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Revenue Regulation and Decoupling:

A Guide to Theory and Application

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Preface

This guide was prepared to assist anyone who needs to understand both the mechanics of a regulatory tool known as *decoupling* and the policy issues associated with its use. This includes public utility commissioners and staff, utility management, advocates, and others with a stake in the regulated energy system.

Many utility-sector stakeholders have recognized the conflicts implicit in traditional regulation that compel a utility to encourage energy consumption by its customers, and they have long sought ways to reconcile the utility business model with contradictory public policy objectives. Simply put, under traditional regulation, utilities make more money when they sell more energy. This concept is at odds with explicit public policy objectives that utility and environmental regulators are charged with achieving, including economic efficiency and environmental protection. This *throughput incentive* problem, as it is called, can be solved with decoupling.

Currently, some form of decoupling has been adopted for at least one electric or natural gas utility in 30 states and is under consideration in another 12 states. As a result, a great number of stakeholders are in need, or are going to be in need, of a basic reference guide on how to design and administer a decoupling mechanism. This guide is for them.

More and more, policymakers and regulators are seeing that the conventional utility business model, based on profits that are tied to increasing sales, may not be in the long-run interest of society. Economic and environmental imperatives demand that we reshape our energy portfolios to make greater use of end-use efficiency, demand response, and distributed, clean resources, and to rely less on polluting central utility supplies. Decoupling is a key component of a broader strategy to better align the utility's incentives with societal interests.

While this guide is somewhat technical at points, we have tried to make it accessible to a broad audience, to make comprehensible the underlying concepts and the implications of different design choices. This guide is accompanied by a spreadsheet that can be used to demonstrate the impacts of decoupling using different pricing structures or, as the jargon has it, *rate designs*.

This guide was written by Jim Lazar, Frederick Weston, and Wayne Shirley. The RAP review team included Rich Sedano, Riley Allen, Camille Kadoch, and Elizabeth Watson. Editorial and publication assistance was provided by Diane Derby and Camille Kadoch.

1 Natural Resources Defense Council, *Gas and Electric Decoupling in the U.S.*, April 2010.

1. Introduction

This document explains the fundamentals of *revenue regulation*[2], which is a means for setting a level of revenues that a regulated gas or electric utility will be allowed to collect, and its necessary adjunct *decoupling,* which is an adjustable price mechanism that breaks the link between the amount of energy sold and the actual (allowed) revenue collected by the utility. Put another way, *decoupling* is the means by which *revenue regulation* is effected. For this reason, the two terms are typically treated as synonyms in regulatory discourse; and, for simplicity's sake, we treat them likewise here.

Revenue regulation does not change the way in which a utility's allowed revenues (i.e., the "revenue requirement") are calculated. A revenue requirement is based on a company's underlying costs of service, and the means for calculating it relies on long-standing methods that need not be recapitulated in detail here. What is innovative about it, however, is how a defined revenue requirement is combined with decoupling to eliminate sales-related variability in revenues, thereby not only eliminating weather and general economic risks facing the company and its customers, but also removing potentially adverse financial consequences flowing from successful investment in end-use energy efficiency.

We begin by laying out the operational theory that underpins decoupling. We then explain the calculations used to apply a decoupling price adjustment. We close the document with several short sections describing some refinements to basic revenue regulation and decoupling.

This printing includes *Decoupling Case Studies: Revenue Regulation Implementation in Six States*, published by RAP in 2014 as a follow-up to this guide.

To assist the reader, an MS Excel spreadsheet is also available that contains sample scenario inputs, analyses, and charts for three forms of revenue regulation, as well as a functioning "decoupling model." It can be downloaded at http://www.raponline.org/wp-content/uploads/2016/05/rap-decouplingmodelspreadsheet-2011-05-17.xlsb.

2 Revenue regulation is often called revenue *cap* regulation. However, when combined with decoupling, the effect is to simply regulate revenue – i.e., there is a corresponding *floor* on revenues in addition to a *cap*.

2. Context for Decoupling

Decoupling is a tool intended to break the link between how much energy a utility delivers and the revenues it collects. Decoupling is used primarily to eliminate incentives that utilities have to increase profits by increasing sales, and the corresponding disincentives that they have to avoid reductions in sales. It is most often considered by regulators, utilities, and energy-sector stakeholders in the context of introducing or expanding energy efficiency efforts; but it should also be noted that, on economic efficiency grounds, it has appeal even in the absence of programmatic energy efficiency.

There are a limited number of things over which utility management has control. Among these are operating costs (including labor) and service quality. Utility management can also influence usage per customer (through promotional programs or conservation programs). Managers have very limited ability to affect customer growth, fuel costs, and weather. Decoupling typically removes the influence on revenues (and profits) of such factors and, by eliminating sales volumes as a factor in profitability, removes any incentive to encourage consumers to increase consumption. This focuses management efforts on cost-control to enhance profits.

In the longer run, this effort constrains future rates and benefits consumers. It also means that energy conservation programs (which reduce customer usage) do not adversely affect profits. A performance incentive system and a customer-service quality mechanism can overlay decoupling to further promote public interest outcomes.

Although it is often viewed as a significant deviation from traditional regulatory practice, decoupling is, in fact, only a slight modification. The two approaches affect behavior in critically different ways, yet the mathematical differences between them are fairly straightforward. Still, it goes without saying that care must be taken in designing and implementing a decoupling regime, and the regulatory process should strive to yield for both utilities and consumers a transparent and fair result.

While traditional regulation gives the utility an incentive to preserve and, better yet, increase sales volumes, it also makes consumer advocates focus on price – after all, that is the ultimate result of traditional regulation. Because decoupling allows prices to change between rate cases, consumer advocates can move the focus of their effort from prices to all cost drivers, including sales volumes – focusing on bills rather than prices.

3. How Traditional Regulation Works

In virtually all contexts, public utilities (including both investor-owned and consumer-owned utilities) have a common fundamental financial structure and a common framework for setting prices.[3] This common framework is what we call the utility's overall *revenue requirement.* Conceptually, the revenue requirement for a utility is the aggregate of all of the operating and other costs incurred to provide service to the public. This includes operating expenses like fuel, labor, and maintenance. It also includes the cost of capital invested to provide service, including both interest on debt and a "fair" return to equity investors. In addition, it includes a depreciation allowance, which represents repayment to banks and investors of their original loans and investments.

In order to determine what price a utility will be allowed to charge, regulators must first compute the total cost of service, that is, the revenue requirement. Regulators then compute the price (or rate) necessary to collect that amount, based on assumed sales levels. In most cases, the regulator relies on data for a specific period, referred to here as the *test period,* and performs some basic calculations.

Here are the two basic formulae used in traditional regulation:

***Formula 1:* Revenue Requirement = (Expenses + Return + Taxes)** TEST PERIOD
***Formula 2:* Rate = Revenue Requirement ÷ Units Sold** TEST PERIOD

The rate is normally calculated on a different basis for each customer class, but the principle is the same – the regulator divides the revenue requirement among the customer classes, then designs rates for each class to recover each class's revenue requirement. Table 1 is an example of this calculation, under the simplifying assumption that the entire revenue requirement is collected through a kWh charge.

3 Conditions vary widely from country to country or region to region, and utilities face a number of local and unique challenges. However, for our purposes, we will assume that there is a fundamental financial need for revenues to equal costs – including any externally imposed requirements to fund or secure other expense items (such as required returns to investors, debt coverage ratios in debt covenants, or subsidies to other operations, as is often the case with municipal- or state-run utilities). In this sense, virtually all utilities can be viewed as being quite similar.

3.1 Revenue Requirement

Table 1

Traditional Regulation Example: Revenue Requirement Calculation	
Expenses	100,000,000
Net Equity Investment	100,000,000
Allowed Rate of Return	10.00%
Allowed Return	$10,000,000
Taxes (35% tax rate)	$5,384,615
Total Return & Taxes	$15,384,615
Total Revenue Requirement	$115,384,615
Price Calculation	
Revenue Requirement	$115,384,615
Test Year Sales (kWh)	1,000,000,000
Rate Case Price ($/kWh)	$0.1154

A utility's revenue requirement is the amount of revenue a utility will actually collect, only if it experiences the sales volumes assumed for purposes of price-setting. Furthermore, only if the utility incurs exactly the expenses and operates under precisely the financial conditions that were assumed in the rate case will it earn the rate of return on its rate base (i.e., the allowed investment in facilities providing utility service) that the regulators determined was appropriate. While much of the rate-setting process is meticulous and often arcane, the fundamentals do not change: in theory a utility's revenue requirement should be sufficient to cover its cost of service — no more and no less.

3.1.1 Expenses

For purposes of decoupling, expenses come in two varieties: production costs and non-production costs.[4]

3.1.1.1 Production Costs

Production costs are a subset of total power supply costs, and are composed principally of fuel and purchased power expenses with a bit of variable operation and maintenance (O&M) and transmission expenses paid to others included. Production costs as we use the term here are those that vary more or less directly with energy consumption in the short run. The mechanisms approved by regulators generally refer to very specific accounts defined in the utility accounting manuals, including "fuel," "purchased power," and "transmission by others."

4 A utility's expenses are often characterized as "fixed" or "variable. However, for purposes of resource planning and other long-run views, all costs are variable and there is no such thing as a fixed cost. Even on the time scale between rate cases, some non-production costs that are often viewed as fixed (e.g., metering and billing) will, in fact, vary directly with the number of customers served. When designing a decoupling mechanism, it is more appropriate to differentiate between "production" and "non-production," since one purpose of the mechanism is to isolate the costs over which the utility actually has control in the short run (i.e., the period between rate cases).

Production costs for most electric utilities are typically recovered through a flow-through account, with a reconciliation process that fully recovers production costs, or an approximation thereof.[5] This is usually accomplished through a separate fuel and purchased-power rate (fuel adjustment clause, or FAC) on the customer's bill. This may be an "adder" that recovers total production costs, or it may be an up-or-down adjustment that recovers deviations in production costs from the level incorporated in base rates.

In the absence of decoupling, a fully reconciled FAC creates a situation in which any increase in sales results in an increase in profits, and any decrease in sales results in a decrease in profits. This is because even if very high-cost power is used to serve incremental sales, and if 100% of this cost flows through the FAC, the utility receives a "net" addition to income equal to the base rate (retail rate less production costs) for every incremental kilowatt-hour sold.[6] An FAC is therefore a negative influence on the utility's willingness to embrace energy efficiency programs and other actions that reduce utility sales. Decoupling is an important adjunct to an FAC to remove the disincentive that the FAC creates for the utility to pursue societal cost-effectiveness.[7]

Because they vary with production and because they are separately treated already, production costs are not usually included in a decoupling mechanism. If a utility is allowed to include the investment-related portion of costs for purchased power contracts (i.e., it buys power to serve load growth from an independent power producer, and pays a per-kWh rate for the power received), it may be necessary to address this in the structure of the FAC to ensure that double recovery does not occur. This can also be addressed by using a comprehensive power cost adjustment that includes all power supply costs, not just fuel and purchased power. Unless otherwise noted, we assume that production costs are not included in the decoupling mechanism.

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5 Many commissions use incentive mechanisms in their fuel and purchased-power mechanisms, to provide utilities with a profit motive to minimize fuel and purchased-power costs and to maximize net off-system sales revenues. For our purposes, these are deemed to fully recover production costs. Some regulators include both fixed and variable power supply costs in their power supply cost recovery mechanism, in which case all of those would be classified as "production" costs and deemed to be fully recovered through the power supply mechanism.

6 Moskovitz, D. (1989, November). *Profits & Progress Through Least-Cost Planning,* p. 4. National Association of Regulatory Utility Commissioners. Retrieved from http://www.raponline.org/knowledge-center/profits-progress-through-least-cost-planning/

7 If a utility does not have an FAC at all, or acquires power from independent power producers on an ongoing basis to meet load growth, the framework for decoupling may need to be slightly different. In those circumstances, revenues from the sale of surplus power or avoided purchased power expense resulting from sales reductions flows to the utility, not to the consumers, through the FAC. In this situation, the definition of "production costs" may need to include both power supply investment-related costs and production-related operating expenses for decoupling to produce equitable results for consumers and investors.

3.1.1.2 Non-Production Costs

Non-production costs include all those that are not production costs — in essence, everything that is related to the delivery of electricity (transmission, distribution, and retail services) to end users. This normally includes all non-production related O&M expenses, including depreciation and interest on debt. In many cases, the base rates also include the debt and equity service (i.e., the interest, return, and depreciation) on power supply investments, in which case the form of the FAC becomes important.

Statistically, a utility's non-production costs do not vary much with consumption in the short run, but are more affected by changes in the numbers of customers served, inflation, productivity, and other factors.[8] Of course, a utility with a large capital expenditure program, such as the deployment of smart grid technologies or significant rebuilds of aging systems, will experience a surge in costs that is unrelated to customer growth. Decoupling does not address this issue, which is better handled in the context of a rate case or infrastructure tracking mechanism.

Non-production costs are usually recovered through a combination of a customer charge,[9] plus one or more volumetric (per kWh, per kW) rates. A utility may face the risk of not recovering some non-production costs if sales decline. Put another way, many of the costs do not vary with sales, so each dollar decline in sales flows straight to — and adversely affects — the bottom line.

3.1.2 Return

For our purposes, the utility's "return" is the same as its net, after-tax profit, or net income for common stock.[10] When computing a revenue requirement for a rate case, this line item is derived by multiplying the utility's net equity investment by its "allowed" rate of return on common equity. We have simplified this return in the illustration, but will address it in more detail in Section 10, *Earnings Volatility Risks and Impacts on the Cost of Capital.*

8 Eto, J., Stoft, S., and Belden, T. (1994, January). *The Theory and Practice of Decoupling Utility Revenues from Sales.* Lawrence Berkeley National Laboratory. Retrieved from http://eetd.lbl.gov/sites/all/files/publications/the-theory-and-practice-of-decoupling-utility-revenues-from-sales.pdf

9 In place of a customer charge, one may also find other monthly fixed charges, such as minimum purchase amounts, access fees, connection fees, or meter fees. For our purposes, these are all the same because they are not based on energy consumption, but, instead, are a function of the number of customers.

10 Regulatory commissions often calculate an "operating income" figure in the process of setting rates; this does not take account of the tax effects on the debt and equity components of the utility capital structure. Net income includes these effects.

11 Shirley, W., Lazar, J. & Weston, F. Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission. Montpelier, VT: Regulatory Assistance Project. Retrieved from http://www.raponline.org/knowledge-center/revenue-decoupling-standards-and-criteria-a-report-to-the-minnesota-public-utilities-commission

In a rate case, the return is a static expected value. In between rate cases, *realized* returns are a function of actual revenues, actual investments, and actual expenses, all of which change between rate cases in response to many factors, including sales volumes, inflation, productivity, and many others.

As a share of revenues in a rate case revenue requirement calculation, the return on equity to shareholders may be as small as 5%-10%. As a result, small percentage changes in total non-production revenues (all of which largely affect return and taxes) can generate large percentage changes in net profits.[11]

3.1.3 Taxes

In a rate case, the amount of taxes a utility would pay on its allowed return is added to the revenue requirement.

In between rate cases, taxes buffer the impact on the utility's shareholders of any deviations of realized returns from expected returns. When realized returns rise, some portion is lost to taxes, so shareholders do not garner gains one-for-one with changes in net revenues. Conversely, if revenues fall, so do taxes. As a result, investors do not suffer the entire loss. If the tax rate is 33%, then one third of every increase or decrease in pre-tax profits will be absorbed by taxes.

From a customer perspective, there is no buffering effect from taxes. To the contrary, customers pay all additional revenues and enjoy all savings, dollar for dollar.

Traditional regulation fixes the price between rate cases and lets revenues float up or down with actual sales.

3.1.4 Between Rate Cases

With traditional regulation, while the determination of the revenue requirement *at the time of the rate case decision* is meticulous, the utility will almost certainly *never* collect precisely the allowed amount of revenue, experience the associated assumed levels of expenses or unit sales, or achieve the expected profits. The revenue requirement is only used as input to the price determination. Once prices are set, *realized* revenues and profits will be a function of *actual sales and expenses* and will have only a rough relationship with the rate case allowed revenues or returns.

Put another way, traditional regulation fixes the price between rate cases and lets revenues float up or down with actual sales. At this point, the rate case formulae no longer hold sway. Instead, two different mathematical realities operate:

***Formula 3:* Revenues $_{\text{ACTUAL}}$ = Units Sold Actual X Price**

***Formula 4:* Profit $_{\text{ACTUAL}}$ = (Revenues – Expenses – Taxes) $_{\text{ACTUAL}}$l**

These two formulae reveal the methods by which the utility can increase its profits. One approach is to reduce expenses. Providing a heightened incentive to operate efficiently is sound. However, there is a floor below which expenses simply cannot be reduced without adversely affecting the level of service, and to ensure that utilities cut fat, but not bone, some regulators have established service quality indices that penalize utilities that achieve lower-than-expected customer service quality. The easier approach is to increase the Units Sold, as this will increase revenues and therefore profits.[12] This is the heart of the throughput incentive that utilities traditionally face – and this is where decoupling comes in.

3.2 How Decoupling Works

There are a variety of different approaches to decoupling, all of which share a common goal of ensuring the recovery of a defined amount of revenue, independent of changes in sales volumes during that period. Some are computed on a revenue-per-customer basis, while others use an attrition adjustment (typically annual) to set the allowed revenue. Some operate on an annual accrual basis, while others operate on a current basis in each billing cycle. Table 2 categorizes these and provides an example of each approach; a greater discussion of these approaches is contained in the appendix.

Table 2

Decoupling Methodology	Key Elements	Example of Application
Accrual Revenue Per Customer	Allowed revenue computed on an RPC basis; one rate adjustment per year	Utah, Questar
Current Revenue Per Customer	Allowed revenue computed on an RPC basis; rates adjusted each billing cycle to avoid deferrals	Oregon, Northwest Natural Gas Company; DC: Pepco
Accrual Attrition	Allowed revenue determined in periodic general rate cases; changes to this based on specified factors determined in annual attrition reviews; rates adjusted once a year	California, PG&E and SCE Hawaii, Hawaiian Electric
Distribution-Only	Only distribution costs included in the mechanism; all power costs (fixed and variable) recovered outside the decoupling mechanism	Massachusetts, NGrid Maryland, BG&E Washington (PSE, 1990-95)

12 This is because, as noted earlier, the utility faces virtually no changes in its non-production costs as its sales change. This means that marginal increases in sales will have a large and positive impact on the bottom line, just as marginal reductions in sales will have the opposite effect.

3.2.1 In the Rate Case (It's the same)

With decoupling there is no change in the rate case methodology, except perhaps for the migration of some cost items into or out of the production cost recovery mechanism.[13] Initial prices are still set by the regulator, based on a computed revenue requirement.

Formula 1: **Revenue Requirement = (Expenses + Return + Taxes) TEST PERIOD**

Formula 5: **Price END OF RATE CASE = Revenue Requirement ÷ Units Sold TEST PERIOD**

3.2.2 Between Rate Cases (It's different)

With decoupling, the price computed in the rate case is only relevant as a reference or beginning point. In fact, the rate case prices may never actually be charged to customers. Instead, under "current" decoupling (described below), prices can be adjusted immediately, based on actual sales levels, to keep revenues at their allowed level. Rather than holding prices constant between rate cases as traditional regulation would do, decoupling adjusts prices periodically, even as frequently as each billing cycle, to reflect differences between units sold TEST PERIOD and units sold ACTUAL, as necessary to collect revenues ALLOWED. This is accomplished by applying the following formulae:

> ***There are two distinct components of decoupling which are embedded in the decoupling formulae: determination of the utility's allowed revenues and determination of the prices necessary to collect those allowed revenues.***

Formula 6: **Price POST RATE CASE = Revenues ALLOWED ÷ Units Sold ACTUAL**

Formula 7: **Revenues ACTUAL = Revenues ALLOWED**

Formula 4: **Profits ACTUAL = (Revenues – Expenses – Taxes) ACTUAL**

Table 3 gives an example of the calculations.

13 Examples of costs that are sometimes recovered on an actual cost basis include nuclear decommissioning (which rises according to a sinking fund schedule), energy conservation program expenses, and infrastructure trackers for non-revenue-generating refurbishments. Where a utility does not have an FAC or purchases power from independent power producers to meet load growth, it may be necessary to include all power supply costs, fixed and variable, in the definition of "production costs."

There are two distinct actions embedded in the decoupling formulae: determination of the utility's *allowed* revenues and determination of the *prices* necessary to collect those allowed revenues. The former can involve a variety of methods, ranging from simply setting allowed revenues at the amount found in the last rate case to varying revenues over time to reflect non-sales-related influences on costs and revenues, as discussed in Section 5, *Revenue Functions.* The latter is merely the calculation which sets the prices that, given sales levels (i.e., billing determinants), will generate the allowed revenue.

Table 3

Decoupling Example: **Revenue Requirement Calculation**	
Expenses	**$100,000,000**
Net Equity Investment	**$100,000,000**
Allowed Rate of Return	**10.00%**
Allowed Return	**$10,000,000**
Taxes (35% tax rate)	**$15,384,615**
Total Revenue Requirement	**$115,384,615**
Price Calculation	
Revenue Requirement	**$115,384,615**
Actual Sales (kWh)	**990,000,000**
Decoupling Price ($/kWh)	**$0.1166**
Decoupling Adjustment ($/kWh)	**$0.0012**

Put another way, while traditional regulation sets prices, then lets revenues float up or down with consumption, decoupling sets revenues, then lets prices float down or up with consumption. This price recalculation is done repeatedly – either with each billing cycle or on some other periodic basis (e.g., annual), through the use of a deferral balancing and reconciliation account.[14]

While traditional regulation sets prices, then lets revenues float up or down with consumption, decoupling sets revenues, then lets prices float down or up with consumption.

There are two separate elements in play in the price-setting component of decoupling. The first is that prices are allowed to change between rates, based on deviations in sales from the test period assumptions. The second is the frequency of those changes. We discuss the frequency idea in greater detail in Section 8, *Application of Decoupling: Current vs. Accrual Methods.*

14 There are, however, good reasons to seek to limit the magnitude of deviations from the reference price. For example, many decoupling mechanisms allow a maximum 3% change in prices in any year, deferring larger variations for future treatment by the regulator. Significant variability in price may threaten public acceptance of decoupling and the broader policy objectives it serves. Policymakers should be careful to design decoupling regimes with this consideration in mind.

4 Full, Partial, and Limited Decoupling

We use a specialized vocabulary to differentiate various approaches to decoupling.

4.1 Full Decoupling

Full decoupling can be likened to the setting of a budget.

Decoupling in its essential, fullest form insulates a utility's revenue collections from any deviation of actual sales from expected sales. The cause of the deviation — e.g., increased investment in energy efficiency, weather variations, changes in economic activity — does not matter. Any and all deviations will result in an adjustment ("true-up") of collected utility revenues with allowed revenues. The focus here is delivering revenue to match the revenue requirement established in the last rate case.

Full decoupling can be likened to the setting of a budget. Through currently used rate-case methods, a utility's revenue requirement — i.e., the total revenues it will need in a period (typically, a year) to provide safe, adequate, and reliable service — is determined. The utility then knows exactly how much money it will be allowed to collect, no more, no less. Its profitability will be determined by how well it operates within that budget. Actual sales levels will not, however, have any impact on the budget.[15]

The most common form of full decoupling is revenue-per-customer decoupling, which is more fully explained with other forms of decoupling in the next section. The California approach, wherein a revenue requirement is fixed in a rate case and incremental (or decremental) adjustments to it are determined in periodic "attrition" cases, is also a form of full decoupling. Tracking mechanisms, designed to generate a set amount of revenue to

15 This is the simplest form of full decoupling. As described in the next section, most decoupling mechanisms actually allow for revenues to vary as factors other than sales vary. The reasoning is that, though in the long run utility costs are a function of demand for the service they provide, in the short run (i.e., the rate-case horizon) costs vary more closely with other causes, primarily changes in the numbers of customers.

cover specific costs (independently of base rates and the underlying cost of service) are not incompatible with full decoupling. They would be reflected in separate tariff surcharges or surcredits.

Full decoupling renders a utility indifferent to changes in sales, regardless of cause. It eliminates the "throughput" incentive. The utility's revenues are no longer a function of sales, and its profits cannot be harmed or enhanced by changes in sales. Only changes in expenses will then affect profits.

Decoupling eliminates a strong disincentive to invest in energy efficiency. By itself, however, decoupling does not provide the utility with a positive incentive to invest in energy efficiency or other customer-sited resources, but it does remove the utility's natural antagonism to such resources due to their adverse impact on short-run profits. Assuming that management has a limited ability to influence costs and behavior, this allows concentration of that effort on cost reductions, rather than sales enhancements.

4.2 Partial Decoupling

Partial decoupling insulates only a portion of the utility's revenue collections from deviations of actual from expected sales. Any variation in sales results in a partial true-up of utility revenues (e.g., 50%, or 90%, of the revenue shortfall is recovered).

One creative application of partial decoupling was the combination conservation incentive/decoupling mechanism for Avista Utilities in Washington. The utility was allowed to recover a percentage of its lost distribution margins from sales declines in proportion to its percentage achievement of a Commission-approved conservation target. If it achieved the full conservation target, it was allowed to recover all of its lost margins, but if it fell short, it was allowed only partial recovery.[16] This proved a powerful incentive to fully achieve the conservation goal.

4.3 Limited Decoupling

Under limited decoupling only specified causes of variations in sales result in decoupling adjustments. For example:

- Only variations due to weather are subject to the true-up (i.e., actual year revenues [sales] are adjusted for their deviation from weather-normalized revenues). This is simply a weather normalization adjustment clause. Other impacts on sales would be allowed to affect revenue collections. Successful implementation of energy efficiency programs would, in this context, result in reductions in sales and

16 Washington Utilities and Transportation Commission, Docket UG-060518, 2007. The recovery was capped at 90%.

revenues from which the utility would not be insulated — that is, all else being equal, energy efficiency would adversely affect the company's bottom line. Weather-only adjustment mechanisms have been implemented for several natural gas distribution companies.

- Lost-margin mechanisms, which recover only the lost distribution margin related to utility-operated energy efficiency programs, have been implemented for several utilities. These generally provide a removal of the disincentive for utilities to operate efficiency programs, but may create perverse incentives for utilities to discourage customer-initiated efficiency measures or improvements in codes and standards that cause sales attrition, because these are not compensated.
- Reduced usage by existing customers may be "decoupled," whereas new customers are not included in the mechanism, on the theory that the utility is more able to influence, through utility programs, the usage of existing customers who were a part of the rate-case determination of a test year revenue requirement.
- Variations due to some or all other factors (e.g., economy, end-use efficiency) except weather are included in the true-up. In this instance, the utility and, necessarily, the customers still bear the revenue risks associated with changes in weather. And, lastly,
- Some combination of the above.

Limited decoupling requires the application of more complex mathematical calculations than either full or partial decoupling, and these calculations depend in part on data whose reliability is sometimes vigorously debated. But more important than this is the fundamental question that the choice of approaches to decoupling asks: how are risks borne by utilities and consumers under decoupling, as opposed to traditional regulation? What value derives from removing sales as a motivator for utility management? What value derives from creating a revenue function that more accurately collects revenue to match actual costs over time? What are the expected benefits of decoupling, and what, if anything, will society be giving up when it replaces traditional price-based regulation with revenue-based regulation?

Limited decoupling does not fully eliminate the throughput incentive. The utility's revenues (and profits, therefore) are still to some degree dependent on sales. So long as it retains a measure of sales risk, the achievement of public policy goals in end-use efficiency and customer-sited resources, environmental protection, and the least-cost provision of service will be inhibited.[17]

17 "Limited decoupling" is synonymous with "net lost revenue adjustments." "Net lost revenue adjustments" is the term of art that describes earlier methods of compensating a utility for the revenue to cover non-production costs that it would have collected had specified sales-reducing events or actions (e.g., cooler-than-expected summer weather, or government-mandated end-use energy investments) not occurred.

5 Revenue Functions

One of the collateral benefits of decoupling is the potential for reducing the frequency of rate cases. In its simplest form, a decoupling mechanism maintains revenues at a constant level between rate cases. However, this would inevitably put increasing downward pressure on earnings due to general net growth in the utility's cost structure as new customers are added and operating expenses are driven by inflation, to the extent these are not offset by depreciation, productivity gains, and, in certain cases, cost decreases.

To avoid this problem, the allowed (or "target") revenue a utility can collect in any post-rate-case period can be adjusted relative to the rate-case revenue requirement. Most decoupling mechanisms currently in effect make use of one or more revenue functions to set allowed revenues between rate cases, and we describe the four standard ones here: (1) adjusting for inflation and productivity; (2) accounting for changes in numbers of customers; (3) dealing with attrition in separate cases; and (4) the application of a "K" factor to modify revenue levels over time. There may be others that are, in particular circumstances, also appropriate.

