REPORT TO THE CALIFORNIA PUBLIC UTILITIES COMMISSION

Performance Based Regulation

Theory and Applications to California

Dan Aas
UC Berkeley
Goldman School of Public Policy and Energy & Resources Group
5/5/2016

Acknowledgements

I would like to express my thanks to Scott Murtishaw of the CPUC for offering me the opportunity to work on this project, and for numerous comments that improved my analysis. Thanks are due as well to Kristin Ralff-Douglas of the CPUC and Devra Wang, who were very helpful in pointing out several key issues that were worth investigating in order to evaluate the efficacy of PBR mechanisms. Finally, I am thankful to the following individuals who I spoke with that offered critical insights including: Sonia Aggarwal (Energy Innovation), Merrian Borgeson (Natural Resources Defense Council), Eddie Burgess (Strategen), Ralph Cavanagh (Natural Resources Defense Council), Michael Colvin (CPUC), Karl Danner (CPUC), Marcel Hawiger (The Utility Reform Network), Benjamin Mandel (NYU Guarini Center), Rolf Nordstrom (Great Plains Institute), Andy Satchwell (Lawrence Berkeley National Laboratory), Rich Sedano (Regulatory Assistance Project), Lee Schavrien (San Diego Gas & Electric Company), Lisa Schwartz (Lawrence Berkeley National Laboratory) and Melissa Whited (Synapse Energy Economics).

Executive Summary

A combination of technological and policy progress means that California's electric power sector will undergo rapid changes over the coming years. An industry that has in the past met increasing load via centralized power plants will need to implement large quantities of distributed energy resources. Further, the energy efficiency savings in California will double by 2030. All of these changes are occurring in an industry that is still largely regulated as a natural monopoly.

Utility regulation aims to provide universal safe and reliable electricity while ensuring that monopoly service providers charge a fair price. Cost-of-service-regulation (COSR) has been used for over a century to accomplish these goals. Today, however, it is an open question as to whether COSR is able to accomplish an evolving set of societal goals; goals that range from customer choice to rapid decarbonization of the power sector.

Cost-of-service regulation, with guaranteed rates of return on prudently incurred capital investments, excels at providing the stable business environment necessary to attract investments needed to build out large quantities of infrastructure. However, a low-load growth future—with high penetrations of DERs—may not require the same magnitude of infrastructure as the COSR model was designed to fund. However, grid investments are still needed to both integrate DERs and to fund general turnover of existing assets. The challenge for regulators to consider is whether the COSR model is able to facilitate a transition to a high DER future in both a technically- and cost-effective fashion.

Performance-based regulation (PBR) has been implemented in many natural monopoly industries as an alternative to COSR. PBR mechanisms are designed to control costs by overcoming the information asymmetries between regulators and firms. To accomplish this goal, PBR mechanisms establish an exogenously benchmarked price- or revenue-cap. If utilities are able to identify cost savings, then they may earn a higher return. On the other hand, if utilities exceed their revenue-cap, then they will incur losses. This combination of an upside and downside replicates the market discipline of a firm that faces competition.

Over the past two decades, the definition of which regulatory reforms constitute PBR has evolved. Today, the term PBR is sometimes used to refer to targeted performance incentive mechanisms (PIMs). PIMs are payments or penalties tied to performance criteria. California has a long and complicated history using PIMs to motivate utility behavior against outcomes ranging from workplace safety to energy efficiency. Other jurisdictions, namely Minnesota and New York, are actively considering potential uses for PIMs as a means to accommodate a variety of grid modernization and environmental outcomes. This paper describes emerging best practices in the development and design of PIMs. Hypothetical PIMs are developed following these best practices for two areas of potential interest to California regulators, natural gas methane leaks and residential time-of-use participation.

The flexibility of PIM mechanisms affords regulators a tool to motivate utility performance against a wide variety of potential desired outcomes. On the other hand, implementing a system that reorients utility behavior may require earnings attached to PIMs to be set at levels that are on par with earnings that can be found in traditional investments. If PIM based earning potential is high, the phenomena of 'teaching to the test' may be an issue, where utilities overemphasize the performance areas in which they are incentivized to the exclusion of necessary investments elsewhere.

In the past five years PBR models have emerged that use a combination of revenue-caps and targeted PIMs. These models, termed Integrated PBR in this paper, tie utility earnings to specific performance areas, but also use a revenue-cap to provide utilities an opportunity to earn on areas of performance that are not easily targeted by PIMs. At present, the model of PBR used in the United Kingdom offers the best example of an Integrated PBR mechanism. The structure of the electricity industry in the United Kingdom is very different from that of California, so this paper concludes with a sketch of how an Integrated PBR mechanism might be used to facilitate least-cost-best-fit distribution system investments.

The examples offered in this paper are meant to be illustrative of how PBR could be used in both targeted and comprehensive fashions. A key takeaway from this paper is that PBR mechanisms hold the potential to better align the outcomes of utility regulation with the goals of society. In fact, simply going through the process of investigating PBR mechanisms offers regulators, utilities and stakeholders the opportunity to lay out their vision for what those goals ought to be.

Contents

1. Intro

The term performance-based regulation (PBR) is used to describe a wide variety of tools regulators can use to incentivize utility accomplishment of desired outcomes. The initial theory and application of PBR was aimed at providing incentives that encourage natural monopolies to behave more like competitive firms. In this context, mechanisms were developed that forced utilities to identify cost savings and operate more efficiently. Over time, the use of PBR mechanisms expanded to include a variety of risk/reward mechanisms to incentivize utilities to accomplish both economic and non-economic policy outcomes.

PBR does not have one definition. In some—typically historical—contexts, PBR mechanisms are aimed almost exclusively at incentivizing increased economic efficiency within utilities (Joskow 2014). This form PBR came directly from the economics literature, where it was often termed 'incentive regulation'. In other contexts, PBR refers to use of targeted performance incentive mechanisms (PIMs) to motivate performance against specific outcomes (Aggarwal and Burgess 2014). Still other forms PBR include some combination of both economic efficiency and targeted outcomes (Mandel 2015a). These different formulations are reflected in the acronym PBR having multiple-meanings, with some defining the R as 'ratemaking' and others as 'regulation.'

PBR was first implemented in the 1980s when it was offered as a superior alternative to conventional cost of service regulation (COSR). After an initial burst of interest in PBR in the 1990s, enthusiasm for the concept waned by early in the following decade as regulatory reforms in general fell out of favor. Recently however, a number of thought leaders (Lehr 2013, Harvey and Aggarwal 2013), regulators (Ofgem 2010) and utilities (Lowry et al 2013) have espoused the virtues of performance-based ratemaking (PBR) to meet the needs of an evolving power sector.

In most cases, PBR oriented papers and regulatory proposals are part of broad—sometimes labeled 'utility of the future'—initiatives (e21 Initiative 2015, NY PSC 2014a) meant to address changes in power sector technologies and public policy goals. Assessments of the implications of these changes are similarly heterogeneous. To some, the COSR model that facilitated the electrification of the United States is outdated, and so are the utilities that are regulated under it (Wellinghoff and Tong, 2014). To others, incremental revisions and reforms to the present utility regulatory model will be sufficient. In this context, both pundits and policy-makers have used the term PBR to describe tools through which utility incentives can be better aligned with a changing power sector.

Much of the modern literature related to PBR takes the form of either visionary narratives of PBR's role in a changing power sector or targeted applications to specific policy goals. The goal of this paper is to first describe the range of approaches to incentivize utility behavior that are described as PBR. With a range of PBR definitions identified, attention is then turned to how PBR might better align utility incentives with California's public policy goals—particularly those goals related to clean energy and greenhouse gas emissions reductions. Rather than propose what form of PBR would work best for California, this paper describes a decision-making framework that policymakers and parties can use to evaluate what incentives utilities should face. This framework is applied at a high level to key CA public policy areas, where combinations of targeted and more comprehensive PBR approaches are considered.

