February 2021

The Distribution of U.S. Electric Utility Revenue Decoupling Rate Impacts from 2005 to 2017

Peter Cappers & Andrew Satchwell, Berkeley Lab

Max Dupuy & Carl Linvill, Regulatory Assistance Project

Investments in energy efficiency and distributed generation reduce electric utility retail sales. Since electric utilities have historically collected a large portion of revenues from volumetric energy rates (¢/kWh), such reductions in sales can impact the utility's ability to sufficiently recover non-production costs. Regulatory mechanisms that "decouple" utility revenues from sales were implemented to help make the utility indifferent to energy efficiency and distributed generation by ensuring the utility is able to collect an allowed level of revenue each year regardless of its sales. However, noticeable and consistent surcharges over time may create the perception of an incorrectly designed or implemented decoupling mechanism.

To date, there are limited quantitative analyses of the rate adjustments due to decoupling mechanisms implemented among U.S. electric utilities (see Morgan, 2013). Given the recent rapid increase in distributed energy resource (DER) adoption in some states and utility service territories, consumers may be facing more prevalent and ongoing decoupling surcharges. This, in turn, may undermine stakeholder support for implementation of decoupling mechanisms and the associated utility support for energy efficiency and DERs.

To determine the size of retail rate adjustments associated with decoupling mechanisms and whether they have a tendency towards bill surcharges or credits, we analyzed a large dataset of historical annual decoupling rate adjustments for 21 electric utilities in 11 states between 2005 and 2017. We found that decoupling mechanisms adjusted rates, both up and down, between rate cases, and the majority of those adjustments (54 percent) are small (within a range of -1 to 1 percent). However, we also found that 64 percent of the rate adjustment observations in our sample showed a positive rate adjustment. Importantly, once a surcharge is applied there is an 86 percent chance that there will be a surcharge in the next year as well.

While our analysis did not seek to understand the root causes for such results, some possible factors include the accuracy of revenue requirement forecasts, emerging structural changes in customer use and production of energy, misaligned financial motivation, and other factors that influence sales (e.g., economic recession).

Introduction

Implementation of federal policies promoting energy conservation and improved energy efficiency standards began in the 1970s (AEE, 2013). Soon thereafter, states implemented programs of their own that sought to dramatically increase the adoption of more energy efficient technologies and help consumers reduce their electricity consumption (AEE, 2013). Energy efficiency efforts have grown substantially with recently reported utility spending of ~$8 billion and ~27.1 million megawatt-hours (MWh) of energy savings in 2018 (Berg et al., 2019). At the same time, deployment of

The work described in this technical brief was funded by the U.S. Department of Energy (DOE)'s Grid Modernization Initiative through the Electricity Resilience Division of the Office of Electricity and the Solar Energy Technologies Office of the Office of Energy Efficiency and Renewable Energy under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231. If you have questions or need clarification of any points, please contact Peter Cappers at pacappers@lbl.gov. Interested in other LBNL Electricity Markets and Policy Group publications? Join our notification list here.

distributed solar photovoltaic (DPV) systems and other forms of distributed energy resources (DERs) have increased in recent years, due in part to enabling state policies (e.g., net-energy metering compensation mechanisms) and sharp declines in costs (Barbose et al., 2017). However, all of these investments (e.g., energy efficiency, DPV) ultimately reduced electric utility retail sales.

Since electric utilities have historically relied on volumetric energy rates ($/kWh) for revenue collection, such reductions in sales can have a substantial effect on a utility's ability to sufficiently recover its non-production costs.[1] Because of this, regulatory mechanisms that sought to "decouple" utility revenue from sales were implemented (Moskovitz, 1989). Such decoupling mechanisms, when properly designed, diminish the link between revenues and sales by ensuring the utility is able to collect an allowed level of revenue each year.[2] In this way, decoupling mechanisms can dampen or eliminate the effect of increased adoption of energy efficiency and DERs on utility revenue, at least in the period between rate cases.[3]

In 2017, 16 states had some form of a decoupling mechanism in place (Berg et al., 2019), and the number of decoupling mechanisms may increase given continuation of ratepayer-funded energy efficiency programs and increased DER penetration.[4] Meanwhile, state and utility efforts are pursuing electrification (i.e., increased adoption of technologies that rely on electricity instead of some other power source). The U.S. Energy Information Administration (EIA) predicts sharp increases in the sale of electric vehicles and electricity use in the transportation sector after 2020 (EIA, 2019). This may limit utilities' support for decoupling, as such mechanisms will credit customers back for revenue collected in excess of any authorized levels, due to the increase in sales between rate cases.