5.1 Inflation Minus Productivity

Before development of the current array of decoupling options, a number of jurisdictions used what has been called "performance-based regulation" (PBR) — relying on a price-cap methodology, instead of decoupling's revenue-based approach. These plans, first developed for telecommunications providers, often included a price adjuster under which the affected (usually non-production) costs of the utility were assumed to grow through the net effects of inflation (a positive value) and increased productivity (a negative

18 Under normal economic conditions, inflation will be a positive value and productivity a negative value, but there can be circumstances that violate this presumption — an extended period of deflation, for instance. In fact, when Great Britain's state-owned electric transmission and distribution companies were privatized in the late 1980s, their prices were regulated under PBR formulas that included positive productivity adjustments. "[Positive] X (that is, an apparent allowance for annual rates of productivity decreases of X percent) factors were chosen in order to provide the industry with sufficient future cash flow in part to meet projected future investment needs and also to increase the attractiveness of the companies

value).[18] Prices were allowed to grow at the rate of inflation, less productivity, in an effort to track these expected changes in the utility's cost of service. In some cases, other factors (often called "Z" factors) were added to the formulae to represent other explicit or implicit cost drivers. For example, if a union contract had a known inflationary factor, this might be used in lieu of a general inflation index, but only for union labor expenses.

This adjustment is being used in revenue-decoupling regulation, too, to determine a revenue path between rate cases. Rather than applying this adjustment to prices, it is applied to the allowed revenue between rates cases.[19] This approach is used in California, with annual "attrition" cases that consider other changes since the last general rate case, then add (or subtract) these from the revenue requirement determined in the rate case.

With the inflation and productivity factors in hand, the allowed revenue amount can be adjusted periodically. In practice, this adjustment has usually been done through an annual administrative filing and review. In theory, however, there is no practical reason these adjustments could not be made on a current basis, perhaps with each billing cycle.[20] In application, the net growth in revenue requirement is usually spread evenly across all customers and all customer classes.

The inflation-minus-productivity approach does not remove all uncertainty from price changes, because the actual inflation rate used to derive allowed revenues (and, therefore, reference prices) will vary over time.

to the investment community during their upcoming public auction. The initial regulatory timeframe was set at the fiscal year 1990/1995 time period." See http://training.itcilo.it/actrav_cdrom1/english/global/frame/elect2.htm. (Note that this adjustment is actually referred to as "negative productivity," since it indicates a reduction, rather than an increase, in productivity. Mathematically, it's denoted as the negative of a negative, and so for simplicity's sake we've described it as positive here.)

19 Under this approach, a government-published (or other accepted "third party" source), broad-based inflation index is used. The productivity factor, which serves to offset inflation, is also an administratively determined or, in some cases, a stakeholder agreed-upon value. It should not, however, be calculated as a function of the particular company's own productivity achievements. Doing so would reward a poorly performing company with an overall revenue adjustment (inflation-minus-productivity factor) that is too high (and which does not give it strong enough incentives to control costs) and would punish a highly performing company with a factor that reduces the gains it would otherwise achieve, in effect holding it to a more stringent standard than other companies face.

20 See also *Current vs. Accrual Methods*, below, for more on the implications of using *accrual* methodologies for decoupling versus using a *current* system. It goes without saying, of course, that price changes of this sort can only be effected through a simple, regular ministerial process, if the adjustment factors on which they are based are transparent, unambiguous, and factual in nature (e.g., customer count). If, however, the adjustment is driven by changes that are within management's discretionary — say, capital budget — then a more detailed review may be required to assure that prudent decisions are underlying the revenue adjustments.

5.2 Revenue-per-Customer (RPC) Decoupling

As noted earlier, analysis has shown that, in the time between rate cases, changes in a utility's underlying costs vary more directly with changes in the number of customers served than they do with other factors such as sales, although the correlation on a total expense basis to any of these is relatively weak. When examining only non-production costs, however, the correlations are much stronger, especially for the number of customers.

In 2001, we previously studied the relationships between drivers such as system peak, total energy, and number of customers to investments in distribution facilities.[21]

The data indicate that customer growth is closely correlated to growth of non-production costs.

RAP prepared studies for correlations between investments in transformers and substations versus lines and feeders as they relate to growth in customers served, system peak, and total energy sales. The data indicate that customer count is somewhat more closely correlated with growth in non-production costs, stronger than either growth in system peak or growth in energy sales. These data support using the number of customers served as the driver for computing allowed revenues between rate cases, particularly in areas where customer growth has been relatively stable and is expected to continue. The revenue-per-customer, or RPC method, may not be appropriate in areas with stagnant economies or volatile spurts of growth, or where new customers are significantly different in usage patterns than existing customers, but in these situations, the attrition method may still work well.

The RPC value is derived through an added "last" step in the rate case determination. It is computed by taking the test period revenues associated with each volumetric price charged, and dividing that value by the end-of-test period number of customers who are charged that volumetric price. This calculation must be made for each rate class, for each volumetric price, and for each applicable billing period (most likely a billing cycle):

Formula 8: **Revenue per Customer** $_{\text{TEST PERIOD}}$ **=**

Revenue Requirement $_{\text{TEST PERIOD}}$ **÷ No. of Customers** $_{\text{TEST PERIOD}}$

With this revenue-per-customer number, allowed revenues can be adjusted periodically to reflect changes in numbers of customers. In any

21 Shirley, W. (2001, September). *Distribution System Cost Methodologies for Distributed Generation*. Regulatory Assistance Project. Retrieved from http://www.raponline.org/knowledge-center/distribution-system-cost-methodologies-for-distributed-generation. Also see accompanying appendices at http://www.raponline.org/knowledge-center/distribution-system-cost-methodologies-for-distributed-generation-volume-ii-appendices

Table 4

Lines & Feeders

Growth in Lines & Feeders Plant Investment vs. Growth in System Peak

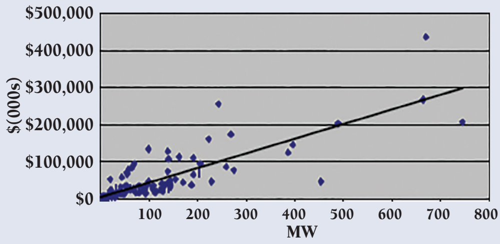
(Five-Year Adjusted Average, 1995-1999)

Statistical Summary

Standard Deviation . . $2,129,439

Average $608,215

Correlation 0.80



Growth in Lines & Feeders Plant Investment vs. Growth in System Energy

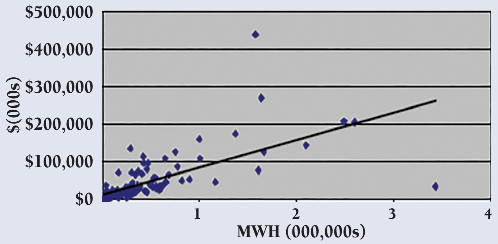
(Five-Year Average, 1995-1999/Excludes Negative Growth)

Statistical Summary

Standard Deviation $606

Average $74

Correlation 0.53



Growth in Lines & Feeders Plant Investment vs. Growth in Customers

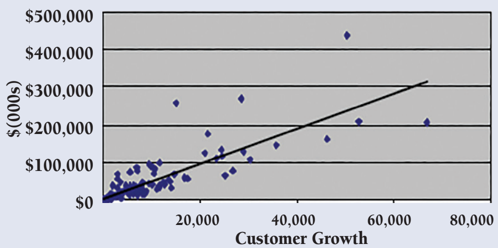
(Five-Year Average, 1995-1999/Excludes Negative Growth)

Statistical Summary

Standard Deviation $13,191

Average $4,551

Correlation 0.82



post-rate-case period, the allowed revenues for energy and demand charges are calculated by multiplying the actual number of customers served by the RPC value for the corresponding billing period. The decoupling adjustment is then calculated in the manner detailed in the earlier sections.

Formula 9: **Revenues $_{\text{ALLOWED}}$ = Revenue per Customer $_{\text{TEST PERIOD}}$ X No. of Customers $_{\text{ACTUAL}}$**

Formula 10: **Price $_{\text{ACTUAL}}$ = Revenues $_{\text{ALLOWED}}$ ÷ Units Sold $_{\text{ACTUAL}}$**

The table below demonstrates the RPC calculations for three billing periods for a sample small commercial rate class. In this example, the billing periods are assumed to be monthly. Note that the revenues per customer are different in each month, because of the seasonality of consumption in the test period.[22]

By calculating the energy and demand revenues per customer for each

Table 5

Deriving the Revenue per Customer Values

Small Commercial Class Example
Test Period Values

Billing Period	**1**	**2**	**3**
Number of Test Period Customers	142,591	142,769	142,947
Customer Charge	$25.00	$25.00	$25.00
Total Customer Charge Revenues	$3,564,775	$3,569,225	$3,573,675
Energy Revenue per Customer			
Energy Sales (kWh)	181,238,883	189,304,436	170,240,013
Rate Case Price	$0.165	$0.165	$0.165
Total Energy Sales Revenues	$29,904,416	$31,235,232	$28,089,602
Energy Revenue per Customer	$209.72	$218.78	$196.50
Demand Revenue per Customer			
Demand Sales (kW)	1,189,355	1,165,396	1,148,975
Rate Case Price	$4.4600	$4.4600	$4.4600
Total Demand Sales Revenues	$5,304,523	$5,197,667	$5,124,429
Demand Revenue per Customer	$37.20	$36.41	$35.85

22 Most utilities typically have 22 or 23 billing cycles per month. For simplicity, we have assumed here that all customers in a month are billed in the same billing cycle (one per month). In the future, with new "smart" metering and communication platforms, a single billing cycle per month, for all customers, may be possible.

billing period, normal seasonal variations in consumption are automatically captured. This causes revenue collection to match the underlying seasonal consumption patterns of the customers.

Some decoupling schemes exclude very large industrial customers. Because the rates for these customers are often determined by contractual requirements and specified payments designed to cover utility non-production costs, there may be little or no utility throughput incentive opportunity relating to these customers anyway. Also, in many utilities, this class of customers may consist of only a small number of large and unique (in load-shape terms) customers, so that a "class" approach is not apt.

In cases in which new customers (that is, those who joined the system during the term of the decoupling plan) have significantly different consumption patterns (and, therefore, revenue contributions to the utility) than existing customers, regulators may want to modify the decoupling formula to account for the difference. This can be accomplished by using different RPC values for new customers and existing customers. The nature of this issue and methodologies for addressing it are discussed in Section 6, *Application of RPC Decoupling: New vs. Existing Customers.*

5.3 Attrition Adjustment Decoupling

Some jurisdictions take a different approach to decoupling. They set base rates in a periodic major rate case, then conduct annual abbreviated reviews to determine whether there are particular changes in costs that merit a change in rates. In such instances, the regulators adjust rate base and operating expenses only for known and measurable changes to utility costs and revenues since the rate case, and adjust for them through a small increment or decrement to the base rates (called "attrition adjustments"). The regulators normally do not consider more controversial issues such as new power plant additions or the creation of new classes of customers, which are reserved for general rate cases.

In attrition decoupling, the utility's allowed revenue requirement is the amount allowed in the first year after the rate case, plus the addition (or reduction) that results from the attrition review. Every few years, a new general rate case is convened to re-establish a cost-based revenue requirement considering all factors.

5.4 K Factor

The K factor is an adjustment used to increase or decrease overall growth in revenues between rate cases.

In its simplest application, the K factor can be used in lieu of either the inflation-minus-productivity method or the RPC method; it could be, for example, a specified percentage per year. Although one could vary the K factor itself over time, in this context the most likely application would simply set an annual between-rate-case growth rate for revenues, resulting in a steady change (probably an increase) in year-to-year allowed revenues for each period between rate cases. Such an approach has a high degree of certainty, but runs the risk of being disassociated from, and therefore out of sync with, measurable drivers of a utility's cost of service. All of the data used in a rate case change over time, and the elements making up the K factor are no different. The K factor therefore may become obsolete within a few years, providing another reason why periodic general rate cases should be required by regulators under decoupling (and, arguably, under traditional regulation as well).

A "successful" revenue function would be one that keeps the utility's actual revenue collection as close as possible to its actual cost of service throughout the period between rate cases.

An alternative approach is to use the K factor as an adjustment to the RPC allowed revenue determination. Here, the K factor growth rate (positive or negative) would be applied to the RPC values, rather than to the allowed revenue value itself. This approach would be useful when an additional revenue requirement is anticipated due to identifiable increases in revenues from capital expenditures or operating expenses, or because of some underlying trend in the RPC values. An example would be a utility with a distribution system upgrade program driven by reliability concerns, where the investment is not generating new revenue. It may also be used as an incentive for the utility to make specific productivity gains, in which case the K factor would be a negative value causing revenues to be slightly lower than they otherwise would have been.

In any case, allowed revenues would still be primarily driven by the number of customers served, but the revenue total would be driven up or down by the K factor adjustment.

Formula 11: **Revenue Per Customer** $_{\text{ALLOWED}}$ **=**
Revenue Per Customer $_{\text{TEST PERIOD}}$ *** K**

Formula 12: **Revenues** $_{\text{ALLOWED}}$ **= Revenue Per Customer** $_{\text{ALLOWED}}$ **X**
No. of Customers $_{\text{ACTUAL}}$

Formula 13: **Price** $_{\text{ACTUAL}}$ **= Revenues** $_{\text{ALLOWED}}$ **÷ Units Sold** $_{\text{ACTUAL}}$

5.5 Need for Periodic Rate Cases

It is useful to have periodic rate cases in which all costs, expenses, investments, programs, policies, and tariff designs can be examined. Many regulators have required general rate cases every three to five years as part of decoupling (or set expiration dates for the decoupling mechanism). Another approach would be a built-in decline in the allowed revenue (or RPC) after three to five years. This would allow the utility to avoid a new general rate case (in which all of the utility's costs would be examined), but only if it reduced customer bills. This leaves the utility with the option to continue to retain a portion of expense containment savings motivated by decoupling (see Formula 4) without a rate case, if it can reduce costs sufficiently to give consumers a measurable benefit.

5.6 Judging the Success of a Revenue Function

One of the shortcomings of traditional utility pricing approaches is that a utility's actual revenue collection can be significantly higher or lower than its actual cost of providing service. The different revenue functions that can be applied with decoupling offer means of keeping the utility's revenue collections much closer to its actual cost of service over time. This should result in smaller rate case revenue deficiencies or excesses, lessening their associated potential for "rate shock."

A "successful" revenue function would be one that keeps the utility's actual revenue collection as close as possible to its actual cost of service throughout the period between rate cases. Indeed, the theoretically ideal result, by this standard, would be to have a zero revenue deficiency or excess in the next rate case and at most points in between, meaning that rates had tracked costs perfectly over time.

Of course, when judging the revenue function on this basis, one should disregard special circumstances that may cause a significant revenue deficiency, such as large additions to the utility's plant-in-service accounts (e.g., the addition of a new transmission line, the installation of an expensive new management information system, or the deployment of smart-grid advanced metering infrastructure).

6 Application of RPC Decoupling: New vs. Existing Customers

As much as half of the change in average usage per customer over time may be explained by differences between existing and new customers. Where new customers, on average, have significantly different usage than existing customers, their addition to the decoupling mechanism can result in small cross-subsidies.

New customers may be significantly different from existing customers. For example, new building codes and appliance standards may mean that new customers are fundamentally more efficient. Typical new homes may be larger or smaller than the average of existing homes (or may reflect a different mix of single-family and multi-family construction). If urban areas are becoming more densely populated, it may mean that new customers are closer together, and thus there is a smaller distribution system investment per customer. If line extension policies require new customers to pay a larger share of distribution system expansion costs than existing customers did, the investment added to the utility rate base per customer may be smaller for new customers. If the regulator is concerned that there may be meaningful differences between new and existing customers, it can require the utility to perform a detailed analysis of usage characteristics (quantity, seasonality, time-of-day) for each cohort of customers connected to the system.

> ***Where new customers, on average, have significantly different usage than existing customers, their addition to the decoupling mechanism can result in small crosssubsidies***

As illustrated in Table 6, new customers, on average, use 450 kWh in a billing period, but the rate case-derived RPC for existing customers is 500 kWh, application of the test year RPC values to new customers has the effect of causing old customers to bear the revenue burden associated with the 50 kWh not needed or used by new customers. This is because the allowed revenue is increased by an amount associated with 500 kWh of consumption, whereas the actual contribution to revenues from the new customers is only the amount associated with 450 kWh.

Table 6

Single RPC for Existing and New Customers			
	Existing Customers	New Customers	Total
Number of Customers	200,000	10,000	210,000
Revenue per Customer	$50.00	$50.00	
Allowed Revenues	$10,000,000	$500,000	$10,500,000
Average Unit Sales	500	450	
Decoupled Price	$0.100478	$0.100478	
Collected Revenues	$10,047,847	$452,153	$10,500,000
Average Customer Contribution	$50.24	$45.22	$50.00

To correct for this, a separate RPC value can be calculated for new customers — in our example, the amount for them would be $45.00. As shown in Table 7, the RPC allowed revenues would not be increased from $10,000,000 to $10,025,000. Instead, the increase would be equal to only $22,500.

This results in collection of an average of $50.00 from existing customers and $45.00 from new customers, thus reflecting the overall lower usage of new customers. On a total basis, the average revenues per customer are equal to $49.76. Accounting for these differences affects the *allowed* revenue to assure no over- or under-recovery, while differences in bills for these two types of customers are automatically reflected in their respective units of consumption applied to the decoupled price.

Table 7

Separate RPC for Existing and New Customers			
	Existing Customers	New Customers	Total
Number of Customers	200,000	10,000	210,000
Revenue per Customer	$50.00	$45.00	
Allowed Revenues	$10,000,000	$450,000	$10,450,000
Average Unit Sales	500	450	
Decoupled Price	$0.100000	$0.100000	
Collected Revenues	$10,000,000	$450,000	$10,450,000
Average Customer Contribution	$50.00	$45.00	$49.76

7 Rate Design Issues Associated With Decoupling

As it does with respect to increased investment in end-use energy efficiency itself, decoupling should also remove traditional utility objections to electric and natural gas rate designs that encourage conservation, voluntary curtailment, and peak load management. For example, assuming average usage of 500 kWh/month, the two following rate designs produce the same amount of revenue, but the volumetric rate provides a much stronger price signal for consumers to pursue energy efficiency:

Table 8

High vs. Low Customer Charges

Rate Element	High Customer	Low Customer
Customer Charge	$25.00	$5.00
Usage Charge	$0.10	$0.14
Total Bill for 500 kWh average usage	$75.00	$75.00

Under volumetric pricing without decoupling, utilities have a significant portion of their revenue requirement for rate base and O&M expenses associated with throughput. In addition, those with fully reconciled fuel and purchased-power adjustment mechanisms completely recover the high cost of augmenting power supply during peak periods when expensive power resources are used, so even increased peak-period sales generate a distribution sales margin.[23] A reduction of throughput will likely reduce

23 See Subsection 3.1.1.1 above, and Moskovitz, *Profits and Progress Through Least Cost Planning*, pp. 3-5. Fuel adjustment mechanisms are the antithesis of energy efficiency mechanisms. They guarantee that any additional sale, no matter how expensive to serve, adds to profit, and any foregone sale diminishes profitability. This is because the clauses ensure that the marginal fuel or purchase cost of incremental sales will be fully recovered, so that the non-production cost component of base rates will always contribute to the bottom line (by either increasing profits or reducing losses).

revenues at a greater rate than it will produce savings in short-run costs, simply because most distribution, billing, and administrative costs are relatively fixed in the short run.

Conversely, with decoupling, the utility no longer experiences a net revenue decrease when sales decline, and will therefore be more willing to embrace rate designs that encourage customers to use less electricity and gas. This can be achieved through energy efficiency investment (with or without utility assistance), through energy management practices (turning out lights, managing thermostats), or through voluntary curtailment.

Currently, the best examples of this are the natural gas and electric rate designs used by California electricity and natural gas utilities, where decoupling has been in place for many years. The residential rates applicable to most customers of Pacific Gas and Electric (PG&E), typical of those of all gas utilities and at least the investor-owned electric utilities in the state, are shown in Table 9. Both the gas and electric rates are set up with a "baseline" allocation, which is set for each housing type and climate zone. Neither rate has a customer charge, although there is a minimum monthly charge for service. If usage in a month falls below the amount covered by the minimum bill, the minimum still applies.

Table 9

PG&E Natural Gas Rate at May 1, 2008

Rate Element	Baseline Quantities	Excess Quantities
Minimum Monthly Charge	~$3.00	
Base Rate per Therm	$1.45131	$1.68248
Multi-Family Discount (per unit per day)	$0.01770	$0.17700
Low-income Discount (per therm)	$0.29026	$0.33650
Mobile Home Park Discount (per unit per day)	$0.35600	$0.35600

Table 10

PG&E Natural Gas Rate at May 1, 2008

Rate Element	Low Income	All Other Customers
Minimum Monthly Charge	~$3.50	~$4.45
Baseline Quantities	$0.83160	$0.11559
101%-130% of Baseline	$0.09563	$0.13142
131%-200% of Baseline	$0.09563	$0.22580
201%-300% of Baseline	$0.09563	$0.31304
Over 300% of Baseline	$0.09563	$0.35876

7.1 Revenue Stability Is Important to Utilities

Clearly these rate designs produce a great deal of revenue volatility for the utility. Without decoupling, the utility could face extreme variations in net income from year to year. However, with decoupling, this type of rate design produces very stable earnings. The earnings per share for PG&E (the utility) for the past three years (since decoupling was restored after the termination of the California deregulation experiment) have been $1.01 billion, $971 million, and $918 million. This stability was achieved despite a $1.4 billion increase in operating expenses, mostly the cost of electricity, during this period.

The revenue stability needs of the company can conflict with principles of cost-causation as they relate to pricing. Utilities are interested in revenue stability, so that they have net income that can predictably provide a fair rate of return to investors, regardless of weather conditions, business cycles, or the energy conservation efforts of consumers. Cost-of-service considerations, however, can produce a very different result. To the extent that utility fixed costs are associated with peak demand (peaking resources, transmission capacity, natural gas storage, and liquefied natural gas (LNG) facilities) and those capacity costs are allocated exclusively to increased use in winter and summer months, the cost to consumers of incremental usage is dramatically higher than the cost of base usage.

A steeply inverted block rate design, such as those used by PG&E, correctly associates the cost of seldom-used capacity with the (infrequent) usage for which that capacity exists. Although this is arguably fair, doing so can result in serious revenue stability problems for the utility. Decoupling is one way to provide revenue stability for the utility, without introducing rate design elements such as high fixed monthly charges, in the form of a Straight Fixed/Variable rate design, that remove the appropriate price signals to consumers.

7.2 Bill Stability Is Important to Consumers

Customers also have an interest in bill stability, because in extremely cold winters or hot summers, their bills can quickly become unmanageable. Absent decoupling, rates such as those used in California, while accurately conveying the real cost of seldom-used capacity, accentuate bill volatility. In a hot summer or cold winter, consumer bills can soar as their end-block usage increases. With decoupling (and budget billing), however, customers can enjoy bill stability at the same time that utilities enjoy revenue stability, without the adverse impacts on usage that a Straight Fixed/Variable rate design can cause. When their usage (as a group) increases, the non-production component of the rate design automatically declines, so that they pay the allowed revenue requirement (and no more) for distribution services. Conversely, when weather is unusually mild, and customer usage declines, they would pay slightly more per unit for distribution services, again ensuring the utility receives its allowed revenue. This effect is most pronounced when decoupling is applied on a current, rather than an accrual basis, as discussed later.

7.3 Rate Design Opportunities

In 1961, James Bonbright published what is considered the seminal work on ratemaking and rate design for regulated monopolies. His context was, of course, traditional price-based utility regulation, and he identified eight principles, some of which are in tension with each other, to guide the design of utility prices. That tension is demonstrated in particular by three of those principles — that rates should yield the total revenue requirement, they should provide predictable and stable revenues, and they should be set so as to promote economically efficient consumption.[24] In certain instances, more economically efficient pricing structures could lead to customer behavior that results in less stable and, in the short run, significant over- or under-collections of revenue. Decoupling mitigates or eliminates the deleterious impacts on revenues of pricing structures that might better serve the long-term needs of society. Some innovative rate designs that regulators may want to consider with decoupling include:

7.3.1 Zero, Minimal, or "Disappearing" Customer Charge

A zero or minimal customer charge allows the bulk of the utility revenue requirement to be reflected in the per-unit volumetric rate. This serves the function of better aligning the rate for incremental service with long-run incremental costs, including incremental environmental and supply costs that may already be trending upward.[25] During the early years of the natural gas industry, this type of rate design was almost universal, as the industry was competing to secure heating load from electricity and oil, and imposing fixed customer charges would have disguised the price advantage being offered and

24 Bonbright, James C., *Principles of Public Utility Rates.* Columbia University Press, New York, 1961, p. 291.

25 For electric utilities depending on coal for the majority of their supply, valuing CO_2 at the levels estimated by the EPA to result from passage of the Warner-Lieberman bill (in the range of \$30 to \$100/tonne) would add up to \$.03/kWh to \$.10/kWh to the variable costs of electricity. For natural gas utilities, the environmental costs of supply are on the order of \$0.30/therm, or approximately equal to total distribution costs for most gas utilities. See http://www.epa.gov/climatechange/economics/economicanalyses.html.

confused customers. Simple commodity billing was the easiest way to make cost comparisons possible for consumers. As natural gas utilities have taken on more of the characteristics of monopoly providers, they have sought to increase fixed charges.

The California utilities, under decoupling, have retained zero or minimal customer charges. In several cases, such as with the PG&E rates discussed earlier in Section 7, it comes in the form of a "disappearing minimum bill," in which customers with zero consumption pay a minimum amount, but once usage passes 100 kWh or so (and 99% of consumption is by customers exceeding this minimum), they pay only for the energy used. In December 2008, the Public Service Commission of Wisconsin approved a settlement of the parties that, among other things, created a decoupling mechanism for Wisconsin Public Service Corporation and, at the same time, reduced the level of fixed customer charges.[26]

7.3.2 Inverted Rate Blocks

Inverted block rates, of the type shown earlier for PG&E, serve several useful functions. First, they align incremental rates with incremental costs, including incremental capacity, energy and commodity, and environmental costs. Second, they recognize that upper-block usage (mostly for space conditioning) is characterized by high seasonality, usage concentrated during the peak hours, and low load-factor end-uses, all of which are more expensive to serve than other end-uses. Inverted block rates therefore properly collect the appropriate costs from these infrequent but expensive end uses. They also serve to encourage energy efficiency and energy management practices by consumers. However, they reduce net revenue stability for utilities by concentrating recovery of return, taxes, and O&M expenses in the prices for incremental units of supply, which tend to vary greatly with weather and other factors.

7.3.3 Seasonally Differentiated Rates

Seasonal rates are typically imposed in service territories whose utilities experience significant seasonal cost differences. For example, a gas utility with a majority of its capacity costs assigned to the winter months will typically have a higher winter rate than summer rate. With traditional regulation, seasonal rates reduce net revenue stability for utilities, by concentrating revenue into the weather-sensitive season.

26 Docket 6690-UR-119, *Application of the Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, Order of December 30, 2008.

7.3.4 Time-of-Use Rates

Rates that collect much higher amounts during the on-peak hours can convey to consumers that usage during those hours puts the entire system under stress and causes investment in new peaking capacity. However, peak-hour consumption is highly weather-sensitive, so time-of-use (TOU) rates make utility revenues more weather-sensitive, just like inverted block rates. Decoupling removes the revenue stability risk associated with TOU rates, allowing the utility to have efficient prices and still be assured of recovering non-production costs in years when weather is mild.

7.4 Summary: Rate Design Issues

A hypothetically "correct" rate design for an electric and gas utility can consist of a customer charge that recovers metering and billing costs (these are both incremental and decremental with changes in customer count) and an inverted block rate structure based on the load factors of typical end-uses. The rates shown for PG&E in California are designed along these lines.

For electric utilities, lights and appliances have steady year-round usage characteristics, and therefore the lowest cost of service. For gas utilities, water heating, cooking, and clothes drying have steady year-round usage characteristics. For both types of utilities, space conditioning (heating and cooling) loads, which are associated with the upper blocks of usage, have the lowest load factors, and therefore the highest costs of service.

Taking a hypothetical electric utility with typical meter reading and billing costs, capacity costs of $15/kW per month, and energy costs of $.05/kWh produces the following cost-based rate design:

Table 11

Cost-based Rate Design – Hypothetical Rates

Rate Element	Load Factor	Capacity Cost	Energy Cost	Total Cost
Customer Charge				$5.00
First 400 kWh Lights/Appliances	70%	$0.03	$0.05	$0.08
Next 400 kWh Water Heat	40%	$0.05	$0.05	$0.10
Over 800 kWh Space Conditioning	20%	$0.10	$0.05	$0.15

Establishing theoretically defensible rate designs such as those used by PG&E provides consumers with very clear economic signals about the costs their usage imposes, but evidence in California is that even with these high prices, utility energy efficiency programs are an essential element of a successful energy policy. The inverted rates tend to drive consumers to the programs, but if the programs are not available, they may be unlikely (or unable) to respond to the incremental cost-based prices.

