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MISSOURI PUBLIC SERVICE COMMISSION
CASE NO. ER-2010-0036
DIRECT TESTIMONY
OF
PAMELA G. LESH
ON
BEHALF OF

THE NATURAL RESOURCES DEFENSE COUNCIL

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I. Background and Qualifications

Q. Please state your name, address, and affiliation.

A. My name is Pamela Lesh. My address is 17 Masaryk, Lake Oswego, Oregon 97035. I am President of Graceful Systems, LLC, the company I formed after I finished my 20+ year career at Portland General Electric (PGE). Graceful Systems consults with utilities, regulators, providers of services and equipment to utilities, and other stakeholders on regulatory strategy and systems approaches to creating opportunities and solving problems. I recently completed work as a Senior Advisor to the Natural Resources Defense Council (NRDC), on loan to that organization from PGE, for which I was Vice President of Regulatory Affairs and Strategic Planning. At NRDC, I worked on national energy policy issues of importance to electric utilities, including a major review of the results of decoupling policies nationwide.

Q. What are your educational background and professional qualifications to appear in this proceeding?

A. I am a graduate of Washington State University and the University of Washington School of Law. I first entered the energy utility field in 1984, representing industrial customers of electric and natural gas utilities in the Pacific Northwest. In 1986, I joined PGE as Associate General Counsel. I held a variety of positions at PGE concerned with regulation, becoming Vice President of Regulatory Affairs in 1996. I briefly left PGE in 1997 to work for a software and services company called ConneXt. I re-joined PGE in 1999 as Vice President of Regulatory Affairs, responsible for state and federal economic regulation among other things, including strategy as of 2004. During the years in Regulatory Affairs, I worked on many matters pertinent to these dockets, including:

- The preparation and review of Integrated Resource Plans, including renewable resources;
- Design and approval of energy efficiency programs;
- All aspects of cost recovery related to energy efficiency, including the collaborative development of a decoupling mechanism that was in place for PGE during 1995 and 1996;
- The development of regulatory guidelines on competitive bidding and subsequent Requests for Proposal done by PGE under those guidelines;
- The development and filing of avoided costs;
- All cost and rate related matters, including recovery of costs associated with a prolonged coal plant outage in 2005/6 and forecasting and recovery of net variable power costs;
- Regulatory accounting; and
- Cost of capital, including the issue of imputed debt from long-term contractual commitments.

In addition, my roles in Regulatory Affairs, Strategy, and Government Affairs required that I be conversant with many electricity and energy policy issues, including those involved in these dockets.

For NRDC, I appeared as witness in the recent Iowa rate case by Black Hills Energy (BHE), testifying in support of BHE's proposed decoupling mechanism and recommending that the Iowa Utilities Board put in place a performance-based energy efficiency incentive program for BHE. I also testified for NRDC regarding the Energy Optimization and Renewable Energy Plans filed by Consumers Energy and Detroit Edison in response to recent Michigan legislation.

Q. On whose behalf are you testifying?

A. I am appearing for NRDC, a party to this case.

Q. What materials have you reviewed in preparation of this testimony?

A. I have reviewed all of the direct testimony filed by AmerenUE in this docket, with particular attention to the testimonies of Stephen Kidwell, Warner Baxter, and Wilbon Cooper.

II. Summary of Recommendations

Q. What is NRDC's overall recommendation in this case?

A. NRDC recommends that the Missouri Public Service Commission (MPSC) strongly support AmerenUE’s efforts to increase significantly the services it provides its customers to help them improve the efficiency with which they use electricity, and support the creation of a regulatory environment for Missouri utilities that encourages the most efficient use of energy resources. Specifically, we recommend that the Commission:

- Require that AmerenUE increase its 2009 – 2011 goals for the amount of energy efficiency savings its customers achieve through Ameren’s programs and services;

- Approve a tracking mechanism by which AmerenUE recovers, on a timely basis, all of the costs it incurs in providing energy efficiency programs and services, including the cost of independently-provided evaluation and verification of its programs;
- Approve a simple decoupling mechanism that neutralizes AmerenUE's incentive to increase sales of electricity, in a fair and balanced manner for AmerenUE's customers and investors;
- Approve a performance-based energy efficiency incentive mechanism that provides AmerenUE an income opportunity for providing energy efficiency programs and services to customers; and
- Require that AmerenUE secure independent evaluation and verification of savings achieved under its programs.

These are the five policy "legs" that we have found best support a utility in meeting a stated goal of helping its customers achieve all cost-effective energy efficiency through the most effective means.

III. Introduction

Q. What is the context in which NRDC is making its recommendations in this docket?

A. The context of NRDC's recommendations is the advent of a decade – 2010 to 2020 – in which America's electric utilities must focus, first and foremost, on helping their customers increase their energy efficiency. The value of energy efficiency goes far beyond postponing a new, fossil (or nuclear) fueled generating plant. Increasing energy efficiency:

- **Improves economic competitiveness**: commercial and manufacturing businesses that use less energy to provide services or produce goods have lower costs and are, therefore, more competitive. In addition, engaging in efforts to reduce energy use often results in updated processes and equipment that improve productivity.
- **Maintains or increases quality of life for electricity consumers**: energy efficiency measures in homes not only reduce energy bills but often provide other benefits as well, including increased comfort, greater capability of appliances, and heightened control over energy use.
- **Provides a path to reduce carbon emissions from existing resources at a net negative cost to society**: energy efficiency is no longer just the best way to meet future growth in electricity use but is also the most cost-effective way to reduce the generation of electricity through means that emit carbon dioxide.
- **Decreases dependence on energy resources from sources outside of Missouri or even the United States**: Missouri obtains virtually all of its fossil fuels for electricity generation from outside the state and some of the natural gas may well come from Canada. Energy efficiency, in contrast, is a resource the spending on which occurs in Missouri.
- **Provides local jobs**: Auditing premises, installing measures, and providing ongoing energy efficiency assistance all involve local jobs. Given the large potential for cost-effective savings, these are not temporary construction jobs,

as often accompany a new generating plant, but permanent jobs across many trades and skill-bases.

In sum, energy efficiency can lower the cost to customers of meeting their energy needs today, and provide even greater savings over time. Lower bills help both residential and smaller business customers; continued access to a low, embedded cost resource base helps larger business customers, who can also benefit greatly from the process improvements that often accompany investments of money and time in increasing energy efficiency.

Energy efficiency is both the lowest cost means of meeting future energy demand and the least costly way to reduce our nation's carbon emissions. Every day presents opportunities to save money for a Missouri resident or business and reduce carbon emissions through increasing the efficiency with which Missouri applies electricity to power its homes and businesses. These savings are significant. AmerenUE projects cumulative savings of nearly 800,000 MWh to result from all of the measures installed in the next three years. With a benefit-to-cost ratio of almost two to one – as estimated by AmerenUE – the value of these savings is high, particularly when one realizes that much of the dollars spent to achieve the savings goes to Missouri businesses, for personnel or equipment, rather than for out-of-state coal and natural gas resources.

Similarly, every day that Missouri does not increase energy efficiency is full of lost opportunities. Every home or business built without the advantage of the best we can do to minimize its future costs and maximize its value through energy efficient design and implementation is an opportunity lost. Every dollar burned into the air to power inefficient lights or unnecessary appliances is a dollar not circulating in the local economy, supporting jobs and enhancing community.

Q. Does the Missouri Energy Efficiency Investment Act address the value of energy efficiency to utility customers?

A. Yes. Section 393.1124.4 establishes a goal for utility demand-side programs "of achieving all cost-effective demand-side savings."

IV. The Commission should require that AmerenUE increase its 2009-2011 energy efficiency goals.

Q. What are AmerenuE's energy efficiency goals?

A. AmerenUE plans to help its customers save about 800,000 MWhrs over the three years ending in 2011. Kidwell, p. 12, l. 1 – 13. AmerenUE indicates that these savings have a Total Resource Cost ratio of 1.8, or almost two to one. Id. This assessment apparently comes from AmerenUE's last Integrated Resource Plan (IRP). I could not confirm this, or see the underlying calculations, because many of the documents in the IRP docket were marked "Highly Confidential," and thus were unavailable. I suspect this is a conservative indicator of the value of the savings AmerenUE proposes to pursue. ACEEE recently completed a study of the Total Resource Cost associated with 14 utilities' energy efficiency programs and found a range from 2.2 to 3.6, with an average value of 2.6 [1] Based on my experience, many assessments of TRC overstate the cost of the energy efficiency (or understate its benefits) and understate the cost of alternatives such as new generation.

[1] "Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs, Friedrich et al., September 2009, Report Number U092. See page 8 for summary results.

Using 2008 FERC Form 1 data on AmerenUE's sales as a proxy for sales in each of these three years, the savings reach about 0.7 percent of AmerenuE's retail load. AmerenUE's proposed program spending is about 1.2 percent of revenues over this period, using this rate case test year's revenue requirement as a proxy for period revenues.

Q. How do AmerenUE's savings goals and expenditures compare to others?

A. I conclude that AmerenUE's goals are significantly lower than even the lowest end of the spectrum for the Midwest. At these levels, AmerenUE will fall short of the goal of all cost-effective conservation, to the detriment of its customers.

Illinois has an annual Energy Efficiency Portfolio Standard (EEPS) of 2% of retail load by 2015[2], with Minnesota at 1.5%,[3] Iowa at 1.5%,[4] Michigan at 1% by 2012,[5] Ohio at 1% by 2014 and 2% by 2019[6], and Indiana at 1.1% by 2014 and 2% by 2019.[7] As of November 2009, 17 states had an EEPS.[8] In addition, in 2007, KCP&L agreed to a 300 MW savings goal, even though it is a much smaller utility than AmerenUE.

Q. Why are you recommending that the Commission require that AmerenUE increase its three-year goals for energy efficiency savings?

[2] SB 1592 (2007). The law requires that utilities reach 1% of retail load annually by 2012.
[3] New Generation Energy Act of 2007 (Minnesota Statutes 2008 § 216B.241).
[4] Docket No. 199IAC 35.4(1) (EEP-02-38, EEP-03-01, EEP-03-04), 2009 Iowa Code Title XI, Subtitle 5, Ch. 476.
[5] PA 295 (SB213) establishes an energy efficiency resource standard (known as an "energy optimization savings standard") for utilities. Electric utilities must achieve 0.3% savings in 2009; 0.5% in 2010; 0.75% in 2011; and 1.0% in 2012 and each year thereafter.
[6] 2008 Senate Bill 221 or Ohio Revised Code 4928.66 requires a gradual ramp-up to a 22% reduction in electricity use by 2025. Starting in 2009, electric distribution utilities must achieve 0.3% savings, ramping up to 1% per year by 2014 and then jumping to 2% per year in 2019 through 2025. The legislation also requires electric distribution utilities to reduce peak demand by 1% in 2009 and to continue to achieve an additional 0.75% reduction per year until 2018.
[7] Cause No. 42693.
[8] See, http://www.aceee.org/energy/state/policies/StateEERSSummaryNov-2009.pdf

A. The primary reason for NRDC's recommendation that AmerenUE increase its goals is because the potential is so large. Both the Electric Power Research Institute (EPRI) and McKinsey recently estimated the cost-effective savings available to the United States through 2020, with EPRI identifying 473 TWh and McKinsey 1080 TWh.[9]

In addition, higher goals help set the expectations necessary for higher performance. Organizations have long recognized the value of stretch goals. Stretch goals are not about imposing penalties if the person, organization, or – in this case – utility fails to achieve the stretch. These are goals to help the person, organization or utility setting the goals align budget, systems, and intangible factors behind the higher level and try their best to achieve it. I address below NRDC's recommendations for a performance-based incentive for AmerenUE that works on this basis.

Q. Do you have specific goals to recommend?

A. Yes. AmerenUE should adopt goals that reach 1.5% by around 2012 and 2% by 2015. These goals are in line with the other Midwest states.

V. The Commission should approve a cost tracker mechanism for AmerenUE to recover its energy efficiency expenditures.

Q. Do you agree with AmerenUE that its current method of recovering energy efficiency costs is inadequate?

A. Yes. The current cost recovery mechanism compares unfavorably to best practices across the country. Accruing energy efficiency expenditures as a regulatory

[9] The EPRI Report can be found at http://my.epri.com/portal/server.pt?space=CommunityPage&cached=true&parentname=ObjMgr&parentid=2&control=SetCommunity&CommunityID=404&RaiseDocID=000000000001016987&RaiseDocType=Abstract_id. The McKinsey Report is at http://www.mckinsey.com/clientservice/ccsi/pdf/US_energy_efficiency_exc_summary.pdf.

asset that can earn only at a utility's AFUDC rate and amortize over ten years has numerous drawbacks, including a return that is lower than that afforded supply-side investments, considerable risk and uncertainty associated with the ten year amortization, and cash flow implications.

Q. Does NRDC support AmerenUE's request to include its planned expenditures for energy efficiency in base rates and then track any differences, positive or negative, for handling in its next rate case?

A. Yes. AmerenUE's proposal provides it current cash flow to operate its programs, as well as coverage should those programs become more popular than expected and demand for the incentives rise. It also protects customers if the reverse happens – programs are not as successful as hoped – although that is not an outcome that is in customers' longer-term interest.

AmerenUE's proposal does not specify whether it includes costs for evaluation and verification. NRDC strongly urges that the base rate/tracker proposal include these costs.

Q. Are there any other features of this proposal for handling energy efficiency program expenditures that you consider important?

A. Yes, it is important that both customers (through the Commission and stakeholders active in AmerenUE's regulatory matters) and AmerenUE know the "rules of the game" for recovery before AmerenUE spends the money. Particularly when a state does not have a long period of experience with energy efficiency programs such that mutual expectations exist, uncertainty about recovery of planned expenditures can impede aggressive utility efforts to help customers save.

In an ideal situation, creating mutual expectations occurs as follows, after the setting of goals through the IRP process or otherwise. First, the utility and stakeholders agree to a set of savings associated with the various measures included in the utility's programs. Initially, this is often done through use of evaluated and verified reports from other states and utilities that have similar customers, electricity uses, and measures. Second, the utility designs its programs and there is a period in which regulatory review of the design occurs, when stakeholders and the Commission can question particular choices and categories of cost. This stage may also include budgets and a budget review, although it is important that the utility not be limited to a budget if the reason for spending more is that a program has proven more popular than anticipated and more customers want to make use of the incentives. Third, the utility runs its programs, recovering the costs per a tracker such as AmerenUE proposes and calculating whether it should earn an incentive using the savings levels in place for that period. Independent evaluation and verification specific to the utility should begin as soon as its programs begin and, fourth, as those results come in, the verified savings levels substitute for the initial savings levels on a going-forward basis. It is also useful for the utility to support a standing committee that reviews the evaluation and verification results and consults with the utility on the implications of those for program design and future measure selection.

It is not clear what process AmerenUE's current energy efficiency programs have followed, including whether stakeholders had an opportunity to agree on initial savings levels or review the program designs. To the extent that has not occurred, the

Commission may want to cause that to happen as it acts on the cost recovery proposal and considers an incentive.

Q. Why shouldn't the savings evaluated and verified for AmerenUE's specific programs be used as they are available for any cost recovery or incentives pending at that time?

