Utility of the Future Center

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May 21, 2014

Commissioner Bob Burns
Arizona Corporation Commission
1200 West Washington St.
Phoenix, AZ 85007

Re: Commission's Inquiry into Potential Impacts to the Current Utility Model Resulting from Innovation and Technological Developments in Generation and Delivery of Energy (Docket No. E-00000J-13-0375)

Dear Commissioner Burns:

During the workshop you held on March 20th 2014 several participants, including some Commissioners, expressed their interest in discussing regulatory reforms that may be necessary to encourage the new technologies and innovation being examined in this proceeding. In our initial comments to this docket, we referred to a research project that the Utility of the Future Center was conducting for the Western Interstate Energy Board's (WIEB) State and Provincial Steering Committee (SPSC), on the subject of "Exploring New Regulatory Models." Phase 1 of this project has now been completed and the corresponding report is available at the following URL: http://westernenergyboard.org/wp-content/uploads/2014/03/SPSC-CREPC_NewRegulatoryModels.pdf

We have also attached the report to this letter for your convenience. We think this report may serve as a useful reference as you consider possible changes to the traditional regulatory model intended to foster technology and innovation in Arizona's power sector. Please do not hesitate to contact us if you have questions or would like to discuss this material further.

Sincerely,

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New Regulatory Models

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Prepared for the State-Provincial Steering Committee and the Committee on Regional Electric Power Cooperation

March 2014

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The authors would like to thank their review committee for valuable feedback and ideas, but any errors remain their own. Thank you to Steve Ellenbecker, Eric Gimon, Ron Lehr, Carl Linvill, and Andy Satchwell.

1. Introduction: Changes in the Power Sector

1.1 Are We Reaching Tipping Points?

In recent months, a steady stream of commentaries has suggested that the U.S. electric power industry is facing new pressures that may require a fundamental reexamination of the traditional utility business model and the regulatory compact that supports it.[1] Some examples include the following:

- Fereidoon Sioshansi, **"Why the time has arrived to rethink the electric business model,"** *Electricity Journal*, August-September 2012.
- Peter Kind, **"Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business,"** prepared for the Edison Electric Institute, January 2013.
- Ahmad Faruqui, **"Surviving Sub-one-percent Growth,"** *Electricity Policy*, June 2013.
- John Slocum, **"Threat from behind the meter,"** *Public Utilities Fortnightly*, July 2013.
- **"America's Power Plan,"** *Electricity Journal*, September 2013.
- **"Why the U.S. power grid's days are numbered,"** *Bloomberg Businessweek*, August 2013.
- **"Lights Flicker for Utilities,"** *Wall Street Journal*, December 2013.

Many observers have emphasized the role of potentially "disruptive" technologies such as solar photovoltaics (PV), automated demand-response, and other distributed energy resources. Other trends identified include flattening commodity (kWh) sales, evolving wholesale markets, and new environmental regulations requiring plant retrofits or retirements. The Western U.S. has witnessed some of these trends first hand. For instance, cost reductions in solar PV technology have allowed both Arizona and California to eliminate the upfront incentives for new rooftop installations. In Colorado, wind and utility scale PV Purchased Power Agreement (PPA) prices have also declined to the point where they are lower than the average system cost to supply energy. Meanwhile, PacifiCorp and the California Independent System Operator are in the process of establishing an Energy Imbalance Market between their respective balancing areas that could transform how energy imbalances are settled in the West.

While these developments have potential to bring significant benefits to electricity customers, they are at odds with the traditional utility business model. More specifically, these developments could have the effect of reducing utility electricity sales growth or limiting opportunities for future capital investments.[2] Given the unique role and ability of utilities to deliver modern electricity services to customers, it is important to think about the long-term financial health of these institutions. This confluence of factors raises challenging questions for state regulators: First, what is the significance and urgency of the trends being described and their possible negative impact on utilities? Second, how will utilities adapt to these changes under the current regulatory framework? Third, what potential changes to regulatory frameworks are warranted in response? In other words, these tipping points cause us to ask: ***Are there modifications -- or more fundamental changes -- to traditional cost-of-service regulation that would be beneficial for achieving 21st century goals for the power sector?***

This report intends to begin addressing these questions by providing a snapshot of novel regulatory approaches in the U.S. and abroad. Our goal is two-fold:

1. To place the discussion of threats to the regulated utility business in context by identifying counterbalancing business opportunities[3]—which some utilities are already realizing.
2. To introduce the concept of **performance-based ratemaking** (Section 2) -- one alternative to traditional cost of service regulation -- by providing real world examples that demonstrate modifications to traditional regulation that orient them more toward performance.

This report does not intend to provide a comprehensive survey of modern regulatory practices. Previous efforts have sufficiently documented how traditional cost-of-service regulation (COSR) has evolved in the U.S.[4] Instead we aim to provide snapshots of a few thought-provoking case studies (Section 3) and draw conclusions from these examples in the form of "principles" for regulators and utilities to consider (Section 4). Finally, we provide a perspective on the prospects for performance-based ratemaking (Section 5) and offer some recommendations for next steps (Section 6).

In addition to the discussion, case studies, principles, and recommendations presented, we also provide a comprehensive annotated bibliography of the current literature on performance-based ratemaking and related topics (see Appendix A). Furthermore, in recognition of the growing interest in distributed generation (DG) and its impact on the utility sector as a whole, we offer some insights into the recent impacts of DG on utility earnings (Appendix B). Finally we summarize initiatives related to extreme weather events, such as Hurricane Sandy, that pose new challenges to utilities and regulators in decisions regarding prudent cost recovery (Appendix C).

1.2 Finding Solutions: Goals for the Power Sector

To determine whether modifications to the regulatory framework are needed to achieve society's modern goals for the power sector, it is first necessary to have a clear idea of what those goals are. Some possible goals are listed in the table below:

Goal	Possible Performance Objectives
Cost	Minimize overall energy service costs to customers; ensure equitable allocation of costs; optimize resource allocation; improve company productivity through innovation
Reliability	Fewer outages; shorter duration of outages; fewer customers impacted by outages
Environmental Performance	Minimize pollution; minimize land use impacts; minimize water consumption
Customer Service	Transparent billing process; adequate response to customer complaints; delivery and support of new value-added products and services (from the utility or from third-party service providers)

Most regulators are quite familiar with these goals, as well as the tradeoffs among them. Indeed, balancing tradeoffs among competing objectives is usually at the core of the most challenging regulatory decisions. However, these performance goals are not always made explicit at the beginning of the traditional cost-of-service ratemaking process. Tools such as Integrated Resource Planning have made strides towards a more forward-looking regulatory process. Yet, despite incremental improvements to ratemaking over the years, traditional cost-of-service regulation in the U.S. can be seen as a backward-looking exercise in many cases – that is, rates are predominately based on incurred costs of utility assets and utility operations. As one recent report observed, U.S. regulatory regimes typically focus on the central question: "Did we pay the correct amount for what we got?" In contrast, other regulatory regimes have emerged (e.g. performance-based ratemaking) that place performance objectives at the forefront, thereby changing the focal question to: ***"How do we pay for what we want?"***[5] In other words, the regulatory regime becomes predicated more on ***value*** provided by serving electric customers ("value for money") rather than simply the ***cost*** of providing service.

2. One Potential Solution: Performance-based Ratemaking

> **Traditional Ratemaking** involves the development of a utility's revenue requirements (and ultimately rates) to recover a utility's costs in the test year (including taxes) plus a reasonable return on its rate base.
>
> **Performance-Based Ratemaking** decouples a utility's profits from its costs and ties utility profit to performance relative to specific benchmarks.
>
> *Excerpted from: Marcus and Grueneich, "Performance-based Ratemaking: Principles and Design Issues." Prepared for The Energy Foundation, November 1994.*

Performance-based ratemaking (PBR) starts with the outcomes that matter to customers, utilities, regulators, and other power sector industry participants. As noted above, these goals might include objectives such as minimizing costs, maximizing reliability, maximizing environmental performance, and enhancing the value of customer service. It aims to align the goals of customers, regulators, and utilities. In performance-based ratemaking, the utility is rewarded based on its achievement of specific performance targets, providing an opportunity to earn a higher return if the company is able to perform on the objectives identified. This contrasts with traditional ratemaking where utility rates are based mainly on incurred costs, which may motivate utilities to overinvest in fixed assets, and may not provide adequate incentives for productivity improvements.[6] Well-designed performance-based ratemaking includes both incentives for over-performance and penalties for underperformance (see Figure A). This system of paying for performance broadens the scope of options utilities can call on to run their business. It can offer investment and business model flexibility to the utilities by decoupling profits from sales, and thus may be able to offset some of the concerns that utilities have raised about revenue erosion from flattening electricity demand and customer-owned generation.

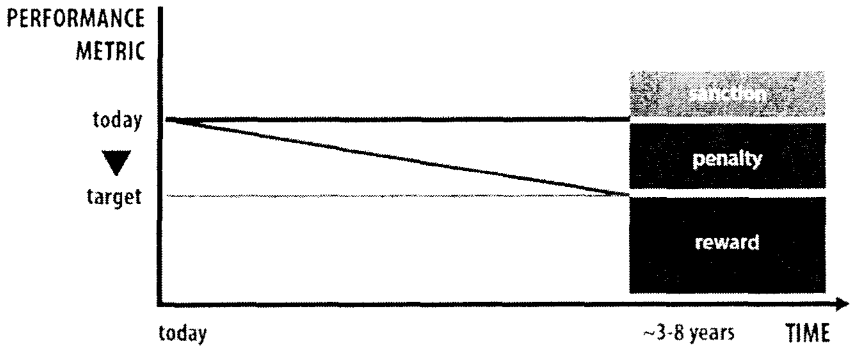


Figure A. An illustration of performance-based ratemaking. Note that the target does not need to be a single number; it can represent a performance band. PUCs set rates or allowed revenues and clear performance standards for several years in the future, and then give utilities the freedom to innovate in the intervening years. At the end of the compliance period, performance is measured. Utilities receive a reward for meeting or exceeding the standard, or a penalty for falling short.[7]

Under some PBR designs, the utility might also be given a multi-year period to try to meet these objectives and must create a business plan for doing so. This performance period provides sufficient lag time to allow the utility time to improve its performance, providing a greater long-term incentive for lowering costs.[8]

Performance-based ratemaking encourages utilities to achieve desired goals by granting them some more freedom to innovate and drive efficiency, but in return for that increased opportunity for upside, the utility takes on some of the risk that the customers would otherwise bear under traditional regulation. Essentially, performance-based ratemaking is focused on delivering value, rather than accounting for costs.

Exploring the potential for performance-based ratemaking begins with engaging important parties to understand system goals (see Figure B). System goals may fall into several categories—for example: cost, reliability, environmental performance. Important customer service outcomes may be measured at the retail level—for example: equity, innovative services, accurate billing. And system outcomes may be measured at the wholesale level—for example: system-wide least cost, reliability resource diversity, open access.[9] It is important to engage a range of parties from the beginning including customers, the Commission, the utility, the grid operator, third-party energy companies, and state policymakers.