Decoupling is a tool that allows the utility's interest in stable net revenues, the consumer's interest in stable bills, and the society's interest in cost-based pricing all to be met. Under decoupling, the utility can implement an inverted rate, knowing that lost distribution revenues that are incurred when sales decline will be recovered. If implemented on a "current" basis as proposed in Section 8 of this report, decoupling can also stabilize customer bills, by reducing the unit rates in months when extreme weather causes a significant variation in sales from the levels assumed in the rate case where rates are set.

8 Application of Decoupling – Current vs. Accrual Methods

Under traditional regulation, utilities have often had different adjustment factors on customer bills. Perhaps the most common is the fuel and purchased-power adjustment clause (FAC) for electric utilities and the purchased gas adjustment (PGA) clause for gas utilities. In both of these cases, utilities compute the actual costs for these items, and then customer bills are adjusted to reflect changes in those costs. There is often a lag in the determination of these costs, and the adjustment factor itself is often based on the forecast units of sales expected in the period when adjustment will be collected. As a result, actual collections usually deviate from expected collections, and a periodic reconciliation must be made to adjust revenues accordingly.

In the application of decoupling, many states use a similar approach or make the calculations on an annual basis. Any accrued charges or credits are held in a deferral account for subsequent application to customers' bills. When applied in this manner, the same reconciliation routines are used to assure collection of the amounts in the accrual account.

The variations in rates and bills caused by decoupling mechanisms are typically very small compared with those caused by FAC and PGA mechanisms. While decoupling adjustments tend to deal with variations in usage of a few percent, the price of natural gas can change by 50% or more over the year after a general rate case. Further, as described earlier, decoupling tends to moderate billing variations, whereas the FAC and PGA mechanism tend to magnify bill variations, because the cost of gas tends to rise in cold winters when demand is highest, and the cost of power tends to rise in the summer with cooling-related demands.

When a lag is present in the application of these adjustments, it has the effect of disassociating individual customers from their respective responsibility for the adjustment. The result may be a shift in revenue responsibility among those customers, and between years. For example, if a warmer-than-average winter produces a significant deferral of costs to be collected, and it is collected the following year, it is possible that the surcharge will be effective during a colder-than-average winter, exacerbating customer bill volatility, during a period when the customer is otherwise accruing credits for the following year.

Unlike commodity adjustment clauses, however, there are no forecasting components needed in decoupling. This is true even for utilities whose rate cases use a future test year. While future test years necessarily involve forecasting the revenue requirement, the calculation of the actual price to be charged to collect that revenue requirement is a function of actual units of consumption. To calculate the price with Revenue Cap Decoupling, one need only divide the Allowed Revenue by the Actual Unit Sales. To calculate the price with RPC Decoupling, one must first derive the Allowed Revenues (based on the current number of customers), and then divide that number by Actual Unit Sales. In either case, all of the information needed to make the calculation is known at the time that customer bills are prepared. For this reason, the required decoupling price adjustment can be applied on a current rather than an accrual basis. This also means there will be no error in collection associated with forecasts of consumption and, hence, no need for a reconciliation process.

This can be done by using the same temperature adjustment data used to produce the test-year normalized results, except to calculate a daily or monthly (or more likely a billing cycle) RPC with the data, not just an annual RPC. In each billing cycle, the "allowed" RPC can be a time-weighted average of the number of days in each month of the year included in the billing cycle,[27] or it can be built up from daily information.[28]

27 For example, if the allowed RPC is $50 for March and $40 for April, and the billing cycle runs from April 16 to March 15 (i.e., 15 days in April and 15 days in March), the allowed RPC would be $45.

28 For more information on this point, see section 3.1.1.2 Non-Production Costs.

9 Weather, the Economy, and Other Risks

While traditional regulation aims to determine a utility's costs and then provide appropriate prices to recover those costs, there are a number of factors that prevent this from happening. Foremost among these are the effects of weather and economic cycles on utility sales and customer bills. These effects are directly related to how prices are set. Full or limited decoupling, and some forms of partial decoupling, will have a direct impact on the magnitude of these risks.

For the most part, full decoupling will eliminate these risks completely. Limited decoupling partially eliminates these risks. Partial decoupling may or may not affect these risks, depending upon whether the presence of a particular risk is desired.

9.1 Risks Present in Traditional Regulation

The ultimate result of a traditional rate case is the determination of the prices charged consumers. In simple terms, a utility's prices are set at a level sufficient to collect the costs incurred to provide service (including a fair rate of return — the utility's profits). Because most of the revenues are normally collected through volumetric prices, based on the amount of energy consumed or the amount of power demanded, the assumed units of consumption are critical to getting the price "right."[29]

As noted earlier, the basic pricing formula under traditional regulation is:

Formula 13: **Price = Revenue Requirement ÷ Units of Consumption**

This formula is applied using Units of Consumption associated with normal weather conditions. As long as the units of consumption remain unchanged, the prices set in a rate case will generate revenues equal to the

29 By "right," we mean consistent with the cost of service methodology.

utility's Revenue Requirement. Also, if extreme weather occurs as often as mild weather, over time the utility's revenues will, on average, approximate the revenue requirement. In theory, this protects the company from under-recovery, and customers from over-payment of the utility's cost of service — because there should be an equal chance of having weather that is more extreme or milder than normal.

With traditional regulation, in economic terms, weather-driven sales changes cause a wealth transfer between the utility and its customers which is unrelated to what the utility needs to recover and what customers ought to pay.

In reality, this is hard to accomplish, because in any given year, the actual weather is unlikely to be normal. Thus, even if the traditional methodology results in prices that are "right" and the weather normalization method used was accurate, the actual revenues collected by the utility and paid by the customers will be a function of the actual units of consumption, which are driven, in large part, by actual weather conditions, according to the following formula:

***Formula 3:* Actual Revenues = Price * Actual Units of Consumption**

With this formula, extreme weather increases sales above those assumed when prices were set, in which case utility revenues and customer bills will rise. Conversely, mild weather decreases utility revenues and customer bills.

To the extent that the utility's costs to provide service due to the weather-related increases or decreases in sales do not change enough to fully offset the revenue change, then the utility will either over- or under-recover its costs. With traditional regulation, in economic terms, weather-driven sales changes cause a wealth transfer between the utility and its customers that is unrelated to the amount that the utility needs to recover and that customers ought to pay. This transfer is not a function of any explicit policy objective. Rather, it is simply an unintended consequence of traditional regulation. There is a volatility risk premium embedded in the utility's cost of capital that reflects the increased variability in earnings associated with weather risk. This premium may be reflected in the equity capitalization ratio, the rate of return, or both.

9.2 The Impact of Decoupling on Weather and Other Risks

Full decoupling causes a utility's non-production revenues to be immune to both weather and economic risk. Once the revenue requirement is determined (in the rate case or via the RPC adjustment), decoupling adjusts prices to maintain the allowed revenue requirement. Any change in consumption associated with weather or other causes will result in an inverse change in prices, according to the following formula:

Formula 6: **Price = Allowed Revenue ÷ Actual Units of Consumption**

As consumption rises, prices are reduced. As consumption falls, prices are increased. This means that decoupling will mitigate the higher overall bill increases associated with extreme weather and mitigate overall bill decreases associated with mild weather. With full decoupling, all changes in units of consumption, regardless of cause, are translated into price changes to maintain the allowed revenue level. Thus, no matter the amount of consumption, the utility and the consumers as a whole will receive and pay the allowed revenue. Neither the company nor its customers are exposed to weather or economic risks in this case.

Under partial decoupling, only a portion of the indicated price adjustment is collected or refunded. To the extent the adjustment falls short of recovering the indicated price adjustment, both weather and economic risks are placed upon the utility and its customers.

Under limited decoupling, the weather or economic risks may be selectively imposed on the utility and its customers. Some states have preserved the existing burden of weather risk in a decoupled environment by weather-normalizing actual unit sales before computing the new price under limited decoupling. This has the effect of fully exposing the utility and its customers to weather risk.

Conversely, one might limit the changes in unit sales to those directly attributable to efficiency programs. Lost margin mechanisms, discussed later in *Other Revenue Stabilization Measures,* are one example of this type of limited decoupling. This has the effect of preserving all of the risks, including weather and economic risks, customers and the utility bear under traditional regulation.

Any risks placed on the utility and its customers will likely increase the overall revenue requirement of the utility because of its impact on the utility's financial risk profile. This is explored further in the following section, *Earnings Volatility Risks and Impacts on the Cost of Capital.*

10 Earnings Volatility Risks and Impacts on the Cost of Capital

Utility earnings can be volatile because of the way weather and other factors influence sales volumes and revenues in the short run, without corresponding short-run impacts on costs. They can also be volatile because of the way weather and other factors influence costs in the short run, without corresponding short-run impacts on revenue (such as a drought has on a hydro-dependent utility). As a result of this volatility, utilities typically retain a relatively higher level of equity in their capital structure, so that a combination of adverse circumstances (adverse weather, economic cycle, cost pressures, and customer attrition) does not render them unable to service their debt. In addition, utilities also try to pay their dividends with current income or from retained earnings. In fact, most bond covenants prohibit paying dividends if retained earnings decline below a certain point. A utility that is forced to suspend its dividend is viewed as a higher-risk venture.

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). This in turn lowers the financial risk for the utility, and that 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 many years to play out, and the consequent benefits for customers are therefore slow to materialize. New debt issues will carry lower interest rates, but utility bonds carry long maturities, and it can take 30 years or more to roll over all of the debt in a portfolio.

Alternatively, a lower equity ratio may be sufficient to maintain the same bond rating for the decoupled utility as for the non-decoupled utility. 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. However, for this to be justified, the investors must have confidence that the decoupling mechanism will remain in effect for many years; a typical three-year approval period may not provide that confidence.

10.1 Rating Agencies Recognize Decoupling

The bond rating agencies have come to recognize that decoupling mechanisms, weather adjustment mechanisms, fuel and purchased-gas adjustment mechanisms, and other outside-the-rate-case adjustment mechanisms all reduce net earnings volatility and risk, and therefore contribute to a lower cost of capital for the utility. It is important when selecting “comparable” utilities for cost of capital studies to use only utilities with similar risk-mitigation tools in place, so that an apples-to-apples comparison is possible.

Standard and Poor’s has explicitly recognized risk mitigation measures by rating the “business risk profile” of utility sector companies on a scale of 1 to 10. The distribution utilities without supply responsibility and with risk mitigation measures are mostly rated 1 to 3, whereas the independent power producers without stable customer bases or any risk mitigation measures are 7 to 10. The vertically integrated utilities with some risk mitigation measures are in between.[30]

The risk mitigation of decoupling can be reflected in either of two ways. First, it can be directly applied to reduce the equity capitalization ratio of the utility in a rate case. This has the effect of reducing the overall cost of capital and revenue requirement, without changing either the cost of debt or the allowed return on equity. This approach recognizes that a utility with more stable earnings does not require as much equity in its capital structure, because there is less likelihood of the utility depleting its retained earnings.

Table 12 summarizes how a change in the equity capitalization ratio reduces the revenue requirement.

Table 12

Quantification of Savings from Capital Structure Shift

Element	Allowed Return	Ratio w/o Decoupling	Ratio with Decoupling
Equity	11%	45%	42%
Debt	8%	55%	58%
Overall Return with Taxes		10.48%	10.13%
Revenue Requirement ($ millions)		$104.80	$101.30
Difference			-$3.50

30 See Standard and Poor’s *New Business Profile Scores Assigned for US Utility and Power Companies: Financial Guidelines*, revised 2 June 2004. See also Moody’s Investor Services, *Local Gas Distribution Companies: Update on Revenue Decoupling And Implications for Credit Ratings*, 2006, and Standard and Poor’s, *Industry Report Card: U.S. Electric Utilities Well Positioned For 2011 Challenges,* December 10, 2010.

The overall impact is on the order of a 3% reduction in the equity capitalization rate, which in turn can produce about a 3% decrease in revenue required for the return on rate base, or about a 1% decrease in the total cost of service to consumers (including power supply or natural gas supply). This is not a large impact — but it is on the same order of magnitude as many utility energy conservation budgets, meaning that cost savings from implementation of decoupling can fully fund a modest energy conservation program at no incremental cost to consumers.

Cost savings from implementation of decoupling can fully fund a modest energy conservation program at no incremental cost to consumers.

It is important to recognize that this type of change involves neither a reduction in the return on equity, nor a reduction in the allowed cost of debt. It simply reflects a realignment of the amount of each type of capital required.

A utility could adapt its actual capital structure to reflect this change, either by issuing debt rather than equity for a period of months or years, or by paying a special dividend (reducing equity) and issuing debt to replace that capital.

The second approach to reflecting the risk reduction afforded by decoupling is simply to reduce the utility's allowed return on equity, discounting by some number of basis points what would otherwise have been approved. This has been done in a number of jurisdictions. There are, however, several points that regulators should consider when weighing this option against the first.

10.2 Some Impacts May Not Be Immediate, Others Can Be

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

If the regulator does not change the allowed equity capitalization ratio when a new risk mitigation measure is implemented, the rating agency will eventually realize that the mitigation is occurring, and that earnings are more stable; and eventually a bond rating upgrade is possible. Once that occurs, the cost of debt will eventually decline, and consumers will realize the benefit of lower costs of debt in the conventional ratemaking process.

In theory, the total cost savings from a bond rating upgrade should be about the same as the savings from an equity capitalization reduction. The principal reason for preferring the equity capitalization option is that it can be implemented concurrently with the imposition of the risk mitigation measure, so that consumers receive an immediate economic benefit when the measure is implemented. The lag to a bond rating upgrade can be years, or as much as a decade; and the cost savings will phase in very slowly as new bonds are issued.

10.3 Risk Reduction: Reflected in ROE or Capital Structure?

Some ratepayer advocates have proposed an immediate reduction in the allowed return on common equity as a condition of implementing decoupling. This may create controversy in the ratemaking process, with the risk that utilities then become resistant to implementation of decoupling. Utilities have pointed to rate cases in other jurisdictions, where many of the "comparable" utilities used to estimate the required return on equity already have risk mitigation measures in place.

Economic theory supports the notion that risk mitigation is valuable to investors and that that value will (eventually) be revealed in some way in the market — through a lower cost of equity, a lower cost of debt, or a lower required equity capitalization ratio. Any of these will eventually produce lower rates for consumers, in return for the risk mitigation measure. Regardless of the theory, however, utilities may tend to view a reduction in the return on equity as a penalty associated with decoupling. In contrast, a restructuring of the capitalization ratio does not necessarily alter the required return on equity, and it is more directly reflective of the risk mitigation that decoupling actually provides — that is, stabilization of earnings with respect to factors beyond the utility's control. By reducing volatility, the utility needs less equity to provide the same assurance that bond coverage ratios and other financial requirements will be met.

Rating agencies have recognized the linkage between risk mitigation and the required equity ratio to support a given bond rating, rather than to the required return on equity. For this reason, there may be advantages to focusing on the utility's capital structure, rather than on its allowed return on equity or the cost of debt, when regulators consider how to flow through the risk-mitigation benefits of decoupling to consumers when a mechanism is put into place.[31]

31 One recent paper concluded that decoupling did not result in a decrease in the cost of equity capital in the short run. The study focused on only one approach to measure the cost of capital, the discounted cash flow method. It did not consider the reduction in systematic risk (the change in earnings relative to the change in the overall market earnings in the same period) that is measured by the Capital Asset Pricing Model. Decoupling will reduce systematic risk (reducing earnings volatility due to economic cycles) because sales variations in business cycles do not affect earnings under decoupling. The study also did not attempt

10.4 Consumer-Owned Utilities

Consumer-owned utilities (COUs) do not pay cash dividends, but they do need to maintain a sound bond rating to support future investments. The rating agencies look at the TIER (times interest earned ratio) of COUs.[32] Typical bond covenants for COUs obligate the utility to maintain its TIER above a minimum defined level, so they might be required to raise rates if they suffered severe earnings attrition (from any cause).

A loss of revenue due to conservation, weather, or other factors can impair the TIER, and therefore the borrowing capacity of a COU. A decoupling mechanism will provide the same stability of earnings for a COU as for an investor-owned utility (IOU). However, there is a smaller body of research on whether decoupling will actually have a meaningful effect on the borrowing costs of COUs, assuming that their TIER remains within a range in which they are able to borrow.

Without decoupling, COUs tend to set rates at levels that provide 75%-90% assurance that the TIER will remain at an acceptable level. It is clear that a decoupling mechanism will ensure that the TIER remains in an acceptable range, and that the COU will be able to borrow. A decoupling mechanism may thus allow a COU to set rates at a slightly lower level, without fear that a variation in weather or sales will cause it to fall to a level that would trigger a larger rate adjustment.

10.5 Earnings Caps or Collars

Some commissions have imposed an earnings cap, or an earnings collar, as part of a decoupling mechanism. These ensure that, if earnings are too high above a baseline (or too low below the baseline), the decoupling mechanism is automatically subject to review. Because decoupling reduces earnings volatility, it should be unlikely for earnings to vary outside a range of reasonableness. Therefore such a cap or collar, while unlikely to be triggered, may provide greater comfort with the change represented by decoupling.

Even so, in practical application, it is simpler to impose a cap on the variability in prices than in earnings, because the calculation of earnings for regulatory purposes can be significantly different than earnings reporting under generally accepted accounting principles and may invite disputes over methodology.

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to measure the change in probability that a utility would exhaust its ability to pay dividends from cash earnings, which is reduced if the utility is protected from variations in earnings driven by weather and economic cycles. These are factors that lead RAP to believe that adjusting the capital structure is more appropriate than adjusting the allowed return on equity when decoupling is implemented on a permanent basis. See Brattle Group, *The Impact of Decoupling on the Cost of Capital,* March, 2011.

32 TIER is a measure of the extent of which earnings are available to meet interest payments. Mathematically it is defined by this formula: TIER = (net income + interest) / (interest).

11 Other Revenue Stabilization Measures, and How They Relate to Decoupling

There are a number of other revenue stabilization measures used by regulatory commissions, some of which are proposed as possible alternatives to decoupling. Some of these provide nearly the same benefits to utility shareholders as decoupling, but all of them fall short of the full range of benefits that revenue decoupling provides, particularly those for consumers and the environment. We discuss several of these below, comparing the consumer impacts and societal benefits to those of decoupling.

11.1 Lost Margin Recovery Mechanisms

A lost margin mechanism provides recovery to the utility for distribution margin that is lost when customers participate in the utility-sponsored energy efficiency programs. The benefit is that the utility resistance to offering such programs is addressed. One side effect is creation of a bias in favor of utility-funded programs to the exclusion of codes, standards, and other lower-cost means to achieve savings. In one experience, a utility was simultaneously offering incentives for participation in its programs, while conducting a political campaign against other types of energy efficiency marketing, to ensure that any lost margins were recovered.

11.2 Weather-Only Normalization

Typically the largest rate adjustments under decoupling are weather-induced. Many natural gas utilities have weather normalization clauses, in which small surcharges are imposed during periods of mild weather, and small surcredits during severe weather. A weather-only adjustment does not address lost sales due to either programmatic energy efficiency on consumer-funded energy efficiency, and therefore does not address one of the principal objectives of decoupling, which is to eliminate utility disincentives for energy efficiency.

11.3 Straight Fixed/Variable Rate Design (SFV)

SFV is an approach to rate design in which all utility fixed costs are recovered in a fixed monthly charge, with only variable costs included in the per-therm or per-kWh rate. The definition of "fixed" costs varies from a strict accounting measure (interest and depreciation) to a broad measure that includes the return on equity, taxes, and labor expenses, but the principle is the same: customers do not pay for utility service on a primarily volumetric basis.

SFV is attractive due to simplicity, but has numerous adverse side effects. These include:

- Energy prices are set far below long-run marginal cost, leading to uneconomic usage;
- Small users, particularly seniors and apartment dwellers, pay much higher electric and gas bills;
- Consumer investment in energy efficiency is discouraged, since the bill savings are small;
- A mismatch occurs between the cost-responsibility and cost-collection for seldom-used peaking facilities (for which the costs should be recovered in incremental usage block rates).

Some studies have estimated that SFV pricing can cause usage to go up 10% or more, enough to offset much or all of the benefit of energy efficiency programs.[33]

11.4 Fuel and Purchased Energy Adjustment Mechanisms

Fuel adjustment clauses (FACs) and purchased gas adjustment (PGAs) mechanisms are used by nearly all gas utilities, and by most electric utilities, to recover variable costs of fuel and purchased energy. They evolved during the first and second oil embargoes in 1973 and 1977, and have become nearly ubiquitous. The benefit of these is that utilities are assured of recovery of a very large set of costs over which they have little control. The side effect is that an FAC or PGA ensures that ANY incremental sale is profitable, since ALL of the increased variable cost is covered, and the incremental sales margin results in incremental profit.

33 Lazar, J., Allen, R. & Schwartz, L. (2011, April). *Pricing Do's and Don'ts.* Montpelier, VT: Regulatory Assistance Project. Retrieved from http://www.raponline.org/knowledge-center/pricing-dos-and-donts-designing-retail-rates-as-if-efficiency-counts

FACs and PGAs are therefore of great concern when trying to design a regulatory framework that encourages utility support of energy efficiency.[34] A properly designed decoupling mechanism can overcome this effect by assuring that only the allowed level of non-fuel or non-power revenues are received if utility sales increase.

11.5 Independent Third-Party Efficiency Providers

Several states have implemented third-party energy efficiency utilities, such as Efficiency Vermont and the Energy Trust of Oregon. Some advocates believe that by moving efficiency outside the utility, there is no longer a need for revenue decoupling, because the utility is no longer in a position to resist or obstruct energy efficiency investment. It is instructive that both Vermont and Oregon have found that revenue decoupling is a useful addition to a framework that includes a third-party provider, because utilities affect energy efficiency in many more ways than simply making grants and loans to consumers for energy efficiency measures.

11.6 Real-Time Pricing

Some academics have taken the position that dynamic utility pricing will result in efficient deployment of energy-efficiency measures, without any need for government or utility intervention. While advanced pricing has many advantages, it does not in any way overcome the multiple barriers to energy efficiency — such as access to capital, perfect information, or short time horizons of consumers, particularly renters. These barriers have been well-documented, and no form of energy pricing has been demonstrated to overcome them.

34 See Moskovitz, David, *Profits and Progress Through Least Cost Planning* for a detailed discussion of the problems with FACs and PGAs at: http://www.raponline.org/docs/rap_moskovitz_leastcostplanningprofitandprogress_1989_11.pdf

12 Decoupling Is Not Perfect: Some Concerns Are Valid

There are many critics of decoupling, and many different issues that they criticize. Decoupling is not a perfect form of regulation — but neither is conventional regulation. Both seek to set prices for utility service that approximate the cost of providing that service. Both seek to provide incentives for management to take actions to reduce costs and to maximize profits.

In this section, we discuss some of the common critiques of decoupling mechanisms, recognizing that all forms of regulation involve compromise.

12.1 "It's an annual rate increase."

Some rate case participants view decoupling as an annual rate increase without a rate case. This may be the case if the use per customer is declining over time, but it does not provide any indication of whether customer energy bills are rising or falling. That may be due to utility programs and policies, or it may be due to other factors that can be taken into account in the design of the decoupling mechanism.

If the decline in usage per customer is due to utility programs and policies, an annual upward rate adjustment (which produces annual decreases in annual bills due to declining usage) may be exactly why the decoupling mechanism was created. If energy efficiency is less expensive than energy production, then customer energy bills are declining. Absent decoupling, the utility would likely be filing annual rate cases, creating a significant workload on the Commission and leading to similar rate increases, since the underlying causes are the same.

To the extent that less frequent rate cases produce fewer opportunities for consumers to present policy issues to the Commission, it is probably appropriate for the regulator to create an alternative forum for such policy review. One approach, for example, might be for the regulator to initiate a general rate case at least once every three to five years, to ensure that the allowed revenues under decoupling do not deviate too far from the utility's underlying costs.

12.2 "Decoupling adds cost."

This reflects a misunderstanding of decoupling. Decoupling increases the likelihood that the revenue requirement found appropriate in a rate case will be the amount actually collected from customers. Certain decoupling elements (e.g., adjustments for inflation, productivity, and numbers of customers) project how those approved costs might change, and allow these changes to be reflected in future collections; but these changes represent costs that are likely to be approved in a rate case, because they are essential to providing service. Decoupling itself adds no significant new costs; to the extent that decoupling reduces the frequency of general rate cases, it can significantly reduce regulatory costs.

12.3 "Decoupling shifts risks to consumers."

Full decoupling means that utility profits are no longer adversely affected by weather conditions that reduce sales volumes, and some critics consider this a shift of weather risk to consumers. This is a fundamentally flawed argument. First, decoupling also removes the profit enhancement that occurs under traditional regulation when weather conditions cause sales increases. Second, with current decoupling, although prices go up when sales go down, they do so simultaneously, so that customer bill volatility is reduced, a benefit to consumers attempting to live within a budget. In addition, when sales go up, prices come down, thereby mitigating the bill's impacts. In this sense, decoupling mitigates earnings risk for utilities and expense risk for consumers, making both better off — and in the process, it creates the earnings stability to justify a lower overall cost of capital, which reduces absolute costs to consumers.

12.4 "Decoupling diminishes the utility's incentive to control costs."

In fact, precisely the opposite is true. Decoupling does not guarantee utilities a level of earnings, only an assurance of a level of *revenue*. If the utility reduces costs, it increases earnings, just as it would under traditional regulation. Also, because the utility cannot increase profits by increasing sales, improved operational efficiency is the *only* means by which it can boost profits.

Because decoupling provides recovery of lost margin due to customer conservation efforts, however, it may extend the period between general rate cases. This is particularly true if aggressive utility conservation efforts are producing significant declines in customer usage; absent decoupling, this sales decline will trigger rate cases. This longer time period provides a stronger incentive for the utility to achieve operational efficiencies and reduce costs, because the utility will be allowed to retain the cost savings for a longer time, until the next general rate case. If costs and revenues become unbalanced for any reason, the utility or the regulator can initiate a general rate case at any time.

12.5 "What utilities really want sales for is to have an excuse to add to rate base —that is, the Averch Johnson Effect."

In a rate case, the net-income line item in the cost of service is a function of the size of the rate base and the return allowed>>. The greater the rate base, the greater the net income that is included in the cost of service (for a given allowed return). Utilities may be motivated to increase sales in order to add to rate base capital assets needed to serve additional load, despite countervailing risks associated with permitting and construction, for instance. This is not a concern decoupling can address, nor is it intended to address. Rather, sound integrated resource planning that identifies the least-cost long-term resource acquisition strategy is the best way to manage incentives associated with the capital program.

12.6 "Decoupling violates the 'matching principle.'"

The matching principle in ratemaking is an implicit assumption that revenues, sales, and costs will move in synchronization: as sales change (go either up or down), revenues and costs will change at the same rate. Absent changes in customers, programs, or policies, this has been generally effective in allowing traditional regulation to function effectively. Implied in the matching principle is that inflation is offset by productivity, and that new customers are about the same in terms of usage, revenue, and cost of service as existing customers. However, as discussed in the sections *How Traditional Regulation Works and How Decoupling Works,* it is the very fact that the matching principle does not hold true (that is, that marginal revenue almost always exceeds marginal cost in providing distribution service) that drives the need for decoupling.

Correspondingly, a change to a more comprehensive approach to energy efficiency means that deliberate programs and policies are implemented to achieve sales reductions for which there are no corresponding cost reductions, at least (for the most part) in distribution services. The very circumstances that counsel most regulators to consider decoupling — a desire to step up the rate of achievement of customer energy efficiency — directly undermine the foundation of the matching principle.

12.7 "Decoupling is not needed because energy efficiency is already encouraged, since it liberates power that can be sold to other utilities."

This condition does exist in some low-cost utilities that have excess capacity available for sale and that do not have FACs. Any utility with a traditional FAC does not benefit from off-system sales, because those revenues are credited to their retail consumers through the adjustment clause.

This concern, however, overlooks the temporary nature of excess capacity, especially if some of it is the result of an aging generation approaching retirement, and the changing nature of power markets. Decoupling encourages utilities to take actions that may increase off-system sales revenues, but only if power costs are covered by a decoupling mechanism will those sales result in increased profits for the companies.

Lastly, off-system sales have less certainty and are subject to the vagaries of market prices, whereas sales to native loads are more certain and subject to less price volatility. Conservative utility managers are likely to prefer the "bird in hand" in such cases.

12.8 "Decoupling has been tried and abandoned in Maine and Washington."

Maine and Washington initiated decoupling mechanisms in the late 1980s and early 1990s, and both terminated the programs after a few years. The reasons for termination were different.

