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Prepared for the
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Acronyms

AFUDC—accumulated funds used during construction
AMI—advanced metering infrastructure
APS—Arizona Public Service Company
CAIDI – Customer Average Interruption Duration Index
COS—cost of service
CPCN—Certificate of Public Convenience and Necessity
CPP—critical-peak pricing
CWIP—construction work in progress
DER—distributed energy resource
DG—distributed generation
DR—demand response
DSPP—distributed system platform provider
DTE—Detroit Edison Company
EE—energy efficiency
EIA—Energy Information Administration
FAC—fuel adjustment clause
IDSO—independent distribution system operator
IHD—in-home display
kW—kilowatt
kWh—kilowatt-hour
LRAM—lost revenue adjustment mechanisms
LRRM—lost revenue recovery mechanism
NEM—net-energy metering
OG&E—Oklahoma Gas & Electric
PBR—performance-based regulation
PCT—programmable communicating thermostat
PSE—Puget Sound Energy
PV—photovoltaic
RIIO—Revenue = Incentives + Innovation + Outputs
ROE—return-on equity
RPC—revenue-per-customer
SFV—Straight Fixed Variable
SI—shareholder incentive
T&D—transmission and distribution
TEP—Tucson Electric Power Company
TOU—time-of-use
VIU—Vertically Integrated Utilities

Executive Summary

Many regulators, utilities, customer groups, and other stakeholders are reevaluating existing regulatory models and the roles and financial implications for electric utilities in the context of today's environment of increasing distributed energy resource (DER) penetrations, forecasts of significant T&D investment, and relatively flat or negative utility sales growth. When this is coupled with predictions about fewer grid-connected customers (i.e., customer defection), there is growing concern about the potential for serious negative impacts on the regulated utility business model. Among states engaged in these issues, the range of topics under consideration is broad. Most of these states are considering whether approaches that have been applied historically to mitigate the impacts of previous "disruptions" to the regulated utility business model (e.g., energy efficiency) as well as to align utility financial interests with increased adoption of such "disruptive technologies" (e.g., shareholder incentive mechanisms, lost revenue mechanisms) are appropriate and effective in the present context. A handful of states are presently considering more fundamental changes to regulatory models and the role of regulated utilities in the ownership, management, and operation of electric delivery systems (e.g., New York "Reforming the Energy Vision" proceeding).

The proposed fundamental changes and future electric utility regulatory models have, to date, been presented conceptually across many studies, papers, and other documents (Eto et al., 1994; Moskovitz et al., 2000; Nimmons and Taylor, 2008; Cappers et al., 2009; Fox-Penner, 2010; Satchwell et al., 2011; Lacy et al., 2012; Aggarwal and Harvey, 2013; Hanelt, 2013; Kind, 2013; Lehr, 2013; Newcomb et al., 2013a; Newcomb et al., 2013b; Richter, 2013a; Wiedman and Beach, 2013; Costello and Hemphill, 2014; EPRI, 2014; Graffy and Kihm, 2014; Hanser and Van Horn, 2014; Rickerson, 2014; Satchwell et al., 2014). In this study, we focus more attention on the link between regulatory/utility business models and the end goals of policymakers; a topic that in our view has received insufficient attention in the previous literature. A more holistic assessment and consistent framework for depicting utility profit motivation and profit achievement aligned with public policy goals and customer technologies may be useful to industry stakeholders in order to provide a lens through which to evaluate specific proposed changes to current practices. Additionally, the implications of changes to existing regulatory paradigms and business models should be included in assessing the viability of new approaches.

To help frame such discussions, we developed a framework to represent the broad spectrum of regulatory paradigms and utility business models that exist today and may develop in the United States over the next 10 to 20 years. Our framework is based on two fundamental utility business model characteristics: profit motivation (see Figure ES-1) and profit achievement (see Figure ES-2). While these are the characteristics of any profitable enterprise and are thus not particular to regulated electric utilities, we use the terms to describe a spectrum of attributes for different regulatory approaches.

