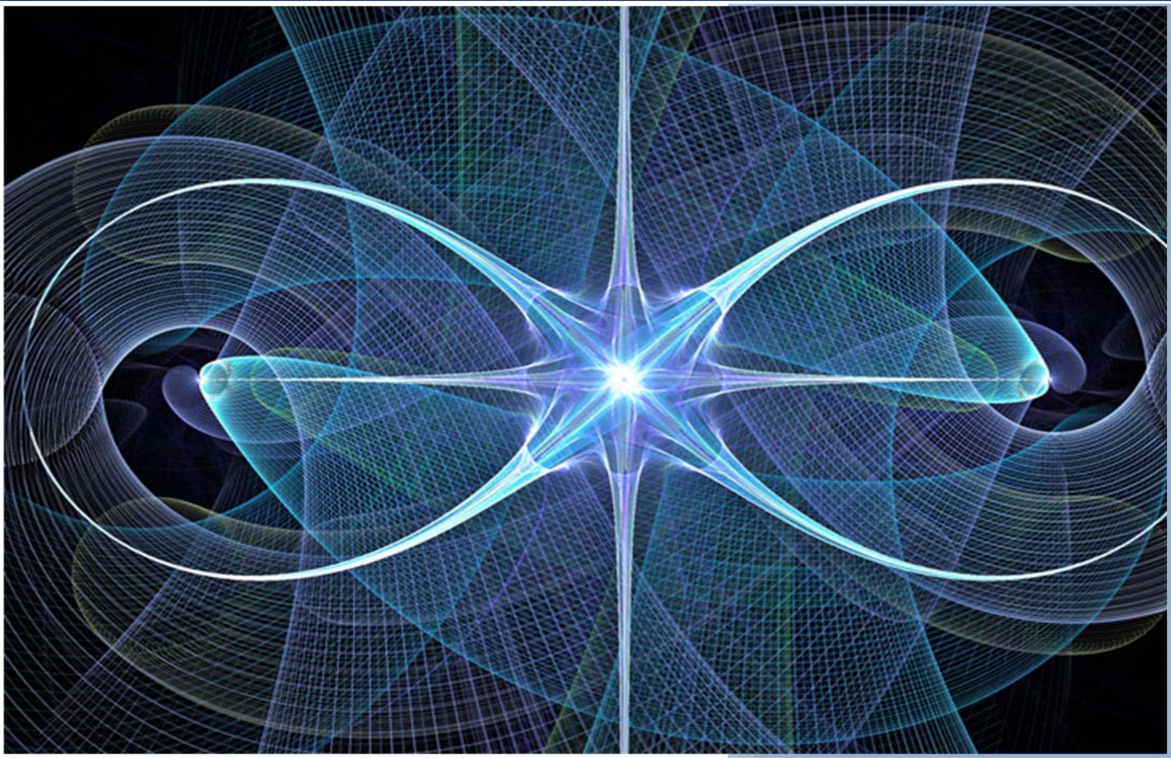
A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations



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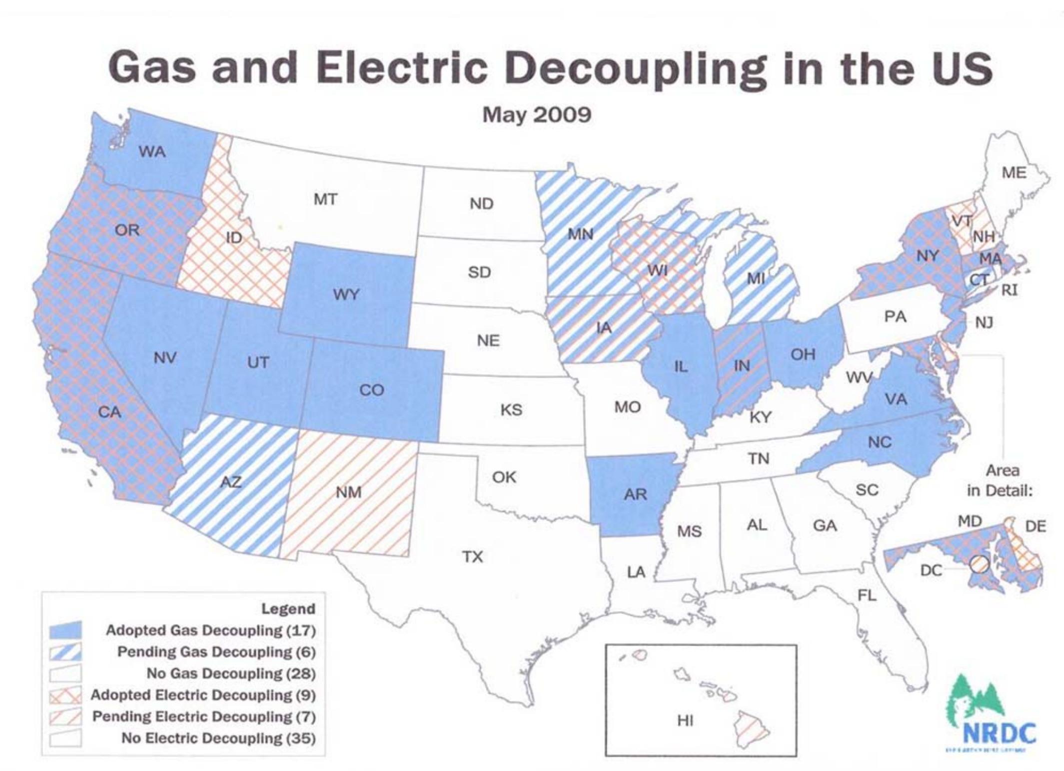
Summary

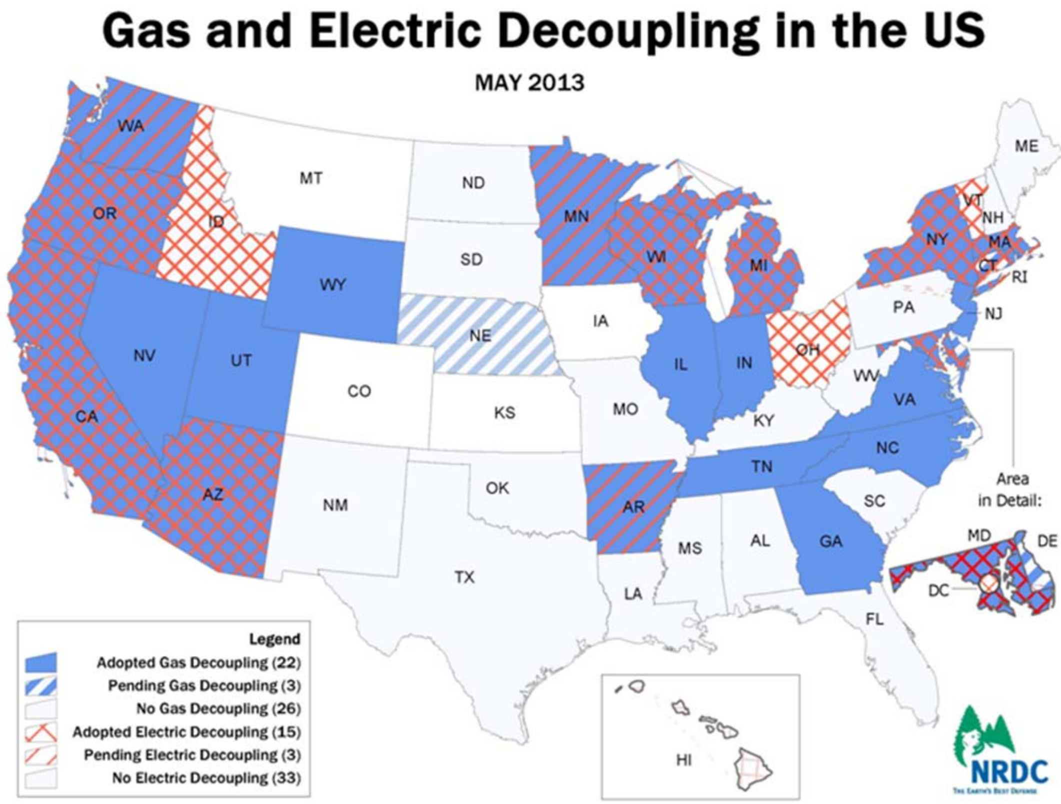
With the turn of the century and its many energy-related events – the western power market crisis, record and unexpected natural gas prices, slowing (electricity) or falling (natural gas) demand, growing concern about climate change – energy utility funding for energy efficiency programs revived after 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 pproaches 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.