Decoupling mechanisms may either increase or decrease retail rates and customer bills. If a utility collects less revenue than it is authorized, then customers see higher retail rates and thus experience higher bills due to a decoupling surcharge. Conversely, if the utility is over-collecting relative to authorized levels, then customers will see a rate reduction and a lower bill by way of a decoupling credit.

Decoupling rate adjustments, at a more granular level, are due to many interrelated factors, including accuracy of revenue requirement forecasts, emerging structural changes in customer use and energy production, and other factors that influence sales (e.g., weather, macroeconomy). Although many of these factors are beyond the utility's control, decoupling mechanisms often have been implemented

---

[1] We use the term "non-production costs" throughout this technical brief to refer to utility costs that do not vary with energy consumption in the short run. See Lazar et al. (2011) for a description of production and non-production costs.
[2] A decoupling mechanism is designed to ensure that a utility collects an authorized level of revenue over a particular period of time. This is done by comparing what was actually collected over that particular period of time (e.g., quarterly, semi-annually or annually) with what was authorized by the utility's regulators. Any shortfall or excess over that time period is identified, and in the following time period a surcharge or refund is levied against the utility's customers to offset the shortfall or excess.
[3] This has been extensively discussed both qualitatively (see Eto et al., 1997; Moskovitz et al., 2000; Kihm, 2009; Lazar et al., 2011) and quantitatively (see Cappers et al., 2009; Satchwell et al., 2011, 2017).
[4] For example, New Mexico adopted legislation in 2019 that allows either the Public Regulation Commission or a utility to propose a revenue decoupling mechanism (State of New Mexico, 2019). Similarly, 2019 legislation in Nevada (that currently has decoupling in effect for electric utilities) directs the Commission to consider alternative ratemaking approaches, including amendment of the current decoupling mechanism (State of Nevada, 2019).

in conjunction with utility obligations to deliver energy efficiency savings. And, as experience with decoupling mechanisms grew among states and utilities, their designs were modified and adapted to better incentivize utility cost management while still trying to address lost revenue concerns (Migden-Ostrander and Sedano, 2016). In this environment, noticeable and consistent surcharges over time may create the perception of an incorrectly designed or implemented decoupling mechanism. This, in turn, may undermine stakeholder support for the implementation of decoupling mechanisms and the associated utility support for energy efficiency and DERs. Regulators, therefore, are particularly interested in the range of and general temporal trends in decoupling-related customer bill adjustments.

To date, there are limited quantitative analyses of decoupling rate adjustments among U.S. electric utilities. One study (Morgan, 2013) reviewed 10 years of rate adjustments associated with decoupling mechanisms implemented by U.S. electric utilities and found fairly symmetrical trends of refunds and surcharges. Given recent increases in the implementation of decoupling mechanisms, as well as increased adoption of energy efficiency and DERs, it is worth reassessing the direction and magnitude of the rate impacts associated with decoupling mechanisms. Accordingly, we analyze a dataset of historical annual rate adjustments for 21 electric utilities that had a decoupling mechanism in place for more than three years by 2017. We assess the distribution of annual decoupling mechanism rate impacts between 2005 and 2017 to determine if there are tendencies towards refunds or surcharges.

Background: Issues and Design Choices for Decoupling Mechanisms

In the most general sense, traditional rate-of-return regulation sets rates during a general rate case, which apply until the next general rate case establishes a new schedule of rates. Such rates are predominantly based on average, not marginal, costs. In the period of time between rate cases, the revenue of the utility is dependent on the level of billing determinants, which is largely driven by electricity sales. As described in Eto et al. (1997), if a utility's marginal costs are greater than its average costs, then a unit increase in sales will produce a larger increase in revenue than in costs. This will result in the utility experiencing an increase in earnings. This link between sales, revenues and earnings is called the *throughput incentive*. The throughput incentive, therefore, motivates utilities to increase revenues (and thereby earnings) by promoting efforts that increase sales. In contrast, activities like energy efficiency and the adoption of DPV have the effect of reducing sales, which will in turn reduce earnings, under the same assumed utility financial conditions (i.e., marginal costs exceed average costs).