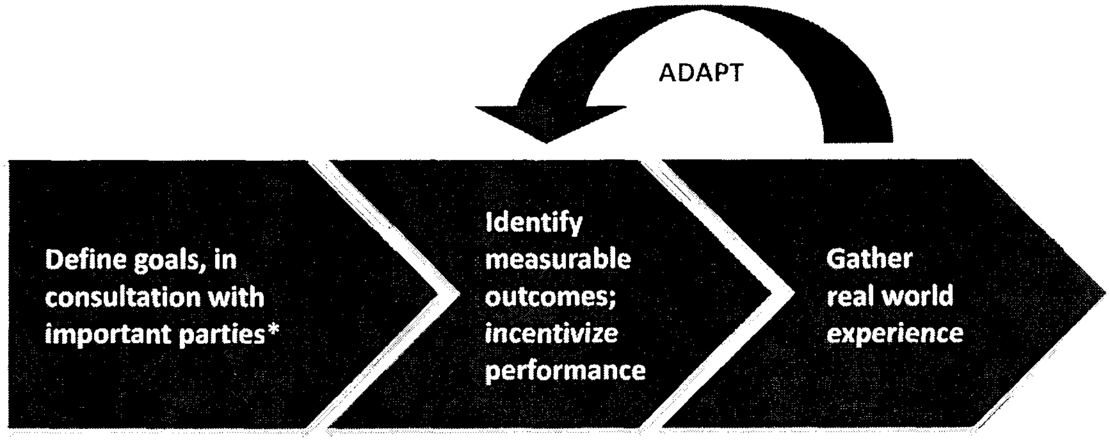


Figure B. The basic process for adopting performance-based ratemaking.

Once goals and outcomes are defined in plain terms, the next step is to develop quantitative metrics against which performance on those goals and outcomes can be measured. For each outcome, Commissioners can work with interested parties to determine the appropriate metric, as well as the level above which the utility should receive a reward and below which they should pay a penalty. See Figure C for a visualization of how performance-based ratemaking works. It is worth noting that the utility industry is already driven by standards, and in some cases these standards are tied to financial penalties. Examples might include alternative compliance payments for not meeting renewable portfolio standards, or penalties for violating NERC reliability standards; performance-based ratemaking goes one more step to develop additional standards and makes the reward and penalty structure a central feature of the ratemaking process.

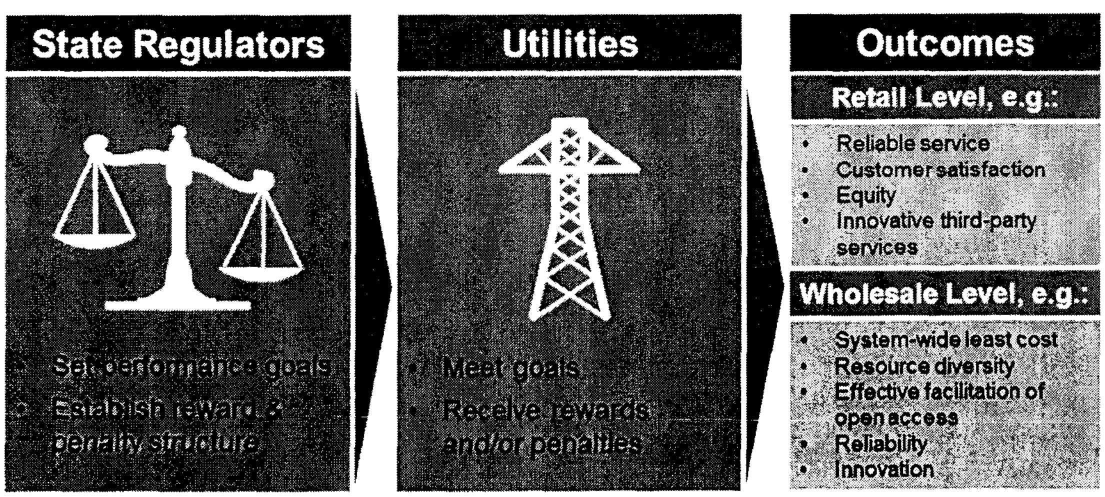


Figure C. Conceptual illustration of the relationship between regulators and utilities in delivering outcomes under a performance-based regulatory model.

Clear methodologies for calculating performance (and the counter-factual) should be developed and made available before any performance program begins. The time horizon for performance must be sufficiently long so as to give the utility time to reorient its business around hitting important targets. At the same time, the program should build in opportunities for refinement as players gain real world experience with the performance measures. It is important to strike the right balance between long-term certainty and fine-tuning based on experience. One idea for doing so is to start small: ensure that changes respect investments already made, and that changes affect a relatively small volume of resources (i.e. less than statewide). If the program works well, expand it to larger and larger volumes with improved characteristics based on experience.[10]

Of course, performance-based ratemaking is just one possible tool for achieving system goals, and should not be considered a panacea. Commissions have a long history of making smart trade-offs between worthy goals that are sometimes in competition with one another. Performance-based ratemaking underscores the importance of those choices, and provides a framework within which Commissioners can develop an integrated strategy for those trade-offs in a more transparent and flexible way. Careful attention must be paid to avoid some of the potential drawbacks of performance-based ratemaking, which include the potential for gaming the system if metrics are not chosen properly and measurements are not made and reported carefully.[11] Performance-based ratemaking may require a larger administrative lift up front for both the state PUC and the utility, but the potential payoff is substantial.

Note that performance-based ratemaking can work in a traditional vertically integrated utility model, or in a more competitive, or restructured system with many third-party service providers. For the former, the Commission sets clear performance targets and the utility works to meet them. For the latter, the utility acts as a market-maker, and uses its powers to buy or build to achieve the clearly-defined objectives as efficiently as possible. To meet the objectives and get suitably rewarded, the utility must be a very efficient buyer of services. In the more competitive case, performance-based ratemaking will only apply to services for which the distribution utility is responsible—but that is a non-trivial suite of responsibilities, including system reliability, local service delivery, and grid stability.

Fortunately, there is a wealth of experience from which to learn. Performance-based ratemaking is not a new concept. Regulators across America have been experimenting with performance-based ratemaking in the energy sector for almost as long as the sector has existed. Much thought and effort has been put into the subject, particularly in the 1990s when a large body of literature was developed on the theory and practice of performance-based ratemaking (see Appendix A.1 for some sample references from this body of literature). The following section describes elements of performance-based ratemaking in action, and extracts principles based on a broad range of experience.

3. Case Studies: Elements of Performance-based Ratemaking in Action

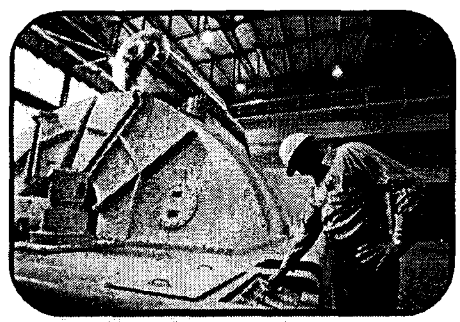
The examples laid out in the following sections represent a spectrum from small performance-oriented experiments to full-scale performance-based ratemaking. This set of short case studies shows that it is entirely possible to adopt elements of performance-based ratemaking without reinventing the regulatory model from the ground up. When considering adopting performance-based ratemaking, an important feature—seen across nearly all of these examples—is a specific, measurable target to which the company's earnings are somehow linked. Several of the cases also include either a potential upside for over-performance or a downside for underperformance, or both.

3.1 Incentives for Nuclear Performance: Fort St. Vrain

The problem: A new nuclear facility in Colorado experienced significant downtime due to operational issues and was therefore very expensive.

The solution: Regulators set a performance standard with an incentive for over-performance. If the utility could keep the facility running more than half the time, they would make money. If they could not, they would pay penalties.

Colorado began construction on its first nuclear power plant, Fort St. Vrain, in 1968. Its design was unusual, using a high-temperature gas cooled reactor design that was intended to be safer than typical boiling water reactors. After more than a decade of building and testing, the nuclear station began commercial operation in 1979. Once in commercial operation, the plant experienced issues with water infiltration and corrosion (as well as issues with electrical equipment), which ultimately resulted in substantial downtime with the station failing to produce electricity consistently. It operated at a low capacity factor until 1989, when it was permanently shut down.[12] Much happened in those intervening years, including an innovative approach that regulators used to drive performance and decrease risk for electricity customers.


Fort St. Vrain inlet turbine

The long construction and commissioning time, combined with the ongoing operational issues and relatively low capacity factor at Fort St. Vrain, meant that the electricity produced from the facility was very expensive on a per kilowatt-hour basis, and electricity customers were bearing the cost of attempted improvements via traditional rate cases through which the plant operator recouped its costs. Although the capital investment to get Fort St. Vrain nuclear station up and running was high, and the possibility of decommissioning was also very expensive, regulators determined that it would be more expensive in the long run to keep repairing the plant if the capacity factor remained as low as it was.[13]

Given all these factors, the Colorado PUC decided to use a straightforward performance incentive for the plant—called the "Wendling Plan" after the innovative staff engineer who proposed it. In simple terms, if the operator could produce power from the plant more than half the time, they would make money. If they could not manage to keep the capacity factor above 50 percent, they would pay penalties into a fund. It is worth noting that average capacity factors for nuclear stations at that time were much higher than 50 percent. This is a straightforward example of performance-based ratemaking with a clear quantitative standard, along with an incentive for over-performance and a penalty for underperformance. This scheme shifted some of the risk from customers back to the plant operators.

Commission staff relied on an existing Energy Cost Adjustment clause to implement this performance-based program, using it in a new way. The staff used a production cost model to calculate a long-run marginal cost of electricity for the region. They examined scenarios with and without the nuclear station, including costs of replacement capacity in the scenario without Fort St. Vrain. This allowed them to understand the likely marginal value of electricity in the long run, and to determine how Fort St. Vrain would need to operate to make it the most cost-effective marginal resource going forward. They then used the process defined in the Energy Cost Adjustment clause to translate this analysis into the performance standard.

Ultimately, Fort St. Vrain was not able to meet the standard and continued to require costly repairs, so it officially closed down in 1989 after paying substantial penalties. The plant's lifetime capacity factor was 14 percent.[14] While plant construction, ongoing repair, and decommissioning were all very expensive, it is widely accepted that this performance-based incentive ratemaking saved Colorado customers money in the long run.

PRINCIPLES

Set a quantitative standard for performance; include incentives for exceptional performance and penalties for missing the standard.

- ✓ Utility ended up paying into a fund because Fort St. Vrain's lifetime capacity factor was only 12-14%.

Shift an appropriate amount of performance risk to the utility, in exchange for longer-term regulatory certainty and perhaps incentive compensation.

- ✓ Customers were shielded from some risk.

Build on an existing framework.

- ✓ The Wendling Plan used an existing Energy Cost Adjustment clause in a new way.

3.2 Revenue Sharing for Off-System REC Sales: Xcel in Colorado

The problem: Xcel was producing more than the minimum required amount of renewable electricity, but could not sell the credits under trading business rules approved by the Public Utilities Commission (PUC).

The solution: The PUC approved a "pilot program" to share proceeds from Renewable Electricity Credit sales between the utility and the customers.

