego Gas & Electric (gas): A.02-12-027
- SoCal Gas: A.02-12-027
- Southwest Gas: A.02-02-012

None of the orders include an ROE reduction in connection with the approval of decoupling.

Because decoupling is intertwined with the regulatory framework, determining the adjustment requires calculations best performed by the utilities. Thus, all information in the tables below is from the respective utilities.

[20] In many cases, the tables include adjustments that include up to six figures to the right of the decimal point. This is common in utility ratemaking and this report leaves these as stated in the filings rather than round them to the nearest hundredth.

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Pacific Gas & Electric - Gas			
Year	Delivery Revenue Requirement ($ millions)	Decoupling Adjustment ($ millions)	% of Delivery Revenue
2006	1027	22.85	2.2%
2007	1027	85.86	8.4%
2008	1069	33.64	3.1%
2009	1091	62.42	5.7%
2010	1,113	71.21	6.4%
2011	1,119	21.30	1.9%
2012	1,210	-11.62	-1.0%

Pacific Gas & Electric - Electric			
Year	Delivery Revenue Requirement ($ millions)	Decoupling Adjustment ($ millions)	% of Delivery Revenue
2005	8925	-127.73	-1.43%
2006	9933	224.6	2.26%
2007	10409	217.27	2.09%
2008	10261	40.32	0.39%
2009	11169	103.55	0.93%
2010	11224	465.56	4.15%
2011	10306	383.9	3.73%
2012	11032	403.04	3.65%

Southern California Edison		
Year	Revenue Requirement Allowed to Actual ($ millions)	Decoupling Adjustment %
2004	Not available	-2.1
2005	Not available	-2.1
2006	Not available	0.1
2007	Not available	-1
2008	64,843	1.6
2009	-69,668	-1.4
2010	78.672	1.6
2011	-76,253	-1.4
2012	-2918	-0.1

Southwest Gas – Northern California			
Year	Decoupling Adjustment	Average Rate	% of Rate
2005	0.00400	1.18	0.300
2006	(0.01000)	1.35	(0.070)
2007	(0.00060)	1.25	0.000
2008	(0.01600)	1.25	(0.013)

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Southwest Gas – Northern California			
2009	(0.05090)	1.06	(0.048)
2010	0.01375	1.08	0.013
2011	0.01001	1.03	0.010
2012	(0.03688)	0.82	(0.045)

Southwest Gas – Southern California			
Year	Decoupling Adjustment	Average Rate	% of Rate
2005	0.05000	1.07	4.700
2006	0.01000	1.30	0.800
2007	0.00400	1.25	0.300
2008	0.01000	1.17	0.900
2009	0.01349	1.18	0.011
2010	0.03692	1.16	0.032
2011	0.04537	1.52	0.030
2012	0.03378	1.02	0.033

Southwest Gas – Lake Tahoe			
Year	Decoupling Adjustment	Average Rate	% of Rate
2010	0.01938	1.06	0.018
2011	0.01665	0.91	0.018
2012	0.00095	0.82	0.001

San Diego Gas & Electric (Electric)			
Year	Rate (¢/kWh)	Decoupling Adjustment (¢/kWh)	Decoupling Adjustment (%)
2005	13.773	-0.055	-0.40%
2006	13.935	-0.21	-1.50%
2007	13.997	-0.051	-0.36%
2008	13.606	0.044	0.32%
2009	16.726	0.128	0.76%
2010	16.107	0.00135	0.008
2011	15.957	0.00183	0.012
2012	15.449	-0.0018	-0.012

San Diego Gas & Electric (Gas) and Southern California Gas			
Year	Rate (¢/therm)	Decoupling Adjustment (¢/therm)	Decoupling Adjustment (%)
2006			
Core	48.3	0.012	0.02%
Non-Core	5.4	0	0

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San Diego Gas & Electric (Gas) and Southern California Gas			
2007			
Core	50.2	0.024	0.05%
Non-Core	4.9	-0.001	-0.01%
2008			
Core	51.5	0.001	0.00%
Non-Core	3.6	-0.001	-0.04%
2009			
Core	41.9	0.19	0.40%
Non-Core	5.5	0.03	0.60%
2010			
Core	44.2	0.23	0.50%
Non-Core	5.8	0.03	0.60%
2011			
Core	46.3	0.33	0.70%
Non-Core	6.2	0.05	0.80%

Colorado

Colorado has approved decoupling only for the gas side of Public Service of Colorado, in Case No. 06S-656G (June 2007). The order did not make an ROE reduction for the approval of decoupling. The decoupling tariff (Partial Decoupling Rate Adjustment Sheet 51), which has now expired, compared the authorized margin revenue per customer to the actual, weather-normalized margin per customer. The utility was allowed to recover only differences greater than or equal to a 1.3% decline in the use per customer (cumulates every year of mechanism) and increases in use-per-customer accrued to offset losses in use-per-customer in prior or future years. The mechanism did not apply if margin per customer rose because of increased use.

During the three years the mechanism was in place, the utility did not make any adjustments because, for each year, its margin-per-customer rose.

Public Service Company of Colorado		
Year	Decoupling Adjustment	Decoupling Adjustment Made?
2007	-910,686	no
2008	-4,124,799	no
2009	-11,399,835	no

Connecticut

In2007, Connecticut passed legislation requiring that the Commission adopt decoupling mechanisms for the states' electric and natural gas utilities. CT Public Act No. 07-242. To date, United Illuminating is the only utility with a mechanism in place. The Commission approved the decoupling mechanism as a two-year pilot in 2009, Docket No. 08-07-04, and has subsequently extended it through the utility's next general rate case. The mechanism, found in Decoupling Rider, C.P.U.C.A. No. 598, reconciles actual,

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non-weather adjusted revenues to ratemaking revenues. Refunds or surcharges are allocated to all classes based on revenue. No adjustment occurs if the revenue difference is $1 million or less and amounts accrued for adjustments do not incur carrying charges. The Commission has not made an explicit ROE reduction for the presence of the decoupling mechanism.

These are the adjustments made to date:

United Illuminating			
Year	Adjustment (cents/kWh)	Retail Price (cents/kWh)	Adjustment %
2009	0.02907	22.1	0.13%
2010	-0.0253	21.6	-0.12%
2011	0.0791	21.6	0.37%

Georgia

Georgia recently approved a decoupling mechanism for Atmos Energy (a local natural gas distribution company) in Docket No. 34734 (January 2012), adopting a stipulation. The Georgia Rate Adjustment Mechanism, Tariff Sheet 33, compares actual non-gas revenue to authorized non-gas revenue and requires refunds or surcharges depending on the difference. Authorized revenues change annually according to a comparison of a historic test year and a forward-looking test year and the adjustments necessary to bring authorized revenues up to a 10.5% ROE or down to a 10.9% ROE (20 basis points to either side of the authorized 10.7%). There have not been any rate adjustments yet under this tariff.

Hawaii

The Commission approved a decoupling mechanism for Hawaiian Electric (HECO) in August 2010, after an investigation into the appropriateness of decoupling and its design. Docket No. 2008-0274 (opening investigation into decoupling) Final Order August 2010; Docket No. 2008-0083 (generate rate case including adoption of decoupling mechanism) Final Order December 2010. The general rate case order made no explicit ROE adjustment for decoupling but did note that the 10% ROE authorized took into account all of the rate mechanisms in place for the utility. HECO's tariff, the Revenue Balancing Account, Revised Sheet 92, took effect March 1, 2011. It compares actual adjusted revenue to a target revenue, which is based on the last test year with adjustments for escalation in O&M and rate base changes. Accrued amounts include carrying charges.

Hawaiian Electric Company			
Year	Decoupling Adjustment (cents/kWh)	Retail Rate	Decoupling %
2011	0.1995	31.49	0.63%
2012	0.3894	36.41	1.07%

The 2011 adjustment took effect June 1 but was reduced to $0 on July 26, 2011 when the Commission granted HECO an interim rate increase of $53.2 million in a 2011 test year general rate case. The 2012 Adjustment runs from June 1, 2012 through May 31, 2013. About 25% of the total relates to the portion of the decoupling mechanism that updates O&M and rate base.

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Idaho

The Commission approved a three-year experimental decoupling mechanism for Idaho Power Company, an electric utility, in Case No. IPC-E-04-15, Order No. 30267. The Commission extended it for an additional two years in Order No. 31063 and made the mechanism permanent in Case No. IPC-E-11-19, Order No. 32505 (March 2012). The tariff, schedule 54, is a revenue-per-customer mechanism, comparing actual, weather-adjusted revenue per customer to authorized revenue per customer, using fixed costs from the rate case. Adjustments are capped at 3% over the previous year, with carry-over to subsequent years. Although the mechanism specifies calculating and refunding/charging any adjustment on a per class basis, the Commission departed from this in the first two adjustments because of concern regarding the lack of current cost of service studies to support the underlying cost allocations.

Idaho Power Company[21]			
	Adjustment Rate	Retail Rate	Decoupling Adjustment %
2007			
Residential	-0.0457	5.9	-0.77%
Commercial	-0.0457	4.28	-1.07%
2008			
Residential	0.0529	6.7	0.90%
Commercial	0.0529	5.1	1.04%
2009			
Residential	0.122	7.7	1.58%
Commercial	0.1535	6.03	2.55%
2010			
Residential	0.18	7.85	2.29%
Commercial	0.2273	6.13	3.71%
2011			
Residential	0.2028	7.85	2.58%
Commercial	0.2597	6.13	4.24%

Illinois

The Commission has approved decoupling for two of Illinois' gas utilities: Peoples Gas & Coke and North Shore Gas, in Case No. 07-0241/07-0242 (Consolidated) (February 2008). The Order approving the decoupling adjustments reduced the utilities' ROE by 10 basis points. This is a four-year pilot only; to continue, the utility must make a general rate filing in which the Commission extends the program. The tariffs – Volume Balancing Adjustment (VBA), sheets 60-64 for North Shore Gas and Volume Balancing Adjustment (VBA), Sheets 61-65 for Peoples Gas – compare actual, non-weather-adjusted margin revenue per customer to ratemaking margin revenue per customer, on a per-class basis. Adjustments occur monthly but the utilities also make an annual reconciliation filing.

[21] All numbers provided by the utility.

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North Shore Gas[22]						
Year	Decoupling Adjustment	Therms	Annualized Therms	Adj/Therm	Retail Price	Adjustment %
2009						
Residential	(547,804.00)	120190873	159853861	(0.003427)	8.97	-0.038%
Commercial	(327,782.00)	75056288	99824863	(0.003284)	8.66	-0.038%
2010						
Residential	(898,009.00)	94852140	126153346	(0.007118)	9.39	-0.076%
Commercial	(130,997.00)	35,529,162	47253785	(0.002772)	8.76	-0.032%
2011						
Residential	66,782.00	96841447	128799125	0.000518	8.6	0.006%
Commercial	(987,442.00)	51327651	68265776	(0.014465)	8.12	-0.178%

Peoples Gas & Coke						
Year	Decoupling Adjustment	Therms	Annualized Therms	Adj/Therm	Retail Price	Adjustment %
2009						
Residential	2,035,714.00	437062567	568181337	0.003583	8.97	0.040%
Commercial	(2,217,245.00)	319190546	424523426	(0.005223)	8.66	-0.060%
2010						
Residential	(3,912,353.00)	339228970	440997661	(0.008872)	9.39	-0.094%
Commercial	(2,602,899.00)	205188433	272900616	(0.009538)	8.76	-0.109%
2011						
Residential	4,866,068.00	358202970	465663861	0.010450	8.6	0.122%
Commercial	(3,595,230.00)	360315843	479220071	(0.007502)	8.12	-0.092%

Indiana

Three of Indiana's gas utilities have decoupling mechanisms in place: Vectren Indiana Gas through Case No. 42943 (December 2006); Vectren Southern Indiana Gas through Case No. 42943 (December 2006); and Citizen's Gas & Coke through Case No. 42767 (April 2007). None of the orders approving decoupling included an ROE adjustment. For both Vectren companies, the tariff – Energy Efficiency Rider, Sheet 38 -- compares actual, non-weather-adjusted margin revenues per customer to ratemaking margin revenues per customer, with an adjustment for customer additions and reductions. The mechanism designs into a rate adjustment only 85% of this difference amount (positive or negative). Earnings are capped at the allowed return on common equity, with earnings shortfalls from prior periods allowed to offset potential returns to customers. The mechanism operates on a per class basis. The utility also has

[22] Calculations above are based on the annual revenue difference calculated for the prior year and estimated therm sales for the refund/surcharge year (the utilities do this over nine months and provide only that period of estimated sales). The adjusted column above multiplies this by 1.33 because the excluded months are the first quarter of the year when heat related sales are likely to be higher.

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a separate weather adjustment tariff that applies only during the seven winter months. For Citizens Gas & Coke, the tariff -- Rider E, page 505 – is identical except that the 85% limitation does not apply.

Vectren North (Indiana Gas)				
	Adjustment ($/therm)	Retail Rate	Retail Rate ($/therm)	Adjustment %
2007				
Residential	0.00155	11.22	1.09	0.142%
General	0.00012	10.2	1.00	0.012%
2008				
Residential	0.01705	12.65	1.23	1.382%
General	0.00344	11.14	1.09	0.317%
2009				
Residential	0.00364	10.81	1.05	0.345%
General	-0.00762	9.18	0.90	-0.851%
2010				
Residential	-0.00006	8.62	0.84	-0.007%
General	-0.00467	7.54	0.74	-0.635%
2011				
Residential	0.00932	9.43	0.92	1.013%
General	0.00448	7.98	0.78	0.575%
2012				
Residential	0.009	12.19	1.19	0.757%
General	0.00255	9.49	0.93	0.275%

Vectren South (Southern Indiana Gas)				
	Adjustment ($/therm)	Retail Rate	Retail Rate ($/therm)	Adjustment %
2008				
Residential	0.0085	12.65	1.23	0.689%
General	0.00346	11.14	1.09	0.318%
2009				
Residential	0.00152	10.81	1.05	0.144%
General	-0.00469	9.18	0.90	-0.524%
2010				
Residential	0.00918	8.62	0.84	1.092%
General	-0.00335	7.54	0.74	-0.455%
2011				
Residential	0.01602	9.43	0.92	1.741%
General	0.00713	7.98	0.78	0.916%
2012				
Residential	0.01807	12.19	1.19	1.519%
General	0.0087	9.49	0.93	0.940%

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Citizens Gas & Coke				
	Adjustment ($/therm)	Retail Rate	Retail Rate ($/therm)	Adjustment %
2008				
Res Non-Heat	0.002	12.65	1.23	0.162%
Res Heat	-0.0002	12.65	1.23	-0.016%
General Non-Heat	-0.0006	11.14	1.09	-0.055%
General Heat	0	11.13	1.09	0.000%
2009				
Res Non-Heat	0.0133	10.81	1.05	1.261%
Res Heat	0.0223	10.81	1.05	2.114%
General Non-Heat	0.0157	9.18	0.90	1.753%
General Heat	0.0212	9.18	0.90	2.367%
2010				
Res Non-Heat	-0.0053	8.62	0.84	-0.630%
Res Heat	0.0129	8.62	0.84	1.534%
General Non-Heat	0.0114	7.54	0.74	1.550%
General Heat	0.0024	7.54	0.74	0.326%
2011				
Res Non-Heat	0.0163	9.43	0.92	1.772%
Res Heat	0.0214	9.43	0.92	2.326%
General Non-Heat	-0.0214	7.98	0.78	-2.749%
General Heat	0.0173	7.98	0.78	2.222%
2012				
Res Non-Heat	0.0212	12.19	1.19	1.783%
Res Heat	0.0178	12.19	1.19	1.497%
General Non-Heat	-0.0218	9.49	0.93	-2.355%
General Heat	0.0126	9.49	0.93	1.361%

Maryland

Maryland has approved decoupling for two gas utilities – Baltimore Gas & Electric (Case 9036, December 2005) and Washington Gas Light (Case 8990, July 2005) – and three electric utilities – PEPCO (Case 9092, July 2007), Delmarva (Case 9093, July 2007) , and Baltimore Gas & Electric (Letter Order November 2007). All of the decoupling mechanisms adjust monthly.

The decoupling mechanisms for the gas utilities are both similar. They each compare actual, non-weather-adjusted distribution revenue to ratemaking distribution revenue, adjusting for net customers added, by rate schedule. For Washington Gas Light (Revenue Normalization Adjustment, General Service Provisions No. 30), the maximum rate change allowed per month is 5¢, with any adjustment amount in excess of that carried over to future periods. For BG&E (Monthly Rate Adjustment, Rider 8) the maximum rate change allowed per month is 10%, with any adjustment amount in excess of that carried over to future periods. Although the Commission made a 50 basis point ROE reduction for BG&E

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upon adopting the gas decoupling mechanism in 2000, it reversed this in 2005 and made no ROE adjustment for Washington Gas Light.

Similarly, the electric utility decoupling mechanisms are also all the same. Each compares actual, non-weather-adjusted distribution revenue to ratemaking distribution revenue, adjusted for net customers added, by rate schedule. The maximum rate change allowed per month is 10%, with any adjustment amount in excess of that carried over to future periods. PEPCO's tariff is the Bill Stabilization Adjustment Rider, page 47; Delmarva's tariff is the Bill Stabilization Adjustment Rider, Leaf 102; and BG&E's tariff is the Monthly Rate Adjustment, Rider 25. Both PEPCO and Delmarva received 50 basis point ROE reductions upon the adoption of their decoupling mechanisms. Although the Commission had initially not made such a reduction for BG&E, it did so in the utility's most recent rate case (Case 9230).

The tables below show the monthly decoupling adjustments for these utilities, from 2006 through 2012 for the gas utilities, 2008 through 2012 for BG&E (electric) and PEPCO and 2009 through 2012 for Delmarva.

Baltimore Gas & Electric (Gas) 2007				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
January				
Residential	-0.01	15.46	1.51	-0.663%
General Service	0.0174	13.17	1.28	1.354%
February				
Residential	0.0397	12.92	1.26	3.150%
General Service	0.0159	12.2	1.19	1.336%
March				
Residential		14.82	1.45	0.000%
General Service		13.14	1.28	0.000%
April				
Residential		14.55	1.42	0.000%
General Service		12.04	1.17	0.000%
May				
Residential	0.0196	18.32	1.79	1.097%
General Service	-0.05	12.31	1.20	-4.163%
June				
Residential	-0.05	20.32	1.98	-2.522%
General Service	-0.05	11.87	1.16	-4.318%
July				
Residential	-0.05	21.54	2.10	-2.379%
General Service	-0.05	11.83	1.15	-4.332%
August				
Residential	-0.05	21.22	2.07	-2.415%
General Service	-0.05	11.32	1.10	-4.527%

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Baltimore Gas & Electric (Gas) 2007				
September				
Residential	-0.05	20.94	2.04	-2.447%
General Service	-0.05	11	1.07	-4.659%
October				
Residential	-0.05	19.6	1.91	-2.615%
General Service	-0.05	12.48	1.22	-4.107%
November				
Residential	-0.05	14.7	1.43	-3.486%
General Service	-0.05	11.85	1.16	-4.325%
December				
Residential	-0.05	14.26	1.39	-3.594%
General Service	-0.05	12.4	1.21	-4.133%

Baltimore Gas & Electric (Gas) 2008				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
January				
Residential	-0.05	14.29	1.39	-3.586%
General Service	-0.0417	12.59	1.23	-3.395%
February				
Residential	0.0073	14.2	1.39	0.527%
General Service	0.0193	12.43	1.21	1.592%
March				
Residential	0.05	14.95	1.46	3.428%
General Service	0.05	12.79	1.25	4.007%
April				
Residential	0.0343	17.91	1.75	1.963%
General Service	0.0416	13.4	1.31	3.182%
May				
Residential	0.05	20.3	1.98	2.525%
General Service	0.004	14.15	1.38	0.290%
June				
Residential	0.05	24.15	2.36	2.122%
General Service	-0.05	15.29	1.49	-3.352%
July				
Residential	-0.05	27.83	2.72	-1.842%
General Service	-0.05	15.95	1.56	-3.213%
August				
Residential	0.05	24.01	2.34	2.135%
General Service	-0.05	14.2	1.39	-3.609%

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Baltimore Gas & Electric (Gas) 2008				
September				
Residential	0.0272	23.02	2.25	1.211%
General Service	-0.05	13.48	1.32	-3.802%
October				
Residential		16.63	1.62	0.000%
General Service		12.26	1.20	0.000%
November				
Residential		14.93	1.46	0.000%
General Service		12.4	1.21	0.000%
December				
Residential	-0.024	15.35	1.50	-1.603%
General Service	-0.0323	13.12	1.28	-2.523%

Baltimore Gas & Electric (Gas) 2009				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
January				
Residential	-0.0251	14.38	1.40	-1.789%
General Service	-0.0187	12.2	1.19	-1.571%
February				
Residential	-0.0005	13.65	1.33	-0.038%
General Service	0.0212	12.12	1.18	1.793%
March				
Residential	-0.0272	13.4	1.31	-2.081%
General Service	0.0129	11.26	1.10	1.174%
April				
Residential	0.008	14.27	1.39	0.575%
General Service	-0.0205	10.7	1.04	-1.964%
May				
Residential	-0.0258	15.88	1.55	-1.665%
General Service	-0.05	10.57	1.03	-4.849%
June				
Residential	0.05	19.83	1.93	2.584%
General Service	-0.05	10.44	1.02	-4.909%
July				
Residential	0.05	20.16	1.97	2.542%
General Service	-0.05	10.07	0.98	-5.089%
August				
Residential	0.05	20.37	1.99	2.516%
General Service	-0.05	9.69	0.95	-5.289%

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Baltimore Gas & Electric (Gas) 2009				
September				
Residential	0.05	19.18	1.87	2.672%
General Service	-0.05	9.32	0.91	-5.499%
October				
Residential	0.05	14.29	1.39	3.586%
General Service	-0.05	9.88	0.96	-5.187%
November				
Residential	-0.0027	11.4	1.11	-0.243%
General Service	-0.05	10.48	1.02	-4.890%
December				
Residential	-0.011	10.82	1.06	-1.042%
General Service	-0.0173	9.72	0.95	-1.824%

Baltimore Gas & Electric (Gas) 2010				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
January				
Residential	0.0146	11.54	1.13	1.297%
General Service	0.0032	10.33	1.01	0.318%
February				
Residential		11.21	1.09	0.000%
General Service		10.1	0.99	0.000%
March				
Residential	-0.023	12.13	1.18	-1.944%
General Service	0.0035	10.29	1.00	0.349%
April				
Residential	-0.019	15.21	1.48	-1.280%
General Service	-0.0185	9.89	0.96	-1.917%
May				
Residential		16.02	1.56	0.000%
General Service		9.89	0.96	0.000%
June				
Residential	0.05	19.85	1.94	2.582%
General Service	-0.0375	10.53	1.03	-3.650%
July				
Residential	0.0158	20.78	2.03	0.779%
General Service	-0.05	10.66	1.04	-4.808%
August				
Residential	0.05	22.58	2.20	2.270%
General Service	-0.0355	10.82	1.06	-3.363%

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Baltimore Gas & Electric (Gas) 2010				
September				
Residential	0.05	20.79	2.03	2.465%
General Service	0.0208	10.34	1.01	2.062%
October				
Residential	0.05	15.14	1.48	3.385%
General Service	0.0169	9.35	0.91	1.853%
November				
Residential	0.05	11.86	1.16	4.321%
General Service	0.0066	9.24	0.90	0.732%
December				
Residential	0.0469	10.11	0.99	4.755%
General Service	0.0062	8.82	0.86	0.721%

Baltimore Gas & Electric (Gas) 2011				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
January				
Residential	0.019	10.44	1.02	1.865%
General Service	-0.0083	9.56	0.93	-0.890%
February				
Residential	-0.05	11.28	1.10	-4.543%
General Service	-0.05	9.96	0.97	-5.146%
March				
Residential	-0.05	11.25	1.10	-4.556%
General Service	-0.0438	9.86	0.96	-4.553%
April				
Residential	-0.05	12.58	1.23	-4.074%
General Service	-0.05	10.06	0.98	-5.094%
May				
Residential	-0.05	15.97	1.56	-3.209%
General Service	-0.0332	11.96	1.17	-2.845%
June				
Residential	-0.05	19.53	1.91	-2.624%
General Service	-0.05	11.89	1.16	-4.310%
July				
Residential	-0.05	20.13	1.96	-2.546%
General Service	0.0212	13.43	1.31	1.618%
August				
Residential	-0.05	19.24	1.88	-2.664%
General Service	-0.0491	11.95	1.17	-4.212%

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Baltimore Gas & Electric (Gas) 2011				
September				
Residential	-0.05	18.63	1.82	-2.751%
General Service	-0.0198	12.13	1.18	-1.673%
October				
Residential	-0.05	12.88	1.26	-3.979%
General Service	-0.05	10.85	1.06	-4.724%
November				
Residential	-0.05	12.88	1.26	-3.979%
General Service	0.0061	10.32	1.01	0.606%
December				
Residential	-0.05	11.86	1.16	-4.321%
General Service	-0.0098	10.36	1.01	-0.970%

Baltimore Gas & Electric (Gas) 2012				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
January				
Residential	-0.0091	11.39	1.11	-0.819%
General Service	-0.0096	10.03	0.98	-0.981%
February				
Residential	0.0096	11.12	1.08	0.885%
General Service	0.0026	9.72	0.95	0.274%
March				
Residential	0.0414	13.7	1.34	3.097%
General Service	0.0092	11.17	1.09	0.844%
April				
Residential	0.0392	13.97	1.36	2.876%
General Service	-0.0077	11.09	1.08	-0.712%
May				
Residential	0.05	16.18	1.58	3.167%
General Service	0.05	10.85	1.06	4.724%
June				
Residential	0.05	17.91	1.75	2.862%
General Service	-0.0061	11.4	1.11	-0.548%
July				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	11.4	1.11	4.496%
August				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	11.4	1.11	4.496%

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Baltimore Gas & Electric (Gas) 2012				
September				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	11.4	1.11	4.496%

Washington Gas Light 2007				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
January				
Residential	0.0064	15.46	1.51	0.424%
General Service	-0.0031	13.17	1.28	-0.241%
February				
Residential	0.05	12.92	1.26	3.967%
General Service	0.0359	12.2	1.19	3.016%
March				
Residential	0.05	14.82	1.45	3.458%
General Service	0.0499	13.14	1.28	3.893%
April				
Residential	0.031	14.55	1.42	2.184%
General Service	-0.05	12.04	1.17	-4.257%
May				
Residential	-0.05	18.32	1.79	-2.797%
General Service	-0.05	12.31	1.20	-4.163%
June				
Residential	-0.05	20.32	1.98	-2.522%
General Service	-0.05	11.87	1.16	-4.318%
July				
Residential	-0.05	21.54	2.10	-2.379%
General Service	-0.05	11.83	1.15	-4.332%
August				
Residential	-0.05	21.22	2.07	-2.415%
General Service	-0.05	11.32	1.10	-4.527%
September				
Residential	-0.05	20.94	2.04	-2.447%
General Service	-0.05	11	1.07	-4.659%
October				
Residential		19.6	1.91	0.000%
General Service		12.48	1.22	0.000%
November				
Residential	-0.0212	14.7	1.43	-1.478%
General Service	-0.05	11.85	1.16	-4.325%

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Washington Gas Light 2007				
December				
Residential	0.0323	14.26	1.39	2.322%
General Service	-0.05	12.4	1.21	-4.133%

Washington Gas Light 2008				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
January				
Residential	0.0343	14.29	1.39	2.460%
General Service	-0.0361	12.59	1.23	-2.939%
February				
Residential	-0.004	14.2	1.39	-0.289%
General Service	-0.0115	12.43	1.21	-0.948%
March				
Residential	0.05	14.95	1.46	3.428%
General Service	0.05	12.79	1.25	4.007%
April				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	13.4	1.31	3.825%
May				
Residential	-0.0217	20.3	1.98	-1.096%
General Service	-0.05	14.15	1.38	-3.622%
June				
Residential	0.0158	24.15	2.36	0.671%
General Service	-0.0223	15.29	1.49	-1.495%
July				
Residential	-0.0398	27.83	2.72	-1.466%
General Service	0.0088	15.95	1.56	0.566%
August				
Residential	-0.05	24.01	2.34	-2.135%
General Service	0.0312	14.2	1.39	2.252%
September				
Residential	-0.05	23.02	2.25	-2.226%
General Service	-0.0263	13.48	1.32	-2.000%
October				
Residential	0.0094	16.63	1.62	0.579%
General Service	-0.0135	12.26	1.20	-1.129%
November				
Residential	0.0047	14.93	1.46	0.323%
General Service	-0.0103	12.4	1.21	-0.851%

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Washington Gas Light 2008				
December				
Residential	-0.0147	15.35	1.50	-0.982%
General Service	-0.0135	13.12	1.28	-1.055%

Washington Gas Light 2009				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
January				
Residential	-0.0269	14.38	1.40	-1.917%
General Service	-0.0208	12.2	1.19	-1.748%
February			0.00	
Residential	-0.0494	13.65	1.33	-3.710%
General Service	-0.0309	12.12	1.18	-2.613%
March			0.00	
Residential	0.0344	13.4	1.31	2.631%
General Service	0.0245	11.26	1.10	2.230%
April			0.00	
Residential	0.0017	14.27	1.39	0.122%
General Service	0.0052	10.7	1.04	0.498%
May			0.00	
Residential	-0.05	15.88	1.55	-3.227%
General Service	-0.0386	10.57	1.03	-3.743%
June			0.00	
Residential	-0.05	19.83	1.93	-2.584%
General Service	-0.05	10.44	1.02	-4.909%
July			0.00	
Residential	-0.05	20.16	1.97	-2.542%
General Service	0.0384	10.07	0.98	3.909%
August			0.00	
Residential	-0.05	20.37	1.99	-2.516%
General Service	0.0266	9.69	0.95	2.814%
September			0.00	
Residential	-0.05	19.18	1.87	-2.672%
General Service	-0.0151	9.32	0.91	-1.661%
October			0.00	
Residential	-0.05	14.29	1.39	-3.586%
General Service	-0.0034	9.88	0.96	-0.353%
November			0.00	
Residential	0.0061	11.4	1.11	0.548%
General Service	-0.0062	10.48	1.02	-0.606%

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December			0.00	
Residential		10.82	1.06	0.000%
General Service		9.72	0.95	0.000%