Now covering 26 states and the District of Columbia, including 50 LDCs and 27 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:

[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. The state reports also include Colorado, which had approved gas decoupling but the mechanism has now expired, and Vermont, which has an alternate form of regulation that can, at times, function as a partial decoupling mechanism. In addition, several of the utilities are combination utilities, including both electricity and natural gas. The count includes a combination utility as two: one for electric and one for natural gas.

[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.

- **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] 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.

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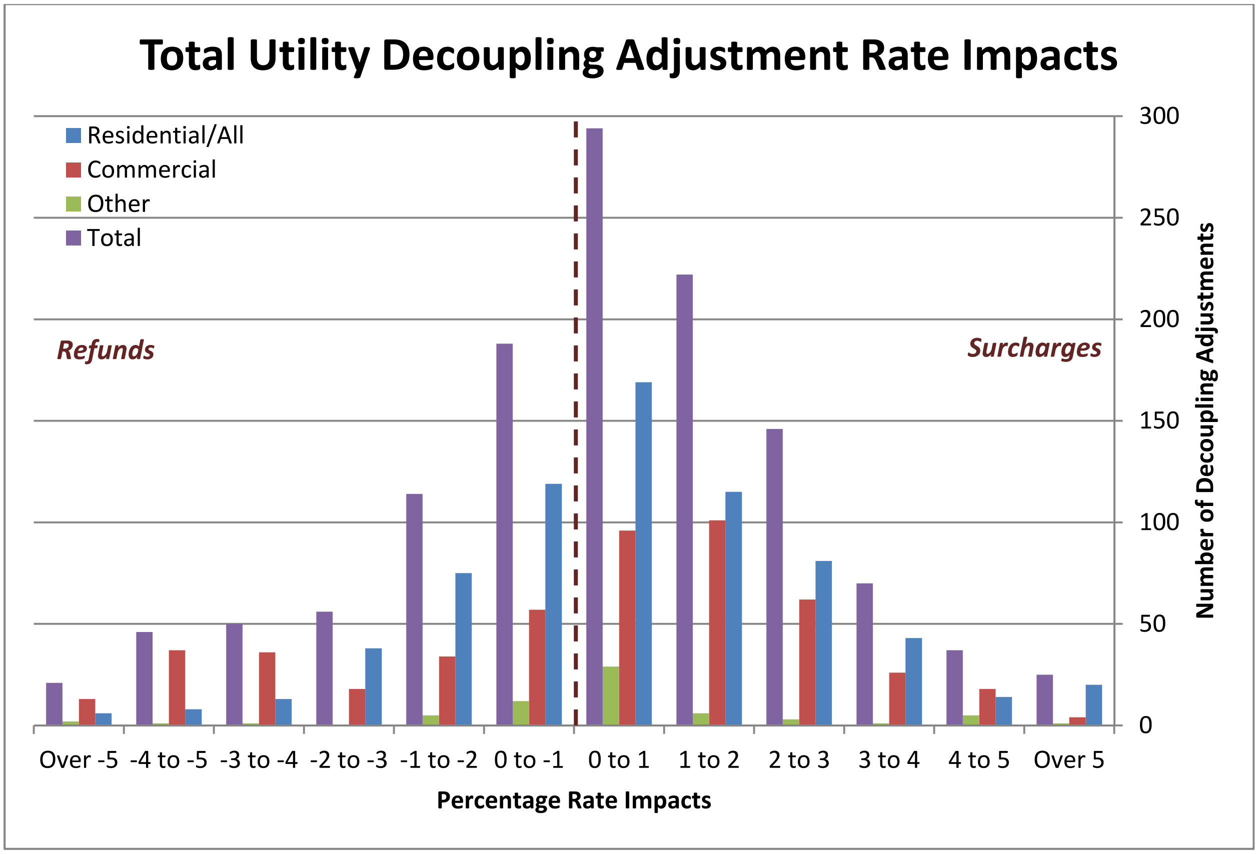
[4] The electric calculation uses an average monthly consumption of 1000 kWh and the 2010 annual average residential price of 11.54¢/kWh from the Energy Information Administration (EIA). An average monthly consumption does not make as much sense for natural gas customers because usage is seasonal. EIA's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