Public Service Company of Colorado, a subsidiary of Xcel Energy, developed a novel way for both its customers and shareholders to benefit from the company's procurement of wind resources. In August 2009, Xcel announced that it had enough wind to exceed the amount of renewable resources necessary to comply with Colorado's Renewable Energy Standard (RES).[15] As a result, the company held excess renewable energy credits (RECs) that it wished to sell to other companies -- particularly California utilities who had a shortfall in RECs needed to meet their own requirements. Typically, Xcel would have been able to trade energy and related products under the CO PUC's approved Trading Business Rules.[16] These rules include revenue sharing mechanisms for off-system sales that permit the company to keep a portion of the sales margins from these transactions.

In this case, the sales contemplated by Xcel involved a novel "Hybrid REC" product that did not match the standard definitions included in the Trading Business Rules. Thus Xcel proposed a new revenue sharing arrangement for the sale of these Hybrid RECs. In response, the CO PUC established an initial revenue sharing mechanism for Hybrid REC sales over a temporary pilot period.[17] Over the first 18 months of the pilot period (Oct 2009-June 2011), the margins realized on Hybrid REC sales reached $62 million[18] with effective sharing of approximately 57 percent to customers, 33 percent to Public Service, and 10 percent to a carbon offset program.[19] Customers realized the benefit of these margins through a reduction in the renewable energy surcharge portion of their bills. After the pilot period, a permanent revenue sharing mechanism was established, which divided margins at 80 percent for customers and 20 percent for the company. While Xcel's strategy has succeeded in recent years, it is also worth noting that California's current RPS law[20] limits procurement of out-of-state RECs for compliance, which may place an upper limit on total REC sales from Colorado in the future.

Why Share Off-System Sales?

Utilities that own power plants often have more capacity than needed to serve their load. This creates an opportunity to sell power to another interconnected utility. Such exchanges are beneficial since they can help reduce overall wholesale costs throughout the region. Several state commissions have determined that if these sales were enabled by revenue from ratepayers, then it is fair for a portion of the sales margins to be returned to ratepayers, instead of the utility.

This example demonstrates how revenue sharing can align customer benefits with utility incentives. Under traditional cost of service ratemaking, utilities are incented to reduce operating costs between rate cases. However, this incentive is limited since the gains are largely erased after each rate case is concluded. Thus, there is little incentive for companies to pursue actions that result in long-term cost reductions or revenue generation from operational activities such as off-system sales, despite the benefit such activities could provide to their customers. Revenue sharing mechanisms such as that used by Xcel in this case can help remedy the problem by providing the company with a financial reward for pursuing actions that provide savings to customers. Meanwhile, the majority of the benefit from the activity is still returned to customers. Similar revenue sharing schemes are a common feature of performance-based regulatory models as a means to encourage increased productivity and cost savings.

Utilities are frequently described to as a "standards driven industry" meaning that companies are commonly motivated to meet a minimum requirement in order to avoid penalties (e.g. NERC reliability standards). Performance-based ratemaking can give companies the opportunity to benefit from exceeding the minimum requirement. In this case, Xcel built renewables above the minimum RES requirement, and the company was rewarded financially by accessing a portion of the revenue from its off-system sales of renewable energy.

PRINCIPLES

Revenue sharing can align utility performance with customer benefits.
- ✓ During 18 month pilot, REC sales margins reached $62 million.
- ✓ Approximately 1/3 went to Xcel, and 2/3 went to customers.

Set a quantitative standard for performance; include incentives for exceptional performance.
- ✓ Xcel rewarded for procuring renewables beyond RES requirement.

Reward entrepreneurialism.
- ✓ Xcel took on a calculated risk with its aggressive procurement of wind resources.
- ✓ Company and customers both benefitted from being first to market.

3.3 Performance Incentives for Energy Efficiency: Massachusetts' Statewide Plan

The problem: Single performance measures and shareholder incentives for energy efficiency were insufficient to drive the multiple objectives sought by state regulators.

The solution: The Commission approved a multi-part performance incentive with three components: savings, value, and a catch-all for additional performance metrics.

Approximately 28 states have authorized performance incentive mechanisms for energy efficiency (EE) that enable utilities or non-utility program administrators to earn additional revenues based on the performance of their EE programs.[21] These incentives are considered to be an important regulatory tool for motivating utilities to pursue EE in a manner similar to supply-side investments.[22] In simple terms, utilities can make extra money by supporting their EE efforts, based on certain outcomes (e.g. total program spending or total savings). While there are several examples to draw from, the performance incentive that Massachusetts developed as part of its statewide energy efficiency planning process[23] offers an illustration of one of the more sophisticated incentive mechanisms to date, and demonstrates how incentive mechanisms can be designed to target multiple outcomes.

Energy efficiency performance incentives are frequently linked to overall EE program spending. However, this design does not necessarily motivate utilities to offer programs in the most cost-efficient manner. It also does not incent companies to pursue novel programs or measures that may ultimately lead to deeper energy savings, or address other goals such as helping low-income customers. The Massachusetts mechanism overcomes this dilemma through a multi-component incentive design based first on the following initial formula to set the total incentive amount potentially available, and second on a three-component definition of performance. [24]

$$\boxed{\text{Total Incentive (\$)}} = \boxed{\text{Basis (EE Program Budget)}} * \boxed{\text{Incentive Rate (e.g. 5\%)}} * \boxed{\text{Performance (\% of goal achieved)}}$$

Each utility has the opportunity to earn a dollar amount equal to a percentage of its spending on EE programs. However, the actual amount received is linked to the achievement of specific performance goals. Massachusetts has established three performance components and a portion of the incentive payout is allocated to each:

1. Savings (rewards utilities for total energy savings, expressed as gross benefits)
2. Value (rewards utilities for achieving benefits cost-efficiently, expressed as net benefits)
3. Performance metrics (provides incentive for additional objectives not necessarily adequately captured by the other two components, e.g. low income, deeper savings)

One key feature of this design is that the first two performance incentive components were designed to send the two most important signals to the utility program administrators, in a balanced manner:

- Maximize benefits for customers (go get savings and benefits)
- Do so cost-efficiently (maximize net benefits, don't waste money getting the benefits)

Statewide Incentive Component Allocation for 2010-2012			
Component	***2010***	***2011***	***2012***
Savings (Benefits)	45%	50%	52%
Value (Net Benefits)	35%	35%	35%
Performance Metrics	20%	15%	13%
Total	**100%**	**100%**	**100%**

Table A. Statewide Incentive Component Allocation for 2010-2012

A formal stakeholder body (the Massachusetts Energy Efficiency Advisory Council) sets a "design" goal for each of the three components, establishing the level of incentive if a utility achieves 100% of its goal. Actual payout, however, is linked to performance, providing utilities the ability to earn more if they exceed the design level (e.g. 110% of goal) or less if they fail to meet it (e.g. 90% of goal). However, the company must achieve at least a 75% "threshold" of this design goal to receive any incentive at all.

An actual example of the incentive category breakdown is illustrated for NSTAR (see Table B below) based on the company's 2012 performance.[26] During this year, NSTAR achieved energy savings equal to 2.31% of retail sales and its EE programs achieved over $672 million in net benefits (according to the Total Resource Cost test).

INCENTIVE COMPONENTS	% OF GOAL ACHIEVED	INCENTIVE AMT.
Savings (Benefits)	98%	$6,132,530
Value (Net Benefits)	102%	$4,398,421
Performance Metrics	114%	$1,825,280
Total Incentive (before-tax)		**$12,356,231**

Table B. NSTAR 2012 EE Performance Incentives received under the Massachusetts statewide energy efficiency planning process.

Notably, the Massachusetts incentive mechanism sets a long-term goal (companies are instructed to develop three-year EE plans), but offers the Commission and other stakeholders flexibility through a variety of policy levers (e.g. budget levels, incentive rate, performance goals, allocation factors). This allows realignment of performance incentives over time to match changes in priorities and to track real performance. For instance, after the first three-year cycle (2010-2012) was completed, stakeholders readjusted the allocation factors for each of the three performance incentive components.

PRINCIPLES

Learn from experience with energy efficiency standards and incentive programs. Apply these approaches to achieve other system goals that produce customer value.

Mid-course correction can be built in.

- ✓ 3-year planning cycle provides some flexibility in incentive design.
- ✓ Incentive components re-weighted accordingly.

Single performance incentives can be designed to achieve multiple objectives.

3.4 Revenue Sharing for Off-System Energy Sales: MidAmerican Iowa

The problem: New revenues were needed to support increased utility costs under Iowa's rate freeze.

The solution: Shared savings mechanism allowed utility to keep a portion of off-system sales revenue.

MidAmerican Energy is one of the largest retail electric providers in Iowa, serving more than 600,000 customers. In 1995, the Iowa Utilities Board established a rate freeze on MidAmerican's base rates. The company operated for 16 years without either a major rate increase or the addition of a fuel adjustment clause. While MidAmerican's costs increased substantially during that time period, this rate stability was possible due to other sources of revenue the company was able to find to offset its cost increases. Among the most important revenue sources MidAmerican benefited from were off-system sales. The Iowa Utilities Board established a revenue-sharing mechanism that provided the company with a fraction of the margins from off-system sales and returned the remaining portion to ratepayers (the exact sharing percentages varied over time and were calculated based on the company's achieved return).

For instance, in 2007, MidAmerican's sales margins enabled $17.2 million in benefits for customers and $23.6 million for the company through the revenue sharing mechanism.[27] The extra revenue obtained from the sharing mechanism enabled MidAmerican to accelerate the depreciation of assets in its rate base, thus alleviating rate impacts. Meanwhile, the company was able install over 2,200 MW of new wind resources without increasing rates, causing Iowa to be one of the leading states in the country for wind generation. Additionally, it was able to absorb $170 million in flood and storm related damage from 2007 to 2011 without increasing rates. It also enabled $300M in environmental compliance projects.

In recent years, the Utilities Board has approved rate increases for MidAmerican. This was necessitated in part due to lower margins from off-system sales during the economic downturn. However, the rate increases proposed are much lower than they would have been, in part due to the accelerated depreciation described above.

It is worth noting that the off-system sales revenues in this case are not strictly tied to any specific performance measures. Thus while Iowa's rate freeze causes this case to fall under the broader rubric of "incentive regulation," it is debatable whether this is truly "performance-based ratemaking." Indeed, revenue sharing of off-system sales could have the negative effect of incenting the company to increase its generating asset base at the expense of its customers. However, new plant investments in Iowa have been governed by Advanced Ratemaking Principles, established by state law in 2001. This approach permits utilities to apply to the Iowa Utilities Board to set the treatment in rates for new generation sources in advance in exchange for provisions related to certain outcomes such as customer rate relief, emissions reduction, and fuel cost volatility. Prior to this, utilities were required to await rate case decisions to learn how cost recovery of their investments would be treated.

Several western states have already implemented revenue sharing mechanisms for off-systems sales. These include Idaho, Oregon, and Colorado.

PRINCIPLES

Revenue sharing can align utility performance with customer benefits. Structure programs so there is enough upside potential for the utility to drive innovation.

✓ Off-system sales contributed $23.6 M to MidAmerican's margins in 2007

Establish a long enough time horizon for the utility and third-parties to make investment decisions with certainty.