2. PBR Alternatives as an Alternative to Cost-of-Service

2.1 Incentives under Cost-of-Service

Cost of service, also called 'rate-of-return', regulation has been the dominant model through which regulators seek to maximize social welfare in natural monopoly markets. Natural monopolies exist where it is more economically efficient for one firm to serve a market than multiple companies. Such markets tend to exist in industries with high fixed-costs and economies of scale. Under COSR, the price level that maximizes societal welfare, while allowing firms to stay viable, is where price equals the average cost of producing a good. So under a simple COSR model regulators have two goals. The first goal is to identify a fair-rate of return on capital expenditures (CAPEX) for utilities so that they can attract the large amounts of investment needed to fund high fixed-cost projects. The second goal is to ensure that utilities investments are prudent.

The advantage of COSR is that it creates a stable business environment in which large capital investments—like the United States electric grid—can be identified, financed and built. However, by the 1970s many regulators and economists came to believe that the theoretical advantages of COSR were not being realized in practice. Critics of COSR hold that the information asymmetries between utilities and regulators make it difficult to accurately assess whether firms minimize their costs. This issue becomes especially acute when large amounts of the data and expertise regulators rely on to make decisions come from the regulated firm itself. In addition to these information issues, critics also point out that utilities can be incentivized to over-spend on the capital investments on which they earn their rate of return. CAPEX incentives create the potential for moral hazard, where utility managers' fiduciary responsibility to shareholders is misaligned with least cost investments.

2.2 Revenue Cap PBR

Revenue Cap PBR[1] mechanisms were initially developed to address the information asymmetries in COSR. In other words, the goal of Revenue Cap PBR is to encourage improvements in the economic efficiency of natural monopoly utilities[2]. Under PBR, revenue-caps are applied via formulas that are specified in advance and typically take the form of:

$R_{new} = R_{old} * (1+ \text{inflation} - X) +/- Z$

Where:

- **R_{old}** is typically revenue in a test year. In some forms of PBR this revenue requirement is set ***exogenously*** through use of statistical benchmarking against peer utilities or simulation of an efficiency frontier using cost optimization techniques
- **Inflation** is tied to an index that most closely matches the price of utility inputs—often in practice the consumer price index, but producer price indices have been used in some jurisdictions
- **X** represents the rate of productivity improvement that is targeted. The productivity level targeted is always derived ***exogenously***
- **Z**-factors allow for costs that are not under utility control to be passed through

A declining revenue-cap simulates the cost pressure a firm in a competitive market would face from other market participants. However, cost-pressure is not the only mechanism through which competitive firms are motivated to pursue an efficient outcome. In an unregulated market firms that identify cost reductions that are unavailable to competitors earn increased returns. In Revenue Cap PBR this profit motive is replicated through a sharing factor, where utilities retain some portion of cost-savings.

The final hallmark of a Revenue Cap PBR plan is an increased period of time between rate-cases, often called ‘regulatory lag.’ When combined with allowed retention of cost savings, longer periods between rate-reviews increases the amount of excess earnings a utility can retain and pass on to shareholders (Comnes et al 1996). Supporters of Revenue Cap PBR also hold that a

[1] In original formulations of PBR, price-cap regulation was the preferred approach. Under price-cap regulation utilities are able to increase profits by selling more electricity at a lower price. Today, many jurisdictions have switched to revenue-cap regulation to remove the ‘throughput incentive’.
[2] A key element that separates Revenue Cap PBR from revenue-per-customer decoupling is that the overall revenue requirement is determined via an exogenous benchmark.

longer period between rate-cases allows utilities to spend more time innovating and less time focusing on the next regulatory review.

Many of the features of Revenue Cap PBR are familiar to those involved in California utility regulatory policy. California uses a multi-year rate-plan (MRP), attrition adjustments and Z-factors. So, to some degree, California's present system has PBR-like features. However, a key distinction between an MRP system like that used in California and PBR mechanisms that better match the economic theory of incentive regulation is how the 'x-factor' is set. In most MRP regulatory systems, 'x- factors' (often called 'attrition escalators') are negotiated quantities. In contrast, jurisdictions that have implemented a form of PBR that is consistent with incentive regulation use either benchmarking or simulation techniques to define exogenously determined economic efficiency goals. By setting x-factors exogenously, Revenue Cap PBR mechanisms are meant to address the information asymmetry challenges of COSR.

2.3 Performance Incentive Mechanisms

Over time, the purpose of PBR has expanded from an almost exclusive focus on economic efficiency to consideration of a broader set utility policy goals. Many targeted utility performance incentives were initially used to mitigate any pernicious cost-cutting incentives (e.g. safety or reliability) of Revenue Cap-PBR (Comnes et al 1996). More recently however, a number of PIMs have been implemented or proposed whose goals are separate not explicitly tied to cost. These new PIMs reflect an overall shift in the goals of utility regulation to include a diverse set of environmental and customer engagement oriented outcomes in addition to traditional cost-based goals.

Expanded use of PIMs that are designed to accomplish goals apart from safe and reliable provision of least-cost power are a core feature of both proposed and existing PBR mechanisms. Table 1—adapted from the recently published guide *Utility Performance Incentives: A Handbook for Regulators*—outlines incentives that have been proposed or implemented that are aligned with 'traditional' performance areas and those that address 'innovative and emerging' areas (Whited et al 2015).

Table 1: Traditional and Emerging Utility Performance Areas

Traditional Performance Areas	Innovative and Emerging Performance Areas
• Reliability • Customer satisfaction • Safety • Plant performance • Cost	• System efficiency • Customer empowerment (demand side resources) • Facilitating third-party participation • Environmental goals

PIMs need not all be tied to financial risks or rewards. For instance, Ontario regulators have developed a PBR mechanism that tracks a large number of performance areas, the majority of which are not tied to earnings (Mandel 2015b). A measurement only approach allows regulators and utilities to gain experience measuring and performing against new metrics. Financial incentives can be instituted after utilities and regulators have sufficient experience with measuring a new performance area.

While in the past PIMs were typically a small component of overall utility revenues, today many PBR proposals focus on targeted incentives as a means to substitute for a significant share of traditional cost-based remuneration (Aggarwal and Harvey 2013). Utilities create value for shareholders by earning a rate of return in excess of their cost of capital (Kihm et al 2014). Under a traditional regulatory model, a rate of return is set to enable utilities to exceed their cost of capital in order to attract the investment needed to build and maintain large amounts of infrastructure.

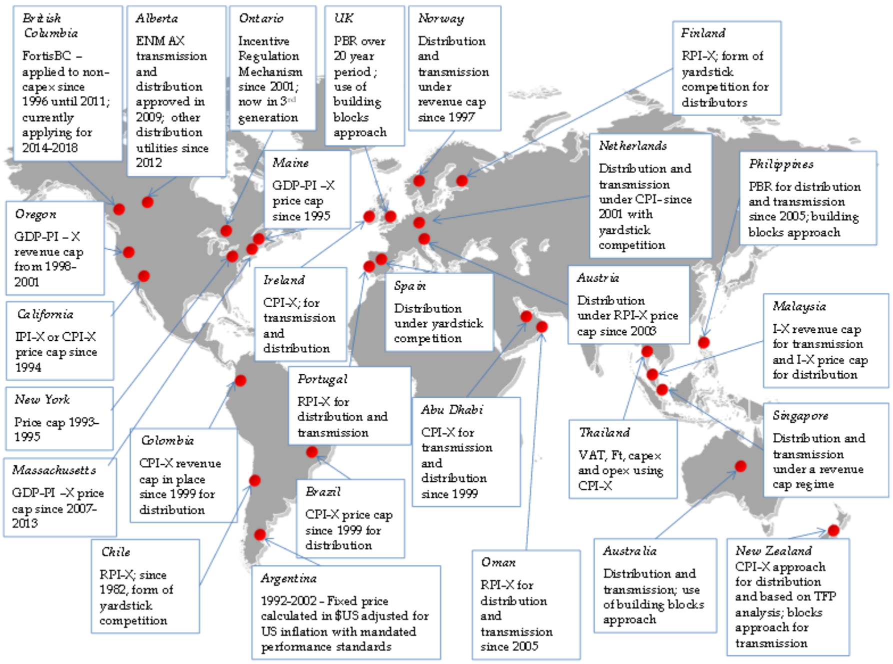
Some PIM oriented proposals suggest that this traditional approach to developing a rate of return no longer effectively aligns utility motivation with societal value. An alternative approach could be to lower utilities' rate of return on their capital expenditures while offering sufficient PIM-based payments to continue to attract private capital (Kihm et al 2015). If utilities' base rate of return were lowered to the cost of capital, shareholder value could only be created via PIM revenues that reflect achievement against the goals society values most