Decoupling mechanisms were introduced, in large part, to mitigate the throughput incentive (Moskovitz, 1989) and can be designed in a number of different ways to accomplish this goal (Migden-Ostrander and Sedano, 2016). Some of the key design decisions include the following:

- **Type of costs to be recovered**. During a general rate case, the utility develops a revenue requirement based on its cost of service to meet a set of functional responsibilities. If the utility is vertically integrated, then it owns and operates central-station electric plants that generate electricity for its customers. Alternatively, if the generation market has been deregulated or restructured, then the utility must procure electricity for its customers, instead of generating it, which is frequently considered to be solely a variable cost. Electric utilities have two other potential functional responsibilities: (1) to transmit electricity on a high-voltage bulk-power grid they own and operate; and (2) to distribute that electricity directly to customers via lower voltage power grids they likewise own and operate. Decoupling mechanisms may be applied to costs associated with any of these functions, but are generally limited to distribution and/or transmission functions. In addition, specific types or categories of costs within a particular function may or may not be eligible for inclusion in the decoupling mechanism. For example, regulators in non-restructured states with decoupling make different choices regarding which functional non-production costs to include, ranging from those that include distribution service non-production costs only to those that include distribution, transmission and even generation non-production costs.

- **Allocation of costs, surcharges and refunds**. In addition to functionalizing costs, the utility must determine how to allocate those costs to the different customer classes and rate schedules within those customer classes as part of its efforts during a general rate case. Likewise, a decoupling mechanism can be designed to collect an authorized revenue requirement associated with all or a subset of customer classes and/or rate schedules, and as such may only apply to customers in those specific classes and/or taking service under those specific rate schedules. When determining the revenue adjustment that must be made between rate cases, some decoupling mechanisms make the comparison of authorized revenues and actual revenues on a class/rate schedule by class/rate schedule basis, calculating an adjustment just for that group of customers. Other mechanisms perform the comparison on the aggregate of authorized and actual revenues across all rate schedules and calculate one adjustment applicable to each included rate schedule. Sometimes the allocation is even done in a way to meet policy goals, such as to better support low-income customers. For example, some utilities allocate refunds to the lowest tier in an "inclining block" rate structure, while allocating surcharges to the highest tier.

- **Change in the authorized revenue requirement between rate cases**. The functions and specific cost elements within those functions eligible for inclusion in the decoupling mechanism determine the authorized revenue the utility may collect under the decoupling mechanism. In some cases, no adjustment may be made to the authorized revenue requirement once it is set; such changes may only be made when a utility files its next rate case. The decoupling mechanism acts to deliver the authorized revenue requirement set during the last general rate case. In other instances, the regulator may authorize the application of a decoupling mechanism that is designed to allow for changes in the authorized revenue requirement between general rate cases. For example, the decoupling mechanism may tie the authorized revenue requirement to the number of customers served (i.e., revenue-per-customer decoupling) or forecasted load growth during some period of time. Alternatively, the decoupling mechanism may allow the authorized revenue requirement to change based on some predetermined measure of cost inflation (i.e., stair-step) or based on unexpected changes in the rate base or operating expense since the last rate case decision (i.e., attrition).[5]

[5] Large rate base additions are typically excluded from the attrition mechanism and held for consideration in the next general rate case.

Data Sources

Data on estimates of the rate adjustments associated with electric utility decoupling mechanisms were collected for the period of 2005 through 2017 following the data sources (i.e., publicly available state regulatory filings) and methodology in Morgan (2013) and Lesh (2009a, 2009b). The prior work noted complexity of establishing a dataset of decoupling adjustments and wide variation in "conventions around what utilities and commissions call things [and] what information appears in filing letters." (Lesh, 2009b, p. 70). Given the complexity and non-standard typologies, we use the previously-established data collection methodology and update it to evaluate a longer time period.

For analysis and reporting purposes, we establish several data screens and thresholds. First, a utility must have reported at least three consecutive years of rate adjustment estimates to be included in our sample so as to provide a reasonable time series; but for any additional years the estimate need not be contiguous (e.g., rate adjustment estimates for Western Massachusetts Electric Company were found for 2012 and 2014–2017).[6] Second, because utilities began implementing and/or reporting rate adjustment estimates for their decoupling mechanism at different times, our sample includes the earliest year for which an estimate could be found. However, we did not require that all utilities have the same number of years of rate adjustments estimates for inclusion in our data sample. Third, some utilities reported rate adjustment estimates at the customer class level, while others reported this metric across all customer classes.[7] Where available, we opted for the most granular (i.e., individual customer class) estimates as possible.