Washington Gas Light 2010				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
January				
Residential	-0.0205	11.54	1.13	-1.821%
General Service	-0.0182	10.33	1.01	-1.806%
February				
Residential	-0.0021	11.21	1.09	-0.192%
General Service	-0.0011	10.1	0.99	-0.112%
March				
Residential	-0.0081	12.13	1.18	-0.684%
General Service	-0.0004	10.29	1.00	-0.040%
April				
Residential	0.0107	15.21	1.48	0.721%
General Service	0.0175	9.89	0.96	1.814%
May				
Residential	-0.05	16.02	1.56	-3.199%
General Service	-0.05	9.89	0.96	-5.182%
June				
Residential	0.05	19.85	1.94	2.582%
General Service	0.05	10.53	1.03	4.867%
July				
Residential	0.05	20.78	2.03	2.466%
General Service	0.0173	10.66	1.04	1.663%
August				
Residential	0.05	22.58	2.20	2.270%
General Service	0.0439	10.82	1.06	4.159%
September				
Residential	0.05	20.79	2.03	2.465%
General Service	-0.0099	10.34	1.01	-0.981%
October				
Residential	0.05	15.14	1.48	3.385%
General Service	-0.0317	9.35	0.91	-3.475%
November				
Residential	-0.0264	11.86	1.16	-2.282%
General Service	0.05	9.24	0.90	5.547%

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Washington Gas Light 2010				
December				
Residential	-0.0148	10.11	0.99	-1.500%
General Service	-0.0155	8.82	0.86	-1.801%

Washington Gas Light 2011				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
January				
Residential	-0.0099	10.44	1.02	-0.972%
General Service	-0.0079	9.56	0.93	-0.847%
February				
Residential	-0.0323	11.28	1.10	-2.935%
General Service	-0.0266	9.96	0.97	-2.737%
March				
Residential	-0.0273	11.25	1.10	-2.487%
General Service	-0.0214	9.86	0.96	-2.225%
April				
Residential	0.013	12.58	1.23	1.059%
General Service	-0.0004	10.06	0.98	-0.041%
May				
Residential	-0.0279	15.97	1.56	-1.791%
General Service	-0.0305	11.96	1.17	-2.614%
June				
Residential	-0.05	19.53	1.91	-2.624%
General Service	-0.0366	11.89	1.16	-3.155%
July				
Residential	-0.0137	20.13	1.96	-0.698%
General Service	-0.0487	13.43	1.31	-3.717%
August				
Residential	0.0169	19.24	1.88	0.900%
General Service	0.0476	11.95	1.17	4.083%
September				
Residential	0.0486	18.63	1.82	2.674%
General Service	-0.0214	12.13	1.18	-1.808%
October				
Residential	0.0211	12.88	1.26	1.679%
General Service	0.0092	10.85	1.06	0.869%
November				
Residential	0.0066	12.88	1.26	0.525%
General Service	-0.0066	10.32	1.01	-0.656%

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December				
Residential	-0.0243	11.86	1.16	-2.100%
General Service	-0.014	10.36	1.01	-1.385%

Washington Gas Light 2012				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
January				
Residential	0.0007	11.39	1.11	0.063%
General Service	0.0007	10.03	0.98	0.072%
February				
Residential	0.0395	11.12	1.08	3.641%
General Service	0.0325	9.72	0.95	3.427%
March				
Residential	0.05	13.7	1.34	3.741%
General Service	0.05	11.17	1.09	4.588%
April				
Residential	0.05	13.97	1.36	3.669%
General Service	0.05	11.09	1.08	4.621%
May				
Residential	0.05	16.18	1.58	3.167%
General Service	0.05	10.85	1.06	4.724%
June				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	11.4	1.11	4.496%
July				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	11.4	1.11	4.496%
August				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	11.4	1.11	4.496%
September				
Residential	0.05	17.91	1.75	2.862%
General Service	0.05	11.4	1.11	4.496%

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Potomac Electric Company 2008			
2008	Adjustment cents/kWh	Retail Rate cents/kWh	Adjustment %
March			
Residential	0.1557	14.9	1.045%
General Service	0.245	14.87	1.648%
April			
Residential	-0.1444	14.9	-0.969%
General Service	-0.1197	14.87	-0.805%
May			
Residential	0.0669	14.9	0.449%
General Service	0.0488	14.87	0.328%
June			
Residential	-0.0402	14.9	-0.270%
General Service	-0.0291	14.87	-0.196%
July			
Residential	-0.0093	14.9	-0.062%
General Service	-0.037	14.87	-0.249%
August			
Residential	0.0253	14.9	0.170%
General Service	0.0222	14.87	0.149%
September			
Residential	0.1865	14.9	1.252%
General Service	0.1119	14.87	0.753%
October			
Residential	0.3881	14.9	2.605%
General Service	0.3647	14.87	2.453%
November			
Residential	0.2817	14.9	1.891%
General Service	-0.0111	14.87	-0.075%
December			
Residential	0.244	14.9	1.638%
General Service	0.2407	14.87	1.619%

Washington Gas Light 2009			
	Adjustment cents/kWh	Retail Rate cents/kWh	Adjustment %
January			
Residential	0.2355	15.76	1.494%
General Service	0.2027	11.93	1.699%
February			
Residential	0.2149	15.76	1.364%
General Service	0.2476	11.93	2.075%

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Washington Gas Light 2009			
March			
Residential	-0.0336	15.76	-0.213%
General Service	-0.0219	11.93	-0.184%
April			
Residential	-0.271	15.76	-1.720%
General Service	-0.2444	11.93	-2.049%
May			
Residential	-0.021	15.76	-0.133%
General Service	-0.0242	11.93	-0.203%
June			
Residential	0.035	15.76	0.222%
General Service	0.0792	11.93	0.664%
July			
Residential	-0.0744	15.76	-0.472%
General Service	0.0978	11.93	0.820%
August			
Residential	0.0684	15.76	0.434%
General Service	0.3451	11.93	2.893%
September			
Residential	0.3769	15.76	2.391%
General Service	0.4034	11.93	3.381%
October			
Residential	0.3881	15.76	2.463%
General Service	0.4032	11.93	3.380%
November			
Residential	0.2817	15.76	1.787%
General Service	0.258	11.93	2.163%
December			
Residential	0.244	15.76	1.548%
General Service	0.2407	11.93	2.018%

Washington Gas Light 2010			
	Adjustment cents/kWh	Retail Rate cents/kWh	Adjustment %
January			
Residential	0.2355	15.69	1.501%
General Service	0.2372	12.04	1.970%
February			
Residential	0.2525	15.69	1.609%
General Service	0.2473	12.04	2.054%

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Washington Gas Light 2010			
March			
Residential	0.2476	15.69	1.578%
General Service	0.2434	12.04	2.022%
April			
Residential	0.0541	15.69	0.345%
General Service	0.2491	12.04	2.069%
May			
Residential	0.1403	15.69	0.894%
General Service	0.2558	12.04	2.125%
June			
Residential	0.795	15.69	5.067%
General Service	0.3293	12.04	2.735%
July			
Residential	-0.0562	15.69	-0.358%
General Service	0.3001	12.04	2.493%
August			
Residential	-0.2128	15.69	-1.356%
General Service	0.3944	12.04	3.276%
September			
Residential	-0.3039	15.69	-1.937%
General Service	0.3154	12.04	2.620%
October			
Residential	0.0585	15.69	0.373%
General Service	0.4475	12.04	3.717%
November			
Residential	0.2066	15.69	1.317%
General Service	0.2503	12.04	2.079%
December			
Residential	-0.1788	15.69	-1.140%
General Service	0.2668	12.04	2.216%

Washington Gas Light 2011			
	Adjustment cents/kWh	Retail Rate cents/kWh	Adjustment %
January			
Residential	0.0882	13.65	0.646%
General Service	0.0736	11.56	0.637%
February			
Residential	-0.0634	13.65	-0.464%
General Service	0.2306	11.56	1.995%

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Washington Gas Light 2011			
March			
Residential	-0.1311	13.65	-0.960%
General Service	0.236	11.56	2.042%
April			
Residential	0.2578	13.65	1.889%
General Service	0.2615	11.56	2.262%
May			
Residential	0.3021	13.65	2.213%
General Service	0.271	11.56	2.344%
June			
Residential	0.054	13.65	0.396%
General Service	0.4413	11.56	3.817%
July			
Residential	0.0524	13.65	0.384%
General Service	0.3696	11.56	3.197%
August			
Residential	-0.4156	13.65	-3.045%
General Service	0.2506	11.56	2.168%
September			
Residential	-0.4158	13.65	-3.046%
General Service	-0.4379	11.56	-3.788%
October			
Residential	-0.445	13.65	-3.260%
General Service	0.2091	11.56	1.809%
November			
Residential	-0.2557	13.65	-1.873%
General Service	0.2503	11.56	2.165%
December			
Residential	-0.0003	13.65	-0.002%
General Service	0.2668	11.56	2.308%

Washington Gas Light 2012			
	Adjustment cents/kWh	Retail Rate cents/kWh	Adjustment %
January			
Residential	0.0618	12.91	0.479%
General Service	0.2446	10.64	2.299%
February			
Residential	0.1738	12.91	1.346%
General Service	0.2526	10.64	2.374%

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Washington Gas Light 2012			
March			
Residential	0.2747	12.91	2.128%
General Service	0.2568	10.64	2.414%
April			
Residential	0.29	12.91	2.246%
General Service	0.2615	10.64	2.458%
May			
Residential	0.3021	12.91	2.340%
General Service	0.271	10.64	2.547%
June			
Residential	0.437	12.91	3.385%
General Service	0.4413	10.64	4.148%
July			
Residential	0.4096	12.91	3.173%
General Service	0.3696	10.64	3.474%
August			
Residential	-0.1257	12.91	-0.974%
General Service	0.4404	10.64	4.139%

Delmarva 2008			
	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
March			
Residential	0.00252	0.1486	1.696%
General Service	0.002546	0.1317	1.933%
April			
Residential	-0.001136	0.1486	-0.764%
General Service	0.001567	0.1317	1.190%
May			
Residential	0.002758	0.1486	1.856%
General Service	0.002683	0.1317	2.037%
June			
Residential	0.00352	0.1486	2.369%
General Service	0.002547	0.1317	1.934%
July			
Residential	0.001852	0.1486	1.246%
General Service	0.002302	0.1317	1.748%
August			
Residential	0.000472	0.1486	0.318%
General Service	0.002288	0.1317	1.737%

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Delmarva 2008			
September			
Residential	0.00101	0.1486	0.680%
General Service	0.00231	0.1317	1.754%
October			
Residential	0.003499	0.1486	2.355%
General Service	0.002402	0.1317	1.824%
November			
Residential	0.00364	0.1486	2.450%
General Service	0.002845	0.1317	2.160%
December			
Residential	0.003243	0.1486	2.182%
General Service	0.002306	0.1317	1.751%

Delmarva 2009			
	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	0.003039	0.1449	2.097%
General Service	0.002387	0.145	1.646%
February			
Residential	0.002525	0.1449	1.743%
General Service	0.001885	0.145	1.300%
March			
Residential		0.1449	0.000%
General Service		0.145	0.000%
April			
Residential	-0.003369	0.1449	-2.325%
General Service	0.002577	0.145	1.777%
May			
Residential	0.001649	0.1449	1.138%
General Service	0.002623	0.145	1.809%
June			
Residential	0.003474	0.1449	2.398%
General Service	0.002517	0.145	1.736%
July			
Residential	0.000693	0.1449	0.478%
General Service	0.002348	0.145	1.619%
August			
Residential	0.001589	0.1449	1.097%
General Service	0.002288	0.145	1.578%

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Delmarva 2009			
September			
Residential	0.003267	0.1449	2.255%
General Service	0.00231	0.145	1.593%
October			
Residential	0.003499	0.1449	2.415%
General Service	0.002402	0.145	1.657%
November			
Residential	0.003647	0.1449	2.517%
General Service	0.002845	0.145	1.962%
December			
Residential	0.003243	0.1449	2.238%
General Service	0.002306	0.145	1.590%

Delmarva 2010			
	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	0.003039	0.1487	2.044%
General Service	0.002387	0.1221	1.955%
February			
Residential	0.003633	0.1487	2.443%
General Service	0.002768	0.1221	2.267%
March			
Residential	0.003681	0.1487	2.475%
General Service	0.002816	0.1221	2.306%
April			
Residential	-0.001255	0.1487	-0.844%
General Service	0.002958	0.1221	2.423%
May			
Residential	-0.004046	0.1487	-2.721%
General Service	0.002919	0.1221	2.391%
June			
Residential	0.000549	0.1487	0.369%
General Service	0.002821	0.1221	2.310%
July			
Residential	0.000271	0.1487	0.182%
General Service	0.000436	0.1221	0.357%
August			
Residential	-0.001115	0.1487	-0.750%
General Service	-0.000562	0.1221	-0.460%

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Delmarva 2010			
September			
Residential	-0.00333	0.1487	-2.239%
General Service	-0.001791	0.1221	-1.467%
October			
Residential	-0.003945	0.1487	-2.653%
General Service	-0.00003	0.1221	-0.025%
November			
Residential	-0.003934	0.1487	-2.646%
General Service	-0.00778	0.1221	-6.372%
December			
Residential	-0.002417	0.1487	-1.625%
General Service	0.000255	0.1221	0.209%

Delmarva 2011			
	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	0.001402	0.1356	1.034%
General Service	0.000452	0.1156	0.391%
February			
Residential	0.001617	0.1356	1.192%
General Service	0.000663	0.1156	0.574%
March			
Residential	-0.003681	0.1356	-2.715%
General Service	-0.00204	0.1156	-1.765%
April			
Residential	-0.00385	0.1356	-2.839%
General Service	0.001503	0.1156	1.300%
May			
Residential	-0.004046	0.1356	-2.984%
General Service	0.001106	0.1156	0.957%
June			
Residential	-0.001353	0.1356	-0.998%
General Service	0.001062	0.1156	0.919%
July			
Residential	-0.000707	0.1356	-0.521%
General Service	-0.000239	0.1156	-0.207%
August			
Residential	-0.002213	0.1356	-1.632%
General Service	-0.00011	0.1156	-0.095%

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Delmarva 2011			
September			
Residential	0.001111	0.1356	0.819%
General Service	0.001126	0.1156	0.974%
October			
Residential	-0.000904	0.1356	-0.667%
General Service	-0.001733	0.1156	-1.499%
November			
Residential	0.002123	0.1356	1.566%
General Service	0.001055	0.1156	0.913%
December			
Residential	0.0078	0.1356	5.752%
General Service	0.00306	0.1156	2.647%

Delmarva 2012			
	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	-0.000602	0.1291	-0.466%
General Service	0.001165	0.1064	1.095%
February			
Residential	0.003777	0.1291	2.926%
General Service	0.003169	0.1064	2.978%
March			
Residential	0.003802	0.1291	2.945%
General Service	0.002331	0.1064	2.191%
April			
Residential	0.004097	0.1291	3.174%
General Service	0.003234	0.1064	3.039%
May			
Residential	0.004257	0.1291	3.297%
General Service	-0.003287	0.1064	-3.089%
June			
Residential	0.004069	0.1291	3.152%
General Service	0.003053	0.1064	2.869%
July			
Residential	0.003833	0.1291	2.969%
General Service	-0.001963	0.1064	-1.845%
August			
Residential	0.003827	0.1291	2.964%
General Service	0.002663	0.1064	2.503%

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Delmarva 2012			
September			
Residential	0.003906	0.1291	3.026%
General Service	0.002829	0.1064	2.659%
October			
Residential	0.004501	0.1291	3.486%
General Service	0.001637	0.1064	1.539%

Baltimore Gas & Electric (Electric) 2008			
	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
March			
Residential	0.00172	0.1477	1.165%
General Service	0.0023	0.1526	1.507%
April			
Residential	0.00016	0.1477	0.108%
General Service	0.00146	0.1526	0.957%
May			
Residential	0.00066	0.1477	0.447%
General Service	0.0023	0.1526	1.507%
June			
Residential	-0.00066	0.1477	-0.447%
General Service	0.0023	0.1526	1.507%
July			
Residential	0.00158	0.1477	1.070%
General Service	0.0023	0.1526	1.507%
August			
Residential	-0.0004	0.1477	-0.271%
General Service	0.00214	0.1526	1.402%
September			
Residential	0.00237	0.1477	1.605%
General Service	0.0023	0.1526	1.507%
October			
Residential	0.00237	0.1477	1.605%
General Service	0.00143	0.1526	0.937%
November			
Residential	0.00237	0.1477	1.605%
General Service	0.0014	0.1526	0.917%
December			
Residential	0.00445	0.1477	3.013%
General Service	0.0023	0.1526	1.507%

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Baltimore Gas & Electric (Electric) 2009			
	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	0.00035	0.1579	0.222%
General Service	-0.00073	0.1346	-0.542%
February			
Residential	0.00025	0.1579	0.158%
General Service	0.0023	0.1346	1.709%
March			
Residential	-0.00237	0.1579	-1.501%
General Service	0.0023	0.1346	1.709%
April			
Residential	-0.00237	0.1579	-1.501%
General Service	0.0023	0.1346	1.709%
May			
Residential	0.00234	0.1579	1.482%
General Service	0.00132	0.1346	0.981%
June			
Residential	0.00237	0.1579	1.501%
General Service	0.0023	0.1346	1.709%
July			
Residential	0.00237	0.1579	1.501%
General Service	0.0023	0.1346	1.709%
August			
Residential	0.00237	0.1579	1.501%
General Service	0.0019	0.1346	1.412%
September			
Residential	0.00237	0.1579	1.501%
General Service	0.0023	0.1346	1.709%
October			
Residential	0.00237	0.1579	1.501%
General Service	0.00124	0.1346	0.921%
November			
Residential	0.00237	0.1579	1.501%
General Service	0.0023	0.1346	1.709%
December			
Residential	0.00156	0.1579	0.988%
General Service	0.00204	0.1346	1.516%

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Baltimore Gas & Electric (Electric) 2010			
2010	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	0.00203	0.1465	1.386%
General Service	0.0023	0.1261	1.824%
February			
Residential	-0.00142	0.1465	-0.969%
General Service	0.0023	0.1261	1.824%
March			
Residential	-0.00237	0.1465	-1.618%
General Service	0.0023	0.1261	1.824%
April			
Residential	-0.00237	0.1465	-1.618%
General Service	0.0023	0.1261	1.824%
May			
Residential	0.00192	0.1465	1.311%
General Service	0.0023	0.1261	1.824%
June			
Residential	0.00191	0.1465	1.304%
General Service	0.0023	0.1261	1.824%
July			
Residential	0.00095	0.1465	0.648%
General Service	0.0023	0.1261	1.824%
August			
Residential	-0.00176	0.1465	-1.201%
General Service	0.00224	0.1261	1.776%
September			
Residential	-0.00237	0.1465	-1.618%
General Service	0.00116	0.1261	0.920%
October			
Residential	-0.00237	0.1465	-1.618%
General Service	0.00081	0.1261	0.642%
November			
Residential	-0.00237	0.1465	-1.618%
General Service	0.00098	0.1261	0.777%
December			
Residential	-0.00079	0.1465	-0.539%
General Service	0.00229	0.1261	1.816%

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Baltimore Gas & Electric (Electric) 2011			
	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	-0.0013	0.1365	-0.952%
General Service	0.0023	0.1156	1.990%
February			
Residential	-0.00253	0.1365	-1.853%
General Service	-0.0002	0.1156	-0.173%
March			
Residential	-0.00018	0.1365	-0.132%
General Service	-0.00063	0.1156	-0.545%
April			
Residential	0.0011	0.1365	0.806%
General Service	-0.00262	0.1156	-2.266%
May			
Residential	0.0001	0.1365	0.073%
General Service	-0.0016	0.1156	-1.384%
June			
Residential	0.00226	0.1365	1.656%
General Service	0.00042	0.1156	0.363%
July			
Residential	0.00253	0.1365	1.853%
General Service	0.00209	0.1156	1.808%
August			
Residential	-0.00007	0.1365	-0.051%
General Service	-0.00157	0.1156	-1.358%
September			
Residential	-0.00253	0.1365	-1.853%
General Service	-0.00177	0.1156	-1.531%
October			
Residential	0.00228	0.1365	1.670%
General Service	0.00262	0.1156	2.266%
November			
Residential	-0.00059	0.1365	-0.432%
General Service	0.00262	0.1156	2.266%
December			
Residential	0.00071	0.1365	0.520%
General Service	0.00262	0.1156	2.266%

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Baltimore Gas & Electric (Electric) 2012			
2012	Adjustment cents/kWh	Retail Rate	Adjustment %
January			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
February			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
March			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
April			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
May			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
June			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
July			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
August			
Residential	0.00253	0.1291	1.960%
General Service	0.0016	0.1064	1.504%

Massachusetts

The Commission adopted decoupling as a statewide regulatory policy in 2008; in the subsequent years, individual utilities filed decoupling tariffs, often as part of a general rate case.

The electric utilities with decoupling mechanisms are:

- Fitchberg Gas & Electric (electric); Docket D.P.U. 11-01 (August 2011); Revenue Decoupling Adjustment Clause, M.D.P.U. No. 203
- Massachusetts Electric and Western Electric (National Grid); Docket D.P.U. 09-39 (August 2011); Revenue Decoupling Adjustment Clause, M.D.P.U. No. 1165
- Western Massachusetts Electric; Docket D.P.U. 10-70 (January 2011); Revenue Decoupling Adjustment Clause, M.D.P.U. No. 1050

Although the Commission considered the effects of decoupling on ROE in each case, it did not make an explicit ROE adjustment for the decoupling mechanisms. The mechanisms for Fitchberg and Western Massachusetts are identical. In each, the utility compares authorized distribution revenue to actual

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distribution revenue, by class, and calculates an adjustment for any difference. Adjustments cannot exceed 1% of revenue and amounts not surcharged or refunded are carried forward to a future year. The mechanism for the National Grid companies is similar, but includes a recalculation of distribution authorized revenues each year to account for capital additions and a 50% sharing for earnings above the authorized ROE. The cap on any year's adjustments is 3%.

The gas utilities with decoupling mechanisms are:

- Bay State Gas; Docket No. D.P.U. 09-30 (October 2009); Revenue Decoupling Adjustment Clause, M.D.P.U. No. 104
- Fitchberg Gas & Electric (gas); Docket D.P.U. 11-01 (August 2011); Revenue Decoupling Adjustment Clause, M.D.P.U. No. 164
- Boston Gas and Colonial Gas; Docket No. D.P.U. 10-55 (November 2010); Revenue Decoupling Adjustment Clause, M.D.P.U. No. 5
- New England Gas; Docket D.P.U. 10-114 (March 2011); Revenue Decoupling Adjustment Clause, M.D.P.U. No. 1025

The gas decoupling mechanisms are all similar. Each compares on a semi-annual basis (for peak and non-peak gas seasons) actual to authorized non-gas revenues per customer for all classes and calculates adjustments for any difference, with peak season adjustments applying in the following peak season and similarly for non-peak adjustments. The cap on any one adjustment is 3%, with amounts over deferred for later recovery.

Adjustments are in the tables below.

Fitchberg Gas & Electric (Electric)			
Year	Decoupling Adjustment ȼ/kWh	Retail Rate ȼ/kWh	Decoupling Adjustment %
2012			
All	0.06	13.96	0.430%

Massachusetts Electric and Nantucket Electric			
Year	Decoupling Adjustment ȼ/kWh	Retail Rate ȼ/kWh	Decoupling Adjustment %
2011			
All	-0.015	14.29	-0.105%
2012			
All	0.044	13.96	0.315%

Western Massachusetts Electric			
Year	Decoupling Adjustment ȼ/kWh	Retail Rate ȼ/kWh	Decoupling Adjustment %
2012			
All	-0.133	13.96	-0.953%

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Bay State Gas				
Year	Decoupling Adjustment $/therm	Retail Rate	Retail Rate $/therm	Decoupling Adjustment %
May-11				
All	0.027	12.15	1.19	2.278%
Nov-11				
All	-0.0147	12.17	1.19	-1.238%
May-12				
All	0.0155	12.06	1.18	1.317%

Boston Gas and Colonial Gas				
Year	Decoupling Adjustment $/therm	Retail Rate	Retail Rate $/therm	Decoupling Adjustment %
Nov-11				
Boston Gas	-0.0181	12.17	1.19	-1.524%
Colonial Gas	-0.0172	12.17	1.19	-1.449%
May-12				
Boston Gas	0.0045	12.06	1.18	0.382%
Colonial Gas	0.0141	12.06	1.18	1.198%

New England Gas				
Year	Decoupling Adjustment $/therm	Retail Rate	Retail Rate $/therm	Decoupling Adjustment %
May-12				
All	0.0252	12.06	1.18	2.142%

Fitchberg Gas & Electric (gas)				
Year	Decoupling Adjustment $/therm	Retail Rate	Retail Rate $/therm	Decoupling Adjustment %
May-12				
All	0.0006	12.06	1.18	0.051%

Michigan

Electric Utility Decoupling

The Michigan Commission has approved decoupling mechanisms for the state's two large electric utilities – Consumers Power (Case No. U-15645, November 2009, and Case No. U-16191 continuing decoupling, November 2010) and Detroit Edison (Case No. U-15768, January 2010) – and a third – Upper Peninsula Power Company (Case No. U-15988, December 2009). No adjustments occurred under the Detroit Edison or Consumers Power mechanisms because of a Michigan Court of Appeals ruling in 2012 finding the Commission did not have authority to adopt these mechanisms. Upper Peninsula has made one adjustment under its mechanism; the second is pending with a party to the settlement agreement

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under which the mechanism was approved moving that the Commission dismiss the filing given the Detroit Edison court decision.

All three decoupling mechanisms calculated adjustments suing comparisons of authorized to actual (not weather adjusted) non-fuel revenue per customer, by customer class. For Detroit Edison, the decoupling mechanism operated in tandem with a similar mechanism that accounted for revenues changes from customer movement between retail access and bundled service. For Consumers Power, the decoupling mechanism covered these revenue changes along with all others. None of the decisions made an ROE adjustment in connection with the decoupling mechanisms.

Although the summary tables do not include adjustments for either Detroit Edison or Consumers Power, the tables below show the adjustment the utilities filed for informational purposes. Consumers Power filed its adjustments two ways because of anomalous results. In customer classes with relatively few numbers of customers and widely varying usage, movement between rate schedules (such as between direct access and bundled or between different types of bundled service) can cause significant changes in use per customer and, thus, the revenue per customer calculations. As the table for Consumers Power shows, the revenue per customer model resulted in some widely varying adjustments and Consumers proposed an alternate (B) spread of the revenue shortfall based on total class revenue requirements rather than changes in revenue per customer by class. The very large residential refund included in Detroit Edison's only decoupling filing stemmed primarily from weather, which was warmer than normal during the period covered.

Detroit Edison Revised Sheet No. C-76.01			
	Decoupling Adjustment ¢/kWh	Retail Rate ¢/kWh	Decoupling Adjustment %
2011			
Residential	-1.557	12.73	-12.231%
Commercial	0.039	10.28	0.379%
Industrial	0.039	7.69	0.507%

Consumers Power Sheet No. D-2.00			
	Decoupling Adjustment ¢/kWh	Retail Rate ¢/kWh	Decoupling Adjustment %
2011 (A)			
Residential	-0.000599	12.73	-0.00471%
Secondary	0.000499	10.28	0.00485%
Primary	0.002052	7.69	0.02668%
2011 (B)			
Residential	0.001102	12.73	0.00866%
Secondary	0.00077	10.28	0.00749%
Primary	0.000483	7.69	0.00628%
2012 (A)			
Residential	-0.000503	13.79	-0.00365%
Secondary	0.00096	10.81	0.00888%
Primary	0.002515	7.91	0.03180%

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Consumers Power Sheet No. D-2.00			
2012 (B)			
Residential	0.002711	13.79	0.01966%
Secondary	0.000746	10.81	0.00690%
Primary	-0.000031	7.91	-0.00039%

The table below shows Peninsula Power's filed adjustments. As noted, the adjustment for 2012 is still pending.

Peninsula Power Company Original Sheet D-75.0			
	Decoupling Adjustment ȼ/kWh	Retail Rate ȼ/kWh	Decoupling Adjustment %
2011			
Residential	0.223	12.73	1.752%
Secondary	0.347	10.28	3.375%
2012			
Residential	0.091 (pending)	13.79	0.660%
Secondary	-0.272 (pending)	10.81	-2.516%

Natural Gas Utility Decoupling

The Michigan Commission has approved decoupling mechanisms for three of the state's natural gas utilities: Consumers Energy (Case No. U-15986, May 2010; terminated in Case No. U-16855, June 2012); Michigan Consolidated Gas (Case No. U-15985, June 2010; revised in Case No. U-16999, April 2012, but not in effect until November 2013); and Michigan Gas Utilities (Case No. U-15990, July 2010). All of the mechanisms reconcile weather-normalized sales per customer to authorized sales per customer by customer class or rate schedule. Michigan Consolidated Gas' new mechanism will replace this design with one that compares weather-normalized revenues to authorized revenues per customer class or rate schedule and adds caps on refunds or surcharges based on the cumulative effects of 150% of the utility's energy efficiency targets for each year that the mechanism operates without the utility filing a general rate case.