3. PBR: Early Applications and Modifications to Theory

The economic theory of PBR was conceived as a means to induce a natural monopoly utility to act more like a competitive firm. The economics literature (Laffont and Tirole 1986) focuses on the information asymmetries in COSR regulation between utilities who have substantial knowledge about their costs and the regulators who must assess the prudence of utility expenditures. This information asymmetry creates the potential for regulatory failure that, like market failures, leads to economically inefficient outcomes (Friedman 2002). In PBR theory, economic efficiency outcomes superior to those under COSR can be accomplished by establishing an exogenously set declining real price-cap that forces utilities to identify cost savings (Joskow & Schmalensee 1986). Those utilities that identify cost savings are able to retain some portion as rents, while those that fail to decrease costs will incur losses.

PBR can be applied to a variety of what are often described as 'network industries,' and early applications of theory occurred in the telecommunications and rail sectors (Comnes et al 1994). The first introduction of PBR for electric utilities occurred in the United Kingdom, where a price-cap form of PBR was introduced in the early 1990s. Additional PBR mechanisms were rolled-out soon after in several jurisdictions including, notably, California (Figure 1). These early applications of PBR were explicitly meant to drive cost savings (Jasamb & Pollitt 2007, Myers & Strain 2000).

Figure 1. PBR Implementation throughout the World.



Source: London Economics, 2010

An additional goal of PBR in many jurisdictions was to decrease the administrative burden of the COSR model (Comnes et al 1994). From a regulator's perspective, increased regulatory lag meant that the recurring cycle of rate-cases could be slowed and more time devoted to goals beyond prudence reviews. In fact, the combination of cost reduction incentives and increased flexibility to earn unregulated earnings led some to describe PBR as a means to complement reforms towards more competitive markets that were underway during the 1990s (Comnes et al 1994).

Practitioners of PBR soon realized that what was a relatively straightforward regulatory strategy in the economics literature became complicated in practice. These early implementers identified the following issues and modifications:

- **Cost-cutting imperatives deteriorated service quality**

  Of primary concern to regulators is that, from society's point of view, not all cost-savings are created equal. In response to cost pressure a utility under PBR may reduce service quality or safety expenditures to unacceptable levels (Jenkins 2011). In fact, early applications of PBR in U.S. electric utilities bore this prediction out as service quality declined (Jasamb & Pollitt 2007, Ter-Martirosyan & Kwoka 2010). To address these issues, regulators began to institute a series of targeted PIMs to discourage service quality deterioration (Jasamb & Pollitt 2007). These targeted service quality incentives represented an initial departure from 'pure' PBR where the regulator simply aims to push a utility to reduce costs.

- **Rate-formulas incentivized utilities to 'game' their base year costs**

PBR is often referred to as an evolution from COSR rather than a revolution. This is especially true of the establishment of base year costs from which Revenue Cap PBR revenue adjustments are applied. Under early forms of PBR this initial revenue requirement was developed using test-year accounting techniques that do not differ substantially from COSR. Utilities faced with a declining 'x-factor' are incentivized to inflate costs in the test year (Comnes et al 1994). Those that succeed in establishing a higher base allowance are able to earn rents without sharing real efficiency gains with consumers.

An innovation to PBR theory called a 'menu-of-contracts' approach was developed as a means to address this pernicious incentive (Laffont & Tirole, 1993). The menu-of-contracts approach to PBR works by offering utilities a choice between relatively high base returns with low upside or relatively low base returns with higher upside than under the more guaranteed option. Figure 2 illustrates a simplified two-option menu of contracts. Under this scenario, a lower cost firm that is able to reduce its expenditures by $500 million would be able to earn a $1.6 billion dollar return on its investment, rather than the $1 billion return under the more guaranteed option.

Figure 2: A Simple Menu-of-Contracts

	Option 1 – High guarantee/ low upside	**Option 2 – Low guarantee/ high upside**
Allowed Revenues	$10 billion	$9.5 billion
Base ROE on capital	9%	8%
Max Efficiency Incentive	100 basis points	350 basis points
Max ROE	10.%	11.5%
Max Return	$1 billion	$1.6 billion

In practice, regulators that use this approach offer a larger variety of menu options to take into account uncertainty of firms' cost structures (Joskow 2014). Regulators' goal in constructing a menu-of-contracts is to ensure that it is ‘incentive compatible,’ meaning that utilities are always most highly rewarded when they meet their ex ante prediction of expenditures (Jenkins and Perez Arriaga, 2014). By offering utilities a potentially higher reward in return for more cost savings, a menu-of-contracts approach allows both regulators and utility managers to reveal additional information about utility cost structures.

- **Revenue Cap PBR mechanisms are not well suited to capital expenses that vary substantially from year to year**

Jurisdictions that implemented PBR have also been faced with the challenge of including capital expenditures in PBR mechanisms. Capital investments tend to be ‘lumpy’ in nature, meaning that many jurisdictions that have implemented PBR placed large amounts of CAPEX in pass through ‘Z-factors’—effectively maintaining COSR for a large portion of utility expenditures (Joskow 2014). To increase the amount of utility expenditures that are subject to PBR incentives, some jurisdictions have implemented what are sometimes labeled 'K-factors' (Brown et al 2014). These adjustments to the typical revenue-cap formula are similar to Z-factors in that they track costs which do not easily fall into the price or revenue cap. Where they differ is that some financial incentive is applied, typically connected to a targeted level of spending. A regulator could establish a K-factor that includes some degree of shared cost savings and overruns between ratepayers and utility shareholders.

The ability of utilities to make large capital expenditures is generally considered to be among the main advantages of their status as regulated monopolies. Therefore, care should be taken when implementing an incentive to lower spending on capital investments. Too powerful of an incentive to cut CAPEX in the near-term may cause greater long-term costs or rate-shocks as needed investments are delayed. An example of potential issues with limiting CAPEX occurred in Maine where Central Maine Power’s PBR mechanism was found by regulators to have led to long-term under-investment in capital. In 2014, this PBR mechanism was scrapped and a large rate-increase was required to cover deferred capital investments (Whited 2015).

A potentially more successful method to include capital expenditures in PBR has recently been implemented in the United Kingdom. Ofgem, the utility regulator in the UK, has attempted to manage the issue of CAPEX in PBR by fixing the capitalized proportion of total expenditures (TOTEX) ex ante (Ofgem 2010). For instance, in planning for the PBR period ahead, regulators and utilities might set the proportion of TOTEX that can be capitalized at 0.6. A utility that is allowed $1 billion expenditures will earn a rate of return on $600 million, regardless of whether their final CAPEX equals the latter amount.

TOTEX revenue caps are then paired with a menu-of-contracts approach that incentivizes the utility to reveal its efficient overall expenditures and most cost-effective mix of CAPEX and OPEX (Mandel 2014). In addition to better incorporating CAPEX expenditures, a TOTEX approach allows utilities to increase the proportion of their spending that is OPEX[3]. In an energy future where utilities' role focuses more on system integration than assets, the ability to spend more on OPEX (e.g. software or staff expertise) could lead to greater gains for society than incentives oriented around building more infrastructure.