✓ Iowa's rate freeze persisted for over 16 years.

✓ Advanced ratemaking principles establish rate treatments for the life of new assets.

3.5 Smart Grid Investment: Illinois' Energy Infrastructure Modernization Act

The problem: Utilities in Illinois were not able to fully deliver the benefits of smart grid investments to their customers due to uncertainty in cost recovery.

The solution: Under Illinois' Energy Infrastructure Modernization Act, utilities can choose to use performance-based ratemaking, contingent on sufficient investment in the distribution system and penalties for underperformance.

In a 2007 rate case, Illinois' largest utility (Commonwealth Edison, "ComEd") proposed a bill rider known at the System Modernization Project, intended to recover the costs of implementing its AMI ("smart meter") program. At the time, consumer advocacy groups were uncertain that benefits of the smart meters justified the costs.

The Illinois Commerce Commission (the state's utility regulator) approved the rider, but required stakeholder workshops to better clarify the value proposition of these investments by identifying specific smart grid functionalities. In other words – what were customers getting in return? In any case, the consumer advocates appealed and ultimately overturned the Illinois Corporation Commission's approval of the rider.

As a consequence, ComEd sought a new approach to cost recovery of "smart grid" investments in its distribution system that offered more certainty. ComEd lobbied for a new piece of legislation known as the Energy Infrastructure Modernization Act (EIMA). Under the new law, passed in 2011, utilities can elect to participate in a performance-based ratemaking (PBR) process rather than the traditional approach of periodic rate cases.

However, utilities' ability to make use of this ratemaking mechanism is contingent upon meeting specific milestones for smart grid investment. For instance, ComEd must spend $1.5 billion over 10 years in its smart grid programs to maintain its eligibility in the PBR scheme. As part of this spending, Illinois utilities were also required to contribute to a $22.5M venture capital fund to fund new companies developing innovative smart grid technologies. Furthermore, each company is required to develop a 10-year investment plan and is held accountable to a 10-year performance plan. Certain penalties are invoked for not meeting specific performance goals such as those illustrated in Table C.

Sample performance goals established by ComEd in its 10-year performance plan:	
Category	**Performance Goal**
Frequency of customer interruptions	Improve system-wide SAIFI[28] by 20%, ratably over the 10-year period.
Duration of customer interruptions	Improve its system-wide CAIDI[29] by 15%, ratably over the 10-year period.
Service reliability targets	Improve the total number of customers who exceed the service reliability targets by 75%, ratably over the 10-year period.
Estimated bills	Reduce the number of estimated electric bills by 90%, ratably over the 10-year period.
Opportunities for minority-owned and women-owned business enterprises (MWBE)	Increase its capital expenditures paid to MWBE contractors by 15% over the 10-year period.

Table C: Performance goals established in ComEd's 10-year EIMA Performance Plan.

SYSTEM SAIFI ANNUAL GOALS

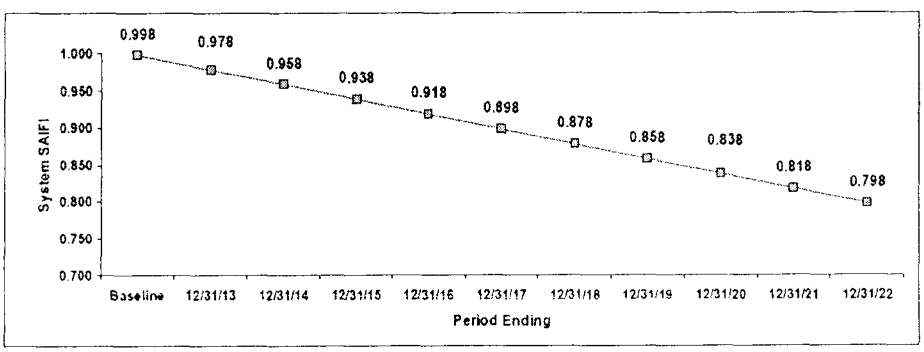


Figure D: This chart depicts one of ComEd's system reliability performance goals under EIMA.[30] System average interruption frequency index (SAIFI) is a commonly used reliability measure that indicates how often utility customers experience loss of power.

In exchange for meeting these participation requirements, rates are not set through periodic rate cases, but rather are modified annually through a formula rate where revenue requirements are based on projected capital spending. This provides companies with greater certainty of cost recovery, but also makes them somewhat accountable to certain performance metrics.

It is important to note that the rollout of the EIMA law proved to be highly controversial and was in fact vetoed by Governor Quinn (the IL state legislature later overrode the veto and the bill was signed into law). This opposition was in part because of the potential reduction in the ICC's authority and its ability to conduct prudence reviews. Additionally, some stakeholders argued that the formula rate included in the bill was far too prescriptive and did not grant the ICC enough flexibility to correct ratemaking procedures over time. However, the Illinois legislature overrode the Governor's veto and passed a "trailer bill" that remedied many of these initial concerns.

PRINCIPLES

Set a quantitative standard for performance; include penalties for missing the standard.

✓ ComEd's Performance Plan establishes specific outage goals (see chart) tied to penalties.

Establish a long enough time horizon for the utility and third-parties to innovate to meet performance targets.

3.6 Full-scale Performance-based Ratemaking: The UK's RIIO Model

The problem: The existing system of price cap regulation was not meeting the UK's targeted goals for the power sector; and costs were outpacing inflation.

The solution: UK regulators worked with distribution companies and other important parties to set measurable performance goals. Distribution companies submitted business plans to achieve the goals, and the regulations will let them innovate for eight years to meet them.

Since the UK restructured its electricity sector 25 years ago, the nation's wires utilities (14 distribution energy network operators and three transmission system operators) have had their revenue decoupled from their sales volume. The UK's regulator—the Office of Gas and Electricity Markets (Ofgem)—uses price controls, or revenue cap regulation plus incentives, to drive efficiency within regulated entities by setting revenues for a relatively long time, and letting the companies keep a profit if they manage to deliver the same outputs at a lower cost. This is the most full-scale move toward performance-based ratemaking of any of the case studies included in this report.

In 2010, after a year of collecting stakeholder comments, Ofgem made some major changes designed to help them "play a full role in the delivery of a sustainable energy sector, and deliver long-term value for money network services for existing and future consumers."[31] Ofgem built on the previous regulatory structure with a new model, known as RIIO: "Revenue set to deliver strong Incentives, Innovation and Outputs" or "Revenue = Incentives + Innovation + Outputs." The new approach combines capex and opex in the assessment of allowable revenue, extends the time between financial reviews, and measures a broader range of performance outputs. At the heart of the new program are detailed "business plans" that each of the wires companies in the UK must develop and submit to the regulator.

RIIO includes six primary output categories: customer satisfaction, reliability and availability, safe network services, connection terms, environmental impact, and social obligations—each with measurable targets. The program also allows utilities to propose higher rates to meet secondary deliverables to manage network risk, deliver outputs in the future, and innovate. See Figure E below.

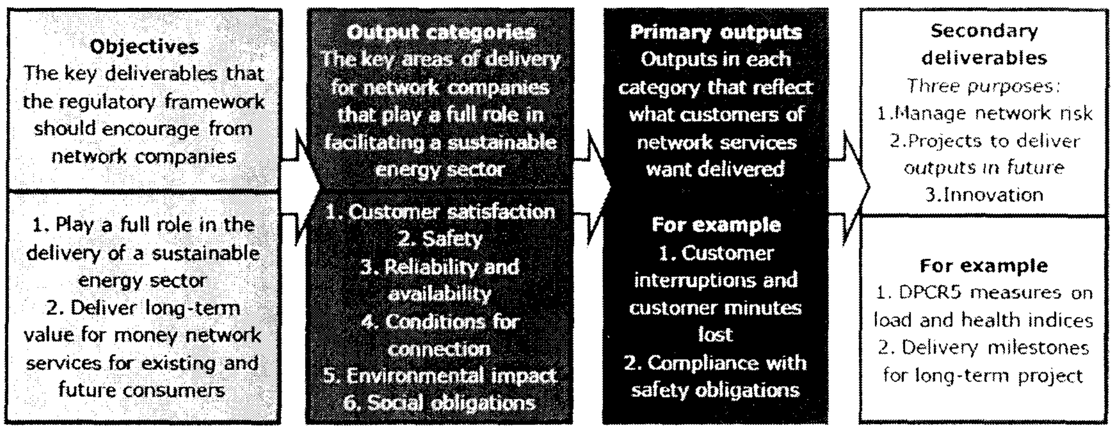


Figure E: RIIO category and output classifications[32]

The business plans submitted by each of the regulated companies in the UK include detailed descriptions and financial analysis associated with meeting standards in each of the six output categories. Either Ofgem or the regulated companies themselves propose appropriate metrics in each category, along with proposed incentives and penalty mechanisms associated with achieving these metrics. For example, Ofgem proposed to add or subtract a maximum of half a percent of revenues based on a customer satisfaction scoring system. Meanwhile, a set of adjustment mechanisms with pre-specified triggers are embedded in the program to deal with uncertainty. This enables changes in the revenue requirement if, for example, the adoption of electric vehicles or distributed generation vastly exceeds the level projected in the plans.

Given the sheer scope across all six categories of outputs, these business plan filings tend to be massive undertakings—for example, National Grid's initial submission was more than 1000 pages[33] and Ofgem expects the whole process to take around 30 months from when the plan is submitted to when it is approved. Once the plans are approved, regulated companies must submit annual reports including progress on outputs, and Ofgem plans do a full financial review to make revenue adjustments every eight years, using a scorecard as shown below in Figure F.

Clearly, this system requires a heavy administrative lift at the outset. Around 360 people work at Ofgem, and the staff is well-resourced to be able to work with the utilities on their eight-year business plans and performance targets. This upfront burden is a trade-off intended to deliver greater value to customers, long-term performance on important outcomes and less administrative oversight in the intervening years as the utility works to meet its predefined targets.