Several utilities update decoupling adjustments more than once per year. For example, utilities in the sample from Maryland and the District of Columbia all file new "bill stabilization adjustments" on a monthly basis. The New York utilities file for decoupling adjustments on an intermittent basis, sometimes several times per year. In each of these cases, we averaged sub-annual decoupling adjustments to produce annual figures. [8]

The details of the full data sample are shown in Table 1.[9] Overall, our sample includes 11 states and the District of Columbia, 21 utilities, and 46 unique utility and customer class combinations.[10] Following prior work (Morgan, 2013; Lesh, 2009a, b), we collected the following data:

- decoupling mechanism rate adjustments from utility filings (typically in $/kWh), and

---

[6] In a very limited number of instances, a utility failed to report (or the authors failed to locate) a rate adjustment estimate during a contiguous period of time.

[7] In most of the utilities studied, the utility applied a separate adjustment for each class. In the limited other cases, the utility applied a uniform adjustment to several classes.

[8] That is, we average the decoupling adjustment that applies in each of the 12 months of a given year to get the annual adjustment.

[9] The sample does not include all states with decoupled electric utilities. See Sullivan and DeCostanzo (2018) for a complete assessment of electric (and gas) decoupling mechanisms in the United States. Due to difficulties in isolating the effects of decoupling from other rate adjustment factors, we opted to omit rate impacts from electric utilities in Vermont. In addition, although electric utilities in Colorado, Illinois, Maine, Minnesota and Washington have adopted decoupling, it has been too recent to have enough annual data points to warrant inclusion.

[10] For example, Delmarva-residential is one utility-class and Delmarva-general service is another. Where a utility applies one adjustment to multiple customer classes, we consider this time series to be a single utility class.

- average annual bundled retail rate ($/kWh) for the relevant class (calculated from Energy Information Agency Form 861 revenues and sales).[11]

These data allow us to calculate a percentage annual rate adjustment that is the ratio of the decoupling mechanism's rate adjustment to the average annual bundled retail rate for each observation in the data sample.

Table 1: States, Utilities, Rate Classes and Time Periods Included in Sample[12]

State	Utility	Customer Classes	Time Period Covered in the Updated Dataset
CA	Pacific Gas & Electric	1 (A)	2005–2017
CT	United Illuminating	1 (A)	2009–2017
HI	Hawaiian Electric Company	1 (A)	2011–2017
ID	Idaho Power Company	2 (C, R)	2007–2017
MA	Mass Electric & Nantucket Electric (National Grid)	2 (C, R)	2011–2017
MA	Fitchburg Gas & Electric	2 (C, R)	2012–2017
MA	Western Mass Electric	2 (C, R)	2012–2017
MD	Baltimore Gas & Electric	2 (GS, R)	3/2008–12/2017
MD	Potomac Electric Power	2 (GS, R)	3/2008–12/2017
MD	Delmarva	2 (GS, R)	3/2008–12/2017
NY	Central Hudson	4 (see footnote[13])	10/2009–12/2017
NY	Consolidated Edison	3 (see footnote[14])	11/2008–12/2017
NY	Niagara Mohawk (National Grid)	2 (Small GS, R)	7/2011–12/2017
NY	New York State Electric & Gas	2 (GS, R)	2011– 2017
NY	Rochester Gas & Electric	2 (GS, R)	2011–2017
NY	Orange & Rockland	3 (GS, Small GS, R)	9/2008–12/2017
OR	Portland General Electric	2 (C, R)	2010–2017
RI	Narragansett Electric (National Grid)	1 (R)	2012–2017
DC	Potomac Electric Power	2 (GS, R)	1/2010–12/2017
OH	Duke Energy	2 (Small C, R)	2014–2016
OH	Ohio Power (American Electric Power)	4 (see footnote[15])	2014– 2017
WI	Wisconsin Public Service[16]	2 (R/small C, C)	2009–2013

[11] Annual Electric Power Industry Report, Form EIA-861 detailed data files, available at: https://www.eia.gov/electricity/data/eia861/. At the time of writing, 2018 EIA-861 utility-specific data was not yet available. Where we include 2018 rate impact data, we used statewide data on retail rates, from EIA's Electric Power Monthly, available at: https://www.eia.gov/electricity/monthly/. Our use of these average retail rates may obscure some variation in decoupling rate impacts across customers, particularly in the case of the industrial and commercial classes, which are typically more diverse than residential customers.
[12] We use the following abbreviations for customer classes: A for all; C for commercial; GS for general service and R for residential.
[13] Our dataset includes a separate decoupling rate adjustment utility-class series for Central Hudson's commercial and industrial (C&I) non-demand, C&I primary demand, C&I secondary demand, and residential customer classes.
[14] Our dataset includes a separate decoupling rate adjustment utility-class series for Consolidated Edison's large general service, small general service, and residential customer classes.
[15] Ohio Power applies separate decoupling rate adjustments for Commercial (Columbus Southern Power Rate Zone), Commercial (Ohio Power Rate Zone), Residential (Columbus Southern Power Rate Zone), and Residential (Ohio Power Rate Zone).
[16] Decoupling in Wisconsin was discontinued after 2013.