4. PBR: A Continuum of Modern Approaches

Applications of PBR have typically been aimed at incentivizing reduced costs compared to COSR, with PIMs serving as a means to prevent degradation in core areas of utility service quality. However, forward looking discussions of PBR have placed an increased or even sole emphasis on PIMs to achieve policy aims. PIM oriented mechanisms are not just proposals in think-pieces; several jurisdictions have either implemented or are actively considering forms of PBR that are increasingly designed with the achievement of targeted policy goals in mind. For instance, the RIIO system in the UK lists among its targeted outcomes innovation and development of a distribution systems that can facilitate greenhouse gas emissions reductions (Ofgem 2013). These outcomes are tied to specific performance incentives, some of which include financial upsides and downsides. The New York PSC has recently proposed a series of performance incentives designed to spur the development of expanded use of distributed energy resources. Ontario, Illinois and Hawaii are examples of jurisdictions that have considered or implemented regulatory structures that rely to a greater degree on PIMs than conventional COSR.

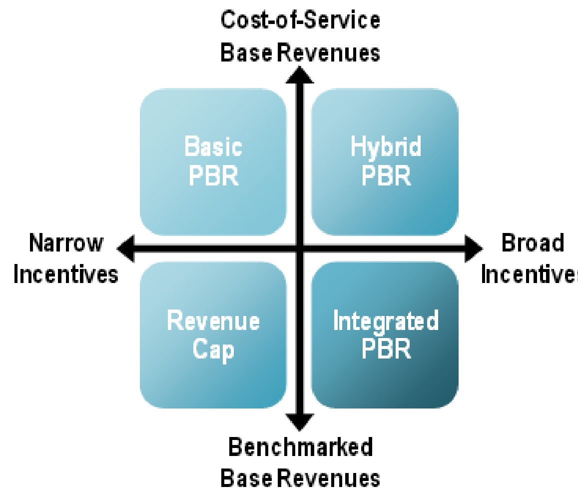
4.1 Interactions Between Revenue Cap PBR and PIMs

Most PBR mechanisms and proposals include some combination of PIMs and Revenue Cap PBR. The nature of the interaction of these PBR variants depends in large part on regulators' goals. The traditional goal of PBR is to achieve economic efficiency. If this is the case, PIMs are a secondary consideration aimed to ensure that the cost-reduction incentives of Revenue Cap PBR do not lead to degraded service quality, customer service and safety. However, it could be argued today that the outcomes PIMs support are increasingly fundamental to the policy goals of utility regulators. In this framing, the role of Revenue-Cap PBR could be to ensure that utility costs are minimized, subject to accomplishment of PIM defined policy goals.

Mandel has developed a useful typology of PBR mechanisms that include varying levels of focus on economic efficiency and targeted performance (Mandel 2015a). They are:

[3] The NY PSC recently investigated the TOTEX approach for their recent Track 2 Report on the Reforming Energy Vision Docket. They found that a TOTEX approach would likely not be allowed under the New York State Public Utilities Code and may also be inconsistent with Financial Accounting Standards Board. The former is a state specific issue that may not come into play in CA, while the latter is a broader issue.

- **Basic PBR (Limited PIMs, Limited Formula)** – Where the majority of utility revenues are subject to COSR, but modified with multi-year rate plans and/or decoupling. PIMs are used to improve core services; some states may include energy efficiency incentives. California's present regulatory system could be considered a form of Basic PBR.



- **Revenue Cap (Limited PIMs, Formula w/ exogenous 'x-factors')** – Where a revenue (or price) cap is established with adjustments based on desired productivity improvements. In this model PIMs are used sparingly, typically to prevent degradation of core services. The UK (prior to RIIO), Australia and several European and Latin American countries have used Revenue Cap regulation and its antecedent price-cap regulation.

- **Hybrid PBR (PIMs, Limited Formula)** – Similar to Basic PBR in that COSR regulation is retained. The approach diverges in that it envisions broad use of performance incentives to accomplish social goals and to meet utilities' revenue requirement. New York's regulatory system may resemble a form of Hybrid PBR once the Reforming Energy Vision (REV) process is completed.

- **Integrated PBR (PIMs, Formula w/ exogenous 'x-factors')** – An Integrated PBR model would include both a revenue cap and broad use of targeted incentives. The best examples of initial attempts at such an approach are the UK RIIO and to a lesser degree the Ontario Renewed Regulatory Framework for Electricity Distributers models.

5. Identifying Potential PBR Structures and Targets for California

On the PBR continuum laid out above, California's current regulatory structure falls into the Basic PBR Category. The combination of three year GRC cycles, revenues set in advance, retention of cost savings/overruns, and prudence reviews mean that California utilities face greater incentives to control costs than a traditional COSR model (Brown et al 2014). The current system also includes a number of existing PIMs aimed to encourage performance against targeted outcomes. For instance, the three large IOUs in California face PIMs for energy efficiency, SDG&E has reliability incentives and Southern California Gas as incentives related to its wholesale gas procurement costs.

California has adopted a series of clean energy and climate change mitigation policies that shape the state's utility regulatory model. These policies include the state's economy-wide greenhouse gas emissions cap, aggressive renewable portfolio standard, goals for deep energy savings and a number of mechanisms to expand use of distributed energy resources [DERs] (California Energy Commission 2015). California's regulatory approach has already evolved to support these goals.

If policy-makers believe that there is insufficient incentive to control cost under the present Basic PBR system, then adoption of an exogenously set revenue-cap approach may be advantageous. If regulators are largely satisfied with utilities' cost-performance, but have concerns about their incentives to meet state environmental policy goals, then an expanded use of PIMs in a Hybrid PBR system may be appropriate. If both cost and policy-consistency are of concern, then the Integrated PBR approach adopted in the UK may be most appropriate. Table 2 illustrates how existing features of California's utility regulatory model could be modified to incorporate additional elements of PBR.

Table 2: CA BAU PBR Features and Opportunities to Expand Incentives

	Present		**Increased PBR**	**Goal**
Regulatory Lag	Three-year multi-year rate plan	⇨	Extended to five years or beyond	Increased incentive power, decreased regulatory burden
Revenue-Requirement	Future test year with negotiated attrition escalators	⇨	Future test year with productivity 'x-factors', both exogenously set using a menu-of-contracts based on benchmarking or simulation techniques	Encourage greater levels of economic efficiency within utilities
PIMs	PIMs for EE, Reliability (SDG&E only)	⇨	PIMs for a broader subset of CA energy policy goals	Realign utility motivations to better reflect non-cost oriented policy goals

California's present regulatory system is not without its flaws. Under BAU, utilities' primary means of creating shareholder value is to expand their rate-base. Policy goals like increased use of DER and customer price responsiveness are partially aimed at reducing overall system costs, which means a reduction in utility CAPEX. These policies' goals may also involve increased utility OPEX on which utilities cannot normally earn a return under the current regulatory model. Further, electric utilities are generally insulated from price fluctuations in fuel-costs given that these costs are passed through to consumers. This transfers a portion of the risk cost of procuring fossil energy resources to ratepayers, potentially distorting utility motivations in resource planning.

Based on the aggressive climate and clean energy policy goals adopted by the State of California, and the central role the CPUC has in implementing these goals, the hypothesis of this paper is that any move towards more use of PBR mechanisms should at minimum consider expanded use of PIMs. Adopting increased regulatory lag or use of an externally benchmarked formula rate-plan are both worth considering insofar as there is a perception that the present regulatory model will not be sufficient to incentivize economically efficient outcomes.

5.1 A Proceeding by Proceeding Approach to Consider PBR

If PBR is worthy of consideration given California's policy goals, how should regulators go about determining what PIMs or Revenue-CAP PBR mechanisms are most appropriate? While a variety of PBR approaches have been either been used or proposed, they can generally be separated into those approaches that consider PBR elements during the normal course of regulatory business, and those that open a separate proceeding to conduct a thorough examination of whether present regulation is aligned with societal goals.