Michigan Gas Utility Original Sheet D-1.02			
	Decoupling Adjustment $/Mcf	Retail Rate $/Mcf	Decoupling Adjustment %
2011			
Residential	-0.05192	10.47	-0.4959%
Multi-Family I	0.27572	10.47	2.6334%
Small Gen'l Service	0.27572	9.14	3.0166%
Multi-Family II	-0.013588	10.47	-0.1298%
2012			
Residential	-0.04603	11.4	-0.4038%
Multi-Family I	0.013044	11.4	0.1144%
Small Gen'l Service	0.013044	8.87	0.1471%
Multi-Family II	0.00174	11.4	0.0153%

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Michigan Consolidated Gas Eighteenth Revised Sheet No. D-2.00			
	Decoupling Adjustment $/Ccf	Retail Rate $/Mcf	Decoupling Adjustment %
2011			
Residential	0.0119	10.47	1.137%
Low Income	0.01832	10.47	1.750%
Multi-Family I	-0.06957	10.47	-6.645%
Multi-Family II	-0.00238	10.47	-0.227%
General Service	0.01971	9.14	2.156%
2012			
Residential	0.00492	11.4	0.432%
Low Income	0.01017	11.4	0.892%
Multi-Family I	-0.06493	11.4	-5.696%
Multi-Family II	-0.005	11.4	-0.439%
General Service	0.0077	8.87	0.868%

Consumers Energy Eleventh Revised Sheet No. D-1.10			
	Decoupling Adjustment $/Mcf	Retail Rate $/Mcf	Decoupling Adjustment %
2012*			
Residential	0.0425	11.4	0.373%
General Service	0.1123	8.87	1.266%
Transportation	0.0346	8.87	0.390%
2013			
Residential	0.1254	Still pending	Still pending
General Service	0.0039	Still pending	Still pending
Transportation	0.041	Still pending	Still pending

* Note: Consumers Energy actually recovered the amounts shown for 2012 over just three months, because of its need to collect the amounts due within 24 months from accrual or incur a write-off (notwithstanding the later recovery). I have calculated the effect of the adjustment as if it had been collected over the entire year, using the utility's application adjustments, to be consistent with other adjustments in this report.

Minnesota

Minnesota has approved decoupling for one of its gas utilities, CenterPoint Energy, in Docket GR-08-1075 (January 2010). The Commission did not adjust ROE for the decoupling mechanism. The CenterPoint tariff (Conservation Enabling Rider, Page 27) compares actual, weather-adjusted revenue per customer to authorized revenue per customer for the residential and small commercial classes and calculates adjustments from any difference. There is a 3% limit on surcharges. The Commission originally adopted an inverted rate structure for CenterPoint along with the decoupling mechanism but abandoned it in November 2010 following considerable adverse response.

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CenterPoint Energy				
	Decoupling Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Decoupling Adjustment %
2010				
Residential	-0.00173	8.76	0.8546	-0.20%
Commercial A	0.01136	7.43	0.7249	1.57%
Commercial B	-0.00077	7.43	0.7249	-0.11%
Commercial C	-0.00531	7.43	0.7249	-0.73%
2010 (rev. 11/2010)				
Residential	-0.00385	8.76	0.8546	-0.45%
Commercial A	0.00951	7.43	0.7249	1.31%
Commercial B	-0.00377	7.43	0.7249	-0.52%
Commercial C	-0.00583	7.43	0.7249	-0.80%
2011				
Residential	-0.00249	8.66	0.8449	-0.29%
Commercial A	0.00002	7.6	0.7415	0.00%
Commercial B	-0.01281	7.6	0.7415	-1.73%
Commercial C	-0.01203	7.6	0.7415	-1.62%

Nevada

The Nevada Commission approved decoupling for Southwest Gas in Docket No. 09-04003 (October 2009), lowering the utility's allowed ROE by 25 basis points in conjunction with the mechanism. Southwest Gas' tariff (P.U.C.N. Sheet No. 88 General Revenues Adjustment Provision) compares actual to authorized per-customer-revenue by class of customer and calculates adjustments from any difference. The utility makes separate calculations for its northern and southern Nevada service territory areas.

Southwest Gas				
	Decoupling Adjustment $/therm	Retail Rate	Retail Rate $/therm	Decoupling Adjustment %
2010 South Nevada				
Residential SFH	0.00305	12.25	1.195122	0.255%
Residential MFH	-0.01136	12.25	1.195122	-0.951%
General Small	0.01646	9.77	0.953171	1.727%
General Medium	-0.00547	9.77	0.953171	-0.574%
General Large	0.00103	9.77	0.953171	0.108%
North Nevada				
Residential SFH	-0.022	12.25	1.195122	-1.841%
Residential MFH	-0.02418	12.25	1.195122	-2.023%
General Small	-0.06688	9.77	0.953171	-7.017%
General Medium	-0.02315	9.77	0.953171	-2.429%
General Large	-0.01498	9.77	0.953171	-1.572%

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Southwest Gas				
South Nevada 2011				
Residential SFH	0.01177	10.66	1.040000	1.132%
Residential MFH	-0.00394	10.66	1.040000	-0.379%
General Small	0.07031	8.05	0.785366	8.953%
General Medium	0.00285	8.05	0.785366	0.363%
General Large	-0.00251	8.05	0.785366	-0.320%
North Nevada				
Residential SFH	-0.0171	10.66	1.040000	-1.644%
Residential MFH	-0.01963	10.66	1.040000	-1.888%
General Small	-0.03397	8.05	0.785366	-4.325%
General Medium	-0.01264	8.05	0.785366	-1.609%
General Large	-0.01423	8.05	0.785366	-1.812%

New Jersey

The New Jersey Commission has approved decoupling mechanisms for two of its gas utilities: for New Jersey Natural Gas Company in Order No. GR05121020 (October 2006) and Docket No. GR05121020 (January 2010) extending the mechanism through 2013; and for South Jersey Gas Company in Docket No. GR05121019 (October 2006) and Docket No. GR05121019 (January 2010) extending the mechanism through 2013. Neither utility received a downward ROE adjustment as a result of the adoption of decoupling. Both of the mechanisms (Conservation Incentive Program, Rider I for New Jersey Natural Gas and Conservation Incentive Program, Rider M, Sheet 97c for South Jersey Gas) operate in the same way: a comparison of authorized margin revenue per customer to actual, non-weather adjusted margin revenue per customer, adjusted for net customers added, on a per rate schedule basis. The recovery of any deficiency that is not related to weather (calculated pursuant to a separate schedule – Rider D) is limited to the amount of offsetting revenue from the sale of surplus gas. Neither may collect a surcharge if it would thereby earn more than its allowed ROE but any amounts excluded carry over.

South Jersey Gas Company				
	Decoupling Adjustment $/therm	Retail Rate	Retail Rate $/therm	Decoupling Adjustment %
2007				
Residential	0.0443	14.48	1.41	3.136%
General	0.0392	12.1	1.18	3.321%
General Large	-0.0037	9.63	0.94	-0.394%
2008				
Residential	0.0707	15.21	1.48	4.764%
General	0.0684	13.38	1.31	5.240%
General Large	0.0062	12.76	1.24	0.498%
2009				
Residential	0.0394	14.54	1.42	2.778%
General	0.0797	10.2	1.00	8.009%
General Large	-0.0012	8.96	0.87	-0.137%

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South Jersey Gas Company				
2010				
Residential	0.0441	12.84	1.25	3.520%
General	0.0422	10.11	0.99	4.278%
General Large	0.0046	9.63	0.94	0.490%
2011				
Residential	0.0095	10.16	0.99	0.958%
General	0.0002	9.54	0.93	0.021%
General Large	0.0018	8.49	0.83	0.217%

New Jersey Natural Gas Company				
	Decoupling Adjustment $/therm	Retail Rate	Retail Rate $/therm	Decoupling Adjustment %
2008				
Residential	0.0261	15.21	1.48	1.759%
General	0.0248	13.38	1.31	1.900%
2009				
Residential	0.0378	14.54	1.42	2.665%
General	0.0424	10.2	1.00	4.261%
General Large	0.0424	8.96	0.87	4.850%
2010				
Residential	0.0079	12.84	1.25	0.631%
General	0.00184	10.11	0.99	0.187%
General Large	0.026	9.63	0.94	2.767%
2011				
Residential	0.0179	10.16	0.99	1.806%
General	0.0339	9.54	0.93	3.642%
Gen' Large	0.0278	8.49	0.83	3.356%

New York

The New York adopted decoupling as a regulatory policy in April 2007. Over the next several years, utilities adopted decoupling mechanisms as they came in for general rate cases. New York also has what it calls “rate plans” in place for many of its utilities. These plans may set two years’ worth of revenue requirements and a methodology for establishing a third year. Most of the decoupling mechanisms use these adjusted revenue requirements for the authorized revenues to which they compare actual revenues; the remainder use the unadjusted revenues authorized in their last general rate case. Although most of the decoupling mechanisms produce an adjustment annually, several of the utilities, including Central Hudson, Consolidated Edison and Niagara Mohawk, have the ability to file for an immediate change in the adjustment if the amount accruing for surcharge or refund exceeds a specified level. This has resulted in some utilities filing revised adjustments much more frequently than others.

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The electric utilities with decoupling mechanisms are:

- Central Hudson, approved in Docket No. 09-E-0588 with an ROE adjustment of 10 basis points; Tariff: PSC 15, Leaf 163.5.4
- Consolidated Edison Docket, approved in Docket No. 09-E-0428 with no ROE adjustment; Tariff: PSC 10, Leaf 349
- Niagara Mohawk, approved in Docket No. 10-E-0050 with no ROE adjustment; Tariff: PSC 220, Leaf 263.2
- New York State Electric & Gas, approved in Docket No. 09-E-0715 with no ROE adjustment; Tariff: PSC 120, Leaf 21
- Orange & Rockland, approved in Docket No. 10-E-0050 with no ROE adjustment; Tariff: PSC 220, Leaf 263.2
- Rochester Gas & Electric in Docket No. 09-E-0717 with no ROE Adjustment; Tariff: PSC 19, Leaf 81.1

The gas utilities with decoupling mechanisms are:

- Consolidated Edison, approved in Docket No. 09-G-0795 with no ROE adjustment; Tariff: PSC 9, Leaf 181.1
- Central Hudson, approved in Docket No. 09-G-0589 with an ROE Adjustment of 10 basis points, based on observation most companies in its peer group did not have decoupling mechanisms; Tariff: PSC 12, Leaf 129
- Niagara Mohawk, approved in Docket No. 08-G-0609 with no ROE Adjustment; Tariff: PSC 219, Leaf 122.2
- National Fuel Gas Distribution, approved in Docket No. 07-G-0141 with no ROE Adjustment; Tariff: PSC 8, Leaf 148.9
- Corning Gas, approved in Docket No 08-G-1137 with no ROE Adjustment; Tariff: PSC 4, Leaf 75.3
- New York State Electric & Gas, approved in Docket No. 09-G-0716 with no ROE adjustment; Tariff: PSC 90, Leaf 105.2 (this applies to PSC 87 (bundled sales) and PSC 88 (transportation))
- Orange & Rockland, approved in Docket No. 08-G-1398 with no ROE adjustment; Tariff: PSC 4, Leaf 113.1
- KeySpan Gas and Brooklyn Union Gas, approved in Docket Nos. 06-G-1185/86 with no ROE adjustment; Tariff: PSC 1, Leaf 119.52 (Keyspan) and PSC 12, Leaf 138.52 (Brooklyn Union)
- Rochester Gas & Electric, approved in Docket No. 09-G-0718 with no ROE adjustment; Tariff: PSC 16, Leaf 127.46.2
- St. Lawrence Gas, approved in Docket No. 08-G-1392 with an ROE adjustment of 10 basis points, per a settlement; Tariff: PSC 3, Leaf 191.1

Central Hudson (Electric)			
	RDM Adjustment	Retail Rate $/kWh	RDM Adjustment %
Oct-09			
Residential	0.00213	15.81	0.013%
Non-Demand	0.00141	12.12	0.012%
Primary Demand	0.00008	12.12	0.001%
Secondary Demand	0.00015	12.12	0.001%

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Central Hudson (Electric)			
Aug-10			
Residential	0.00304	16.51	0.018%
Non-Demand	0.00197	12.64	0.016%
Primary Demand	0	12.64	0.000%
Secondary Demand	-0.00014	12.64	-0.001%
Oct-10			
Residential	0.0091	16.51	0.055%
Non-Demand	0.00056	12.64	0.004%
Primary Demand	-0.00008	12.64	-0.001%
Secondary Demand	0.01143	12.64	0.090%
Oct-11			
Residential	-0.00187	17.88	-0.010%
Non-Demand	0.00029	15.54	0.002%
Primary Demand	0.00139	15.54	0.009%
Secondary Demand	0.00123	15.54	0.008%
Apr-12			
Residential	-0.00079	17.12	-0.005%
Non-Demand	0.00145	14.72	0.010%
Primary Demand	0.00336	14.72	0.023%
Secondary Demand	0.00262	14.72	0.018%
Aug-12			
Residential	0.00095	17.12	0.006%
Non-Demand	0.00116	14.72	0.008%
Primary Demand	0.00197	14.72	0.013%
Secondary Demand	0.00139	14.72	0.009%

Consolidated Edison (Electric)[23]			
	RDM Adjustment	Retail Rate $/kWh	RDM Adjustment %
Nov-08			
Residential	-0.1502	24.18	-0.621%
General Small	-0.0071	21.2	-0.033%
General Large	0.1178	19.56	0.602%

[23] A general large price for 2011 was not available. The table uses the ratio from the prior year - 93% of the general small rate. The New York average industrial price – used in some of the other tables – seemed likely too low.

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Consolidated Edison (Electric)			
May-09			
Residential	0.0711	23.58	0.302%
General Small	-0.0292	19.64	-0.149%
General Large	-0.0061	18.05	-0.034%
Aug-09			
Residential	0.4814	23.58	2.042%
General Small	0.138	19.64	0.703%
General Large	0.116	18.05	0.643%
Nov-09			
Residential	0.7295	23.58	3.094%
General Small	0.1953	19.64	0.994%
General Large	0.11	18.05	0.609%
Feb-10			
Residential	1.2632	25.85	4.887%
General Small	0.2749	20.38	1.349%
General Large	0.1314	18.92	0.695%
Apr-10			
Residential	1.2632	25.85	4.887%
General Small	0.2749	20.38	1.349%
General Large	0.1274	18.92	0.673%
4/16/2010			
Residential	0.8529	25.85	3.299%
General Small	0.1077	20.38	0.528%
General Large	0.0147	18.92	0.078%
May-10			
Residential	0.2605	25.85	1.008%
General Small	0.0231	20.38	0.113%
General Large	-0.0131	18.92	-0.069%
Aug-10			
Residential	-0.1371	25.85	-0.530%
General Small	-0.6707	20.38	-3.291%
General Large	-1.0901	18.92	-5.762%
Sep-10			
Residential	-0.0104	25.85	-0.040%
General Small	-0.708	20.38	-3.474%
General Large	-0.6693	18.92	-3.538%
Oct-10			
Residential	-0.4169	25.85	-1.613%
General Small	0.07374	20.38	0.362%
General Large	-0.7745	18.92	-4.094%

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Consolidated Edison (Electric)			
Nov-10			
Residential	-0.0669	25.85	-0.259%
General Small	-0.0626	20.38	-0.307%
General Large	-0.0943	18.92	-0.498%
May-11			
Residential	0.0907	17.88	0.507%
General Small	-0.2222	15.54	-1.430%
General Large	-0.2133	14.45	-1.476%
Sep-11			
Residential	-0.1033	17.88	-0.578%
General Small	-0.6916	15.54	-4.450%
General Large	-1.0475	14.45	-7.248%
Nov-11			
Residential	0.118	17.88	0.660%
General Small	-0.0377	15.54	-0.243%
General Large	-0.1941	14.45	-1.343%

Niagara Mohawk (Electric)			
	RDM Adjustment	Retail Rate $/kWh	RDM Adjustment %
Jul-11			
Residential	-0.00305	17.88	-0.017%
Feb-12			
Residential	-0.0013	17.12	-0.008%
Small General Service	-0.00044	14.72	-0.003%

New York State Electric & Gas (Electric)			
	RDM Adjustment	Retail Rate $/kWh	RDM Adjustment %
Nov-11			
Residential	-0.002045	17.12	-0.012%
General Service	-0.000067	14.72	0.000%

Rochester Gas & Electric (Electric)			
	RDM Adjustment	Retail Rate $/kWh	RDM Adjustment %
Sep-11			
Residential	-0.00465	17.12	-0.027%
Nov-11			
Residential	-0.000273	17.12	-0.002%
General Service	-0.000185	14.72	-0.001%

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Orange & Rockland (Electric)			
	RDM Adjustment	Retail Rate $/kWh	RDM Adjustment %
Sep-08			
Residential	0.00028	18.12	0.002%
Small General Service	0.0003	14.7	0.002%
General Service	0.00011	11.64	0.001%
Dec-08			
Residential	0.00164	18.12	0.009%
Small General Service	0.00061	14.7	0.004%
General Service	0.00026	11.64	0.002%
Aug-09			
Residential	0.00156	17.63	0.009%
Small General Service	0.00115	13.09	0.009%
General Service	0.00037	7.59	0.005%
Sep-09			
Residential	0.0035	17.63	0.020%
Small General Service	0.00209	13.09	0.016%
General Service	0.00056	7.59	0.007%
Jan-10			
Residential	0.00515	18.88	0.027%
Small General Service	0.00271	14.31	0.019%
General Service	0.00013	8.08	0.002%
Aug-10			
Residential	0.00189	18.88	0.010%
Small General Service	0.00194	14.31	0.014%
General Service	0.00044	8.08	0.005%
Jun-11			
Residential	0.00272	17.88	0.015%
Small General Service	0.00336	15.54	0.022%
General Service	0.00048	8.07	0.006%
Aug-11			
Residential	0.00077	17.88	0.004%
Small General Service	0.00215	15.54	0.014%
General Service	0.00058	8.07	0.007%
Sep-11			
Residential	0.00136	17.88	0.008%
Small General Service	0.00222	15.54	0.014%
General Service	0.00163	8.07	0.020%
Apr-12			
Residential	0.00136	17.12	0.008%
Small General Service	0.00222	14.72	0.015%
General Service	0.00163	6.81	0.024%

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Orange & Rockland (Electric)			
Aug-12			
Residential	-0.00118	17.12	-0.007%
Small General Service	-0.00277	14.72	-0.019%
General Service	0.00285	6.81	0.042%

Consolidated Edison (Gas)				
	Decoupling Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Decoupling Adjustment %
Jun-08				
General Service	0.017675	12.86	1.25	1.409%
General Service - Heat	0.015429	12.86	1.25	1.230%
Residential Heat <4 units	0.053515	16.78	1.64	3.269%
Residential Heat > 4 units	-0.006065	16.78	1.64	-0.370%
Nov-08				
General Service	0.022403	12.86	1.25	1.786%
General Service - Heat	0.005226	12.86	1.25	0.417%
Residential Heat <4 units	0.042244	16.78	1.64	2.580%
Residential Heat > 4 units	-0.019822	16.78	1.64	-1.211%
Jun-09				
General Service	0.043801	10.72	1.05	4.188%
General Service - Heat	0.036944	10.72	1.05	3.532%
Residential Heat <4 units	0.105825	15.05	1.47	7.207%
Residential Heat > 4 units	-0.019169	15.05	1.47	-1.306%
Oct-09				
General Service	0.021398	10.72	1.05	2.046%
General Service - Heat	0.031718	10.72	1.05	3.033%
Residential Heat <4 units	0.063581	15.05	1.47	4.330%
Residential Heat > 4 units	0.000653	15.05	1.47	0.044%
Nov-09				
General Service	0.023511	10.72	1.05	2.248%
General Service - Heat	0.021304	10.72	1.05	2.037%
Residential Heat <4 units	0.062294	15.05	1.47	4.243%
Residential Heat > 4 units	-0.008936	15.05	1.47	-0.609%
Jan-10				
General Service	0.0513	10.88	1.06	4.833%
General Service - Heat	0.042481	10.88	1.06	4.002%
Residential Heat <4 units	0.148421	14.04	1.37	10.836%
Residential Heat > 4 units	-0.0309	14.04	1.37	-2.256%

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Consolidated Edison (Gas)				
Nov-10				
General Service	0.002233	10.88	1.06	0.210%
General Service - Heat	0.000197	10.88	1.06	0.019%
Residential Heat <4 units	0.026096	14.04	1.37	1.905%
Residential Heat > 4 units	-0.021983	14.04	1.37	-1.605%
Nov-11			0.00	
General Service	-0.014855	9.37	0.91	-1.625%
General Service - Heat	-0.011081	9.37	0.91	-1.212%
Residential Heat <4 units	-0.023599	13.64	1.33	-1.773%
Residential Heat > 4 units	-0.015729	13.64	1.33	-1.182%
May-12				
General Service	-0.0105	7.05	0.69	-1.527%
General Service - Heat	-0.028878	7.05	0.69	-4.199%
Residential Heat <4 units	-0.029645	14.22	1.39	-2.137%
Residential Heat > 4 units	-0.055757	14.22	1.39	-4.019%

Corning Gas			
	Decoupling Adjustment $/Mcf	Retail Rate $/Mcf	Decoupling Adjustment %
Jan-11			
Residential 1 Corning	0.02357	13.64	0.173%
Residential 14 Corning	0.00229	13.64	0.017%
Residential 1 Hammondsport	-0.0932	13.64	-0.683%
Residential 7 Hammondsport	-0.30455	13.64	-2.233%
Jan-12			
Residential 1 Corning	-0.08184	14.22	-0.576%
Residential 14 Corning	-0.11354	14.22	-0.798%
Residential 1 Hammondsport	-0.21382	14.22	-1.504%
Residential 7 Hammondsport	-0.06315	14.22	-0.444%

Niagara Mohawk (Gas)				
	Decoupling Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Decoupling Adjustment %
Aug-10				
Residential	0.00805	14.04	1.37	0.588%
Commercial	0.01385	10.88	1.06	1.305%
Industrial	0.03816	8.55	0.83	4.575%
Jan-11				
Residential	0.00245	13.64	1.33	0.184%
Commercial	0.01385	9.37	0.91	1.515%
Industrial	0.03816	8.25	0.80	4.741%

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Niagara Mohawk (Gas)				
Aug-11				
Residential	0.0035	13.64	1.33	0.263%
Commercial	0.01298	9.37	0.91	1.420%
Industrial	0.04008	8.25	0.80	4.980%
Jan-12				
Residential	0.0035	14.22	1.39	0.252%
Commercial	0.01298	7.05	0.69	1.887%
Industrial	0.04008	7.51	0.73	5.470%
Aug-12				
Residential	0.00537	14.22	1.39	0.387%
Commercial	0.02191	7.05	0.69	3.185%
Industrial	0.00509	7.51	0.73	0.695%

Central Hudson (Gas)				
	Decoupling Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Decoupling Adjustment %
Aug-10				
Residential	0.0266	14.04	1.37	1.942%
Commercial	0.01541	10.88	1.06	1.452%
Jun-11				
Residential	0.00492	13.64	1.33	0.370%
Commercial	-0.00151	9.37	0.91	-0.165%
Aug-11				
Residential	-0.02168	13.64	1.33	-1.629%
Commercial	-0.01692	9.37	0.91	-1.851%
Aug-12				
Residential	-0.01151	14.22	1.39	-0.830%
Commercial	-0.00405	7.05	0.69	-0.589%

National Fuel Gas Distribution				
	Decoupling Adjustment $/Ccf	Retail Rate $/Mcf	Retail Rate $/Ccf	Decoupling Adjustment %
Mar-09				
All	-0.00082	12.89	1.29	-0.06%
Mar-10				
All	0.0084	12.46	1.25	0.67%
Mar-11				
All	0.00354	11.51	1.15	0.31%
Mar-12				
All	-0.00082	10.64	1.06	-0.08%

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New York State Electric & Gas (Gas)				
	Decoupling Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Decoupling Adjustment %
Feb-11				
General Service	-0.01819	9.37	0.91	-1.990%
Nov-11				
Residential	-0.003498	13.64	1.33	-0.263%
General Service	-0.017152	9.37	0.91	-1.876%

Orange & Rockland (Gas)				
	Decoupling Adjustment $/Ccf	Retail Rate $/Mcf	Retail Rate $/Ccf	Decoupling Adjustment %
Dec-10				
Residential	0.0026	14.04	1.40	0.185%
General Service	0.01497	10.88	1.09	1.376%
Dec-11				
Residential	0.00944	13.64	1.36	0.692%
General Service	0.00488	9.37	0.94	0.521%
Apr-12				
Residential	0.06176	14.22	1.42	4.343%
General Service	0.04392	7.05	0.71	6.230%

Rochester Gas & Electric (Gas)				
	Decoupling Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Decoupling Adjustment %
Jun-11				
Residential	0.04942	13.64	1.33	3.714%
Nov-11				
Residential	-0.002445	13.64	1.33	-0.184%
General Service	-0.002697	9.37	0.91	-0.295%

Brooklyn Union Gas				
	Decoupling Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Decoupling Adjustment %
May-11				
All	0.011	11.51	1.12	0.98%
May-12				
All	0.0051	10.64	1.04	0.49%

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KeySpan Gas Distribution				
	Decoupling Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Decoupling Adjustment %
May-11				
All	-0.0039	11.51	1.12	-0.35%
May-12				
All	-0.0067	10.64	1.04	-0.64%

St. Lawrence Gas				
	Decoupling Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Decoupling Adjustment %
Apr-11				
All	0.014657	11.51	1.12	1.31%
Jun-11				
All	0.013893	11.51	1.12	1.24%
Apr-12				
All	0.012631	10.64	1.04	1.21%

North Carolina

North Carolina has approved decoupling for two of its gas utilities: Public Service of North Carolina in Docket No. G-5, Sub 495 (October 2008) and Piedmont Gas in Docket G-9, Sub 499 Final Order (November 2005) extended in G-9, Sub 550 (November 2008). In none of the order did the Commission make an ROE adjustment for the decoupling mechanisms. Both tariffs – Rider C for North Carolina Public Service and the Customer Utilization Tracker (CUT) (now called Margin Decoupling Tracker Appendix C) for Piedmont Gas – operate similarly, comparing actual, non-weather adjusted margin per customer to the authorized margin per customer, by rate schedule, to calculate adjustments, which occur semi-annually.

North Carolina Public Service Company[24]			
	Decoupling Adjustment $/therm	Retail Rate $/therm	Decoupling Adjustment %
Apr-09			
Residential	-0.0029	1.10179	-0.26%
Small General	-0.00051	0.99271	-0.05%
Oct-09			
Residential	0.01737	1.02322	1.70%
Small General	0.00685	0.86379	0.79%
Apr-10			
Residential	-0.01437	1.06451	-1.35%
Small General	-0.01035	0.89978	-1.15%

[24] The retail rate and adjustment percentage are from the utility filings.

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North Carolina Public Service Company			
Oct-10			
Residential	0.00012	1.05014	0.01%
Small General	-0.00504	0.88943	-0.57%
Apr-11			
Residential	-0.0237	0.98749	-2.40%
Small General	-0.01312	0.81519	-1.61%
Oct-11			
Residential	0.03481	0.96379	3.61%
Small General	0.01748	0.80207	2.18%
Apr-12			
Residential	0.04674	0.89824	5.20%
Small General	0.02691	0.70429	3.82%

Piedmont Gas Company				
	Decoupling Adjustment $/therm	Retail Rate	Retail Rate $/therm	Decoupling Adjustment %
Apr-06				
Residential	0.02262	15.09	1.47	1.536%
Small Commercial	0.0123	12.6	1.23	1.001%
Medium Commercial	0.00086	12.6	1.23	0.070%
Nov-06				
Residential	0.05181	15.71	1.53	3.380%
Small Commercial	0.02339	13.78	1.34	1.740%
Medium Commercial	0.011389	13.78	1.34	0.847%
Apr-07				
Residential	0.07791	15.35	1.50	5.202%
Small Commercial	0.04127	12.34	1.20	3.428%
Medium Commercial	0.00996	12.34	1.20	0.827%
Nov-07				
Residential	0.06153	15.81	1.54	3.989%
Small Commercial	0.03118	13.09	1.28	2.442%
Medium Commercial	0.01213	13.09	1.28	0.950%
Apr-08				
Residential	0.08471	17.2	1.68	5.048%
Small Commercial	0.04732	14.16	1.38	3.425%
Medium Commercial	0.01452	14.16	1.38	1.051%
Nov-08				
Residential	0.07494	15.39	1.50	4.991%
Small Commercial	0.03819	14.12	1.38	2.772%
Medium Commercial	0.02394	14.12	1.38	1.738%

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Piedmont Gas Company				
Apr-09				
Residential	0.04659	15.81	1.54	3.021%
Small Commercial	0.02293	12	1.17	1.959%
Medium Commercial	0.02124	12	1.17	1.814%
Nov-09				
Residential	0.0087	13.58	1.32	0.657%
Small Commercial	-0.00395	11.56	1.13	-0.350%
Medium Commercial	0.02116	11.56	1.13	1.876%
Apr-10				
Residential	-0.00467	19.11	1.86	-0.250%
Small Commercial	-0.00899	11.72	1.14	-0.786%
Medium Commercial	0.01944	11.72	1.14	1.700%
Nov-10				
Residential	-0.01827	12.02	1.17	-1.558%
Small Commercial	-0.02077	9.62	0.94	-2.213%
Medium Commercial	0.01944	9.62	0.94	2.071%
Apr-11				
Residential	-0.02487	14.73	1.44	-1.731%
Small Commercial	-0.02438	10.45	1.02	-2.391%
Medium Commercial	0.01587	10.45	1.02	1.557%
Nov-11				
Residential	-0.00112	11.81	1.15	-0.097%
Small Commercial	-0.0163	9.84	0.96	-1.698%
Medium Commercial	0.02542	9.84	0.96	2.648%
Apr-12				
Residential	0.04319	15.14	1.48	2.924%
Small Commercial	0.01235	8.45	0.82	1.498%
Medium Commercial	0.03611	8.45	0.82	4.380%

Ohio

The Ohio Commission recently approved decoupling mechanisms for two of its electric utilities: AEP Ohio, Case No. 11-5905-EL-RDR (May 2012), and Duke Energy Ohio, Case No. 11-5905-EL-RDR (May 2012). In neither case, which were not general rate cases but dockets specific to decoupling, did the Commission include an ROE adjustment in conjunction with the decoupling approval. Both are three-year pilot programs and both calculate adjustments by comparing authorized distribution revenues and actual distribution revenues for the residential and small commercial classes. Adjustments under the tariffs will occur annually, based n the prior year's difference. There is a 3% cap on any surcharge, but amounts not recovered carry forward to future years. The AEP Ohio tariff is P.U.C.O. No. 20, Pilot Throughput Balancing Adjustment Rider, Original Sheet 464-1D; Duke's is Rider DDR Distribution Decoupling Rider P.U.C.O. Electric No. 19, Sheet No. 117. The first adjustments under these mechanisms should occur in June 2013.