Analysis and Results

Table 2 presents summary statistics for annual rate adjustments on a percentage basis associated decoupling mechanisms for the overall sample (2005–2017). Positive numbers denote decoupling mechanism surcharges to customers, while negative numbers reflect refunds to customers. On average, decoupling mechanisms across our sample resulted in rate adjustments of 0.4 percent of all-in average retail rates, with a median annual rate adjustment of 0.2 percent, a maximum of 11.4 percent, and a minimum of -4.2 percent.

Table 2. Summary Statistics from the Full Data Sample

	2005–2017
Max	11.4%
Average	0.4%
Median	0.2%
Min	-4.2%
Std Dev	1.8%
N	352

Figure 1 shows the distribution of rate adjustments for the entire data sample. Fifty-four percent of the observations had an annual rate adjustment between -1 percent and 1 percent, suggesting that the majority of rate adjustments were relatively modest, in percentage terms. However, 64 percent of the 352 rate adjustment observations in our sample were positive, suggesting there is a tendency towards decoupling mechanism surcharges.

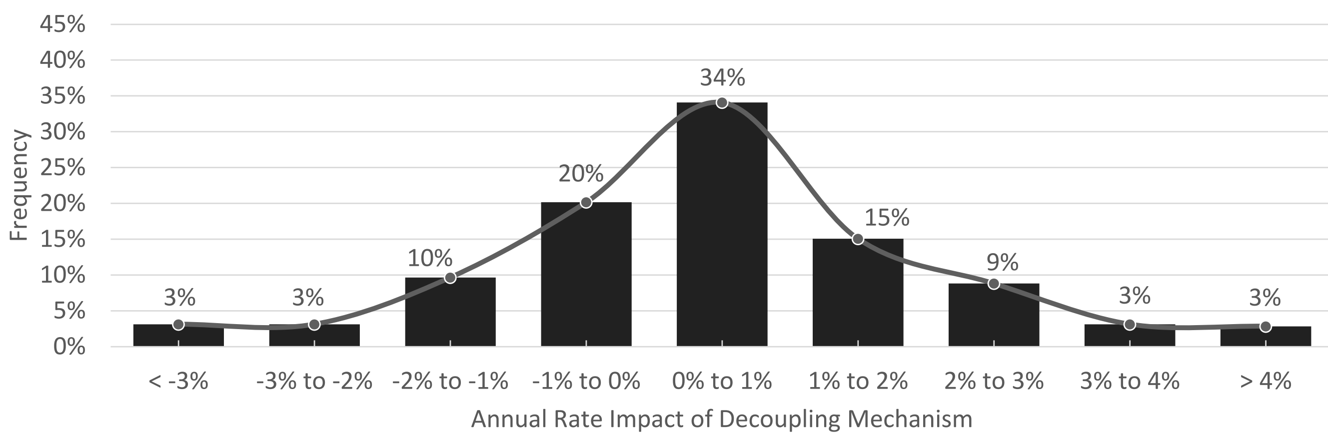

Figure 1. Frequency distribution of annual rate adjustments of decoupling mechanisms

Figure 2 depicts for each unique combination of utility and customer class as shown in Table 1 (row) whether the annual rate adjustment is a surcharge (black) or a credit (gray). Entries in white represent missing data for that unique combination of utility, customer class and year. Most decoupling mechanisms exhibit a sustained annual pattern of credits or surcharges over consecutive years, based on visual inspection.

As discussed earlier, persistent surcharges may suggest the revenue decoupling mechanism is improperly designed or implemented. Whether the decoupling mechanism (or its implementation) is flawed or this is merely the perception among stakeholders, the success of ratepayer-funded energy efficiency (or other distributed energy resource) programs may be undermined.