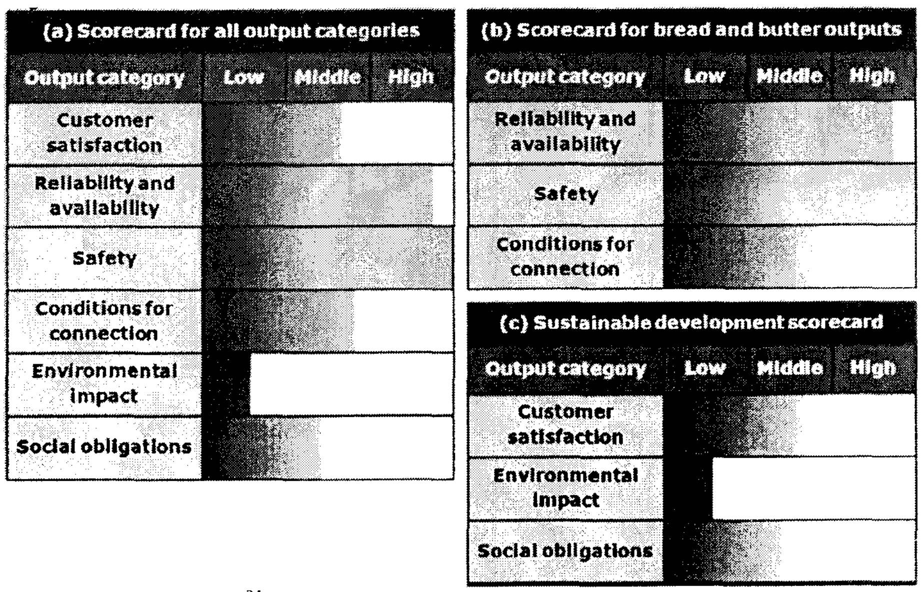


Figure F: RIIO Scorecard[34]

The RIIO system offers important innovations in four categories: the length of time between cost reviews, the process used to engage stakeholders, incentives for out-performance, and incentives for innovation.[35]

- **Length of time between cost reviews**: RIIO extends the length of the price control period from five to eight years, aiming for a "lighter touch regulatory approach that frees up management time to focus on running the networks" in the interim, to minimize regulatory uncertainty and encourage long-term planning that better reflects the 30-40 year lifetime of most of these companies' assets. RIIO's administrators also plan to perform small-scale intermediate reviews four years into the program. RIIO will use benchmarks based on past performance and comparable companies' costs to determine how much regulatory scrutiny each company receives in each period—some of the best performers are unlikely to be subject to deep review (which is in itself another performance incentive).
- **Stakeholder engagement**: RIIO was born from workshops with stakeholders, and the model is to value the outcomes that customers identify as important to as much as (or more than) the outcomes that regulators or utility officials deem important. Information must be made available to all, in order to minimize the effects of information disparity on the ability of important parties to participate in decision-making.

- **Incentives for out-performance**: RIIO offers incentives to utilities that do better than the minimum performance standards in each category. Incentives can be financial, or they can be in the form of reduced regulatory scrutiny (as mentioned above). On the other hand, failure to meet performance standards can result in reduced earnings, or in extreme cases, Ofgem could revoke a company's license to operate (see Figure A above). Similar to a feebate in the transportation sector, penalty payments from underperforming utilities fund rewards for utilities that out-perform.
- **Incentives for innovation**: RIIO provides funding for innovative projects from the R&D stage through the pilot stage. Funding is reserved in two separate pots for electricity and natural gas projects. In order to be eligible, recipients of RIIO's innovation funding must agree to share the lessons and ideas generated as part of the research and development process.

RIIO also sets out to be adaptable, based on policy changes and experience gained through implementation. Major feedback received so far includes: concern that the intermediate review (four years into the program) will turn into a full review, resistance to such deep involvement and power of new stakeholder groups, and a desire to put asset management performance on an even longer timescale (20 years) while keeping other performance metrics on a shorter clock (five years). In thinking about how RIIO can adapt based on this feedback, Ofgem acknowledges the need for any changes to be clearly announced well in advance of implementation, in order to minimize uncertainty.

PRINCIPLES

Engage with customers to find out which outcomes they care about.

- ✓ The regulator started by asking stakeholders what they cared about.
- ✓ Determined that delivering *sustainability* and *value* for money was most important.

Aim to find holistic solutions that go far enough to align incentives.

- ✓ Rather than adding PBR in one or two categories, UK regulators reoriented all of the utilities' incentives to drive a cultural shift toward innovation.

Mid-course correction can be built in, but the need for any changes must be announced well in advance of implementation.

- ✓ UK regulators are already gathering feedback, but have not acted on it yet.

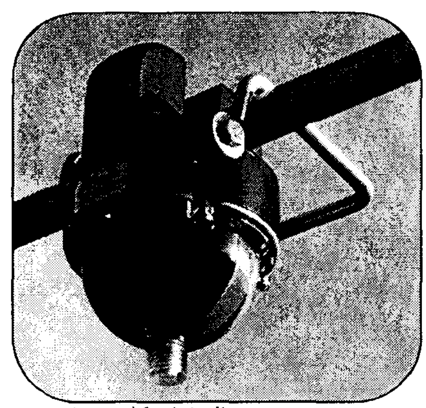
3.7 Changing Culture: Utility-driven Measurement

The problem: Incentives for internal business efficiency are not always explicit in a monopoly utility environment.

The solution: PacifiCorp began measuring internal performance and setting quantitative targets.

PacifiCorp is a major utility in the Western part of the U.S., operating in Utah, Wyoming, Idaho, Washington, Oregon, and California. It also owns generating facilities in Arizona, Montana, and Colorado. The company is wholly owned by MidAmerican Energy Holdings, a Berkshire Hathaway affiliate. MidAmerican also holds at least two companies that are part of the RIIO system in the UK.

In large part because of this connection to these UK companies—whose revenue is tied to performance outcomes via RIIO—MidAmerican has adopted a performance-oriented approach for driving internal business efficiency. In many cases the costs for completing discrete activities within the utility were not consistently measured. So, PacifiCorp began by breaking activities into repeatable units, developing clear methodologies for measuring important outcomes of those activities—like cost or volume. The same could be done for environmental performance, or other important outcomes. The company then developed quantitative targets for each discrete activity, and began to track performance against those targets.


Ground fault indicator

The results were dramatic (see Figure G). Taking the cost of overhead fault repairs in the distribution system as an example, PacifiCorp was able to slash costs by almost half in just 13 months. Experience has shown that simply beginning to measure a variety of unitized outcomes consistently can drive performance.

Unitized Activities		YTD Unit Costs Target	YTD Unit Costs Actual	YTD Volume Target	YTD Volume Actual
Wires Operations					
502	Distribution Overhead Fault Repair Cost Per Fault	$ 621	$ 631	1,745	1,254
504	Distribution Underground Fault Repair Cost Per Fault	$ 2,910	$ 2,803	253	255
501	Distribution Streetlight Repair	$ 25.38	$ 24.91	16,401	16,299
507	Distribution Underground Locates	$ 13.16	$ 13.03	20,639	20,535
Wires Corrective Maintenance					
526	Distribution OLM/OCR Cost per condition corrected	$ 230	$ 189	9,309	14,643
527	Distribution ULM/UCR cost per condition corrected	$ 606	$ 1,026	142	110
846	Local Trans OLM/OCR cost per condition corrected	$ 232	$ 325	808	662
884	Main Grid OLM/OCR cost per condition corrected	$ 1,020	$ 3,015	162	31
513	Cost Per Vault Repair	$ 2,200	$ 1,810	39	17

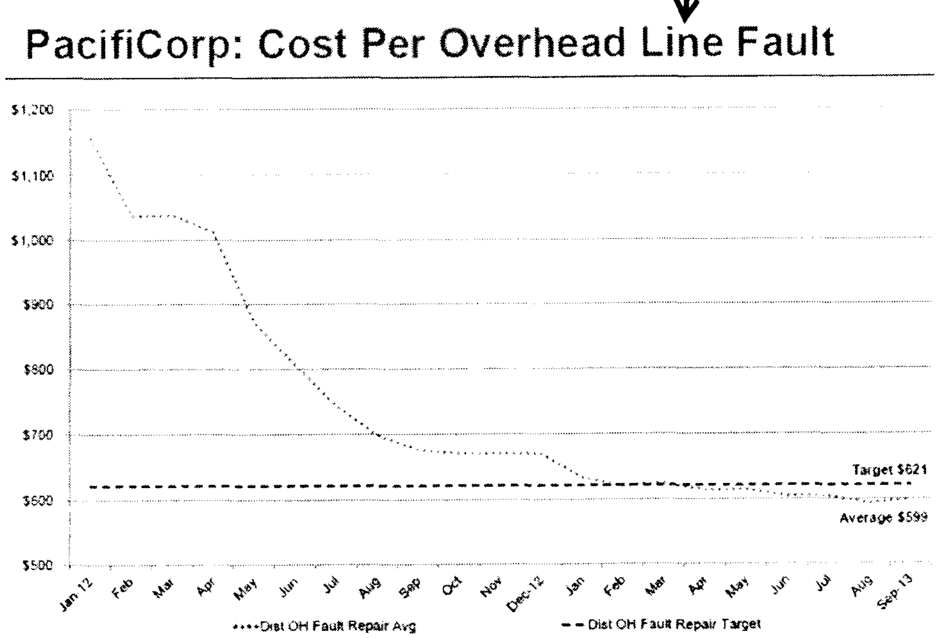


Figure G. The top table show sample unitized activities from PacifiCorp, including internal targets and actual costs. The bottom chart shows that the target was met within 13 months of beginning to measure costs.[36]

PRINCIPLE

It's all about measurement. Simply beginning to measure performance can reveal substantial opportunities for savings.

✓ PacifiCorp cut costs nearly in half in just 13 months of measuring the cost of repairing overhead faults.

4. Principles for Performance-based Ratemaking

The case studies reviewed here illuminate the opportunity that lies in performance-based ratemaking. It is clear that tying the financial health of the utility to outcomes that society cares about can be very powerful to reveal new potential for savings and efficiency – delivering value at both the retail and wholesale levels. But there are pitfalls to avoid. A handful of top design principles can help (aggregated from the preceding case studies):

PRINCIPLES FOR DESIGNING PERFORMANCE-BASED RATEMAKING

1. Define goals and outcomes. Then, set a quantitative standard for performance; include incentives for exceptional performance and penalties for missing the standard.
2. A clear methodology for measuring performance and a *counterfactual* should be defined at the outset of the program. Simply beginning to measure performance can reveal substantial opportunities for savings.
3. Shift an appropriate amount of performance risk to the utility, in exchange for longer-term regulatory certainty and perhaps incentive compensation. Reward entrepreneurialism.
4. Establish a long enough time horizon for the utility and third-parties to make investment decisions with certainty and innovate to meet performance targets.
5. Revenue sharing can align utility performance with customer benefits. Structure programs so there is enough upside potential for the utility to drive innovation.
6. Build on an existing framework, but aim to find holistic solutions that go far enough to align incentives and simplify the regulatory process. Adding piecemeal performance-based ratemaking to existing regulation—without carefully adjusting the terms and conditions of each—can add complexity and undermine both.
7. Single performance incentives can be designed to achieve multiple objectives.
8. Mid-course correction can be built in, but the need for any changes must be announced well in advance of implementation, in order to minimize uncertainty.
9. Engage with customers and power sector participants early to find out which outcomes they care about. Both the Commission and the utility can be proactive on this.
10. Learn from experience with energy efficiency standards and incentive programs. Apply these approaches to achieve other system goals that produce customer value.