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.

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.

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

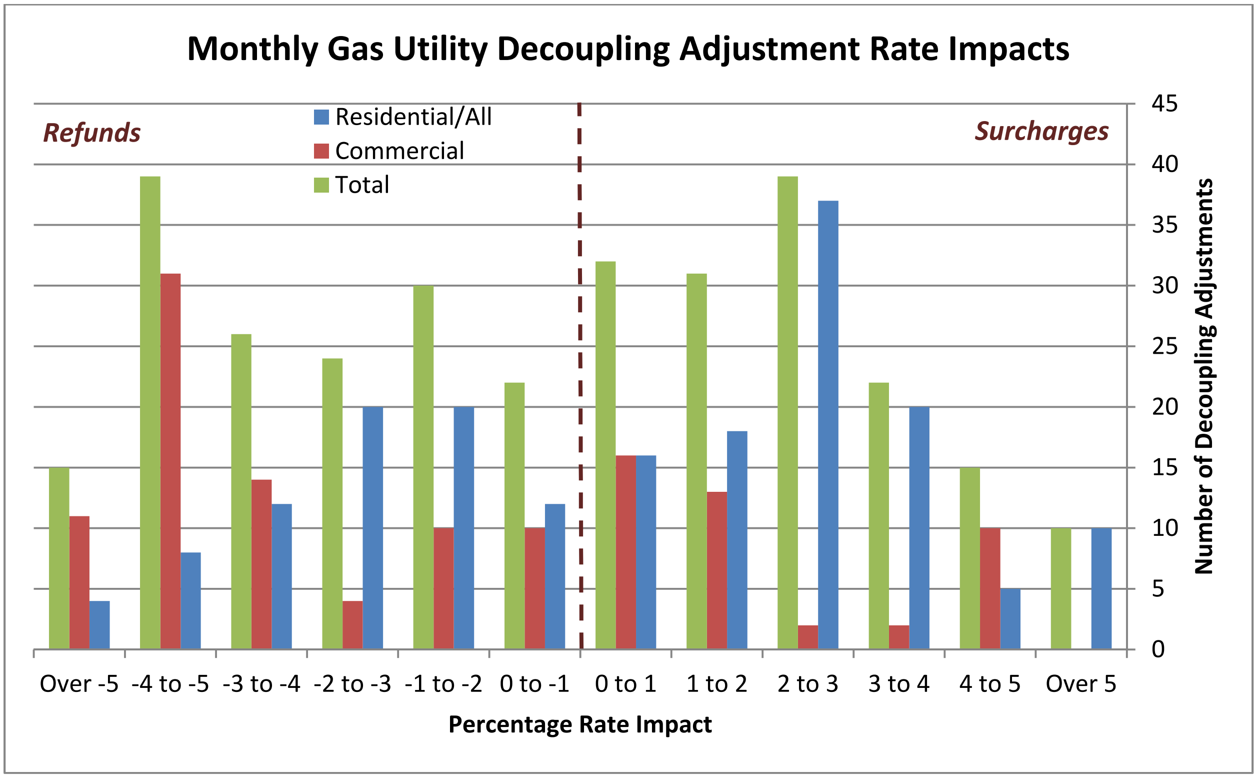
Below are chart/table sets for gas utilities that make decoupling adjustments monthly and those that make decoupling adjustments annually or on some frequency other than monthly, and the same two sets for electric utilities. Overall, the charts reveal some differences in the distribution of surcharges 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%