Figure ES-1. Spectrum of regulated utility profit motivation

At one end of the spectrum, profit motivation is defined by a utility's motivation to build incremental assets for the primary purpose of expanding its ratebase (e.g., expand/upgrade the distribution network to improve distribution system reliability). At the other end of the profit motivation spectrum, a utility may focus on extracting maximum value through the efficient use of existing assets (e.g., use a customer's distributed generation system to improve distribution system reliability in lieu of expanding/upgrading the distribution network) or build incremental assets that maximize creation of value (e.g., replace aged distribution infrastructure with "smart" distribution automation technologies that has the ability to better integrate distributed generation) (see Figure ES-1).

The utility industry is capital intensive as the generation, transmission, and delivery of electricity requires significant investment in assets. Traditional cost-of-service (COS) regulation provides utilities with a return of and on capital investments as an incentive to drive utilities towards building and maintaining their systems in order to provide customers with reliable and affordable service, and thus falls at the far left end of the profit motivation spectrum. Under traditional COS regulation, a utility is motivated to solve system reliability and customer access issues by investing capital instead of maximizing the value it can extract from existing assets.

Given that utilities are regulated, one way that regulators can shift the profit motivation more toward "value" is by linking the utility's earnings to achievement of pre-established targets and goals. These more fundamental changes to utility profit motivation moves the utility along the spectrum where the utility's profits are largely, if not exclusively, based on targets and goals set by regulators and is motivated to maximize the value it extracts from existing assets (e.g., equipment, customer service representatives). Incremental capital investments are made to meet or exceed targets and goals, but do not drive overall authorized profit levels.

Figure ES-2. Spectrum of regulated utility profit achievement

Profit achievement establishes the second dimension of our framework. At one end of the spectrum, electric utilities can achieve greater profits by promoting increases in sales of the electricity commodity. At the other end of the profit achievement spectrum, a utility can increase profits through greater provision of services. We define the ends of this spectrum by profit achievement exclusively through commodity sales and profit achievement exclusively through services provision (see Figure ES-2).

Under traditional COS regulation, the profits achieved by an electric utility is based on its actual operating costs and revenue collected from retail rates set during and maintained between infrequent rate cases. An electric utility faces some combination of fixed and variable costs, not all of which can be avoided in the short-run between rate cases. Furthermore, under traditional COS regulation, utilities collect most of their revenues based on volumetric sales to customers. Thus, any decrease in sales due to economic conditions, weather, or energy conservation negatively impacts utility profitability.

If regulators want utilities to increasingly play a role in delivering value-added services (e.g., energy efficiency programs, energy storage programs, home automation, and electric vehicle charging), regulatory and utility business models are likely to link and tie utility profits to services provision. Under such a situation, the utility would still likely be motivated to invest in new capital investments (i.e., assets). However, the particular capital investments will likely be made to drive increased delivery and enablement of utility or third-party services which will generate larger achieved profit.

The pace of DER adoption will vary by region in the US driven by technology costs, customer preferences and policy frameworks. Electric utility regulatory models will likewise continue to vary by state, largely dependent on electric industry market structure and associated asset ownership, as well as history and experience with ratemaking approaches and policy decisions in the state.

Effective transition strategies can help mitigate risk to utility shareholders, customers, and third-party providers of DER services and also facilitate achievement of DER public policy goals. Key issues that should be considered as part of transition strategies include:

- Market structure and asset ownership
- Planning and operational responsibilities
- Utility roles in providing value-added services
- Openness of utility networks
- Regulatory processes
- Leveraging past experience
- Incremental changes to COS regulation
- Assessing and ensuring customer benefits

1. Introduction

At present, there are a number of trends confronting electric utilities that are shaping the regulatory and business environment, and will in some cases accelerate change in the electric industry. For example, energy efficiency (EE) programs funded by electric utility customers, EE standards for appliances and equipment, and more efficient building codes for new construction and major renovations are likely to continue to offset the majority of the forecasted electric load growth. Projected incremental annual savings from customer-funded EE programs are expected to reach about 0.8% per year by 2025 driven primarily by compliance with statewide savings or spending targets (Barbose et al., 2013). Costs of distributed energy technologies are also declining steadily and may soon be competitive with retail rates in several states (Barbose et al., 2014; Bronski et al., 2014). As of year-end 2013, electricity generation from customer-sited PV in the United States was equivalent to 0.2% of total U.S. with projected residential and commercial PV penetration reaching almost 0.8% of U.S. retail sales by 2017 ((GTM/SEIA), 2014). Costs also are falling for technologies that can adjust loads up and down through real-time information and control and automation systems (Kiliccote et al., 2008; Ghatikar et al., 2014). Taken all together, consumers, as well as third-party investments in energy efficiency EE and customer-sited generation, such as distributed energy resources (DERs)[1], are contributing in some jurisdictions to stagnant, or even declining, electricity sales. The Energy Information Administration (EIA) Reference Case forecasts retail electric sales growth of 0.8% per year from 2013 to 2040 (EIA, 2015).