These principles were derived from the case studies laid out in Section 3. However, not every example presented here exhibits every principle that might be desired from a theoretically ideal PBR framework. To illustrate this point, Table D lays out how each case study measures up to the criteria identified in Principle 1:

Case Study	Is revenue tied to a clear performance goal? If yes, what is the goal?	Is there an upside opportunity for exceeding goal?	Is there a downside risk for failing to meet the goal?
1. Ft. St. Vrain	Yes. Operate plant at >50% capacity factor.	Yes	Yes
2. Xcel REC sales	Somewhat. Related to RES, but incentive tied to over-performance.	Yes, from REC sales.	Somewhat. Out of RES compliance if insufficient RECs.
3. Mass EE Performance Incentive	Yes. Multiple targets for savings, value & performance.	Yes	No
4. MidAmerican IA off-system sales	No. But subject to Advanced Ratemaking Principles and rate freeze.	Somewhat. Not specific goal, but utility can earn more from efficient performance.	Somewhat. No specific goal, but lower sales means lower margins. May necessitate rate case.
5. Illinois EIMA	Yes. Multiple performance goals (e.g. SAIDI improvement).	Yes. The ability to opt out of the current structure.	Yes. ROE reduced for goals not met in each year.
6. UK RIIO	Yes. Scorecard system for performance outputs.	Yes	Yes
7. PacifiCorp internal Metrics	Yes (in short run). Internal targets for unit costs.	Somewhat. Larger operating cost savings between rate cases.	Somewhat. Smaller operating cost savings between rate cases.

Table D. Case study performance on the first principle of effective PBR design

5. A Path to Performance-based Ratemaking?

The examples described in this paper illustrate that elements of performance-based regulatory approaches are already used today in many U.S. states and abroad. However, none of the approaches highlighted here are widespread or universal. Moreover, the mechanisms for incentivizing performance frequently appear to be established in an *ad hoc* or piecemeal fashion, rather than through a more holistic process (with the exception of the UK RIIO example).

As changes in technologies, markets, and economic conditions continue to present challenges to traditional ratemaking, decision-makers in some states may be compelled to transition from their current regulatory framework to one that is more performance-oriented rather than cost-oriented. If such a transition becomes desirable, it may be useful to consider what the end-result should look like and, perhaps more importantly, what the right path is for making the transition. Even if there is agreement that such a transition is beneficial, there will undoubtedly be different opinions regarding the speed and scale of any transition to a performance-based approach.

States could choose to pursue more holistic changes, such as those undertaken in the UK. These undertakings are more thorough, but also require significant time investment by regulatory staff and other stakeholders. Additionally, the governor's veto in the Illinois case demonstrates that landmark shifts in regulatory models can often have pitfalls and political implications.

Alternatively, if state policy-makers are not prepared for a whole-cloth change to a new regulatory model, they might consider a more incremental approach that builds a "portfolio" of different performance-based earnings mechanisms over time. New opportunities for utility earnings, such as those illustrated by Xcel's REC sales or NSTAR's EE Performance Incentive, could be added incrementally until most utility decisions and investments are oriented towards performance outcomes, rather than commodity sales growth or investment in physical assets. Performance-based earnings could be added either by:

a) Broadening the ***scope*** by introducing new performance incentives, or

b) Enlarging the ***scale*** by increasing the fraction of utility earnings derived from existing performance incentives (rather than simply cost of service).

Ideas for new performance measures (i.e. expanding the scope)	
Unit costs for operational activities (e.g., EIM revenue sharing)	Interconnection Customer Experience (both utility-scale and DG)
DG location optimization	Reliability measures (e.g., CAIDI, SAIFI)
Customer satisfaction/complaints	Environmental Performance (e.g., lbs CO_2/MWh)

Regardless of the approach (incremental versus holistic), the end result is likely to be similar – a regulatory model that rewards utility employees and shareholders for delivering the outcomes that customers and society value. This "value based" approach contrasts with the traditional cost of service model, which usually incentivizes growth in asset base and sales volumes. Such incentives are increasingly at odds with the industry trends discussed in the introduction to this paper, and performance-based ratemaking provides a solution for utilities and regulators facing the challenges and opportunities in a 21^{st} century power system.

6. Recommendations for the State-Provincial Steering Committee and the Committee on Regional Electric Power Cooperation

Recommendations

This initial exploration has revealed some promising attributes of a performance-based approach to regulation that may warrant further consideration by stakeholders in the Western U.S. However, as stated earlier, performance-based ratemaking is not a panacea and requires a thoughtful approach. Accordingly, we recommend that SPSC and CREPC consider the following next steps for developing performance-based tools to adapt to trends unfolding in the industry today.

Possible next steps for SPSC and CREPC:

1. Develop a **handbook** for regulators interested in understanding how PBR might be implemented.
2. Conduct a **survey** of stakeholders throughout the West to find out what outcomes matter to them.
3. Develop an **inventory** of existing and desired regional performance indicators.
4. Use the "**Principles for Designing Performance-based Ratemaking**" in this paper as a starting point for developing future work.

Additionally, there are steps that could be taken outside of the SPSC and CREPC forum that both commissioners and utilities could consider.

Possible next steps for commissioners and utilities:

1. Commissioners: Open a **proceeding** on performance measures.
2. Utilities: Convene customers and other stakeholders to identify important performance outcomes; bring **proposals** to your Commission.

Concluding Thoughts

Commissioners and utilities in the United States today have a choice between paying for value in the electricity system, or paying for capital investment. These outcomes are neither mutually exclusive, nor are they substitutable. Well-designed performance-based ratemaking, drawing from experience to follow the principles outlined here, has the potential to drive important societal outcomes, as well as to create new business opportunities for innovative utilities and third-party players alike, while retaining low costs, high reliability, environmental performance, and customer service.

Appendices

A. Annotated Bibliography

References in each section are ordered chronologically.

A.1 Foundational Concept Literature

1. **Marcus, William B. & Dian M. Grueneich. *Performance-Based Ratemaking: Principles and Design Issues.* Prepared for the Energy Foundation. November 1994. (135 pp)**

   This report provides a clear and thorough description of Performance-Based Ratemaking and is a useful reference for stakeholders new to the subject. The report describes PBR in contrast traditional ratemaking, along with the strengths and weaknesses of each. The bulk of the paper walks through the mechanics of several PBR design elements, such as cost formulas, X-factors, sharing mechanisms, and performance criteria.

2. **Comnes, G. A., et al. <u>*Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource-Planning Issues, Volume I*</u>. Lawrence Berkeley National Laboratory. November 1995. (135 pp)**

   This report provides a technical deep-dive into the economics underlying PBR. It includes a critical examination of various PBR mechanisms that draws heavily from scholarly economic literature on regulation. It also reviews 11 PBR plans being implemented or proposed by utilities at the time.

3. **Costello, Kenneth. <u>*Future Trends in Performance-Based Regulation for U.S. Investor-Owned Electric Utilities*</u>. The National Regulatory Research Institute. January 1999. (43 pp)**

   This paper offers case studies and insights into the observed trend towards PBR in the U.S. in the late 1990s (in tandem with restructuring). These case studies include examples of PBR Rhode Island, Massachusetts, California, and Maine. The author portrays PBR as a superior alternative to traditional rate-of-return regulation, and provides well-reasoned arguments for this view (e.g. traditional regulation gives weak incentives for utilities to lower costs due to the Averch-Johnson effect). He also provides insight on the viewpoints of various stakeholders including PUCs, utilities, consumer advocates, and economists.

4. **Regulatory Assistance Project. <u>*Performance-Based Regulation for Distribution Utilities*</u>. November 2000. (47 pp).**

   This paper provides advice to regulators on how to design Performance-Based Ratemaking. In theory, PBR could provide better incentives to utilities to cut costs than cost of service (COS) regulation. The paper covers two basic forms of PBR: price caps and revenue caps and explains the structural elements of each. For these two models, either prices or revenues are fixed (initially based on cost of service) for a predefined period (e.g. 3-5 years). However, each includes adjustment factors to modify the predefined level over this period. These adjustment

factors include inflation, "X-factors" to promote innovation and efficiency, and "Z-factors" to control for exogenous or uncontrollable costs. Earnings sharing mechanisms can also be applied to share some of the cost reductions (or cost increases) with ratepayers. The paper also has specific language focused on how revenue cap PBR can reduce utility disincentives for distributed generation.

5. **Costello, Kenneth. *How Performance Measures Can Improve Regulation*. The National Regulatory Research Institute. June 2010. (46 pp)**

   This paper provides an overview of the rationale and techniques for using performance measures in utility regulation. It also enumerates specific applications of performance measures such as: monitoring performance outside of a rate case (e.g. specific unit costs), designing incentive mechanisms, evaluating the reasonableness of costs within a rate case. It also provides useful guidance on how to approach setting benchmarks for performance-based ratemaking.

6. **Shumilkina, Evgenia. *Where Does Your Utility Stand? A Regulator's Guide to Defining and Measuring Performance*. The National Regulatory Research Institute. August 2010. (30 pp)**

   This paper provides a comprehensive survey of different possible measures that could be used to evaluate utilities' performance. The paper organizes these measures in a useful table that defines each measure and suggests potential data sources. Categories of measures considered include: Reliability, Safety, Customer Satisfaction, Financial Health, Costs, Plant Performance, Innovation, Asset Management.

A.2. Reviews of Current and Historical Industry Practice

1. **Brown, Toby, Paul Carpenter, Johannes Pfeifenberger. *Incentive Regulation: Lessons from Other Jurisdictions*. The Brattle Group. May 2010. (11 slides).**

   This short presentation surveys the experience with PBR to date with examples including: UK's (RPI-X), Ontario (gas distribution), U.S. states (e.g. rate freezes, targeted incentives, broad-based PBR), Australia, and the Netherlands. Notably, the presentation mentions that PBR in the US has declined from 16 states in 2000 to 5 states in 2007.

2. **McDermott, Karl. *Cost of Service Regulation In the Investor-Owned Electric Utility Industry: A History of Adaptation*, prepared for the Edison Electric Institute June 2012. (60 pp)**

   This report provides a comprehensive history of cost-of-service regulation of electric utilities in the U.S. It lays out the foundation of the regulatory compact and walks through the major changes and trends that developed over time (e.g. nuclear prudence review in the 1980s, restructuring in the 1990s). Descriptions of incentive mechanisms are included throughout.

3. **Lowry, Mark Newton, et al. *Alternative Regulation for Evolving Utility Challenges: An Updated Survey*, prepared for the Edison Electric Institute. January 2013. (45 pp)**

This report provides a fairly comprehensive and up-to-date description of certain energy efficiency ratemaking techniques currently employed in each state. These techniques include: Cost Trackers, Construction-Work-In-Progress (CWIP) in Rate Base, Revenue Decoupling, Forward Test Years, Multiyear Rate Plans, and Formula Rates. For each of these, references are provided for specific proceedings that enabled the mechanism for a particular state or company.

4. **The Edison Foundation, Institute for Electric Innovation (IEE).** State Electric Efficiency Regulatory Frameworks. **July 2013. (24 pp)**

   This report provides comprehensive and detailed information on regulatory structures within each state that are intended to promote energy efficiency. Through tables and maps the report summarizes the status of each state's specific framework and adoption of each of the following: 1) direct cost recovery of EE programs, 2) lost fixed cost recovery and decoupling, and 3) performance incentives.