In Maine, the decoupling mechanism was instituted for Central Maine Power shortly before a serious recession hit the country. Sales declined and the decoupling mechanism generated significant rate increases, because of the large annual adjustment resulting from the use of an accrual methodology. The Commission elected to discontinue the mechanism. Of course, for the most part, decoupling only implemented what a new rate case would have yielded in any event, the root cause of the problem not being the mode of regulation, but the recession. The lesson learned is that a cap on annual rate increases may be appropriate, and a complete review of costs, sales, and revenues (i.e., a general rate case or equivalent) should be required every few years under a decoupling mechanism.

In Washington, a decoupling mechanism applied to "base costs" was introduced at the same time that a separate mechanism was introduced to recover "power costs." The utility (Puget Sound Power and Light Company) was acquiring significant new resources to replace expiring power supply contracts. Rates went up sharply due to the operation of the power cost mechanism, not the decoupling mechanism. The increases raised public concerns, and the public utility commission (PUC) opened an inquiry into the Puget's resource decisions. The Commission found that, with respect to certain power supply contracts, the utility had acted imprudently. The combined mechanism was terminated. The rate adjustments due to the decoupling portion had been minor, and were not the primary focus of the Commission's inquiry. Shortly thereafter, Puget applied for a merger with Washington Natural Gas Company. A multi-year rate plan was approved as part of the merger, displacing both the power-cost and base-cost decoupling mechanisms.

12.9 "Classes that are not decoupled should not share the cost of capital benefits of decoupling."

Many commissions have excluded large-volume electricity and natural gas consumers from decoupling mechanisms. The reason for this is that classes of customers with few members may really require customer-specific attention in ratemaking, and a decoupling mechanism could result in significant rate increases to remaining customers if another customer or customers in the class discontinued or reduced operations.

Because decoupling results in a lower risk profile for the utility, particularly with respect to weather and economic cycles, it is expected (either immediately or over time) that a reduction in the cost of capital will result. A class that is not exposed to decoupling rate adjustments due to sales variations is not a part of the cause of the lower risk profile. However, because Commissions normally apply the same rate of return to all classes, it may not be pragmatic to calculate a different rate of return for each class.

As a practical matter, large-use customer classes often have other revenue stabilization elements in their rates, such as contract demand levels, demand ratchets, and straight fixed/variable rate designs that have a stabilizing effect on revenues similar to that of decoupling. Consequently, one might argue that, under traditional regulation, the classes with more variable loads were benefiting from the risk-reducing nature of larger-volume customers, and that decoupling merely balances the scales.[35]

35 But it is fairer to say that all loads impose both risks and benefits on the utility. A large-volume user may have a higher-than-average load factor and provide stable revenues to the utility, but the adverse impacts of its leaving the system are significantly greater than those of individual lower-volume customers. Many factors affect the market's valuation of the risks that a utility faces; load diversity is only one of them.

12.10 "The use of frequent rates cases using a future test year eliminates the need for decoupling."

A future test year may have the effect of causing a utility's "revenue requirement" to more closely track a utility's revenue requirement over time. A future test year does not, however, have the effect of constraining *allowed revenues* to a utility's revenue requirement. In addition, a future test year does not address the throughput issue, which is one of the primary reasons for using decoupling. The term "decoupling" itself is rooted in the notion of separating the utility's incentive to increase profits through increased sales, and to avoid decreased profits through decreased sales by breaking the link between — that is, by decoupling revenues from sales.

12.11 "Decoupling diminishes the utility's incentive to restore service after a storm."

This can be a problem if not addressed in the design of the decoupling mechanism. After a storm, utilities normally bring in extra crews, pay overtime, airlift in supplies, and otherwise do everything reasonably possible to restore service. The primary reasons for this are the deeply-held sense of obligation that drives utilities and their employees to provide reliable service and their appreciation of the far-reaching and deleterious impacts of an outage.

But there is also a more prosaic motive: the need to "get the cash register running" again, so revenue flows to the utility. If a decoupling mechanism allows the utility to receive the revenues that it would have collected if the power were on, consumers both suffer an outage and pay for service they did not receive. The utility is made whole, and really does not suffer any penalty from slow service restoration.

This is easily addressed in the design of an RPC decoupling mechanism. One approach would be to adjust the number of customers for whom the allowed revenue is computed to reflect only those who were receiving service during a particular time period, deducting days when power was unavailable. (This same concern applies equally to straight fixed/variable pricing: the charges to consumers must be halted during an outage, or the incentive to restore service is diminished.) Another approach would be to address service quality issues such as outages separately, in a comprehensive Service Quality Index, with penalties tied to outage frequency and duration.

12.12 "The problem is that utility profits don't reward utility performance."

At least two states have tried to overcome utility resistance to energy efficiency investment by allowing a higher rate of return for investment in energy efficiency than utilities receive on supply-side investments. While this can work in theory, it is difficult to make it work in practice, because the incentive return must be quite high to overcome the lost margin effect that decoupling addresses. In addition, a premium return may tend to reinforce the Averch-Johnson effect, giving utilities an incentive to spend as much as possible (to attract the incentive return) on measures that save little or no energy (to avoid creating lost margins). An incentive return mechanism can be a very important part of regulation, for example, by tying the utility's return (or the utility's recovery of deferral margins under decoupling) to the utility's achievement of energy efficiency achievement and cost control targets approved by the commission. But, as a general matter, incentive return mechanisms have not been effective alternatives to decoupling; in combination *with* decoupling, however, they can be.

13 Communicating with Customers about Decoupling

Preparing a utility's customers for the effects of decoupling on their bills can be a challenge, both because the components of a utility's bill are not always straightforward, indeed are often confusing, and because variable prices are a new phenomenon to most. Regulators, utilities, and consumer advocates should all want to make the transition to decoupling as smooth as possible for customers. This requires some thought about bill design and consumer education. The guiding principle here should be simplicity. In fact, the implementation of decoupling offers an opportunity to overhaul the utility's bill with an eye toward simplification.

In many states, the utility bill has become a rather dense tangle of line items that represent, in many cases, a long history of policy initiatives and regulatory decisions. In many cases, they are a kind of tally of the rate-case battles won and lost by advocates and utilities, a catalogue of special charges and "trackers" dealing with particularly knotty investment and expenditure requirements. The accumulated result is often a bill that consumers find difficult to navigate. A customer's electric bill typically consists of a monthly customer charge, one or more usage blocks (or time-of-use periods), and as many as ten surcharges, credits, and taxes added to these usage-related prices. Some utilities present all of the detail on the bill, and it can be confusing and overwhelming to the consumer. Table 13a shows an example of how the customer's bill may look with all of the detail. To the extent that line items can be eliminated or combined, consumer confusion is likely to be reduced.

Alternatively, all of the detail can be provided, but the bill should "roll up" all of the rate components, adjustments, taxes, surcharges, and credits into an "effective" rate that the consumer pays. Table 13b shows what the customer actually pays if they use more electricity, or saves if they use less electricity. Utilities should be encouraged to display the "effective" rate to customers, including all surcharges, credits, and taxes, so consumers can measure the value of investing in energy efficiency or other measures that reduce (or increase) their electricity consumption.

Tables 13a and 13b show a conversion of a rate with multiple surcharges into an effective rate.

Table 13a

Example of an electric bill that lists all adjustments to a customer's bill			
	Your Usage: 1,266 kWh		
Base Rate	**Rate**	**Usage**	**Amount**
Customer Charge	$5.00	1	$5.00
First 500 kWh	$0.05000	500	$25.00
Next 500 kWh	$0.10000	500	$50.00
Over 1,000 kWh	$0.15000	266	$39.90
Fuel Adjustment Charge	$0.01230	1,266	$15.57
Infrastructure Tracker	$0.00234	1,266	$2.96
Decoupling Adjustment	$(0.00057)	1,266	$(0.72)
Conservation Program Charge	$0.00123	1,266	$1.56
Nuclear Decommissioning	$0.00037	1,266	$0.47
Subtotal:			$139.74
State Tax	5%		$6.99
City Tax	6%		$8.80
Total Due			**$155.53**

Table 13b

The rate above, with all of the surcharges, credits, and taxes applied to each of the usage-related components of the rate design			
Base Rate	**Rate**	**Usage**	**Amount**
Customer Charge	$5.56500	1	$ 5.56
First 500 kWh	$0.07309	500	$ 36.55
Next 500 kWh	$0.12874	500	$ 64.37
Over 1,000 kWh	$0.18439	266	$ 49.05
Total Due			**$155.53**

A secondary issue is whether the changes in price occasioned by decoupling should, themselves, be detailed in a line item on the bill or subsumed in a total price. We are all familiar with changing prices at the gas pump, but do not expect a "line item" description of the latest adjustment up or down in that price. We expect to pay the price on the sign, and expect it to include all taxes, fees, profit, transportation charges, and other elements of cost. In fact, if gas stations were required to track price changes in such a way, consumers would see a confusing array of information that is largely unrelated to changes in the total price being paid. Again, simplicity argues for rolling the decoupling adjustments directly into the total price, rather than having a separate decoupling adjustment line item. The full detailed tariff must be available for the customer to review, generally on the utility website, but it may not need to be on the bill; only the effective prices – what a customer pays if he or she uses more or less service – is relevant to the consumption decision.

When decoupling is implemented, a communication strategy should be in place to help consumers understand why prices are being allowed to vary from bill to bill. They may see decoupling as a "profit guarantee" rather than a "revenue assurance." Information making clear the ultimate impacts of decoupling will likely be more understandable than a brochure that attempts to, say, summarize the contents of this guide.

Aside from the total size of their bills, customers tend to be most concerned about whether they are being fairly charged by their utility. Decoupling strikes to the heart of this issue because, unlike traditional regulation, it has a high probability, if not certainty, that consumers will actually pay the revenue requirement determined by the Commission. In addition, where weather risk is eliminated, decoupling has the effect of countering the impacts of high bills during extreme weather (with the symmetric effect of slightly increasing bills during mild weather).

Most consumers would likely welcome a little "help" when the bills are higher than usual, at the "cost" of a slightly higher bill when bills are lower. This is merely the softening of the peaks and valleys. It is these aggregate effects that consumers should understand, and which a communication strategy should address.

14 Conclusion

Revenue regulation and decoupling provide simple and effective means to eliminate the utility throughput incentive, remove a critical barrier to investment in effective energy efficiency programs, stabilize consumer energy bills, and reduce the overall level of business and financial risk that utilities and their customers face.

This guide has identified and explained key issues in decoupling for the benefit of regulators and participants in the regulatory process alike. Each utility and each state will be a little bit different, so there may not be a cookie-cutter approach that is right for all. However, the principles remain fairly constant: minor periodic adjustments in rates stabilize revenues, so that the utility is indifferent to sales volumes. This eliminates a variety of revenue and earnings risks, in particular those associated with effective investment in end-use energy efficiency, and can bring provision of least-cost energy service closer to reality for the benefit of utilities and consumers alike.

Decoupling Case Studies: Revenue Regulation Implementation in Six States

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Decoupling Case Studies: Revenue Regulation Implementation in Six States

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List of Acronyms

BGE	Baltimore Gas and Electric
CPUC	California Public Utilities Commission
C&I	Commercial and Industrial
DG	Distributed Generation
DPU	Department of Public Utilities
DSM	Demand-Side Management
FCA	Fixed Cost Adjustment
GAAP	Generally Accepted Accounting Practices
GRC	General Rate Case
HECO	Hawaiian Electric Company
IPC	Idaho Power Company
kWh	Kilowatt-Hour
MECO	Maui Electric Company
O&M	Operation and Maintenance
PCA	Power Cost Adjustment
PGE	Portland General Electric
PG&E	Pacific Gas and Electric
PSC	Public Service Commission
PSCW	Public Service Commission of Wisconsin
RAM	Revenue Adjustment Mechanism
RBA	Revenue Balancing Account
ROE	Return on Equity
RPC	Revenue Per Customer
RSM	Revenue Stabilization Mechanism
TOU	Time-Of-Use
WPS	Wisconsin Public Service Corporation

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Introduction:
Policy Overview for Decoupling

Over the last several decades there have been major shifts away from the traditional utility service paradigm in which the local utility supplied customers with all their resource needs, and those resource needs were met through the construction and operation of power plants. Some states have restructured their electric utilities so that the resource supply is a competitive service. Others have maintained the traditional vertically integrated model, while other states have developed hybrids combining features of each. Also different today is the expectation that the customer demand for electricity will be provided exclusively from power plants. Energy efficiency as a substitute for new power plants to meet customer needs has been gaining acceptance in the regulatory world, significantly during the last decade. Moreover, as the price of renewable resources used for distributed generation (DG) continues to decline, there has been a growth in the adoption of on-site generation by customers as they demand a more diverse set of services. The potential for deployment of customer-side resources of all types is large.

Traditional regulatory practice creates an environment in which the utility is able to earn more profit by selling more electricity. Because of this dynamic, the utility is essentially in competition with the customer, as well as with private sector companies that provide services, to supply the energy needs of that customer. This can greatly impede the ability of the marketplace to achieve the optimal least-cost solution for energy services. A regulatory scheme that depends on increasing throughput as a means for achieving earnings is likely to be increasingly out of step with customer needs and desires—and with public policy objectives—in the coming years. As the utility service environment changes, so too must regulation as customers demand more and different services and as regulators increasingly encourage clean energy outcomes. The growth in customer-sided resource options compounds the challenge of net lost distribution revenues for utilities, especially as it affects their ability to maintain and upgrade their grid infrastructure. Thus, as nontraditional resources (that are neither supply options nor provided by the utility) are proliferating, revenue regulation, while not a silver bullet, becomes even more important as a means of managing revenues and removing utility barriers to adoption of these alternatives.[1]

Although the concept of increasing energy efficiency and DG may be fairly straightforward, the impact and reaction of electric utilities to engage in comprehensive energy efficiency and encourage DG is not. Ask any business how it makes money and it will invariably respond that it does so through increasing the number of units of the products it is selling, through growth. Energy efficiency requires utilities to do the exact opposite of the traditional model, and instead requires the utility to market and promote buying less of its product. The net lost revenues that the utility will encounter as a result of these activities is no trivial matter, especially as energy efficiency programs ramp up. Many states have Energy Efficiency Resource Standards requiring cumulative reductions in consumption by 20 to 25 percent in the 2020 decade. Others have commission-ordered energy efficiency portfolio requirements, requiring similar reductions in consumption. A new study cosponsored by The Edison Foundation Institute for Electric Innovation found that electric utility efficiency programs saved 126 terawatt-hours of electricity in 2012. If utilities were unable to collect two cents per kilowatt-hour (kWh) contribution to fixed costs as a result of these efficiency program savings, they would experience a significant reduction in returns.

The growth in DG will also impact utility sales, and have a similar impact on revenue as energy efficiency. According to a Bloomberg report, financial investments in DG have grown from $19 billion in 2004 to $143 billion in 2010.[2] The onsite energy production from these investments will decrease utility sales from what they otherwise would have been, and could result in absolute decreases in sales in states that have strong energy efficiency programs and low baseline growth. As states pursue a more aggressive efficiency agenda, there might come a point where the current rate-setting model is no longer sustainable. Utilities have embedded investment-related and labor costs (not sensitive to volume)[3] included in their rates to support investments already made and necessary for good service, reliability, safety, and other utility services, which are adjusted during periodic rate cases.

1 For an in-depth discussion of revenue regulation, see: Shirley, W., Lazar, J. & Weston, F. *Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission.* Montpelier, VT: Regulatory Assistance Project. Retrieved from http://www.raponline.org/knowledge-center/revenue-decoupling-standards-and-criteria-a-report-to-the-minnesota-public-utilities-commission

2 Bloomberg New Energy Finance. (2011). *Global Trends in Renewable Energy Investment 2011,* UNEP SEFI Frankfurt School, Global Trends in Renewable Energy Investment.

3 Technically, the only truly "fixed" costs for a utility are interest and depreciation. Labor costs are technically variable costs, but they vary little in the short-run in response to sales volumes. Over a long time, one or more decades, some costs that are fixed in the short-term, such as transformers and conductors, are revealed to be volume- and usage-sensitive, especially when assets and systems are replaced.

Without a mechanism in place to address the utility impact of reduced sales, the lost revenues from energy efficiency programs and DG will make it more difficult for utilities to cover their fixed cost obligations and to reach their earnings targets for shareholders. As a result, various strategies to allow utilities to recapture these lost revenues have been developed. Environmental imperatives, including promotion of customer-side alternatives to utility supply, motivate regulators to consider forms of regulation in which sales do not matter and utilities are motivated to find the best investments to meet public policy objectives irrespective of which side of the meter it resides or what degree of utility control is maintained.

Lost revenue recovery allows utilities to recover the deficit in revenue resulting from reduced sales.[4] There are several mechanisms that accomplish this: lost revenue adjustment mechanisms, straight-fixed variable rates, and revenue regulation. Only one of these mechanisms, decoupling - revenue regulation, however, accomplishes the dual goals of both removing the throughput incentive and continuing to send more economically appropriate price signals to customers. Both of these principles are key to successful energy efficiency programs.[5]

Revenue regulation, however, is a not a single distinct mechanism. Rather, there are various elements that can be assembled in numerous ways based on state priorities and preferences that serve to eliminate the throughput incentive. This publication will focus on six utilities: Pacific Gas and Electric Company, Idaho Power Company, Baltimore Gas and Electric Company, Wisconsin Public Service Company, National Grid, and Hawaiian Electric Company, and the different forms of revenue regulation their regulators have implemented. These examples provide a range of options on how to implement revenue regulation. After considering the decoupling mechanisms of numerous utilities across the nation, these specific utilities were chosen in order to provide examples across many regions, and also to contrast the different approaches taken by each utility to provide a broader overview of the options available in designing decoupling mechanisms and to describe how they have worked.

4 Strictly speaking, it is *net* lost revenue that is at issue. To the extent that avoided sales avoid some amount of variable cost (low in the case of delivery services only), that avoided cost should be netted from the foregone gross revenue, in order to calculate the correct amount of revenue that would have otherwise gone to cover the company's return of and return on investment. Revenue regulation solves this problem automatically. In contrast, lost revenue adjustments require these calculations, which predictably become quite contentious in the rate-making process.

5 Although this paper does not focus on the rationale for sending appropriate price signals, references on this issue can be found at: Lazar, J., Schwartz, L., and Allen, R. (2011) *Pricing Do's and Don'ts.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/docs/RAP_Lazar_PricingDosandDonts_2011_04.pdf, and Lazar et al. (2011).

Rate adjustments under a revenue regulation scheme do not represent additional costs to ratepayers, but are a reallocation of approved, recoverable costs to a changing base of retail sales. Rates are set assuming a certain sales volume, and many costs that do not vary with usage in the short run are collected through a volumetric sales rate. When a utility engages in programs or policies that result in lower customer usage, some revenues that should have offset some of these costs are not billed to customers as a result (and vice versa where usage increases). The revenue regulation adjustment tracks those lost revenues and allows recovery in a subsequent period. In all cases, the revenue regulation adjustment represents a reconciliation of revenues that were approved for collection from customers that were not collected as a result of changed sales volumes. Revenue regulation adjustments can also result in reduced rates when excessive revenues are collected due to weather or other variations in sales amounts.[6]

Background: Measuring the Success of Decoupling/ Revenue Regulation Mechanisms

A revenue regulation mechanism designed to promote energy efficiency may be viewed as successful if the utility is no longer concerned about increases and decreases in sales, is no longer taking actions to increase sales or reduce decreases in sales, and is improving the overall efficiency of its operations and management. Although a particular mechanism can be designed to meet other goals (other performance goals, with dedicated metrics and specific rewards and penalties attached), this paper is primarily concerned with mechanisms designed to mitigate revenue losses that can impede the desire of a utility to aggressively pursue programmatic energy efficiency. By taking an in-depth look at six diverse utilities that have implemented revenue regulation, this study describes the similarities and differences among the adopted mechanisms and attempts to answer the question of how each is working to achieve its goals.

A second significant determinant of the success of a revenue regulation mechanism is its acceptance by the stakeholders. This can be manifested by a lack of objection or support of revenue regulation by consumers and

6 For a detailed analysis of the economic and public policy rationales for revenue regulation, see: Lazar et al., 2011. See also: Shirley, W., Lazar, J., & Weston, F. (2008). Revenue decoupling: standards and criteria: A report to the Minnesota Public Utilities Commission. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/docs/RAP_Shirley_DecouplingRevenueRpt_2008_06_30.pdf

it can be manifested through changes in utility behavior that customers respond to. Revenue regulation provides utilities who act prudently and in accordance with the mechanism assurance that they will collect their allowed revenues. As a result, they are better able to focus on other activities, such as programmatic energy efficiency, that reduces costs in the long run. The utilities studied also found benefits to include providing customers with a lower-cost product, improved customer interaction, and other efforts as sanctioned by the regulator that will produce additional revenue streams. Indeed, the Oregon Commission recognized as much when it commented on Portland General Electric's (PGE) ability to influence individual customers through direct contacts and referrals. The Commission also noted that PGE can influence usage depending on how aggressively it pursues DG; whether it supports improvements to building codes; and whether it provides timely, useful information on energy efficiency programs.[7] Engaging actively in these programs can also help develop better customer relationships as the utility industry evolves to a more service-oriented business. Instead of just handing customers a bill, the utility can be providing them efficiency-based solutions that serve cumulatively to avoid more expensive ways to meet customer demand.

Financial incentives for specified performance—relating to energy efficiency achievements or improvements in customer service, to name only two—are examples of ways to influence utility behavior in furtherance of public policy objectives. If awarded, such incentives are included in periodic adjustments to the allowed revenue. One goal is to turn the utility from being a reluctant participant to being an enthusiastic advocate for (or at least not an active inhibitor of) energy efficiency while creating a stable regulatory environment to accomplish other complementary policies. Moreover, combining revenue regulation with performance incentives creates a stronger inducement for utilities to engage in least-cost planning, which benefits its customers.

Environmental groups will want to ensure that there are robust programs and policies in place that advance clean energy solutions. Consumers will be cautious about rate impacts that will need to be addressed in the design of a decoupling mechanism (see text box on next page).

Striking a balance among competing stakeholder concerns while creating effective mechanisms to advance good public policy falls to the regulators and, as will be seen in the six case studies, there seems to be no generally accepted approach. This demonstrates that revenue regulation is not a static, one-size-fits-all policy, but rather it can be fashioned in a number of ways to

7 Oregon Public Utility Commission. Order No. 09-020, p 27.

meet the needs of any given community.

An additional way to evaluate the success of a revenue regulation mechanism is to look at the rate impacts and how manageable they are. Most annual rate impacts from revenue regulation fall between plus or minus one to three percent. These impacts are generally manageable and may in fact be less than the fluctuations customers might otherwise experience with fuel adjustment clauses or under a variable generation rate. Over the long term, observers might expect to note avoided load-driven capital costs and other long-lived commitments.

Another measurement of the success of decoupling is how the results of its implementation are viewed by financial institutions. Revenue regulation can be a factor considered by the rating agencies in determining a bond rating for a utility. With multiple mergers and the creation of holding companies with subsidiaries, it becomes more difficult to measure this because there are multiple utility companies and affiliates in multiple states that are being evaluated. Nevertheless, Standard and Poors noted that revenue regulation mechanisms were a positive factor and that they would better align the interests of consumers with utility shareholders by implementing rate designs that encourage energy efficiency.[8]

Some consumer groups have expressed concerns with decoupling, because, depending on how it is designed, there could be future rate adjustments that are not subject to the same rigorous review as would occur in a rate case. Below is a list of considerations in designing revenue regulation mechanism that attempts to address those concerns:

- Making revenue regulation contingent on a robust energy efficiency commitment and portfolio;
- Requiring structural symmetry in the mechanism, such that credits as well as surcharges flowing from a reconciliation be accounted for and refunded to customers;
- Creating a bandwidth around the amount of adjustment permitted in any given year;
- Adjusting the cost of capital or, more appropriately, the imputed capital structure, to reflect lower risk; and,
- Requiring periodic rate cases to assess the appropriate level of revenues for the utility—which is helpful only if the utility's revenue requirement is set too high and does not account for downward adjustments in costs such as reduced labor expense.

8 Standard and Poor's. (2012, May 15). Poors. Credit Matters Report.

Because revenue regulation reduces the utility's risk profile by providing revenue and earnings stability, the upside can be a better credit rating from the major rating agencies. Alternatively, the utility may be able to retain the existing credit rating with a lower common equity ratio in its capital structure. A better credit rating or lower equity ratio can translate into a lower financing rate, which benefits the utility and ultimately the customers who pay for utility-financed construction projects. These construction projects can include distribution and transmission upgrades or expansion as well as pollution control investments on existing generating units or, if necessary, new plant construction.

Finally, a more tangible means of ascertaining the success of a revenue regulation mechanism is whether there is an increase in energy efficiency and DG. Although some of the incremental increases may be motivated by statutory or regulatory requirements, a utility decision to increase or voluntarily go beyond the requirements through its own efforts or by assisting others, especially if innovative means are used to achieve these results, can be viewed as a demonstration that revenue regulation is working.

This publication contains an in-depth look at six instances of revenue regulation, representing a wide cross-section of such regimes in the United States. We look first at each utility and provide a summary of its revenue regulation mechanism. Next we discuss various components or decision points in designing a revenue regulation mechanism and look at how each state addressed that mechanism. What emerges is that despite the differences in designing revenue regulation, each mechanism is customized so that the pieces and parts fit together into a complete tableau. This is perhaps one of the most critical lessons to be drawn from these analyses, that is, that there is no one right way to do revenue regulation. What counts most is making sure that all the parts of a revenue regulation mechanism work together.

California: Pacific Gas and Electric Company

Pacific Gas and Electric Company's (PG&E) revenue regulation mechanism compares authorized revenues plus annual attrition adjustments with non–weather-adjusted actual revenues and reconciles any over- or under-collection annually. The authorized revenues are established through a general rate case every three years based on a future test year. Each of PG&E's functional operating areas is decoupled and the authorized revenue requirement is determined separately for each unit: electric distribution, gas distribution, public purpose programs, and the like. During the general rate case, authorized revenues are also established for the two years following the future test year. Each year, an "attrition case" measures changes in the approved costs that have been experienced, and adjusts the test-year revenue requirement. Collected revenue is tracked through balancing accounts, and surpluses/deficits in these accounts are amortized and refunded/collected to or from ratepayers through rate adjustments in the following year. Revenue regulation applies collectively to all of PG&E's customer classes (i.e., deviations in sales revenues relative to forecasted levels are tracked and reconciled at the system level). The revenue regulation mechanism is in addition to adjustments for PG&E's electric and gas energy procurement costs.

Authority

California first adopted revenue regulation for gas utilities in 1978. By 1982, the California Public Utilities Commission (CPUC) put revenue regulation in place for its three major electric investor-owned utilities, PG&E, Southern California Edison, and San Diego Gas & Electric. The original construct, called the Electric Revenue Adjustment Mechanism, established a revenue requirement for each utility annually and then reconciled billed revenues to authorized revenues. The Commission determined that the mechanism would "eliminate any disincentives PG&E may have to promote vigorous conservation measures and also be fair to ratepayers in assuring that PG&E receives no more or no less than the level of revenues intended to be earned."[9] However, the CPUC largely

9 CPUC Decision 93887 12/30/1981.

suspended the electric revenue regulation mechanisms in 1996 owing to the implementation of electric restructuring.

In 2001, the California Assembly passed Assembly Bill 29, which established programs to reduce energy usage in the wake of the Western Energy Crisis and required that "[t]he commission shall ensure that errors in estimates of demand elasticity or sales do not result in material over or under-collection of the electrical corporations."[10] Now incorporated into the Public Utilities Code, section 739.10, this required the CPUC to re-implement revenue regulation. The CPUC first re-implemented revenue regulation for PG&E in 2004, when the company came out of Chapter 11 bankruptcy following the Western Energy Crisis.

Authorized Revenue Requirement

The CPUC determines PG&E's authorized revenue requirement through a General Rate Case (GRC) every three years. Each of PG&E's functional operating areas is decoupled and the Commission determines a separate authorized revenue requirement for each area.

In order to determine the appropriate revenue requirement and rates, a future test year is used, meaning that the costs included in the revenue requirement and sales levels used to determine rates are forecasted. For example, on December 21, 2009, PG&E filed its application for the 2011 GRC. This GRC used the future test year 2011 to determine PG&E's authorized revenue requirements in 2011. The test year revenue requirement includes both projected expenses and capital expenditures.

The electric distribution revenue requirement request was based on the costs PG&E forecasted it would incur in 2011 to:

- Own, operate, and maintain:
  - Its distribution plant;
  - A portion of its transmission plant providing service directly to specific customers and connecting to specific generation resources; and
  - A portion of its common and general plant; as well as
- Provide services to its electric customers.

The generation revenue requirement request was based on the costs PG&E forecasted it would incur in 2011 to:

- Own, operate, and maintain its electric generating plant; and
- Perform the transactions necessary to procure electricity for its bundled-service electric customers.