A. In my experience, this risk and uncertainty to the utility resulting from this practice costs customers far more in terms of a significant reduction in the utility's willingness to aggressively seek savings than it gains them in terms of costs that may be disallowed or incentives denied. Requiring that everyone agree on (or the Commission choose) a set of savings estimates that will apply until replaced by a better set protects customers from unsupported savings estimates without creating needless uncertainty for the utility.

I further discuss NRDC's recommendations around verification and evaluation below.

VI. The Commission should approve a revenue decoupling mechanism for AmerenUE.

Q. Is AmerenUE proposing a revenue decoupling mechanism (RDM) in this case?

A. No.

Q. Why is NRDC nevertheless strongly recommending that the Commission approve an RDM?

A. An RDM is the only regulatory policy that eliminates a utility's incentive to increase sales of electricity, as well as ensure that the savings it helps its customers achieve do not come at the cost of its bottom line. Among the alternatives that exist, an RDM is best for utility customers because it:

- Does not compensate the utility for revenue “lost” through the operation of energy efficiency programs that was actually not lost because of increases in usage elsewhere in the system, as lost revenue recovery can do; and
- Does not deprive customers of the highest possible short-term economic benefits of energy efficiency, as various rate design solutions (such as straight- fixed variable) can do.

And, an RDM is best for utilities because it permits them to stop focusing on selling more and more electricity and permits them to begin orienting their business to helping customers use energy wisely instead.

Q. Why is an RDM so important to long-term achievement of energy efficiency goals?

A. The Missouri regulatory status quo, and the business model that results from it, unintentionally undercuts utility engagement in this highly important purpose of increasing energy efficiency. The current business/regulatory model is the one designed in the early part of the 20th century to facilitate infrastructure construction, first of electricity and then of natural gas, for use in our homes and businesses. It drives this result by focusing on sales of these two commodities and rewarding business efforts to increase consumption and build more infrastructure. In the short term, both types of utilities do better financially the more of the commodity that customers use. This means, of course, that the business/regulatory model also penalizes utility investors for any reductions in customers' use of these commodities, regardless of the merit in the actions causing or enabling the reduction in consumption and regardless of the benefit accruing to customers when they can achieve their desired outcomes - personal or business - with less expense.

The lack of alignment between AmerenUE's business/regulatory model and what Missouri now expects of it creates a barrier to the synergy that AmerenUE could otherwise achieve in concert with its customers. Missouri residents and businesses face significant barriers to the adoption of all cost-effective energy efficiency – energy efficiency that will provide enormous long-term benefit to their state. It makes no sense to attempt to overcome these barriers and simultaneously maintain a business and regulatory model for its utilities that orients their business success to ever-increasing consumption of electricity.

The old business/regulatory model produces no sustainable benefit to customers; a business/regulatory model aligned with ever-increasing customer efficiency in the use of electricity and natural gas will produce sustainable benefits for customers and the state as a whole.

Q. Is there an analogy that helps understand the policy disconnect in a state pursuing all cost-effective energy efficiency without addressing the underlying utility business model built on sales?

A. Yes, I have one I like to use. Imagine for a moment that you are driving north on a narrow, twisty road and you realize you need to go south. What is the first thing you must do? STOP.

Let's add to this scene that the car is an energy utility and that the northbound lane of this road is the sale of kilowatt-hours and therms. Once we STOP, we can turn around and being work on the process of driving south. South is energy services that include not only the sale of kilowatt-hours or therms, but also the services that make each of those as valuable and useful as possible for the customer, minimizing their total cost of energy services over time, not just the input cost. Decoupling through an RDM means the car can stop driving north and, with full engagement of stakeholders, figure out what going south might look like.

Some argue that we have to keep energy utilities driving north, seeking ever more sales of primary and secondary energy, BUT at the same time looking in the rearview mirror at the southern direction so that these utilities can offer their customers energy efficiency incentives to spur the adoption of specific measures and technologies. The problem with driving one direction while you are looking in the rearview mirror is:

- You can't go very fast in either direction, but momentum continues to pull the car north.
- You're not looking north and may not even see what is happening.
- Everyone in the system, energy utilities, customers, and stakeholders alike, is confused.

If we allow these energy utilities to STOP, we can expect not just continued strong performance under the energy efficiency programs they offer but also:

- Greater utility interest in supporting their customers in changing their behavior around energy use, running the spectrum from information, to the ability to respond, and then to the ability to manage;
- A review of policies, such as those for line extensions and distribution equipment sizing, that may have been appropriate when the goal was enabling easy growth

in the use of electricity and natural gas but that do not fit with the needs of the coming decades; and

- Greater willingness to experiment with new, optional price designs to complement energy efficiency programs and behavioral work or with services that include equipment, energy and energy management systems.

We can also expect these energy utilities to take some of the time and space created by stopping and think about the capabilities and characteristics of the distribution system of the future, to envision that system as a network that enables sharing of local generation and storage resources and works with the transmission grid and remote resources to make more use of fixed assets and less use of fossil fuels.

AmerenUE is embarking on a significant increase in its energy efficiency spending and goals. This case is a perfect time for the Commission to allow it to stop its "car" through an RDM.

Q. Do you see in this filing signs that AmerenUE is still looking north – toward higher electricity sales?

A. Yes, I see this in several places. One of the most obvious is the design in effect for winter electric rates to residential and smaller commercial customers. AmerenUE is still offering declining block rates. These rates signal to customers that, the more they use, the less each unit costs. In the context of energy efficiency, declining block rates lengthen payback periods for energy efficiency improvements. Many states long since abandoned declining block designs when it became clear that the marginal price of electricity exceeded the embedded price. Some have adopted inverted rates instead and, in some cases, the blocks are quite steep. Without decoupling, it would be foolish for AmerenUE to even consider changing these out-dated rate designs.

AmerenUE's proposal to increase its customer charge is a less obvious illustration of a continuing focus on sales but it serves the same purpose as declining block rates, just to a smaller extent. The support AmerenUE offers for this proposal is couched in terms of the effect energy efficiency savings has on its revenues: "AmerenUE has embarked on an aggressive energy efficiency and demand response effort to give customers more control over their energy usage and to lower their bills via reduced consumption. Therefore, the Company is proposing material increases in customer charges and corresponding reductions in the percentage of revenue derived from volumetric or consumption charges for these classes." Cooper, p. 23, l. 3-22. This change will also lengthen payback periods for customers who choose to invest in energy efficiency.

Another passage from the rate spread and rate design testimony indicates AmerenUE is still very much looking "north" to selling electricity, rather than "south" to helping its customers with energy services designed to get them the outcomes they need at the lowest possible use of energy and outlay of cost. The passage states: "A third consideration is that of competition. Cost-based electric rates permit the Company to compete effectively with alternative fuels, co-generation and other electric utilities for new commercial and industrial customers." Cooper, p. 16, l. 20 – p. 17, l. 5. An often-overlooked benefit of decoupling is that it removes the disincentive utilities otherwise face pro-actively to assist their customers with net metering or combined heat and power projects. The former can result in emissions savings, even if they do not directly reduce energy consumption and the latter can markedly improve the customer's energy efficiency.

Q. How much difference can an energy efficiency program make to a utility's short-term profitability?

A. A strong, successful energy efficiency program can make a significant difference to a utility's profitability, which is why an RDM is so important. In a 2008 Report to the Minnesota Public Utility Commission on decoupling, the Regulatory Assistance Project (RAP) provided an example to illustrate the effect of changes in sales, both up and down, on a utility's earnings.[10] In the hypothetical, a 1% change in revenues had an effect about ten times greater on utility earnings; for example, a 2% gain or loss in revenues caused a 23.76% gain or loss in earnings. The extent to which some portion of a utility's revenue requirement is a pass-through, such as purchased gas costs or electric utility fuel and net interchange costs, can mitigate the magnitude of the difference but never eliminate it.

AmerenuUE estimates that the revenues it loses by offering energy efficiency programs will be approximately $5 million in 2010 and $12 million in 2013. This does not count the revenue it would lose by proactively helping with net metering and combined heat and power projects, or revamping its wait-time messages to encourage energy savings, or supporting code changes to help the next batch of houses and commercial structures prepare for conditions in the 21st century, rather than the 20th. It is not difficult to imagine, however, that the impact would be substantial. Only an RDM can address this in a way that protects customers by ensuring AmerenUE recovers only

[10] Regulatory Assistance Project, *Revenue Decoupling: Standards and Criteria, A Report to the Minnesota Public Utilities Commission*, 36 (2008).

for revenues actually lost, removes AmerenUE's incentive to increase sales, and minimizes regulatory effort and uncertainty around handling this important issue.

Q. Generically, does a performance-based incentive for energy efficiency savings substitute for decoupling?

A. No. A performance-based incentive helps align the utility's interests with customers by providing the utility an income opportunity that grows as the customer value produced by the energy efficiency savings grows. But a performance-based incentive does not eliminate the utility's incentive to keep finding other places and ways in which to increase sales of electricity.

Q. Would it make a difference if the incentive levels chosen specifically considered expected lost revenues?

A. In my opinion, this approach would worsen the situation for customers without improving it markedly for the utility. It is worse for customers for two reasons. First, the utility would have no reason to engage in any efforts to help customers reduce energy use except those related to its programs. Second, if circumstances within or without the utility's control actually raised sales, those revenues would not offset the "lost" revenues. The performance-based incentive would replace revenues not actually lost.

Q. Why shouldn't the Commission just allow AmerenUE to recover lost revenues resulting specifically from its programs and services, rather than approve an RDM?

A. There are several reasons that "lost revenue recovery" is not desirable, one of which I mentioned above: the revenue may not actually have been lost. Another reason why lost revenue recovery is not a good solution is the potential for contentiousness over the level of savings, which can take hours of proceedings and years to resolve. During this resolution, the utility can do nothing about the short-term drain on earnings from its energy efficiency efforts. Of equal importance is that such an approach puts all of the emphasis on programs and overlooks other activities in which the utility could engage that would help its customers increase their energy efficiency, but that are hard or impossible to "count." Most compelling to NRDC, however, is that this leaves the utility wanting very much to keep adding kWh usage, even as it offers energy efficiency programs. Using my analogy from above, the car is still driving north as fast as it can. Lost revenue recovery means that when the utility looks in the mirror it doesn't grimace, but it doesn't stop the car.

Q. Could the Commission address the effect of increasing sales or energy efficiency on utility earnings through a different rate design?

A. No. Rate design refers to the tariff elements used for particular classes of customers, such as a customer charge, a demand-based charge, an energy or kilowatt-hour charge and, for some customers, charges such as those for reactive power or specific facilities. When people suggest using rate design to eliminate the sales incentive or address energy efficiency effects, they typically mean increasing the charges that do not vary with consumption – such as the customer charge – so that those charges cover all of the utility's fixed (again, not varying with consumption) costs. This makes the utility neutral to increasing or decreasing sales but at significant harm to customers' interests. Although the increase in the resulting fixed charge is much greater for electric utilities than natural gas utilities, in both cases the re-design weakens customer benefits from energy efficiency investment and lengthens the pay-back period.

Moreover, such rate designs send very poor price signals about the true cost of future consumption. A third consequence is that customers that had been using smaller amounts of electricity prior to such a change can face very large rate increases simply from the redesign.

Perhaps it is because of this that SB 376 requires a docket to study the matter of changing rate design and adoption of a rule.

Q. Can the Commission simply address the effect of energy efficiency on utility revenues through frequent rate cases?

A. No, although with a forecasted test year and rate cases every year, it can mitigate the effect. Such a partial solution is extremely burdensome and likely counter-productive in other ways, however. Regardless how often a utility has a rate case, its actual revenues will always differ from the revenues assumed in the ratemaking process and an energy efficiency program will always reduce those actual revenues over what they would have been without the program. At a minimum, the utility will face a disincentive to increase penetration of the energy efficiency programs beyond the amount included in the forecast.

Moreover, a "rate case" approach will do little to assist a cultural change under which all utility employees, not just those involved directly with the "programs," begin to see and then seek opportunities to help customers increase their energy efficiency. This may be an energy efficiency message on the call center's voice response system or a simple interaction between a utility employee and one of their friends or neighbors about the personal and community benefits possible by applying energy more efficiently or reducing uses that do not provide much value. It would be virtually impossible to capture the effects of such informal activities in a load forecast.

I do believe that AmerenUE's expectation of frequent rate cases can be useful in designing a simple RDM. I address this further below.

Q. How many states, and utilities, presently use RDMs?

A. RDMs have gained significantly in acceptance in the last several years. The maps attached as Attachment 2 show that, as of November 2009, ten states have adopted electric decoupling, with nine more considering the matter. The latest addition was Michigan, which approved decoupling for the electric operations of Consumers Power. Eighteen states have adopted decoupling for gas utilities in their jurisdictions and five have the matter under consideration. In a report I prepared earlier this year, I counted (and reviewed the decoupling tariffs of) 28 gas utilities and 12 electric utilities with RDMs. I have attached that report as Attachment 1. Included within it are the decoupling adjustments actually made, positive and negative, as well as a review of RDM features.

In a number of these cases, the records on which the Commissions made their decisions fully consider the alternatives I briefly mentioned above, and reject them. The RAP report I mentioned above has a good summary of the alternatives and arguments for and against decoupling.[11]

Q. What are the primary concerns typically raised during consideration of an RDM?

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[11] Regulatory Assistance Project, *Revenue Decoupling: Standards and Criteria, A Report to the Minnesota Public Utilities Commission*, 36 (2008).

A. Parties to proceedings in which the Commission is considering an RDM usually raise three concerns:

- That the RDM will cause the utility to lose focus on the need to control costs
- That the RDM will eliminate or reduce the benefit of regulatory lag
- That the RDM will shift risk to customers

I address each of these briefly below.

Q. Do you agree that decoupling causes a utility to lose focus on the need to control cost?

A. No, not at all. Cost control remains as important as ever, if not more so. It is extremely important when thinking about decoupling to remember that it affects only revenues. It does not address costs. To the extent that a utility incurs costs lower than estimated in its last rate case, it will do better financially and vice versa. Decoupling can actually enhance this focus if the utility was otherwise enjoying a steady increase in load that contributed to rising fixed costs without the need for a rate case. For example, if load is growing at 2% per year, the lack of an RDM means that the utility's revenues will increase by 2% without any intervention by regulation. Depending on the design of the decoupling mechanism, the revenues to which the utility reconciles its actual revenues may be fixed at the level last approved in a rate case or may change according to the change in the number of customers or a formula such as inflation less productivity. It is simply a misconception that the RDM reduces a utility's interest in cost control.

Q. Does RAP reach this conclusion as well?

A. Yes. The RAP report explains:

> Decoupling, which allows a utility to collect revenues
> according to a mathematical rule (i.e. revenue per customer,

> historic or future test year revenue requirement, etc.) that is not driven by unit sales, gives the first a strong incentive to improve its operational efficiency. Indeed, it is only through such productivity increases that the company will be able to earn increased profits, as any margins associated with incremental sales will be returned to consumers (as, conversely, will any lost margins resulting from decreased sales be absorbed by consumers). In this light, an argument can be made that decoupling is appropriate on broad economic efficiency grounds, since it removes the company's inhibition from supporting investment in and use of least-cost energy resources, when they are most efficient, and likewise relieves it of its incentive to promote sales, even when they are wasteful.[12]

Q. Does an RDM deprive customers of the benefits of regulatory lag?

A. This concern is odd from the start because regulatory lag historically works both ways. In my understanding, regulatory lag is the period between which it is clear than enough change has occurred in either or both a utility's costs and revenues that its rates no longer produce a reasonable return based on current capital market conditions and the time that new rates reflecting the changed conditions take effect, either on an interim or permanent basis. The return may be unreasonably high (a detriment to customers) or unreasonably low (a detriment to the utility) and the new rates either an increase or a decrease. Based on this understanding, the concern appears to be that, to the extent the regulatory lag relates to ratemaking revenues exceeding actual revenues, customers benefit from rates that are, in reality, too low to produce a reasonable return, and decoupling would remove this benefit.