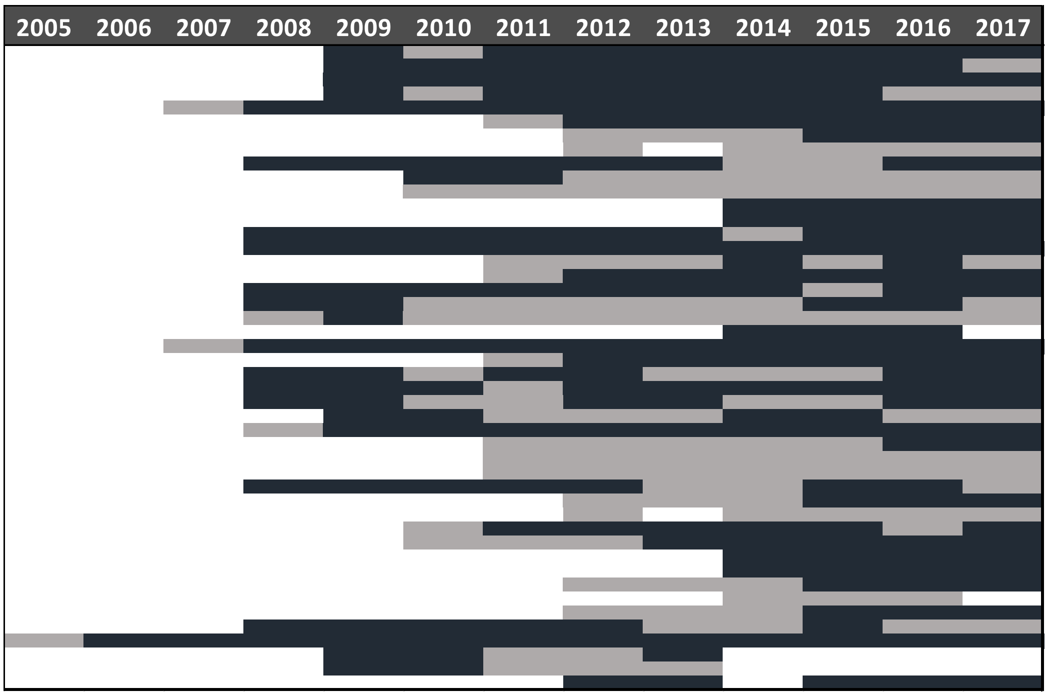

Figure 2. Annual rate adjustments of decoupling mechanisms for each unique combination of utility and customer class: Surcharges (Black) vs. Credits (Grey)

One way to more systematically assess the persistence of the decoupling mechanisms' rate adjustments is to assume that this is a random process in which the future rate impact is independent of the past, given the current year's rate impact. In other words, we want to know what the probability is of moving from one state (i.e., surcharge or credit) in the current year to either that same state or the other state in the following year. This is known as a Markov chain, and it can be applied to the data in our sample, where each observation is characterized as either being a surcharge or a credit (i.e., the level of the surcharge or credit is irrelevant).[17] From there, for each unique combination of utility and customer class (i.e., rows in Table 1), we determine the frequency with which that decoupling mechanism moves from one state in a given year to another state in the following year (e.g., surcharge to surcharge, surcharge to credit, credit to surcharge,

[17] There are three basic assumptions associated with Markov Chain analysis. First, there must be a finite number of possible states. In our case, there are only two possible states: surcharge or credit. Second, the size and makeup of the system does not change during the analysis. In this case, we know that utility rates are set during infrequent rate cases (e.g., 2–5 years on average). Thus, rates do not change appreciably, if at all, from one year to the next. In addition, annual changes in sales, which likewise drive collected utility revenue, do not change dramatically from one year to the next (e.g., even aggressive energy efficiency and distributed generation deployment would not suggest rapid and dramatic changes in sales on an annual basis). Furthermore, the main exogenous drivers (e.g., weather, macroeconomy) for what is likely to substantially affect sales growth does exist and are oftentimes incorporated into the decoupling mechanism to mitigate their effect (Migden-Ostrander and Sedano, 2016). Third, the probability of changing states remains the same over time. Although our analysis does focus on a contiguous 12 year period, there are only eight annual rate adjustments in our sample for a unique combination of utility and customer classes (our cross-sections), on average. Given the relatively short time horizon for the majority of our data observations, the frequency of rate cases, and the various design elements available to mitigate year-to-year variations in key drivers of the decoupling mechanism, it seems reasonable to assume that the probabilities of changing states does not change dramatically over time.

credit to credit). Then we sum the frequencies for each of the four state change options across all combinations of utility and customer classes and divide them by the total number of opportunities for a state change from a particular starting state in our data sample (i.e., 202 opportunities where the decoupling mechanism exhibited a surcharge and could then move to either a surcharge or a credit, and 107 opportunities where the decoupling mechanism exhibited a credit and could then move to either a surcharge or a credit).[18] This produces an average probability of moving from one state to another across the entire data sample.