A piecemeal approach to implementing additional PBR features involves considering PIMs in a proceeding-by-proceeding fashion. For instance, a proceeding centered on energy storage might consider a risk/ reward continuum on some elements of utility performance against the proceeding's goals (e.g. cost, timing of deployment, etc…). The advantage of this approach is that the implementation of a new PIM can be incorporated into a thorough investigation of a discreet policy decision. Further, no new proceedings would be needed, so the initial administrative burden of implementing PIMs is lessened.

While a piecemeal approach benefits from its consistency with present regulatory practice and ability to complement in-depth policy development, the approach lacks in its ability to prioritize preferred outcomes. The development of performance-based incentives is an opportunity to identify what aspects of utility regulation need to be better aligned with public policy goals. Additionally, by implementing PBR proceeding-by-proceeding regulators are less able to assess trade-offs between incentive mechanisms. Finally, a proceeding-by-proceeding approach will make it more challenging for regulators to assign incentive magnitudes that are consistent with policy goals. If magnitudes are set too low, then there may be limited incentives for utilities to change their behavior. If magnitudes are set too high, then utility incentives could be distorted to over-emphasize performance against the monetized goals to the detriment of other important outcomes.

5.2 A Thorough Approach to Consider PIMs and Formula PBR

Jurisdictions that have moved forward with PBR mechanisms in recent years have done so in a comprehensive fashion. The New York REV process and UK RIIO system are notable examples of where regulators have engaged in thorough reviews of utility incentives.

When considering implementation of PBR, regulators should base their work on what policy goals/outcomes society seeks from utilities. An approach to considering the use of PBR mechanisms should therefore be based on an identification and prioritization of key policy goals. Knowing what goals matter most to society will direct regulators' attention to the development of metrics and incentive designs that best balance desired outcomes. The mechanisms used to accomplish these outcomes may range from targeted PIMs to application of 'x-factors' that incentivize cost-containment. Which type(s) of incentives are identified depends in large part on the performance of the BAU regulatory structure vis a vis high priority goals.

A dedicated proceeding designed to consider modifications to the state's regulatory model benefits from its ability to consider reforms using a stepwise approach. A stepwise approach allows regulators and parties to pair representative metrics to policy goals, and to consider the degree to which performance against these metrics should be tied to financial outcomes. A step-by-step process[4] to implement a form of PBR that meets the goals of regulators and ratepayers could work as follows:

1. Identify and prioritize **policy goals** that regulators and the public want utilities to achieve.
2. Develop metrics for policy goals that are **measurable**. Metrics need not be entirely within utilities' control, but they should be responsive to changes in utility performance or attention.
3. Determine whether or not to tie metric performance to **compensation** or to have the performance area be **measurement only**. This decision depends in large part on whether regulators are concerned that unfamiliar performance areas, or areas where new metrics are being assessed, might be susceptible to **gaming** or unintended **perverse outcomes.**

[4] This process is in large part derived from the steps to develop an individual PIM laid out in by Whited et al (2015) in their recent report on performance incentive mechanisms.

4. Think through areas of **overlap** with other PIMs that are in place or are being developed. Identifying areas of overlap may be an opportunity to consolidate PIMs into the minimum necessary number.
5. Consider whether **risks and rewards** from each PIM should be **symmetrical or asymmetrical**. Upside only rewards may be most appropriate where new value is being created or where downside creates unacceptable investor perceptions of risk. When considering incentive design regulators should also consider whether or not to include a dead-band or higher returns/losses as performance diverges from targets to control for less meaningful variations in outcomes.
6. Determine what **magnitude** of financial incentives are appropriate to accomplish regulators' goals and whether incentives should be tied to some estimate of the economic value of performance or calibrated to meet an exogenous policy target (e.g. a level of public safety). Magnitude discussions should also consider whether financial risks and rewards should be capped.
7. Consider whether or not the cost-containment features of COSR regulation are sufficient to encourage efficient accomplishment of societal goals incentivized via PIMs. If the cost of achieving targeted policy goals appears to be unacceptably high, explore use of an Integrated PBR approach using an exogenously set revenue-cap, based on benchmarked or simulated estimates of efficient expenditures.

Note on Incentive Design and Magnitude:
Several jurisdictions that have implemented PIMs have applied financial risks and rewards via modifiers to utilities' allowed ROE. However, ROE adders hold the potential to incentivize utilities to increase rate-base. Lump sum incentives are a more transparent alternative and the simplest form of incentive to administer. Whited et al (2015) note that regulators can use some metric that reflects utility motivation (e.g. targeted ROE, cents per share) as a basis to develop a lump sum dollar incentive.

This approach is reminiscent of how PBR schemes have been implemented or considered in jurisdictions like the United Kingdom, New York and Hawaii. The development of RIIO in the UK was a multi-year process that involved substantial work there by regulators, utilities and civil society (Mandel 2014). This process allowed RIIO's incentives to be calibrated around customers' perceptions of 'what good service looks like'. New York's REV proceeding began with the premise that increased use of DERs would be critical to meeting the state's clean energy and resilience goals (NY PSC 2014a). As part of developing their recent Track II white paper, the NY PSC worked with parties to identify metrics that reflect the state's goals (NY PSC 2015). These metrics were then separated into those that would be subject to a financial payment and those that are measurement only. Finally, Hawaii expanded on an existing decoupling proceeding to solicit broad input from stakeholders on what performance incentives would be most appropriate to meet the state's energy policy goals (HI PUC 2014). Ultimately this process was put on hold due to the proposed sale of the Hawaii Electric Companies. Table 3 maps out what aspects of each jurisdiction's PBR development process followed the approach outlined above.

5.3 Gaming and Unintended Consequences

The potential for targeted PIMs to over incentivize some areas of performance was noted above. However, another concern is that high stakes performance incentives may lead to outright cheating or gaming of data used to report progress.

Addressing gaming of PIMs is a particularly salient concern given California's past experience with PIMs. In 1993 California instituted a price-cap PBR mechanism for SDG&E. Under its original design, SDG&E's PBR provided a formula rate plan, sharing of cost savings, a productivity improvement factor and six-year gap between rate-cases (Schavrien 2015). This PBR mechanism also included PIMs for safety, reliability and customer satisfaction. SCE adopted a similar PBR plan in 1996, while PG&E filed a PBR mechanism in 1998 that was never enacted and withdrawn in 1999 (CPUC 2001). Each of plan was implemented in the context of electric industry restructuring in order to encourage increased economic efficiency within those elements of utilities that could not be deregulated (Whited et al 2015). Explanations for why these forms of PBR were not continued in CA differ, but most include waning interest in deregulation following the California Energy Crisis and a need for increased large capital expenditures. By the early 2000s most of the features of price-cap PBR were no longer in use for both SDG&E and SCE.

The use of PIMs continued at both SDG&E and SCE after price-caps were abandoned. Any discussion of their efficacy is marred by the fact that SCE was found to have gamed its customer service and safety incentives. For customer service, SCE staff systematically biased consumer feedback towards positive reviews through self-reporting of the quality of interactions and intentionally avoiding or excluding negative customer experiences (Whited et al 2015). On safety, SCE employees under-reported injuries and recorded time lost to injury as sick or vacation days. In its investigation, the CPUC found that financial incentives were passed down to rank-and-file employees, leading to a culture that discouraged reporting of safety violations to ensure at-risk pay was received (CPUC 2007). In the end, the CPUC required that SCE refund $80.7 million in incentive payments, forgo $35 million in awards, and pay a fine of $30 million. The Commission also ordered SCE to not propose some incentive mechanisms until the 2018 GRC cycle. This episode highlights the potential for gaming of incentives that must be addressed in the design of any regulatory scheme that involves PIMs.