[12] Id. at p. 8.

What this concern overlooks is that, before decoupling, customers have the risk that actual revenues will be more than ratemaking revenues and that regulatory lag relating to this changed circumstance will prolong the period that customers must pay rates that are higher than necessary to produce a reasonable return. If the risk of ratemaking revenues being higher or lower than actual revenues is evenly distributed in the ratemaking process, decoupling simply eliminates or lessens the risk that both the utility and customers bear and constrains regulatory lag to cost changes. Considered in total, an RDM does not reduce the benefit of regulatory lag so much as it simply lessens the equal risk of regulatory lag by removing revenues from its operation.

Q. Does RAP reach a similar conclusion on this?

A. Yes.[13]

Q. But won't regulatory lag benefit customers if the utility's revenues fall because customers significantly increase their energy efficiency, either through utility efforts or for other reasons?

A. Theoretically, this is true, but this is an instance where the cost of the trade-off is far greater than the benefit. To keep regulatory lag in place for utility revenues while hoping that customers can somehow significantly increase their energy efficiency is nonsensical. It indeed makes that result a hope, not a designed outcome.

A recent briefing paper by the National Regulatory Research Institute (NRRI) concludes that: "it would seem both unfair and counterproductive to order a utility to promote energy efficiency when detrimental to its shareholders." NRRI performs research on behalf of public utility commission. It is not a utility organization and does not advocate for utility investors. What its quote implies is that ordering aggressive

[13] Id. at p. 9.

energy efficiency programs without ensuring that their results are not detrimental to utility shareholders is a regulatory “gotcha” that undermines the effectiveness of the system in producing results we want.

Moreover, driving the utility’s business and regulatory model on consumptions requires that one believe that increasing consumption is good for customers and that the utility, therefore, should bear the risk that customers do not increase consumption and gain this benefit. Missouri and the United States do not need to increase consumption of fossil fuels. What we need is to apply what we already know about how to get more work out of less energy.

Q. Does an RDM shift risk to customers?

A. This concern is a corollary of the concern about regulatory lag. Thus, the answer is that it does not shift risk but instead reduces risk for both customers and the utility. In this respect, it is just like a fuel adjustment clause, environmental cost adjustment clause or any one of several examples of regulatory mechanisms Commissions have approved to reduce the risk to customers and shareholders that the ratemaking estimates of certain costs would vary significantly from the actual levels of those costs. The mechanisms typically true-up the estimated cost to the actual cost, refunding any cost reduction to customers or surcharging customers if actual costs increase over the estimate. Decoupling is no different, other than it works on revenues.

Theoretically, a reduction in risk to both customers and the utility might affect the utility’s need for equity capital in its capital structure or change its position relative to comparable utilities to which the Commission looks in setting a return. Whether it does so or not will depend on the utility’s experience under the changed business model and the results its peers experience, as well as conditions in the capital markets. With more utilities operating under a regulatory and business model that includes an RDM, it is less clear that adopting such a mechanism will reduce the cost of capital. In any event, the formulas, models, and procedures the Commission follows today to determine a reasonable rate of return on common equity or the reasonableness of its capital structure will continue to apply after decoupling and, presumably, indicate the effect of the mechanism along with all of the other regulatory policies in place for a particular utility.

Q. Does RAP address this issue in its Report?

A. Yes. Their analysis is particularly good on this topic and worth reproducing here:

> Decoupling can significantly reduce earnings volatility due to weather and other factors and can eliminate earnings attrition when sales decline, regardless of the cause (e.g., appliance standards, energy codes, customer or utility-financed conservation, self-curtailment due to price elasticity, etc.) This in turn, lowers the financial risk for the utility, which in turn is reflected in the company's cost of capital. The reduction in the cost of capital resulting from decoupling could, if the utility's bond rating improves, result in lower costs of debt and equity; but this generally requires several years to play out and the consequent benefits for customers are therefore slow to materialize. Alternatively, a lower equity ratio may be sufficient to maintain the same bond rating for the decoupled utility as for the non-decoupled. This would allow the benefits associated with the lower risk profile of the decoupled company to flow through to customers in the first few years after the mechanism is put in place.[14] RAP Report at page 13.

RAP cautions, however, that:

> If the rating agencies perceive a risk mitigation measure will be in place for an extended period, they may be willing to

[14] Id. at p. 15.

> recognize the benefit of risk mitigation immediately upon implementation. If the risk mitigation measure is put in place only for a limited period, or the regulatory commission has a record of changing its regulatory principles frequently, the rating agency may not recognize the measure.[15]

Q. What are your conclusions about the concerns some have with adopting an RDM and thereby changing the business and regulatory model to drive revenues on some basis other than consumption?

A. My conclusion is that the risk to customers of NOT doing this is far greater than the risk of doing it. The risk of never experiencing what could happen if Missouri aligned the interests of AmerenUE and its customers toward increasing the efficiency with which those customers use electricity to do work outweighs the risk that customers could temporarily experience lower rates because regulatory policy leaves consumption as the driver of at least part of the utility's recovery of fixed costs and (a) intentionally refuses to recognize the effect of planned energy efficiency savings in setting rates; or (b) assumes that, over time, regulatory lag will "benefit" customers through temporarily lower rates more often than it harms them through temporarily higher rates.

Q. Are you proposing a specific RDM for AmerenUE?

A. Yes. There are several basic design choices a Commission can make in approving an RDM for a utility. See Attachment 2 at p. 6-8. These include:

- How to determine what level of revenue the utility should book, if not the actual revenues (driven from consumption);
- How often to reconcile actual revenues to the decoupled revenues and how often to adjust rates for any difference;

[15] Id.

- Whether to spread any adjustments on a class by class basis or over all customers; and
- Whether to normalize actual revenues for weather before reconciling to the decoupled revenues.

Given my understanding of AmerenUE's situation, I recommend a simple RDM that reconciles actual, not weather-adjusted, revenues to the most recent test year approved revenues on an annual basis, applying any adjustment over the following year, and spreads those adjustments on a general basis to all customers. Other choices could work as well and this is certainly a matter that the Commission could request the parties to discuss and resolve if possible among themselves.

VII. The Commission should approve a performance-based incentive for AmerenUE's achievements under its energy efficiency programs.

Q. Has AmerenUE proposed a performance-based incentive that would apply to savings customers achieve under its energy efficiency programs?

A. No. AmerenUE states that an incentive is important to it but is not proposing one at this time in preference for further dialogue with parties to this case. Kidwell at P. 17.

Q. Does NRDC support a performance-based incentive for AmerenUE?

A. Yes. A performance-based incentive is one of the key policy supports for strong utility energy efficiency performance.

Q. Why does NRDC support an incentive in addition to cost recovery and an RDM?

A. Cost recovery of energy efficiency expenditures and an RDM serve only to make a utility neutral to helping its customers achieve energy efficiency savings. These mechanisms, alone, do not make increasing energy efficiency a profitable opportunity. AmerenUE will still need to find aspects of its business model that include an opportunity to earn income into the future and these will likely relate to consumption and related infrastructure investment unless a substitute is found. Without an income opportunity related to helping customers increase energy efficiency, the activity is just a cost center, albeit one that is popular with customers.

Q. Do others recognize the importance of including an incentive in policy support for utility energy efficiency?

A. Yes. The National Action Plan for Energy Efficiency is a private-public initiative begun in the fall of 2005 to create a sustainable, aggressive national commitment to energy efficiency through the collaborative efforts of gas and electric utilities, utility regulators, and other partner organizations. The Executive Summary to the 2006 Plan includes the following recommendation: "Modify policies to align utility incentives with the delivery of cost-effective energy efficiency and modify ratemaking practices to promote energy efficiency investments;" and lists this option among others: "Provide utility incentives for the successful management of energy efficiency programs.[16] A NAPEE Report specifically addressing aligning utilities' business and regulatory models with increased energy efficiency explains further:

> Under traditional regulation, investor-owned utilities earn returns on capital invested in generation, transmission, and distribution. Unless given the opportunity to profit from the

[16] The following link is to the Executive Summary of the 2006 Report. http://www.epa.gov/cleanenergy/documents/napee/napee_exsum.pdf See p. 8.

> energy efficiency investment that is intended to substitute for this capital investment, there is a clear financial incentive to prefer investment in supply-side assets, since these investments contribute to enhanced shareholder value. Providing financial incentives to a utility if it performs well in delivering energy efficiency can change that business model by making energy efficiency profitable rather than merely a break-even activity.[17]

Q. Why are incentives important?

A. As the Report just cited explains: Culture Matters.

> One important test of a cost recovery and incentives policy is its impact on corporate culture. A policy providing cost recovery is an essential first step in removing financial disincentives associated with energy efficiency investment, but it will not change a utility's core business model. Earnings are still created by investing in supply-side assets and selling more energy. Cost recovery plus a policy enabling recovery of lost margins might make a utility indifferent to selling or saving a kilowatt-hour or therm, but still will not make the business case for aggressive pursuit of energy efficiency. A full complement of cost recovery, lost margin recovery, and performance incentive mechanisms can change this model, and likely will be needed to secure sustainable funding for energy efficiency at levels necessary to fundamentally change the resource mix.[18]

Q. Have other states recognized the importance of incentives?

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[17] Aligning Utility Incentives with Investment in Energy Efficiency, a Resource of the National Action Plan for Energy Efficiency, November 2007, at Exec. Sum. p. 3

[18] Id. at Exec. Sum. p. 8

A. Yes. The NAPEE Report mentioned above notes the incentives for energy efficiency in place in 14 states as of Fall 2007. I am also aware of performance-based incentives in Texas[19], Colorado[20], Virginia[21], and Michigan.[22]

Q. Has NRDC supported energy efficiency performance incentives in other cases?

A. Yes. Generally, NRDC supports shared savings, under which the incentive relates directly to independent verification of savings and the net benefits delivered by a utility's programs, not to its spending on those programs. For performance exceeding a certain threshold specified by the Commission, in terms of verified savings and net benefits to its customers, the utility keeps a fraction of those net benefits at least comparable to the risk-adjusted reward on an equivalent investment in infrastructure assets; exemplary performance should qualify for higher rewards, subject to assurance that, in all cases, utility customers are collective beneficiaries based on their retained share of system-wide monetary savings.

Q. Can you give an example of a performance-based incentive design that meets this description?

A. Yes. The incentive program recently agreed to among Duke Ohio and its stakeholders[23] operates as follows:

% Mandate[24]	Return on Investment Cap
> 125%	15%
116 – 125%	13%

[19] Texas Code Section 39-905.
[20] Colorado statutes section 40-3.2-103.
[21] Virginia statutes section 56-600 through 602.
[22] 09-29-09 U-15805 MPSC Order approving final incentive mechanism.
[23] Docket numbers 08-920-EL-SSO; 08-921-EL-AAM; 08-922-EL-UNC; 08-923-EL-ATA.
[24] Mandate means the benchmarks and baseline for energy efficiency set pursuant to R.C. 4929.66.

111 – 115%	11%
101 – 110%	6%
< or =100%	0%

Arizona Public Service also has an incentive based on net benefits, although it is capped at 10% of energy efficiency program spending.[25]

Q. What is your recommendation here?

A. As AmerenUE implies, performance-based incentives are best designed in a collaborative fashion. If the parties cannot achieve that in this case, NRDC recommends that the Commission, in this docket, endorse the concept of a performance-based incentive as a necessary measure to propel Missouri's energy efficiency savings to much higher levels, specify any parameters that it believes important and order the parties to participate in a collaborative process to develop such an incentive. If after a reasonable time, the parties cannot agree, AmerenUE should be free to file a proposal that the Commission processes expeditiously.

VIII. The Commission should require that AmerenUE establish an independently-run evaluation and verification program.

Q. Why are you recommending that the Commission require AmerenUE to develop a strong, independently run, evaluation, measurement and verification (EM&V) program?

A. EM&V is critical to two things:

[25] Arizona Corporation Commission, Decision # 67744 (2005).

- Enabling both customers and the utility to have confidence in the savings that are the basis of the utility's performance-based incentives; and
- Enabling good planning, both at the resource plan level and for individual programs.

Among other things, EM&V allows program managers to determine the difference between projected energy savings from a given measure or project and the actual amount realized. The difference can be attributed to a number of factors that affect retention, including performance deterioration, equipment failure, or customer actions (resetting controls, removal). In addition, energy impacts may be adjusted based on net-to-gross factors that measure to what extent programs influence decision making. Participants who would have made the energy efficiency upgrade in the absence of the program, but, nonetheless, participated, would be considered "free riders." EM&V studies enable refining this assumption for each program.

Handling this important function independently of the utility removes any possibility of a conflict of interest and also allows the utility to focus on delivering its programs, not evaluating them. Information learned through EM&V then can help program managers adjust programs and, ultimately, help resource planners make better assumptions for IRP purposes.

Q. When should AmerenUE begin an EM&V program?

A. Program evaluation and impact studies through EM&V should begin as soon as possible. Adjustments to energy and demand savings levels would apply to program years following the year in which the verified results were obtained. NRDC also recommends that AmerenUE establish a collaborative process for review of these market impact evaluations in 2011. The purpose of the collaborative process would be to reach consensus regarding the findings and their application to future program design in 2012. These adjustments would also be used to determine the basis for utility earnings from the program on a going forward basis.

Q. How would AmerenUE recover the costs of EM&V?

A. The Commission should include these costs in whatever mechanism it adopts to allow AmerenUE to recover energy efficiency costs going forward. Using AmerenUE's tracker proposal, the Commission would include an estimate of these costs in AmerenUE's test year and then the true-up would apply to any differences.

Q. Does this conclude your testimony?

1. A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area	)))))	**Case No. ER-2010-0036**

AFFIDAVIT OF PAMELA G. LESH

STATE OF OREGON)
) ss
CITY OF PORTLAND)

Pamela G. Lesh, being first duly sworn on her oath, states:

1. My name is Pamela G. Lesh. I work in the City of Lake Oswego, Oregon, and I am an independent consultant retained by the Natural Resources Defense Council.

2. Attached hereto and made part hereof for all purposes is my Direct Testimony on behalf of the Natural Resources Defense Council consisting of 35 pages, and two Attachments, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Pamela G. Lesh
Pamela G. Lesh

Subscribed and sworn to before me this 16 day of December, 2009.