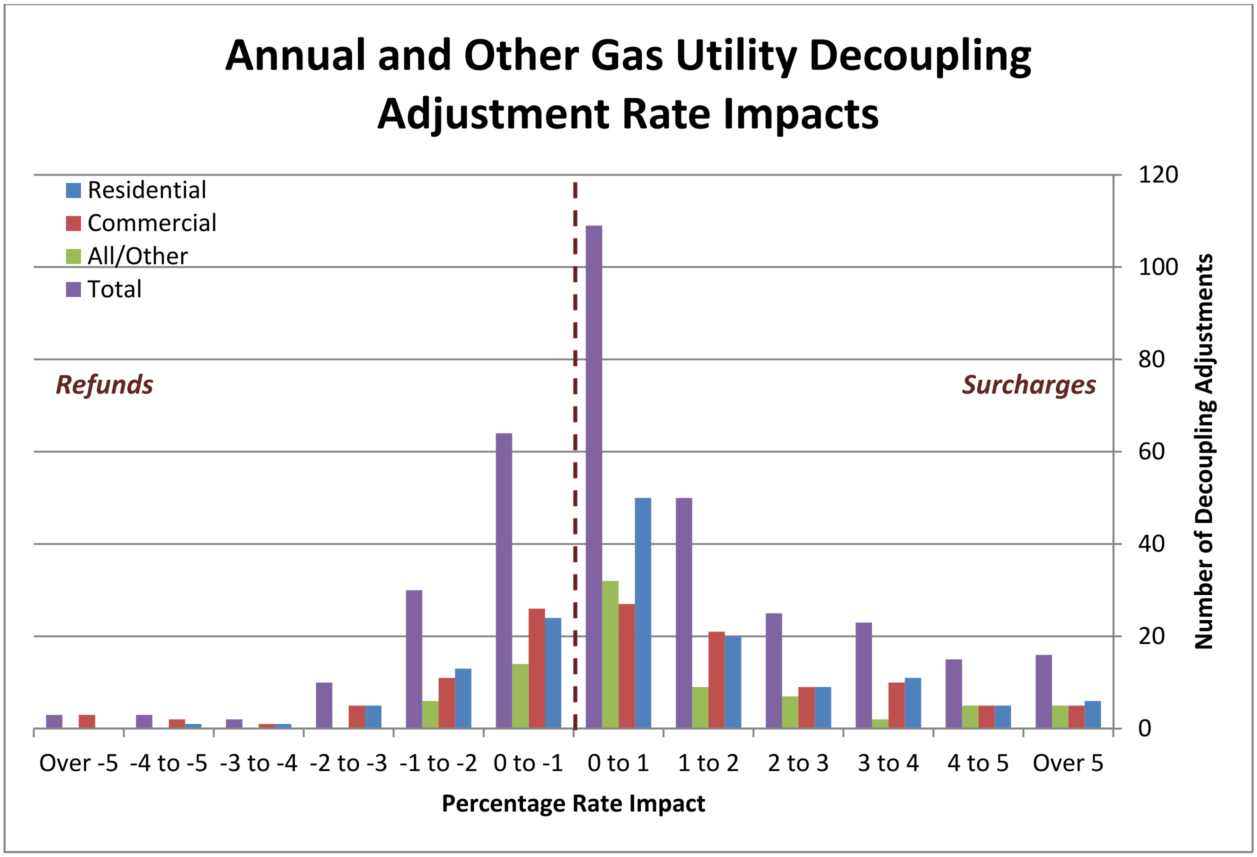
[11] For natural gas utilities, these fixed costs are virtually all of their fixed costs, although some pipeline-related fixed costs may flow through purchased gas cost adjustment clauses. For electric utilities, the limitation to distribution fixed costs stems from state retail market restructuring, 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.