10 Assem. Bill 29, ch 8, 2001 Cal. Stat. http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0001-0050/abx1_29_bill_20010412_chaptered.pdf

Because all customer classes are decoupled, the revenue requirement also includes costs related to serving all customers.

In the 2011 GRC, PG&E received a total revenue requirement of $5977 million. The retail revenue requirement for electric distribution was $3190 million, for gas distribution $1131 million, and for electric generation $1656 million.

Rate of Return

CPUC calculates the authorized revenue requirements for PG&E based on a rate of return on its rate base of 8.79 percent, which is projected to provide an 11.35-percent return on equity. Although intervening parties in the state's consolidated cost of capital proceedings have alleged that revenue regulation reduces financial risk, there has been no explicit reduction of the return on equity or debt-equity ratio attributable to the implementation of revenue regulation.

Costs Not Included in Revenue Regulation

According to PG&E, only approximately six percent of its electric revenues are "at risk," meaning not decoupled or tracked through another mechanism; only 4.2 percent of natural gas revenues are not decoupled.[11] In addition to energy procurement costs, revenue regulation does not apply to PG&E's FERC-regulated electric transmission revenue requirement or to a portion of PG&E's gas transmission and storage revenue requirement. Costs not included in PG&E's revenue requirement include energy procurement costs.

Revenue Adjustment Mechanism

PG&E's revenue adjustment mechanism allows for two methods for changing the authorized revenue requirement between rate cases. The first mechanism is the stair-step method, through which adjustments to the revenue requirement are predetermined during the GRC. Second, PG&E's revenue adjustment mechanism allows for changes in the post–test-year revenue requirements, in addition to the predetermined adjustments, for "exogenous changes."

During the GRC, the CPUC also determines the authorized revenue requirements, called post–test-year attrition increases, for the two years following the test year. In the 2011 GRC, the Commission determined the authorized revenue requirement for the future test year 2011 in addition to the post–test-year attrition increases for 2012 and 2013.

11 Risser, R. (2006, August 2). *Decoupling in California: more than two decades of broad support and success.* Presentation to the NARUC Workshop on Aligning Regulatory Incentives with Demand-Side Resources.

The annual attrition adjustments were fixed dollar amounts of $180 million in 2012, and $185 million in 2013, except for allowed exogenous changes. In this context, attrition refers to the decrease in utility revenues compared with costs between rate cases; attrition adjustments refer to adjustments to the authorized revenue designed to allow the utility to recover the increased costs. The 2012 increase includes $123 million for electric distribution, $35 million for gas distribution, and $22 million for electric generation. The 2013 increase includes $123 million for electric distribution, $35 million for gas distribution, and $27 million for electric generation.

Next, PG&E's attrition mechanism allows adjustments to the post–test-year revenue requirements for exogenous factors, limited to five factors, which are determined during the GRC. The five factors determined through the 2011 GRC to be applied to the 2012 and 2013 attrition adjustments are: postage rate changes, franchise fee changes, income tax rate changes, payroll tax rate changes, and ad valorem tax changes. A $10 million threshold is applicable to each factor each year.

Reconciling Actual Revenue With Authorized Revenue

Since 2004, PG&E has utilized balancing accounts to implement revenue regulation. Balancing accounts track the difference between billed revenue and the authorized revenue requirement each month in order to determine the total annual under- or over-collection of revenue. The revenue balancing accounts (RBAs) are credited each month with billed retail revenue and debited each month with the total amount of authorized annual revenue divided by 12. Any surplus or deficit is tracked and all monthly surpluses and deficits are totaled at the end of the year. The total annual surplus or deficit, plus interest, is amortized and refunded to or collected from ratepayers in the following year through a rate adjustment. PG&E uses different balancing accounts to track specific revenue streams separately and recover or refund over or under-collections separately. For example, PG&E may over-collect distribution revenue, leading to a surplus in that account and requiring a refund to ratepayers. In the same period, the utility could under-collect public purpose revenue, leading to a deficit in that account, which would be recovered from ratepayers. It is possible that from a ratepayer perspective, refunds from surplus accounts and recovery from deficit accounts could cancel each other out. PG&E tracks numerous revenue streams through balancing accounts, including:[12]

- Distribution Revenue Adjustment Mechanism;

12 PG&E. *Tariff Book*. Available at: http://www.pge.com/tariffs/EPS.SHTML

- Public purpose program Revenue Adjustment;
- Nuclear decommissioning Adjustment Mechanism;
- Utility Generation Balancing Account; and
- Regulatory Asset Revenue Adjustment Mechanism

Generally, rate adjustments apply equally to all customers in all rate schedules, with some exceptions. For example, direct access customers are exempt from changes in generation costs. Revenue regulation rate adjustments occur annually, with rate adjustments attributable to over- or under-collection in a year being effective January 1 the following year. CPUC requires PG&E to file an Annual Electric True-Up advice letter by September 1 of each year with its preliminary forecast of electric rate changes expected, including revenue regulation and other adjustments. The account balances as of December 31 will determine the final changes to rates that become effective on January 1. In its 2012 Annual Electric True-Up advice letter, PG&E included 23 balancing accounts that were approved for that year.[13]

Complementary Policies

California has implemented energy savings goals for its investor-owned utilities, calling for approximately one-percent savings annually through 2020. The Risk/Reward Incentive Mechanism, implemented in 2007, provides an incentive if the utility meets at least 85 percent of its savings goals. Utilities can receive 9 percent of net benefits if they achieve between 85 and 99 percent of savings goals and 12 percent of net benefits[14] if they meet or exceed savings goals up to the earnings cap of $450 million. Penalties are triggered when actual energy efficiency savings are at or below 65 percent of the individual utility savings goal. First, utilities must reimburse ratepayers dollar-for-dollar for any negative net benefits; this is considered part of the penalty payment. Utilities must also pay a per-unit penalty rate of $0.05/kWh and $25/kW. The total penalty is also capped at $450 million.

PG&E currently offers residential customers service under a default inclining block rate structure. Residential customers may volunteer for time-of-use (TOU) rates, with peak, part-peak, and off-peak tiers for summer, and part-peak and off-peak tiers for winter. Discounted rates for low-income and medically fragile customers are available, but they too are inclining. Commercial customers take service on a Peak Day Pricing default rate but can opt out to take service under a TOU structure. Peak Day Pricing is TOU pricing with a surcharge added on top during 9 to 15 peak events called

13 PG&E. (2012, August 31). *Annual Electric True-up Filing*. Available at: http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4096-E.pdf

14 ACEEE. *California*. Available at: http://database.aceee.org/state/california

during the year. Each of these rate structures signals customers that increased use of energy will be increasingly more expensive. These rate designs create a situation in which utility revenues are greatly affected by weather, whereas their investment and labor costs are not; the revenue regulation mechanism buffers utility revenues and earnings from these weather effects.

Some Commissions have implemented service quality programs to ensure that utilities don't engage in destructive cost cutting to improve margins under revenue regulation. PG&E files annual reliability reports, but there is no explicit penalty or reward associated with performance. However, a new initiative by the CPUC is exploring how to elevate the importance of safety in gas and electric utility rate cases, which would be supported through a performance-based ratemaking platform.

Energy Efficiency Outcomes

Because PG&E has been decoupled in one form or another since 1984, it is very difficult to determine the effect of revenue regulation on the implementation of energy efficiency programs. However, PG&E has reported that incremental energy efficiency savings have consistently exceeded one percent of retail sales over the last ten years.[15]

Resources

California Division of Ratepayer Advocates

Report on the Cost of Capital for Test Year 2013, Docket A. 12-04-015 (August 6, 2012)

California Public Utilities Commission

Docket 09-12-020
Settlement Agreement (May 13, 2011)
Docket 10-07-027
Decision 11-05-018 (May 5, 2011)
Resolution E-3862 (April 1, 2004)

Pacific Gas and Electric Company

Advice Letters 3896-E, 3896-E-A, 3896-E-B:
Annual Electric True-Up and Supplemental Filings (January 23, 2012)
Advice 3727-E: Annual Electric True-Up Filing (September 1, 2010)
General Rate Case Application of Pacific Gas and Electric Company (December 21, 2009)

15 EIA. Form EIA-861 data files. Available at: http://www.eia.gov/electricity/data/eia861/

Idaho:
Idaho Power Company

Idaho Power Company's (IPC) Fixed Cost Adjustment (FCA) mechanism compares the authorized fixed-cost revenue requirement with weather-normalized sales and reconciles the difference annually for residential and small business customers. The allowed revenue is determined on a per-customer basis during the general rate case, and the total fixed-cost recovery amount is adjusted based on the number of customers.

Authority

In 2004, the Idaho Public Utilities Commission established a case to investigate financial disincentives to investment in energy efficiency by IPC. After a series of workshops, in 2007 the Commission approved a three-year pilot of IPC's proposed revenue regulation mechanism. In 2009, the Commission extended the pilot for an additional two years, starting January 1, 2010. On April 2, 2012, the Idaho Public Utilities Commission made the IPC pilot program permanent.

Authorized Revenue Requirement

During the general rate case, the Commission establishes the class-specific portion of IPC's revenue requirement. For purposes of the FCA, this includes the fixed costs collected through Residential Service and Small General Service customer rates. During the general rate case, the Commission also establishes a fixed-cost per-customer rate—the amount of fixed cost revenue the Company will recover from each customer. Finally, the Commission must also establish the fixed-cost per-kWh rate—the portion of retail rates that covers fixed costs. "Fixed costs" are defined much more broadly than accounting standards provide, including return, taxes, and labor expenses.

Rate of Return

IPC's most recent rate case resulted in an overall settlement. The Stipulation specified an overall rate of return of 7.86 percent, which combines return on equity (ROE), capital structure, and cost of debt. The Commission made no explicit adjustment to the Company's allowed rate of return based on the implementation of the FCA.

Revenue Adjustment Mechanism

The revenue adjustment mechanism was designed to be weather normalized. For each customer class included in the revenue regulation mechanism, the actual number of customers (CUST) is multiplied by the fixed-cost per-customer rate (FCC) to give the allowed fixed-cost recovery amount. This pro forma amount is then compared to the fixed costs recovered by the company. This actual fixed-cost recovery is determined by taking the weather-normalized sales for each class (NORM) and multiplying it by the cost-per-kWh rate (FCE) as determined in a general rate case. The difference (allowed fixed cost recovery minus actual fixed cost recovery) determines the FCA. In this way, the revenue requirement is adjusted between rate cases based on the number of customers, and is weather normalized, leaving the weather risk with the company. This difference is the FCA and is applied to each decoupled customer class.

The mathematical formula is FCA = (CUST × FCC) – (NORM × FCE). The number of customers is determined by class on the same basis as the methodology used in the general rate case.

Reconciling Actual Revenue With Authorized Revenue

Each month, the actual fixed-cost recovered amount is determined based on the weather-normalized sales for each customer class multiplied by the fixed-cost per-kWh rate. For reporting, a monthly "shaped" fixed cost per kWh is used for calculating actual fixed-cost revenue. This adheres to Generally Accepted Accounting Practices (GAAP) and better reflects end-of-year impacts within the year. The methodology used to weather-normalize actual monthly energy used in the FCA is the same as used in the general rate case. Finally, the actual fixed-cost recovered amount is subtracted from the allowed fixed-cost recovery amount and the difference is recorded as a line item in the monthly Power Cost Adjustment (PCA) report provided to the Commission. Differences are deferred with interest until the end of the year. The actual FCA balance will differ from that recorded in the monthly reports to reflect the fact that the deferral balance is calculated on an annual, not monthly basis. FCA balance is based on annual average prorated customer count, annual weather normalized sales, and non-shaped FCE rates, which would affect both the balance accrual and the associated interest.

Each year, the Company totals the FCA results, including interest, for the period from January 1 to December 31. If the total is negative, it represents an under-collection of revenue from customers and the amount will be recovered from ratepayers in the following year through an adder to rates (Schedule 54.) Likewise, if the total is positive, the Company has over-collected its fixed-cost revenue, and will return the excess amount to customers through an adder in rates using a credit or surcharge mechanism. These adjustments are currently included in the Annual Adjustment Mechanism line item on customer bills. Since July 2012, the Annual Adjustment Mechanism includes PCA and FCA to avoid customer confusion.

Originally, FCAs were calculated for each decoupled customer class; however, the FCA is now recovered proportionally between the residential and small general service customers for such reason as a lack of cost of service studies to support the underlying cost allocations and acknowledgment of the "portfolio" approach toward energy efficiency. Annual adjustments are capped at three percent and differences beyond that are rolled over until the next period. Adjustments to the rate occur June 1 of the year following the previous one-year period from January 1 to December 31.

IPC was initially obligated to submit its adjustment request, subject to Staff audit, on March 15 of each year. Under the pilot program, this included a detailed summary of demand-side management (DSM) activities that demonstrate an enhanced commitment to DSM resulting from implementation of the FCA. "Evidence of enhanced commitment will include, but not be limited to broad availability of efficiency and load management programs, building code improvement activity, pursuit of appliance code standards, expansion of DSM programs, pursuit of energy savings programs beyond peak shaving/load shifting programs, and third party verification" (IPC-E-04-15 Settlement Stipulation, p 5). However, the Company is no longer required to file the separate annual report specifying ways in which it increased its investment in energy efficiency and DSM as a result of the FCA mechanism. DSM is comprehensively reported in annual DSM reports filed with the Commission.

Potential Changes

The Commission noted when approving the permanent FCA that it "does not isolate or identify changes in cost recovery associated solely with the Company's energy efficiency programs."[16] The Company was required to file a proposal to adjust the FCA to address the capture of changes in load not related to energy efficiency programs. In its compliance filing, IPC recommended making no change to the FCA mechanism, but did propose an altered mechanism in order to comply with the Commission's request. The proposal would cap the annual change in per-customer consumption to two percent (up

16 Order No. 32505, p 6. Available at: http://www.puc.idaho.gov/orders/32599.ord/32505.pdf

or down). The Commission Staff had previously proposed that the FCA balance be equally shared between the customers and the Company in order to account for variations in energy consumption other than weather and energy efficiency. However, the Commission found that neither proposal satisfied its needs, stating that the Company's proposal to cap deviations in annual usage would not have had any effect on previous FCA results. Additionally, both IPC and the Idaho Conservation League filed comments stating that the Staff's 50/50 sharing proposal failed to remove the financial disincentives inherent in DSM programs. The Commission finally determined to keep the FCA mechanism unchanged and continue to monitor the results.

Complementary Policies

Idaho requires its investor-owned utilities to pursue all cost-effective energy efficiency; however, it does not have incentives for achieving energy efficiency savings.

IPC uses inclining block rates as the default rate structure for its residential customers, but there is also available an optional Time-of-Day pilot program with summer and winter peak and off-peak periods. Small general service customers take service on a two-tier, inclining block schedule.

IPC has no filing or reporting requirements relating to service quality (except in Oregon).

Energy Efficiency Outcomes

Before IPC implemented revenue regulation in January 2007, it reported increasing incremental energy efficiency savings from 0 percent of retail load in 2003 to 0.5 percent of retail load in 2006. Since the revenue regulation mechanism was implemented, reported savings have increased from 0.6 percent in 2007 to 1.3 percent in 2010 (with low or no reported savings in 2009 and 2011.)[17] The DSM Report for 2012 shows this to be 1.2 percent.

Resources

Idaho Public Utilities Commission

IPC-E-04-15 - Idaho Power — Investigation of Financial Disincentives
IPC-E-09-28 - Idaho Power — Application to Make the Fixed Cost Adjustment Permanent
IPC-E-11-19 - Idaho Power — Request to Convert Schedule 54 (Fca) From Pilot to Permanent

17 EIA. Form EIA-861 data files. Available at: http://www.eia.gov/electricity/data/eia861/

Maryland:
Baltimore Gas and Electric

Baltimore Gas and Electric's (BGE) revenue regulation mechanism compares actual distribution revenue to the authorized revenue, adjusted for the number of customers, for each applicable rate schedule. The authorized revenue, including the cost of power, is based on test year requirements and sales levels. Over- or under-collections are reconciled monthly through a rider. This mechanism differs from the others we describe by having a monthly, rather than annual, deferral and recovery period.

Authority

BGE requested a revenue regulation mechanism in 2007 due to the expected impact on electricity sales of the company's conservation and demand response programs. BGE stated that the revenue regulation mechanism was necessary to eliminate the inherent disincentive in the traditional ratemaking process with respect to conservation and demand response. Under traditional ratemaking, BGE pointed out that, "a one percent reduction in electricity use and demand on the Company's system for the residential and small commercial classes would cut cost recovery by approximately $4 million. This first year impact on recovery is then followed by $8 million in the second year (as an equal amount of savings is added), and so on: the five-year loss to shareholders from this steady-state utility investment program would be more than $20 million"[18] The revenue regulation mechanism proposed by BGE was based on its gas revenue regulation mechanism, which has been in place since 1998.

Authorized Revenue Requirement

BGE initially calculated its revenue requirement per class separately for each rate scale based on weather-normalized 2007 sales and the number of customers. Because BGE proposed the mechanism in 2007, the test year 2007

18 BGE. (2007, October 26). 9111FilingConserva102607F. Available at: http://webapp.psc.state.md.us/intranet/maillog/content.cfm?filepath=C:%5CCasenum%5CAdmin%20Filings%5C60000-109999%5C108061%5C9111FilingConserva102607F.pdf.

included nine months of actual sales and three months of forecasted sales. BGE used three steps to calculate the base monthly revenue requirement:

1. Calculate the Customer Charge revenues by multiplying the number of customers by the Customer Charge for each class.
2. Calculate the Delivery Service revenues by multiplying the weather-normalized sales by the Delivery Price for each class.
3. Add the Customer Charge revenues and the Delivery Service revenues to determine the base revenue requirements for each class.

BGE's residential, small general service and general service customers are included in the revenue regulation mechanism.

Rate of Return

BGE was allowed a return on common equity of 9.75 percent applied to a common equity ratio of 51.05 percent in its most recent rate case. BGE strongly opposed the reduction of its ROE and preferred another lost revenue mechanism over revenue regulation if an ROE reduction was implemented as a result of revenue regulation.

The Public Service Commission (PSC) made no adjustment to BGE's ROE when revenue regulation was first implemented in 2007, but did reduce its allowed ROE by 50 basis points in the last rate case. The Commission had previously reduced the ROE of another utility by 50 basis points when it adopted a similar revenue regulation mechanism for that utility.[19, 20]

Revenue Adjustment Mechanism

On a monthly basis, the adjustment to base revenue requirement is calculated for each rate class using the following steps:

1. Calculate the revenue adjustment for the change in the number of customers by multiplying the change in the number of customers by the Customer Charge.
2. Calculate the revenue adjustment associated with the change in sales by multiplying the change in the number of customers by the average use per customer and multiplying that product by the Delivery Price for the class.
3. Calculate the target base revenues for each class for the current period by adding the two types of adjustments to the revenue requirement.

The Delivery Price for each class is the delivery rate, established by the PSC, adjusted for the electric universal service charge, nuclear

19 Potomac Electric Power Company.

20 BGE's gas mechanism was approved in a 1998 settlement that did not discuss any adjustment to ROE.

decommissioning credits, and the administrative credit associated with the administrative adder portion of the Standard Offer Service rates.[21]

BGE had a full electric and gas rate case in 2010[22] and another one filed in 2013 and concluded in 2014.[23] Both reset the required decoupling elements—monthly revenue requirement, monthly average usage per customer, and number of customers. Neither case changed the mechanism.

The decoupling mechanism now excludes lost sales resulting from major storms.

Reconciling Actual Revenue With Authorized Revenue

On a monthly basis, each rate class's target base revenues are compared to the actual base revenues for the month. The difference is divided by the forecasted sales for the following period to calculate the monthly rate adjustment. Balancing accounts are used to record the timing differences associated with when the adjustments are calculated versus when they are billed or refunded. The monthly rate adjustment, Rider 25, is capped at ten percent of rates. Any amount beyond ten percent of the current rate will be carried over and reconciled in the subsequent period.

Complementary Policies

Maryland requires its electric utilities to provide energy efficiency services to achieve a ten-percent reduction in per capita electricity use by 2015. The state's overall goal is a 15 percent reduction of per capita electricity use by 2015. Although the PSC is explicitly allowed to approve financial incentive mechanisms to promote energy efficiency, no incentives have been approved yet.[24]

BGE's default service to its standard offer residential customers (those customers who have not elected to take generation service from an alternate supplier) features seasonal rates—summer and winter. BGE also offers a TOU rate as an option to standard offer residential customers and as the default rate for small general service customers.

21 BGE. (2007, October 26). 9111FilingConserva102607F. Available at: http://webapp.psc.state.md.us/intranet/maillog/content.cfm?filepath=C:%5CCasenum%5CAdmin%20Filings%5C60000-109999%5C108061%5C9111FilingConserva102607F.pdf

22 Case No. 9230 – See references above.

23 Case No. 9326 – See references above.

24 ACEEE. *Maryland.* Available at: http://database.aceee.org/state/maryland

Regarding performance incentives under revenue regulation, in October 2012, Maryland issued a four-part plan designed to speed up investments that will strengthen the state's distribution grid. Part of that plan would set a ratemaking structure that aligns customer and utility incentives by rewarding reliability that exceeds established reliability metrics and penalizing failure to reach those metrics. A task force has encouraged the Maryland state regulatory commission to implement a performance-based ratemaking process for IOUs such as BGE, linking a utility's progress or failure to meet certain reliability metrics with its authorized rate of return.

Energy Efficiency Outcomes

When BGE implemented electric revenue regulation in mid 2007, it had not achieved incremental energy savings for several years. In 2008 it reported incremental savings of 0.5 percent of retail load, increasing to 1.7 percent in 2010 and 2011.[25]

Resources

Maryland Public Service Commission

Letter Order ML 108061 (December 27, 2007)
Letter Orders ML 108069 (November 30, 2007)
- Case No. 9036
  - Order No. 80460 (December 21, 2005)
- Case No. 9230
  - Order No. 83907 (December 13, 2013)
- Case No. 9326
  - Order No. 86060 (December 13, 2013)

25 EIA. Form EIA-861 data files. Available at: http://www.eia.gov/electricity/data/eia861/

Wisconsin: Wisconsin Public Service Corporation

Wisconsin Public Service Corporation's (WPS) Revenue Stabilization Mechanism (RSM) began in 2009 as a four-year revenue regulation pilot that reconciled target marginal revenue per customer with actual marginal revenue per customer. As of 2012, the pilot was extended,[26] albeit with some modifications. This section focuses on the current iteration of the RSM.

Authority

The Public Service Commission of Wisconsin (PSCW) approved a revenue regulation pilot for WPS in a December 2008 rate case order (Docket No. 6690-UR-119). The revenue regulation mechanism was effective from January 1, 2009 through December 31, 2012 and applied to the utility's electric and gas operations. In a rate case completed in December 2012 (Docket No. 6690-UR-121), the pilot was extended, and a modified RSM was approved. The extended RSM is in effect from January 2013 until the next rate case.

Authorized Revenue Requirement

The authorized revenue requirement is determined through a rate case. The Commission uses a future test year to determine the revenue requirement. The cost of fuel is not included in the revenue requirement but is addressed through a "Retail Electric Fuel Rule" adjustment.

Rate of Return

The Commission authorized a rate of return on utility common equity of 10.30 percent in Docket No. 6690-UR-120. This rate remained the same in Docket No. 6690-UR-121 and is currently in effect.

26 The pilot extension is in effect until the effective date of a Final Decision issued by the Commission on an application for a general base rate case filed after January 1, 2013.

Revenue Adjustment Mechanism

WPS implemented a new electric RSM based on a "Total Rate Case Margin" mechanism instead of a "Total Rate Case Margin per Customer" mechanism, which had been the practice during the initial four-year pilot phase. The revision was intended to remove the calculation sensitivities related to sales per customer from the original RSM calculation. The margin reflected in the formula equals the total revenue for each tariff, less the costs associated with the annual per-kWh value established for monitored fuel costs, and excluding any surcharges, credits, taxes, or similar charges. The "Total Rate Case Margin" mechanism allows WPS to achieve the total margin assumed in the forecasted test year, no more, and no less. The new RSM will be in effect on a pilot basis until the effective date of WPS's next general rate order, which WPS committed to filing for the 2014 and/or 2015 test years. The RSM applies to most tariffs, except large commercial and industrial customers.[27]

Reconciling Actual Revenue With Authorized Revenue

Each year, the utility compares the total target revenue and the total actual revenue and defers the difference, subject to carrying costs based on WPS's last approved short-term debt rate. The margin will be based on annual per-kWh value established for monitored fuel costs, which is done in a rate case. The margin is determined by subtracting the average kWh value from the authorized energy rates.

The formula for calculating an electric under-recovery or over-recovery is:

Under-recovery or over-recovery equals

$$\sum_{i=1}^{n} \textit{[actual margin minus ratecase forecasted margin established in the most recent rate proceeding]}$$

The summation is over each tariff. A positive value equals an over-recovery, and a negative value equals an under-recovery. The margin reflected in the formula equals the total revenue for each tariff, less the costs associated with the annual per-kWh value established for monitored fuel costs, and excluding any surcharges, credits, taxes, or similar charges.

In the event that a true-up will cause rates to increase, the Commission will provide an opportunity for a hearing. Revenue regulation adjustments occur as a part of the general rate case.

27 Except the Direct Load Control, Cp - Large Commercial & Industrial Service, Cp-ND - Pilot Large Commercial & Industrial - Day Ahead, Cp-RR - Large Commercial & Industrial Response Rewards, Automatic Transfer Switch, Parallel Generation, Lighting, Nature Wise, and Real Time Market Pricing tariffs.

The revenue regulation adjustments are subject to a $14 million per year cap for electric, excluding carrying costs. Any adjustments over that amount will not be carried over and will not be collected from ratepayers. Equivalently, revenue over collection in excess of $14 million will not be returned to ratepayers.

Complementary Policies

WPS, like all other investor-owned utilities in Wisconsin, is required to spend 1.2 percent of its annual operating revenues on energy efficiency and customer-owned renewable resource programs that are administered by a third party through the Focus on Energy program, which was established in 2002.[28] Separately, through a contract, the PSCW approves annual electricity savings goals for the Focus on Energy program. The savings goals were equivalent to 0.75 percent of electric sales for the participating utilities from 2011 to 2013. In addition, the PSCW approved a rate of return on investments in energy efficiency for Wisconsin Power & Light, and other utilities can propose incentives as part of their rate cases. However, WPS has not yet proposed an incentive mechanism.[29]

WPS offers residential customers a default flat rate, but they also offer a TOU option with winter and summer on-peak, off-peak, and shoulder tiers. For small commercial and industrial customers, there are flat rates, TOU rates, and critical peak rates. Large commercial and industrial customers can take service under a TOU rate with summer and winter on-peak and off-peak rates, a TOU with critical peak rate, or under a special contract rate unique to the customer and approved by the Commission.

The authorized level of expensed conservation costs recoverable in rates for the test year (2013) is $19,778,728. The level for electric utility operations consists of the conservation budget of $17,669,792, and an escrow adjustment of $2,108,936, which represents the test year amortization of the projected overspent escrow balance at December 31, 2012, over two years.

Wisconsin has a statute requiring filing of reliability data, but no reward or penalty system to support its revenue regulation system.

28 The required spending level was higher for the year 2011 owing to a temporary change in state policy.

29 ACEEE. *Wisconsin*. Available at: http://database.aceee.org/state/wisconsin

Energy Efficiency Outcomes

WPS implemented revenue regulation in 2009. In order to gain approval for the original revenue regulation mechanism, WPS agreed to fund energy efficiency and renewable energy programs at levels above their 1.2-percent statutory minimum contribution to Focus on Energy. Focus on Energy produces an annual report of energy efficiency program activities. In its 2012 report, Focus on Energy reports the following outcomes achieved for WPS' service territory. The table below represents the savings under the statewide Focus on Energy Programs and does not represent the savings attributed under the funding levels above 1.2 percent.[30]

Territory	Utility Type	Segment	Per Capita Lifecycle Bill Savings ($)	Customer Participation Rate (%)	Per Capita Incentive ($)
WPS	Electric	Commercial	$115,258	3%	$83.30
WPS	Electric	Industrial	$9,026,768	96%	$8,924.63
WPS	Electric	Residential	$6,494	36%	$6.66

Resources

Public Service Commission of Wisconsin

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates, Final Decision. (December 7, 2012). Docket No. 6690-UR-121.

David J. Kyto, Wisconsin Public Service Corporation

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates, Supplemental Direct Testimony. (May 15, 2012). Docket No. 6690-UR-121.

Focus on Energy

The Cadmus Group, Inc. (2013). Focus on Energy Calendar Year 2012 Evaluation Report: Appendixes. Portland, OR: The Cadmus Group, Inc. Retrieved from http://www.focusonenergy.com/sites/default/files/FOC_XC_CY%2012%20Report%20Appendices%20A-O%20Final%2005-3-13.pdf.