OFFICIAL SEAL
KAREN J LEWIS
NOTARY PUBLIC-OREGON
COMMISSION NO. 409533
MY COMMISSION EXPIRES OCTOBER 20, 2010

Karen J. Lewis
Notary Public

My commission expires: October 20, 2010

GRACEFUL SYSTEMS LLC

RATE IMPACTS AND KEY DESIGN ELEMENTS OF GAS AND ELECTRIC UTILITY DECOUPLING

A COMPREHENSIVE REVIEW

Pamela G. Lesh

6/30/2009

ATTACHMENT 1

This report catalogues all of the decoupling mechanisms in place for electric or gas utilities as of Spring 2009, and discusses several older, now expired, mechanisms as well. Where the information was obtainable, it includes the rate adjustments made under the decoupling mechanisms and expresses those as a percentage of rates. It also reviews major features of the mechanisms studied.

RATE IMPACTS AND KEY DESIGN ELEMENTS OF GAS AND ELECTRIC UTILITY DECOUPLING:
A COMPREHENSIVE REVIEW

Prepared by Pamela G. Lesh

June 2009

This report compiles the rate impact experience during this decade with decoupling of retail gas and electric utility revenues from sales volumes and provides, along with this, information on relevant order numbers, statutes, mechanism descriptions, and implementing tariffs. Sources included utility and state regulatory commission websites, the American Gas Association and the Edison Electric Institute, and, in a few cases, helpful utilities. Immediately below is a brief explanation of "decoupling" as used in this report, followed by a summary of the findings and a short description of methodology. The report concludes with observations about utility ratemaking.

Decoupling

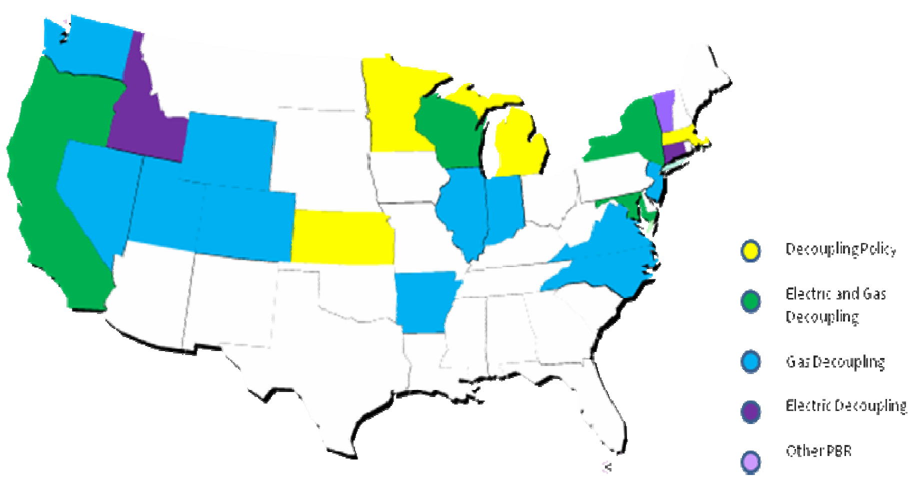
Decoupling is a regulatory term indicating that, through any one of several means, a given energy utility does not derive the portion of its revenues necessary to provide it an opportunity to recover its fixed costs of service on the basis of its sales of natural gas or electricity. Fixed costs of service include such things as the capital recovery cost of installed plant and equipment (depreciation, debt interest, and equity return), most operations and maintenance expenses and taxes. The largest cost that is not fixed is typically the cost of fuel or purchased power.

One primary means of decoupling, albeit with many variations, is through a regulatory adjustment mechanism that adjusts rates periodically to ensure that a utility records as revenue for fixed cost recovery no more and no less than the amount of revenue authorized for that cost coverage. This means of accomplishing decoupling does not affect how customers pay for energy utility services, enabling utilities to maintain volumetric rates and the incentive for customers to conserve or use energy more efficiently. In general, current rate designs include some amount of fixed customer charge per month and a per unit charge based on either gas or electricity consumption, or demand, or both. Although the utility continues to receive revenues from customers on this basis under a decoupling mechanism, it books only the revenue to cover fixed costs that its regulator has authorized, typically in a rate case or through the operation of a formula for calculating a change in fixed costs over time. For example, some such formulas change revenues authorized for fixed cost recovery according to the change in the number of customer accounts (often called revenue per customer); others change revenues for fixed cost recovery according to an inflation index, decreased for an assumed amount of productivity improvement (often called an attrition adjustment). On some regular basis, the decoupling mechanism provides 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 regulator authorized. This difference can occur for many reasons, primary among which are weather, economic conditions, and customer behavior that differ from assumptions in the ratemaking process.

It is also possible to break the link between fixed cost recovery and electricity or natural gas consumption by changing how customers pay for energy utility services. In general, this is called "straight fixed-variable" rate design, in which the fixed monthly customer charge recovers all of the utility's fixed costs of service and the variable, energy-related charge, covers only the variable cost of energy. Some Commissions adopting this type of rate design have called it 'decoupling." While this rate design does break the link between sales and fixed cost recovery, it does so by greatly diminishing customer incentives to conserve or invest in energy efficiency. Moreover, the change in rate design from a more traditional form can significantly shift costs within and between classes of customers. In particular, those customers with lower than average consumption can experience much higher bills as costs shift from variable, usage-based, charges to fixed, billing period, charges. This decoupling report excludes examples of this rate design because it does not result in adjustments to rates as the regulatory mechanism method does.

Review Summary

A total of 28 natural gas local distribution gas utilities (LDCs) and 12 electric utilities, across 17 states, have operative decoupling mechanisms.[1] Six other states have approved decoupling in concept, through legislation or regulatory order, but specific utility mechanisms are not yet in place. The map below shows the states covered by this report:

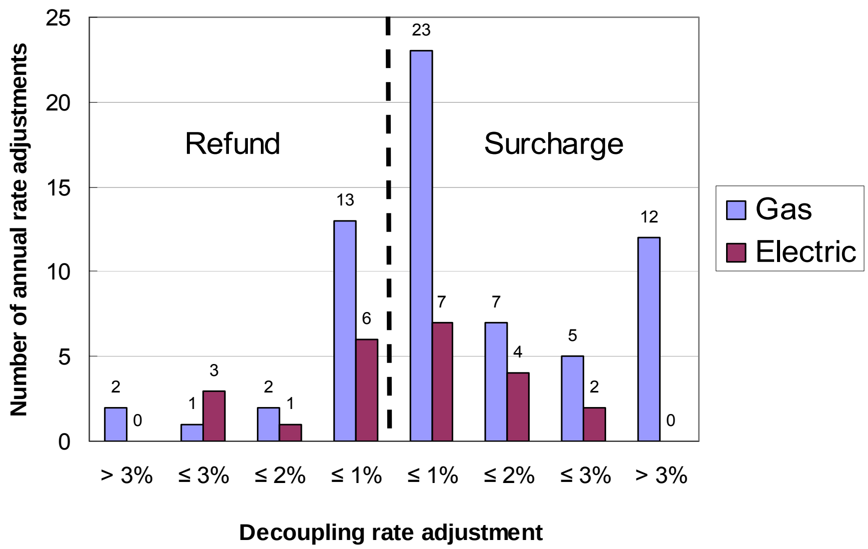


[1] This report includes two other current electric regulatory mechanisms that operate to some extent to decouple utility revenues from sales but do not permit calculation of decoupling adjustments. It also includes information on a few now-expired decoupling mechanisms, to the extent such information was discoverable.

Many of the mechanisms that exist began operation only within the last few years, although the California utilities have had some form of decoupling for much longer. Based on the available data, this review supports two definitive conclusions:

- Decoupling adjustments tend to be small, even miniscule. Compared to total residential retail rates, including gas commodity and variable electricity costs, decoupling adjustments have been most often under two percent, positive or negative, with the majority under 1 percent.[2] Using Energy Information Administration (EIA) data for 2007 on gas and electric consumption per customer and average rates, this amounts to less than $1.50 per month in higher or lower charges for residential gas customers and less than $2.00 per month in higher or lower charges for residential electric customers.
- Decoupling adjustments go both ways, providing both refunds and surcharges to customers. This is particularly true for those mechanisms that operate on a monthly basis, but also is true for those adjusted annually or semi-annually. There are many reasons, of course, that actual revenues can deviate from the revenues assumed in ratemaking. Most of the mechanisms do not adjust revenues for the effects of weather, leaving that as the primary cause of greater and lower sales volumes, particularly for residential rate schedules. 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.

The figure below summarizes the distribution of decoupling adjustments in place since 2000.



[2] These are not actual rate changes, simply a comparison of the decoupling adjustment to the total rate at or near the time of the adjustment. See methodology summary for an explanation of why it is impossible to determine actual decoupling rate changes that customers may have experienced. Counts in the figure include only the annual average of those mechanisms that have monthly adjustments.

By comparison, rate adjustments under purchased gas cost adjustment or fuel/purchased power cost adjustment clauses tend to be much larger. Although a review of actual adjustments under these clauses was beyond the scope of this study, the following history for one electric (Idaho Power Company) and one gas utility (Northwest Natural Gas Company), both of which had decoupling mechanisms for part of the period, provides an example for context:

		Northwest Natural		Idaho Power	
Year		PGA % Change	Decoupling % Change[3]	PCA % Change (Res)	Decoupling % Change
1995		(6.2)			
1996		(4.8)			
1997		10.5			
1998		9.2			
1999		7.2			
2000		21.4			
2001		20.8			
2002		(12.7)		7.5	
2003		4.9	0.6	(18.9)	
2004		20.1	0.36	0	
2005		16.6	0.77	0	
2006		3.8	(0.27)	(14.0)	
2007		(8.7)	(0.1)	11.0	
2008		15.6	<(1.0)	8.45	(0.8)
2009				10.2	0.8

The information gathered below supports several other observations about decoupling:

- The mechanisms have a great variety of names, almost none of which contain the word "decoupling." Names ranged from "Billing Determinant Adjustment" to "Volume Balancing Adjustment" to "Bill Stabilization Rider" and more.
- Most mechanisms appear in a separate tariff page, although in one or two cases the mechanism is combined with an energy efficiency program tariff and the California utilities do not have a tariff for decoupling. Instead, the California utilities have regulatory authority to make the calculations and rate adjustments as part of an "Annual True-up" procedure.
- Almost all of the gas utilities with decoupling mechanisms also adjust rates to account for the effects of weather on revenues. For some, this occurs logically under the decoupling mechanism, which performs calculations based on actual, not weather-adjusted, revenues. For others, eliminating the effects of weather on the revenues the utility collects to cover fixed costs occurs under a separate tariff. Under either approach, the utilities no longer face a risk of under-

[3] For Northwest Natural, the decoupling adjustment is included in the overall PGA; thus, these are not additive.

recovering fixed costs or reaping a windfall if weather is different from that assumed in the ratemaking process. In contrast, a couple of electric utilities calculate decoupling adjustments on the basis of weather-adjusted revenues. For these, the utility keeps revenues associated with sales caused by weather more extreme, and forgoes revenues lost because of weather milder, than that assumed for ratemaking purposes.

- Most of the mechanisms produce an annual adjustment, but a handful of utilities adjust rates monthly and one or two semi-annually. The monthly adjustments tend to be very small but can go up and down six times in as many months. The tables below show only the annual average of monthly adjustments and, in a few cases, high and low adjustments during the year.
- Most mechanisms perform the calculation of the difference between actual fixed cost revenues and authorized fixed costs revenues on a per customer class or per rate schedule basis, refunding or surcharging the result only to that schedule or class.
- A number of these decoupling mechanisms are in place only on a "pilot" basis, subject to cancellation or further regulatory process after 3-4 years.
- Most of the mechanisms allow utilities to keep additional revenues from growth in the number of customer accounts during a decoupling period. This can occur either by expressing the fixed costs as a revenue-per-customer amount and reconciling actual revenues to the revenue per customer amount times the current number of customers, or by adjusting the allowed revenue requirement for customer growth and reconciling actual revenues to that adjusted amount. A few utilities receive an explicit attrition adjustment, approved by the Commission and not dependent on the number of customers.
- Some of the 28 mechanisms include some unusual features. For three utilities, adjustments only occur if they are surcharges; the mechanism does not require refunds. Another two utilities can collect surcharges only if savings in gas costs offset the lost margin. Some mechanisms limit the dollar amount or percentage of rate change permitted, either deferring any excess for later recovery/credit or simply eliminating it.

The table below summarizes some of the different features of decoupling mechanisms, indicating how many of the mechanisms have each type of feature.

Feature	Gas Decoupling	Electric Decoupling
Revenue change between rate cases		
Revenue-per-customer[1]	23	4
Attrition adjustment[2]	3	4
No change	3	1
No separate tariff	3	3
Timing of Rate True-ups		
Annual	19	8
Semi-annual/quarterly	2	1
Monthly	4	3

Weather[3]		
Not weather-adjusted	20	10
Weather-adjusted	8	2
Limit on adjustments and/or dead-band[4]	9	6
Per class calculation and adjustments[5]	25	7
Earnings Test[6]	4	
Pilot/known expiration date	11	4
Surcharges only	3	
Total Utilities Analyzed	**28**	**12**

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 would refund any amount by which its actual revenues exceeded $1.05 billion. Thus, the additional customer accounts contribute $50 million to fixed cost recovery.
2. "Revenue requirement true-up" means that the decoupling mechanism simply compares the actual foxed cost revenues to the amount authorized for fixed cost recovery in the utility's last rate case, even if that was several years prior. Thus, the utility may face declining income as inflation and other factors increase fixed costs. The sub-category of these that are "with attrition" indicate the utilities for whom that authorized revenue requirement changes from year to year according some formula, generally an inflation index less an assumed amount of productivity improvement. This may be part of the decoupling mechanism, done as a means of calculating the comparator for the actual revenues collected, or external to the decoupling mechanism and causing its own rate adjustment.
3. "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.
4. "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.

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 do not do this.
6. "Earnings test" refers to a limitation on decoupling surcharges by which the utility may not recover revenue differences calculated by the mechanism to the extent that recovery would increase its earnings over a specified return on common equity, whether the last authorized or another amount.

The next several years will significantly increase experience with decoupling, both for those utilities for whom decoupling is of relatively long-standing and for those that have just begun their implementation. It would be worthwhile to update this review at some point to determine whether these conclusions hold true with additional experience, particularly among the electric utilities for whom data is presently scarcer than for gas utilities.

Methodology

Generally, it was possible to find a tariff stating the decoupling adjustment, either in cents or dollars per therm, or cents per kWh. This was not the case only for the California utilities, whose decoupling does not occur under a separate tariff but as part of a much larger annual filing. Those utilities very helpfully provided the information needed for this report. Amounts in ( ) are rebates to customers; other amounts are surcharges. In general, amounts are rounded to two to three digits.

It was much more difficult to find a total retail rate for the rate classes covered by the decoupling mechanism and, thus, to calculate the size of the decoupling adjustment as a percentage of the total rate. This was particularly problematic where the adjustments were for prior years or the commodity portion of the rate changed frequently, as is common for gas utilities and restructured electric utilities. In many cases, this report uses average annual (or monthly for 2009) retail gas and electric price information for the appropriate state found on the EIA website. The goal was to provide context for the decoupling adjustment, not state precise percentages and the EIA data served well for the purpose.