The charts and tables below follow this order:

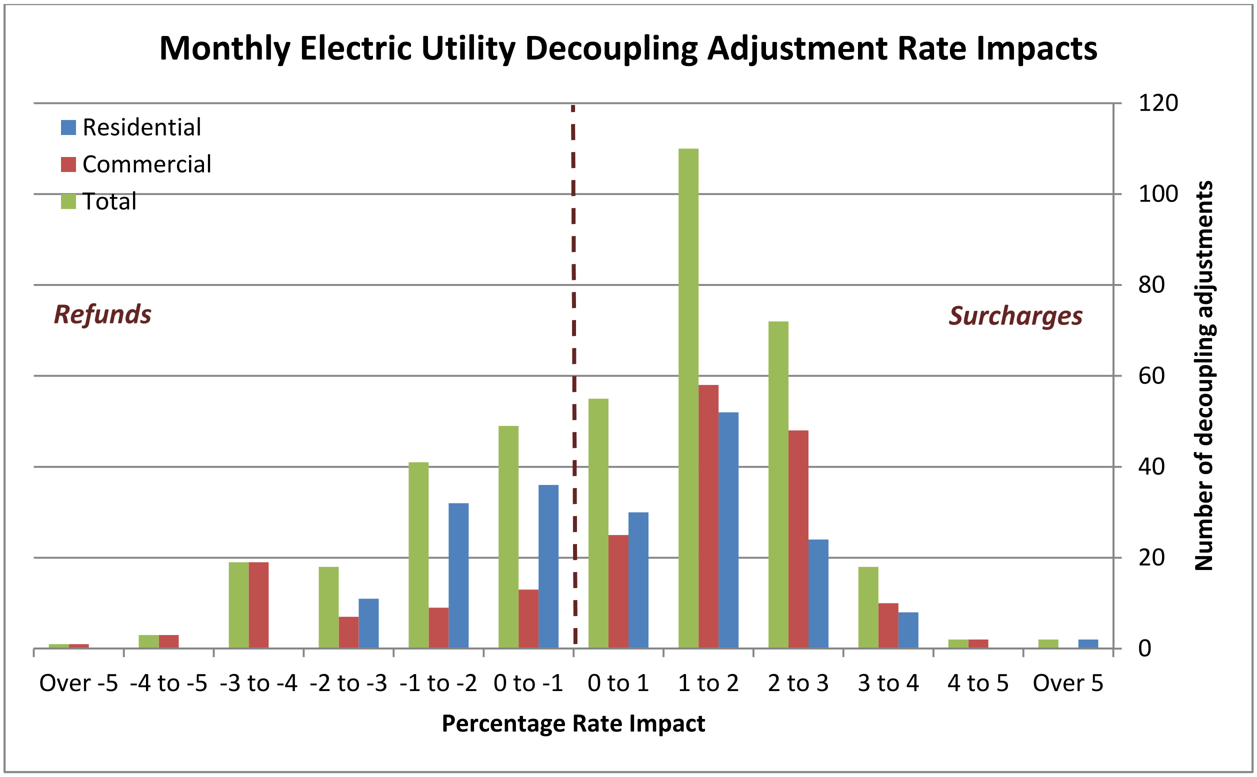
- Monthly gas utility decoupling mechanisms
- Annual and other gas utility decoupling mechanisms
- Monthly electric utility decoupling mechanisms
- Annual and other electric utility decoupling mechanisms