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Oregon

Oregon has had decoupling in place for two of its gas utilities for a number of years. The mechanism for Northwest Natural Gas Company was approved in Docket UG 143, September 2002 and re-approved in August 2005 in UG 163 and September 2007 in UG 152/163. A request to extend the mechanism further is pending in the utility's current rate case. Northwest Natural's decoupling mechanism uses a straight-forward revenue-per-customer design, but expected revenues are updated annually through a forecast of the price elasticity effects of the change in the cost of gas. Cascade Natural Gas' decoupling mechanism was approved in Docket UG 167 in April 2006 and extended in UM 1283 to September 2012; a request to extend it further is pending. This decoupling mechanism also uses the revenue-per-customer design, and an earnings sharing applies once the utility's earnings exceed 175 basis points over its allowed ROE. For neither utility has the Oregon Commission explicitly lowered ROE to account for the decoupling mechanism.

Only one of Oregon's electric utilities presently has decoupling.[25] In January 2009, Docket UE 197, the Commission approved a decoupling mechanism for Portland General Electric, lowering PGE's allowed ROE by 10 basis points in conjunction with approving the mechanism. The tariff (Schedule 123) calculates adjustments by comparing actual, weather-adjusted fixed cost revenue per customer for residential and small general service to the authorized fixed cost revenue per customer, by customer class. Decoupling adjustments are limited to two percent per year, positive or negative, and amounts in excess of this do not roll over to future periods.

Adjustments under the decoupling mechanisms are as follows.

Cascade Natural Gas				
	Decoupling Adjustment ($/therm)	Retail Rate ($/Mcf)	Retail Rate ($/therm)	Decoupling %
2006				
Residential				0.940%
Commercial				0.660%
2007				
Residential	0.03231	14.65	1.43	2.261%
Commercial	0.02472	12.46	1.22	2.034%
2008				
Residential	-0.03885	13.89	1.36	-2.867%
Commercial	-0.03705	11.57	1.13	-3.282%
2009				
Residential	0.01813	14.52	1.42	0.164%
Commercial	0.01319	11.86	1.16	0.782%
2010				
Residential	0.00232	12.49	1.22	-0.128%
Commercial	0.00905	10.1	0.99	0.365%

[25] Both Portland General Electric and PacifiCorp had decoupling mechanisms during part of the 1990s. These mechanisms are not covered in this report but adjustments from the PacifiCorp mechanism are available in the 2009 version of this report, which can be found at [link to RAP]

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Cascade Natural Gas				
2011				
Residential	-0.00156	12.62	1.23	-0.127%
Commercial	0.0036	9.81	0.96	0.376%
2012				
Residential	-0.01355	12.92	1.26	-1.075%
Commercial	-0.01355	9.4	0.92	-1.478%

Northwest Natural Gas Company						
	Price Elasticity Adjustment	Decoupling True-Up	Total Decoupling Adjustments	Retail Rate	Retail Rate	Decoupling
	$/therm	$/therm	($/therm)	($/Mcf)	($/therm)	%
2005						
Residential	0.00978	0.01265	0.02243	12.9	1.26	1.782%
Commercial	0.00742	0.00846	0.01588	10.42	1.02	1.562%
2006						
Residential	0.00478	-0.00212	0.00266	14.53	1.42	0.188%
Commercial	0.00226	-0.00696	-0.0047	12.94	1.26	-0.372%
2007						
Residential	-0.00413	0.00767	0.00354	14.65	1.43	0.248%
Commercial	-0.00156	-0.00853	-0.01009	12.46	1.22	-0.830%
2008						
Residential	0.01872	0.00427	0.02299	13.89	1.36	1.697%
Commercial	0.01094	-0.01646	-0.00552	11.57	1.13	-0.489%
2009						
Residential	-0.01277	0.03311	0.03311	14.52	1.42	2.337%
Commercial	-0.00595	0.00258	0.00258	11.86	1.16	0.223%
2010						
Residential	0.00044	0.0412	0.04164	12.49	1.22	3.417%
Commercial	0	0.01253	0.01253	10.1	0.99	1.272%
2011						
Residential	-0.00044	0.04768	0.04724	12.62	1.23	3.837%
Commercial	-0.00062	0.01048	0.00986	9.81	0.96	1.030%
2012						
Residential		0.03869	0.03869	12.92	1.26	3.069%
Commercial		0.00639	0.00639	9.4	0.92	0.697%

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Portland General Electric			
	Decoupling Adjustment ȼ/kWh	Retail Rate	Decoupling Adjustment %
2010			
Residential	-0.048	10.1	-0.475%
Commercial	0.125	8.47	1.476%
2011			
Residential	0.051	9.43	0.541%
Commercial	0.149	8.18	1.822%
2012			
Residential	0.005	9.8	0.051%
Commercial	-0.155	8.37	-1.852%

Rhode Island

Rhode Island has approved decoupling for both the electricity and natural gas operations of Narragansett Electric Company (a National Grid company), pursuant to state legislation. Docket 4206 (April 2011 – written order available May 2012). The Distribution Adjustment Charge ("DAC") tariff R.I.P.U.C. NG-Gas No. 101, Section 3, Schedule A applies to the gas sales and RDM Provision R.I.P.U.C. No. 2073 to the electric. The gas decoupling mechanism is a revenue-per-customer true-up that compares actual revenues per customer to the target revenues calculated by updating the last authorized revenues for numerous adjustments, including infrastructure, safety, and reliability expenses, low income assistance, environmental response and pension costs, and capital additions. The update adjustments occur on a forecast basis. The electric decoupling mechanism does not include an update of authorized revenues but simply compares actual and authorized distribution revenues to calculate the decoupling adjustment, although the Commission may approve additions to the authorized revenues. Both mechanisms adjust annually and have only one adjustment to date.

Narragansett Electric Company (Gas)				
	Decoupling adjustment rate $/therm	Retail Rate $/mCf	Retail Rate $/therm	Decoupling adjustment %
2012				
	0.0421	16.16	1.58	2.670%

Narragansett Electric Company (Electric)			
	Decoupling adjustment rate	Retail Rate	Decoupling adjustment
	$/kWh	$/kWh	%
2012			
	-0.00014	0.1352	-0.1036%

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Tennessee

Tennessee approved decoupling for the Chattanooga Natural Gas Company in Docket No. 09-00183 (November 2010), reducing the utility's allowed ROE by 25 basis point in conjunction with the approval. The mechanism (Alignment and Usage Adjustment: Original Sheet No. 57) calculates adjustments by comparing actual base revenue per customer to test year base revenue per customer, for residential and small general service customers. There is a 2% cap on accruals which, as the table below shows, has limited adjustments, in one case significantly. Amounts not included in adjustments carry forward to future years. The capped numbers were used in the summary tables.

Chattanooga Natural Gas Company[26]						
	Adjustment Rate (cap)	Adjustment Rate (no cap)	Retail Rate $/mCf	Retail Rate $/therm	Adjustment % (cap)	Adjustment % (no cap)
2011						
Residential	-0.0074	-0.0077	10.16	0.99	-0.0728%	-0.776%
Commercial	0.0093	0.0166	8.88	0.87	0.1047%	1.917%
2012						
Residential	0.0088	0.0229	13.77	1.34	0.0639%	1.702%
Commercial	0.0112	0.0950	8.66	0.84	0.1293%	11.248%

Utah

The Utah Commission approved decoupling for Questar Gas Company in Docket No. 05-057-T01 (October 2006). Although initially in place as three-year pilot, the Commission made it permanent in Docket No. 09-057-16 (June 2010). There was no ROE adjustment in conjunction with the decoupling. The mechanism (2.08 Conservation Enabling Tariff) compares actual, non-weather adjusted margin revenues per customer with ratemaking margin revenues per customer, only for the general service class. Accruals to the balancing account per year are capped at 5% of gross revenues per twelve-month period and amortizations are limited to 2.5%.

Questar Gas Company				
	Block/Dth		Decoupling Adjustment $/therm	Decoupling Adjustment %[27]
Jul-06				
				0.27
Apr-07				
				0.36
Sep-07				
				-0.47

[26] All data supplied by the utility.
[27] As stated in utility filings.

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Questar Gas Company				
Apr-08				
				0.01
Jul-08				
GS1	Block	/ Dth		-0.47
Winter	Block #1	0-45	-0.04031	
	Block #2	Over 45	-0.01674	
Summer	Block #1	0-45	-0.03395	
	Block #2	Over 45	-0.0126	
Nov-08				
GS1	Block	/ Dth		0.01
Summer	Block #1	0-45	0.00079	
	Block #2	Over 45	0.00029	
Winter	Block #1	0-45	0.00094	
	Block #2	Over 45	0.00039	
Mar-09				
GS1	Block	/ Dth		0
Summer	Block #1	0-45	0.00492	
	Block #2	Over 45	0.00728	
Winter	Block #1	0-45	0.00584	
	Block #2	Over 45	0.00242	
Oct-09				
GS1	Block	/ Dth		0.2
Summer	Block #1	0-45	0.01962	
	Block #2	Over 45	0.00728	
Winter	Block #1	0-45	0.0233	
	Block #2	Over 45	0.00967	
Aug-10				
GS1	Block	/ Dth		0.75
Summer	Block #1	0-45	-0.03643	
	Block #2	Over 45	-0.01352	
Winter	Block #1	0-45	-0.04325	
	Block #2	Over 45	-0.01796	
Jan-11				
GS1	Block	/ Dth		0.2
Summer	Block #1	0-45	-0.03499	
	Block #2	Over 45	-0.01299	
Winter	Block #1	0-45	-0.04154	
	Block #2	Over 45	-0.01725	

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Questar Gas Company				
May-11				
GS1	Block	/ Dth		-0.32
Summer	Block #1	0-45	-0.0599	
	Block #2	Over 45	-0.02242	
Winter	Block #1	0-45	-0.07112	
	Block #2	Over 45	-0.02953	
Oct-11				
GS1	Block	/ Dth		0.52
Summer	Block #1	0-45	-0.01994	
	Block #2	Over 45	-0.0094	
Winter	Block #1	0-45	-0.02368	
	Block #2	Over 45	-0.00983	
Sep-12				
GS1	Block	/ Dth		-0.11
Summer	Block #1	0-45	-0.02758	
	Block #2	Over 45	-0.01024	
Winter	Block #1	0-45	-0.03274	
	Block #2	Over 45	-0.01359	

Vermont

Vermont initially adopted alternative regulatory plans for both Central Vermont Public Service and Central Vermont Public Service in Case No. 7336 (September 2008), revised and extended in various subsequent dockets; and Green Mountain Power in Case No. 7175 and 7176 (December 2006), extended in Docket 7438 and recently revised and extended in Docket 7585 (April 2010). Under both plans, the utilities may adjust rates every year based on forecast costs and sales. This limits any benefit of increased sales during a given year to a partial year, at best. In addition, there is an adjustment mechanism for earnings that fall outside of a dead-band of 75 basis points around the allowed return on common equity. Outside of the dead-band, any excess or shortfall is first shared between the utility and customers and, beyond a certain amount, passed through in full to customers. If consumption reductions have caused revenues to fall, this mechanism may trigger a partial collection of the shortfall from customers. It is not possible to calculate to what extent revenue changes driven by consumption changes have contributed to any adjustment.

Virginia

Pursuant to an authorizing statute, the Virginia Commission has approved decoupling mechanisms for three natural gas utilities: Virginia Natural Gas in Docket PUE-2008-00064 (December 2008); Columbia Gas of Virginia in Docket PUE-2009-00051 (December 2009), extended in Docket PUE-2012-00013 (August 2012); and Washington Gas Light in Docket PUE-2009-00064 (March 2010). In none of these dockets, which were not general rate case proceedings, did the Commission make an ROE adjustment in conjunction with the decoupling approval. All of the mechanisms make monthly adjustments based on

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the difference between actual and authorized distribution revenue per customer; the adjustments lag the monthly difference by two months. The tariffs are:

- Virginia Natural Gas: Rider D Revenue Normalization Adjustment, for residential only – this tariff has now expired
- Columbia Gas of Virginia: Revenue Normalization Adjustment, General Terms and Conditions 12.3, for residential and small commercial customers
- Washington Gas Light: CARE Ratemaking Adjustment, General Service Conditions 30, for residential customers in two separate parts of the service territory

Virginia Natural Gas Company 2009				
	Adjustment $/Ccf	Retail Rate $/Mcf	Retail Rate $/Ccf	Adjustment %
March				
Residential	0.07	11.92	1.19	5.872%
April				
Residential	0.06947	14.37	1.44	4.834%
May				
Residential	-0.06762	16.39	1.64	-4.126%
June				
Residential	0.07	18.23	1.82	3.840%
July				
Residential	0.07	19.74	1.974	3.546%
August				
Residential	0.07	20.5	2.05	3.415%
September				
Residential	0.07	21.74	2.17	3.220%
October				
Residential	0.07	14.98	1.50	4.673%
November				
Residential	0.02425	13.35	1.34	1.816%
December				
Residential	0.01647	12.41	1.24	1.327%

Virginia Natural Gas Company 2010				
	Adjustment $/Ccf	Retail Rate $/Mcf	Retail Rate $/Ccf	Adjustment %
January				
Residential	-0.0142	11.88	1.19	-1.20%
February				
Residential	0.04703	11.75	1.18	4.00%
March				
Residential	0.07	12.46	1.25	5.62%
April				
Residential	0.06528	15.94	1.59	4.10%

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Virginia Natural Gas Company 2010				
May				
Residential	-0.15155	16.72	1.67	-9.06%
June				
Residential	0.07	18.92	1.89	3.70%
July				
Residential	0.07	21.45	2.15	3.26%
August				
Residential	0.07	21.98	2.20	3.18%
September				
Residential	0.05533	19.87	1.99	2.78%
October				
Residential	0.07	16.43	1.64	4.26%
November				
Residential	0.02132	12.38	1.24	1.72%
December				
Residential	0.03916	10.56	1.06	3.71%

Virginia Natural Gas Company 2011				
	Adjustment $/Ccf	Retail Rate $/Mcf	Retail Rate $/Ccf	Adjustment %
January				
Residential	-0.0064	11.06	1.11	-0.58%
February				
Residential	0.05427	11.93	1.19	4.55%
March				
Residential	0.07	11.49	1.15	6.09%
April				
Residential	0.04994	13.5	1.35	3.70%
May				
Residential	0.01282	17.59	1.76	0.73%
June				
Residential	0.07	19.36	1.94	3.62%
July				
Residential	0.07	20.82	2.08	3.36%
August				
Residential	0.07	19.11	1.91	3.66%
September				
Residential	0.07	19.11	1.91	3.66%
October				
Residential	0.07	14.77	1.48	4.74%
November				
Residential	0.06083	12.97	1.30	4.69%

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Virginia Natural Gas Company 2011				
December				
Residential	0.01856	12.72	1.27	1.46%

Virginia Natural Gas Company 2012				
	Adjustment $/Ccf	Retail Rate $/Mcf	Retail Rate $/Ccf	Adjustment %
January				
Residential	-0.00673	11.99	1.20	-0.56%
February				
Residential	0.02993	11.26	1.126	2.66%

Columbia Gas of Virginia 2010			
	Adjustment $/Mcf	Retail Rate $/Mcf	Adjustment %
March			
Residential	0.513	12.46	4.12%
General Service	0	0	
April			
Residential	0.454	15.94	2.85%
General Service	0.119	9.87	1.21%
May			
Residential	0.135	16.72	0.81%
General Service	0.374	9.71	3.85%
June			
Residential	0.871	18.92	4.60%
General Service	0.199	9.62	2.07%
July			
Residential	0.649	21.45	3.03%
General Service	0.431	9.56	4.51%
August			
Residential	0.916	21.98	4.17%
General Service	0.357	9.37	3.81%
September			
Residential	-0.285	19.87	-1.43%
General Service	0.19	9.08	2.09%
October			
Residential	0.176	16.43	1.07%
General Service	0.114	9.22	1.24%
November			
Residential	0.017	12.38	0.14%
General Service	0.09	8.93	1.01%

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Columbia Gas of Virginia 2010			
December			
Residential	0.123	10.56	1.16%
General Service	0.107	8.93	1.20%

Columbia Gas of Virginia 2011			
	Adjustment $/therm	Retail Rate $/Mcf	Adjustment %
January			
Residential	0.025	11.88	0.21%
General Service	0.111	9.44	1.18%
February			
Residential	-0.07	11.93	-0.59%
General Service	0.102	10.04	1.02%
March			
Residential	0.197	11.49	1.71%
General Service	-0.005	9.35	-0.05%
April			
Residential	0.28	13.5	2.07%
General Service	-0.174	9.86	-1.76%
May			
Residential	1.092	17.59	6.21%
General Service	-0.133	10.39	-1.28%
June			
Residential	0.725	19.36	3.74%
General Service	0.12	10.76	1.12%
July			
Residential	0.762	20.82	3.66%
General Service	0.101	10.15	1.00%
August			
Residential	-0.3	20.82	-1.44%
General Service	0.013	10.31	0.13%
September			
Residential	-0.732	19.11	-3.83%
General Service	0.223	10.53	2.12%
October			
Residential	-0.557	14.77	-3.77%
General Service	-0.029	9.07	-0.32%
November			
Residential	0.1	12.97	0.77%
General Service	0.12	9.29	1.29%

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Columbia Gas of Virginia 2011			
December			
Residential	0.105	12.72	0.83%
General Service	0.102	9.29	1.10%

Columbia Gas of Virginia 2012			
	Adjustment $/therm	Retail Rate $/Mcf	Adjustment %
January			
Residential	-0.004	11.99	-0.03%
General Service	0.029	9.31	0.31%
February			
Residential	-0.092	11.26	-0.82%
General Service	0.029	8.73	0.33%
March			
Residential	0.032	13.33	0.24%
General Service	-0.105	8.91	-1.18%
April			
Residential	0.389	13.57	2.87%
General Service	-0.058	8.37	-0.69%
May			
Residential	0.454	15.94	2.85%
General Service	0.291	8.48	3.43%
June			
Residential	2.01	19.49	10.31%
General Service	0.088	9.69	0.91%
July			
Residential	0.587	19.49	3.01%
General Service	0.176	9.69	1.82%
August			
Residential	1.061	19.49	5.44%
General Service	0.134	9.69	1.38%
September			
Residential	0.61	19.49	3.13%
General Service	0.297	9.69	3.07%
October			
Residential	0.336	19.49	1.72%
General Service	0.076	9.69	0.78%

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Washington Gas Light 2010				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
May				
Virginia	0.0039	16.02	1.56	0.250%
Shenandoah	-0.0949	9.89	0.96	-9.835%
June				
Virginia	-0.0154	19.85	1.94	-0.795%
Shenandoah	0.0542	10.53	1.03	5.276%
July				
Virginia	0.0447	20.78	2.03	2.205%
Shenandoah	0.1307	10.66	1.04	12.567%
August				
Virginia	0.0167	22.58	2.20	0.758%
Shenandoah	-0.0198	10.82	1.06	-1.876%
September				
Virginia	0.0159	20.79	2.03	0.784%
Shenandoah	0.039	10.34	1.01	3.866%
October				
Virginia	0.0057	15.14	1.48	0.386%
Shenandoah	0.0245	9.35	0.91	2.686%
November				
Virginia	-0.002	11.86	1.16	-0.173%
Shenandoah	-0.0171	9.24	0.90	-1.897%
December				
Virginia	-0.0079	10.11	0.99	-0.801%
Shenandoah	0.0238	8.82	0.86	2.766%

Washington Gas Light 2011				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
January				
Virginia	0.0104	10.44	1.02	1.021%
Shenandoah	-0.0492	9.56	0.93	-5.275%
February				
Virginia	0.0196	11.28	1.10	1.781%
Shenandoah	-0.0233	9.96	0.97	-2.398%
March				
Virginia	0.0545	11.25	1.10	4.966%
Shenandoah	-0.0147	9.86	0.96	-1.528%
April				
Virginia	0.0455	12.58	1.23	3.707%
Shenandoah	0.0318	10.06	0.98	3.240%

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Washington Gas Light 2011				
May				
Virginia	-0.0459	15.97	1.56	-2.946%
Shenandoah	-0.1869	11.96	1.17	-16.018%
June				
Virginia	0.0322	19.53	1.91	1.690%
Shenandoah	0.1579	11.89	1.16	13.612%
July				
Virginia	0.0391	20.13	1.96	1.991%
Shenandoah	0.0346	13.43	1.31	2.641%
August				
Virginia	0.0325	19.24	1.88	1.731%
Shenandoah	-0.0159	11.95	1.17	-1.364%
September				
Virginia	0.0134	18.63	1.82	0.737%
Shenandoah	0.0345	12.13	1.18	2.915%
October				
Virginia	0.0152	12.88	1.26	1.210%
Shenandoah	-0.0105	10.85	1.06	-0.992%
November				
Virginia	-0.0083	12.88	1.26	-0.661%
Shenandoah	0.0052	10.32	1.01	0.516%
December				
Virginia	0.0034	11.86	1.16	0.294%
Shenandoah	0.0189	10.36	1.01	1.870%

Washington Gas Light 2012				
	Adjustment $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Adjustment %
January				
Virginia	0.0265	11.39	1.11	2.385%
Shenandoah	0.0826	10.03	0.98	8.441%
February				
Virginia	-0.0198	11.12	1.08	-1.825%
Shenandoah	0.0356	9.72	0.95	3.754%
March				
Virginia	0.0525	13.7	1.34	3.928%
Shenandoah	0.1565	11.17	1.09	14.361%
April				
Virginia	0.032	13.97	1.36	2.348%
Shenandoah	0.4846	11.09	1.08	44.789%

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Washington Gas Light 2012				
May				
Virginia	-0.1348	16.18	1.58	-8.540%
Shenandoah	0.294	10.85	1.06	27.774%
June				
Virginia	0.0281	17.91	1.75	1.608%
Shenandoah	0.312	11.4	1.11	28.053%
July				
Virginia	-0.0184	17.91	1.75	-1.053%
Shenandoah	0.0226	11.4	1.11	2.032%
August				
Virginia	0.1221	17.91	1.75	6.988%
Shenandoah	0.0762	11.4	1.11	6.851%

Washington D.C.

The Commission approved decoupling for PEPCO (Potomac Electric Company) in Case 1053 (September 2009). In a general rate case decision the following year, Case 1076 (March 2010), the Commission reduced PEPCO's ROE by 50 basis points because of the decoupling mechanism. PEPCO's Bill Stabilization Rider (Tariff page R-49) applies to most of its schedules and calculates adjustments monthly by comparing actual delivery revenue per customer to the test year normalized revenue per customer within each service class.

Potomac Electric Company 2010			
	Adjustment cents/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	-0.000181	0.1492	-0.121%
General Service	0.001092	0.1402	0.779%
February			
Residential	-0.000105	0.1492	-0.070%
General Service	-0.002146	0.1402	-1.531%
March			
Residential	-0.001171	0.1492	-0.785%
General Service	0.000328	0.1402	0.234%
April			
Residential	-0.001513	0.1492	-1.014%
General Service	-0.002487	0.1402	-1.774%
May			
Residential	0.001572	0.1492	1.054%
General Service	0.002125	0.1402	1.516%
June			
Residential	0.000783	0.1492	0.525%
General Service	-0.005082	0.1402	-3.625%

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Potomac Electric Company 2010			
July			
Residential	-0.000715	0.1492	-0.479%
General Service	-0.004904	0.1402	-3.498%
August			
Residential	-0.002227	0.1492	-1.493%
General Service	-0.004956	0.1402	-3.535%
September			
Residential	-0.002392	0.1492	-1.603%
General Service	-0.004839	0.1402	-3.451%
October			
Residential	-0.002396	0.1492	-1.606%
General Service	0.003661	0.1402	2.611%
November			
Residential	-0.002204	0.1492	-1.477%
General Service	-0.004268	0.1402	-3.044%
December			
Residential	-0.002144	0.1492	-1.437%
General Service	-0.004001	0.1402	-2.854%

Potomac Electric Company 2011			
	Adjustment cents/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	-0.001915	0.1399	-1.369%
General Service	-0.003841	0.1323	-2.903%
February			
Residential	-0.001506	0.1399	-1.076%
General Service	-0.003887	0.1323	-2.938%
March			
Residential	-0.002038	0.1399	-1.457%
General Service	-0.004071	0.1323	-3.077%
April			
Residential	-0.002184	0.1399	-1.561%
General Service	-0.004066	0.1323	-3.073%
May			
Residential	0.000016	0.1399	0.011%
General Service	-0.00369	0.1323	-2.789%
June			
Residential	0.00041	0.1399	0.293%
General Service	-0.0052	0.1323	-3.930%

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Potomac Electric Company 2011			
July			
Residential	-0.000872	0.1399	-0.623%
General Service	-0.004911	0.1323	-3.712%
August			
Residential	-0.002383	0.1399	-1.703%
General Service	-0.004959	0.1323	-3.748%
September			
Residential	-0.002392	0.1399	-1.710%
General Service	0.004839	0.1323	3.658%
October			
Residential	0.002396	0.1399	1.713%
General Service	0.005006	0.1323	3.784%
November			
Residential	-0.002204	0.1399	-1.575%
General Service	-0.004268	0.1323	-3.226%
December			
Residential	-0.00119	0.1399	-0.851%
General Service	-0.004001	0.1323	-3.024%

Potomac Electric Company 2012			
	Adjustment cents/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	-0.001002	0.1236	-0.811%
General Service	-0.003841	0.1221	-3.146%
February			
Residential	0.001628	0.1236	1.317%
General Service	-0.003887	0.1221	-3.183%
March			
Residential	-0.000757	0.1236	-0.612%
General Service	-0.004071	0.1221	-3.334%
April			
Residential	-0.000676	0.1236	-0.547%
General Service	-0.004066	0.1221	-3.330%
May			
Residential	0.000476	0.1236	0.385%
General Service	-0.00369	0.1221	-3.022%
June			
Residential	0.002463	0.1236	1.993%
General Service	-0.0052	0.1221	-4.259%

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Potomac Electric Company 2012			
July			
Residential	-0.000388	0.1236	-0.314%
General Service	-0.004911	0.1221	-4.022%
August			
Residential	-0.001782	0.1236	-1.442%
General Service	-0.004959	0.1221	-4.061%
September			
Residential	-0.002312	0.1236	-1.871%
General Service	-0.004839	0.1221	-3.963%

Washington

The Washington Commission has approved decoupling for two of its natural gas utilities: Cascade Natural Gas in Docket No. UG-060256 Final Order Nos. 05, 06, and 07 (January 2007) and Avista Utilities in Docket No. UG-060518; Final Order (February 2007). The Commission did not adjust allowed ROE for either company in connection with decoupling. Cascade's decoupling mechanism (Rule 21: Conservation Alliance Plan Mechanism) was a three-year pilot that has now expired. The Avista decoupling mechanism (Schedule 159) was extended in Docket No. UG-090135; Final Order (December 2009), although the Commission reduced the recovery of the difference between actual and authorized margin from 90% to 45%. Both of the decoupling mechanisms include an earnings test. This test precluded Cascade from recovering two decoupling surcharges. Avista's also adjusts for revenues associated with new customers and normalizes the effect of weather on sales.

Cascade Natural Gas				
	Decoupling Adjustment $/Therm	Retail Rate $/Mcf	Retail Rate $/therm	Decoupling Adjustment %
2008				
	0.001724	12.28	1.20	0.144%
2009				
	0.000422	13.11	1.28	0.000% (earnings test cap)
2010				
		11.37	1.11	0.000%

Avista Utilities (Gas)[28]		
	Decoupling Adjustment $/Therm	Decoupling Adjustment %
Nov-07		
	0.257	0.23
Jan-08		
	0.257	0.23
Nov-08		
	0.593	0.52

[28] All data supplied by the utility.

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Avista Utilities (Gas)		
Jan-09		
	0.593	0.5
Jan-09		
	0.593	0.52
Feb-09		
	0.593	0.51
Jun-09		
	0.593	0.56
Nov-09		
	0.499	0.65
Jan-10		
	0.499	0.65
Apr-10		
	0.499	0.64
Nov-10		
	0.490	0.59
Dec-10		
	0.490	0.57
Jul-11		
	0.490	0.58
Nov-11		
	0.237	0.28
Jan-12		
	0.237	0.27
Mar-12		
	0.237	0.29
Aug-12		
	0.237	0.29
Proposed –11-12		
	0.004	0.00

Wisconsin

The Wisconsin Commission approved decoupling for Wisconsin Public Service Corporation, both the electric and gas operations, in Docket No. 6690-UR-119 (June 2009). The Commission did not adjust the utility's allowed ROE for the decoupling mechanism. The tariffs – Revenue Stabilization Mechanism, E4.70 (electric), G8.20 (gas) – calculate decoupling adjustments by comparing target margin revenue-per-customer with actual margin revenue-per-customer. Electric decoupling adjustments are subject to a $14 million per year cap; gas to an $8 million per year cap. The utility calculates the dollar amount each year and defers it; amortization of any adjustment occurs in a general rate case. General rate cases occur every year. Therefore, authorized margin per customer and sales are also updated each year.

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Because WPSC makes decoupling adjustments as part of general rate case filings, the calculations below are based on "what if" it made such adjustments based on sales from the year it accrued the decoupling adjustments. The calculations reflect those based on actual decoupling deferrals and the capped decoupling accruals. These are estimates only for purposes of indicating the size of decoupling adjustments.

Wisconsin Public Service (Electric)					
	Derived adjustment $/kWh	Derived adjustment capped $/kWh	Retail Rate $/kWh	Decoupling % actual	Decoupling % capped
2009					
Residential/Small Commercial	0.0048705	0.00168154	0.129	3.78%	1.30%
Commercial	0.0084951	0.00293293	0.0945	8.99%	3.10%
2010					
Residential/Small Commercial	0.0033043	0.00166936	0.1291	2.56%	1.29%
Commercial	0.0056630	0.00286103	0.946	0.60%	0.30%
2011					
Residential/Small Commercial	(0.0018666)	$ (0.00163719)	0.1288	-1.45%	-1.27%
Commercial	(0.0032565)	$ (0.00285629)	0.1037	-3.14%	-2.75%

Wisconsin Public Service (gas)						
	Derived adjustment $/therm	Derived adjustment capped $/therm	Retail Rate $/Mcf	Retail Rate $/therm	Decoupling % actual	Decoupling % capped
2009						
Residential	0.0121666	NA	10.76	1.05	1.16%	
Commercial	0.0299860	NA	8.95	0.87	3.43%	
2010						
Residential	0.0480839	0.02270960	10.34	1.01	4.77%	2.25%
Commercial	0.0569683	0.02690547	8.53	0.83	6.85%	3.23%
2011						
Residential	(0.0091654)	NA	9.77	0.95	-0.96%	
Commercial	(0.0069981)	NA	8.04	0.78	-0.89%	

Wyoming

Wyoming approved decoupling for Questar Gas in Docket No. 30010-94-GR-08 (June 2009) and extended the mechanism in Docket No. 30010-113-GR-11 (June 2012). The Commission did not adjust the utility's allowed ROE for the decoupling mechanism. The tariff – the Conservation Enabling Tariff, 2.07 – calculates decoupling adjustments by comparing target revenue-per-customer with actual revenue-per-customer, only for the general service class.