Applying this methodology, we can see in Figure 3 that if a decoupling mechanism in our sample produced a surcharge in a given year, there was an 86 percent probability a surcharge would be applied in the following year but only a 14 percent chance that a credit would instead be observed. Alternatively, if a decoupling mechanism produced a credit in a given year, there was a 69 percent probability that next year another credit would be applied but only a 31 percent chance of a surcharge.

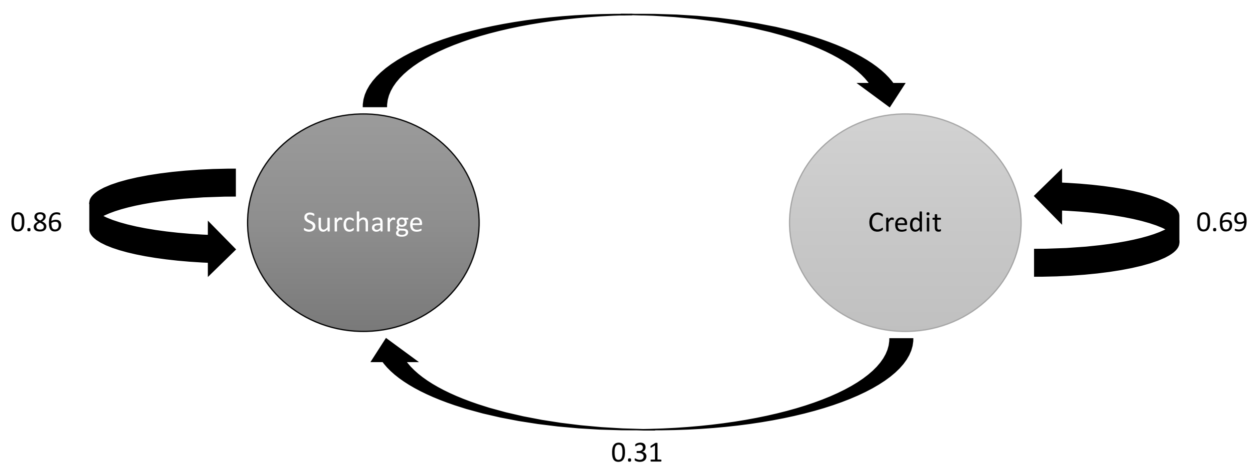

Figure 3. Markov Chain Transition Probabilities for Annual Decoupling Mechanism Surcharges/Credits

Conclusions

Our analysis of data collected on annual rate adjustments from decoupling mechanisms between 2005 and 2017 for 21 utilities in 11 states representing 46 unique combinations of utility and customer classes revealed modest surcharges and refunds (on a percentage change basis). Overall, these results indicate that decoupling mechanisms adjust rates, both up and down, between rate cases, and the majority of those adjustments (54 percent) are small (within a range of -1 to 1 percent). However, we also find that not only do a majority (64 percent) of the 352 decoupling rate adjustment observations show a positive rate adjustment, once a surcharge is applied there is an 86 percent chance that there will be a surcharge in the next year as well.

The data shows that revenue decoupling mechanisms result in both refunds and surcharges with a tendency towards small retail rate increases. Two possible conclusions may be drawn about revenue

[18] State change probabilities can only be derived where there are observations for a given combination of utility and customer class in successive years. As can be seen from Figure 2, state change probabilities can neither be derived for observations in the final year of the analysis (as there are no data for which to determine the state of the decoupling mechanism in the following year) nor for observations that lack decoupling mechanism rate adjustments in the following year (i.e., where a black/grey block is followed by a white block). The result is a total number of observations that assess these state changes (n=309) which is smaller than the full data sample (n=352).

decoupling mechanisms. First, they are working as intended to collect additional revenue from customers in order to counteract the impacts of energy efficiency and DPV on retail sales. Second, the revenue decoupling mechanisms themselves, or underlying forecasting practices, may be poorly designed or incorrectly implemented. While our analysis did not seek to understand the root causes for such results, some possible factors include the accuracy of revenue requirement forecasts, emerging structural changes in customer use and production of energy, misaligned financial motivation (Kihm, 2009), and other factors that influence sales (e.g., economic recession).