30 The Cadmus Group, Inc. (2013).

Massachusetts: National Grid

The revenue regulation mechanism for National Grid (Massachusetts Electric Company and Nantucket Electric Company together doing business as National Grid) compares authorized distribution revenue to actual distribution revenue. Revenue is compared and adjustments are made separately for each customer class.

Authority

The Massachusetts Department of Public Utilities (DPU) adopted revenue regulation as a statewide regulatory policy in 2008 and individual utilities filed revenue regulation tariffs in response. In its *Investigation Into Rate Structures that will Promote Efficient Deployment of Demand Resources*,[31] the DPU investigated rate structures and revenue recovery mechanisms that may reduce disincentives to the efficient deployment of demand resources in the state and considered how the electric and natural gas distribution companies' existing cost recovery mechanism could be changed to better align the companies' financial incentives with policy objectives while ensuring that the companies are not financially harmed by the increased use of demand resources. The DPU finally concluded that revenue regulation mechanisms would eliminate the financial disincentives because they sever the link between the companies' revenue and reduction in sales. The DPU also endorsed a revenue per customer approach, but recognized that other factors could result in changes to distribution-related costs and consented to consider company-specific ratemaking proposals that accounted for the impact of capital spending and inflationary pressures on the company's required revenue.

31 D.P.U. 07-50. (2007).

Authorized Revenue Requirement

The authorized revenue requirement does not include costs that are reconciled outside of base distribution rates, including energy supply costs for basic service customers, transmission costs, the energy efficiency system benefits charge and reconciling charge, and costs recovered through the residential assistance adjustment factor.

Rate of Return

The Commission recognized the effects of revenue regulation on ROE, and determined that revenue regulation reduces volatility, which reduces risk, and a downward adjustment to ROE was appropriate, but did not make its actual ROE adjustment for the revenue regulation mechanism explicit in its order.[32] The DPU determined that a return on equity equal to 10.35 percent was sufficient. The testimony from National Grid supporting its proposed ROE presented comparisons of allowed ROE for a set of companies that had revenue regulation or another risk management mechanism in place to account for an implied reduced risk profile in developing that proposal.

Revenue Adjustment Mechanism

Each year the authorized revenue requirement is adjusted to account for capital expenditures in the previous year. The CapEx Adjustment applies to capital expenditures incurred by National Grid for distribution system investments in the previous year, net of the amount recovered through depreciation expense in base rates. This accounts for the material difference in expected capital expenditures compared with prior years. In this way, the CapEx Adjustment in the National Grid revenue regulation mechanism is a special case of a "K Factor," which characterizes an expected change in costs in the future and accounts for those changes when they occur. Each year, the Company files with the Department documentation in support of the capital expenditures it has incurred since the previous review. The Department reviews the filings to determine the prudence of the incremental expenditures and whether the expenditures are used and useful. National Grid then allocates approved expenditures to rate classes based on the cost of service study. For each class, the Company determines the adjustment allocated to the rate class then divides this sum by the forecasted kWh sales for the following year to determine the per-kWh adjustment.

In order to provide a balance between providing the Company with sufficient funds to ensure the safety and reliability of the distribution system and protecting ratepayers against the incentive the Company has to

32 D.P.U. 07-50. (2007). pp 392–396.

overinvest in infrastructure, the mechanism limits the level of annual capital expenditures that is recoverable through the mechanism. To arrive at the amount, the Department set a limit of $170 million per year, which is equal to the approximate three-year average of the Company's capital spending in previous years. Should the Company's capital expenditures exceed this limit, it may seek to include the investment in the rate base during the next base rate proceeding.

The Company submits its CapEx filing no later than July 1 of each year. On November 1 of each year, the Company submits all other information in support of its proposed adjustment factors. The factors will take effect on March 1 of each year.

The authorized revenue is also adjusted to include a 50-percent sharing for earnings above the authorized ROE.

Reconciling Actual Revenue With Authorized Revenue

Each year, National Grid calculates on a rate class-specific basis, the difference between the actual distribution revenue billed to customers through distribution rates and the annual target revenue. For each rate class, the difference between the actual billed distribution revenue and the annual target revenue is summed to determine the Company-wide reconciliation amount. That amount is divided by the Company-wide kWh forecasted for the upcoming year to arrive at a cent-per-kWh reconciliation charge or credit. To determine the final adjustment for each rate class, the Company-wide reconciliation adjustment is added to the rate class-specific adjustment resulting from the target revenue adjustment mechanisms.

The adjustment to the authorized revenue in any year is capped at three percent of total revenues.[33] Any excess can be carried forward to a future year with carrying charges equal to the customer deposit rate.

National Grid must report to the DPU if the difference between the year-to-date billed revenue and year-to-date annual target revenue equals or exceeds ten percent of the target revenue and the Company believes that the difference will fall outside of the ten-percent threshold in the coming months. In this case, interim revenue regulation adjustments can be made. In order to avoid an interim adjustment too close to the scheduled annual rate adjustment, National Grid must notify the Department of variances exceeding ten percent of annual target revenue by August 31 of each year.

33 D.P.U. 07-50. (2007). p 87.

Complementary Policies

Massachusetts requires that electric utilities procure all cost-effective energy efficiency before more expensive supply-side resources. This requirement was translated into annual savings requirements for electric utilities starting from 1 percent of sales in 2009, to 1.4 percent in 2010, 2 percent in 2011, and 2.4 percent in 2012, and potentially increased savings in subsequent years. Utilities can earn approximately five percent of program costs for meeting or exceeding savings targets.[34]

National Grid offers inclining block rates as the default residential rate, but there is an optional TOU rate with peak and off-peak tiers also available to residential customers. Small and large industrial and commercial customers can take service under flat rates, inclining block rates, or TOU rates.

National Grid operates under a penalty and reward system for service quality, established in Docket D.T.E. 99-84. The impetus behind the DPU's original establishment of the Service Quality Guidelines was to prevent Massachusetts utilities from allowing service quality to deteriorate under a new regulatory regime.

Energy Efficiency Outcomes

Before Massachusetts Electric implemented revenue regulation in 2009, it reported consistently high levels of incremental energy efficiency savings, approximately 0.9 percent of retail load. In 2010, the company reported 1.36 percent savings and 1.59 percent in 2010 and 2011, respectively.[35]

Resources

Massachusetts Department of Public Utilities

Docket 09-39

Petition of Massachusetts Electric Company
(November 30, 2009)

34 ACEEE. *Massachusetts*. Available at: http://database.aceee.org/state/massachusetts

35 Personal communication with National Grid.

Hawaii:
Hawaiian Electric Company

Hawaiian Electric Company (HECO) uses a revenue regulation mechanism that compares actual revenue to target revenue in each year. The target revenue is based on the authorized revenue for the last test year adjusted for operation and maintenance (O&M) increases and rate base changes.

HECO is a subsidiary of Hawaiian Electric Industries, which also operates Maui Electric Company (MECO) and Hawaiian Electric Light Company; these subsidiaries service the islands of Maui and Hawaii County, while HECO serves Oahu (Honolulu).

Authority

In 2008, the Governor of Hawaii, the Division of Consumer Advocacy, and HECO entered into an agreement as a result of the Hawaii Clean Energy Initiative.[36] The agreement is intended to move Hawaii away from its dependence on imported fossil fuels for electricity and ground transportation, and toward locally produced renewable energy and energy efficiency. In the agreement, the State, the Consumer Advocate, and HECO committed to, among other things, a transition away from a model that encourages increased electricity usage and to a model that implements revenue regulation decoupling to encourage the development of renewable energy by HECO. The Commission opened Docket 2008-0274 in order to examine the features of a revenue regulation mechanism. The Opening Order directed HECO and the Consumer Advocate to file a joint proposal on revenue regulation within 60 days. This joint proposal was modeled closely after the California mechanism described earlier for PG&E, with a rate-case determined revenue requirement, plus annual attrition adjustments, plus separate mechanisms to recover power supply and energy efficiency costs.

36 Energy Agreement Among the State of Hawaii, Division of Consumer Advocacy of the Department of Commerce & Consumer Affairs, and Hawaiian Electric Companies. Available at: http://files.hawaii.gov/dcca/dca/HCEI/HECI%20Agreement.pdf

The Hawaii Public Utilities Commission approved revenue regulation for HECO in August 2010 based on an investigation into the appropriateness of revenue regulation and its design. The revenue regulation mechanism took effect on March 1, 2011. This replaced a previous lost revenue adjustment mechanism.

Authorized Revenue Requirement

The Commission establishes the Authorized Base Revenues through a general rate case based on traditional cost-of-service ratemaking principles. The Authorized Base Revenue is the annual amount of revenues required for the utility to recover its estimated O&M, depreciation, amortization, and tax expenses for the period.

The Target Revenue is equal to the base revenue requirement less any revenue being separately tracked or recovered through any other surcharge or tracking mechanism, including revenue for fuel and purchased power expenses.

The revenue regulation order also requires staggered triennial rate cases for each of the Hawaiian Electric Industries Companies to determine approved baseline Revenue Adjustment Mechanism (RAM) inputs.

Rate of Return

The Commission made no explicit adjustment to ROE owing to the revenue regulation mechanism, but noted that the allowed ROE of ten percent reflects the approval of revenue regulation and other cost-recovery mechanisms that will lower HECO's business risk.[37] Most recently, the Hawaiian Public Utilities Commission approved a 9.0-percent ROE for MECO, reflecting both a lower baseline cost of capital and a penalty of 0.50 percent associated with inadequate performance bringing renewable energy into the MECO system.[38] A companion Order also established new guidance on future revenue regulation mechanisms.[39]

37 The HECO Companies described as follows in their Reply SOP in the Schedule A decoupling proceedings: "the Commission effectively reduced the Companies' return on common equity by 50 basis points to "fairly compensate ratepayers" for what it perceived as the "risk-reducing" effects of the RBA and RAM mechanisms, the Renewable Energy Infrastructure Program ('REIP") Surcharge and the Purchased Power Adjustment Clause ("PPAC")." Available at: http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A10L29B5532 6B47993

38 Hawaii PUC, Decision and Order No. 31288. (2013, May 31). pp. 97–112.

39 Hawaii PUC, Decision and Order No. 31289. (2013, May 31).

Revenue Adjustment Mechanism

The RAM is designed to replace the need for annual rate cases by adjusting Authorized Base Revenue levels to reflect estimated changes in the utility's cost of service. The RAM is intended to, via formula-driven estimates and escalators, compensate the HECO Companies for changes in utility costs and infrastructure investment between rate cases and reduce the frequency of rate cases. The RAM Period is the calendar year containing the Annual Evaluation Date (March 31, the date of the annual RAM filing). The RAM adjusts the revenue requirement according to changes in four main categories of expenses:

- Base expenses, which are changes in designated O&M expenses;
- Rate base, the return on incremental investment in designated rate base components[40];
- The incremental depreciation and amortization expenses; and
- Exogenous tax changes, changes in costs owing to significant changes in tax laws or tax regulations

Base expenses are segregated between labor and non-labor amounts. The labor component is adjusted annually by the Labor Cost Escalation Rate, reduced by the Labor Productivity Offset (fixed at 0.76 percent). The non-labor component uses the Non-labor Escalation Rate to annually adjust those costs. Tracked O&M expenses for fuel, purchased power, pension and post-employment benefits, integrated resource planning, DSM, and other rate adjustment provisions are not adjusted in the RAM, because any changes in these costs are accounted for in other cost-tracking mechanisms.

The Rate Base equals the average net investment estimated for the RAM Period. The average rate base is the rate base for the rate case test year, with adjustments for changes in only four components of rate base: (1) average plant-in-service, (2) average Accumulated Depreciation, (3) average accumulated contributions in aid of construction, and (4) average accumulated deferred income taxes. All other components of the rate base remain the same as in the preceding rate case test year. The average plant-in-service is equal to the average of the actual plant-in-service at the end of the year prior to the RAM period, the Evaluation Year, and the same year-end balance plus estimated plant additions for the RAM period. Plant additions include Baseline Capital Project plant additions and Major Capital Projects plant additions estimated to be in service by September 30 of the RAM period.

40 Hawaii PUC, Decision and Order No. 31908. (2014, Feb. 1).

The RAM also includes an Earnings Sharing Revenue Credit mechanism in order to protect against excessive overall utility revenue levels. The RAM will escalate and update the Company's approved base revenue requirement, reduced by earnings sharing credits and major project revenue credits to customers. Based on the Company's achieved return on common equity for the Evaluation Year, the mechanism credits the RBAs according to the following chart:

ROE at or below the authorized ROE	**Retained entirely by shareholders, no customer credits**
First 100 basis points (1%) over authorized ROE	25% share credit to customers
Next 200 basis points (2%) over authorized ROE	50% share credit to customers
ROE exceeding 300 basis points (3%) over authorized ROE	90% share credit to customers

Finally, the RAM includes additional consumer protections:

- A provision for Major Capital Projects Credits;
- A provision for Baseline Capital Projects Credits;
- Notification is provided to all affected customers of the RAM filing in newspapers and bills;
- Evaluation procedures for filing, examination, and any exceptions to annual revenue regulation filings;
- Continued ability of HECO or the Consumer Advocate to request formal rate proceedings to replace and terminate RAM at any time; and
- Formal review of revenue regulation as a part of the next round of rate case proceedings;

A recent order[41] added two additional consumer protections:

- A limitation that only 90 percent of the current RAM Period Rate Base that exceeds the Rate Base Adjustment Mechanism from the prior year can be included in the Decoupling Mechanism for baseline utility plant projects, which, unlike major capital projects, are not subject to prior Commission review and approval; and,
- A requirement to post a number of metrics online for customer review, although not at this point tied to performance.

41 February 7, 2014 order on schedule A issues. Available at: http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A14B10B22326F07922. p 42–47.

This order also examined four issues with respect to the application of the RAM. The Commission determined that the short-term debt rate, as reflected in the most recent rate case, should be used to adjust over- and under-collections. The Commission also resolved its concern that, without a sustainable business plan, there exists no strategic framework under which to evaluate capital expenditure programs. The Commission required the parties in the Docket to further explore capital expenditure issues in conjunction with other risk-sharing mechanisms discussed elsewhere in the order. The commission ordered a further evaluation of a proposed risk-sharing mechanism within the RBA. Furthermore, the Commission ordered the parties to work together to establish appropriate metrics, which the utility would report on its website.

Once the total RAM Revenue Adjustment is calculated, it is applied through a uniform adjustment to the per-kWh energy charge for all customer classes.

Reconciling Actual Revenue with Authorized Revenue

RBAs record the monthly differences between target revenues and the adjusted recorded electric sales revenues. The RBA also applies monthly interest, equal to the annual rate for short-term debt from the cost of capital in each HECO Company's last base rate case, to the simple average of the beginning and ending balances each month in the RBA. In effect, the RBA applies one-twelfth of the rate each month. Finally, the RBA provides for collection or return of the calendar year-end balances in the RBA and recovery of the RAM Revenue Adjustment over the subsequent May 1 through April 30 period. The target revenue is the most recent Authorized Base Revenue or the re-determined Authorized Base Revenue calculated under the RAM.

On or before March 28, the Company must file with the Commission a statement of the previous year-end balance in each RBA sub-account and the Authorized Base Revenue level for the current calendar year with supporting calculations. An amortization of the year-end balance in the RBA sub-accounts and the RAM Revenue Adjustment are recovered through the per-kWh RBA rate adjustments. The rate adjustment occurs from May 1 of the current calendar year to April 30 of the next year.

Complementary Policies

Currently, electric utilities in Hawaii may use energy efficiency to meet a portion of their Renewable Portfolio Standard requirements. Starting in 2015, electricity savings from energy efficiency will be applied to the State's Energy Efficiency Portfolio Standard, which sets a target equivalent to 30-percent forecast sales by 2030. This goal is translated into a target of

1.4 percent annual savings. HECO transferred administration of all of its energy efficiency programs to a third party administrator in 2009. The administrator is compensated for satisfactory performance.[42]

Because of its heavy dependence on petroleum as a generation fuel, electricity prices in Hawaii are very high; solar and wind are typically lower-cost resources for these systems. HECO's default residential rates are inclining block rates with a $9.00/month customer charge, and a three-block inclining rate design of $0.34/kWh to $0.37/kWh. Residential customers can elect to

Revenue regulation represents a regulatory framework that removes the financial disincentive for utilities to pursue clean energy strategies. It doesn't, in and of itself, align the utility business model with those utility policies and practices that address customer expectations. In fact, some commissions are concerned that it might create a dynamic in which the utility, assured of its revenue needs, becomes complacent and lacks motivation to innovate and develop strategies that may be more in line with the public interest.

In a recent order (Docket 2011-0092, May 31, 2013) the Hawaiian Public Utilities Commission addressed this big picture issue in a rate order for Maui Electric. The Commission called out the management as lacking a long-term vision for creating customer value and expressed concern that "the HECO Companies' over-reliance upon a link between the [Decoupling] Agreement and utility financial health obfuscates utility performance and ultimately customer service and satisfaction."[43] The implementation of clean energy policies is not a singular goal, but rather a policy that must be part of a larger effort to create customer value.

The Commission laid out a hard path and a soft path to achieve the results they desire for consumers. The hard path involves a closer examination of utility investments, operations, and expenditures. The soft path is opened through the actions of management to create and execute a vision for the utility of the future. The Commission remains committed to regulatory innovations that are in the public interest and will work with the utility, consumer advocate, and other stakeholders to create and implement this vision.

The results of this effort will likely produce ideas and outcomes that will have applicability beyond this one utility.

42 ACEEE. *Hawaii*. Available at: http://database.aceee.org/state/hawaii

43 Hawaii PUC: Decision and Order No. 31288. Maui Electric Company, Limited; Docket No. 2011-0092. (2013, May 31). Appendix C, p 2.

take service under a TOU rate with off-peak, mid-peak, and priority-peak tiers. General service and large power service customers take service under a flat rate, unless they opt to take service under a TOU.

Hawaii is developing reliability standards, in part as a response to deteriorating service quality as a result of distributed and customer-owned generation (see text box). In an effort to make electricity reliability and interconnection standards as transparent as possible, the Reliability Standards Working Group was formed in the Feed-In Tariff docket and continues its work in Docket No. 2011-0206 to find solutions to integrating high penetrations of renewable energy consistent with reliability and power quality standards.

Energy Efficiency Outcomes

HECO implemented revenue regulation in 2011. Since 2003, HECO has reported incremental energy efficiency savings between 0 and 0.5 percent of retail load, with 1.31 percent savings reported in 2011 by Hawaii Energy, the State's ratepayer funded efficiency program administrator. The company has not yet reported its savings for 2012.[44] In addition, HECO has seen more than a sixfold increase in renewable installations under its net metering and feed-in tariff policies since the inception of the revenue regulation plan.

Resources

Hawaii Public Utilities Commission

Docket No. 2008-0274
Final Decision and Order (August 31, 2010)
Docket No. 2008-0083
Final Decision and Order (December 29, 2010)
Docket No. 2011-0092
Final Decision and Order May 31, 2013, including Decision and Orders Nos. 31288 and 31289
Docket No. 2013-0141
Final Decision and Order (February 1, 2014), including Decision and Order No. 31908.

44 EIA. Form EIA-861 data files. Available at: http://www.eia.gov/electricity/data/eia861/

Discussion of the Six Utilities Overall

Authority

The first step in implementing a revenue regulation mechanism is to understand the authority of the regulating body: the Public Utility Commission or PSC. It is important for any Commission to clarify its justification for acting on revenue regulation in order to prevent any decisions from being overturned. Over the years, Utilities Commissions have relied on different justifications for implementing revenue regulation mechanisms. Commissions have implemented revenue regulation at their own discretion, justified by their directive to ensure safe, reliable, and economic public utility service to citizens to justify changing the regulatory environment. In some cases, the Commission is unable to engage on narrow issue ratemaking and rates can change only as the result of a full rate case. In this case, statutes must be amended to enable revenue regulation.

In all of the case studies discussed here, the Commissions first implemented revenue regulation at their own discretion, but each followed slightly different paths to do so. The CPUC first implemented revenue regulation in 1978 at its discretion. In 2001, after a period when mechanisms were suspended, the California Legislature required that deviations from projected sales not result in under- or over-collections by utilities, and so the CPUC re-implemented revenue regulation according to statutory requirement. The Hawaii Public Utilities Commission implemented revenue regulation after an agreement between the utility, the Governor, and other stakeholders called for it. In Idaho, the Commission established a case in which to investigate revenue regulation and held a series of stakeholder workshops before implementing the policy. The Massachusetts DPU adopted revenue regulation as a statewide regulatory policy and required individual utilities to file tariffs in response as the result of its general investigation into rate structures that promote demand-side resources. The Maryland Commission implemented revenue regulation for BGE when the utility requested the mechanism. Thus the impetus to develop a revenue regulation mechanism may come from different sources and the Commission may be comfortable in moving forward under their general supervisory statutes.

Nevertheless, specific statutory language can be helpful to shore up the existing authority.

Authorized Revenue Requirement

Under the traditional regulatory framework, the Commission (or other authority in the case of publicly owned utilities) must determine a utility's revenue requirement. This function does not change under revenue regulation. The revenue requirement of a utility is the aggregate of all the operating and other costs incurred to provide service to the public. This typically includes operating expenses, depreciation, and the cost of capital invested, including interest on debt and a "fair" return on equity to investors. The (simplistic) formula for determining revenue requirements is as follows:

$$\textit{Revenue Requirements} = (\textit{Rate Base} \times \textit{Rate of Return}) + \textit{Operating Expenses} + \textit{Depreciation} + \textit{Taxes}$$

Traditionally, the revenue requirement, along with sales, is used to determine the rates consumers will pay for electricity.[45] The rates are also broken down by customer class, and intraclass tariffs are created based usually on a cost of service study that determines each customer class and subclass contribution to the utility's costs. The (simplistic) formula for determining the rate per unit is:

$$\textit{Rate} = \textit{Revenue Requirement} \div \textit{Units Sold}$$

In this way, rates are set to allow the utility to exactly recover its revenue requirement when the sales level used to calculate rates is equal to actual sales. However, it is important to recognize that actual expense and revenue varies with actual sales. When actual sales are greater than the sales level used in ratemaking, revenue increases and expenses increase by a different amount; when actual sales are lower than the ratemaking sales level, actual revenue declines and expenses decrease by a different amount. Under revenue regulation, rates are initially set in the same way, but when actual sales differ from the level used to calculate rates, the actual revenue level is maintained at the rate case amount as rates are allowed to vary inversely with sales—increased sales lead to decreased rates and vice versa. Because the primary expenses that change in the short run as sales levels change are power supply expenses, and most regulators allow these to be tracked using a power cost adjustment mechanism, revenue regulation mechanisms are generally designed to ensure recovery of the non-power costs (which do not change significantly in the short-run) as sales volumes change.

45 Lazar et al., 2011.

Revenue regulation ensures that actual revenue is equal to the revenue requirement established by the Commission or appropriate authority. Although the description above presents an overly simplified view of the revenue requirement and its use in traditional price regulation and revenue regulation, there are many variations on how a Commission can establish a revenue requirement, particularly when implementing revenue regulation. With revenue regulation, as in traditional ratemaking, imprudent costs can always be removed from rates, and there is no change to the ability of a Commission to impose penalties.

Utility Functions to be Included

First, the regulator must determine which utility functions will be included in the revenue regulation framework. With vertically integrated utilities, this usually includes a utility's regulated generation, transmission, and distribution units. As we discuss below, however, it is critical to structure power supply recovery mechanisms to avoid providing for double-recovery of certain power supply costs. For utilities operating in areas of the country that have restructured electricity markets, only the regulated distribution business is decoupled. Utilities that also provide gas services may have their gas distribution business operating under revenue regulation as well.

Table 1

Business Unit Included in the Revenue Regulation Model	
Pacific Gas & Electric	*Electric generation and distribution; gas distribution*
Idaho Power Company	*Electric generation and distribution*
Baltimore Gas & Electric	*Electric distribution; gas distribution*
Wisconsin Public Service Corporation	*Electric generation and distribution*
National Grid	*Electric distribution*
Hawaiian Electric Company	*Electric generation and distribution*

Test Year

One consideration in establishing the revenue requirement is what period of time will be used as a "test period" or "test year." The test year is the year on which the Commission will base its computations of the utility's total costs and sales levels. A historic test year uses actual data on sales and costs from

Table 2

Test Year Used	
Pacific Gas & Electric	*Future test year*
Idaho Power Company	*Historic test year*
Baltimore Gas & Electric	*Hybrid test year*
Wisconsin Public Service Corporation	*Future test year*
National Grid	*Historic test year*
Hawaiian Electric Company	*Future test year*

a past year. Whereas a historic test year allows for the use of actual cost data, it cannot account for expected variations in sales. A future test year requires assumptions to be made about a utility's sales in a future year. This can allow expected changes in sales, like those from energy efficiency programs, to be included in sales projections: however, because regulators are relying on estimates provided by the utility, there may be a greater risk for inaccuracy. A Commission may also choose to use a test year that includes both past and future periods. This may provide a sense of balance between historic and future data. Furthermore, as the case proceeds, the Commission can require the utility to substitute historical data for projected data from the test year.

Rate of Return

As in any rate case, regulators must determine the appropriate rate of return that a utility can earn on its investments, including the cost of debt and the allowed ROE for its shareholders. The approved ROE is only used to establish the return on investments that are included in the rate base when determining revenue requirements. Although revenue regulation ensures that a utility recovers no more or less than its target revenue, revenue regulation does not guarantee that the utility will earn the authorized ROE. Depending on how a utility manages its costs between rate cases, it will realize an actual ROE either higher (in the case of reduced costs) or lower (in the case of increased costs) than the authorized level.[46]

46 In a rate case, the Commission determines an allowed return on equity. This is used to set a price (price regulation) or an allowed revenue requirement (revenue regulation). Once set, however, the actual return earned by the utility is affected by anything that changes either revenue or expenses; for example, an increase in employee compensation, a change in the number of employees, or, under price regulation, a change in sales volumes.

A utility's allowed ROE generally represents the return deemed necessary to attract investment considering the level of risk of that investment. Riskier investments require a higher return to attract investors and vice versa. Utility earnings can be volatile because of short-run impacts on sales volumes and revenues, which include changes in sales owing to weather, economic conditions, and energy efficiency and DG programs. This volatility typically causes utilities to retain a higher level of equity in their capital structures so that reduced revenues do not leave them unable to service their debt. Revenue regulation can reduce this volatility by stabilizing revenues regardless of the cause. Because of this reduced risk, many stakeholders have proposed that the implementation of a revenue regulation mechanism be associated with a corresponding reduction in the utility's equity capital ratio (the percentage of capital supplied by common equity). This reflects the utility's more stable revenue owing to revenue regulation and reduces the overall revenue requirement that will be recovered from consumers.[47]

An alternative option to reducing the utility's equity ratio is to reduce the ROE, reflecting a lower risk level. For the utilities included in these case studies, only BGE and Mass Electric experienced a reduction in their ROE. The Commission did not reduce BGE's ROE at the time the revenue regulation mechanism was implemented, but reduced it by 50 basis points during the subsequent rate case. The Massachusetts Commission did not reveal its adjustment, but incorporated a lowered ROE into its decision.

Absent an explicit adjustment to the cost of capital, investors' expectations will adjust to the presence of revenue regulation if its presence is reliable. The more stable earnings will likely, in time, contribute to a higher credit rating. That in turn will lead to lower cost debt that will be revealed in future cost of capital calculations. An adjustment to the ROE or capital structure by the regulator in a rate proceeding will be reflected immediately in lower rates to consumers; simply allowing the utility's credit rating to improve over time, and its cost of debt to decline, will have the same effect, but on a lagged basis, as new bonds are issued at lower interest rates.[48]

Beginning in 2004, Standard and Poor's began publishing "risk profiles" for utilities, which classified utilities based on their earnings variability and other risks; those with more stable earnings were determined eligible for higher bond ratings at any given equity capitalization ratio (or, alternatively, able to retain a given bond rating with a lower equity ratio).[49] One utility

47 Lazar et al., 2011.

48 Lazar et al., 2011.

49 Standard and Poor's. (2004, June 2). *New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised.*

with a revenue regulation mechanism, Northwest Natural Gas, was believed to have had their business risk profile upgraded by one step in response to the benefits of the mechanism.[50]

Effect on Bond Ratings

Revenue regulation stabilizes a utility's revenue streams, reducing risk to investors; this reduced risk may be a contributing factor in an increase in a utility's bond rating. Bond rating agencies have recognized that revenue regulation mechanisms and other mechanisms that reduce net earnings volatility and risk contribute to a lower cost of capital for the utility.[51] Standard and Poor's has explicitly stated that it "views decoupling as a positive development from a credit perspective."[52] However, in the case of the utilities examined in this report, none experienced an improved credit rating after the implementation of revenue regulation with the exception of PG&E. However, PG&E came out of Chapter 11 bankruptcy in the same year that its revenue regulation mechanism was implemented, making it impossible to attribute the improvement to revenue regulation alone. Bond rating changes are generally slow to evolve. Numerous other factors are taken into account when assigning an overall credit rating, which appear to have outweighed any positive effect of revenue regulation. These factors certainly include the recession of the U.S. economy that began in 2007.