5. **Kelly, John, Greg Rouse, Brian Bunte, Ruth Nechas, and Amanda Wirth.** POWER SUPPLY PERFORMANCE INDEX: ANNUAL STATE REPORT, **Perfect Power Institute. July 2013. (11 pp)**

   This is Perfect Power Institute's first annual state PEER Power Supply Performance Index, which provides a rating for each of the U.S. states in terms of its overall energy efficiency and environmental electricity supply performance. The article also includes ratings for selected microgrids, power suppliers, and electricity procurement contracts. The article aims for consumers to gain access to key electricity performance data while providing a new rating tool to make it easier for consumers to compare electricity supply performance in terms of outcomes that matter. It gives an example of some metrics that can be applied to evaluating a power fleet as well as sample measures that can drive improvement (e.g. a nice sample of measures that the state of Georgia could use to improve their scores relative to peers). These metrics were recently used by Chicago's Community Choice Aggregator to decide on a power supply contractor, allowing Chicago to achieve substantial reductions in energy use and harmful power plant emissions including CO_2. It is not an example of performance-based ratemaking, but does give a sense of what types of metrics could be used in such a scheme if energy efficiency and environmental performance are used as criteria.

A.3 Related Policy Papers

6. **Travers, William D.** *White Paper on Risk-informed and Performance-based Regulation.* Nuclear Regulatory Agency. **March 1999. (5 pp)**

   This whitepaper describes the incremental move from deterministic and prescriptive regulation of nuclear power to more risk-informed performance-based ratemaking, defining risk as the answer to three questions: "what can go wrong?" "How likely is it?" and "what are the consequences?" It suggests that developing and integrating quantitative answers to these questions into the regulatory process will improve its efficiency and effectiveness. Still, regulators should not solely rely on risk calculations – the author describes "risk-informed" regulation as somewhere along the spectrum between deterministic and fully risk-based regulation. Performance-based ratemaking need not necessarily incorporate an assessment of risk, but the author indicates that well-designed programs will. Risk-informed performance-based ratemaking focuses attention on important activities, establishes objective criteria for evaluating performance, develops measurable parameters for monitoring performance, provides flexibility in how to meet the performance criteria in a manner designed to encourage improved outcomes, and focuses on the results as the primary basis for decision-making.

7. **Fox-Penner, Peter (2010). *Smart Power.* Washington: Island Press.**

   This book provides the first description of the "smart integrator" role for the utility. This concept has gained much popularity and is complementary to a performance-based ratemaking structure.

8. **Binz, Ron, Richard Sedano, Denise Fury, and Daniel Mullens. *Practicing Risk-aware Electricity Regulation: What Every State Regulator Needs to Know.* Ceres. April 2012. (60 pp)**

   This paper focuses on resource investment decisions by investor-owned utilities—providing recommendations in particular for states planning for larger volumes of coal retirements. It covers the role of regulators in the face of increasing investment needs in a time of historic risk and uncertainty—including how to assess the costs and risks of those new generation resources; challenges to effective regulation and seven strategies for practicing risk-aware regulation. The authors suggest: diversifying utility supply portfolios, using robust planning processes, employing transparent ratemaking practices, using financial and physical hedges, holding utilities accountable, operating in active "legislative" mode, and reforming or re-inventing ratemaking policies.

9. **Aggarwal, Sonia and Hal Harvey. America's Power Plan: *Rethinking Policy to Deliver a Clean Energy Future*. Sept 2013. (32 pp)**

   This paper covers pressures facing America's power sector and describes potential solutions at a high level, setting the stage for a series of seven more reports on specific policy interventions designed to help manage the transformation of America's power sector to cleaner and more flexible resources. The authors lay out best practices for competitive markets and for performance-based ratemaking, laying out ten principles for good PBR design.

10. **Lehr, Ron. America's Power Plan: *Utility and Regulatory Models for the Modern Era*. Sept 2013. (34 pp)**

    This paper makes a case for establishing new approaches to utility ratemaking and business models to accommodate a high amount of renewable energy. It describes several several possible roles that utilities might play in the future of the grid: minimal involvement, "smart integrator", and "energy services utility". It then describes specific regulatory regimes that may be able drive such a transition, with a particular focus on PBR. These examples include: the UK's RIIO model, the Iowa model, and "A Grand Bargain" which combines elements of the RIIO and Iowa models.

A.4. Recent Issue Areas and Case Studies

11. **Energy Future Coalition.** ***Utility 2.0: Piloting a Better Future for Maryland's Electric Utilities and their Customers.*** **March 15, 2013. (134 pp)**

    In response to a request from Governor Martin O'Malley to explore bold new ideas for utility structures that align compensation with customers' changing needs and values, EFC suggests five performance metrics (measuring cost, reliability, customer service, adoption of smart grid technologies and services, and support for alternate energy) that would be used to vary the utility's rate of return on equity by up to one percent above or below the otherwise allowed return for satisfactory service, adjusting the relative weight of these factors based on customers' own rankings of their importance. In addition to the discussion of performance-based ratemaking, EFC suggests ways to enable a smarter and customer-driven grid, on-bill energy efficiency financing, microgrids, and electric vehicles. The paper also summarizes the related ideas, proposals, and interests of 55 stakeholders.

12. **Fox-Penner, Peter, Dan Harris, and Serena Hesmondhalgh.** ***A Trip to RIIO in Your Future?*** **Public Utilities Fortnightly. October 2013.**

    This short article describes the structure and implementation of RIIO, with particular attention to the process and reporting requirements for the 14 distribution energy network companies and the three transmission operating companies in the UK.

13. **Smith, Joshua and Ron Lehr.** ***UK Utility Incentives: Applications to U.S. Clean Energy Transition.*** **2013.**

    This paper describes the UK's RIIO model for performance-based ratemaking, with detail on the output categories, early implementation, and stakeholder concerns. It then applies the model to the U.S. utility industry context, offering descriptions and performance metrics in seven categories: energy diversity, new financial models, enhanced stakeholder involvement and third party integration, make or buy, pollution reductions, transmission network improvements, customer services. The authors conclude that the U.S. has much to learn from the RIIO model, which would enable the utility to run more like a traditional business, focusing on targets set by consumers and other stakeholders.

14. **Standard & Poor's Capital IQ.** ***Why U.S. Electric Utilities' Credit Quality Can Withstand the Rise of Rooftop Solar.*** **November 15, 2013. (6 pp)**

    Strong sales are an important aspect of credit quality, but other credit factors weigh more heavily for utilities—namely the utilities' ability to successfully manage regulatory risk (including the ability to recover costs in a timely manner, earn allowed returns on equity, and minimize volatility in the customer's bill). To date, S&P's ratings on the electric utility sector have consistently demonstrated that the competitive threat from rooftop solar panels is not significant enough to impact credit, expecting that regulatory responses will be constructive, and even the most affected utilities will be able to adequately manage this risk. The article acknowledges the potential "death spiral" scenario, but points to California's Assembly Bill 327 as an example of constructive policy response.

15. **National Renewable Energy Laboratory (NREL)/Regulatory Assistance Project (RAP), *Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar.* November 2013. (73 pp).**

Increased adoption of distributed solar photovoltaics (PV), and other forms of distributed generation, have the potential to affect utility-customer interactions, system costs recovery, and utility revenue streams. This report examines regulatory tools, utility and non-utility business models for delivering solar energy services and rate designs for addressing emerging issues with the expanded adoption of distributed. It offers the groundwork needed in order for regulators to explore mechanisms and ensure that utilities can collect sufficient revenues to provide reliable electric service, cover fixed costs, and balance cost equity among ratepayers—while creating a value proposition for customers to adopt distributed PV.

16. **Arizona Corporation Commission Docket No. 13-0375.** *Commission's Inquiry into Potential Impacts to the Current Utility Model Resulting from Innovation and Technological Developments in Generation and Delivery of Energy.*

In mid-2013, the ACC undertook a serious investigation into the possibility of deregulating the state's electric utility sector and transitioning to retail competition. While the deregulation effort ultimately ended, the Commission decided to established a separate docket to investigate the types of technological innovations that would theoretically thrive under retail competition. Indeed, the stated goal of this proceeding is to "apprise the Commission on innovations and technological developments that could impact our current energy utility model in Arizona." This investigation raises questions about what regulatory framework that can incentivize utilities and other market participants to invest in emerging energy technologies. In a recent letter (http://images.edocket.azcc.gov/docketpdf/0000149798.pdf) Commissioner Bob Burns proposed several topic areas to be addressed in a series of workshops to be held in 2014:

- Distributed Supply and Storage Resources Enabling Customer Self-supply
- Customer Load Management Technology, Energy Efficiency, Major New Loads and Related Services
- Utility-Scale Storage Technology
- Metering Technology & Services
- Transmission and Distribution Automation
- Micro-Grids

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B. The DG Earnings Threat

The emergence of distributed resources is indeed a profound development, but assessments of DG's present impact on utility profitability have been much more qualitative than quantitative in nature and may be overstated in some cases. This section attempts to provide some additional clarity on how DG is currently affecting utilities. Note that this discussion is limited to the impact of DG on utility earnings, and does not address the separate but related topic of how fixed costs should be allocated as DG penetration increases. That topic has been at the heart of several ongoing public debates on net energy metering policies.

Part of the general concern that the current utility business model is inadequate to deal with current headwinds is the notion that DG may negatively affect earnings and thereby increase utilities' cost of capital. Thus, it is instructive to consider how Wall Street is reacting to the rise of DG. A survey of recent utility investor earnings calls and financial reports indicates that the issue has received some attention in a number of Western utilities, but does not appear to be an issue of widespread concern among utility investors at this point in time.

Company	Source	Discussion of Distributed Energy Resources
Mid-American Energy Holdings (PacifiCorp, NV Energy)	Sept 30, 2013 Financial Report	None
Xcel (Public Service Company of Colorado)	Q3 2013 Earnings Call http://78449.choruscall.com/dataconf/productusers/xel/media/xel131024.mp3	Rate base growth has been limited in part due to the economy and in part due to energy efficiency (23:00). No discussion of DG.
Sempra Energy (San Diego Gas & Electric)	Q3 2013 Earnings Call	Some discussion of AB 327 legislation and its impact on rates. (12:35)
Edison International (Southern California Edison)	Q3 2013 Earnings Call http://edge.media-server.com/m/p/g7jzaaxo/lan/en	Discussion of AB 327 and its impact on rate structures (10:30) (37:20). Mention of DG as a preferred resource solution to address the SONGS shutdown (50:15).
Pacific Gas and Electric	Q3 2013 Earnings Call http://edge.media-server.com/m/p/e6vdjp9r/lan/en	Some discussion of tiered rates and AB 327 legislation that restores CPUC authority to set rates. (4:15), (42:00)

Hawaiian Electric Industries Inc.	Q3 2013 Earnings Call http://edge.media-server.com/m/p/ki8ypnbz/lan/en	Mention of PV growth as part of reason for the PUC's new investigation into its existing decoupling mechanism. (32:30)
Pinnacle West Corporation (Arizona Public Service)	Q3 2013 Earnings Call http://edge.media-server.com/m/p/i8obtwjo/lan/en	Thorough discussion of APS' net metering proposal (8:15). DG currently impacts approximately 0.5% of APS' sales revenue. No expectation that this should to change since overall number of customers will grow in tandem with DG (28:15). No plans to get involved with DG and will remain focused on utility scale solar (30:18). Discussion of energy efficiency (36:22). APS' proposal would create new monthly charge, but no new money to APS since it simply offsets its lost-revenue adjustment charge (41:15). DG is still a small part of system and impact to ROE is relatively small. Issue has nothing to do with APS' thinking for its next rate case (50:25).