For a couple of reasons, it is impossible to determine from the sources available what changes in rates actually occurred when. First and foremost, whether a given decoupling adjustment caused a rate increase or decrease depends on what was in rates before for decoupling. For example, if a decoupling adjustment produced a refund one year and a somewhat smaller refund the second year, the rate change customers would experience would be a small increase, as the prior credit expired and was not fully replaced by the current credit. The reverse can also happen: the expiration of a decoupling surcharge will produce a rate decrease unless the subsequent decoupling adjustment is the same or a larger surcharge. Second, many utilities combine one or more rate changes at one time.

Changes in commodity costs or balancing accounts or other tariff riders along with the decoupling adjustment are common and could easily offset or mask the decoupling adjustment. For two utilities, such offsetting was the deliberate design.

STATE/UTILITY INFORMATION

Arkansas

Arkansas Oklahoma (gas)
Case/Order No.: 07-026-U, Order No. 7 (11/20/07)
http://www.apscservices.info/efilings/docket_search_results.asp
Type of decoupling: Reconciles actual weather-adjusted revenues to rate case revenues for the residential and small business classes. No refund for over-recovery; only surcharge for under-recovery (net across all schedules). Deficiencies recovered within each class where a deficiency occurs. There is a separate weather adjustment.
Decoupling tariff: Billing Determinant Adjustment
http://www.apscservices.info/tariffs/112_gas_1.PDF
The tariff expires August 31, 2011; the utility must re-file to continue decoupling.
Energy efficiency cost recovery: incremental costs per the Energy Efficiency cost recovery tariff (adopted in Docket 07-077-TF); forecast and true-up procedure filed by April, for June adjustments.
History of Adjustments: The October 2008 filing was for no adjustment because sales were above those used in ratemaking.

Arkansas Western (gas)
Case/Order No.: 06-124-U, Order No. 6 (7/13/07)
http://www.apscservices.info/efilings/docket_search_results.asp
Type of decoupling: Reconciles actual weather-adjusted revenues to rate case revenues for the residential and small business classes only. No refund for over-recovery; only surcharge for under-recovery (net across all schedules). Deficiencies recovered within each class where a deficiency occurs. There is a separate weather adjustment.
Decoupling tariff: Billing Determinant Adjustment Tariff, Rider No. 3.6
http://www.apscservices.info/tariffs/145_gas_1.PDF
The tariff expires July 31, 2010; the utility must re-file to continue decoupling.
Energy efficiency cost recovery: Incremental costs per the Energy Efficiency cost recovery tariff (for programs approved in Docket 07-078-TF); forecast and true-up procedure; April filings for January 1 adjustment.
History of Adjustments: The October 2008 filing was for no adjustment because sales were above those used in ratemaking.

CenterPoint Energy Resources (gas)
Case/Order No.: 06-161-U; Order No. 6 (10/25/07)
http://www.apscservices.info/efilings/docket_search_results.asp
Type of decoupling: Reconciles actual weather-adjusted revenues to rate case revenues for the residential and small business classes only. No refund for over-recovery; only

surcharge for under-recovery (net across all schedules). Deficiencies recovered within each class where a deficiency occurs. There is a separate weather adjustment.
Decoupling tariff: Billing Determinant Adjustment Tariff, Rider No. 6
http://www.apscservices.info/tariffs/64_gas_2.PDF
Tariff expires on December 31, 2010; the utility must re-file to continue.
Energy efficiency cost recovery: Incremental costs per the Energy Efficiency cost recovery tariff (for programs approved in Docket 07-081-TF); forecast and true-up procedure; April filings for January adjustment.
History of Adjustments: The first filing under the tariff was March 31, 2009. CenterPoint made no adjustment because sales slightly exceeded revenue requirement sales.

California

California first adopted decoupling, through the Supply Adjustment Mechanism (SAM), for gas utilities in 1978 in Decision 88835. By 1982, similar mechanisms were in place for the three electric IOUs. The ratemaking construct worked by establishing a revenue requirement for each utility annually and then reconciling actual revenues to the allowed revenues. Information on the electric decoupling adjustments during this first period is available for most years from 1983 through 1993 through an analysis done by Lawrence Berkeley Labs in 1994.[4] The authors compared the rate adjustments that took place with those that would have occurred without the decoupling amounts. The following were the decoupling-only rate adjustments identified:

Year	PG&E (% of total rates)	SCE (% of total rates)	SDG&E[5] (% of total rates)
1983	2.3	Not available	1.2
1984	(3.4)	(0.5)	1.0
1985	(4.8)	(2.1)	(6.8)
1986	1.9	2.1	1.8
1987	2.1	(1.0)	11.0
1988	5.0	(1.5)	(12.0)
1989	(4.3)	2.4	0.7
1990	(5.4)	(2.1)	4.8
1991	3.9	3.5	(1.8)
1992	3.4	(0.6)	1.4
1993	0.0	(1.9)	Not available

As the gas industry restructured, gas utilities began to serve large (non-core) customers under a straight fixed-variable rate design, which continues through today. For core customers (commonly residential and smaller commercial), decoupling continued.

4 The Theory and Practice of Decoupling, Joeseph Eto et al., Lawrence Berkeley Laboratory, January 1994 Website: http://eetd.lbl.gov/EA/emp/reports/34555.pdf
5 The article providing these historical decoupling adjustments does not explain the outlying double-digit increase and decrease for SDG&E. Given that the two are in consecutive years, one might surmise that a load forecasting or mathematical error caused the decoupling increase in the one year only to correct it and reverse the amount in the following year.

The CPUC largely stopped the electric decoupling mechanisms in 1996, with the advent of electric restructuring. It is unclear whether the last reconciliation adjustment was 1995 or 1996. In 2001, however, the Legislature passed Public Utilities Code section 739.10, which required that the CPUC resume decoupling.

739.10. The commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or under-collections of the electrical corporations.

In individual rate cases following this, the CPUC approved resumption of electric.[6]

Pacific Gas and Electric (electric)
Case/Order Nos.: A.02-11-017 et al.
http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/37086.htm
The first adjustment under the various mechanisms occurred at the end of 2004 to be effective during 2005.
Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years. PG&E has three specific accounts that combine to accomplish decoupling: the Distribution Revenue Adjustment Mechanism, the Nuclear Decommissioning Revenue Adjustment Mechanism, and the Utility Generation Balancing Account.
Decoupling tariff: No specific tariff.
Filing Schedule: Adjustments occur through the Annual Electric True-Up filing.
Energy efficiency cost recovery: Yes
History of Adjustments

Year of Adjustment[7]	Revenue Rqmt ($ millions)	Decoupling Adjustment ($ millions)	Decoupling as % of Total Revenue[8]
2005	9,715	99.41	1.0
2006	9,875	24.64	0.25
2007	10,371	148.9	1.4
2008	10,609	11.4	0.11
2009	11,169	103.55	0.9

Pacific Gas and Electric (gas)
Case/Order Nos.: A.02-11-017 et al.
http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/37086.htm
The first adjustment under the various mechanisms occurred at the end of 2004 to be effective during 2005.
Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.

[6] Some amount of decoupling, for some of the utilities, may have occurred between adoption of restructuring and the adoption of section 739.10. It is unclear.
[7] The adjustment is collected in the year following the year that the revenue variance occurred.
[8] Because the decoupling adjustments occur along with other adjustments, it is not possible to determine specific adjustments (dollars or percentages) by rate schedule. It is possible to identify the total decoupling adjustment as a percentage of total revenues for the year to which the adjustment relates.

Decoupling tariff: No specific tariff; adjustment occurs in Annual True-Up filing
Filing Schedule: Filings occur in December for January 1 effective dates
Energy efficiency cost recovery: Yes
History of Adjustments

Year of Adjustment	Revenue Rqmt ($ millions)	Decoupling Adjustment ($ millions)	Decoupling as a % of Delivery Revenue[9]
2006	982.8	37.95	3.9
2007	1,026	46.77	4.6
2008	1,095	11.26	1
2009	1,091	50.86	4.7

Southern California Edison (electric)
Case/Order Nos.: A.93-120-29; Decision 02-04-055. The first adjustment under the various mechanisms occurred at the end of 2004 to be effective during 2005.
Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.
Decoupling tariff: No specific tariff.
Filing Schedule: Adjustments occur through the Annual Electric True-Up filing.
Energy efficiency cost recovery: Yes
History of Adjustments

Year	Annual Change in Rates for Decoupling[10] (%)
2004	(2.1)
2005	(2.1)
2006	0.1
2007	(1.0)
2008	2.2

San Diego Gas & Electric (electric)
Case/Order No.: Case/Order No.: A.02-12-027
http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/44820.htm

[9] The percentages would be much smaller with commodity reflected in the total as well. Because PG&E could not provide the per-therm adjustment related to decoupling, it was not possible to calculate the decoupling as a percentage of the total rate to customers, even using EIA data.
[10] Rate changes reflect the difference between the rate change without the base revenue requirement balancing account (BRRBA) and the rate change with the BRRBA. Because the decoupling adjustments occur along with other adjustments, it is not possible to determine specific adjustments (dollars or percentages) by rate schedule. It is possible to identify the total decoupling adjustment as a percentage of total revenues for the year to which the adjustment relates.

Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.
Decoupling tariff: No separate tariff
Filing Schedule: Adjustments occur in annual filings that combine many adjustments, including both revenue and cost reconciliations.
Energy efficiency cost recovery: Yes
History of Adjustments[11]

Year	Rate (¢/kWh)	Decoupling Rate Change (¢/kWh)	Decoupling change compared to Rate (%)
2005	13.773	(0.055)	(0.40)
2006	13.935	(0.210)	(1.5)
2007	13.997	(0.051)	(0.36)
2008	13.606	(0.044	0.32
2009	16.726	0.128	0.76

SoCal Gas/SDG&E (gas)
Case/Order No.: A.02-12-027; D.05-03-023
http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/44820.htm
Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.
Decoupling tariff: No separate tariff
Filing Schedule: Adjustments occur in annual filings that combine many adjustments, including both revenue and cost reconciliations
Energy efficiency cost recovery: Yes
History of Adjustments[12]

Year/ Core/Non-Core	Rate (¢/therm)	Decoupling Rate Change (¢/therm)	Decoupling Change compared to Rate (%)
2006			
Core	48.348	0.012	0.02
Non-Core	5.36	0	0
2007			
Core	50.196	0.024	0.05
Non-Core	4.852	(0.001)	(0.01)
2008			
Core	51.526	0.001	0

[11] The numbers are estimates only and reflect the best efforts of SDG&E to isolate the decoupling elements. Contact Lisa Davidson at 858-636-3928 for information or updates.
[12] The numbers below are estimates only and reflect the company's best efforts to isolate the decoupling elements. Rates shown are for delivery services only.

Non-Core	3.576	(0.001)	(0.04)
2009			
Core	55.052	0.003	0.01
Non-Core	2.954	0.002	0.07

Southwest Gas Corporation (gas)
Case/Order No.: A.02-02-012, Order 04-03-034
http://docs.cpuc.ca.gov/Published/Final_decision/35920.htm
Type of decoupling: Reconciles actual, non-weather-adjusted revenues to approved revenue requirement. An attrition adjustment increases revenue requirement in non-rate case years.
Decoupling tariff: Core Fixed Cost Adjustment Mechanism (line item in cost of gas)
http://www.swgas.com/tariffs/catariff/rates/historic/2009/06-07-2009/rates-nocal.pdf and
http://www.swgas.com/tariffs/catariff/cover/ca_gas_tariff.pdf (see Sheet 6739-G)
Filing Schedule: Changes occur every January 1
Energy efficiency cost recovery: Yes
History of Adjustments

Year	Average Commercial Rate[13] ($/therm)	Northern Territory Decoupling Adj ($/therm)	% of Retail Rate (est[14])	Southern Territory Decoupling Adj ($/therm)	% of Retail Rate[15]
2005	1.07	0.004	0.4	0.05	4.7
2006	1.04	0	0	0.05	4.8
2007	1.02	(0.0006)	<(.01)	0.004	0.4
2008	1.17	(0.016)	(1.4)	0.010	0.9
2009	0.94	(0.051)	(5)	0.013	1.4

Colorado

Colorado has adopted decoupling only for one utility – gas – and then only for a three-year experiment. Recent legislation authorizes the Commission to ensure cost recovery for both electric and natural gas energy efficiency programs but does not address decoupling. See §40-3.2-103 and 104.

[13] Source: EIA data, annual through 2008 and January 2009. For simplicity, this assumes translates MCF into therms without the small additional amount of btu associated with a therm.
[14] This is an estimate only, using EIA average California commercial retail prices for each of the years above. Although the core class includes both residential and commercial, the percentage estimate uses the lower commercial number to be conservative regarding the size of the adjustment as a percentage of customer rates.
[15] This is an estimate only, using EIA average California commercial retail prices for each of the years above. Although the core class includes both residential and commercial, the percentage estimate uses the lower commercial number to be conservative regarding the size of the adjustment as a percentage of customer rates.

Public Service of Colorado (gas)
Case/Order No.: 06S-656G; Order No. C07-0568
http://www.dora.state.co.us/puc/DocketsDecisions/HighprofileDockets/06S-656G.htm
Type of decoupling: Reconciliation of residential use-per-customer times ratemaking margin to actual, weather-normalized use-per-customer times ratemaking margin; utility allowed to recover only differences greater than or equal to 1.3% decline in use per customer (cumulates every year of mechanism); increases in use-per-customer accrue to offset losses in use-per-customer in prior or future years.
Decoupling Tariff: Partial Decoupling Rate Adjustment, Sheet 51
http://www.xcelenergy.com/SiteCollectionDocuments/docs/psco_gas_entire_tariff.pdf
The tariff expires October 1, 2011; the utility must re-file to continue decoupling. Filing Schedule: Adjusts every year on October 1
Energy efficiency cost recovery: Cost recovery reconciled to actual costs; semi-annual filing for July 1 and January 1 rate changes
History of adjustments

September 2008 filing for margin differences July 2007 through June 2008: $0

Connecticut

2007 Connecticut legislation requires that the Commission adopt decoupling mechanisms for the states' electric and natural gas utilities. CT Public Act No. 07-242
http://www.cga.ct.gov/2007/ACT/PA/2007PA-00242-R00HB-07432-PA.htm

United Illuminating (electric)
Case/Order No.: 08-07-04 (February 2009 and June 2009)
http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/f4217b3542e2b08b852575530075d08c?OpenDocument and
http://www.dpuc.state.ct.us/FINALDEC.NSF/2b40c6ef76b67c438525644800692943/3b76f3e31c22cb19852575cb005cea73?OpenDocument
Type of decoupling: Reconciliation of actual, non-weather adjusted revenues to ratemaking revenues. Refunds or surcharges allocated to all classes based on revenue.
Decoupling Tariff: United Illuminating has not yet filed a tariff to implement the Commission's approval of its decoupling mechanism because it was awaiting the results of a request for reconsideration. A tariff will likely be filed shortly. Extension beyond 2010 requires specific Commission approval.
Filing Schedule: Within 14 months after new rates effective
Energy efficiency cost recovery: Yes
History of Adjustments

There will not be any adjustments under this order for approximately 14 months.

Idaho

Idaho Power Company (electric)
Case/Order No.: IPC-E-04-15; Order No. 30267
http://www.puc.idaho.gov/search/search.htm (Search under order number).