Customer Classes Included

When determining the target revenue for a utility revenue regulation mechanism, regulators must also consider which customer classes to include in the mechanism. In some cases, industrial customers have objected to a revenue regulation mechanism. This is due to the wide difference in rates among customers, making the design of a revenue regulation mechanism more challenging. If regulators choose to exclude a class of customers from revenue regulation, they must determine the revenue requirement associated with serving only the included customer classes. This generally requires a detailed cost of service study to ensure that revenue responsibility is accurately allocated by customer class.

50 Christensen Associates. (2005, March). *A review of distribution margin normalization as approved by the Oregon Public Utility Commission for Northwest Natural.*

51 Lazar et al., 2011.

52 Standard & Poor's. (2008, February 19). *Decoupling: the vehicle for energy conservation?*

Table 3

Customer Classes Included in Revenue Regulation Mechanism	
Pacific Gas & Electric	*All customer classes*
Idaho Power Company	*Residential and small general service*
Baltimore Gas & Electric	*Residential and small general service*
Wisconsin Public Service Corporation	*All customer classes*
National Grid	*All customer classes*
Hawaiian Electric Company	*All customer classes*

Included Costs

Finally, regulators may wish to exclude specific costs from the overall revenue requirement if those costs will be tracked through another mechanism, like fuel costs in a PCA mechanism, energy efficiency program expenditures, or smart grid costs, for example. Separate tracking mechanisms can also be used for those costs that are difficult to project based on historical data or costs over which the utility has very little control, like fuel costs. Although revenue regulation tracks collected revenue, mechanisms like Fuel Adjustment Clauses, Purchased Power Adjustments, and Energy Efficiency Riders can be designed to track actual costs as well as collected revenue.

This topic raises a note of caution: if mechanisms are not well designed, double-recovery of costs can occur for vertically integrated utilities that provide both power supply and distribution services. For example, if a per-customer revenue regulation mechanism includes investment-related power supply costs in the revenue-per-customer formula, but excludes fuel and purchased power costs that are recovered through a separate tracking mechanism, double recovery of some power supply costs is likely. If the utility experiences customer and sales growth, the amount it recovers for investment-related power supply costs will go up. However, if that utility serves this growth by operating existing power plants more, by selling less power on the surplus market, or by purchasing power from other suppliers, it will not incur any increases in the type of power supply costs accounted for in the revenue per customer (RPC) calculation. The increased power supply costs to serve that growth will be recovered through the fuel and purchased power tracking mechanism. The net effect for the utility will be to recover incremental power supply costs twice—once in the per-customer mechanism, and again in the fuel and purchased power mechanism. It is essential to make sure that the other adjustment mechanisms do not overlap the cost impacts

Table 4

Costs Excluded From Revenue Regulation Mechanism	
Pacific Gas & Electric	*Energy procurement costs*
Idaho Power Company	*All variable costs*
Baltimore Gas & Electric	*Energy supply costs*
Wisconsin Public Service Corporation	*Energy costs*
National Grid	*Energy supply costs for basic service customers, transmission costs, the energy efficiency system benefits charge and reconciling charge, and costs recovered through the residential assistance adjustment factor*
Hawaiian Electric Company	*Fuel and purchased power*

that are treated in the revenue regulation mechanism. One way to do this is to ensure that all power supply costs (investment, labor, fuel, purchased power) are recovered through a single mechanism. There are several ways to achieve this:

a) A comprehensive power supply recovery mechanism that includes all power supply costs, that is separate from the costs treated in the revenue regulation adjustment (e.g., Puget Sound Energy, Washington State)
b) No power supply adjustment whatsoever, with all utility costs included in an RPC mechanism (e.g., National Grid)
c) An annual attrition calculation, with all costs reviewed for changes since the last proceeding (e.g., HECO)

Revenue Adjustment Mechanism in Revenue Regulation

A RAM[53] is not necessary to achieve revenue regulation, but provides attrition relief—increasing authorized revenue commensurate with increased costs—between rate cases. Whereas revenue regulation sets a target revenue that the utility will earn regardless of sales levels, the RAM adjusts the target

53 We use the RAM term applied in Hawaii here to address any type of attrition or similar mechanism, other than a revenue-per-customer framework, that changes the allowed revenue between general rate cases.

Table 5

Type of Revenue Adjustment Mechanism	
Pacific Gas & Electric	*Hybrid*
Idaho Power Company	*RPC*
Baltimore Gas & Electric	*RPC*
Wisconsin Public Service Corporation	*RPC*
National Grid	*No RAM; potential capital expenditure adjustment*
Hawaiian Electric Company	*Hybrid*

revenue between rate cases. Regulators may choose to take several different approaches to RAM:

- **No RAM.** Regulators may choose not to implement a RAM, leaving the revenue requirement unchanged between rate cases. This requires the utility to request a rate case when it requires additional revenue to cover its costs.
- **Stairstep.** Stairstep adjustments provide predetermined increases in target revenue. These increases can be determined during a rate case and generally reflect forecasts of cost growth.
- **Indexing.** Indexing ties adjustments to the target revenue to multiple factors like inflation, productivity, customer growth, and changes in capital expenditures.
- **RPC.** The RPC approach is a form of indexing. RPC adjusts the total revenue requirement for the number of customers served. Regulators using an RPC mechanism will determine the revenue requirement per customer and the overall revenue requirement will be determined by multiplying the total number of customers by the revenue requirement per customer. The amount of revenue required to serve each customer can be determined separately for customer classes and for existing and new customers. This way, the RPC method accounts for a utility's growth in fixed costs that is related to growth in the number of customers served. RPC is useful where the correlation between cost growth and customer growth is significant. It also protects customers from making up the deficit if there is a loss in customer load, such as if a large business closes down or relocates.
- **Hybrid.** Hybrid RAMs generally use stairstep increases to account for projected capital costs and indexing to account for O&M expenses.

Adjustments from any type of RAM can be implemented automatically or through an attrition proceeding. Some stakeholders oppose adjustments to the revenue requirement outside of a rate case on the basis that this could allow the revenue requirement to increase significantly without examination of the impact on ratepayers or without due consideration of other costs and revenues. For this reason, some regulators choose to cap the total adjustment that can be made to the revenue requirement outside of a rate case.

Calculation of Actual Revenue

Regulators have options when ensuring that actual revenue equals target revenue under revenue regulation. First, regulators must decide how to determine "actual revenue." In most cases, actual revenue simply equals the amount of revenue a utility collects from its customers. The Idaho Public Utilities Commission, however, has chosen to use weather-normalized revenues as the basis for utility revenues in revenue regulation. Although this prevents the utility from recovering revenue lost to it owing to milder than expected weather, it further complicates the revenue regulation mechanism and reduces its risk-reduction benefits. By the same token, if weather is severe and increases sales above the revenue requirements, weather normalization would allow the utility to retain some of the revenues.

Next, regulators must determine whether to implement revenue regulation using a current or accrual method.

- **Current Method.** With the current method of revenue regulation, the target revenue for a period, say a month, is divided by the actual sales in that period to determine the rate per kWh. The current method ensures that actual revenue equals target revenue by calculating the rate at the end of the period so that the target revenue can be recovered. The current method allows for no lag in revenue recovery. One effect of this method is that, although customer rates vary, total bills are generally more stable. For example, in a hotter than expected July, customers will purchase more kWh, but they will be charged a lower rate. A milder than average winter would lead to fewer sales, but at slightly increased rates. This way, customers do not experience the same bill variability as they would if rates were set before the sales deviations occurred. On the other hand, the current method does not provide customers with the ability to plan ahead based on a predictable rate for electricity. This method has been used for revenue regulation of natural gas utilities.[54]

54 Because this method results in changes in the price for service that are calculated after that service has been provided, it fails the "no retroactive ratemaking" statutes that guide most electricity regulators. Customers are entitled to know the price of the commodity they are consuming at the time they use it.

Table 6

Tracking and Accrual of Difference Between Actual and Authorized Revenue		
	Track Difference	**Accrual Period**
Pacific Gas & Electric	*Monthly*	*Year*
Idaho Power Company	*Monthly*	*Year*
Baltimore Gas & Electric	*Monthly*	*Month*
Wisconsin Public Service Corporation	*Yearly*	*Year*
National Grid	*Yearly*	*Year*
Hawaiian Electric Company	*Monthly*	*Year*

- **Accrual Method.** Under the accrual method, rates are set based on an assumed sales level and the differences between actual and target revenue are allowed to accrue over some period. Then the total difference between actual and target revenue is reconciled through an adjustment to rates in the subsequent period; this is known as the true-up process. Presently all revenue regulation mechanisms for electric utilities use the accrual method.[55]

If regulators use the accrual method of revenue regulation, they will next need to determine the period over which the difference between actual and target revenue will be allowed to accrue. One year is typical; however, shorter periods are also used. Next the frequency of comparing collected revenue to target revenue should be determined. It is possible to do this comparison only once at the end of the accrual period. It is common, however, for comparisons to occur more frequently, often monthly. When revenues are compared within the accrual period, the differences are tracked, generally for the purpose of applying interest to the difference that will be deferred until the end of the accrual period.

Rate Adjustments

In designing a revenue regulation mechanism, there are a number of decision points that regulators need to consider to balance the interests of all the stakeholders. One of the decision points revolves around the

55 The closest to a current method in use for electric utilities in the BGE system of monthly reconciliation.

determination of the mechanism used to adjust rates. The issues that regulators need to consider include the following:

1. **Rate Case Requirements.** One of the often-mentioned concerns about surcharges, especially when they are numerous, is how that will impact the frequency of rate cases. For regulators and stakeholders, rate cases provide the best mechanism to correctly align rates and costs, but they are time-consuming and expensive for all parties. This is because a rate case presents an opportunity to closely examine all of the utility's expenses and adjust rates to reflect cost increases and decreases. Because under a revenue regulation mechanism the goal is to match revenues received from all customers with revenue requirements, a correct determination of revenue requirements is important, as is the specification of appropriate cost indices to adjust the revenue requirements. As the time between rate cases increases, some regulators feel the base rate case data, even with adjustments, need to be reexamined. As a result, some regulators have chosen to mandate the frequency of rate cases to address this, whereas others have not. It may be that in some cases, where there are numerous surcharges recovering a multitude of costs, there may not be as many costs subject to review in the rate case, making it less significant to a regulator than a case in which most costs are being analyzed and recovered in the rate case itself.
2. **Collection Mechanism.** Integrally tied to the mechanism for recovering revenues is how the utility will collect or refund the revenues. Options that are available include recovery through a rate case or periodic adjustments to rates through a surcharge mechanism. As can be seen by the case studies, depending on the plan in place, some utilities have very discreet requirements dictating the frequency of rate cases with adjustments occurring in those cases or between those cases. Other utilities have no requirements upon them with respect to the frequency of rate case filings. This will be discussed in more detail below. What does emerge from these case studies is that the discreet components or choices in how to execute a revenue regulation plan are carefully interwoven to create a holistic approach. Each component works with the other and the value of this case study is in examining the different pathways that can be chosen. As discussed previously, some of the commissions have authorized revenue regulation to recover the revenue requirements in the last rate case, whereas others have authorized adjustments to rates between rate cases; this impacts the pathway that the adjustment mechanism takes.
3. **Timing.** How often should rates be adjusted to true up to the utility's revenue requirement. States have chosen different options ranging from monthly to annually.

4. **Allocation of Revenue Regulation Revenue Surpluses or Deficits.** There are a number of decision points regarding allocation. Should the revenue regulation apply to all rate classes or just the smaller customers whose usage per customer and load variations are not as dramatic as those of larger-use customer classes? Should there be a different allocation to each rate class or should the allocation of costs among the classes be the same? Different mechanisms accomplish different goals. Some states have allocated revenue regulation revenues based on the revenues lost by customer class as a result of energy efficiency. This can sometimes be a political decision to mitigate opposition to energy efficiency programs by large customers. Other states recognize that the system savings resulting from energy efficiency benefit all customers, so that all customers should pay equally.
5. **Carrying Charges.** Depending on the timing issue discussed previously, regulators may want to consider carrying charges on any adjustments. This should be symmetrical in its application, however, so that it applies to surcharges and refunds. Consideration should be given for the basis of the carrying charge rate, whether weighted average cost of capital, rate of return, a risk-free rate, or some other mechanism should be adopted.
6. **Rate Caps.** In order to mitigate potential rate impacts, a regulator may want to consider a cap on how much rates can go up when the revenue regulation adjustment is made. This might be more critical if the regulator is aware of other potential rate increases that will impact customers' bills. If a cap is used, the case in which the utility's adjustment would exceed the cap must be considered. Some regulators have opted to allow the utility to carry over the excess unrecovered amount for a period of years, whereas others do not. This allows the utility to recover those revenues in a subsequent year when perhaps the adjustment is less. As a practical matter however, adjustments of greater than three percent are less common, as shall be discussed later.
7. **Impact on At-Risk Consumers.** Low-income and consumer advocates have expressed concern about revenue regulation as a vehicle for annual rate increases without the scrutiny of a general rate case, creating rate increases for the low-use customers doing the most to constrain usage and help achieve targeted energy savings. One proposal to address this has been to impose any resulting surcharges only to above-average usage customers, and any resulting credits only to below-average usage.[56]

56 Cavanagh and Howat. (2012, May 2). Finding common ground between consumer and environmental advocates. *Electricity Policy.*

Rate Case Requirement

Requirements as to the frequency of rate cases can be tied to the recovery mechanism or to the entire regulatory framework for implementing revenue regulation. In the cases studied, two of the utilities require periodic rate cases: PG&E every three years and WPS every year. Two others, National Grid and HECO, require annual mini rate cases, explained later, in which adjustments are made, and two others, IPC and BGE, have no requirements for scheduled rate cases. Nevertheless, if the concern is to ensure that the utility's revenue recovery meets its revenue requirements, some kind of periodic rate case to examine costs is appropriate. Having periodic rate cases can provide a measure of assurance to consumer advocates that the level at which the revenues, and hence the rates, are set, is correct. One of the criticisms of revenue regulation is in fact the lack of rate cases to produce a proper level of confidence in the allowed amounts. Multiple surcharges are usually additive to existing rates, therefore not permitting an opportunity to reduce the base rate for reductions in cost. Moreover, the infrequency in cases impedes the examination of rate allocations as would occur through a cost of service study.

This is a particular issue where utilities are augmenting power supply with purchased power from independent power producers, which is the most common method for acquiring wind and solar production today. The increased cost for purchased power may flow through a fuel and purchased power adjustment mechanism, while the (depreciating) investment in conventional power plants remains static in base rates.

Both PG&E and WPS use a future test year that allows the utility to project revenue requirements during the time period that the rates are to be in effect. The benefit to this is that it can help identify and account for projected changes in costs over the timeframe between rate cases. However, given that these costs are utility projections, most consumer advocates have less confidence in these numbers than they would using actual numbers from a historical or only hybrid test year.[57] When trying to garner support for revenue regulation from more skeptical stakeholders, using a future test year may not be helpful. Furthermore, in the case of WPS that has annual rate cases, using a future test year becomes less justifiable, as revenues are recalculated annually anyway.

57 The most common criticism of future test years is that utilities forecast costs under an assumption that all authorized personnel positions will be filled, while in retrospect, any large organization has some level of vacancy in its employee count. A historic test year captures this effect fully.

The absence of a rate case requirement can also cause consternation among detractors of revenue regulation because of the belief that the utility will be guaranteed its revenue requirements for as long as it is satisfied with that level, irrespective of how well it manages. However, this is no different from the status quo in traditional regulation in most places. The incentive to manage well is always there with or without revenue regulation as it translates into more profit for the utility.

In the cases of HECO and National Grid, the mini rate cases serve two purposes. In the one instance, it serves as a means to reconcile revenue recovery with revenue requirements, and in the second instance, it provides an opportunity to adjust rates in accordance with changes in costs. Specifically, for National Grid, the revenue requirement is adjusted to reflect capital expenditures. For HECO, revenues are adjusted to reflect changes in the cost of service. In the two examples here, revenue regulation is wrapped in with other adjustments as part of a mini adjustment. Given the structure for determining revenue requirements, which accounts for changes in costs, including revenue regulation within the mini rate cases is a workable option.

These examples highlight how rate cases can be used to adjust revenue requirements either in a more controlled regulatory environment with frequent rate cases or left to the utility's discretion to decide when to adjust costs. A set schedule of periodic rate cases, such as that used by PG&E, may strike an appropriate balance for reviewing revenue requirements, however, with the modification of a partial historical partial forecasted test year. Frequent rate cases can, depending on the resources of the regulator and stakeholders, be too costly and time-intensive. When there are too many rate cases, stakeholders and regulators may not be able to dedicate the level of resources needed for any one proceeding and may be spread too thin. Regular known rate cases at reasonable intervals may strike the best balance of adequate review and adjustment of revenue requirements.

Collection Mechanism and Timing

The collection mechanism for the differential between actual and authorized revenue requirements varies by utility as well. Both PG&E and WPS do not have adjustment clauses or surcharges, but instead have structured their revenue regulation plans to recover their costs in a rate case with rates adjusted annually. Although PG&E has rate cases every three years, the utility files its preliminary forecast every September 1 for the following year, including adjustments for revenue regulation and other costs. This practice promotes transparency, keeping all stakeholders aware of the current situation of the utility. IPC, BGE, National Grid, and HECO use surcharges on customer bills to collect or credit the difference between actual revenues collected and the revenue requirement. Although the other three (IPC,

Table 7

Rate Case Requirements	
Pacific Gas & Electric	*Every three years; annual "attrition" adjustments in between*
Idaho Power Company	*No requirement*
Baltimore Gas & Electric	*No requirement*
Wisconsin Public Service Corporation	*Annual rate case*
National Grid	*Annual capital expenditure adjustment case*
Hawaiian Electric Company	*Abbreviated annual rate case*

National Grid, and HECO) calculate the rate adjustment annually, only BGE does a more contemporaneous adjustment of one month. Certainly where there are no regularly scheduled rate cases, using an adjustment mechanism becomes more critical. PG&E has created a tracking mechanism known as a balancing account that allows the utility to track the surpluses and deficits to help ensure accuracy at year end when rates are actually adjusted. The creation of such monthly balancing accounts will make it easier at the end of the year to track what happened each month and then determine the adjustment for that year. It provides a more detailed trail for review and analysis by stakeholders and regulators. However, other mechanisms that just look at total revenues as compared to revenue requirements at the end of the year can work as well.

Table 8

Rate Adjustments	
Pacific Gas & Electric	*Base rates adjusted annually*
Idaho Power Company	*Annual adjustment through surcharge*
Baltimore Gas & Electric	*Monthly adjustment through surcharge*
Wisconsin Public Service Corporation	*Annual adjustment through rate case*
National Grid	*Annual adjustment*
Hawaiian Electric Company	*Annual adjustment*

Table 9

Allocation of Surplus or Deficit	
Pacific Gas & Electric	*Allocated to all customers according to business unit (e.g., electric distribution, electric generation)*
Idaho Power Company	*Included in the annual adjustment mechanism for each customer class*
Baltimore Gas & Electric	*Separate for each customer class*
Wisconsin Public Service Corporation	*Allocated to all customers, except certain tariffs (see above)*
National Grid	*Separate for each customer class*
Hawaiian Electric Company	*Separate for residential and commercial/ industrial*

Allocation of Revenue Regulation Revenue Surpluses or Deficits

The allocation of revenue regulation revenue surpluses or deficits should be symmetrical so that overpayments are credited to customers just as underpayments are paid by those same customers. The six utilities studied follow that formula. The application of revenue regulation, however, varies from utility to utility. BGE and IPC apply revenue regulation to the residential and commercial classes, thereby excluding industrial customers. In contrast, however, PG&E, WPS, National Grid, and HECO allocate revenue regulation adjustments to all customer classes. In terms of how the costs are allocated, IPC, BGE, WPS, National Grid, and HECO allocate costs differently among the customer classes. PG&E, however, allocates costs uniformly among the customers. Because PG&E has separated its business units, it also separately calculates and allocates revenue regulation surpluses and deficits among its electric distribution, gas distribution, and electric generation businesses. This illustrates that there are several ways to address revenues from revenue regulation depending on the policy outcomes that are desired.

Carrying Charges

Carrying charges applied to uncollected or surplus revenues can be used to account for the time value of money and the lost opportunity or value to having those revenues in hand. PG&E and BGE do not accrue carrying charges. On the other hand, IPC, WPS, National Grid, and HECO do. For

Table 10

Carrying Charges	
Pacific Gas & Electric	*None*
Idaho Power Company	*Yes*
Baltimore Gas & Electric	*None*
Wisconsin Public Service Corporation	*Yes, at the short-term debt rate*
National Grid	*Yes, at the customer deposit rate*
Hawaiian Electric Company	*Yes, at the customer deposit rate*

BGE, given that the revenue regulation revenues are reconciled and recovered monthly, it would make little sense to include a carrying cost. Where carrying costs have been used, they have included in the cases of these utilities the short-term debt rate or the customer deposit rate, which for one utility is six percent and probably close to the short-term debt rate. Thus, the carrying charge rates are appropriately at the lower end of the spectrum reflecting their short-term nature. In the application of the carrying charge, symmetry should be preserved by applying it to both deficits and surpluses. Application of carrying charges given the short period that costs are carried (one year) is somewhat discretionary. Although it does more accurately account for costs, it does add a modest level of complication in tracking costs.

Rate Caps and Collars

One of the ways to protect customers in the event of significant adjustments is to impose a rate cap (or collar) that limits the amount of a rate increase (and decrease). Some customers are sensitive to changes in foundational costs like utility bills and if costs are going to rise, they benefit from a pattern of steady modest increases rather than a large step increase. Any structural increases in rates attributable to reductions in sales or increases in costs recognized by the revenue regulation plan would be eventually included in rates under any system. A cap reflects a controlled way to manage customer expectations and customer impacts. Structural changes can only be managed for a while until a complete rate case is needed to reset all assumptions.

Typically, when a rate cap is imposed, if the formulaic increase exceeds the cap or collar, the utility will be able to carry over any uncollected revenues until the next rate adjustment. Two of the utilities studied, PG&E and HECO, do not have rate caps. On the other hand, the other four utilities do include

Table 11

Cap on Rate Adjustment	
Pacific Gas & Electric	*No*
Idaho Power Company	*3% rate cap; excess carried over to next period*
Baltimore Gas & Electric	*10% rate cap; excess carried over to next period*
Wisconsin Public Service Corporation	*Cap of $14 million per year*
National Grid	*$170 million in CapEx*
Hawaiian Electric Company	*No*

rate caps in varying amounts. National Grid has a one-percent revenue cap, whereas IPC and BGE have a one-percent and a ten-percent rate cap, respectively. WPS, unlike the others, has a cap tied to the dollar amount of $14 million as opposed to a percentage. Consistent with the goals of revenue regulation, all of the utilities studied have a carryover provision that is important for reducing the risk that the utility will not recover its revenue requirements.

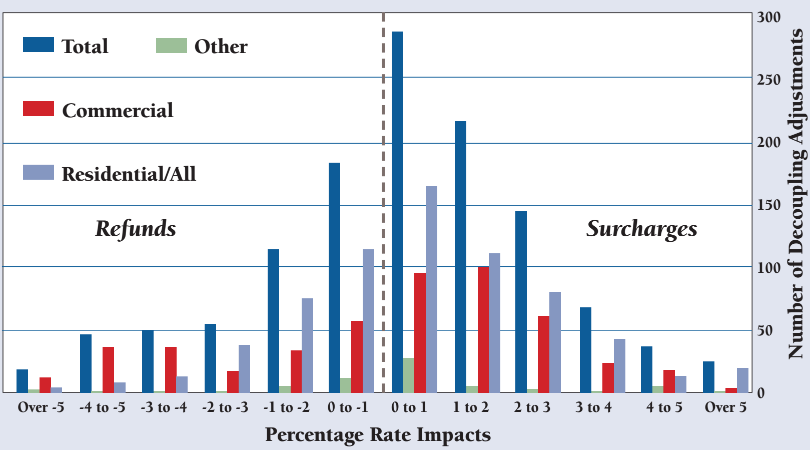
Note that National Grid differs from BGE and HECO in that its cap is on revenues, whereas the other two utilities cap rates and rate impacts. A revenue cap is more focused on ensuring minimal change to the revenue requirements authorized by the commission. National Grid, as discussed previously, allows for mini rate cases to adjust the revenue requirements. Having the one-percent cap limits the amount of increase that can occur through that process, requiring revenue changes that are greater to occur in a full rate case. However, note also that some of the adjustments allowed in the mini rate case have their own separate cap. The IPC rate cap is in line with what many other utilities with caps have in place, which generally range from one to three percent. The ten-percent rate cap in the BGE plan is reflective of its monthly adjustment pattern. An annual adjustment allows more time to smooth out peaks and valleys in revenues, whereas a monthly adjustment will be influenced by more of the spikes (particularly weather-driven variation), thus the need for a larger bandwidth for the carryover. Like a variable energy rate or fuel adjustment clause that fluctuates monthly, the monthly adjustment introduces more volatility into the rates.

Actual Historical Adjustments

For many ratepayer advocates there is a concern that some of the utility management risk will be transferred to customers as a consequence of a policy that seeks to ensure that the utility will be made whole. However, the utility retains management risk and the requirement to demonstrate that it has acted prudently. Thus the utility still has just as much of an incentive to operate efficiently as it did without revenue regulation. If the utility can lower its costs, it can still increase its profits. Second, by designing rates symmetrically such that under- and over-recoveries are reconciled, it provides customers with an opportunity to obtain credits that under traditional regulation would be retained by the utility. It has often been opined that when there are large gaps in time between utility rate cases, it is because the utility is over-earning and exceeding its revenue requirements. In those instances, customers never get to examine what the utility is collecting, much less receive a refund. Under revenue regulation, with its periodic adjustments and scheduled general rate cases, the revenue requirements are examined and refunds or credits allocated, such that customers have a better knowledge base for understanding the utility's earnings. And annual reconciliation of the utility's actual revenues versus authorized revenues provides consumers with a tool to reign in excess revenue recovery beyond authorized amounts. Third, the adjustments that do occur under revenue regulation are manageable and frequently less than the adjustments customers are used to seeing on their

Figure 1

Total Utility Decoupling Adjustment Rate Impacts[58]



58 Morgan, P. (2012, December). Graceful Systems, LLC. *A decade of decoupling for US energy utilities: rate impacts, designs and observations.* p5.

bills for fuel or variable generation rates, or for the myriad of other surcharges that can be tacked on to a customer's bill, such as an infrastructure (smart grid) surcharge, maintenance upgrade fee, regulatory asset charge, or system benefit charge.

As seen in Figure 1, the range of rate impacts cluster around plus or minus two percent, but can at times exceed plus or minus five percent. The total of surcharges has somewhat exceeded the total of credits.

As can be seen with the utilities studied above, the larger fluctuations are attributable to adjustment mechanisms that are reconciled more frequently, such as monthly, as those are less able to smooth out anomalies as an annual adjustment would do. From a dollar perspective, for the roughly 64 percent of adjustments that fall within the plus or minus two-percent range, the monthly bill impact is approximately $2.30 for average electric customers and $1.40 for average gas customers.[59]

Of the six utilities studied, the fluctuations in adjustment have for the most part stayed within the one- to three-percent range as shown below.

- PG&E from 2005 to 2012 has had annual revenue regulation adjustments ranging from –1.43 percent to 4.15 percent, with an average adjustment of 1.97 percent.
- For IPC, the adjustments are separated between residential and commercial customers. For residential customers, the annual adjustments from 2007 through 2011 ranged from 0.77 percent to 2.58 percent for an average of 1.62 percent. As for the commercial customers, the annual adjustments for that same period were higher, ranging from 1.04 percent to 4.24 percent, with an average adjustment of 2.52 percent.
- BGE has monthly adjustments that ranged from –1.853 percent to 3.013 percent, with an average of 0.57 percent for residential customers from March 2008 through August 2012. For General Service Customers, the monthly adjustment ranged from –2.264 percent to 2.462 percent. The average adjustment was 1.308 percent.
- For WPS, the annual adjustments from 2009 through 2011 ranged from –1.45 percent to 3.78 percent for residential and small commercial, and from –3.14 percent to 8.99 percent for commercial. Note that because of a $14 million per year cap, some of these percentages were carried over. The average annual adjustment for residential and small commercial and for commercial was 1.63 percent and 2.15 percent, respectively, with carry-overs to subsequent years.

59 Id, p 3.

- For Massachusetts Electric and Nantucket Electric, both of which operate under National Grid, the annual revenue regulation adjustment for all for 2011 and 2012 was –0.105 percent and 0.315 percent, for an average revenue regulation adjustment over the two years of 0.105 percent.
- HECO, like National Grid, has one annual revenue regulation mechanism for its customers, which resulted in adjustments in 2011 and 2012 of 0.63 percent and 1.07 percent, respectively, for an average adjustment of 0.85 percent.