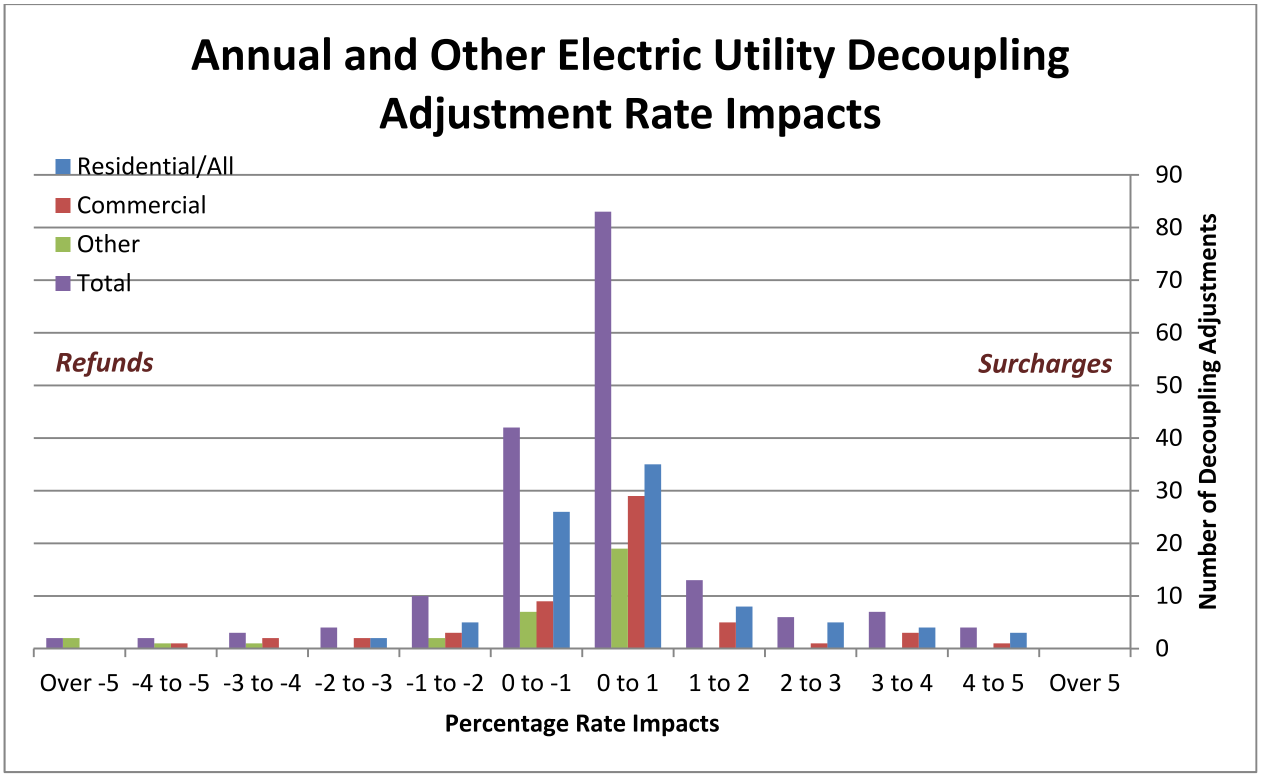
Adjustment Amount %	Residential/All	Commercial	Total
Over 5	10		
4 to 5	5	10	15
3 to 4	20	2	22
2 to 3	37	2	39
1 to 2	18	13	31
0 to 1	16	16	32
0 to -1	12	10	22
-1 to -2	20	10	30
-2 to -3	20	4	24
-3 to -4	12	14	26
-4 to -5	8	31	39
Over -5	4	11	15



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



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



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?

- 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

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.

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[14]	Result of Settlement Agreement?
None	60	29
10 basis points	8	4
25 basis points	3	1
50 basis points	4	
Total	75	34

As the table demonstrates, the large majority of decisions adopting decoupling make no ROE reduction. Of the reductions that occurred, 10 basis points[15] 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.

[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] Two of the decisions cover combination utilities. For purposes of this table, I have counted the combination utility as only one because the order applied to both sides of the company.
[15] Basis points are hundredths of a percent. Thus, 9.10% is 910 basis points; 50 basis points is 0.5%.

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 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.[16] 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.

[16] 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.

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.**[17] 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.

[17] 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.

- **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.[18]
- **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?[19] 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[20] 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

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[18] 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.
[19] 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.
[20] 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.

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.