Type of decoupling: For residential and small commercial customers, the mechanism reconciles actual number of customers to ratemaking number of customers times a set fixed cost per customer and weather-adjusted sales per customer to ratemaking sales per customer for a set fixed cost per kWh amount. 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. This is a three-year pilot program, expiring May 31, 2010.
Decoupling tariff: Schedule 54
http://www.puc.state.id.us/tariff/approved/Electric/Idaho%20Power%20Company.pdf
Filing Schedule: Adjustments occur each June 1 (filed March 15), with adjustments based on results from the prior calendar year.
Energy efficiency cost recovery: Incremental costs per the Energy Efficiency cost recovery tariff (adopted in Docket 07-077-TF); forecast and reconciliation procedure filed by April for June adjustments.
History of Adjustments

Year	Residential Decoupling ($ million)	Adjustment[16] (¢/kWh)	Rate change (%)	Small Commercial Decoupling ($ million)	Adjustment (¢/kWh)	Rate change (%)
2008	(3.6)	(0.0457)	(0.71)[17]	1.2	(0.0457)	(0.71)
2009[18]	1.3	0.0529	0.82	1.4	0.0529	0.82

Kansas

In 2008, the Commission issued an order addressing generally cost recovery and incentives associated with utility energy efficiency programs. Docket No. 08-GIMX-441-GIV (November 14, 2008) http://www.kcc.state.ks.us/scan/200811/20081114142730.pdf. The Commission endorsed the concept of using a tariff rider to recover program costs on a timely basis, with pre-filing of programs and budgets to provide utilities assurance of concurrence in their plans. In the order, the Commission also determined that decoupling was the best method of addressing the throughput incentive that utilities otherwise face, rejecting both a straight fixed-variable rate design and lost revenue recovery as reasonable alternatives. It invited utilities to file decoupling proposals in connection with their energy efficiency programs.

[16] The Commission ordered that the decoupling adjustments be summed and the result designed into an even adjustment across the two customer classes. This was, in part, because Idaho Power lacked a recent cost of service study suitable to allocate fixed costs between the two classes.
[17] This is an estimate using the 2009 retail rate implied by the filing of the 2009 adjustment and the 2008 adjustment.
[18] Filed March 15, but not yet approved.

Illinois

North Shore Gas (gas)
Case/Order No.: 07-0241/07-0242 (Cons)
http://www.icc.illinois.gov/docket/files.aspx?no=07-0241&docId=119858
Type of decoupling: Reconciles actual, non-weather-adjusted margin revenue per customer to ratemaking margin per customer, on a per-class basis.
Decoupling tariff: Volume Balancing Adjustment (VBA), sheets 60-64
http://www.northshoregasdelivery.com/news/tariffs/vba.pdf
This is a four-year pilot only; to continue, the utility must make a general rate filing in which the Commission extends the program.
Filing Schedule: Monthly adjustments began March 2008. The utility will make a reconciliation filing every February. The first filing was in February 2009 for the ten months of 2008 included in the mechanism.
Energy efficiency cost recovery: Rider Energy Efficiency Program (EEP); program period runs July 1 to June 30 each year.
History of adjustments[19]

North Shore Gas Service Classification	True-up: rate case to actual margin ($)	True-up: percentage of margin (%)	True-up: percentage of total revenues (%)[20]
Residential Sales	(547,804.42)	(3.3)	(0.46)
Residential Transportation	(5,101.34)	(1.3)	(0.1)
Comm/Ind Sales	(89,053.00)	(3)	(0.33)
Comm/Ind Transportation	(327,781.95)	(0.5)	(0.5)

Peoples Gas and Coke (gas)
Case/Order No.: 07-0241/07-0242 (Cons)
http://www.icc.illinois.gov/docket/files.aspx?no=07-0241&docId=119858
Type of decoupling: Reconciles actual, non-weather-adjusted margin revenue per customer to ratemaking margin per customer, on a per class basis.
Decoupling tariff: Volume Balancing Adjustment (VBA), Sheets 61-65
http://www.peoplesgasdelivery.com/news/tariffs/vba.pdf
This is a four-year pilot only; to continue, the utility must make a general rate filing in which the Commission extends the program.
Filing Schedule: Monthly adjustments began March 2008. The utility will make a reconciliation filing every February. The first filing was in February 2009 for the ten months of 2008 included in the mechanism.
Energy efficiency cost recovery: Rider Energy Efficiency Program (EEP); program period runs July 1 to June 30 each year.

[19] Prepared from the annual reconciliation filing.
[20] Commodity rates change frequently. The percentage was estimated using average city gate gas cost for Illinois per EIA data, annual 2008, $8.48/Mcf.

History of adjustments[21]

Peoples Gas Service Classification	True-up: rate case to actual margin ($)	True-up: percentage of margin (%)	True-up: percentage of total revenues (est.)[22] (%)
Residential Sales	(2,035,714.64)	(2)	(0.43)
Residential Transportation	(53,882.01)	(2.4)	(0.15)
Comm/Ind Sales	(431,457.89)	(1)	(0.19)
Comm/Ind Transportation	(2,217,245.22)	(6.9)	(0.73)

Indiana

Vectren Indiana Gas (gas)
Case/Order No.: 42943 (December 2006)
https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631800befe7
Type of decoupling: Reconciles actual, non-weather-adjusted margin revenues per customer to ratemaking margin revenues per customer, with an adjustment for customer additions and reductions; only 85% of amount (positive or negative) included in rates; earnings capped at 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 a separate weather adjustment tariff that applies only during the seven winter months.
Decoupling tariff: Appendix I, Energy Efficiency Rider, Sheet 38
https://www.vectrenenergy.com/cms/assets/pdfs/indiana_gas_tariff.pdf
Energy efficiency cost recovery: Yes, in the same tariff
History of adjustments

Rate Schedule/Year	Decoupling Adjustment ($/therm)	Adjustment as a % of Margin	Adjustment as a % of Total Rate
2008			
Residential (210)	0.017	6.4	1.5
General (220/225)	0.0034	2.0	0.3
2009			
Residential (210)	0.00364	1.4	0.4
General (220/225)	(0.00762)	4.4	(0.86)

[21] Prepared from the annual reconciliation filing.
[22] Commodity rates change frequently. The percentage was estimated using average city gate gas cost for Illinois per EIA data, annual 2008, $8.48/Mcf.

Vectren Southern Indiana Gas (gas)
Case/Order No.: 42943 (December 2006)
https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631800befe7
Type of decoupling: Reconciles actual, non-weather-adjusted margin revenues per customer to ratemaking margin revenues per customer, with an adjustment for customer additions and reductions; only 85% of amount (positive or negative) included in rates; earnings capped at 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 a separate weather adjustment tariff that applies only during the seven winter months.
Decoupling tariff: Appendix I, Energy Efficiency Rider, Sheet 38
https://www.vectrenenergy.com/cms/assets/pdfs/south_services_gas_tariff.pdf
Energy efficiency cost recovery: Yes, in the same tariff
History of adjustments

Rate Schedule/Year	Decoupling Adjustment ($/therm)	Adjustment as a % of Margin	Adjustment as a % of Total Rate
2008			
Residential (110)	0.0085	4.7	0.8
General (120/125)	0.0035	2.9	0.3
2009			
Residential (110)	0.00152	0.8	0.2
General (120/125)	(0.00469)	(4)	(0.6)

Citizen's Gas & Coke (gas)
Case/Order No.: 42767 (April 2007)
https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631800dd673
Type of decoupling: Reconciles actual, non-weather-adjusted margin revenues per customer to ratemaking margin revenues per customer, with an adjustment for customer additions and reductions. The mechanism operates on a per class basis. The utility also has a separate weather adjustment tariff that applies only during the seven winter months.
Decoupling tariff: Rider E, page 505
http://www.citizensgas.com/pdf/NGRatesRidersTC/RiderE.pdf
Energy efficiency cost recovery: Yes, through Rider E
History of adjustments

Rate Schedule/Year	Decoupling Adjustment ($/therm)	Adjustment as a % of Margin	Adjustment as a % of Total Rate
2008			
Res Non-Heat	0.002	0.45	0.16
Res Heat	(0.0002)	(0.067)	(0.02)
General Non-Heat	(0.0006)	(0.5)	(0.006)

General Heat	0	0	0
2009			
Res Non-Heat	0.0133	3	1.2
Res Heat	0.0223	7.3	2.2
General Non-Heat	0.0157	12.86	1.9
General Heat	0.0212	12.9	2.4

Maryland

Maryland has both gas and electric decoupling in place; the former began in the early 2000s, and the latter just within the last few years. All of the mechanisms make monthly adjustments. The amounts below are averages of the monthly adjustments for the periods shown. For several of the utilities, the largest and smallest adjustments within a given year are also shown.

Baltimore Gas & Electric (electric)
Case/Order No.: [Unable to locate]
Type of Decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule. Maximum change in rates per month is 10%, with any adjustment amount in excess of that carried over to future periods.
Decoupling Tariff: Monthly Rate Adjustment, Rider 25
http://www.bge.com/portal/site/bge/menuitem.b0ab2663e7ca6787047eb471016176a0/
Filing Schedule: Monthly
Energy efficiency cost recovery: Yes
History of Adjustments

Period	Res. Dec. Adj (¢/kWh)	Dec. Adj % of Retail Rate[23]	Small Comm. Dec. Adj (¢/kWh)	Dec. Adj % of Retail Rate	Gen'l Comm. Dec. Adj (¢/kWh)	Dec. Adj % of Retail Rate
2008[24]						
Largest Adj	0.445		0.215		0.2303	
Smallest Adj	(0.066)		(0.215)		0.1456	
Average Adj	0.136	1.1	0.025	0.22	0.21	2.1
2009						
Largest Adj	0.237		0.119		0.23	
Smallest Adj	(0.237)		(0.215)		(0.215)	
Average Adj	(0.069)	(0.5)	(0.048)	(0.4)	(0.043)	(0.4)

Delmarva (electric)

[23] EIA data on Maryland retail rates for the respective years used as a proxy to determine percentages.
[24] The mechanism was effective January 2008, with the first adjustment occurring in March 2008 based on January variances. The filing for the November 2008 adjustment was missing from the Maryland Commission website.

Case/Order No.: Case Jacket 9093; Order 81518, July 2007
http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction_new.cfm?RequestTimeout=500
Type of decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule. Maximum change in rates per month is 10%, with any adjustment amount in excess of that carried over to future periods. Adjusts monthly.
Decoupling Tariff: Bill Stabilization Adjustment Rider, Leaf 102
http://www.delmarva.com/home/choice/md/tariffs/
Energy efficiency cost recovery: Yes, Demand-Side Management Surcharge Rider, Leaf 132
History of adjustments

Period/Rate	Average Decoupling Adjustment[25] (¢/kWh)	Estimated Total Rate[26] (¢/kWh)	Decoupling as % of Rate[27]
11/07 – 10/08			
Residential	0.16	11.09	1.4
General	0.21	11.80	1.8
11/08 – 4/09			
Residential	0.16	10.69	1.5
General	0.29	11.40	2.5

PEPCO (electric)
Case/Order No.: Case Jacket 9092, Order 81517, July 2007
http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction_new.cfm?RequestTimeout=500
Type of decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule. Maximum change in rates per month is 10%, with any adjustment amount in excess of that carried over to future periods. Adjusts monthly.
Decoupling tariff: Bill Stabilization Adjustment Rider, page 47
http://www.pepco.com/_res/documents/md_tariff.pdf
Energy efficiency cost recovery: Yes, Demand-Side Management Surcharge Rider, page 48
History of Adjustments

[25] PEPCO makes a monthly adjustment. The numbers shown are the average across the periods identified. For the year 11/07 to 10/08, there were 14 downward adjustments across the three classes and 22 upward adjustments. For the partial period 11/08 to 2/09, there were 2 downward adjustments and 10 upward.
[26] For residential, this is the average (summer/winter) standard offer rate for the decoupling periods. For general, the rate is estimated from the price to compare on PEPCO's website. For large industrial, the rate is from EIA 2006 price data for Maryland.
[27] The percentage shown is only as of total rate for residential and general service. The percentage is of delivery costs only for large industrial; with added commodity, the percentage change would be much lower.

Period/Rate	Average Decoupling Adjustment[28] (¢/kWh)	Estimated Total Rate[29] (¢/kWh)	Decoupling as % of Rate
11/07 – 10/08			
Residential	0.06	10.75	0.56
General	0.08	12.74	0.63
Large	0.013	8.14	0.16
11/08 – 2/09			
Residential	0.25	10.75	2.3
General	0.14	12.74	1.1
Large	0.02	8.14	0.25

Baltimore Gas & Electric (gas)
Case/Order No.: Case 9036; Order 80460
http://webapp.psc.state.md.us/Intranet/Casenum/submit_new.cfm?DirPath=C:\Casenum\9000-9099\9036\Item_116\&CaseN=9036\Item_116
Type of decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule. Maximum change in rates per month is 10%, with any adjustment amount in excess of that carried over to future periods. Adjusts monthly.
Decoupling tariff: Monthly Rate Adjustment, Rider 8
http://www.bge.com/portal/site/bge/menuitem.d7305449a99570c7047eb471016176a0/
Energy efficiency cost recovery: Yes. Gas Efficiency Charge, Rider 1
History of Adjustments

Period	Residential Decoupling Adjustment ($/therm)	Decoupling Adjustment % of Retail Rate[30]	Commercial Decoupling Adjustment ($/therm)	Decoupling Adjustment % of Retail Rate
2006[31]				
Largest Adj	0.05		0.05	
Smallest Adj	(0.01)		(0.05)	
Average Adj	0.0316	1.9	(0.005)	(0.4)
2007[32]				

[28] PEPCO makes a monthly adjustment. The numbers shown are the average across the periods identified. For the year 11/07 to 10/08, there were 14 downward adjustments across the three classes and 22 upward adjustments. For he partial period 11/08 to 2/09, there were 2 downward adjustments and 10 upward.
[29] For residential, this is the average (summer/winter) standard offer rate for the decoupling periods. For general, the rate is estimated from the price to compare on PEPCO's website. For large industrial, the rate is from EIA 2006 price data for Maryland. It is not clear if the standard offer rate is with or without distribution charges built in. This analysis assumes these are included. If they are not, the decoupling adjustment as a percentage of the total rate would be even lower.
[30] EIA data for the respective years used as a proxy for the retail rate.
[31] The first decoupling adjustment appears to have occurred in July 2006. The filing for the 09/06 adjustment was missing from the Maryland Commission website.