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Questar Gas				
	Decoupling Amount	Adjustment 1st 45 Dth	Adjustment remainder	Adjustment %
2010				
	$ 137,552.00	$0.04505	$0.02848	0.51
2011				
	$ 57,097.00	$0.01879	$0.01188	-0.31
2012				
	$ (214,857.00)	($0.07045)	($0.04453)	-1.07

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Utility	State	RPCD?	Include Weather Effects?	EE Performance Incentives?	Cap on Deferral	Cap Level	Soft or Hard Cap?
PG&E	California	No	Yes	Yes	No	n/a	n/a
SCE	California	No	Yes	Yes	No	n/a	n/a
SDG&E	California	No	Yes	Yes	No	n/a	n/a
United Illuminating	Connecticut	No	Yes	Yes	No	n/a	n/a
PEPCO	District of Columbia	Yes	Yes	No	Yes	10% of base rate	Soft
Hawaii Electric	Hawaii	No	Yes	Yes	No	n/a	n/a
Idaho Power	Idaho	Yes	No	No	No	n/a	n/a
Delmarva	Maryland	Yes	Yes	No	Yes	10% of base rate	Soft
PEPCO	Maryland	Yes	Yes	No	Yes	10% of base rate	Soft
Baltimore Gas & Electric	Maryland	Yes	Yes	No	Yes	10% of base rate	Soft
Fitchburg Gas & Electric	Massachusetts	No	Yes	Yes	Yes	1% of total rev.	Soft
Western Mass. Elec.	Massachusetts	No	Yes	Yes	Yes	1% of total rev.	Soft
Mass. Elec. and Nantucket	Massachusetts	No	Yes	Yes	Yes	3% of total rev.	Soft
Central Hudson	New York	No	Yes	Yes	No	n/a	n/a
Consolidated Edison	New York	No	Yes	Yes	No	n/a	n/a
NYSEG	New York	No	Yes	Yes	No	n/a	n/a
Niagara Mohawk	New York	No	Yes	Yes	No	n/a	n/a
Orange & Rockland	New York	No	Yes	Yes	No	n/a	n/a
Rochester Gas & Elec.	New York	No	Yes	Yes	No	n/a	n/a
American Electric Power	Ohio	Yes	Yes	Yes	Yes	3% of dist. rev.	Soft
Duke Energy Ohio	Ohio	Yes	No	Yes	Yes	3% of dist. rev.	Soft
Portland General Electric	Oregon	Yes	No	No	Yes	2% of total bill	Hard
Narragansett Electric	Rhode Island	No	Yes	Yes	No	n/a	n/a
Puget Sound Energy	Washington	Yes	Yes	No	Yes	3% of rates	Soft
Wisconsin Public Service	Wisconsin	Yes	Yes	No	Yes	$14 mill.	Hard
	# Yes	10	22	17	12		

ILLUSTRATIVE REVENUE DECOUPING AJUSTMENTS

ACTUAL RESIDENTIAL UPC 1% LESS THAN BASE RESIDENTIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	717	710	7	1,195,152	$ 409,340
Feruary	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	594	588	6	1,196,272	$ 339,635
March	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	619	613	6	1,197,403	$ 353,890
April	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	528	522	5	1,198,546	$ 302,060
May	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	537	532	5	1,199,700	$ 307,787
June	$ 0.05998	$ 0.00887	$ 0.05111	$ 0.06568	605	599	6	1,200,863	$ 477,402
July	$ 0.06404	$ 0.00887	$ 0.05517	$ 0.07089	757	750	8	1,202,034	$ 645,320
August	$ 0.06682	$ 0.00887	$ 0.05795	$ 0.07446	731	724	7	1,203,214	$ 655,237
September	$ 0.06515	$ 0.00887	$ 0.05628	$ 0.07232	591	585	6	1,204,400	$ 514,775
October	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	566	560	6	1,205,591	$ 325,923
November	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	614	608	6	1,206,787	$ 353,773
December	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	696	690	7	1,207,989	$ 401,864
Total					7,556	7,481		14,417,951	$ 5,087,006
Projected 2015 Res. Revenue									$ 1,153,996,000
Res. Rate Impact									0.44%

ACTUAL COMMERCIAL UPC 1% LESS THAN BASE COMMERCIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,059	1048	11	108,758	$ 45,401
Feruary	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	983	974	10	108,834	$ 42,205
March	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,037	1026	10	108,909	$ 44,526
April	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	955	945	10	108,985	$ 41,030
May	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	970	960	10	109,061	$ 41,699
June	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	960	950	10	109,138	$ 75,355
July	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,064	1053	11	109,215	$ 83,612
August	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,044	1034	10	109,292	$ 82,088
September	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	966	956	10	109,369	$ 75,974
October	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	913	904	9	109,447	$ 39,416
November	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	890	881	9	109,526	$ 38,438
December	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,045	1035	10	109,604	$ 45,190
Total					11,884	11766	119	1,310,138	$ 654,934
Projected 2015 Comm. Revenue									$ 156,982,000
Comm. Rate Impact									0.42%

ILLUSTRATIVE REVENUE DECOUPING AJUSTMENTS

ACTUAL RESIDENTIAL UPC 3% LESS THAN BASE RESIDENTIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	717	696	22	1,195,152	$ 1,228,019
Feruary	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	594	577	18	1,196,272	$ 1,018,905
March	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	619	600	19	1,197,403	$ 1,061,669
April	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	528	512	16	1,198,546	$ 906,181
May	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	537	521	16	1,199,700	$ 923,360
June	$ 0.05998	$ 0.00887	$ 0.05111	$ 0.06568	605	587	18	1,200,863	$ 1,432,206
July	$ 0.06404	$ 0.00887	$ 0.05517	$ 0.07089	757	735	23	1,202,034	$ 1,935,960
August	$ 0.06682	$ 0.00887	$ 0.05795	$ 0.07446	731	709	22	1,203,214	$ 1,965,710
September	$ 0.06515	$ 0.00887	$ 0.05628	$ 0.07232	591	573	18	1,204,400	$ 1,544,324
October	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	566	549	17	1,205,591	$ 977,768
November	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	614	595	18	1,206,787	$ 1,061,320
December	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	696	676	21	1,207,989	$ 1,205,593
Total					7,556	7,330		14,417,951	$ 15,261,017
Projected 2015 Res. Revenue									$ 1,155,385,000
Res. Rate Impact									1.32%

ACTUAL COMMERCIAL UPC 3% LESS THAN BASE COMMERCIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,059	1027	32	108,758	$ 136,203
Feruary	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	983	954	30	108,834	$ 126,616
March	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,037	1006	31	108,909	$ 133,577
April	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	955	926	29	108,985	$ 123,089
May	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	970	940	29	109,061	$ 125,097
June	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	960	931	29	109,138	$ 226,066
July	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,064	1032	32	109,215	$ 250,835
August	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,044	1013	31	109,292	$ 246,265
September	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	966	937	29	109,369	$ 227,921
October	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	913	886	27	109,447	$ 118,247
November	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	890	863	27	109,526	$ 115,314
December	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,045	1014	31	109,604	$ 135,570
Total					11,884	11,528		1,310,138	$ 1,964,801
Projected 2015 Comm. Revenue									$ 157,167,000
Comm. Rate Impact									1.25%

ILLUSTRATIVE REVENUE DECOUPING AJUSTMENTS

ACTUAL RESIDENTIAL UPC 5% LESS THAN BASE RESIDENTIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	717	681	36	1,195,152	$ 2,046,699
Feruary	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	594	565	30	1,196,272	$ 1,698,176
March	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	619	588	31	1,197,403	$ 1,769,449
April	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	528	501	26	1,198,546	$ 1,510,302
May	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	537	510	27	1,199,700	$ 1,538,934
June	$ 0.05998	$ 0.00887	$ 0.05111	$ 0.06568	605	575	30	1,200,863	$ 2,387,011
July	$ 0.06404	$ 0.00887	$ 0.05517	$ 0.07089	757	719	38	1,202,034	$ 3,226,600
August	$ 0.06682	$ 0.00887	$ 0.05795	$ 0.07446	731	695	37	1,203,214	$ 3,276,183
September	$ 0.06515	$ 0.00887	$ 0.05628	$ 0.07232	591	561	30	1,204,400	$ 2,573,873
October	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	566	538	28	1,205,591	$ 1,629,614
November	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	614	583	31	1,206,787	$ 1,768,866
December	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	696	662	35	1,207,989	$ 2,009,321
Total					7,556	7,178		14,417,951	$ 25,435,028
Projected 2015 Res. Revenue									$ 1,155,385,000
Res. Rate Impact									2.20%

ACTUAL COMMERCIAL UPC 5% LESS THAN BASE COMMERCIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,059	1006	53	108,758	$ 227,005
Feruary	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	983	934	49	108,834	$ 211,027
March	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,037	985	52	108,909	$ 222,629
April	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	955	907	48	108,985	$ 205,149
May	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	970	921	48	109,061	$ 208,496
June	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	960	912	48	109,138	$ 376,776
July	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,064	1011	53	109,215	$ 418,059
August	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,044	992	52	109,292	$ 410,442
September	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	966	917	48	109,369	$ 379,869
October	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	913	868	46	109,447	$ 197,078
November	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	890	845	44	109,526	$ 192,190
December	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,045	993	52	109,604	$ 225,950
Total					11,884	11,290		1,310,138	$ 3,274,669
Projected 2015 Comm. Revenue									$ 157,167,000
Comm. Rate Impact									2.08%

ILLUSTRATIVE REVENUE DECOUPING AJUSTMENTS

ACTUAL RESIDENTIAL UPC 10% LESS THAN BASE RESIDENTIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	717	645	72	1,195,152	$ 4,093,398
Feruary	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	594	535	59	1,196,272	$ 3,396,352
March	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	619	557	62	1,197,403	$ 3,538,898
April	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	528	475	53	1,198,546	$ 3,020,605
May	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	537	483	54	1,199,700	$ 3,077,868
June	$ 0.05998	$ 0.00887	$ 0.05111	$ 0.06568	605	545	61	1,200,863	$ 4,774,021
July	$ 0.06404	$ 0.00887	$ 0.05517	$ 0.07089	757	682	76	1,202,034	$ 6,453,201
August	$ 0.06682	$ 0.00887	$ 0.05795	$ 0.07446	731	658	73	1,203,214	$ 6,552,366
September	$ 0.06515	$ 0.00887	$ 0.05628	$ 0.07232	591	532	59	1,204,400	$ 5,147,746
October	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	566	509	57	1,205,591	$ 3,259,227
November	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	614	552	61	1,206,787	$ 3,537,732
December	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	696	627	70	1,207,989	$ 4,018,642
Total					7,556	6,801		14,417,951	$ 50,870,056
Projected 2015 Res. Revenue									$ 1,155,385,000
Res. Rate Impact									4.40%

ACTUAL COMMERCIAL UPC 10% LESS THAN BASE COMMERCIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,059	953	106	108,758	$ 454,009
Feruary	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	983	885	98	108,834	$ 422,055
March	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,037	933	104	108,909	$ 445,258
April	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	955	859	95	108,985	$ 410,297
May	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	970	873	97	109,061	$ 416,991
June	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	960	864	96	109,138	$ 753,552
July	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,064	958	106	109,215	$ 836,117
August	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,044	940	104	109,292	$ 820,883
September	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	966	869	97	109,369	$ 759,737
October	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	913	822	91	109,447	$ 394,157
November	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	890	801	89	109,526	$ 384,380
December	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,045	941	105	109,604	$ 451,901
Total					11,884	10,696		1,310,138	$ 6,549,337
Projected 2015 Comm. Revenue									$ 157,167,000
Comm. Rate Impact									4.17%

ILLUSTRATIVE REVENUE DECOUPING AJUSTMENTS

ACTUAL RESIDENTIAL UPC 1% MORE THAN BASE RESIDENTIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	717	724	-7	1,195,152	$ (409,340)
Feruary	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	594	600	-6	1,196,272	$ (339,635)
March	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	619	625	-6	1,197,403	$ (353,890)
April	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	528	533	-5	1,198,546	$ (302,060)
May	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	537	543	-5	1,199,700	$ (307,787)
June	$ 0.05998	$ 0.00887	$ 0.05111	$ 0.06568	605	611	-6	1,200,863	$ (477,402)
July	$ 0.06404	$ 0.00887	$ 0.05517	$ 0.07089	757	765	-8	1,202,034	$ (645,320)
August	$ 0.06682	$ 0.00887	$ 0.05795	$ 0.07446	731	739	-7	1,203,214	$ (655,237)
September	$ 0.06515	$ 0.00887	$ 0.05628	$ 0.07232	591	597	-6	1,204,400	$ (514,775)
October	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	566	572	-6	1,205,591	$ (325,923)
November	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	614	620	-6	1,206,787	$ (353,773)
December	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	696	703	-7	1,207,989	$ (401,864)
Total					7,556	7,632		14,417,951	$ (5,087,006)
Projected 2015 Res. Revenue									$ 1,155,385,000
Res. Rate Impact									-0.44%

ACTUAL COMMERCIAL UPC 1% MORE THAN BASE COMMERCIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,059	1069	-11	108,758	$ (45,401)
Feruary	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	983	993	-10	108,834	$ (42,205)
March	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,037	1047	-10	108,909	$ (44,526)
April	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	955	964	-10	108,985	$ (41,030)
May	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	970	979	-10	109,061	$ (41,699)
June	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	960	969	-10	109,138	$ (75,355)
July	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,064	1075	-11	109,215	$ (83,612)
August	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,044	1054	-10	109,292	$ (82,088)
September	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	966	975	-10	109,369	$ (75,974)
October	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	913	922	-9	109,447	$ (39,416)
November	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	890	899	-9	109,526	$ (38,438)
December	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,045	1056	-10	109,604	$ (45,190)
Total					11,884	12,003		1,310,138	$ (654,934)
Projected 2015 Comm. Revenue									$ 157,167,000
Comm. Rate Impact									-0.42%

ILLUSTRATIVE REVENUE DECOUPING AJUSTMENTS

ACTUAL RESIDENTIAL UPC 3% MORE THAN BASE RESIDENTIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	717	739	-22	1,195,152	$ (1,228,019)
Feruary	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	594	612	-18	1,196,272	$ (1,018,905)
March	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	619	637	-19	1,197,403	$ (1,061,669)
April	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	528	543	-16	1,198,546	$ (906,181)
May	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	537	553	-16	1,199,700	$ (923,360)
June	$ 0.05998	$ 0.00887	$ 0.05111	$ 0.06568	605	623	-18	1,200,863	$ (1,432,206)
July	$ 0.06404	$ 0.00887	$ 0.05517	$ 0.07089	757	780	-23	1,202,034	$ (1,935,960)
August	$ 0.06682	$ 0.00887	$ 0.05795	$ 0.07446	731	753	-22	1,203,214	$ (1,965,710)
September	$ 0.06515	$ 0.00887	$ 0.05628	$ 0.07232	591	609	-18	1,204,400	$ (1,544,324)
October	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	566	583	-17	1,205,591	$ (977,768)
November	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	614	632	-18	1,206,787	$ (1,061,320)
December	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	696	717	-21	1,207,989	$ (1,205,593)
Total					7,556	7,783		14,417,951	$ (15,261,017)
Projected 2015 Res. Revenue									$ 1,155,385,000
Res. Rate Impact									-1.32%

ACTUAL COMMERCIAL UPC 3% MORE THAN BASE COMMERCIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,059	1090	-32	108,758	$ (136,203)
Feruary	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	983	1013	-30	108,834	$ (126,616)
March	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,037	1068	-31	108,909	$ (133,577)
April	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	955	983	-29	108,985	$ (123,089)
May	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	970	999	-29	109,061	$ (125,097)
June	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	960	988	-29	109,138	$ (226,066)
July	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,064	1096	-32	109,215	$ (250,835)
August	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,044	1075	-31	109,292	$ (246,265)
September	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	966	994	-29	109,369	$ (227,921)
October	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	913	941	-27	109,447	$ (118,247)
November	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	890	917	-27	109,526	$ (115,314)
December	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,045	1077	-31	109,604	$ (135,570)
Total					11,884	12,241		1,310,138	$ (1,964,801)
Projected 2015 Comm. Revenue									$ 157,167,000
Comm. Rate Impact									-1.25%

ILLUSTRATIVE REVENUE DECOUPING AJUSTMENTS

ACTUAL RESIDENTIAL UPC 5% MORE THAN BASE RESIDENTIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	717	753	-36	1,195,152	$ (2,046,699)
Feruary	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	594	624	-30	1,196,272	$ (1,698,176)
March	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	619	650	-31	1,197,403	$ (1,769,449)
April	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	528	554	-26	1,198,546	$ (1,510,302)
May	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	537	564	-27	1,199,700	$ (1,538,934)
June	$ 0.05998	$ 0.00887	$ 0.05111	$ 0.06568	605	636	-30	1,200,863	$ (2,387,011)
July	$ 0.06404	$ 0.00887	$ 0.05517	$ 0.07089	757	795	-38	1,202,034	$ (3,226,600)
August	$ 0.06682	$ 0.00887	$ 0.05795	$ 0.07446	731	768	-37	1,203,214	$ (3,276,183)
September	$ 0.06515	$ 0.00887	$ 0.05628	$ 0.07232	591	621	-30	1,204,400	$ (2,573,873)
October	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	566	594	-28	1,205,591	$ (1,629,614)
November	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	614	644	-31	1,206,787	$ (1,768,866)
December	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	696	731	-35	1,207,989	$ (2,009,321)
Total					7,556	7,934		14,417,951	$ (25,435,028)
Projected 2015 Res. Revenue									$ 1,155,385,000
Res. Rate Impact									-2.20%

ACTUAL COMMERCIAL UPC 5% MORE THAN BASE COMMERCIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,059	1111	-53	108,758	$ (227,005)
Feruary	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	983	1033	-49	108,834	$ (211,027)
March	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,037	1089	-52	108,909	$ (222,629)
April	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	955	1002	-48	108,985	$ (205,149)
May	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	970	1018	-48	109,061	$ (208,496)
June	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	960	1008	-48	109,138	$ (376,776)
July	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,064	1117	-53	109,215	$ (418,059)
August	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,044	1096	-52	109,292	$ (410,442)
September	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	966	1014	-48	109,369	$ (379,869)
October	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	913	959	-46	109,447	$ (197,078)
November	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	890	934	-44	109,526	$ (192,190)
December	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,045	1098	-52	109,604	$ (225,950)
Total					11,884	12,479		1,310,138	$ (3,274,669)
Projected 2015 Comm. Revenue									$ 157,167,000
Comm. Rate Impact									-2.08%

ILLUSTRATIVE REVENUE DECOUPING AJUSTMENTS

ACTUAL RESIDENTIAL UPC 10% MORE THAN BASE RESIDENTIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	717	789	-72	1,195,152	$ (4,093,398)
Feruary	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	594	654	-59	1,196,272	$ (3,396,352)
March	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	619	681	-62	1,197,403	$ (3,538,898)
April	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	528	580	-53	1,198,546	$ (3,020,605)
May	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	537	591	-54	1,199,700	$ (3,077,868)
June	$ 0.05998	$ 0.00887	$ 0.05111	$ 0.06568	605	666	-61	1,200,863	$ (4,774,021)
July	$ 0.06404	$ 0.00887	$ 0.05517	$ 0.07089	757	833	-76	1,202,034	$ (6,453,201)
August	$ 0.06682	$ 0.00887	$ 0.05795	$ 0.07446	731	804	-73	1,203,214	$ (6,552,366)
September	$ 0.06515	$ 0.00887	$ 0.05628	$ 0.07232	591	650	-59	1,204,400	$ (5,147,746)
October	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	566	623	-57	1,205,591	$ (3,259,227)
November	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	614	675	-61	1,206,787	$ (3,537,732)
December	$ 0.04604	$ 0.00887	$ 0.03717	$ 0.04776	696	766	-70	1,207,989	$ (4,018,642)
Total					7,556	8,312		14,417,951	$ (50,870,056)
Projected 2015 Res. Revenue									$ 1,155,385,000
Res. Rate Impact									-4.40%

ACTUAL COMMERCIAL UPC 10% MORE THAN BASE COMMERCIAL UPC

Month	Base Energy Charge ($/kWh)	Variable O&M O&M and DSM Component ($/kWh)	Net Base Energy Charge ($/kWh)	With GRSA ($/kWh)	Base UPC	Actual UPC	Difference	Actual # of Bills	Revenue Decoupling Adjustment ($)
January	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,059	1164	-106	108,758	$ (454,009)
Feruary	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	983	1082	-98	108,834	$ (422,055)
March	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,037	1140	-104	108,909	$ (445,258)
April	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	955	1050	-95	108,985	$ (410,297)
May	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	970	1066	-97	109,061	$ (416,991)
June	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	960	1056	-96	109,138	$ (753,552)
July	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,064	1170	-106	109,215	$ (836,117)
August	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	1,044	1148	-104	109,292	$ (820,883)
September	$ 0.06450	$ 0.00851	$ 0.05599	$ 0.07195	966	1062	-97	109,369	$ (759,737)
October	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	913	1005	-91	109,447	$ (394,157)
November	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	890	979	-89	109,526	$ (384,380)
December	$ 0.03920	$ 0.00851	$ 0.03069	$ 0.03944	1,045	1150	-105	109,604	$ (451,901)
Total					11,884	13,073		1,310,138	$ (6,549,337)
Projected 2015 Comm. Revenue									$ 157,167,000
Comm. Rate Impact									-4.17%

ELECTRIC RATES
PARTIAL DECOUPLING REVENUE REQUIREMENT N

APPLICABILITY

This Partial Decoupling Revenue Requirement (PDRR) is applicable for all electric service under Residential General Service (Schedule R) and Commercial Service (Schedule C). The PDRR derived under this tariff will be recovered from or credited to customers through modifications to the General Rate Schedule Adjustments (GRSA) that are applied to the Schedule R and Schedule C customers.

DEFINITIONS

The following definitions apply for the calculation of the PDRR:

Adjusted Energy Charge (AEC)

The base kilowatt-hour charge(s) minus the component of the charge(s) earmarked for the recovery of Demand Side Management ("DSM") costs and variable Operations and Maintenance ("O&M") expenses. For each month of the performance Year the AEC will be derived separately for each of the R and C schedules, using the rates effective during that month.

Base Year

The test year approved by the Commission in the Company's most recent Phase I rate proceeding.

Base Year Monthly Usage per Customer (BUPC)

The average kilowatt-hour usage per customer for each of the R schedule and C schedule, respectively, for each billing month of the Base Year. For the R schedule the usage per customer during the summer months is split between usage subject to the Tier 1 charge and usage subject to the Tier 2 charge.

Performance Year (PY)

The calendar year during which the PDRR will be determined separately for the R and C schedules. If the Commission approves this tariff after January 1, 2015, the 2015 PY will begin with the first calendar month after the date of the Commission's Final Decision and extend through December 2015.

PDRR Cap

The maximum PDRR that can be collected in total from customers on each of the R and C schedules during the Recovery Period. This PDRR Cap shall be 5 percent of the total annual revenues for the R and C service schedules during the Performance Year and will be calculated separately for each schedule.

(Continued on Sheet No. 102A)

PUBLIC SERVICE COMPANY OF COLORADO

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ELECTRIC RATES
PARTIAL DECOUPLING REVENUE REQUIREMENT N

DEFINITIONS: - Cont'd

Performance Year Monthly Usage per Customer Values (PUPC)

The average weather-normalized usage per customer for each billing month of the Performance Year. This monthly usage will be derived separately for the R and C schedules, and the R schedule monthly usage during the summer months will be split between Tier 1 usage and Tier 2 usage. The weather-normalized usage per customer will be derived using the same weather-normalization procedure that the Commission approved as the basis for establishing test-year billing determinants in the Base Year.

Performance Year Total Monthly Bills

The total number of customer bills issued to customers taking service under each of the R and C schedules during the billing month in the Performance Year.

General Rate Schedule Adjustment (GRSA)

The percentage adjustment to R and C base rates under the General Rate Schedule Adjustment electric tariff.

Monthly Decoupling Component (MDC)

The monthly component of the PDRR for each of the R and C schedules that is entered into the schedule-specific Revenue Tracking Account.

Partial Decoupling Revenue Requirement (PDRR)

The sum of the monthly Decoupling Components during the Performance Year for each of the R and C schedules.

Recovery Period

The period over which the PDRR for any Performance Year will be recovered from or credited to customers. This period will be the 12 months beginning April 1 of the calendar year subsequent to the Performance Year.

(Continued on Sheet No. 102B)

ELECTRIC RATES
PARTIAL DECOUPLING REVENUE REQUIREMENT N

DETERMINATIONS

Adjusted Energy Charge (AEC)

The Adjusted Energy Charge is calculated for each of the R and C schedules as follows:

AEC = (A – (B + C)) times (1 + (E – D));

Where:
A = Base Energy Charge
B = The DSM component of the Base Energy Charge
C = The component of the Base Energy Charge earmarked for the recovery of variable O&M expenses
D = The PDDR component of the GRSA applied to the R or C schedule.
E = The GRSA applied to the R or C schedule.

Monthly Decoupling Component (MDC)

The Monthly Decoupling Component shall be calculated for each of the R and C Rate Schedules as follows:

MDC = (A – B) times C times D;

Where:
A = Base Year Monthly Usage per Customer (BUPC),
B = Performance Year Monthly Usage per Customer (PUPC);
C = Performance Year Total Monthly Bills; and
D = Adjusted Energy Charge (AEC)

Partial Decoupling Revenue Requirement (PDRR)

For each of the R and C schedules the PDRR is the lesser of A or (B + C);

Where:
A = 5% of the total revenues from each of the R and C schedules during the Performance Year,
B = The summation of each Monthly Decoupling Component (MDC) during the Performance Year, and
C = The sum of MDC amounts in prior years that were uncollected because they exceeded the PDRR Cap.

(Continued on Sheet No. 102C)

ELECTRIC RATES
PARTIAL DECOUPLING REVENUE REQUIREMENT

N

PARTIAL DECOUPLING REVENUE REQUIREMENT ANNUAL FILING

The Company shall file an annual advice letter with the Commission by March 1 to adjust the GRSAs applicable to the R and C schedules to recover from or credit to customers the PDRRs as derived under the provisions of this tariff. The first such filing will be submitted on or before March 1, 2016. In its advice letter filing the Company will provide the data and calculations supporting the proposed PDRRs.

BASE YEAR MONTHLY USAGE PER CUSTOMER VALUES

Using the method for Determination described in this tariff, the base year Monthly Usage per Month Values are as follows:

Month	R Schedule	C Schedule
January	717.08	1058.53
February	594.41	983.34
March	618.77	1036.69
April	527.65	954.62
May	537.13	969.52
June		959.67
June Tier One	413.29	
June Tier Two	191.99	
July		1064.07
July Tier One	447.31	
July Tier Two	310.02	
August		1043.95
August Tier One	385.66	
August Tier Two	345.67	
September		965.51
September Tier One	334.10	
September Tier Two	256.91	
October	566.00	913.20
November	613.76	889.90
December	696.50	1045.48

SUMMARY OF REVENUE DECOUPLING FOR ROBERT HEVERT'S ELECTRIC COMPARABLE GROUP

UTILITY & JURISDICTION	DECOUPLING MECHANISM?	ROE ADJUSTMENT?
AEP		
Ohio	**Yes**	**No**
Arkansas	No	N/A
West Viginia	No	N/A
Virginia	No	N/A
Tennessee	No	N/A
Indiana	No	N/A
Michigan	No	N/A
Kentucky	No	N/A
Oklahoma	No	N/A
Louisiana	No	N/A
Texas	No	N/A
Duke Energy		
Ohio	**Yes**	**No**
Florida	No	N/A
Indiana	No	N/A
Kentucky	No	N/A
North Carolina	No	N/A
South Carolina	No	N/A
Empire District Electric Company		
Arkansas	No	N/A
Kansas	No	N/A
Oklahoma	No	N/A
Missouri	No	N/A
NextEra Energy, Inc	No	N/A

UTILITY & JURISDICTION	DECOUPLING MECHANISM?	ROE ADJUSTMENT?
Otter Tail		
Minnesota	No	N/A
North Dakota	No	N/A
South Dakota	No	N/A
PNM Resources		
New Mexico	No	N/A
Texas	No	N/A
Southern Company		
Alabama	No	N/A
Geogia	No	N/A
Mississippi	No	N/A
Florida	No	N/A
Cieco (CLECO)	No	N/A
Great Plains Energy -- Missouri	No	N/A
Hawaiian Electric Industries	**Yes**	**No**
IDACORP -- Idaho	**Yes**	**No**
Pinnacle West Capital Corp. (Arizona)	**Yes**	**No**
Portland General Electric Company (Oregon)	**Yes**	**Yes**
Westar Energy (Kansas)	No	N/A

SUMMARY OF REVENUE DEOUPLING FOR ROBER HEVERT'S COMBINATION GROUP

Alliant Energy Corporation		
Iowa	No	N/A
Wisconsin	No	N/A
Minnesota	No	N/A
Black Hills Energy		
Colorado	No	N/A
Iowa	No	N/A
Kansas	No	N/A
Nebraska	No	N/A
South Dakota	No	N/A
Montana	No	N/A
Wyoming	No	N/A
Wyoming (Cheyenne Light Fuel & Power	No	N/A

CMS Energy Corporation - Michigan	**Yes**	**No**
DTE Energy Corporation - Michigan	No	N/A
SCANA Corporation	No	N/A
South Carolina	No	N/A
North Carolina	No	N/A
Georgia	No	N/A
TECO Energy, Inc. - Tampa Electric	No	N/A
Vectren Corporation		
Indiana	No	N/A
Ohio	No	N/A

PUBLIC SERVICE COMPANY OF COLORADO

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Denver, CO 80201-0840

ELECTRIC RATES
TRANSMISSION COST ADJUSTMENT

APPLICABILITY

All rate schedules for electric service are subject to a Transmission Cost Adjustment (“TCA”) rider to reflect the ongoing capital costs associated with transmission investment that are not being recovered through the Company’s base rates. The TCA amount will be subject to annual changes to be effective on January 1 of each year. The TCA to be applied to each rate schedule is as set forth on Sheet No. 109B.