In addition to equity investors, the major credit ratings agencies have weighed in on the matter. In general their view is that the legislative and regulatory processes will serve to make any corrections necessary to help stabilize utilities as needs arise from DG. The following excerpts partially illustrate this view:

> "If the use of rooftop solar panels rises only gradually, as we expect, electric utilities should be able to handle this competitive threat without compromising credit quality by continuing to manage regulatory risk, which includes working with regulators to minimize volatility in the customer's bill. As such, our outlook for the electric utility sector continues to be stable despite growing competitive challenges from distributed generation."
> --S&P "Why U.S. Electric Utilities' Credit Quality Can Withstand The Rise Of Rooftop Solar," Nov 2013
>
> "In October 2013, Governor Jerry Brown signed into law A.B. 327. Fitch believes enactment of A.B. 327 is a constructive development from a credit point of view. The legislation shifts residential rate design authority from the legislature to the CPUC, removing legislatively imposed restrictions on certain customer rates and setting milestones for the commission to address net metering issues and set appropriate incentives to meet California renewable portfolio standards (RPS). "
> --Fitch, "California Regulation: Uncertain Outlook," Dec 2013

Additionally, it is worth noting that several states in the West have rate mechanisms for recovering the fixed cost revenue that is lost from distributed resources. Most of these mechanisms were designed to address lost revenue from demand side management (DSM) programs and are limited to DSM-related revenue loss. However, Arizona explicitly includes DG as a component of its lost fixed cost recovery mechanism. Under this framework, the impact that DG has on utility earnings is somewhat mitigated since a portion of fixed costs are recovered regardless of the amount of DG on the system. Other western states have adopted full revenue decoupling or revenue per customer schemes. These mechanisms should similarly reduce the impact of DG on utility earnings by

Rate mechanisms that may limit the impact of distributed resources on utility earnings in Western states	
Mechanism	**States Implemented**
Lost revenue recovery for DSM programs only	CO, MT, NV, NM, WY
Lost revenue recovery for DSM and DG	AZ (only applies to a portion of fixed transmission and distribution costs)
Full revenue decoupling or revenue per customer	CA, ID, OR, WA

A comprehensive summary of current state practices regarding lost revenue recovery and decoupling can be found in: *The Edison Foundation, Institute for Electric Innovation (IEE). State Electric Efficiency Regulatory Frameworks. July 2013.*

These mechanisms may reduce but do not fully eliminate the disincentive for utilities to support DG due to the potential displacement of utility investments. If DG resources are considered to be in the public interest, then a DSM-style performance incentive may be necessary to eliminate this disincentive. To date, no such performance incentives have been designed for DG.

C. Hurricane Sandy Responses

Maryland

Governor O'Malley established a Grid Resiliency Task Force in July 2012. Among others, one of the main recommendations was performance-based ratemaking. Then, in July 2013 the Maryland Public Service Commission approved a utility's request to include a "grid resilience charge" on customers' monthly bills.[37] This unbundling of reliability service means that certain customers could pay more for additional reliability. One additional interesting idea on the table in Maryland is a varying rate-of-return based on performance (proposed by the Energy Future Coalition), but the state has not yet taken it up.

New York

All utilities in the state have come together and agreed that cost of service regulation is no longer serving their long-term interests. They have joined with third party advanced energy companies to submit an official working group document to the Public Service Commission. The new paper describes the value of performance-based regulation in solving the post-Sandy resilience challenges, citing the important role of third-party service providers in creating a resilient grid via a combination of innovative distributed energy service models as well as traditional utility-driven hardening measures.[38] The commission is planning to open a docket on performance-based ratemaking in the next few months.

New Jersey

Public Service Electric & Gas has proposed "Energy Strong," aiming to recover costs of infrastructure hardening before the work is done. The request is for a $3.9 billion program over 10 years, calling for hardening 29 substations, strengthening distribution lines, deploying technology that restores electric service quickly, and undergrounding certain sections of the wires. The program has not been approved, though it is now receiving broad support from more than 100 towns and counties across New Jersey, as well as business groups, labor unions, and educational institutions. This represents a fairly traditional response, with the utility requesting funds (plus a rate of return) for investing in grid hardening measures.

[1] This report is primarily focused on regulatory models for investor-owned utilities, however, we believe some of the lessons learned are also applicable to publicly owned utilities.

[2] These trends don't necessarily displace utility investment, however, they may affect the kind of investments that utilities make. For instance, distributed generation may reduce need to construct large generating stations, but may also create opportunities for investment in distribution system. Utilities that are already out of the generation construction business (e.g. Southern California Edison) should benefit because they aren't losing opportunity. Meanwhile, third party gas generation companies may lose investment opportunities.

[3] This paper is limited to business opportunities for regulated utility businesses and does not consider unregulated business opportunities, which might also be a meaningful way for utility holding companies to be successful.

[4] See for example:

- Dr. Karl McDermott, "Cost of Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation," Edison Electric Institute, June 2012,
- Lowry, Mark Newton, et al. *Alternative Regulation for Evolving Utility Challenges: An Updated Survey*, prepared for the Edison Electric Institute. January 2013.

[5] Lehr, Ron (2013). *Utility and Regulatory Models for the Modern Era*. America's Power Plan. <http://americaspowerplan.com/site/wp-content/uploads/2013/10/APP-UTILITIES.pdf>

[6] This unintended consequence is commonly known as the Averch-Johnson effect after the two economists who first described it. See: Johnson, H. and L. Averch 1962. "Behavior of the Firm Under Regulatory Constraint." *American Economic Review.* 52:1052-69.

[7] Harvey, Hal and Sonia Aggarwal (2013). *Rethinking Policy to Deliver a Clean Energy Future.* America's Power Plan. <http://americaspowerplan.com/site/wp-content/uploads/2013/10/APP-OVERVIEW.pdf>

[8] Under traditional cost-of-service regulation, utility motivated to reduce costs insofar as this will increase profits between rate cases. If rate cases are infrequent, this cost-cutting motivation will persist over time. However, the industry has seen an increased frequency of rate cases as well as an increased number of balancing accounts (e.g. fuel adjustment clauses) that reduce the incentive to reduce costs. The longer regulatory lag under certain PBR is intended in part to bolster the incentive for utilities to reduce costs.

[9] A comprehensive list of potential performance measures can be found in: Shumilkina, Evgenia. *Where Does Your Utility Stand? A Regulator's Guide to Defining and Measuring Performance*. The National Regulatory Research Institute. August 2010.

[10] Gimon, Eric et al (2013). "A New Approach to Capabilities Markets: Seeding Solutions for the Future." *Electricity Journal.* <http://www.deepdyve.com/lp/elsevier/a-new-approach-to-capabilities-markets-seeding-solutions-for-the-XkjsB1R6d0>

[11] For example, see: http://docs.cpuc.ca.gov/published/FINAL_DECISION/91249-16.htm

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[14] Shrader-Frechette, Kristin. *What Will Work.* Oxford University Press, 2011. P. 81.

[15] See Xcel's August 14, 2009 Application, p1: https://www.dora.state.co.us/pls/efi/EFI_Liberty_API.View_Liberty_Image?p_doc_id=3461836

[16] See Xcel's June 15, 2011 Application: https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=114977&p_session_id=

[17] See CO PUC's Decision C10-0267: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=33859

[18] See CO PUC's Decision C12-0294, at p6 https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=150022

[19] While some carbon offsets were purchased, the bulk of the REC sales margins collected for this purpose was ultimately returned to customers at the conclusion of the pilot period.

[20] SBX1 2 http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.html
[21] Innovation Electricty Efficiency, "State Electric Efficiency Regulatory Frameworks," July 2013, http://www.edisonfoundation.net/iee/documents/iee_stateregulatoryframe_0713.pdf
[22] Hayes, S. Et al. "Carrots for Utilities: Providing Financial Returns for Utility Investments in Energy Efficiency" *ACEEE*, January 2011, http://www.aceee.org/research-report/u111
[23] In 2008, Massachusetts passed the Green Communities Act, which requires utilities (in coordination with an advisory council) to develop a three-year statewide EE plan. This plan established the performance incentive described here. See: D.P.U. Orders 09-116 through D.P.U. 09-120, http://www.ma-eeac.org/Docs/6_DPU%20Proceedings%20Page/1-28-10%20DPU%20Order%20Electric%20PAs.pdf
[24] Adapted from: http://www.ma-eeac.org/Docs/7_Presentations/2012/07_July%202012/EEAC_PerformanceIncentivesConsultant_072312F.pdf slide 8.
[25] http://www.ma-eeac.org/Docs/6_DPU%20Proceedings%20Page/1-28-10%20DPU%20Order%20Electric%20PAs.pdf
[26] See at p 130: http://www.ma-eeac.org/Docs/5.1_Annual%20Reports/2012/Electric/NSTAR%20Electric%202012%20Annual%20Report.pdf
[27] That yearyearIn 2007, the company'scompany'sMidAmerican's total Net Operating Income from ititits regulated electric utility business was approximately $280280289 million. $40.8 million of this available for sharing, approximately 42% of which went to MidAmerican customers.
[28] System Average Interruption Frequency Index (SAIFI) is a commonly used indicator for reliability.
[29] Customer Average Interruption Duration Index (CAIDI) is a commonly used indicator for reliability.
[30] ComEd Multi-Year Performance Metrics Plan, 2012, https://www.comed.com/Documents/customer-service/rates-pricing/rates-information/proposed/Exhibit_1_0_Performance_Metrics_Plan.pdf
[31] *RIIO: A New Way to Regulate Energy Networks, Final Decision.* Rep. no. 128/10. Office of Gas and Electricity Markets, Oct. 2010. Web. Oct. 2011. <www.ofgem.gov.uk>
[32] *Handbook for Implementing the RIIO Model.* Handbook. Office of Gas and Electricity Management, 4 Oct. 2010. Web. Oct. 2011. <http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/RIIO%20handbook.pdf>. Pp 31.
[33] Fox-Penner, Peter et al. *A Trip to RIIO in your Future?* Public Utilities Fortnightly. October 2013.
[34] *Handbook for Implementing the RIIO Model.* Handbook. Office of Gas and Electricity Management, 4 Oct. 2010. Web. Oct. 2011. Pp 81.
[35] *UK Utility Incentives: Applications to U.S. Clean Energy Transition.* Joshua Smith and Ron Lehr. 2013.
[36] Kelly, Andrea. *Utility Business Models – RIIO.* Presented to the Committee on Regional Electric Power Cooperation, October 2013. <http://www.westgov.org/wieb/meetings/crepcfall2013/present/a_kelly.pdf>
[37] Pentland, William. *Maryland's Grid Resiliency Model May Galvanize New Wave of Deregulation.* Forbes. 13 July 2013. <http://www.forbes.com/sites/williampentland/2013/07/13/marylands-power-grid-resiliency-policy-may-trigger-new-wave-of-industry-deregulation/>
[38] Advanced Energy Economy. *Creating a 21st Century Electricity System for New York State.* 26 February 2014. <https://www.aee.net/initiatives/21st-century-electricity-system.html#ny-state-energy-industry-working-group>