Largest Adj	0.0397		0.0159	
Smallest Adj	(0.05)		(0.05)	
Average Adj	(0.0323)	(2.1)	(0.043)	(3.5)
2008[33]				
Largest Adj	0.073		0.05	
Smallest Adj	(0.05)		(0.05)	
Average Adj	0.02	1.2	(0.0223)	(1.7)
2009				
Largest Adj	0.008		0.0212	
Smallest Adj	(0.0272)		(0.05)	
Average Adj	(0.014)	<(0.1)	(0.01)	(0.8)

Washington Gas Light (gas)
Case/Order No.: Case 8990; Order No. 80130
http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction_new.cfm?RequestTimeout=500
Type of decoupling: Reconciles actual, non-weather-adjusted revenue to ratemaking revenue, adjusted for net customers added, on distribution only, by rate schedule. Maximum change in rates per month is 5¢, with any adjustment amount in excess of that carried over to future periods. Adjusts monthly.
Decoupling tariff: Revenue Normalization Adjustment, General Service Provisions No. 30 http://www.washgas.com/FileUpload/File/Tariffs/MD/md9899.pdf
Energy efficiency cost recovery: Yes. Demand-side Management Surcharge Adjustment, General Service Provisions No. 22
History of Adjustments:

Period	Residential Decoupling $/therm	Decoupling Adjustment % of Retail[34]	Commercial Decoupling $/therm	Decoupling Adjustment % of Retail
December 2005	0.0258	1.7	0.0139	1.2
2006				
Largest Adj	0.05		0.045	
Smallest Adj	0.0146		(0.05)	
Average Adj	0.0415	2.5	(0.02)	(1.5)
2007				
Largest Adj	0.0323		0.0499	
Smallest Adj	(0.05)		(0.05)	
Average Adj	(0.0085)	(0.56)	(0.027)	(2.2)
2008				
Largest Adj	0.05		0.05	
Smallest Adj	(0.05)		(0.05)	

[32] Filings for adjustments for January, March and April were missing from the Maryland Commission website.
[33] Filings for adjustments in April, October and November were mission from the Maryland Commission website.
[34] Retail prices based on EIA data for Maryland for respective years.

Average Adj 2009[35]	(0.0013)	(0.08)	(0.005)	(0.39)
Largest Adj	0.0344		0.0245	
Smallest Adj	(0.05)		(0.0386)	
Average Adj	(0.018)	(1.5)	(0.022)	(2.0)

Massachusetts

Massachusetts has announced a regulatory policy in favor of decoupling for all of its gas and electric utilities. D.P.U 07-50-A (July 2008) http://www.mass.gov/Eoeea/docs/dpu/electric/07-50/71608dpuord.pdf. None of the utilities have mechanisms in place yet.

Minnesota

In 2007, the Minnesota legislature enacted Section 216B.2412, https://www.revisor.leg.state.mn.us/statutes/?id=216B.2412 in which it defined an alternative approach to utility regulation, *decoupling*, and directed the Public Utilities Commission to "establish criteria and standards" by which it could adopt decoupling for the state's rate-regulated utilities. In addition, the legislation authorized the PUC to allow one or more utilities "to participate in a pilot program to assess the merits of a rate-decoupling strategy to promote energy efficiency and conservation," subject to the criteria and standards that the PUC will have established. To date, no utility pilots are in place.

Michigan

In 2008, Michigan passed PA 295, http://legislature.mi.gov/doc.aspx?2007-SB-0213 a comprehensive bill adopting a renewable energy portfolio standard and an energy efficiency portfolio standard for state electric and natural gas utilities. Section 89(6) states that the commission shall authorize any natural gas utility that spends a minimum of 0.5% of total natural gas retail sales revenues, including natural gas commodity costs, in a year on commission-approved energy efficiency programs to implement a symmetrical revenue decoupling true-up mechanism that adjusts for sales volumes that are above or below the projected levels that were used to determine the authorized revenue requirement. The Commission has not yet approved a decoupling mechanism under this section.

Nevada

In 2008, the Nevada Public Service Commission adopted temporary rules allowing gas utilities to propose a decoupling mechanism in a general rate case filed within one year of the approval of a set of energy efficiency programs for that utility. Docket No. 07-06046. http://pucweb1.state.nv.us/wx/DocView.aspx?DataSource=PUCN+Imaging&ParamEnc=

[35] Through May 2009.

28%3a4D605690F11E27F012E1E60C8921FD1EEDD79CFEA0229DFE8B7EB14452AF2C471C7CEAA1CF970B67CDA2AD4AE0CDFC51ED5922B5E6DD1B98989E303FB8F15D5D6D08D6153BAE4347AB1F5BA1161334F5CABA7968A9E94DA44ABC5B285CF46983F6774787FD62A42DC2948DCD8AA319003AF71485E3D7CE47887E97027141DC1825216D42A37388884DCB825AF30A075ADD824901B04B3682834A110EC55B357C08408C4D4732131396D0FDA84963BDD583915C2B541AC56C896E054A5B867D68DE185F5C7EA0D65E1F97F262BB32E527A71B4540EC51FFAA201E818A3E9D5315 The rules specify revenue per customer mechanism design, with adjustments done on a per class basis. NAC (Nevada Administrative Code) 704.953. http://pucweb1.state.nv.us/PUCN/general/pucnac.aspx

New Jersey

South Jersey Gas Company (gas)

Case/Order No.: Order No. GR05121019 (October 2006) (Link not available)
Type of decoupling: Reconciles ratemaking margin revenue per customer with actual, non-weather adjusted margin per customer, adjusted for net customers added, on a per rate schedule basis. Any revenue deficiency related to non-weather (calculated pursuant to a separate schedule – Rider D) causes is limited to the amount of offsetting revenue from sales of surplus gas. Surcharges recoveries may not occur if the utility would earn more than its allowed return on common equity but amounts excluded carry over.
Decoupling tariff: Conservation Incentive Program, Rider M, Sheet 97c
http://www.southjerseygas.com/108/tariff/Tariff060109.pdf
Energy efficiency cost recovery: Yes. Rider K, Clean Energy Program Clause (CLEP) Note that this includes lost revenue associated with programmatic savings.
History of Adjustments[36]

Class/Year	Decoupling Adjustment[37] ($/therm)	Decoupling amount as % of margin[38]	Decoupling amount as % of rate[39]
2008			
Residential	0.0443	9.8	2.8
General	0.0392	10.9	2.6
General Large Volume	(0.0037)	(1.3)	(0.3)
2009			
Residential	0.0707	15.6	4.8
General	0.0684	19	5
General Large Volume	0.0062	2.1	0.5

[36] The mechanism began in October 2006, with the first adjustment in October 2007.
[37] South Jersey does not make rate changes for the decoupling adjustments because its tariff requires that it offset the amounts against revenues it earns from the release of gas supplies.
[38] Margin based on currently published tariffs.
[39] This is an estimate using the EIA natural gas city gate price for 2008 and January 2009, respectively. These amounts are not rate changes per se. In particular, the 2009 decoupling adjustments as a percentage of the total rate is shown without regard to the prior 2008 rate change. On a cumulative basis, the increase was only approximately 1.6% for residential customers.

New Jersey Natural Gas Company (gas)
Case/Order No.: Order No. GR05121020 (October 2006) (link not available)
Type of decoupling: Reconciles ratemaking margin revenues per customer with actual, non-weather adjusted margin per customer, adjusted for net customers added, on a per rate schedule basis. Any revenue deficiency attributable to non-weather (calculated pursuant to a separate schedule – Rider D) causes is limited to the amount of offsetting revenue from sales of surplus gas. Surcharges recoveries may not occur if the utility would earn more than its allowed return on common equity but any recovery so excluded carries over.
Decoupling tariff: Conservation Incentive Program, Rider I
http://www.njng.com/regulatory/pdf/060109.pdf
Energy efficiency cost recovery: Yes. Rider E, Clean Energy Program Clause (CLEP)

History of Adjustments[40]

Class/Year	Decoupling Adjustment[41] ($/therm)	Decoupling amount as % of rate[42]
2008		
Residential	0.0261	1.7
General	0.0248	2.0
2009		
Residential	0.0378	2.5
General	0.0424	2.8

New York

Consolidated Edison (gas)
Case/Order No.: 06-G-1332; 1-102-06G1332 (September 2007)
http://documents.dps.state.ny.us/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=06-G-1332&submit=Search+for+Case%2FMatter+Number
Type of decoupling: Reconciles actual, non-weather-adjusted revenues per customer with ratemaking revenues per customer, according to several service classification groupings.
Decoupling tariff: General Information Special Adjustment No. 14, leaf 181-182; apparently in force only 10/07 through 9/08
http://www.coned.com/documents/gas_tariff/pdf/0003(09)-General_Information.pdf#page=12
Energy efficiency cost recovery: Yes
History of Adjustments (Unable to locate)

[40] The mechanism began in October 2006, with the first adjustment in October 2007.
[41] New Jersey Natural Gas does not make rate changes for the decoupling adjustments because its tariff requires that it offset the amounts against revenues it earns from the release of gas supplies.
[42] This is an estimate using the EIA natural gas city gate price for 2008 and January 2009, respectively. These amounts are not rate changes per se. 2008 EIA commercial retail gas price data for New Jersey was not available; this uses the 2007 annual.

Consolidated Edison (electric)
Case/Order No.: 07-E-0523; 1-301-07E0523 (March 25, 2008)[43]
http://documents.dps.state.ny.us/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=07-E-0523&submit=Search+for+Case%2FMatter+Number
Type of decoupling: Reconciles actual, non-weather adjusted revenues to ratemaking revenues on a per class basis. Adjusts semi-annually.
Decoupling tariff: PSC No. 9-Electricity, Leaf 168F
http://www.coned.com/documents/elec/165-168i.pdf
Energy efficiency cost recovery: Pending; decoupling specifically adopted without connection to an approved energy efficiency program
History of Adjustments[44]

Service Class	Adjustment	Percent of Delivery Charge[45]
Residential (1)	(0.1502)	(2.3)
General Commercial (2)	(0.0071)	(0.8)

National Fuel Gas Distribution (gas)
Case/Order No.: 07-G-0141, 1-102-07G0141 (December 2007)
http://documents.dps.state.ny.us/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=07-G-0141&submit=Search+for+Case%2FMatter+Number
Type of decoupling: Reconciles actual, weather-normalized margin revenue per customer with ratemaking margin per customer, adjusted for net customers added. There is a separate weather adjustment that applies for October through May only.
Decoupling tariff: Conservation Incentive Program Cost Recovery, Sheet 148.9; adjustments effective on annual basis, December through November
https://www2.dps.state.ny.us/ETS/jobs/display/download/4677590.pdf
Energy efficiency cost recovery: Yes
History of Adjustments

Service Class	Adjustment $/Mcf	Percent of Rates[46]
Residential	(0.082)	(0.77)
General Service	(0.082)	(0.87)

[43] The order included a 10 basis point ROE reduction ordered to account for the effect of the decoupling mechanism on the utility's risk.
[44] The decoupling mechanism applies to 10 schedules in total. Many of those contain demand charges that make calculation of the per kWh decupling adjustment as a percentage of the rate difficult. The two shown above contain by far the greatest number of customers.
[45] This charge does not include electricity commodity. The decoupling adjustments as a percentage of that amount would be even smaller.
[46] Based on May 2009 retail rates. These rates change monthly.

Orange & Rockland (electric)
Case/Order No.: 07-E-0949; Order No. 1-302-07E0949
http://documents.dps.state.ny.us/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=07-E-0949&submit=Search+for+Case%2FMatter+Number
Type of decoupling: Reconciles actual, non-weather adjusted revenues with ratemaking revenues (delivery only) per class with certain schedules excluded: economic development, lighting, special contracts. Ratemaking revenues adjust automatically according to a three-year schedule. Program ends June 30, 2011.
Decoupling tariff: General Information Sheet 25
http://www.oru.com/documents/tariffsandregulatorydocuments/ny/electrictariff/electricGI25.pdf ;
Energy efficiency cost recovery: Programs and recovery pending in separate proceeding 07-M-0548 to be decided later in 2008.
History of Adjustments: None to date.

North Carolina

In 2007, North Carolina enacted a statute specifically authorizing the Commission to approve decoupling mechanisms for natural gas utilities.
http://www.ncleg.net/EnactedLegislation/Statutes/HTML/BySection/Chapter_62/GS_62-133.7.html

Piedmont Natural Gas (gas)
Case/Order No.: Dockets G-9, Sub 499 (November 2005) and G-9, Sub 550 (November 2008) http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=KAAAAA52350B&parm3=000123283 and http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=SAAAAA89280B&parm3=000128268
Type of decoupling: Reconciles actual, non-weather adjusted margin per customer with ratemaking margin per customer, by rate schedule. Adjusts twice a year.
Decoupling tariff: Customer Utilization Tracker (CUT), now called Margin Decoupling Tracker, Appendix C
http://www.piedmontng.com/rates/tariffs/uploadedTariffs/ncTariff.pdf
Energy efficiency cost recovery: In the initial 3-year decoupling experiment, the utility donated funds totaling $750,000 for energy efficiency without recovery; in the extension, the Commission approved including $1.275 million in rates for these programs
Energy efficiency incentives: No.
History of Adjustments

Period	Residential Adjustment $/therm	% of Rate[47]	Small Comm. Adjustment $/therm	% of Rate	Med. Comm. Adjustment $/therm	% of Rate
Apr 2006	0.02262	1.3	0.0123	0.87	0.000860	<0.1
Nov 2006	0.05181	3.1	0.02339	1.7	0.011389	1.0
Apr 2007	0.07791	5.0	0.04127	3.2	0.00996	1.0
Nov 2007	0.06153	3.9	0.03118	2.4	0.01213	1.2
Apr 2008	0.08471	5.1	0.04732	3.3	0.01452	1.2
Nov 2008	0.07494	4.5	0.03819	2.7	0.02394	1.9

Public Service Company of North Carolina (gas)
Case/Order No.: G-5, Sub 495 (October 2008) http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=RAAAAA89280B&parm3=000128260
Type of decoupling: Reconciles actual, non-weather adjusted margin per customer with ratemaking margin per customer, by rate schedule. Adjusts twice a year.
Decoupling tariff: Rider C Customer Usage Tracker
http://www.psncenergy.com/NR/rdonlyres/0E0B99DA-911C-4674-AF7E-EA5602091DB6/0/Rider_C.pdf
Energy efficiency cost recovery: Yes, up to $750,000 per year, with no true-up to actual expenditures
History of Adjustments
The Commission just approved the decoupling mechanism for PS Co of North Carolina in October 2008. The first adjustment under the mechanism has not occurred as of May 2009, but will likely appear shortly.

Oregon

Cascade Natural Gas (gas)
Case/Order No.: UG 167; Order No. 06-191
http://apps.puc.state.or.us/orders/2006ords/06-191.pdf
Type of decoupling: Reconciles actual margin per customer with ratemaking margin per customer, adjusted for current customer count but does so separately for weather-related variances and all other variances. Calculations and rate adjustments done on a per rate schedule basis. Earnings sharing applies to extent earnings with adjustment clauses recoveries exceed 175 basis points over allowed return on common equity. Decoupling ends after three years unless the utility re-files.
Decoupling tariff: Rule 19, Original Sheet 30, Conservation Alliance Plan mechanism
http://www.cngc.com/post/rates_tariffs/oregon/0030_Rule_19_-_Conservation_Alliance_Plan.pdf

[47] EIA annual city gate prices for respective years used as a proxy for total rate. It is useful to remember these are not necessarily rate changes in customer bills. Assuming nothing else was occurring, slight rate increases would have occurred in April and November 2006 and April 2007, but then a decrease in November 2007 as the decoupling adjustment declined from the prior level, an increase in April 2008 and an decrease again in November 2008.