DEFINITIONS

Over/Under Recovery Amount – The Over/Under Recovery Amount is the balance, positive or negative, of TCA revenues received less the Transmission Cost intended to be recovered each year through the rider.

True-Up Amount – The True-Up Amount is equal to the difference, positive or negative, between the Transmission Cost, calculated based on the projected year-end net transmission plant and transmission CWIP balances, and the Transmission Cost calculated based on the actual year-end net transmission plant and transmission CWIP balances.

Transmission Cost – For the purpose of this tariff, the Transmission Cost is defined as (1) a return, equal to the Company’s weighted average cost of capital, on the projected increase in the retail jurisdictional portion of the thirteen month average net transmission plant for the ~~thirteen months immediately preceding the~~ year in which the TCA will be in effect; (2) the plant-related ownership costs associated with such incremental transmission investment, including depreciation, accumulated deferred income taxes, income taxes and pre-funded AFUDC, and (3) a return, equal to the Company’s weighted average cost of capital, on the projected year-end transmission construction work in progress (“CWIP”) balance as of December 31 of the year immediately preceding the effective date of the TCA. ~~that is not being recovered through base rates.~~

Transmission Cost Adjustment - The Transmission Cost Adjustment is equal to the Transmission Cost, plus, beginning with the second year of the rider, the True-Up Amount and, beginning with the third year of the rider, the Over/Under Recovery Amount, charged on a dollar per kilowatt basis for tariff schedules with demand rates and on a dollar per kilowatt-hour basis for tariff schedules without demand rates.

(Continued on Sheet No. 109A)

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 109B

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Denver, CO 80201-0840

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ELECTRIC RATES
TRANSMISSION COST ADJUSTMENT

RATE TABLE

Rate Schedule	Applicable Charge	Monthly Rider Rate
Residential Service		
R, RTOU, RPTR, RCPP	Energy Charge	$0.00006~~106~~/kWh
RD	Demand Charge	$ 0.01~~12~~ /kW-Mo
Small Commercial Service		
C	Energy Charge	$ 0.00006~~105~~ /kWh
NMTR	Energy Charge	$ 0.00006~~105~~ /kWh
Commercial & Industrial General Service		
SGL	Energy Charge	$ 0.00023~~436~~ /kWh
SG, STOU, SPVTOU	Demand Charge	$ 0.02~~35~~ /kW-Mo
PG, PTOU	Demand Charge	$ 0.02~~33~~ /kW-Mo
TG, TTOU	Demand Charge	$ 0.02~~31~~ /kW-Mo
Special Contract Service		
SCS-7	Production Demand Charge	$ 0.02~~33~~ /kW-Mo
Standby Service		
SST	Gen & Trans Standby Capacity Reservation Fee	$ 0.00~~04~~ /kW-Mo
	Usage Demand Charge	$ 0.02~~31~~ /kW-Mo
PST	Gen & Trans Standby Capacity Reservation Fee	$ 0.00~~04~~ /kW-Mo
	Usage Demand Charge	$ 0.02~~29~~ /kW-Mo
TST	Gen & Trans Standby Capacity Reservation Fee	$ 0.00~~04~~ /kW-Mo
	Usage Demand Charge	$ 0.02~~27~~ /kW-Mo
Lighting Service		
RAL, CAL, PLL, MSL, ESL, SL, SSL, COL, SLU	Energy Charge	$ 0.00003~~53~~/kWh
TSL, MI	Energy Charge	$ 0.00003~~53~~/kWh

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PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 109

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Sheet No.

ELECTRIC RATES
TRANSMISSION COST ADJUSTMENT

APPLICABILITY

All rate schedules for electric service are subject to a Transmission Cost Adjustment ("TCA") rider to reflect the ongoing capital costs associated with transmission investment that are not being recovered through the Company's base rates. The TCA amount will be subject to annual changes to be effective on January 1 of each year. The TCA to be applied to each rate schedule is as set forth on Sheet No. 109B.

DEFINITIONS

Over/Under Recovery Amount – The Over/Under Recovery Amount is the balance, positive or negative, of TCA revenues received less the Transmission Cost intended to be recovered each year through the rider.

True-Up Amount – The True-Up Amount is equal to the difference, positive or negative, between the Transmission Cost, calculated based on the projected year-end net transmission plant and transmission CWIP balances, and the Transmission Cost calculated based on the actual year-end net transmission plant and transmission CWIP balances.

Transmission Cost – For the purpose of this tariff, the Transmission Cost is defined as (1) a return, equal to the Company's weighted average cost of capital, on the projected increase in the retail jurisdictional portion of the thirteen month average net transmission plant for the year in which the T
TCA will be in effect; (2) the plant-related ownership costs associated with such incremental transmission investment, including depreciation, accumulated deferred income taxes, income taxes and pre-funded AFUDC, and (3) a return, equal to the Company's weighted average cost of capital, on the projected year-end transmission construction work in progress ("CWIP") balance as of December 31 of the year immediately preceding the effective T
date of the TCA. T

Transmission Cost Adjustment - The Transmission Cost Adjustment is equal to the Transmission Cost, plus, beginning with the second year of the rider, the True-Up Amount and, beginning with the third year of the rider, the Over/Under Recovery Amount, charged on a dollar per kilowatt basis for tariff schedules with demand rates and on a dollar per kilowatt-hour basis for tariff schedules without demand rates.

(Continued on Sheet No. 109A)

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 109B

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Sheet No.

ELECTRIC RATES
TRANSMISSION COST ADJUSTMENT

RATE TABLE

Rate Schedule	Applicable Charge	Monthly Rider Rate	
Residential Service			
R, RTOU, RPTR, RCPP	Energy Charge	$0.00006/kWh	R
RD	Demand Charge	$ 0.01 /kW-Mo	R
Small Commercial Service			
C	Energy Charge	$ 0.00006 /kWh	R
NMTR	Energy Charge	$ 0.00006 /kWh	R
Commercial & Industrial General Service			
SGL	Energy Charge	$ 0.00023 /kWh	R
SG, STOU, SPVTOU	Demand Charge	$ 0.02 /kW-Mo	R
PG, PTOU	Demand Charge	$ 0.02 /kW-Mo	R
TG, TTOU	Demand Charge	$ 0.02 /kW-Mo	R
Special Contract Service			
SCS-7	Production Demand Charge	$ 0.02 /kW-Mo	R
Standby Service			
SST	Gen & Trans Standby Capacity Reservation Fee	$ 0.00 /kW-Mo	R
	Usage Demand Charge	$ 0.02 /kW-Mo	R
PST	Gen & Trans Standby Capacity Reservation Fee	$ 0.00 /kW-Mo	R
	Usage Demand Charge	$ 0.02 /kW-Mo	R
TST	Gen & Trans Standby Capacity Reservation Fee	$ 0.00 /kW-Mo	R
	Usage Demand Charge	$ 0.02 /kW-Mo	R
Lighting Service			
RAL, CAL, PLL, MSL, ESL, SL, SSL, COL, SLU	Energy Charge	$ 0.00003/kWh	R
TSL, MI	Energy Charge	$ 0.00003/kWh	R

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PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 111

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Sheet No.

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

APPLICABILITY

All rate schedules for electric service are subject to an Electric Commodity Adjustment (ECA) to reflect the cost of energy utilized to supply electric service. The Electric Commodity Adjustment Factors for all applicable rate schedules are as set forth on Sheet No. 111G~~F~~ and will be applied to all kilowatt-hours sold by the Company with the exception of any buy-through kilowatt-hours (BT kWh) sold to participants in the Interruptible Service Option Credit (ISOC) program who buy through an Economic Interruption. The ECA Factors for lighting service bills and other non-metered service will be determined by applying the ECA Factor to the calculated monthly kilowatt-hour consumption.

TIME-OF-USE ECA FACTORS APPLICABILITY

All kilowatt-hours used under any Rate Schedule for Commercial and Industrial Primary, Transmission or Special Contract Service customers shall be billed under the appropriate Time-of-Use ECA Factor. Customers that receive electric service under any Commercial and Industrial Secondary Service Rate Schedule that have measured demands of three hundred kilowatt (300 kW) or more for twelve (12) consecutive months may elect to be billed prospectively under the Secondary Time-of-Use ECA Factor. Subsequent to a customer’s election to be billed under the Secondary Time-of-Use ECA Factor, customer must have a measured demand of three hundred kilowatts (300 kW) or more every month, except a customer may have one month within the previous twelve (12) months where the customer demand is less than three hundred kilowatts (300 kW). In the event that a second month occurs in any twelve month period where the customer’s measured demand is less than three hundred kilowatts (300 kW), the Company shall bill the customer under the non-Time-of-Use Secondary ECA Factor.

The On-peak hours shall be 9:00 AM to 9:00 PM for all non-holiday weekdays. Holidays are defined as New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The Off-peak period shall be all other hours. The On-peak and Off-peak price differentials are based on the ratio of system marginal costs for a calendar year. The On-peak and Off-peak price ratio will be projected annually and will be filed with the Commission on the first business day of November, and shall remain in effect for the subsequent calendar year. The TOU ECA rates will be updated with the Quarterly ECA rates and will be determined by applying the fixed annual On-peak and Off-peak ratios to the quarterly ECA cost of service.

(Continued on Sheet No. 111A)

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

TIME-OF-USE NOTICE AND METERING REQUIREMENTS

Customers receiving service under the Time-of-Use ECA must have their usage metered by an Interval Data Recorder ("IDR") meter. If a requesting customer is not currently metered with an IDR meter the Company will install an IDR meter as soon as reasonably practicable and the customer will be eligible for the Time-of-Use rate beginning with the first billing cycle immediately subsequent to the installation of the IDR meter.

ELECTRIC COMMODITY ADJUSTMENT QUARTERLY FILING

The Company shall file each quarter, on not less than fifteen (15) days notice, an application with the ECA Factors on Sheet No. 111G~~F~~ to be effective on the first day of the month of the next calendar quarter. The Company may also file for more frequent changes to the ECA factors, subject to Commission Approval.

ELECTRIC COMMODITY ADJUSTMENT

The ECA shall be calculated quarterly with the new ECA Factors to be effective on a prorated basis on the first day of the quarter. The ECA Factors shall be determined by dividing the Quarterly ECA Revenue Requirement by the projected kilowatt-hour sales to which the ECA is applicable for the next calendar quarter. The ECA Factors shall be differentiated by service delivery voltage to reflect line losses.

LOSS FACTOR

The ECA Factors take into account service delivery voltage to reflect line losses. Loss Factors are as follows:

Transmission	1.0000
Primary	1.0235
Secondary	1.0500

Primary and Secondary voltage losses may be updated by the Company from time to time.

(Continued on Sheet No. 111B)

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

ELECTRIC COMMODITY ADJUSTMENT – Cont'd

8) NGS Balance shall be the total cost for the sales of natural gas less the natural gas sales credit for all revenue received by the Company for the sale of natural gas to Southwest Generation for their Fountain Valley Facility.

The ECA revenue collected for the quarter will be adjusted for billing cycle lag.

Interest shall accrue monthly on the average monthly deferred balance (whether the balance is positive or negative). The monthly interest rate shall be at a rate equal to the average of the daily rates for Commercial Paper, Financial, 3-Month rates, published by the United States Federal Reserve H.15 report (http://www.federalreserve.gov/releases/h15/data.htm).

ADJUSTMENT FOR SHORT-TERM SALES MARGIN

Positive short-term sales margins from the calendar year shall be shared with retail customers through an adjustment to the ECA. Margin sharing shall be calculated separately for both the Generation Book margins and Proprietary Book margins. Proprietary Book margins shall be calculated from the Company's share of margins under the Joint Operating Agreement. Within each of these books, the retail jurisdictional Gross Margin shall be aggregated annually. If the aggregated Gross Margin from either book is negative, the negative margin shall not be passed on to retail customers.

If the annual retail jurisdictional aggregated Gross Margin in either book is positive, then such positive annual retail jurisdictional Gross Margin shall be shared annually with retail customers through the ECA as follows:

1) Generation Book: Gross Margin in excess of $678,027~~789,519~~ for calendar year 2012 and subsequent years shall be shared ninety percent (90%) retail customers/ten percent (10%) Company.

2) Proprietary Book: Gross Margin in excess of $514,659~~508,794~~ for calendar year 2012 and subsequent years shall be shared ten percent (10%) retail customers/ninety percent (90%) Company.

(Continued on Sheet No. 111E)

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

ADJUSTMENT FOR SHORT-TERM SALES MARGIN – Cont'd

The Company shall include in its quarterly filing for effect April 1 of each year a report setting forth the retail customer share of positive short-term sales margins from the prior calendar year. The total positive short-term sales margins will be divided by three (3), and the quotient shall be subtracted from each quarterly ECARR for the remainder of the calendar year.

ADJUSTMENT FOR SO_2 ALLOWANCE MARGINS

Margins earned from the sale of SO_2 allowances by the Company shall be shared with retail customers in accord with Commission orders. The Company shall include in its quarterly filing for effect April 1 of each year a report setting forth the retail customer share of the SO_2 allowance margins from the prior calendar year. The margins to be shared will be divided by three (3), and the quotient shall be subtracted from each quarterly ECARR for the remainder of the calendar year.

PUEBLO INCENTIVE PROPERTY TAX CREDIT

An adjustment shall be made to the Deferred Account Balance to include the flow-through to customers of the amount of any incentive property tax credit or payment received by the Company from the City of Pueblo or Pueblo County pursuant to agreements entered into by the Company with the City of Pueblo and Pueblo County in 2005, commencing with incentive property tax credits or payments attributable to property taxes payable for tax year 2012. As to each regular quarterly ECA application, the adjustment to the applicable Deferred Account Balance shall include all such incentive property tax credits and payments received by the Company during the quarterly period ending as of the last day of the calendar month immediately preceding the date of the ECA application.

ADJUSTMENT FOR TRUE-UP OF COSTS BETWEEN THE RESA AND ECA

An adjustment shall be made to the ECA Deferred Account Balance to collect the component of costs that were charged to the Renewable Energy Standard Adjustment ("RESA") that should have been charged to the ECA for the period 2010 – 2012. An adjustment to the ECA Deferred Account Balance shall commence beginning with the subsequent month after the Company receives Commission approval of said adjustment and shall be collected in the ECA Deferred Account Balance equally over a period of twelve months.

EQUIVALENT AVAILABILITY FACTOR PERFORMANCE MECHANISM

The Equivalent Availability Factor Performance Mechanism ("EAFPM") will apply only to the Company's performance in calendar years 2015 and 2016. An adjustment shall be made to the Deferred Account Balance to include the incentive or penalty attributable to the EAFPM for performance in both 2015 and 2016.

(Continued on Sheet No. 111F)

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

EQUIVALENT AVAILABILITY FACTOR PERFORMANCE MECHANISM - CONT'D

These adjustments to the Deferred Account Balance shall be included in the Company's quarterly filing to be effective April 1, 2016, and April 1, 2017, and will include the total amount of the incentive or penalty for the prior calendar year.

For calendar years 2015 and 2016, the Company shall calculate the Current Year Weighted Average EAF for the Eligible Units. The Current Year Weighted Average EAF for the calendar year shall then be compared to the Historic Weighted Average EAFs for the Eligible Units, weighted by their Net Maximum Capacity, for the years 2009-2013. If the Current Year Weighted Average EAF is greater than or equal to the second highest Historic Weighted Average EAF from the period 2009-2013 (at or above 84.18 percent), the Company will earn an incentive of $3 million. If the Current Year Weighted Average EAF is equal to or lower than the fourth highest Historic Weighted Average EAF from the period 2009-2013 (at or below 80.76 percent), the Company will be assessed a penalty of $3 million. If the Current Year Weighted Average EAF falls between 80.76 percent and 84.18 percent, non-inclusive, the Company will neither earn an incentive nor be assessed a penalty.

The Company shall exclude the following circumstances from the Current Year EAF calculation:

1.) Outage events that are classified as Outside Management Control in the Generating Availability Data System ("GADS").
2.) All outage events that are specifically attributable to an order from a state or federal regulatory agency or an adopted state or federal law.

For purposes of this Equivalent Availability Factor Incentive Mechanism section, the following definitions will apply:

Eligible Units. Cherokee 4, Comanche 1-3, Hayden 1-2, Pawnee, Fort St. Vrain 1-4 and Rocky Mountain Energy Center 1-3.

Equivalent Availability Factor ("EAF"). The total number of available hours for the specified time period divided by the number of hours in the same period. The EAF shall be calculated consistent with the North American Electric Reliability Council requirements as reported in GADS.

Current Year Weighted Average EAF. The average of the EAFs of the Eligible Units in the current year, weighted by the Net Maximum Capacity of the Eligible Units.

(Continued on Sheet No. 111G)

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ELECTRIC RATES

ELECTRIC COMMODITY ADJUSTMENT

ECA FACTORS FOR THE SECOND QUARTER OF 2014

ECA Factors for Billing Purposes

Residential, applicable to all kilowatt-hours used under any Rate Schedule for Residential Service	$0.03806/kWh
Small Commercial and Non-Metered, applicable to all kilowatt-hours used under any Rate Schedules for Small Commercial Service and Non-Metered Service	$0.03806/kWh
Commercial and Industrial Service at Secondary Voltage applicable to all kilowatt-hours used under any Rate Schedules for Commercial and Industrial Secondary Service Rate Schedules for Commercial and Industrial Service	$0.03806/kWh
Optional Time-of-Use Off-Peak	$0.03097/kWh
On-Peak to Off-Peak Ratio	1.53
Optional Time-of-Use On-Peak	$0.04739/kWh
Commercial and Industrial Service at Primary Voltage, applicable to all kilowatt-hours used under any Rate Schedules for Commercial and Industrial Primary or Special Contract Service	
Mandatory Time-of-Use Off-Peak	$0.03082/kWh
On-Peak to Off-Peak Ratio	1.53
Mandatory Time-of-Use On-Peak	$0.04715/kWh
Commercial and Industrial Service at Transmission Voltage, applicable to all kilowatt-hours used under any Rate Schedules for Commercial and Industrial Transmission Service	
Mandatory Time-of-Use Off-Peak	$0.03048/kWh
On-Peak to Off-Peak Ratio	1.53
Mandatory Time-of-Use On-Peak	$0.04663/kWh
Lighting, applicable to all kilowatt-hours used under any Rate Schedule for Commercial Lighting or Public Street Lighting Service	$0.03806/kWh

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Sheet No.

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

APPLICABILITY

All rate schedules for electric service are subject to an Electric Commodity Adjustment (ECA) to reflect the cost of energy utilized to supply electric service. The Electric Commodity Adjustment Factors for all applicable rate schedules are as set forth on Sheet No. 111G and will be applied to all kilowatt-hours sold by the Company with the exception of any buy-through kilowatt-hours (BT kWh) sold to participants in the Interruptible Service Option Credit (ISOC) program who buy through an Economic Interruption. The ECA Factors for lighting service bills and other non-metered service will be determined by applying the ECA Factor to the calculated monthly kilowatt-hour consumption. T

TIME-OF-USE ECA FACTORS APPLICABILITY

All kilowatt-hours used under any Rate Schedule for Commercial and Industrial Primary, Transmission or Special Contract Service customers shall be billed under the appropriate Time-of-Use ECA Factor. Customers that receive electric service under any Commercial and Industrial Secondary Service Rate Schedule that have measured demands of three hundred kilowatt (300 kW) or more for twelve (12) consecutive months may elect to be billed prospectively under the Secondary Time-of-Use ECA Factor. Subsequent to a customer's election to be billed under the Secondary Time-of-Use ECA Factor, customer must have a measured demand of three hundred kilowatts (300 kW) or more every month, except a customer may have one month within the previous twelve (12) months where the customer demand is less than three hundred kilowatts (300 kW). In the event that a second month occurs in any twelve month period where the customer's measured demand is less than three hundred kilowatts (300 kW), the Company shall bill the customer under the non-Time-of-Use Secondary ECA Factor.

The On-peak hours shall be 9:00 AM to 9:00 PM for all non-holiday weekdays. Holidays are defined as New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The Off-peak period shall be all other hours. The On-peak and Off-peak price differentials are based on the ratio of system marginal costs for a calendar year. The On-peak and Off-peak price ratio will be projected annually and will be filed with the Commission on the first business day of November, and shall remain in effect for the subsequent calendar year. The TOU ECA rates will be updated with the Quarterly ECA rates and will be determined by applying the fixed annual On-peak and Off-peak ratios to the quarterly ECA cost of service.

(Continued on Sheet No. 111A)

ADVICE LETTER NUMBER		ISSUE DATE
DECISION NUMBER	VICE PRESIDENT, Rates & Regulatory Affairs	EFFECTIVE DATE

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

TIME-OF-USE NOTICE AND METERING REQUIREMENTS

Customers receiving service under the Time-of-Use ECA must have their usage metered by an Interval Data Recorder ("IDR") meter. If a requesting customer is not currently metered with an IDR meter the Company will install an IDR meter as soon as reasonably practicable and the customer will be eligible for the Time-of-Use rate beginning with the first billing cycle immediately subsequent to the installation of the IDR meter.

ELECTRIC COMMODITY ADJUSTMENT QUARTERLY FILING

The Company shall file each quarter, on not less than fifteen (15) days notice, an application with the ECA Factors on Sheet No. 111G to be effective on the first day of the month of the next calendar quarter. The Company may also file for more frequent changes to the ECA factors, subject to Commission Approval. T

ELECTRIC COMMODITY ADJUSTMENT

The ECA shall be calculated quarterly with the new ECA Factors to be effective on a prorated basis on the first day of the quarter. The ECA Factors shall be determined by dividing the Quarterly ECA Revenue Requirement by the projected kilowatt-hour sales to which the ECA is applicable for the next calendar quarter. The ECA Factors shall be differentiated by service delivery voltage to reflect line losses.

LOSS FACTOR

The ECA Factors take into account service delivery voltage to reflect line losses. Loss Factors are as follows:

Transmission	1.0000
Primary	1.0235
Secondary	1.0500

Primary and Secondary voltage losses may be updated by the Company from time to time.

(Continued on Sheet No. 111B)

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 111D

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Sheet No.

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

ELECTRIC COMMODITY ADJUSTMENT – Cont'd

8) NGS Balance shall be the total cost for the sales of natural gas less the natural gas sales credit for all revenue received by the Company for the sale of natural gas to Southwest Generation for their Fountain Valley Facility.

The ECA revenue collected for the quarter will be adjusted for billing cycle lag.

Interest shall accrue monthly on the average monthly deferred balance (whether the balance is positive or negative). The monthly interest rate shall be at a rate equal to the average of the daily rates for Commercial Paper, Financial, 3-Month rates, published by the United States Federal Reserve H.15 report (http://www.federalreserve.gov/releases/h15/data.htm).

ADJUSTMENT FOR SHORT-TERM SALES MARGIN

Positive short-term sales margins from the calendar year shall be shared with retail customers through an adjustment to the ECA. Margin sharing shall be calculated separately for both the Generation Book margins and Proprietary Book margins. Proprietary Book margins shall be calculated from the Company's share of margins under the Joint Operating Agreement. Within each of these books, the retail jurisdictional Gross Margin shall be aggregated annually. If the aggregated Gross Margin from either book is negative, the negative margin shall not be passed on to retail customers.

If the annual retail jurisdictional aggregated Gross Margin in either book is positive, then such positive annual retail jurisdictional Gross Margin shall be shared annually with retail customers through the ECA as follows:

1) Generation Book: Gross Margin in excess of $678,027 for calendar year 2012 and subsequent years shall be shared ninety percent (90%) retail customers/ten percent (10%) Company. C

2) Proprietary Book: Gross Margin in excess of $514,659 for calendar year 2012 and subsequent years shall be shared ten percent (10%) retail customers/ninety percent (90%) Company. C

(Continued on Sheet No. 111E)

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ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

ADJUSTMENT FOR SHORT-TERM SALES MARGIN – Cont'd

The Company shall include in its quarterly filing for effect April 1 of each year a report setting forth the retail customer share of positive short-term sales margins from the prior calendar year. The total positive short-term sales margins will be divided by three (3), and the quotient shall be subtracted from each quarterly ECARR for the remainder of the calendar year.

ADJUSTMENT FOR SO_2 ALLOWANCE MARGINS

Margins earned from the sale of SO_2 allowances by the Company shall be shared with retail customers in accord with Commission orders. The Company shall include in its quarterly filing for effect April 1 of each year a report setting forth the retail customer share of the SO_2 allowance margins from the prior calendar year. The margins to be shared will be divided by three (3), and the quotient shall be subtracted from each quarterly ECARR for the remainder of the calendar year.

PUEBLO INCENTIVE PROPERTY TAX CREDIT

An adjustment shall be made to the Deferred Account Balance to include the flow-through to customers of the amount of any incentive property tax credit or payment received by the Company from the City of Pueblo or Pueblo County pursuant to agreements entered into by the Company with the City of Pueblo and Pueblo County in 2005, commencing with incentive property tax credits or payments attributable to property taxes payable for tax year 2012. As to each regular quarterly ECA application, the adjustment to the applicable Deferred Account Balance shall include all such incentive property tax credits and payments received by the Company during the quarterly period ending as of the last day of the calendar month immediately preceding the date of the ECA application.

ADJUSTMENT FOR TRUE-UP OF COSTS BETWEEN THE RESA AND ECA

An adjustment shall be made to the ECA Deferred Account Balance to collect the component of costs that were charged to the Renewable Energy Standard Adjustment ("RESA") that should have been charged to the ECA for the period 2010 – 2012. An adjustment to the ECA Deferred Account Balance shall commence beginning with the subsequent month after the Company receives Commission approval of said adjustment and shall be collected in the ECA Deferred Account Balance equally over a period of twelve months.

EQUIVALENT AVAILABILITY FACTOR PERFORMANCE MECHANISM N

The Equivalent Availability Factor Performance N
Mechanism ("EAFPM") will apply only to the Company's N
performance in calendar years 2015 and 2016. An N
adjustment shall be made to the Deferred Account N
Balance to include the incentive or penalty N
attributable to the EAFPM for performance in both 2015 N
and 2016. N

(Continued on Sheet No. 111F)

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

EQUIVALENT AVAILABILITY FACTOR PERFORMANCE MECHANISM - CONT'D N

These adjustments to the Deferred Account Balance shall be included in the Company's quarterly filing to be effective April 1, 2016, and April 1, 2017, and will include the total amount of the incentive or penalty for the prior calendar year.

For calendar years 2015 and 2016, the Company shall calculate the Current Year Weighted Average EAF for the Eligible Units. The Current Year Weighted Average EAF for the calendar year shall then be compared to the Historic Weighted Average EAFs for the Eligible Units, weighted by their Net Maximum Capacity, for the years 2009-2013. If the Current Year Weighted Average EAF is greater than or equal to the second highest Historic Weighted Average EAF from the period 2009-2013 (at or above 84.18 percent), the Company will earn an incentive of $3 million. If the Current Year Weighted Average EAF is equal to or lower than the fourth highest Historic Weighted Average EAF from the period 2009-2013 (at or below 80.76 percent), the Company will be assessed a penalty of $3 million. If the Current Year Weighted Average EAF falls between 80.76 percent and 84.18 percent, non-inclusive, the Company will neither earn an incentive nor be assessed a penalty.

The Company shall exclude the following circumstances from the Current Year EAF calculation:

1.) Outage events that are classified as Outside Management Control in the Generating Availability Data System ("GADS").
2.) All outage events that are specifically attributable to an order from a state or federal regulatory agency or an adopted state or federal law.

For purposes of this Equivalent Availability Factor Incentive Mechanism section, the following definitions will apply:

Eligible Units. Cherokee 4, Comanche 1-3, Hayden 1-2, Pawnee, Fort St. Vrain 1-4 and Rocky Mountain Energy Center 1-3.

Equivalent Availability Factor ("EAF"). The total number of available hours for the specified time period divided by the number of hours in the same period. The EAF shall be calculated consistent with the North American Electric Reliability Council requirements as reported in GADS.

Current Year Weighted Average EAF. The average of the EAFs of the Eligible Units in the current year, weighted by the Net Maximum Capacity of the Eligible Units.

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COLO. PUC No. 7 Electric

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 111G

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Sheet No.

ELECTRIC RATES

ELECTRIC COMMODITY ADJUSTMENT

ECA FACTORS FOR THE SECOND QUARTER OF 2014 M

ECA Factors for Billing Purposes

Residential, applicable to all kilowatt-hours used under any Rate Schedule for Residential Service	$0.03806/kWh
Small Commercial and Non-Metered, applicable to all kilowatt-hours used under any Rate Schedules for Small Commercial Service and Non-Metered Service	$0.03806/kWh
Commercial and Industrial Service at Secondary Voltage applicable to all kilowatt-hours used under any Rate Schedules for Commercial and Industrial Secondary Service Rate Schedules for Commercial and Industrial Service	$0.03806/kWh
Optional Time-of-Use Off-Peak	$0.03097/kWh
On-Peak to Off-Peak Ratio	1.53
Optional Time-of-Use On-Peak	$0.04739/kWh
Commercial and Industrial Service at Primary Voltage, applicable to all kilowatt-hours used under any Rate Schedules for Commercial and Industrial Primary or Special Contract Service	
Mandatory Time-of-Use Off-Peak	$0.03082/kWh
On-Peak to Off-Peak Ratio	1.53
Mandatory Time-of-Use On-Peak	$0.04715/kWh
Commercial and Industrial Service at Transmission Voltage, applicable to all kilowatt-hours used under any Rate Schedules for Commercial and Industrial Transmission Service	
Mandatory Time-of-Use Off-Peak	$0.03048/kWh
On-Peak to Off-Peak Ratio	1.53
Mandatory Time-of-Use On-Peak	$0.04663/kWh
Lighting, applicable to all kilowatt-hours used under any Rate Schedule for Commercial Lighting or Public Street Lighting Service	$0.03806/kWh

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ELECTRIC RATES

GENERAL RATE SCHEDULE ADJUSTMENT

The charge for electric service calculated under Company's electric base rate schedules shall be increased or decreased by the Rider amount for each rate schedule as shown below. Said increase or decrease shall not apply to charges determined by Non-Base Rate Adjustments. For the R and C Rate Schedules, the GRSA shall include the revenue requirement adjustment derived in accordance with the Partial Decoupling Revenue Requirement (PDRR) tariff.