As can be gleaned from the above information, the range of average adjustments for small use customers was a low of 0.105 percent for National Grid to a high of 1.97 percent for PG&E. For larger use customers, the range was a low of 0.105 percent for National Grid to a high of 2.52 percent for IPC. This demonstrates that on average for these utilities with well-developed and diversely designed revenue regulation proposals, their adjustments on average stayed at or below approximately 2.5 percent.

One of the metrics for determining if a revenue regulation program is working successfully that was discussed above was the impact on rates of a revenue regulation mechanism. As can be seen by the analysis of the adjustment levels for each of the utilities, they are within a reasonable range.

Complementary Policies

Although a revenue regulation mechanism does not need to be accompanied by other policies, energy efficiency is frequently at the root of the reason revenue regulation was proposed in the first place. The states examined in this paper have various obligations for energy efficiency achievement placed upon their utilities. Only Idaho does not have an Energy Efficiency Resource Standard, but energy efficiency objectives are developed through an integrated resource plan process. Energy efficiency spending at IPC has increased dramatically in recent years.[60]

In recognition of the fact that revenue regulation only removes the disincentive to pursue energy efficiency, several states have instituted some form of incentives to reward the desired outcome. This mechanism can not only incentivize management to aggressively pursue energy efficiency, but also make shareholders supportive in the face of lost investment opportunity.

Rate design can also play an important part in assisting the utility in achieving favorable energy efficiency outcomes. Inclining block rates penalize inefficient use of electricity and shorten payback times from the customer perspective. Because efficiency reduces consumption at the tail block rate,

60 Schultz, T. Energy Efficiency at Idaho Power. Available at: http://www.energy.idaho.gov/energyalliance/d/ida_power.pdf

Table 12

Complementary Policies for Energy Efficiency				
	Energy Efficiency Requirement	**Incentive Structure**	**Default Residential Rate Design**	**Performance Incentives**
Pacific Gas & Electric[61]	*1% annually*	*Risk reward incentive mechanism*	*Inclining block*	*Reliability reporting only*
Idaho Power Company[62]	*IRP*	*No*	*Inclining block*	*None*
Baltimore Gas & Electric	*10% by 2015*	*No*	*TOU, seasonal*	*Under consideration*
Wisconsin Public Service Corporation[63]	*0.75% annually*	*No*	*Flat*	*Reliability reporting only*
National Grid[64]	*2.4% annually*	*5% of program costs*	*Inclining block*	*Service quality reward and penalty*
Hawaiian Electric Company[65]	*Energy efficiency can satisfy portion of RPS*	*Third-party administrator paid for contract performance*	*Inclining block*	*Under consideration*

the value of kWh savings is greater than with flat rates. On the other side of the spectrum, declining block rates, which have a reduced rate in the tail block, do little to encourage conservation. In fact, they operate more like a discounted bulk rate by reducing the average cost of a kWh in a customer's bill for the more kWh used.

Performance incentives or other ways to avoid destructive cost-cutting in the name of creating margins that reduce service or reliability or lessen customer value have been implemented only in Massachusetts of the six

61 Optional rate designs for PG&E include TOU and Peak Time Pricing.

62 IPC also has an optional TOU rate design.

63 Optional rate designs for this utility include TOU, Critical Peak Pricing, and Contract.

64 National Grid also offers optional TOU and flat rate designs.

65 HECO also offers optional TOU and flat rate designs.

utilities illustrated here. Several other states have implemented various schemes in reaction to perceived deficiencies in utility service.[66] Performance incentives are not unique to revenue regulation. Commissions wishing to implement such a scheme can find many models of incentive reward and penalty mechanisms developed for other purposes.

Taken together, a suite of policy and program features can create an atmosphere that is conducive to achievement of energy efficiency goals within the utility and for the customers. By appropriate application of these techniques, regulators, working with utilities and stakeholders, can remove barriers and create an opportunity for energy efficiency to be fully integrated into the utility supply option portfolio.

Table 13

Annual Incremental Energy Efficiency Savings as Percentage of Retail Sales[67]

Highlighted cells are the year that utility started decoupling.

	2004	2005	2006	2007	2008	2009	2010
Pacific Gas & Electric[68]	1.1%	1.6%	1.0%	2.1%	3.5%	2.0%	1.9%
Idaho Power Company	0.1%	0.3%	0.5%	0.6%	1.0%	1.1%	1.3%
Baltimore Gas & Electric	0.0%	0.0%	0.0%	0.0%	0.5%	0.6%	1.7%
Wisconsin Public Service Corporation[69]	0.3%	0.3%	0.3%	0.3%	0.9%	1.0%	0.9%
National Grid	1.1%	0.9%	1.2%	0.9%	0.5%	1.1%	1.36%
Hawaiian Electric Company[70]	0.0%	0.5%	0.5%	0.4%	0.5%	1.1%	1.2%

66 See, e.g., Alexander, B. (1996, April). How to construct a service quality index in performance-based ratemaking. Electricity Policy.

67 EIA. Form EIA-861 data files. Available at: http://www.eia.gov/electricity/data/eia861/

68 PG&E began revenue regulation in 1974 and it was later suspended and recommenced in 2001.

69 WPS savings are represented by the statewide program savings from the Focus on Energy program. WPS provided additional funds to Focus on Energy, starting in CY10, through their territory-wide program activities.

70 In 2009, Hawaii Energy, a ratepayer-funded statewide energy efficiency provider, began delivering services. Savings reported after 2009 represent savings achieved through the programs of Hawaii Energy.

Energy Efficiency Outcomes

Although revenue regulation itself does not create an incentive for a utility to implement energy efficiency, it does address the issue of lost revenues associated with energy efficiency and DG programs. Revenue regulation should be combined with other mechanisms that require or incentivize the implementation of energy efficiency by the utility or a third party. The level of energy efficiency achieved can be one measure of the success of a revenue regulation mechanism as implemented in a larger program designed to achieve energy efficiency. Table 13 shows the incremental annual energy efficiency savings reported by each utility, with the shaded box indicating the year that the utility's revenue regulation mechanism was implemented. National Grid had achieved a high level of energy efficiency savings in the years before it implemented revenue regulation.

This paper has not evaluated DG outcomes to correlate with revenue regulation, as it is not perceived that states and utilities have made that connection expressly in historical mechanisms. However, it is expected that this connection will be made in future mechanisms, and furthermore it is anticipated that follow on work to this paper will want to study that connection between revenue regulation and DG performance.

Conclusions

An increasing number of states are looking to increase the rate of energy efficiency investments for their long-run cost and risk advantages. The benefits of energy efficiency include not only its ability to reduce system costs across the distribution, transmission, and generation functions, but also the opportunity for customers to reduce their individual energy costs for their own electric bills. Nevertheless, it is counterintuitive to encourage or order a utility to sell less of its product. In order to encourage the proliferation of energy efficiency programs as a solution that can contribute to this nation's energy needs, this tension between the goals of society versus the goals of the utility needs to be addressed. Revenue regulation can be such a solution by removing the link between sales and revenues.

There are many ways to implement revenue regulation and multiple decision points that regulators must consider in designing a revenue regulation mechanism. This paper focused on six utilities, each of which implemented revenue regulation in different ways in accordance with the objectives of that state. Different decision points discussed include:

- Should revenue regulation apply to all functions (generation, transmission, and distribution), which sometimes depends on if the utility is regulated or restructured?
- Should revenue regulation apply to all customer classes?

- Should there be symmetry such that a reconciliation adjustment occurs for both over- and under-recoveries of the revenue requirements?
- Should recovery of indicated surcharges be conditioned on acceptable performance on customer service quality or energy efficiency goals?
- Should there be an attrition adjustment to account for other expenses, or should the revenue regulation adjustment be limited to reconciling existing revenue requirements?
- Should there be an inflation adjustment?
- To calculate the revenue requirements, should the current or accrual method be used?
- Should the adjustments be made in rate cases or through a rider?
- How frequently should adjustments be made: monthly, annually, or some other time period?
- Depending on the period of time between true up and recovery, should there be carrying charges, and if so, how should they be calculated?
- Should there be a requirement authorizing the frequency of rate case?
- Should there be an annual cap on the amount of the adjustment, and if so, should there be an opportunity to carry over any additional amounts and for how many years?
- Should there be an adjustment to the cost of capital to reflect the reduced risk?

Other considerations for regulators, whether or not they implement revenue regulation, but certainly as part of a comprehensive package, are other measures that can be put in place to encourage consumers and utilities alike to actively participate in energy efficiency. For example, an inclining block rate structure by virtue of its incentive to consume less pairs well with an energy efficiency program, helps drive consumers to participate in efficiency programs, and accelerates the payback of an energy efficiency investment. By the same token, an incentive payment to the utility helps provide its management with a good reason to excel and exceed targets for energy efficiency programs.

A key point illustrated by the list of considerations above is that there is not just one static way to design and implement revenue regulation, but rather there are a variety of options for doing so. In this study, a diverse group of utilities were reviewed. The differences among the utilities included geographic diversity, vertically integrated and restructured utilities, different levels of energy efficiency in place, and certainly differences in how the revenue regulation mechanisms were implemented. No two utilities were alike and no two utilities had the same revenue regulation mechanism. The key is that revenue regulation should eliminate the throughput incentive, but the means for accomplishing this goal can vary and be tailored to each jurisdiction and each utility and still be successful.

There are several considerations in the design of a revenue regulation mechanism that can help ensure its successful adoption. To begin, revenue regulation should be granted to utilities only as a precondition to implementing comprehensive energy efficiency and/or DG policies. Unless accompanied by a commitment to engage in providing least-cost resource options that could impact sales, there is not really any good policy reason for its adoption. All of the utilities studied are actively engaging in energy efficiency. Furthermore, as a matter of fairness, the revenue regulation mechanism should be symmetrical so that any revenues above those authorized are refunded back to consumers. As Figure 1 demonstrates, although there are more surcharges to customers, there is nevertheless a healthy amount of credits back to consumers. This is the bargain. Barring imprudence or other unforeseen circumstances, the utility receives its authorized revenue requirements and nothing more or less under a simple revenue regulation mechanism.

Rate design plays an important role in the effectiveness of energy efficiency in concert with revenue regulation. A low customer charge is preferable so that the customer can benefit from real bill reductions tied to reduced volumetric consumption. Reductions in consumption not only reduce bills but also positively impact the payback period for investments in energy efficient appliances. Declining block rates in which the tail block rate is lower than the first tier also do not encourage conservation. Inclining block rates that reward low usage in the first block with a lower rate send the better price signals. None of the six utilities studied had declining block residential rates. They were inclining, flat, and time-varying.

The revenue adjustment mechanism is also a critical decision point in terms of whether a revenue per customer mechanism is adopted that accounts for only the current revenue requirements or whether latitude is given to include an inflation adjustment or other cost increases in the revenue adjustment mechanism. Three of the utilities studied adopted this approach, whereas another two used a hybrid approach. Finally, to reduce volatility, five of the six utilities opted for annual rather than monthly adjustments, thereby creating a level of rate stability that customers in general prefer.

Once the goals for revenue regulation are set by the regulators, the next step is to design programs that will implement that goal. For energy efficiency to be as successful as possible, regulators may want to adopt a complement of other policies to accompany revenue regulation. These can include rate designs that reward reduced use and conservation as well as incentive payments to utilities that reward them for meeting or exceeding targets. Of the six utilities studied, three have adopted some form of incentive. One simple approach that was used in Washington was to link recovery of any surcharges under the revenue regulation mechanism to achievement of energy efficiency targets.[71]

For the utilities examined above that have implemented revenue regulation, the evidence demonstrates that revenue regulation as a strategy and a mechanism to enable energy efficiency has been working well. The fact that each revenue regulation mechanism varies from the next demonstrates that there are many different paths that can be followed in implementing revenue regulation based on the needs of the utility and its stakeholders in a particular region. This study demonstrates that revenue regulation does work and provides examples of how it can be implemented, each one different and unique because of the number of decision points to be considered in designing a revenue regulation mechanism.

71 Avista Utilities. (2009). Washington Utilities and Transportation Commission Docket UE-090134.

Appendix

Historic Rate Adjustments

Table 14

PG&E Revenue Regulation Rate Adjustments 1983 to 1993[72]

Year	Revenue Regulation Adjustment as % of Total Rates
1983	2.3
1984	(3.4)
1985	(4.8)
1986	1.9
1987	2.1
1988	5.0
1989	(4.3)
1990	(5.4)
1991	3.9
1992	3.4
1993	0.0

72 Lesh, P. (2009, June 30). *Rate impacts and key design elements of gas and electric utility decoupling.*

Table 15

PG&E Revenue Regulation Adjustments 2005 to 2012[73]			
Year	**Delivery Revenue Requirement ($ millions)**	**Revenue Regulation Adjustment ($ millions)**	**% of Delivery Revenue**
2005	8925	–127.73	–1.43%
2006	9933	224.6	2.26%
2007	10409	217.27	2.09%
2008	10261	40.32	0.39%
2009	11169	103.55	0.93%
2010	11224	465.56	4.15%
2011	10306	383.90	3.73%
2012	11032	403.04	3.65%

73 Morgan, P. (2012, November). *A decade of decoupling for US energy utilities: rate impacts, designs, and observations.*

Table 16

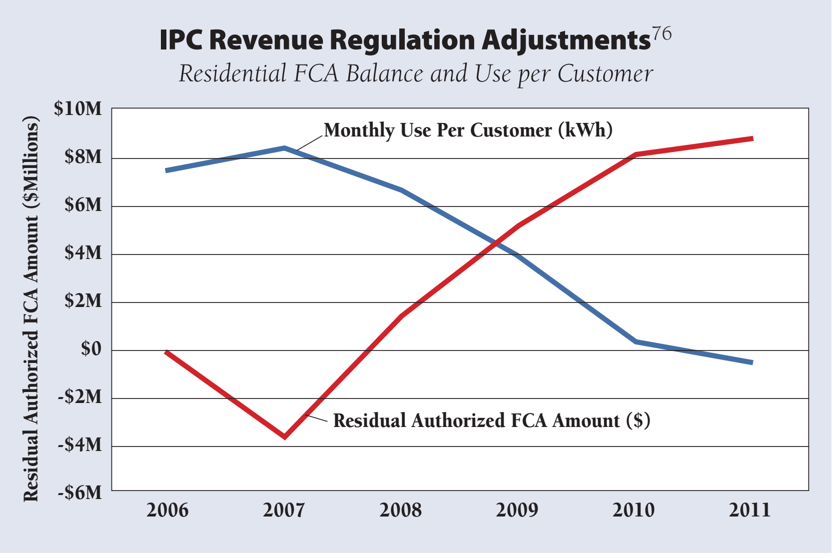
IPC Revenue Regulation Adjustments[74]
Idaho Power Company[75]

	Adjustment Rate	Retail Rate	Revenue Regulation Adjustment %
2007			
Residential	–0.0457	5.90	–0.77%
Commercial	–0.0457	4.28	–1.07%
2008			
Residential	0.0529	6.70	0.90%
Commercial	0.0529	5.10	1.04%
2009			
Residential	0.1220	7.70	1.58%
Commercial	0.1535	6.03	2.55%
2010			
Residential	0.1800	7.85	2.29%
Commercial	0.2273	6.13	3.71%
2011			
Residential	0.2028	7.85	2.58%
Commercial	0.2597	6.13	4.24%

74 Morgan, P. (2012, November). *A decade of decoupling for US energy utilities: rate impacts, designs, and observations.*

75 All numbers provided by the utility.

Figure 2



76 Idaho Power Company. Case No. IPC-E-11-19- fixed cost adjustment permanent mechanism. Available at: http://www.puc.idaho.gov/internet/cases/elec/IPC/IPCE1119/company/20120928COMPLIANCE%20FILING.PDF

Table 17a

Baltimore Gas and Electric *BGE Monthly Revenue Regulation Adjustments, 2008 to 2012*[77]			
2008	**Adjustment $/kWh**	**Retail Rate $/kWh**	**Adjustment %**
March			
Residential	0.00172	0.1477	1.165%
General Service	0.00230	0.1526	1.507%
April			
Residential	0.00016	0.1477	0.108%
General Service	0.00146	0.1526	0.957%
May			
Residential	0.00066	0.1477	0.447%
General Service	0.00230	0.1526	1.507%
June			
Residential	–0.00066	0.1477	–0.447%
General Service	0.00230	0.1526	1.507%
July			
Residential	0.00158	0.1477	1.070%
General Service	0.00230	0.1526	1.507%
August			
Residential	–0.00040	0.1477	–0.271%
General Service	0.00214	0.1526	1.402%
September			
Residential	0.00237	0.1477	1.605%
General Service	0.00230	0.1526	1.507%
October			
Residential	0.00237	0.1477	1.605%
General Service	0.00143	0.1526	0.937%
November			
Residential	0.00237	0.1477	1.605%
General Service	0.00140	0.1526	0.917%
December			
Residential	0.00445	0.1477	3.013%
General Service	0.00230	0.1526	1.507%

77 Morgan, P. (2012, November). *A decade of decoupling for US energy utilities: rate impacts, designs, and observations.*

Table 17b

Baltimore Gas and Electric

BGE Monthly Revenue Regulation Adjustments, 2008 to 2012[77]

2009	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	0.00035	0.1579	0.222%
General Service	–0.00073	0.1346	–0.542%
February			
Residential	0.00025	0.1579	0.158%
General Service	0.00230	0.1346	1.709%
March			
Residential	–0.00237	0.1579	–1.501%
General Service	0.00230	0.1346	1.709%
April			
Residential	–0.00237	0.1579	–1.501%
General Service	0.00230	0.1346	1.709%
May			
Residential	0.00234	0.1579	1.482%
General Service	0.00132	0.1346	0.981%
June			
Residential	0.00237	0.1579	1.501%
General Service	0.00230	0.1346	1.709%
July			
Residential	0.00237	0.1579	1.501%
General Service	0.00230	0.1346	1.709%
August			
Residential	0.00237	0.1579	1.501%
General Service	0.00190	0.1346	1.412%
September			
Residential	0.00237	0.1579	1.501%
General Service	0.00230	0.1346	1.709%
October			
Residential	0.00237	0.1579	1.501%
General Service	0.00124	0.1346	0.921%
November			
Residential	0.00237	0.1579	1.501%
General Service	0.00230	0.1346	1.709%
December			
Residential	0.00156	0.1579	0.988%
General Service	0.00204	0.1346	1.516%

Table 17c

Baltimore Gas and Electric

BGE Monthly Revenue Regulation Adjustments, 2008 to 2012[77]

2010	Adjustment $/kWh	Retail Rate $/kWh	Adjustment %
January			
Residential	0.00203	0.1465	1.386%
General Service	0.00230	0.1261	1.824%
February			
Residential	–0.00142	0.1465	–0.969%
General Service	0.00230	0.1261	1.824%
March			
Residential	–0.00237	0.1465	–1.618%
General Service	0.00230	0.1261	1.824%
April			
Residential	–0.00237	0.1465	–1.618%
General Service	0.00230	0.1261	1.824%
May			
Residential	0.00192	0.1465	1.311%
General Service	0.00230	0.1261	1.824%
June			
Residential	0.00191	0.1465	1.304%
General Service	0.00230	0.1261	1.824%
July			
Residential	0.00095	0.1465	0.648%
General Service	0.00230	0.1261	1.824%
August			
Residential	–0.00176	0.1465	–1.201%
General Service	0.00224	0.1261	1.776%
September			
Residential	–0.00237	0.1465	–1.618%
General Service	0.00116	0.1261	0.920%
October			
Residential	–0.00237	0.1465	–1.618%
General Service	0.00081	0.1261	0.642%
November			
Residential	–0.00237	0.1465	–1.618%
General Service	0.00098	0.1261	0.777%
December			
Residential	–0.00079	0.1465	–0.539%
General Service	0.00229	0.1261	1.816%

Table 17d

Baltimore Gas and Electric *BGE Monthly Revenue Regulation Adjustments, 2008 to 2012*[77]			
2011	**Adjustment $/kWh**	**Retail Rate $/kWh**	**Adjustment %**
January			
Residential	–0.00130	0.1365	–0.952%
General Service	0.00230	0.1156	1.990%
February			
Residential	–0.00253	0.1365	–1.853%
General Service	–0.00020	0.1156	–0.173%
March			
Residential	–0.00018	0.1365	–0.132%
General Service	–0.00063	0.1156	–0.545%
April			
Residential	0.00110	0.1365	0.806%
General Service	–0.00262	0.1156	–2.266%
May			
Residential	0.00010	0.1365	0.073%
General Service	–0.00160	0.1156	–1.384%
June			
Residential	0.00226	0.1365	1.656%
General Service	0.00042	0.1156	0.363%
July			
Residential	0.00253	0.1365	1.853%
General Service	0.00209	0.1156	1.808%
August			
Residential	–0.00007	0.1365	–0.051%
General Service	–0.00157	0.1156	–1.358%
September			
Residential	–0.00253	0.1365	–1.853%
General Service	–0.00177	0.1156	–1.531%
October			
Residential	0.00228	0.1365	1.670%
General Service	0.00262	0.1156	2.266%
November			
Residential	–0.00059	0.1365	–0.432%
General Service	0.00262	0.1156	2.266%
December			
Residential	0.00071	0.1365	0.520%
General Service	0.00262	0.1156	2.266%

Table 17e

Baltimore Gas and Electric *BGE Monthly Revenue Regulation Adjustments, 2008 to 2012*[77]			
2012	**Adjustment $/kWh**	**Retail Rate $/kWh**	**Adjustment %**
January			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
February			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
March			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
April			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
May			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
June			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
July			
Residential	0.00253	0.1291	1.960%
General Service	0.00262	0.1064	2.462%
August			
Residential	0.00253	0.1291	1.960%
General Service	0.00160	0.1064	1.504%

Table 18

Wisconsin Public Service Corporation Revenue Regulation Adjustments 2009 to 2011[78]

	Derived Adjustment $/kWh	Derived Adjustment Capped $/kWh	Retail Rate $/kWh	Revenue Regulation % Actual	Revenue Regulation % Capped
2009					
Residential/ Small Commercial	0.0048705	0.00168154	0.1290	3.78%	1.30%
Commercial	0.0084951	0.00293293	0.0945	8.99%	3.10%
2010					
Residential/ Small Commercial	0.0033043	0.00166936	0.1291	2.56%	1.29%
Commercial	0.0056630	0.00286103	0.9460	0.60%	0.30%
2011					
Residential/ Small Commercial	(0.0018666)	$ (0.00163719)	0.1288	–1.45%	–1.27%
Commercial	(0.0032565)	$ (0.00285629)	0.1037	–3.14%	–2.75%

78 Morgan, P. (2012, November). *A decade of decoupling for US energy utilities: rate impacts, designs, and observations.*

Table 19

National Grid Revenue Regulation Adjustments, 2011-2012[79] *Massachusetts Electric and Nantucket Electric*			
	Revenue Regulation Adjustment ¢kWh	**Retail Rate ¢kWh**	**Revenue Regulation Adjustment %**
2011 All	–0.015	14.29	–0.105%
2012 All	0.044	13.96	0.315%

Table 20

Hawaiian Electric Company			
	Revenue Regulation Adjustment ¢kWh	**Retail Rate**	**Revenue Regulation**
2011	0.1995	31.49	0.63%
2012	0.3894	36.41	1.07%

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

79 Morgan, P. (2012, November). *A decade of decoupling for US energy utilities: rate impacts, designs, and observations.*

Additional Resources

Decoupling Design: Customizing Revenue Regulation to Your State's Priorities

http://www.raponline.org/knowledge-center/decoupling-design-customizing-revenue-regulation-state-priorities

The history of U.S. states' adoption of revenue regulation, or decoupling—the separation of sales and revenues to mitigate the impact on utilities' bottom line of energy efficiency and distributed energy resources—demonstrates that no two decoupling mechanisms are alike. Over the process of their design, these mechanisms contain a number of decision points that address policy and stakeholder priorities. From an overall perspective of the good of the state, or from the distinct perspective of individual stakeholders, these decisions will enhance the decoupling mechanism or make it less attractive. This paper, the third in a trilogy of RAP papers on decoupling, examines these decision points in detail. It considers the applicability of revenue regulation by utility function, customer class, and included and excluded costs; the frequency and timing of rate cases; the design of a revenue adjustment mechanism; and issues such as rate design and bill simplification. It then lays out representative pathways for states considering a decoupling mechanism.

Pricing Do's and Don'ts: Designing Retail Rates as if Efficiency Counts

http://www.raponline.org/knowledge-center/pricing-dos-and-donts-designing-retail-rates-as-if-efficiency-counts

Rate design is a crucial element of an overall regulatory strategy that fosters energy efficiency and sends appropriate signals about efficient system investment and operations. Rate design is also fully under the control of state regulators. Progressive rate design elements can guide consumers to participate in energy efficiency programs and reduce peak demand, yet relatively few utilities and commissions have implemented many of these elements. This RAP paper identifies some best practices. Because pricing issues tie closely to utility growth incentives, we also address revenue decoupling.

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

http://www.raponline.org/knowledge-center/a-decade-of-decoupling-for-us-energy-utilities-rate-impacts-designs-and-observations

This report, written by Pamela Morgan of Graceful Systems LLC, builds on a 2009 report. Now covering 25 states, including 49 LDCs and 24 electric utilities, this report summarizes the decoupling mechanism designs these utilities use and the rate adjustments they have made under those mechanisms. In total, this report estimates the retail rate impacts of 1,244 decoupling mechanism adjustments since 2005.

The Role of Decoupling Where Energy Efficiency is Required by Law

http://www.raponline.org/knowledge-center/the-role-of-decoupling-where-energy-efficiency-is-required-by-law

This Issuesletter gives an overview of energy efficiency resource standards, the need to decouple utility profits from utility sales, and explains why decoupling is needed even where a third party administers energy efficiency programs.

Revenue Decoupling Standards and Criteria: A Report to the Minnesota Public Utilities Commission

http://www.raponline.org/knowledge-center/revenue-decoupling-standards-and-criteria-a-report-to-the-minnesota-public-utilities-commission

In 2007, the Minnesota legislature enacted a new statute, Section 216B.2412, in which it defined an alternative approach to utility regulation, decoupling, and directed the Public Utilities Commission (PUC) to "establish criteria and standards" by which decoupling could be adopted for the state's rate-regulated utilities. To fulfill its obligation to develop criteria and standards for decoupling, the PUC sought the advice of the Regulatory Assistance Project (RAP). This report is the output of that collaboration.

Designing Distributed Generation Tariffs Well

http://www.raponline.org/knowledge-center/designing-distributed-generation-tariffs-well

Improvements in distributed generation economics, increasing consumer preference for clean, distributed energy resources, and a favorable policy environment in many states have combined to produce significant increases in distributed generation adoption in the United States. Regulators are looking for the well-designed tariff that compensates distributed generation adopters fairly for the value they provide to the electric system, compensates the utility fairly for the grid services it provides, and charges non-participating consumers fairly for the value of the services they receive. This paper offers regulatory options for dealing with distributed generation. The authors outline current tariffs and ponder what regulators should consider as they weigh the benefits, costs, and net value to distributed generation adopters, non-adopters, the utility, and society as a whole. The paper highlights the importance of deciding upon a valuation methodology so that the presence or absence of cross-subsidies can be determined. Finally, the paper offers rate design and ratemaking options for regulators to consider, and includes recommendations for fairly implementing tariffs and ratemaking treatments to promote the public interest and ensure fair compensation.

Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed

http://www.raponline.org/knowledge-center/rate-design-where-advanced-metering-infrastructure-has-not-been-fully-deployed

This paper identifies sound practices in rate design applied around the globe using conventional metering technology. Rate design for most residential and small commercial customers (mass market consumers) is most often reflected in a simple monthly access charge and a per-kWh usage rate in one or more blocks and one or more seasons. A central theme across the practices highlighted in this paper is that of sending effective pricing signals through the usage-sensitive components of rates in a way that reflects the character of underlying long-run costs associated with production and usage. While new technology is enabling innovations in rate design that carry some promise of better capturing opportunities for more responsive load, the majority of the world's electricity usage is expected to remain under conventional pricing at least through the end of the decade, and much longer in some areas. Experience to date has shown that the traditional approaches to rate design persist well after the enabling technology is in place that leads to change.

Time-Varying and Dynamic Rate Design

http://www.raponline.org/knowledge-center/time-varying-and-dynamic-rate-design

This report discusses important issues in the design and deployment of time-varying rates. The term, time-varying rates, is used in this report as encompassing traditional time-of-use rates (such as time-of-day rates and seasonal rates) as well as newer dynamic pricing rates (such as critical peak pricing and real time pricing). The discussion is primarily focused on residential customers and small commercial customers who are collectively referred to as the mass market. The report also summarizes international experience with time-varying rate offerings.

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