Energy efficiency cost recovery: Yes, through a public purpose charge the revenue from which goes to the Energy Trust of Oregon for programs
History of Adjustments

	Decoupling Use-Per-Customer Forecast Change ($/therm)	Decoupling True-Up ($/therm)	Average Total Rate ($/therm)	Total Decoupling as % of Rate
7/06 – 6/07				
Residential	0.01693	0.01538	1.26	2.6
Commercial	0.00934	0.01538	1.12	2.2
7/07 – 6/08				
Residential	(0.0292)	(0.02055)	1.39	(3.6)
Commercial	(0.0112)	(0.02055)	1.25	(2.5)

Northwest Natural Gas (gas)
Case/Order No.: UG 163, Order No. 07-426
http://apps.puc.state.or.us/orders/2007ords/07-426.pdf
Type of decoupling: Reconciles actual, weather-adjusted margin per customer with ratemaking margin per customer, adjusted for current customer count, by customer class. Weather-adjustment occurs through a separate tariff from which customers can choose to opt out. Program runs through October 2012.
Decoupling tariff: Schedule 190
https://www.nwnatural.com/CMS300/uploadedFiles/24190ai(3).pdf
Energy efficiency cost recovery: Through a public purpose charge – the revenues collected go to the Energy Trust of Oregon to run programs.
History of Adjustments

Year	Decoupling Adjustment ($ million)	Decoupling Adjustment (% of rate)
2003	3.6	0.6
2004	2.1	0.36
2005	6.2	0.77
2006	(2.2)	(0.27)
2007	0.8	<0.1
2008	(2.5)	<(1.0)

PacifiCorp (electric)
Case/Order No.: UE-94; Order No. 98-191 (not available electronically)
http://apps.puc.state.or.us/edockets/docket.asp?DocketID=5178
Type of decoupling: Reconciled actual weather-adjusted revenues to ratemaking revenues for distribution services only. Ratemaking revenues increased each year, automatically, by inflation less a 0.3% productivity factor. The mechanism was part of a 3-year

alternate-form-of-regulation (AFOR). The AFOR expired shortly before Oregon restructuring (February 2002).
Decoupling tariff: NA
Energy efficiency cost recovery: Yes, through a public purpose charge included in the package.
History of Adjustments[48]

Customer Class	1999	2000	2001
Residential	(0.39)	1.9	1.85
Small General Service	(0.6)	(0.22)	0.06
General Service	(0.83)	(0.31)	0.09
Large General Service	0.61	0.33	(0.3)
Irrigation	0.45	0.25	(0.2)

Portland General Electric (electric)
Case/Order No.: UE-197; Order No. 09-020 and 09-196
http://apps.puc.state.or.us/orders/2009ords/09-176.pdf
Type of decoupling: Reconciles actual, weather-adjusted fixed cost revenue per customer for residential and small general service to ratemaking fixed cost revenue per customer, by customer class. Decoupling adjustments limited to two percent per year, positive or negative; amounts in excess do not roll over to future periods.[49] Program runs two years.
Decoupling tariff: Schedule 123
http://www.portlandgeneral.com/about_pge/regulatory_affairs/pdfs/schedules/Sched_123.pdf
Energy efficiency cost recovery: Yes, through a regular and an add-on public purpose charge; virtually all of the funding goes to the Energy Trust of Oregon to run programs.
History of Adjustments: None yet. The first should occur in 2010.

Utah

Questar Gas (gas)
Case/Order No.: 05-057-T01 (October 2006)
http://www.psc.utah.gov/utilities/gas/06orders/Oct/05057t01oass.pdf
Type of decoupling: Reconciles 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 capped at a cumulative 1% of gross revenues per twelve-month period. Three-year program ends December 2009. Renewal dockets are pending.
Decoupling tariff: 2.08 Conservation Enabling Tariff
http://www.questargas.com/Tariffs/uttariff.pdf
Energy efficiency cost recovery: Yes, 2.09 Demand-side Management tariff
History of Adjustments

[48] The figures shown are actual rate changes (in %) attributable to decoupling within the overall alternate form of regulation.
[49] Commission order approving decoupling applied a 10 basis point return on common equity reduction.

Period	Decoupling Adjustment (% of overall rate)
7/06 – 3/07	0.27
4/07 – 8/07	0.36
9/07 – 3/08	(0.47)
4/08 – 8/08	0.01

Vermont

Central Vermont Public Service (electric)
Case/Order No.: 7336, http://www.state.vt.us/psb/orders/2008/files/7336%20Final.pdf
Type of decoupling: CVPS has an alternative regulatory plan under which it 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 will be difficult to calculate to what extent revenue changes driven by consumption changes have contributed to any adjustment, however.
Decoupling tariff: NA
Energy efficiency cost recovery: Public Purpose Charge with funds sent to Efficiency Vermont, a non-profit third-party provider
History of Adjustments: It will not be possible to isolate the effects of sales changes from other elements included in the plan.

Green Mountain Power (electric)
Case/Order No.: 7175 and 7176 http://www.state.vt.us/psb/orders/2006/files/7175-7176finalorder.pdf
Type of decoupling: As with Central Vermont Public Service (CVPS), the partial decoupling occurs through a comprehensive alternative form of regulation. Under the 3-year plan, GMP changes its rates every year based on a forecast of sales and costs. Thus, sales increases provide, at most, a partial year benefit to the Company. In addition, the earnings sharing provision operates, as CVPS' does, to minimize the loss if sales should fall significantly from forecast as well as share the benefit with customers if sales should rise. The Board explicitly found that full decoupling was unnecessary with this comprehensive plan.
Decoupling tariff: NA
Energy efficiency cost recovery: Public Purpose Charge with funds sent to Efficiency Vermont, a non-profit third-party provider
History of Adjustments: It will not be possible to isolate the effects of sales changes from other elements included in the plan.

Virginia

Virginia Gas (gas)
Case/Order No.: PUE-2008-00060 (December 2008)
http://docket.scc.virginia.gov/vaprod/main.asp
Type of decoupling: For residential customers only, reconciles actual, weather-adjusted revenue per customer to ratemaking revenue per customer approved in an existing performance-based ratemaking plan. A separate weather adjustment rider exists.
Decoupling tariff: Revenue Normalization Adjustment Rider D (not available in utility's on-line tariff)
Energy efficiency cost recovery: Yes
History of Adjustments: None to date.

Washington

Cascade Natural Gas (gas)
Case/Order No.: UG-060256 (January 2007), Order Nos. 05, 06, and 07
http://wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/c6d08ccab87aceb2882572610082a4df!OpenDocument ,
http://wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/2293364b330b249c8825733900798c2c!OpenDocument,
http://wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/67316d49ff5b839e882573670080db42!OpenDocument
Type of decoupling: Reconciles actual, weather-adjusted margin revenue per customer with ratemaking margin revenue per customer, for residential and general commercial service only, by rate schedule. Adjustments occur the annual Temporary Technical Adjustment filing.
Decoupling tariff: Original Sheet 25, Conservation Alliance Plan mechanism
http://www.cngc.com/post/rates_tariffs/washington/021_Rule_Conservation_Alliance_Plan_Mechanism.pdf
Energy efficiency cost recovery: Yes
History of Adjustments: The mechanism took effect October 2007 and the first adjustment period ran through December 2008. Cascade reported an adjustment of ($401,328.82) in March 2009. The minor rate decrease associated with this will occur along with Cascade's PGA filing in Fall 2009.

Avista (gas)
Case/Order No.: UG-060518 (February 2007)
http://wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/f1f6a64cb9d2aa0688257275007a230d!OpenDocument
Type of decoupling: Reconciles actual, weather-adjusted margin revenue per customer with ratemaking margin revenue per customer, for general service customers only, with a positive or negative adjustment of 90% of the difference. Recoveries limited to amounts that bring the utility up to its allowed return on common equity and contingent upon meeting certain energy efficiency targets, using a sliding scale. Any surcharges resulting

from the decoupling calculation limited to two percent per year, cumulative over the program (6%). Three-year pilot program.
Decoupling tariff: Schedule 159 (applies only to General Service)
http://www.avistautilities.com/services/energypricing/tariffs/wa/gas/Documents/WA_159.pdf
Energy efficiency cost recovery: Yes, schedule 191
History of Adjustments

Period	Adjustment Effective in Rates ¢/therm	Percentage of Margin	Percentage of Total Rate[50]
1/07 – 6/07	.257	1.25	0.28
7/07 – 12/07	.257	1.18	0.25
1/08 – 6/08	.593	2.73	0.58
7/08 – 12/08	.593	2.73	0.56

Wisconsin

Wisconsin Public Service Corporation (electric and gas)
Case/Order No.: Docket No. 6690-UR-119
http://psc.wi.gov/apps/erf_share/view/viewdoc.aspx?docid=106184 and
http://psc.wi.gov/apps/erf_share/view/viewdoc.aspx?docid=108565
Type of Decoupling: For both gas and electric, reconciles actual, non-weather-adjusted margin revenues per customer, by customer class, with ratemaking margin revenues per customer, adjusted for actual number of customers. Margin determined several different ways, depending on customer class and whether distribution fixed costs or supply fixed cost. Caps apply – amounts in excess of the cap not booked for later credit or surcharge; caps based on revenue requirement value of 100 basis points of return on common equity ($8 for gas; $14 for electric). Four-year pilot program.
Decoupling Tariffs: PSCW-8, Schedule GRSM-1 (gas)
http://www.wisconsinpublicservice.com/news/gas/GRSM.pdf: PSCW-7, Schedule ERSM-1 (electric) http://www.wisconsinpublicservice.com/news/electric/ERSM.pdf ling
Weather: Revenues not weather adjusted – actual revenues used
Energy efficiency cost recovery: Yes
History of Adjustments: None to date.

Wyoming

Questar Gas Company (gas)
Case/Order No.: 30010-94-GR-8 (May 2009)[51] (order not yet available electronically)

[50] Estimated using 2007, 2008 and January 2009 City Gate gas prices for Washington from EIA. These are not actual rate changes; rather just the adjustment expressed as a percentage of the entire rate. During the period of Avista's decoupling adjustment so far, there have been only two rate changes.
[51] The order is not yet available on the Commission's website.

Type of decoupling: Reportedly similar to Utah mechanism, which reconciles actual, non-weather adjusted margin revenues per customer with ratemaking margin revenues per customer, only for one class of customer.
Decoupling tariff: (tariff not yet available electronically)
Energy efficiency cost recovery: Yes

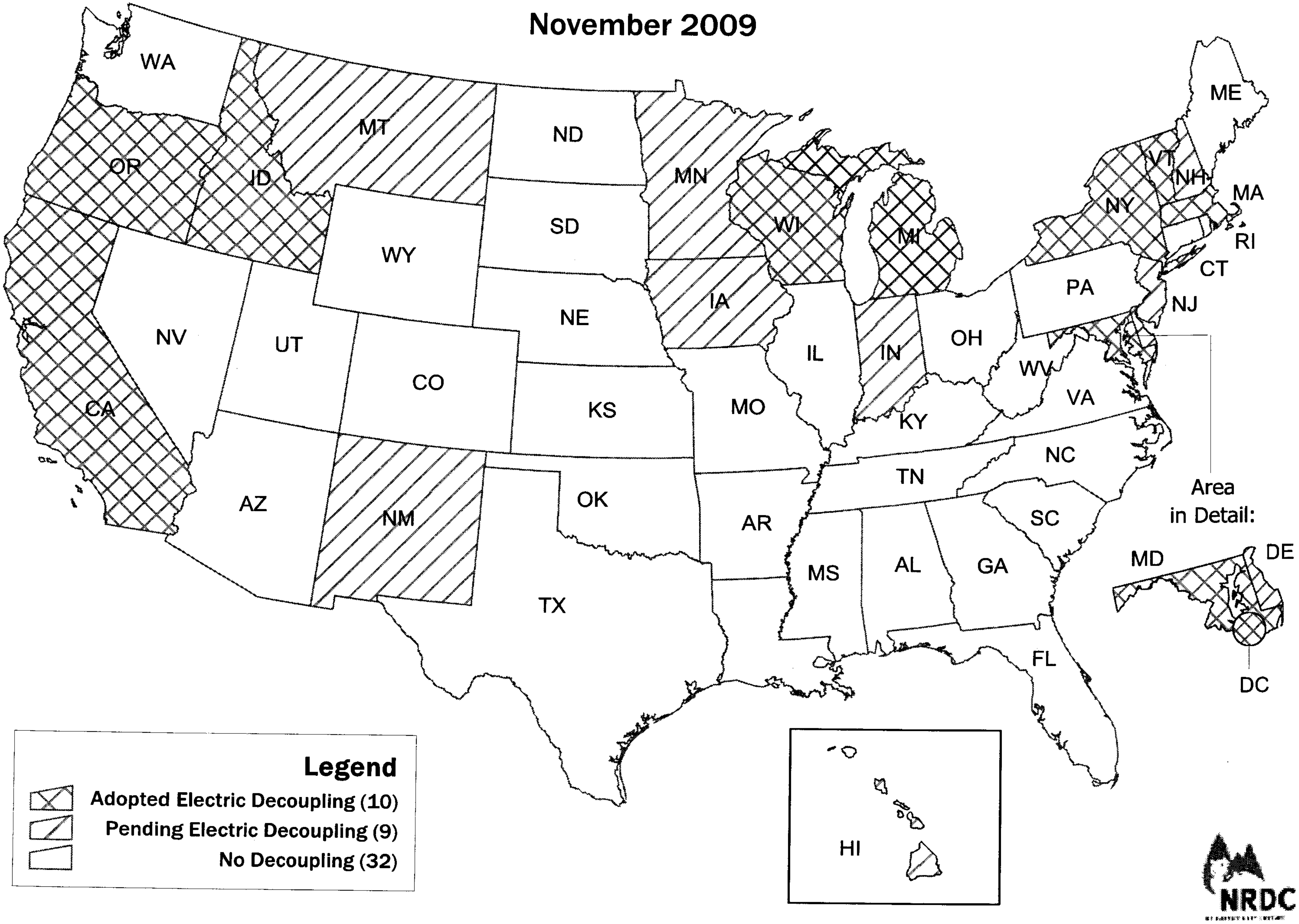
Closing Observation

Finding all of the decoupling mechanisms and summarizing the adjustments made under them was an exceedingly difficult task. I have a total of over 25 years in utility matters, most spent in the regulatory affairs department of a mid-sized electric utility. I know my way around a tariff and am generally familiar with naming conventions and so forth used by public utility commissions. Despite this wealth of experience, the task was difficult. This caused me to wonder what those not on the "inside" can possibly think of how utilities and regulators present information? Most would not think that the obfuscation was deliberate but many would conclude that ensuring people actually understood utility rates and regulation was not the goal.

The means of tackling this issue range from the simple to the significant. As a simple matter, some conventions around what utilities and commissions call things, what information appears in filing letters and annual (perhaps) information compiling tariffs and riders into complete rate information would help. This would seem a useful place for NARUC to work, in collaboration with the AGA and EEI. A far more significant effort would be the re-thinking of the tariff structure used by virtually every utility in the country. I suspect that most have changed little, in structure, for well over 50 years. General conditions appear in one place, riders and adjustments clauses in another, "base" rates somewhere else in schedule numbers that mean nothing to anyone. Tariffs may now be "on" the Internet, but they are not Internet-enabled or Internet-friendly. It seems likely that the future holds more variation in, and personalization of, rates, not less. Again, the utilities and regulators should collaborate to envision the "tariffs" (if we still call them that) of the future and how the industry might go about the transformation.

Electric Decoupling in the US

November 2009



Gas and Electric Decoupling in the US

October 2009