General Rate Schedule Adjustment (GRSA)

~~RIDER~~

~~General Rate Schedule Adjustment (GRSA)~~	~~17.07%~~
For all Rate Schedules except R and C	28.50%
For Rate Schedule R	28.50%
For Rate Schedule C	28.50%
~~TOTAL:~~	~~17.07~~%

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ELECTRIC RATES

GENERAL RATE SCHEDULE ADJUSTMENT

The charge for electric service calculated under Company's electric base rate schedules shall be increased or decreased by the Rider amount for each rate schedule as shown below. Said increase or decrease shall not apply to charges determined by Non-Base Rate Adjustments. For the R and C Rate Schedules, the GRSA shall include the revenue requirement adjustment derived in accordance with the Partial Decoupling Revenue Requirement (PDRR) tariff. C C C C C

General Rate Schedule Adjustment (GRSA)

For all Rate Schedules except R and C	28.50%	CI
For Rate Schedule R	28.50%	N
For Rate Schedule C	28.50%	N

PUBLIC SERVICE COMPANY OF COLORADO

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Sheet No.

ELECTRIC RATES	RATE
ELECTRIC SERVICE	

MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE

Under this schedule, the Company will specifically bill the customer for all maintenance and replacement of street lighting facilities, other than what is provided under each lighting service schedule, in accordance with the following rates, percentages, and general criteria.

Labor

For work performed during normal working hours, per man-hour..	$~~54.00~~57.00
For work performed during hours other than normal working hours, and except for Sundays and holidays, per man-hour..	~~79.00~~94.00
For work performed on Sundays and holidays, per man hour..	~~113.00~~112.00

Materials

Stores Overhead Percentage............................	9.04%

The above percentage will be applied to and then added to the Company's individual materials costs to develop the total materials charge. Individual materials costs will be charged on a current actual cost basis and will be subject to change without notice.

Vehicles

1/2 Ton Pick-up Truck (12 Series):

Per Hour	~~8.25~~8.23

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ELECTRIC RATES	RATE
ELECTRIC SERVICE	
MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE	
Vehicles - Cont'd	
3/4 or 1 Ton Truck, Special Body, 6,200-9,600 GVW (18 Series) Per Hour	$ ~~8.39~~11.83
1 Ton Truck, Special Body, 10,000-16,000 GVW (20 Series): Per Hour	~~14.49~~17.92
Utility Truck (21 Series): Per Hour	~~18.32~~14.54

(Continued on Sheet No. 26B)

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ELECTRIC RATES	RATE
ELECTRIC SERVICE	
MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE	
Vehicles - Cont'd	
Welding Truck (26 Series): Per Hour	$ ~~10.27~~11.74
Line Center Mount Truck (30 Series): Per Hour	~~18.47~~19.41
2 Ton Truck (31 Series): Per Hour	30.44
Boom Truck (32 Series): Per Hour	~~22.38~~21.90
35 Foot One-man Bucket Truck (33 Series): Per Hour	~~19.48~~20.04
40 Foot One-man Bucket Truck (34 Series): Per Hour	~~22.80~~21.33
50 Foot One-man Bucket Truck (35 Series): Per Hour	~~16.33~~15.96
85 Foot and Higher Two-man Bucket Truck (37 Series): Per Hour	~~79.38~~35.09

(Continued on Sheet No. 26C)

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ELECTRIC RATES	RATE
ELECTRIC SERVICE	
MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE	
Vehicles - (Cont'd)	
Dump Truck (38 Series): Per Hour	$ ~~23.28~~20.93
Trencher (44 Series): Per Hour	~~14.90~~11.45
Earthboring Machine, Truck or Trailer Mounted (46 Series): Per Hour	100.00
Portable Welder or Air Compressor (58 Series): Per Hour	~~6.47~~6.83
Multiple Axle Trailer (61 Series): Per Hour	~~4.47~~4.81
Backhoe (62 Series): Per Hour	15.53
Misc. Boring & Restoration Truck (63 Series): Per Hour	37.57
Misc. Boring & Restoration Equipment (64 Series): Per Hour	23.97

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ELECTRIC RATES | RATE

ELECTRIC SERVICE

MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE

Under this schedule, the Company will specifically bill the customer for all maintenance and replacement of street lighting facilities, other than what is provided under each lighting service schedule, in accordance with the following rates, percentages, and general criteria.

	Rate	
<u>Labor</u>		
For work performed during normal working hours, per man-hour	$57.00	I
For work performed during hours other than normal working hours, and except for Sundays and holidays, per man-hour	94.00	I
For work performed on Sundays and holidays, per man hour	112.00	R
<u>Materials</u>		
Stores Overhead Percentage	9.04%	

The above percentage will be applied to and then added to the Company's individual materials costs to develop the total materials charge. Individual materials costs will be charged on a current actual cost basis and will be subject to change without notice.

	Rate	
<u>Vehicles</u>		
1/2 Ton Pick-up Truck (12 Series):		
Per Hour	8.23	R

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ELECTRIC RATES	RATE	
ELECTRIC SERVICE		
MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE		
Vehicles - Cont'd		
3/4 or 1 Ton Truck, Special Body, 6,200-9,600 GVW (18 Series) Per Hour	$ 11.83	I
1 Ton Truck, Special Body, 10,000-16,000 GVW (20 Series): Per Hour	17.92	I
Utility Truck (21 Series): Per Hour	14.54	R

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ELECTRIC RATES	RATE	
ELECTRIC SERVICE		
MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE		
Vehicles - Cont'd		
Welding Truck (26 Series):		
Per Hour	$ 11.74	I
Line Center Mount Truck (30 Series):		
Per Hour	19.41	I
2 Ton Truck (31 Series):		
Per Hour	30.44	
Boom Truck (32 Series):		
Per Hour	21.90	R
35 Foot One-man Bucket Truck (33 Series):		
Per Hour	20.04	I
40 Foot One-man Bucket Truck (34 Series):		
Per Hour	21.33	R
50 Foot One-man Bucket Truck (35 Series):		
Per Hour	15.96	R
85 Foot and Higher Two-man Bucket Truck (37 Series):		
Per Hour	35.09	R

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ELECTRIC RATES

ELECTRIC SERVICE

MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE

Vehicles - (Cont'd)

	RATE	
Dump Truck (38 Series): Per Hour	$ 20.93	R
Trencher (44 Series): Per Hour	11.45	R
Earthboring Machine, Truck or Trailer Mounted (46 Series): Per Hour	100.00	
Portable Welder or Air Compressor (58 Series): Per Hour	6.83	I
Multiple Axle Trailer (61 Series): Per Hour	4.81	I
Backhoe (62 Series): Per Hour	15.53	
Misc. Boring & Restoration Truck (63 Series): Per Hour	37.57	
Misc. Boring & Restoration Equipment (64 Series): Per Hour	23.97	

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ELECTRIC RATES	RATE
ELECTRIC SERVICE	
SCHEDULE OF CHARGES FOR RENDERING SERVICE	
To institute or reinstitute electric service requiring a premise visit within:	
24 hours	$ ~~35.00~~38.00
12 hours	~~73.00~~77.00
To institute or reinstitute both gas and electric service requiring a premise visit within:	
24 hours	~~114.00~~96.00
12 hours	~~133.00~~132.00
To provide a non-regularly scheduled final meter Reading at customers request	24.00
To transfer service at a specific location from one customer to another customer where such service is continuous, either electric service or both electric and gas service at the same time not requiring a premise visit	8.00
To perform non-gratuitous labor for service work, not specified below, (not including appliance repair and premium power) in addition to charges for materials, is as follows:	
Trip Charge	~~38.00~~40.00
(Assessed when no actual service work is performed, other than a general diagnosis of the customer's problem)	
For service work during normal working hours	
per man-hour	~~71.00~~75.62
Minimum Charge, one hour	~~71.00~~75.62
An overtime rate will be applicable to non-gratuitous labor for service work performed before and after normal working hours of 8:00 AM to 5:00 PM Monday through Saturday. The overtime rate shall be,	
per man-hour	~~87.00~~94.26
Minimum Charge, one hour	~~87.00~~94.26

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Sheet No.

ELECTRIC RATES

ELECTRIC SERVICE

SCHEDULE OF CHARGES FOR RENDERING SERVICE

	RATE
When such service work is performed on Sundays and holidays, per man hour	~~102.00~~112.90
Minimum Charge, one hour	~~102.00~~112.90

When customer requests one or more of the specific non-gratuitous services listed below to be performed at a time specified by the customer that is different from when the Company would ordinarily schedule the service(s) to be performed, such service(s) will be charged at the applicable overtime rates.

Specific non-gratuitous services:

Holding poles, minimum 4 hours	$~~766.00~~856.00
Each additional hour	~~192.00~~214.00
Line Covering – Primary, minimum 3 hours	~~862.00~~945.00
Each additional hour	~~287.00~~345.00
Line Covering – Secondary, minimum 2 hours	~~356.00~~397.00
Each additional hour	~~178.00~~199.00
Relocate Overhead Loop, minimum 2 hours	~~218.00~~236.00
Each additional hour	~~109.00~~118.00
Connect/Reconnect Loop Charge, minimum 2 hours	~~144.00~~181.00
Each additional hour................................	~~85.00~~90.00
Transformer opening, minimum 1 hour	~~91.00~~97.00
Each additional hour................................	~~91.00~~97.00
To process a check from a customer that is returned to the Company by the bank as not payable..................	15.00

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PUBLIC SERVICE COMPANY OF COLORADO

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ELECTRIC RATES

ELECTRIC SERVICE

SCHEDULE OF CHARGES FOR RENDERING SERVICE

	RATE	
To institute or reinstitute electric service requiring a premise visit within:		
24 hours	$ 38.00	I
12 hours	77.00	I
To institute or reinstitute both gas and electric service requiring a premise visit within:		
24 hours	96.00	R
12 hours	132.00	R
To provide a non-regularly scheduled final meter Reading at customers request	24.00	
To transfer service at a specific location from one customer to another customer where such service is continuous, either electric service or both electric and gas service at the same time not requiring a premise visit	8.00	
To perform non-gratuitous labor for service work, not specified below, (not including appliance repair and premium power) in addition to charges for materials, is as follows:		
Trip Charge	40.00	I
(Assessed when no actual service work is performed, other than a general diagnosis of the customer's problem)		
For service work during normal working hours per man-hour	75.62	I
Minimum Charge, one hour	75.62	I
An overtime rate will be applicable to non-gratuitous labor for service work performed before and after normal working hours of 8:00 AM to 5:00 PM Monday through Saturday. The overtime rate shall be, per man-hour	94.26	I
Minimum Charge, one hour	94.26	I

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ELECTRIC RATES

ELECTRIC SERVICE

SCHEDULE OF CHARGES FOR RENDERING SERVICE

	RATE	
When such service work is performed on Sundays and holidays, per man hour	112.90	I
Minimum Charge, one hour	112.90	I

When customer requests one or more of the specific non-gratuitous services listed below to be performed at a time specified by the customer that is different from when the Company would ordinarily schedule the service(s) to be performed, such service(s) will be charged at the applicable overtime rates.

Specific non-gratuitous services:

Holding poles, minimum 4 hours	$856.00	I
Each additional hour	214.00	I
Line Covering – Primary, minimum 3 hours	945.00	I
Each additional hour	345.00	I
Line Covering – Secondary, minimum 2 hours	397.00	I
Each additional hour	199.00	I
Relocate Overhead Loop, minimum 2 hours	236.00	I
Each additional hour	118.00	I
Connect/Reconnect Loop Charge, minimum 2 hours	181.00	I
Each additional hour................................	90.00	I
Transformer opening, minimum 1 hour	97.00	I
Each additional hour................................	97.00	I

To process a check from a customer that is returned to the Company by the bank as not payable...................	15.00

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Public Service Company of Colorado
Electric Department
Customer Impact Study 2014-2015

Please Note:
Riders are held constant at current 2014 levels, with the exception of the TCA.
TCA is updated to reflect implementation of an updated GRSA
ESA is 8/2014 rate
ECA is based on actual 1st and 2nd Q as filed with CPUC and projection for 3rd and 4th Q.

Customer Class	2014 Rate	Proposed 2015 Rate	Monthly Average Usage	2014 Current Bill	2015 Proposed Bill	Monthly Difference $	Difference %
Residential - Schedule R							
Service and Facility Charge	$ 6.75	$ 6.75		$ 6.75	$ 6.75	$ -	
Energy Charge - Annualized	$ 0.05177 /kWh	$ 0.05177 /kWh	632 kWh	32.72	32.72	-	
Subtotal				$ 39.47	$ 39.47	$ -	0.00%
GRSA	17.07%	28.50%		6.74	11.25	4.51	
ESA	-3.35%	-3.35%		(1.32)	(1.32)		
Base Rate Amount				$ 44.89	$ 49.40	$ 4.51	10.05%
DSMCA	$ 0.00285 /kWh	$ 0.00285 /kWh		$ 1.80	$ 1.80	$ -	
PCCA	$ 0.00638 /kWh	$ 0.00638 /kWh		$ 4.03	$ 4.03	$ -	
TCA	$ 0.00106 /kWh	$ 0.00006 /kWh		$ 0.67	$ 0.04	$ (0.63)	
ECA - Secondary	$ 0.03420 /kWh	$ 0.03420 /kWh		$ 21.61	$ 21.61	$ -	
Subtotal Base Rate Adjustments				$ 28.11	$ 27.48	$ (0.63)	
Total Bill Subtotal				$ 73.00	$ 76.88	$ 3.88	5.32%
RESA	2.00%	2.00%		$ 1.46	$ 1.54	$ 0.08	
Total Bill				$ 74.46	$ 78.42	$ 3.96	**5.32%**
Commercial - Schedule C							
Service and Facility Charge	$ 10.75	$ 10.75		$ 10.75	$ 10.75	$ -	
Energy Charge - Annualized	$ 0.04763 /kWh	$ 0.04763 /kWh	1,123 kWh	53.49	53.49	-	
Subtotal				$ 64.24	$ 64.24	$ -	0.00%
GRSA	17.07%	28.50%		10.97	18.31	7.34	
ESA	-3.35%	-3.35%		(2.15)	(2.15)		
Base Rate Amount				$ 73.06	$ 80.40	$ 7.34	10.05%
DSMCA	$ 0.00281 /kWh	$ 0.00281 /kWh		$ 3.16	$ 3.16	$ -	
PCCA	$ 0.00630 /kWh	$ 0.00630 /kWh		$ 7.07	$ 7.07	$ -	
TCA	$ 0.00105 /kWh	$ 0.00006 /kWh		$ 1.18	$ 0.07	$ (1.11)	
ECA - Secondary	$ 0.03420 /kWh	$ 0.03420 /kWh		$ 38.41	$ 38.41	$ -	
Subtotal Base Rate Adjustments				$ 49.82	$ 48.71	$ (1.11)	
Total Bill Subtotal				$ 122.88	$ 129.11	$ 6.23	5.07%
RESA	2.00%	2.00%		$ 2.46	$ 2.58	$ 0.12	
Total Bill				$ 125.34	$ 131.69	$ 6.35	**5.07%**

Public Service Company of Colorado
Electric Department
Customer Impact Study 2014-2015

Customer Class	2014 Rate	Proposed 2015 Rate	Monthly Average Usage	2014 Current Bill	2015 Proposed Bill	Monthly Difference $	Difference %
Secondary General - Schedule SG							
Service and Facility Charge	$ 40.00	$ 40.00	51.49% L.F.	$ 40.00	$ 40.00	$ -	
Energy Charge	$ 0.00473 kWh	$ 0.00473 kWh	26,685 kWh	126.22	126.22	-	
Distribution Demand Charge	$ 4.84 /kW	$ 4.84 /kW	71.00 kW	343.64	343.64	-	
G & T Demand Charge - Annualized	$ 8.99 /kW	$ 8.99 /kW	71.00 kW	638.29	638.29	-	
Subtotal				$ 1,148.15	$ 1,148.15	$ -	0.00%
GRSA	17.07%	28.50%		195.99	327.22	131.23	
ESA	-3.35%	-3.35%		(38.46)	(38.46)		
Base Rate Amount				$ 1,305.68	$ 1,436.91	$ 131.23	10.05%
DSMCA	$ 0.94 /kW	$ 0.94 /kW		$ 66.74	$ 66.74	$ -	
PCCA	$ 2.08 /kW	$ 2.08 /kW		$ 147.68	$ 147.68	$ -	
TCA	$ 0.35 /kW	$ 0.02 /kW		$ 24.85	$ 1.42	$ (23.43)	
ECA - Secondary	$ 0.03420 /kWh	$ 0.03420 /kWh		$ 912.63	$ 912.63	$ -	
Subtotal Base Rate Adjustments				$ 1,151.90	$ 1,128.47	$ (23.43)	
Total Bill Subtotal				$ 2,457.58	$ 2,565.38	$ 107.80	4.39%
RESA	2.00%	2.00%		$ 49.15	$ 51.31	$ 2.16	
Total Bill				$ 2,506.73	$ 2,616.69	$ 109.96	**4.39%**
Primary General - Schedule PG							
Service and Facility Charge	$ 305.00	$ 305.00	64.82% L.F.	$ 305.00	$ 305.00	$ -	
Energy Charge	$ 0.00461 kWh	$ 0.00461 kWh	492,079 kWh	2,268.48	2,268.48	-	
Distribution Demand Charge	$ 3.98 /kW	$ 3.98 /kW	1,040.00 kW	4,139.20	4,139.20	-	
G & T Demand Charge - Annualized	$ 8.03 /kW	$ 8.03 /kW	1,040.00 kW	8,351.20	8,351.20	-	
Subtotal				$ 15,063.88	$ 15,063.88	$ -	0.00%
GRSA	17.07%	28.50%		2,571.40	4,293.21	1,721.81	
ESA	-3.35%	-3.35%		(504.64)	(504.64)		
Base Rate Amount				$ 17,130.64	$ 18,852.45	$ 1,721.81	10.05%
DSMCA	$ 0.86 /kW	$ 0.86 /kW		$ 894.40	$ 894.40	$ -	
PCCA	$ 1.92 /kW	$ 1.92 /kW		$ 1,996.80	$ 1,996.80	$ -	
TCA	$ 0.33 /kW	$ 0.02 /kW		$ 343.20	$ 20.80	$ (322.40)	
ECA - Primary On-Peak (1)	$ 0.04236 /kWh	$ 0.04236 /kWh		$ 8,006.57	$ 8,006.59	$ 0.02	
ECA - Primary Off-Peak (1)	$ 0.02769 /kWh	$ 0.02769 /kWh		$ 8,391.91	$ 8,391.91	$ -	
Subtotal Base Rate Adjustments				$ 19,632.88	$ 19,310.50	$ (322.38)	
Total Bill Subtotal				$ 36,763.52	$ 38,162.95	$ 1,399.43	3.81%
RESA	2.00%	2.00%		$ 735.27	$ 763.26	$ 27.99	
Total Bill				$ 37,498.79	$ 38,926.21	$ 1,427.42	**3.81%**

(1) Assumes 38.411% on-peak and 61.589% off-peak usage factors.

Customer Class	2014 Rate	Proposed 2015 Rate	Monthly Average Usage	2014 Current Bill	2015 Proposed Bill	Monthly Difference $	Difference %
Transmission General - Schedule TG							
Service and Facility Charge	$ 14,800.00	$ 14,800.00	72.68% L.F.	$ 14,800.00	$ 14,800.00	$ -	
Energy Charge	$ 0.00451 /kWh	$ 0.00451 /kWh	12,889,873 kWh	58,133.33	58,133.33	-	
Demand Charge - Annualized	$ 7.68 /kW	$ 7.68 /kW	24,294 kW	186,577.92	186,577.92	-	
Subtotal				$ 259,511.25	$ 259,511.25	$ -	0.00%
GRSA	17.07%	28.50%		44,298.57	73,960.71	**29,662.14**	
ESA	-3.35%	-3.35%		(8,693.63)	(8,693.63)		
Base Rate Amount				$ 295,116.19	$ 324,778.33	$ 29,662.14	10.05%
DSMCA	$ 0.81 /kW	$ 0.81 /kW		$ 19,678.14	$ 19,678.14	$ -	
PCCA	$ 1.77 /kW	$ 1.77 /kW		$ 43,000.38	$ 43,000.38	$ -	
TCA	$ 0.31 /kW	$ 0.02 /kW		$ 7,531.14	$ 485.88	$ (7,045.26)	
ECA - Transmission On-Peak (2)	$ 0.04190 /kWh	$ 0.04190 /kWh		$ 192,621.56	$ 192,621.56	$ -	
ECA - Transmission Off-Peak (2)	$ 0.02739 /kWh	$ 0.02739 /kWh		$ 227,137.05	$ 227,137.05	$ -	
Subtotal Base Rate Adjustments				$ 489,968.27	$ 482,923.01	$ (7,045.26)	
Total Bill Subtotal				$ 785,084.46	$ 807,701.34	$ 22,616.88	2.88%
RESA	2.00%	2.00%		$ 15,701.69	$ 16,154.03	$ 452.34	
Total Bill				$ 800,786.15	$ 823,855.37	$ 23,069.22	**2.88%**

(2) Assumes 35.665% on-peak and 64.335% off-peak usage factors.

Public Service Company of Colorado
Electric Department
Customer Impact Study 2014-2015
Please Note:
ESA is 8/2014 rate
All other rates reflect projections for 2014 and 2015
2014 ECA is based on actual 1st and 2nd Q as filed with CPUC and projections for 3rd and 4th Q

Customer Class	2014 Rate	Proposed 2015 Rate	Monthly Average Usage	2014 Current Bill	2015 Proposed Bill	Monthly Difference $	Difference %
Residential - Schedule R							
Service and Facility Charge	$ 6.75	$ 6.75		$ 6.75	$ 6.75	$ -	
Energy Charge - Annualized	$ 0.05177 /kWh	$ 0.05177 /kWh	632 kWh	32.72	32.72	-	
Subtotal				$ 39.47	$ 39.47	$ -	0.00%
GRSA	17.07%	28.50%		6.74	11.25	4.51	
ESA	-3.35%	-3.35%		(1.32)	(1.32)		
Base Rate Amount				$ 44.89	$ 49.40	$ 4.51	10.05%
DSMCA	$ 0.00285 /kWh	$ 0.00375 /kWh		$ 1.80	$ 2.37	$ 0.57	
PCCA	$ 0.00638 /kWh	$ 0.00711 /kWh		$ 4.03	$ 4.49	$ 0.46	
TCA	$ 0.00106 /kWh	$ 0.00006 /kWh		$ 0.67	$ 0.04	$ (0.63)	
ECA - Secondary	$ 0.03420 /kWh	$ 0.03282 /kWh		$ 21.61	$ 20.74	$ (0.87)	
Subtotal Base Rate Adjustments				$ 28.11	$ 27.64	$ (0.47)	
Total Bill Subtotal				$ 73.00	$ 77.04	$ 4.04	5.53%
RESA	2.00%	2.00%		$ 1.46	$ 1.54	$ 0.08	
Total Bill				$ 74.46	$ 78.58	$ 4.12	**5.53%**
Commercial - Schedule C							
Service and Facility Charge	$ 10.75	$ 10.75		$ 10.75	$ 10.75	$ -	
Energy Charge - Annualized	$ 0.04763 /kWh	$ 0.04763 /kWh	1,123 kWh	53.49	53.49	-	
Subtotal				$ 64.24	$ 64.24	$ -	0.00%
GRSA	17.07%	28.50%		10.97	18.31	7.34	
ESA	-3.35%	-3.35%		(2.15)	(2.15)		
Base Rate Amount				$ 73.06	$ 80.40	$ 7.34	10.05%
DSMCA	$ 0.00281 /kWh	$ 0.00370 /kWh		$ 3.16	$ 4.16	$ 1.00	
PCCA	$ 0.00630 /kWh	$ 0.00702 /kWh		$ 7.07	$ 7.88	$ 0.81	
TCA	$ 0.00105 /kWh	$ 0.00006 /kWh		$ 1.18	$ 0.07	$ (1.11)	
ECA - Secondary	$ 0.03420 /kWh	$ 0.03282 /kWh		$ 38.41	$ 36.86	$ (1.55)	
Subtotal Base Rate Adjustments				$ 49.82	$ 48.97	$ (0.85)	
Total Bill Subtotal				$ 122.88	$ 129.37	$ 6.49	5.28%
RESA	2.00%	2.00%		$ 2.46	$ 2.59	$ 0.13	
Total Bill				$ 125.34	$ 131.96	$ 6.62	**5.28%**

Customer Class	2014 Rate	Proposed 2015 Rate	Monthly Average Usage	2014 Current Bill	2015 Proposed Bill	Monthly Difference $	Difference %
Secondary General - Schedule SG							
Service and Facility Charge	$ 40.00	$ 40.00	51.49% L.F.	$ 40.00	$ 40.00	$ -	
Energy Charge	$ 0.00473 kWh	$ 0.00473 kWh	26,685 kWh	126.22	126.22	-	
Distribution Demand Charge	$ 4.84 /kW	$ 4.84 /kW	71.00 kW	343.64	343.64	-	
G & T Demand Charge - Annualized	$ 8.99 /kW	$ 8.99 /kW	71.00 kW	638.29	638.29	-	
Subtotal				$ 1,148.15	$ 1,148.15	$ -	0.00%
GRSA	17.07%	28.50%		195.99	327.22	131.23	
ESA	-3.35%	-3.35%		(38.46)	(38.46)		
Base Rate Amount				$ 1,305.68	$ 1,436.91	$ 131.23	10.05%
DSMCA	$ 0.94 /kW	$ 1.24 /kW		$ 66.74	$ 88.04	$ 21.30	
PCCA	$ 2.08 /kW	$ 2.32 /kW		$ 147.68	$ 164.72	$ 17.04	
TCA	$ 0.35 /kW	$ 0.02 /kW		$ 24.85	$ 1.42	$ (23.43)	
ECA - Secondary	$ 0.03420 /kWh	$ 0.03282 /kWh		$ 912.63	$ 875.80	$ (36.83)	
Subtotal Base Rate Adjustments				$ 1,151.90	$ 1,129.98	$ (21.92)	
Total Bill Subtotal				$ 2,457.58	$ 2,566.89	$ 109.31	4.45%
RESA	2.00%	2.00%		$ 49.15	$ 51.34	$ 2.19	
Total Bill				$ 2,506.73	$ 2,618.23	$ 111.50	**4.45%**
Primary General - Schedule PG							
Service and Facility Charge	$ 305.00	$ 305.00	64.82% L.F.	$ 305.00	$ 305.00	$ -	
Energy Charge	$ 0.00461 kWh	$ 0.00461 kWh	492,079 kWh	2,268.48	2,268.48	-	
Distribution Demand Charge	$ 3.98 /kW	$ 3.98 /kW	1,040.00 kW	4,139.20	4,139.20	-	
G & T Demand Charge - Annualized	$ 8.03 /kW	$ 8.03 /kW	1,040.00 kW	8,351.20	8,351.20	-	
Subtotal				$ 15,063.88	$ 15,063.88	$ -	0.00%
GRSA	17.07%	28.50%		2,571.40	4,293.21	1,721.81	
ESA	-3.35%	-3.35%		(504.64)	(504.64)		
Base Rate Amount				$ 17,130.64	$ 18,852.45	$ 1,721.81	10.05%
DSMCA	$ 0.86 /kW	$ 1.13 /kW		$ 894.40	$ 1,175.20	$ 280.80	
PCCA	$ 1.92 /kW	$ 2.15 /kW		$ 1,996.80	$ 2,236.00	$ 239.20	
TCA	$ 0.33 /kW	$ 0.02 /kW		$ 343.20	$ 20.80	$ (322.40)	
ECA - Primary On-Peak (1)	$ 0.04236 /kWh	$ 0.04074 /kWh		$ 8,006.57	$ 7,700.39	$ (306.18)	
ECA - Primary Off-Peak (1)	$ 0.02769 /kWh	$ 0.02663 /kWh		$ 8,391.91	$ 8,070.66	$ (321.25)	
Subtotal Base Rate Adjustments				$ 19,632.88	$ 19,203.05	$ (429.83)	
Total Bill Subtotal				$ 36,763.52	$ 38,055.50	$ 1,291.98	3.51%
RESA	2.00%	2.00%		$ 735.27	$ 761.11	$ 25.84	
Total Bill				$ 37,498.79	$ 38,816.61	$ 1,317.82	**3.51%**

(1) Assumes 38.411% on-peak and 61.589% off-peak usage factors.

Customer Class	**2014 Rate**		**Proposed 2015 Rate**		**Monthly Average Usage**		**2014 Current Bill**	**2015 Proposed Bill**	**Monthly Difference $**	**Difference %**
Transmission General - Schedule TG										
Service and Facility Charge	$ 14,800.00		$ 14,800.00		72.68%	L.F.	$ 14,800.00	$ 14,800.00	$ -	
Energy Charge	$ 0.00451	/kWh	$ 0.00451	/kWh	12,889,873	kWh	58,133.33	58,133.33	-	
Demand Charge - Annualized	$ 7.68	/kW	$ 7.68	/kW	24,294	kW	186,577.92	186,577.92	-	
Subtotal							$ 259,511.25	$ 259,511.25	$ -	0.00%
GRSA	17.07%		28.50%				44,298.57	73,960.71	**29,662.14**	
ESA	-3.35%		-3.35%				(8,693.63)	(8,693.63)		
Base Rate Amount							$ 295,116.19	$ 324,778.33	$ 29,662.14	10.05%
DSMCA	$ 0.81	/kW	$ 1.07	/kW			$ 19,678.14	$ 25,994.58	$ 6,316.44	
PCCA	$ 1.77	/kW	$ 1.99	/kW			$ 43,000.38	$ 48,345.06	$ 5,344.68	
TCA	$ 0.31	/kW	$ 0.02	/kW			$ 7,531.14	$ 485.88	$ (7,045.26)	
ECA - Transmission On-Peak (2)	$ 0.04190	/kWh	$ 0.04030	/kWh			$ 192,621.56	$ 185,266.08	$ (7,355.48)	
ECA - Transmission Off-Peak (2)	$ 0.02739	/kWh	$ 0.02634	/kWh			$ 227,137.05	$ 218,429.71	$ (8,707.34)	
Subtotal Base Rate Adjustments							$ 489,968.27	$ 478,521.31	$ (11,446.96)	
Total Bill Subtotal							$ 785,084.46	$ 803,299.64	$ 18,215.18	2.32%
RESA	2.00%		2.00%				$ 15,701.69	$ 16,065.99	$ 364.30	
Total Bill							$ 800,786.15	$ 819,365.63	$ 18,579.48	**2.32%**

(2) Assumes 35.665% on-peak and 64.335% off-peak usage factors.