Table 3: Comparison of PBR Development Processes in New York, Hawaii and the UK

	New York	**Hawaii**	**United Kingdom**
0. PBR as part of existing or stand-alone proceeding?	A combination; REV was a new proceeding—PBR was included as a component	Existing proceeding; PBR was addressed as part of a docket focused on revenue decoupling	Stand-alone; the RIIO development process was designed to modify an existing PBR system
1. Consideration of broad policy goals	Yes; though with a heavy emphasis on DERs and attracting third-party capital	Yes; regulators solicited broad input on policy targets that performance metrics might address	Yes; Ofgem worked with stakeholders for several years to identify top priorities for the UK distribution system
2. Development of metrics to match goals	Yes	Yes	Yes
3. Identification of measurement only metrics?	Yes	Yes	Yes
4. Address areas of overlap	Yes, proposed PIMs in the Track II whitepaper are designed to be complementary	No, due to uncertainty of utility ownership, Hawaii chose to table further consideration of PBR at this stage	Yes, PIMs were consolidated into broad categories to capture multiple outcomes where possible
5. Incentive design	Not yet determined		RIIO contains upside only, downside only and symmetrical metrics.
6. Incentive magnitude	Not yet determined		RIIO financial incentives typically sum to about a +/- 400 basis point variation around initial allowed ROE
7. Cost containment	NY PSC staff have identified Revenue-Cap PBR as an area for future consideration		RIIO includes a revenue-cap as a core component of PBR used in the UK.

It is clear that California has a fraught history with gaming of new regulatory models and mechanisms. However, it is important to recognize that PBR mechanisms have been in use for decades in a wide variety of industries and jurisdictions. Among the multitude of other PBR experiences, gaming of incentives on the order of the SCE example do not appear to have occurred.

In their report on PIMs, Whited and Woolf suggest that starting with relatively modest incentives lowers the stakes of making an error in the implementation of new performance goals. In fact, for Ontario and the United Kingdom—two jurisdictions that have recently expanded use of PIMs as part of their PBR mechanisms—several performance areas are measurement only (Mandel 2014). Starting with a measurement-only approach allows stakeholders to develop a familiarity with the performance areas in question and lowers the risk of unintended consequences. In addition to starting measurement-only, Whited and Woolf also suggest that regulators should implement a diverse set of PIMs, identify PIMs for operational areas that are relatively isolated from one another, apply extra scrutiny to areas where existing industry standards do not already exist, and allow for PIMs to evolve over time.

6. PBR Implementation Process Applied to a Subset of California Policy Goals

California energy policy includes a number of cost, environmental and equity oriented goals. A thorough approach to expansion of PBR in California would attempt to prioritize these goals, identify metrics for outcomes that rank highly, and consider using financial incentives to motivate performance in a few areas. Mapping out what policy goals, metrics and financial incentives are most appropriate to California is beyond the scope of this paper. Instead of attempting to do so, this paper works through three examples of how PBR might be implemented in CA. The first two examples—implementation of time-of-use rates and reduced methane leaks—follow the PBR development process outlined above. The final example explores how an Integrated-type PBR system might work to help California regulators ensure that distributed energy resources are deployed in a least-cost fashion. In addition to these examples, a more comprehensive list of PIMs that are potentially applicable to CA is provided in Appendix A.

6.1 Performance Incentives for Implementation of Time-of-Use Rates

California residential electricity rates are in the process of shifting from tiered inclining block pricing to a time-of-use (TOU) approach, with implementation of default TOU rates scheduled for 2019 (CPUC 2015). This change in electricity pricing represents a substantial shift in how consumers' electricity bills are determined. If consumers are not engaged in a fashion that communicates the benefits of TOU pricing, then there may a backlash that involves a substantial number of customers choosing to opt-out.

Outcome Targeted

Time varying rate mechanisms are generally described as a means to ensure that the cost of supplying electricity is reflected in the prices consumers pay to use it (Fine 2013). By communicating the high costs of using electricity in certain times of day, and the low cost in others, time-of-use price signals will better align the marginal benefits and costs of electricity consumption than flat or tiered pricing. Some portion of the efficiency gains achieved via improved price signals can be shared with consumers, so a move towards TOU pricing may be a means to enable customers to reduce their overall bills. TOU pricing is also viewed as an important mechanism to better integrate renewable energy, so improved environmental outcomes are also a target of this policy.

Present Motivation

Arizona and Texas are two states that have had success in ensuring customer participation in TOU energy rates. In both states, customer acquisition and retention are important motivators for utilities to promote TOU rates (King 2012). California utilities, by-and-large, do not face a similar motivation. A well designed PIM could be a means of replicating the upsides and downsides a firm in a more competitive market might face.

Metrics

CA customers will be defaulted into TOU rates in 2019. Those customers who determine that TOU rates do not meet their needs will have the option to opt-out (CPUC 2015). While customer choice may be important to protect vulnerable ratepayers and to increase public acceptance of this pricing change, a substantial number of opt-outs would diminish the societal benefits of TOU pricing. Therefore, a metric that measures the number or proportion of customers that opt-out would likely be appropriate.

A TOU pricing participation metric is easily measurable by utilities given that customer metering and billing is directly under their control. It is less clear how much influence a utility can exert on consumers’ decisions to opt-out of a TOU rate structure. However, utilities have established customer relations that can be leveraged to promote the consumer benefits of TOU pricing.

Incentive Design

The initial shift to TOU is a discreet event, so it is plausible that most consumers’ decision to opt-out would occur within a limited time period. A financial incentive may therefore be warranted given the timeframe in which consumer education must occur. It could be argued that—since implementing opt-out TOU rates is a new performance area for utilities—a measurement only approach would be preferable. However, if large numbers of customers decide to opt-out in the years following TOU implementation, then utilities will be faced with the well documented challenge of successfully encouraging consumers to opt-in to new rate structures (USDOE 2013). In this case the phenomena of default bias (Samuelson and Zeckhauser 1998) may be compounded by the fact that opt-out customers made the affirmative choice to not participate in TOU rates.

A symmetrical incentive structure design based on a targeted level would likely make the most sense for this PIM. USDOE recently funded a number of empirical studies that document levels of attrition in opt-out TOU programs (USDOE 2013). These data provide a basis from which to set a targeted customer TOU participation rates. The studies also suggest that there is room for improvement in TOU participation rates, with opt-out rates generally falling in the 10% to 20% range. Pilot studies in advance of full TOU implementation will be a useful opportunity to develop more utility specific estimates of opt-out rates. Given the uncertainty around the counterfactual level of TOU participation absent an incentive, use of a deadband or non-linear incentive function could be appropriate in this situation.

Magnitude

Estimates of the economic benefits of TOU rates are contingent on the degree to which they affect customer loads coincident with periods of high system costs and the value of any avoided generation, transmission and distribution capacity resulting from peak load reductions. Given the difficulty of accurately estimating the economic benefits of TOU pricing, a shared-savings incentive approach may not be appropriate. However, a preponderance of evidence suggests that the value of TOU pricing to society is not zero (CPUC 2015). A careful consideration of the resource value of load shifting that occurs as a result of TOU pricing would be needed to set appropriate incentive values.

Overlap with other Performance Areas

The effectiveness of opt-in TOU rates depends on the ability of consumers to respond to price signals during both peak- and off-peak periods. Other potential PIMs would either directly (e.g. the number of residential customers enrolled in demand response programs) or indirectly (e.g. interoperable product deployment) affect the price-responsiveness of demand. Further, promotion of products and services that help consumers manage their loads might be a customer service strategy to help utilities reduce TOU opt-out rates.

6.2 Performance Incentives for Methane Leaks

SB 1371 directs the CPUC to minimize methane emissions from the California natural gas transmission and distribution system. Minimization of methane emissions requires both timely repairs of leaks within the natural gas T&D system, as well as proactive strategies to prevent leaks in the first place (CPUC 2015).

Outcome Targeted

Methane is a powerful greenhouse gas, with a global warming potential between 20 and 80 times that of CO2 depending on the timeframe considered (USEPA 2015). Reducing methane leaks within the natural gas utility sector would therefore contribute to achievement of California's climate change mitigation goals.

Current Incentives

At present, there are few incentives for utilities to minimize methane leakage within their systems. Gas utilities are allowed to pass both intentional and unintentional losses due to leaks on to customers (Costello 2014). In practice, most methane leak repairs occur as a side benefit of otherwise necessary safety improvements.