Therefore, a more systematic assessment and characterization of decoupling mechanisms, their design, and their interaction with other regulatory practices and utility planning practices would be useful. This would help regulators and utilities understand what is driving revenue decoupling surcharges and assess whether surcharges are appropriate.

Acknowledgements

We would like to thank Elaine Ulrich and Joe Paladino (U.S. DOE) for their support of this project. We would also like to thank Pamela Morgan for very valuable advice and information regarding data sources, methodology, and interpretation – and also for comments on early drafts. We also thank Joe Eto (Berkeley Lab) for guidance and feedback. Lastly, we would like to thank Mark LeBel, Megan O'Reilly, John Shenot, Jessica Shipley, and Joni Sliger of Regulatory Assistance Project for contributions to research and data collection. Any remaining errors or omissions are our own.

References

AEE (2013) The History of Energy Efficiency. Alliance to Save Energy. January.

Barbose, G., Dargouth, N., Millstein, D., LaCommare, K. H., DiSanti, N. and Widiss, R. (2017) Tracking the Sun 10: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States. Lawrence Berkeley National Laboratory, Berkeley, CA. September 2017. LBNL-2001062.

Berg, W., Vaidyanathan, S., Junga, E., Cooper, E., Perry, C. N., S., Relf, G., Whitlock, A., DiMascio, M., Waters, C. and Cortez, N. (2019) The 2019 State Energy Efficiency Scorecard. American Council for an Energy-Efficient Economy. October. Report U1908.

Cappers, P., Goldman, C., Chait, M., Edgar, G., Schlegel, J. and Shirley, W. (2009) Financial Analysis of Incentive Mechanisms to Promote Energy Efficiency: Case Study of a Prototypical Southwest Utility. Lawrence Berkeley National Laboratory, Berkeley, CA. March. LBNL-1598E.

EIA (2019) Annual Energy Outlook 2019 with Projections to 2050. Energy Information Administration, Washington, D.C.

Eto, J., Stoft, S. and Belden, T. (1997) The Theory and Practice of Decoupling Revenues from Sales. *Utilities Policy*. 6(1):43-56.

Kihm, S. (2009) When Revenue Decoupling Will Work... And When It Won't. *The Electricity Journal.* 22(8): 19-28.

Lazar, J., Weston, F. and Shirley, W. (2011) Revenue Regulation and Decoupling: A Guide to Theory and Application. Regulatory Assistance Project, Montpelier, VT. June.

Lesh, P., 2009a. Rate Impacts and Key Design Elements of Gas And Electric Utility Decoupling: A Comprehensive Review. Graceful Systems LLC. June.

Lesh, P., 2009b. Rate impacts and key design elements of gas and electric utility decoupling: a comprehensive review. Electr. J. 22 (8), 65–71.

Migden-Ostrander, J. and Sedano, R. (2016) Decoupling Design: Customizing Revenue Regulation to Your State's Priorities. The Regulatory Assistance Project, Montpelier, VT.

Morgan, P. (2013) A Decade of Decoupling for U.S. Energy Utilities: Rate Impacts, Designs, and Observations. Graceful Systems LLC. Prepared for Regulatory Assistance Project,. February.

Moskovitz, D. (1989) Profits and Progress through Least-Cost Planning. National Association of Regulatory Commissioners, Washington D.C.,. November.

Moskovitz, D., Harrington, C., Cowart, R., Shirley, W. and Weston, F. (2000) Profits and Progress through Distributed Resources. The Regulatory Assistance Project, Gardiner, ME. February.

Satchwell, A., Cappers, P. and Goldman, C. (2011) Carrots and Sticks: A Comprehensive Business Model for the Successful Achievement of Energy Efficiency Resource Standards. *Utilities Policy.* 19(2011): 218-225.

Satchwell, A., Cappers, P. and Goldman, C. (2017) Financial Impacts of a Combined Energy Efficiency and Net-Metered PV Portfolio on a Prototypical Northeast Utility. Lawrence Berkeley National Laboratory, Berkeley, CA. April. LBNL-1007280.

State of Nevada (2019). *Revises provisions governing the rates charged by electric utilities.* Nevada Senate Bill No. 300.

State of New Mexico (2019). *Efficient Use Of Energy Act Changes*. New Mexico House Bill No. 291.

Sullivan, D. and DeCostanzo, D. (2018) Electric and Gas Decoupling. Natural Resource Defense Council. August.

Disclaimer and Copyright Notice