Public Service Company of Colorado
Electric Department
Customer Impact Study 2015-2016
CACJA Impact Only

Please Note:
***ESA is 8/2014 rate**
****2016 Riders are held constant at 2015 level**

Customer Class	Proposed 2015 Rate		Proposed **2016 Rate		Monthly Average Usage		Proposed 2015 Bill		Proposed 2016 Bill		Monthly Difference $		Difference %
Residential - Schedule R													
Service and Facility Charge	$ 6.75		$ 6.75				$	6.75	$	6.75	$	-	
Energy Charge - Annualized	$ 0.05177	/kWh	$ 0.05177	/kWh	632	kWh		32.72		32.72		-	
Subtotal							$	39.47	$	39.47	$	-	0.00%
GRSA	28.50%		28.50%					11.25		11.25		-	
*ESA	-3.35%		-3.35%					(1.32)		(1.32)			
Base Rate Amount							$	49.40	$	49.40	$	-	0.00%
DSMCA	$ 0.00375	/kWh	$ 0.00375	/kWh			$	2.37	$	2.37	$	-	
PCCA	$ 0.00711	/kWh	$ 0.00711	/kWh			$	4.49	$	4.49	$	-	
CACJAR	**$ -**	**/kWh**	**$ 0.00164**	**/kWh**			**$**	**-**	**$**	**1.04**	**$**	**1.04**	
TCA	$ 0.00006	/kWh	$ 0.00006	/kWh			$	0.04	$	0.04	$	-	
ECA - Secondary	$ 0.03282	/kWh	$ 0.03282	/kWh			$	20.74	$	20.74	$	-	
Subtotal Base Rate Adjustments							$	27.64	$	28.68	$	1.04	
Total Bill Subtotal							$	77.04	$	78.08	$	1.04	1.35%
RESA	2.00%		2.00%				$	1.54	$	1.56	$	0.02	
Total Bill							$	78.58	$	79.64	$	1.06	**1.35%**
Commercial - Schedule C													
Service and Facility Charge	$ 10.75		$ 10.75				$	10.75	$	10.75	$	-	
Energy Charge - Annualized	$ 0.04763	/kWh	$ 0.04763	/kWh	1,123	kWh		53.49		53.49		-	
Subtotal							$	64.24	$	64.24	$	-	0.00%
GRSA	28.50%		28.50%					18.31		18.31		-	
*ESA	-3.35%		-3.35%					(2.15)		(2.15)			
Base Rate Amount							$	80.40	$	80.40	$	-	0.00%
DSMCA	$ 0.00370	/kWh	$ 0.00370	/kWh			$	4.16	$	4.16	$	-	
PCCA	$ 0.00702	/kWh	$ 0.00702	/kWh			$	7.88	$	7.88	$	-	
CACJAR	**$ -**	**/kWh**	**$ 0.00162**	**/kWh**			**$**	**-**	**$**	**1.82**	**$**	**1.82**	
TCA	$ 0.00006	/kWh	$ 0.00006	/kWh			$	0.07	$	0.07	$	-	
ECA - Secondary	$ 0.03282	/kWh	$ 0.03282	/kWh			$	36.86	$	36.86	$	-	
Subtotal Base Rate Adjustments							$	48.97	$	50.79	$	1.82	
Total Bill Subtotal							$	129.37	$	131.19	$	1.82	1.41%
RESA	2.00%		2.00%				$	2.59	$	2.62	$	0.03	
Total Bill							$	131.96	$	133.81	$	1.85	**1.40%**

Public Service Company of Colorado
Electric Department
Customer Impact Study 2015-2016

Customer Class	Proposed 2015 Rate	Proposed **2016 Rate	Monthly Average Usage	Proposed 2015 Bill	Proposed 2016 Bill	Monthly Difference $	Difference %
Secondary General - Schedule SG							
Service and Facility Charge	$ 40.00	$ 40.00	51.49% L.F.	$ 40.00	$ 40.00	$ -	
Energy Charge	$ 0.00473 kWh	$ 0.00473 kWh	26,685 kWh	126.22	126.22	-	
Distribution Demand Charge	$ 4.84 /kW	$ 4.84 /kW	71.00 kW	343.64	343.64	-	
G & T Demand Charge - Annualized	$ 8.99 /kW	$ 8.99 /kW	71.00 kW	638.29	638.29	-	
Subtotal				$ 1,148.15	$ 1,148.15	$ -	0.00%
GRSA	28.50%	28.50%		327.22	327.22	-	
*ESA	-3.35%	-3.35%		(38.46)	(38.46)		
Base Rate Amount				$ 1,436.91	$ 1,436.91	$ -	0.00%
DSMCA	$ 1.24 /kW	$ 1.24 /kW		$ 88.04	$ 88.04	$ -	
PCCA	$ 2.32 /kW	$ 2.32 /kW		$ 164.72	$ 164.72	$ -	
CACJAR	**$ - /kW**	**$ 0.54 /kW**		**$ -**	**$ 38.34**	**$ 38.34**	
TCA	$ 0.02 /kW	$ 0.02 /kW		$ 1.42	$ 1.42	$ -	
ECA - Secondary	$ 0.03282 /kWh	$ 0.03282 /kWh		$ 875.80	$ 875.80	$ -	
Subtotal Base Rate Adjustments				$ 1,129.98	$ 1,168.32	$ 38.34	
Total Bill Subtotal				$ 2,566.89	$ 2,605.23	$ 38.34	1.49%
RESA	2.00%	2.00%		$ 51.34	$ 52.10	$ 0.76	
Total Bill				$ 2,618.23	$ 2,657.33	$ 39.10	**1.49%**
Primary General - Schedule PG							
Service and Facility Charge	$ 305.00	$ 305.00	64.82% L.F.	$ 305.00	$ 305.00	$ -	
Energy Charge	$ 0.00461 kWh	$ 0.00461 kWh	492,079 kWh	2,268.48	2,268.48	-	
Distribution Demand Charge	$ 3.98 /kW	$ 3.98 /kW	1,040.00 kW	4,139.20	4,139.20	-	
G & T Demand Charge - Annualized	$ 8.03 /kW	$ 8.03 /kW	1,040.00 kW	8,351.20	8,351.20	-	
Subtotal				$ 15,063.88	$ 15,063.88	$ -	0.00%
GRSA	28.50%	28.50%		4,293.21	4,293.21	-	
*ESA	-3.35%	-3.35%		(504.64)	(504.64)		
Base Rate Amount				$ 18,852.45	$ 18,852.45	$ -	0.00%
DSMCA	$ 1.13 /kW	$ 1.13 /kW		$ 1,175.20	$ 1,175.20	$ -	
PCCA	$ 2.15 /kW	$ 2.15 /kW		$ 2,236.00	$ 2,236.00	$ -	
CACJAR	**$ -**	**$ 0.49** /kW		**$ -**	**$ 509.60**	**$ 509.60**	
TCA	$ 0.02 /kW	$ 0.02 /kW		$ 20.80	$ 20.80	$ -	
ECA - Primary On-Peak (1)	$ 0.04074 /kWh	$ 0.04074 /kWh		$ 7,700.37	$ 7,700.39	$ 0.02	
ECA - Primary Off-Peak (1)	$ 0.02663 /kWh	$ 0.02663 /kWh		$ 8,070.66	$ 8,070.66	$ -	
Subtotal Base Rate Adjustments				$ 19,203.03	$ 19,712.65	$ 509.62	
Total Bill Subtotal				$ 38,055.48	$ 38,565.10	$ 509.62	1.34%
RESA	2.00%	2.00%		$ 761.11	$ 771.30	$ 10.19	
Total Bill				$ 38,816.59	$ 39,336.40	$ 519.81	**1.34%**

(1) Assumes 38.411% on-peak and 61.589% off-peak usage factors.

Customer Class		**Proposed 2015 Rate**			**Proposed **2016 Rate**		**Monthly Average Usage**			**Proposed 2015 Bill**		**Proposed 2016 Bill**		**Monthly Difference $**	**Difference %**
Transmission General - Schedule TG															
Service and Facility Charge	$	14,800.00		$	14,800.00		72.68%	L.F.	$	14,800.00	$	14,800.00	$	-	
Energy Charge	$	0.00451	/kWh	$	0.00451	/kWh	12,889,873	kWh		58,133.33		58,133.33		-	
Demand Charge - Annualized	$	7.68	/kW	$	7.68	/kW	24,294	kW		186,577.92		186,577.92		-	
Subtotal									$	259,511.25	$	259,511.25	$	-	0.00%
GRSA		28.50%			28.50%					73,960.71		73,960.71		-	
*ESA		-3.35%			-3.35%					(8,693.63)		(8,693.63)			
Base Rate Amount									$	324,778.33	$	324,778.33	$	-	0.00%
DSMCA	$	1.07	/kW	$	1.07	/kW			$	25,994.58	$	25,994.58	$	-	
PCCA	$	1.99	/kW	$	1.99	/kW			$	48,345.06	$	48,345.06	$	-	
CACJAR	**$**	**-**	**/kW**	**$**	**0.46**	**/kW**			**$**	**-**	**$**	**11,175.24**	**$**	**11,175.24**	
TCA	$	0.02	/kW	$	0.02	/kW			$	485.88	$	485.88	$	-	
ECA - Transmission On-Peak (2)	$	0.04030	/kWh	$	0.04030	/kWh			$	185,266.08	$	185,266.08	$	-	
ECA - Transmission Off-Peak (2)	$	0.02634	/kWh	$	0.02634	/kWh			$	218,429.71	$	218,429.71	$	-	
Subtotal Base Rate Adjustments									$	478,521.31	$	489,696.55	$	11,175.24	
Total Bill Subtotal									$	803,299.64	$	814,474.88	$	11,175.24	1.39%
RESA		2.00%			2.00%				$	16,065.99	$	16,289.50	$	223.51	
Total Bill									$	819,365.63	$	830,764.38	$	11,398.75	**1.39%**

(2) Assumes 35.665% on-peak and 64.335% off-peak usage factors.

Public Service Company of Colorado
Electric Department
Customer Impact Study 2016-2017
CACJA Impact Only

Please Note:
***ESA is 8/2014 rate**
****2017 Riders are held constant at 2016 level**

Customer Class	Proposed 2016 Rate		Proposed **2017 Rate		Monthly Average Usage		Proposed 2016 Bill		Proposed 2017 Bill		Monthly Difference $		Difference %
Residential - Schedule R													
Service and Facility Charge	$ 6.75		$ 6.75				$	6.75	$	6.75	$	-	
Energy Charge - Annualized	$ 0.05177	/kWh	$ 0.05177	/kWh	632	kWh		32.72		32.72		-	
Subtotal							$	39.47	$	39.47	$	-	0.00%
GRSA	28.50%		28.50%					11.25		11.25		-	
*ESA	-3.35%		-3.35%					(1.32)		(1.32)			
Base Rate Amount							$	49.40	$	49.40	$	-	0.00%
DSMCA	$ 0.00398	/kWh	$ 0.00398	/kWh			$	2.52	$	2.52	$	-	
PCCA	$ 0.00618	/kWh	$ 0.00618	/kWh			$	3.91	$	3.91	$	-	
CACJAR	**$ 0.00164**	**/kWh**	**$ 0.00147**	**/kWh**			**$**	**1.04**	**$**	**0.93**	**$**	**(0.11)**	
TCA	$ 0.00006	/kWh	$ 0.00006	/kWh			$	0.04	$	0.04	$	-	
ECA - Secondary	$ 0.03309	/kWh	$ 0.03309	/kWh			$	20.91	$	20.91	$	-	
Subtotal Base Rate Adjustments							$	28.42	$	28.31	$	(0.11)	
Total Bill Subtotal							$	77.82	$	77.71	$	(0.11)	-0.14%
RESA	2.00%		2.00%				$	1.56	$	1.55	$	(0.01)	
Total Bill							$	79.38	$	79.26	$	(0.12)	**-0.15%**

Customer Class	Proposed 2016 Rate		Proposed **2017 Rate		Monthly Average Usage		Proposed 2016 Bill		Proposed 2017 Bill		Monthly Difference $		Difference %
Commercial - Schedule C													
Service and Facility Charge	$ 10.75		$ 10.75				$	10.75	$	10.75	$	-	
Energy Charge - Annualized	$ 0.04763	/kWh	$ 0.04763	/kWh	1,123	kWh		53.49		53.49		-	
Subtotal							$	64.24	$	64.24	$	-	0.00%
GRSA	28.50%		28.50%					18.31		18.31		-	
*ESA	-3.35%		-3.35%					(2.15)		(2.15)			
Base Rate Amount							$	80.40	$	80.40	$	-	0.00%
DSMCA	$ 0.00392	/kWh	$ 0.00392	/kWh			$	4.40	$	4.40	$	-	
PCCA	$ 0.00611	/kWh	$ 0.00611	/kWh			$	6.86	$	6.86	$	-	
CACJAR	**$ 0.00162**	**/kWh**	**$ 0.00145**	**/kWh**			**$**	**1.82**	**$**	**1.63**	**$**	**(0.19)**	
TCA	$ 0.00006	/kWh	$ 0.00006	/kWh			$	0.07	$	0.07	$	-	
ECA - Secondary	$ 0.03309	/kWh	$ 0.03309	/kWh			$	37.16	$	37.16	$	-	
Subtotal Base Rate Adjustments							$	50.31	$	50.12	$	(0.19)	
Total Bill Subtotal							$	130.71	$	130.52	$	(0.19)	-0.15%
RESA	2.00%		2.00%				$	2.61	$	2.61	$	-	
Total Bill							$	133.32	$	133.13	$	(0.19)	**-0.14%**

Public Service Company of Colorado
Electric Department
Customer Impact Study 2016-2017

Customer Class	Proposed 2016 Rate	Proposed **2017 Rate	Monthly Average Usage	Proposed 2016 Bill	Proposed 2017 Bill	Monthly Difference $	Difference %
Secondary General - Schedule SG							
Service and Facility Charge	$ 40.00	$ 40.00	51.49% L.F.	$ 40.00	$ 40.00	$ -	
Energy Charge	$ 0.00473 kWh	$ 0.00473 kWh	26,685 kWh	126.22	126.22	-	
Distribution Demand Charge	$ 4.84 /kW	$ 4.84 /kW	71.00 kW	343.64	343.64	-	
G & T Demand Charge - Annualized	$ 8.99 /kW	$ 8.99 /kW	71.00 kW	638.29	638.29	-	
Subtotal				$ 1,148.15	$ 1,148.15	$ -	0.00%
GRSA	28.50%	28.50%		327.22	327.22	-	
*ESA	-3.35%	-3.35%		(38.46)	(38.46)		
Base Rate Amount				$ 1,436.91	$ 1,436.91	$ -	0.00%
DSMCA	$ 1.32 /kW	$ 1.32 /kW		$ 93.72	$ 93.72	$ -	
PCCA	$ 2.02 /kW	$ 2.02 /kW		$ 143.42	$ 143.42	$ -	
CACJAR	**$ 0.54 /kW**	**$ 0.48 /kW**		**$ 38.34**	**$ 34.08**	**$ (4.26)**	
TCA	$ 0.02 /kW	$ 0.02 /kW		$ 1.42	$ 1.42	$ -	
ECA - Secondary	$ 0.03309 /kWh	$ 0.03309 /kWh		$ 883.01	$ 883.01	$ -	
Subtotal Base Rate Adjustments				$ 1,159.91	$ 1,155.65	$ (4.26)	
Total Bill Subtotal				$ 2,596.82	$ 2,592.56	$ (4.26)	-0.16%
RESA	2.00%	2.00%		$ 51.94	$ 51.85	$ (0.09)	
Total Bill				$ 2,648.76	$ 2,644.41	$ (4.35)	**-0.16%**
Primary General - Schedule PG							
Service and Facility Charge	$ 305.00	$ 305.00	64.82% L.F.	$ 305.00	$ 305.00	$ -	
Energy Charge	$ 0.00461 kWh	$ 0.00461 kWh	492,079 kWh	2,268.48	2,268.48	-	
Distribution Demand Charge	$ 3.98 /kW	$ 3.98 /kW	1,040.00 kW	4,139.20	4,139.20	-	
G & T Demand Charge - Annualized	$ 8.03 /kW	$ 8.03 /kW	1,040.00 kW	8,351.20	8,351.20	-	
Subtotal				$ 15,063.88	$ 15,063.88	$ -	0.00%
GRSA	28.50%	28.50%		4,293.21	4,293.21	-	
*ESA	-3.35%	-3.35%		(504.64)	(504.64)		
Base Rate Amount				$ 18,852.45	$ 18,852.45	$ -	0.00%
DSMCA	$ 1.20 /kW	$ 1.20 /kW		$ 1,248.00	$ 1,248.00	$ -	
PCCA	$ 1.88 /kW	$ 1.88 /kW		$ 1,955.20	$ 1,955.20	$ -	
CACJAR	**$ 0.49**	**$ 0.44 /kW**		**$ 509.60**	**$ 457.60**	**$ (52.00)**	
TCA	$ 0.02 /kW	$ 0.02 /kW		$ 20.80	$ 20.80	$ -	
ECA - Primary On-Peak (1)	$ 0.04107 /kWh	$ 0.04107 /kWh		$ 7,762.74	$ 7,762.76	$ 0.02	
ECA - Primary Off-Peak (1)	$ 0.02684 /kWh	$ 0.02684 /kWh		$ 8,134.31	$ 8,134.31	$ -	
Subtotal Base Rate Adjustments				$ 19,630.65	$ 19,578.67	$ (51.98)	
Total Bill Subtotal				$ 38,483.10	$ 38,431.12	$ (51.98)	-0.14%
RESA	2.00%	2.00%		$ 769.66	$ 768.62	$ (1.04)	
Total Bill				$ 39,252.76	$ 39,199.74	$ (53.02)	**-0.14%**

(1) Assumes 38.411% on-peak and 61.589% off-peak usage factors.

Public Service Company of Colorado
Electric Department
Customer Impact Study 2016-2017

Customer Class	**Proposed 2016 Rate**			**Proposed **2017 Rate**			**Monthly Average Usage**			**Proposed 2016 Bill**		**Proposed 2017 Bill**		**Monthly Difference $**	**Difference %**
Transmission General - Schedule TG															
Service and Facility Charge	$	14,800.00		$	14,800.00		72.68%	L.F.	$	14,800.00	$	14,800.00	$	-	
Energy Charge	$	0.00451	/kWh	$	0.00451	/kWh	12,889,873	kWh		58,133.33		58,133.33		-	
Demand Charge - Annualized	$	7.68	/kW	$	7.68	/kW	24,294	kW		186,577.92		186,577.92		-	
Subtotal									$	259,511.25	$	259,511.25	$	-	0.00%
GRSA		28.50%			28.50%					73,960.71		73,960.71		**-**	
*ESA		-3.35%			-3.35%					(8,693.63)		(8,693.63)			
Base Rate Amount									$	324,778.33	$	324,778.33	$	-	0.00%
DSMCA	$	1.13	/kW	$	1.13	/kW			$	27,452.22	$	27,452.22	$	-	
PCCA	$	1.74	/kW	$	1.74	/kW			$	42,271.56	$	42,271.56	$	-	
CACJAR	**$**	**0.46**	**/kW**	**$**	**0.41**	**/kW**			**$**	**11,175.24**	**$**	**9,960.54**	**$**	**(1,214.70)**	
TCA	$	0.02	/kW	$	0.02	/kW			$	485.88	$	485.88	$	-	
ECA - Transmission On-Peak (2)	$	0.04062	/kWh	$	0.04062	/kWh			$	186,737.18	$	186,737.18	$	-	
ECA - Transmission Off-Peak (2)	$	0.02655	/kWh	$	0.02655	/kWh			$	220,171.18	$	220,171.18	$	-	
Subtotal Base Rate Adjustments									$	488,293.26	$	487,078.56	$	(1,214.70)	
Total Bill Subtotal									$	813,071.59	$	811,856.89	$	(1,214.70)	-0.15%
RESA		2.00%			2.00%				$	16,261.43	$	16,237.14	$	(24.29)	
Total Bill									$	829,333.02	$	828,094.03	$	(1,238.99)	**-0.15%**

(2) Assumes 35.665% on-peak and 64.335% off-peak usage factors.

Public Service Company of Colorado
Electric Department
Customer Impact Study 2015-2016

Please Note:
ESA is 8/2014 rate
All other rates relect projections for 2015 and 2016

Customer Class	Proposed 2015 Rate	Proposed 2016 Rate	Monthly Average Usage	Proposed 2015 Bill	Proposed 2016 Bill	Monthly Difference $	Difference %
Residential - Schedule R							
Service and Facility Charge	$ 6.75	$ 6.75		$ 6.75	$ 6.75	$ -	
Energy Charge - Annualized	$ 0.05177 /kWh	$ 0.05177 /kWh	632 kWh	32.72	32.72	-	
Subtotal				$ 39.47	$ 39.47	$ -	0.00%
GRSA	28.50%	28.50%		11.25	11.25	-	
ESA	-3.35%	-3.35%		(1.32)	(1.32)		
Base Rate Amount				$ 49.40	$ 49.40	$ -	0.00%
DSMCA	$ 0.00375 /kWh	$ 0.00398 /kWh		$ 2.37	$ 2.52	$ 0.15	
PCCA	$ 0.00711 /kWh	$ 0.00618 /kWh		$ 4.49	$ 3.91	$ (0.58)	
CACJAR	$ - /kWh	$ 0.00164 /kWh		$ -	$ 1.04	$ 1.04	
TCA	$ 0.00006 /kWh	$ 0.00006 /kWh		$ 0.04	$ 0.04	$ -	
ECA - Secondary	$ 0.03282 /kWh	$ 0.03309 /kWh		$ 20.74	$ 20.91	$ 0.17	
Subtotal Base Rate Adjustments				$ 27.64	$ 28.42	$ 0.78	
Total Bill Subtotal				$ 77.04	$ 77.82	$ 0.78	1.01%
RESA	2.00%	2.00%		$ 1.54	$ 1.56	$ 0.02	
Total Bill				$ 78.58	$ 79.38	$ 0.80	**1.02%**
Commercial - Schedule C							
Service and Facility Charge	$ 10.75	$ 10.75		$ 10.75	$ 10.75	$ -	
Energy Charge - Annualized	$ 0.04763 /kWh	$ 0.04763 /kWh	1,123 kWh	53.49	53.49	-	
Subtotal				$ 64.24	$ 64.24	$ -	0.00%
GRSA	28.50%	28.50%		18.31	18.31	-	
ESA	-3.35%	-3.35%		(2.15)	(2.15)		
Base Rate Amount				$ 80.40	$ 80.40	$ -	0.00%
DSMCA	$ 0.00370 /kWh	$ 0.00392 /kWh		$ 4.16	$ 4.40	$ 0.24	
PCCA	$ 0.00702 /kWh	$ 0.00611 /kWh		$ 7.88	$ 6.86	$ (1.02)	
CACJAR	$ - /kWh	$ 0.00162 /kWh		$ -	$ 1.82	$ 1.82	
TCA	$ 0.00006 /kWh	$ 0.00006 /kWh		$ 0.07	$ 0.07	$ -	
ECA - Secondary	$ 0.03282 /kWh	$ 0.03309 /kWh		$ 36.86	$ 37.16	$ 0.30	
Subtotal Base Rate Adjustments				$ 48.97	$ 50.31	$ 1.34	
Total Bill Subtotal				$ 129.37	$ 130.71	$ 1.34	1.04%
RESA	2.00%	2.00%		$ 2.59	$ 2.61	$ 0.02	
Total Bill				$ 131.96	$ 133.32	$ 1.36	**1.03%**

Public Service Company of Colorado
Electric Department
Customer Impact Study 2015-2016

Customer Class	Proposed 2015 Rate			Proposed 2016 Rate			Monthly Average Usage			Proposed 2015 Bill		Proposed 2016 Bill		Monthly Difference $	Difference %
Secondary General - Schedule SG															
Service and Facility Charge	$	40.00		$	40.00		51.49%	L.F.	$	40.00	$	40.00	$	-	
Energy Charge	$	0.00473	kWh	$	0.00473	kWh	26,685	kWh		126.22		126.22		-	
Distribution Demand Charge	$	4.84	/kW	$	4.84	/kW	71.00	kW		343.64		343.64		-	
G & T Demand Charge - Annualized	$	8.99	/kW	$	8.99	/kW	71.00	kW		638.29		638.29		-	
Subtotal									$	1,148.15	$	1,148.15	$	-	0.00%
GRSA		28.50%			28.50%					327.22		327.22		-	
ESA		-3.35%			-3.35%					(38.46)		(38.46)			
Base Rate Amount									$	1,436.91	$	1,436.91	$	-	0.00%
DSMCA	$	1.24	/kW	$	1.32	/kW			$	88.04	$	93.72	$	5.68	
PCCA	$	2.32	/kW	$	2.02	/kW			$	164.72	$	143.42	$	(21.30)	
CACJAR	$	-	/kW	$	0.54	/kW			$	-	$	38.34	$	38.34	
TCA	$	0.02	/kW	$	0.02	/kW			$	1.42	$	1.42	$	-	
ECA - Secondary	$	0.03282	/kWh	$	0.03309	/kWh			$	875.80	$	883.01	$	7.21	
Subtotal Base Rate Adjustments									$	1,129.98	$	1,159.91	$	29.93	
Total Bill Subtotal									$	2,566.89	$	2,596.82	$	29.93	1.17%
RESA		2.00%			2.00%				$	51.34	$	51.94	$	0.60	
Total Bill									$	2,618.23	$	2,648.76	$	30.53	**1.17%**
Primary General - Schedule PG															
Service and Facility Charge	$	305.00		$	305.00		64.82%	L.F.	$	305.00	$	305.00	$	-	
Energy Charge	$	0.00461	kWh	$	0.00461	kWh	492,079	kWh		2,268.48		2,268.48		-	
Distribution Demand Charge	$	3.98	/kW	$	3.98	/kW	1,040.00	kW		4,139.20		4,139.20		-	
G & T Demand Charge - Annualized	$	8.03	/kW	$	8.03	/kW	1,040.00	kW		8,351.20		8,351.20		-	
Subtotal									$	15,063.88	$	15,063.88	$	-	0.00%
GRSA		28.50%			28.50%					4,293.21		4,293.21		-	
ESA		-3.35%			-3.35%					(504.64)		(504.64)			
Base Rate Amount									$	18,852.45	$	18,852.45	$	-	0.00%
DSMCA	$	1.13	/kW	$	1.20	/kW			$	1,175.20	$	1,248.00	$	72.80	
PCCA	$	2.15	/kW	$	1.88	/kW			$	2,236.00	$	1,955.20	$	(280.80)	
CACJAR	$	-		$	0.49	/kW			$	-	$	509.60	$	509.60	
TCA	$	0.02	/kW	$	0.02	/kW			$	20.80	$	20.80	$	-	
ECA - Primary On-Peak (1)	$	0.04074	/kWh	$	0.04107	/kWh			$	7,700.37	$	7,762.76	$	62.39	
ECA - Primary Off-Peak (1)	$	0.02663	/kWh	$	0.02684	/kWh			$	8,070.66	$	8,134.31	$	63.65	
Subtotal Base Rate Adjustments									$	19,203.03	$	19,630.67	$	427.64	
Total Bill Subtotal									$	38,055.48	$	38,483.12	$	427.64	1.12%
RESA		2.00%			2.00%				$	761.11	$	769.66	$	8.55	
Total Bill									$	38,816.59	$	39,252.78	$	436.19	**1.12%**

(1) Assumes 38.411% on-peak and 61.589% off-peak usage factors.

Customer Class	Proposed 2015 Rate		Proposed 2016 Rate		Monthly Average Usage		Proposed 2015 Bill	Proposed 2016 Bill	Monthly Difference $	Difference %
Transmission General - Schedule TG										
Service and Facility Charge	$ 14,800.00		$ 14,800.00		72.68%	L.F.	$ 14,800.00	$ 14,800.00	$ -	
Energy Charge	$ 0.00451	/kWh	$ 0.00451	/kWh	12,889,873	kWh	58,133.33	58,133.33	-	
Demand Charge - Annualized	$ 7.68	/kW	$ 7.68	/kW	24,294	kW	186,577.92	186,577.92	-	
Subtotal							$ 259,511.25	$ 259,511.25	$ -	0.00%
GRSA	28.50%		28.50%				73,960.71	73,960.71	-	
*ESA	-3.35%		-3.35%				(8,693.63)	(8,693.63)		
Base Rate Amount							$ 324,778.33	$ 324,778.33	$ -	0.00%
DSMCA	$ 1.07	/kW	$ 1.13	/kW			$ 25,994.58	$ 27,452.22	$ 1,457.64	
PCCA	$ 1.99	/kW	$ 1.74	/kW			$ 48,345.06	$ 42,271.56	$ (6,073.50)	
CACJAR	$ -	/kW	$ 0.46	/kW			$ -	$ 11,175.24	$ 11,175.24	
TCA	$ 0.02	/kW	$ 0.02	/kW			$ 485.88	$ 485.88	$ -	
ECA - Transmission On-Peak (2)	$ 0.04030	/kWh	$ 0.04062	/kWh			$ 185,266.08	$ 186,737.18	$ 1,471.10	
ECA - Transmission Off-Peak (2)	$ 0.02634	/kWh	$ 0.02655	/kWh			$ 218,429.71	$ 220,171.18	$ 1,741.47	
Subtotal Base Rate Adjustments							$ 478,521.31	$ 488,293.26	$ 9,771.95	
Total Bill Subtotal							$ 803,299.64	$ 813,071.59	$ 9,771.95	1.22%
RESA	2.00%		2.00%				$ 16,065.99	$ 16,261.43	$ 195.44	
Total Bill							$ 819,365.63	$ 829,333.02	$ 9,967.39	**1.22%**

(2) Assumes 35.665% on-peak and 64.335% off-peak usage factors.