Metrics

An incentive for reduced utility fugitive methane emissions should capture both leak prevention and leak repair. Based on this criterion, an inventory based accounting of annual methane emissions would be the most comprehensive approach. Developing an accurate accounting of system methane emissions is a highly involved process that requires use of nascent approaches (Magee 2015). Most of the sources of methane leakage within CA utilities' systems are under utility ownership, so this metric is one that utilities can exert significant control over (Magee 2015).

Design

Methane detection and inventory techniques are relatively new and inexact (EDF 2014). Further, the application of these techniques would require development of new competencies both within utilities and at the CPUC. Therefore, a measurement only approach may be appropriate until such time as inventory technologies and approaches mature.

The environmental harm of methane is a clear case of an externality. The most efficient means to manage an externality is to apply some cost to its emission or benefit to its reduction (Coase 1960), suggesting that a financial incentive approach would be appropriate once measurement issues are settled.

Magnitude

The value of financial incentives should at minimum allow the utility to retain some of the savings from reduced fuel losses. A complete assessment of the benefits of methane reduction would also take into account the value of reduced GHG emissions. That value could be based on the market value of greenhouse gas emissions credits in the California Cap-and-Trade Program or estimates of avoided emissions cost used in typical CPUC proceedings.

Overlap

As noted above, SB 1371 directs the CPUC to address methane leaks in the state's natural gas transmission and distribution system. In a recent paper, CPUC Safety and Enforcement Division staff propose that all methane leaks be classified as either 'Tier1' or 'Tier 2', meaning that utilities would obligated to repair them within a defined time period (Magee 2015). However, this standard would be prefaced on utility performance against detected leaks. Performance against undetected leaks would not be incentivized, so a PIM may still be appropriate.

6.3 Performance Incentives for Least Cost Distribution System Investments and Expansion of DERs

California policy makers have targeted expansion of DERs as a key policy priority. DERs are viewed as a means to transition the grid from a centralized fossil-fuel driven paradigm to a distributed clean energy based system. In addition to environmental benefits, proponents of DERs also point to their ability to reduce overall system costs by avoiding or deferring transmission and distribution system upgrades (Beach & McGuire 2013). However, these benefits are not evenly distributed across locations, with some studies suggesting very large differences in location-based value of DERs (Cohen et al 2015). The present COSR model does not discriminate returns based on location, and so may not be well suited for optimization of DER deployments.

At present, there are no applications of PBR mechanisms to the problem of optimizing the locations of DER development. However, two general approaches have been proposed. The first approach is project specific, typically taking the form of identifying some conventional investment and then considering a DER oriented alternative. This is the model proposed in the much cited Brooklyn-Queens-Demand-Management Program (BQDM) and that is proposed in SDG&E's Distribution Resource Plan (DRP) [NY PSC 2014, SDG&E 2015]. The second approach relies on a version of Integrated PBR applied to a utility's distribution system expenditures.

6.3.1 Project Specific Approaches to DER Alternatives to Conventional Distribution Infrastructure

A project specific DER performance incentive aims to provide an upside to a utility that identifies traditional system investments that could be avoided or deferred at a net benefit to society. Generally, the calculation would follow the form:

Net benefits = $ estimated conventional investment - $ estimated DER

Example: circuit upgrade w/ 50% sharing of net benefits

Estimated Conventional Cost	$20 million
DER Alternative Cost	$15 million
Net Benefits	$5 million
Utility return at PBR w/ 50% sharing	$2.5 million
Utility return under cost-of-service (10% ROR, 20 year lifetime w/ depreciation)	> $12 million

Under conventional regulation, a utility would earn about a 10% rate of return on the $20 million in capital expenditures needed to complete the substation upgrade. In this case however, we assume that a less expensive DER oriented option is available, likely via some combination of utility and third-party expenditures. However, this model is flawed in that it does not account for the fact that, under COSR, utilities continue to an annual 10% earn on the depreciated value of their investment.

A different approach would be to offer utilities the opportunity to earn both an increased rate of return and to capitalize alternatives like procuring DERs in place of a traditional infrastructure investments. The Brooklyn-Queens-Demand-Management pilot underway in New York has taken the form of:

- A financial incentive of 45 basis points increased return for replacing a 41 MW conventional distribution upgrade project with the same amount or more DER
- A 25 basis point adjustment based on the diversity of vendors that are retained to meet this target
- A 1 basis point increase—up to 30 basis points—in return for every 1% decrease in $/MW costs compared to the conventional alternative.
- 10 year capitalization of some OPEX related to the BQDM project

These project specific PBR approaches offer utilities an upside for identifying areas where DER investments are more cost effective than conventional alternatives and for ensuring their successful development.

However, project specific approaches offer downsides in the form high transaction costs. Both of the above project specific incentive designs rely on an accurate estimate of the costs of conventional alternatives. Utilities that earn a return based on net benefits have an incentive to inflate their estimates of the cost of a conventional approach to distribution grid investments. To mitigate this concern a regulator could require that costs be based on some benchmark of past similar expenditures, or by retaining an engineering consulting firm to conduct an independent estimate. These approaches imply a multitude of instances where a counterfactual will need to be developed in order for DER incentives to be applied. California's distribution system includes thousands of feeders, so the challenge of ensuring this regulatory model does not balloon into an unworkable approach is significant.

6.3.2 A Revenue-Cap Approach to Least-Cost Distribution System Investments

An alternative approach offered by Jenkins and Perez-Arriaga (2014) at the MIT Center for Energy and Environmental Policy Research uses a revenue cap applied to all distribution grid expenditures. This approach attempts to overcome regulators' information asymmetries using two mechanisms. The first mechanism is an engineering/economic simulation that projects what an efficient distribution system will look like. The second is to offer utilities a menu of revenue cap options to choose from; with upside varying based on the stringency of the cap.

The engineering/economic simulations (called Reference Network Models [RNM]) this proposed regulatory approach relies on are meant to serve as alternatives to the project-by-project counterfactual development required in the BQDM and SDG&E models. Jenkins and Perez-Arriaga describe their use of an RNM as a means for regulators to "peer into the future." This ability to forecast a changing grid is contrasted with the backward looking statistical techniques that have been the most common means of establishing an exogenous efficiency benchmark in Integrated or Revenue-Cap PBR. A forward looking model is advantageous given that substantial shifts in generation and grid management technologies are expected to occur in California's distribution system.

The model proposed by Jenkins and Perez-Arriaga takes an approach to designing a menu-of-contracts that strives for 'incentive compatibility,' meaning that a firm is always better off by meeting its ex ante estimate of expenditures.

The process for implementing this regulatory model involves the following ex ante and ex post steps:

Ex Ante

1. The utility establishes a forecast for expected loads and penetrations of DERs on its electric grid. In many respects, the process that the authors propose is similar to California IOUs' recently filed Distribution Resource Plans.
2. The regulator uses this forecast to run an RNM to identify its estimate of economically efficient expenditures. This estimate also includes establishing a fixed-proportion of total expenditures that will be capitalized based on simulated

efficient CAPEX. This is similar to the TOTEX approach used in the UK, described above.

3. Based on this estimate, the regulator develops a menu-of-contracts.

4. The utility targets a level of expenditures and associated incentives are implemented following the menu. This process also includes enumeration of 'Z-factors' which allow for revenue adjustments based on eventualities that are outside utility control. Z-factors also serve as a means to reduce the weight placed on the RNM in determining the magnitude of at risk incentive payments.

Ex Post

5. The utility makes expenditures and reports them to the regulator annually. The regulator also conducts an annual audit of these expenditures.

6. Automatic adjustments are applied to modify the initial expenditure baseline selected from the initial menu-of-contracts. For instance, the base revenue target might be lowered if PV penetrations were higher than expected.

7. Efficiency incentives are applied based on the capitalized proportion of total expenditures (step 2) and true-ups to revenue-requirement are implemented for the following year. This process is relatively similar to the practice of revenue decoupling in California.

The principal advantage of this approach is that it decreases information asymmetry between utilities and regulators. First, the reference network model affords the regulator, utility and interested parties the opportunity to develop a forward looking assessment of needed expenditures in the distribution grid. Development of the model would start with utility filings similar to California's Distribution Resource Plans and allow for substantial public participation to tweak its inputs. Second, by offering an incentive-compatible-menu-of-contracts regulators are able to encourage utilities to reveal the most efficient cost structure available to them. It may also be the case that the business planning required to respond to such a menu will motivate utilities to identify cost savings they may not have otherwise under a COSR framework.

These advantages are tempered by the relatively complicated and unfamiliar nature of this regulatory approach. Neither regulators nor utilities are well versed in the use of models to determine how rate-payer funds should be spent. Regulators have traditionally applied accounting techniques to determine the prudence of utility expenditures ex post. Utilities are likely better versed with using engineering models to conduct business planning than regulators, but not necessarily as part of an ex ante regulatory proceeding. Another issue is that the approach envisioned by Jenkins and Perez-Arriaga is relatively complex, requiring application of annual adjustments to allowed revenues. These adjustments do occur via per-determined adjustment factors, but it is unlikely that the application of these factors could truly be as low friction as the authors envision. Some adjudication of the conditions which trigger a 'Z-factor' adjustment would almost certainly be necessary.

These disadvantages are mitigated to some degree by the ability of the regulator to use adjustments—particularly the option to decrease the weight of their model—to limit the amount of at-risk money determined via menu-of-contracts incentives. An approach that places limited weight on the RNM is, in many respects, similar to the current practice of revenue decoupling. As confidence in both form and substance of this regulatory model increase, so too could the incentive power of risk/reward options offered to the utility. That sort of incremental approach may be preferable when taking into account investor perceptions of regulatory risk.

7. Conclusions

Performance-based ratemaking is not a new concept. PBR mechanisms aimed at incentivizing monopoly utilities to behave more like competitive firms have been in use for over three decades. Furthermore, performance incentive mechanisms, which are often described as PBR, have been in use for a similarly long period of time. Why then the resurgence of interest in PBR in the present environment of distributed energy resources and disruptive challenges? PBR mechanisms allow regulators, utilities and civil society the opportunity to agree on what aspects of utility performance they collectively prioritize most highly. Initially, this prioritization may focus on simply measuring outcomes of interest. However, most discussions of PBR also envision that some amount of utility revenues should be tied to performance against either an economic efficiency benchmark or some targeted outcome.

California policy makers have adopted some of the most ambitious climate and clean energy goals in the world. A question that regulators must ask is whether the existing regulatory system—a system that involves substantial information asymmetries and a motivation to invest in inefficient CAPEX—is capable of shepherding this transition. This paper lays out a process through which regulators can determine the answer to this question. Regulators should first determine what outcomes matter most, and second what incentive designs are most appropriate to achieve these outcomes. Jurisdictions that have considered PBR recently (e.g. New York, the United Kingdom, Hawaii) have done so using fairly comprehensive proceedings, an approach California should consider. A proceeding focused on how greater amounts of performance incentives could be integrated into California energy regulation would offer an opportunity for all involved parties to prioritize policy outcomes, and consider what incentive structures would accomplish desired outcomes.

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Appendix: A list of PIMs that are in use or have been proposed that are relevant to California policy goals

Policy Goal	Performance Target	Potential Incentive	In Use?	References (if applicable
Customer Engagement/ Smart Grid	MW or % residential DR resources	Upside/downside – on amount that clears DR auction	No	
	% of customers on time-varying rates	Upside/ downside – on targeted opt-in and -out levels	Yes, measurement only in IL	Whited et al 2015
	Interoperable Product Deployment	Upside/ downside – on targets for utility supported roll-out of grid-enabled devices	Yes, measurement only in IL	Whited et al 2015
Resource Planning	Accurate assessment of fuel-cost savings in procurement	Upside/ downside – retention of some risk/ upside from fuel	Yes, in HI	Whited et al 2015, HI Consumer Advocate 2014
	Average cost of fuel per KWh	Upside/ downside – against a target	No	Whited et al 2015
	Incorporation of future GHG allowance prices	Upside/ downside – retention of risk/upside from GHG allowance price changes	No	
	Resource planning engagement	Upside/ downside – awards or penalties based on stakeholder engagement	No,	HI Consumer Advocate 2014
Pollution	Criteria air pollutant emissions	Downside – penalty for exceeding emissions limits	Typically set by air regulators	EPA CAA

Policy Goal	Performance Target	Potential Incentive	In Use?	References (if applicable
Pollution (continued)	CO2 emissions per capita	Downside – penalty for exceeding emissions limits	No	Orvis & Aggarwal 2015
	CO2 emissions per $ GDP	Downside – penalty for exceeding emissions limits	No	
	Environmental footprint of utility	Upside/ downside – against GHG emissions related to utility operations and supply chain	Yes, in the UK	Mandel 2015

Policy Goal	Performance Target	Potential Incentive	In Use?	
DER - Locational Optimization	Net economic benefits	Upside - Shared net benefits of DER solution	No, proposed for BQDM in NYC and in Sempra DRP Filing	SDG&E 2015, ConEd 2015
	Reduction in network losses	Upside/downside – Reduction in line losses from baseline		Mandel 2015, Whited et al 2015
	Performance against simulated benchmark	Upside/downside - How close a utility is able to match a simulated efficient network	No, proposed by MIT	Jenkins and Perez-Arriaga, 2014
DER – Market Animation	Interconnection time	Upside/downside – speed of approved interconnection requests	Ontario (measurement only)	Mandel 215

Policy Goal	Performance Target	Potential Incentive	In Use?	
DER – Market Animation (continued)	Vendor Satisfaction	Upside/downside – against a benchmark of third-party DER provider satisfaction	No	Whited et al 2015
	DER share of peak MW	Upside/ downside – compared to some targeted level of peak DER share	No	Mandel 2015, Whited et al 2015
	Vendor Diversity	Upside/downside – Incentive based on number of different vendors	No, proposed for BQDM in NYC	NY PSC 2015
	Load Factor	Upside/ downside – against a targeted improvement	No	Whited et al 2015

Policy Goal	Performance Target	Potential Incentive	In Use?	
Safety	Total case rate/ Days away from work/ # of incidents	Downside/ penalty only – against an acceptable level	Yes, but often enforced by workplace safety enforcement agencies	White et al 2015
	Failure to report incidents	Downside/ penalty only -	No, but frequently in use in other industries	Hopkins 2009
	Incident response time	Upside/ downside	Yes, but standards oriented	CPUC
	Leak repair time	Upside/ downside	Yes, but standards oriented	CPUC
Customer Service	Call center wait times	Upside/ downside	Yes, in MA and NY	Mandel 2015, MA DPU 2014
	Customer surveys	Upside/ downside	Yes, UK, ON and MA	Mandel 2015
	Number of complaints	Upside/ downside	Yes, UK	Mandel 2015

Policy Goal	Performance Target	Potential Incentive	In Use?	
Customer Service (continued)	Speed of order fulfillment	Upside/ downside	Unknown	Synapse 2014
Reliability	Interruptions: SAIDI/SAIFI/CAIDI/MAIFI	Upside/ downside	Yes, SDG&E, the UK and several other jurisdictions	SDG&E 2014, Ofgem 2014
	Power Quality: Voltage sag/swell/transient, harmonic distortion	Downside	No	
Demand-side management	Customer participation rates	Upside/ downside	Yes, Vermont	Vermont Public Service Board 2011
	Energy savings (MWh)	Upside/ downside	Yes, several jurisdictions	ACEEE 2015, EEI 2014
	Peak savings (MW)	Upside/ downside	Yes, Ontario and Vermont	Mandel 2015
	Net benefits	Upside/ downside	Yes, several jurisdictions	ACEEE 2011
	% customers on EV charging rates	Upside/ downside	No	
	% customers enrolled in DR programs	Upside/ downside	No	
	Use of customer data	Upside/ downside	No	