Reductions in growth rates of retail sales will likely have implications for the bottom line of many regulated electric utilities. Retail rates are often designed today to collect large portions of fixed costs in volumetric charges (i.e., $/kWh, $/kW). When sales decline, revenues drop without equivalent reductions in costs resulting in the potential for earnings erosion between rate cases (Eto et al., 1994). Because of this, utilities increasingly view DERs as a threat to their financial stability making the pursuit of more aggressive DER penetration goals not well aligned with their business interests.

In addition, many utilities are facing the prospects of large capital investments in transmission and especially distribution (T&D) system upgrades. According to the Edison Foundation, total distribution costs at a national level for the period of 2010 to 2030 are forecasted to be $582 billion in nominal terms (Edison Foundation, 2008). In New York State, the Department of Public Service is forecasting investments of $30 billion over the next 10 years (NYS Department of Public Service Staff, 2014).

Many regulators, utilities, customer groups, and other stakeholders are reevaluating regulatory approaches, roles, and financial implications for electric utilities in the context of today's environment of increasing DER penetration, forecasts of significant T&D investments, and relatively flat or negative

[1] We simplify the term distributed energy resources (DERs) to include a variety of different distributed generation options (e.g., solar photovoltaic, gas microturbines) as well as demand-side options including energy efficiency and demand response. In this report, the term DER is meant to encompass all types of resources that could effectively reduce and/or alter the timing of a customer's electricity consumption from the utility's perspective.

utility sales growth. Among states engaged in these issues, the range of topics under consideration is broad. Most of these states are assessing whether approaches that have been applied historically to mitigate the impacts of previous “disruptions” to the regulated utility business model (e.g., energy efficiency) as well as to align utility financial interests with increased adoption of such “disruptive technologies” (e.g., shareholder incentive mechanisms, lost revenue mechanisms) are appropriate and effective in the present context. A handful of states are presently considering more fundamental changes to regulatory models and the role of regulated utilities in the ownership, management, and operation of electric delivery systems (e.g., New York “Reforming the Energy Vision” proceeding).

Previous studies have examined questions about potential misalignments between regulatory and utility business models in a future state of increasing customer adoption of DER and declining sales, and other questions about the viability of the current utility business model from various stakeholder viewpoints and positions. Earlier work on alternative regulatory approaches to align regulated utility business models with EE goals may serve as a useful foundation for incremental changes to traditional regulatory approaches (e.g., Eto et al., 1994; Cappers et al., 2009; Satchwell et al., 2011). A more recent set of studies and reports has looked at particular threats to utility profitability and customer rates. For example, impacts of customer-sited PV (Satchwell et al., 2014), combined customer-sited solar and storage systems could lead to potential widespread customer “defection”(Newcomb et al., 2013a), and more broadly “disruptive technologies” (Kind, 2013). Other studies have attempted to qualitatively evaluate a possible “utility death spiral” (Costello and Hemphill, 2014; Graffy and Kihm, 2014), a phenomenon in which a utility must repeatedly seek price increases to cover its fixed costs as sales decline and reaches a point where the utility is no longer financially viable. A number of studies identify incremental or more fundamental changes to utility business and regulatory models to facilitate adoption of and, in some cases mitigate, impacts of DERs and declining sales (Moskovitz et al., 2000; Nimmons and Taylor, 2008; Lacy et al., 2012; Aggarwal and Harvey, 2013; Hanelt, 2013; Lehr, 2013; Newcomb et al., 2013a; Newcomb et al., 2013b; Richter, 2013b, a; Wiedman and Beach, 2013; EPRI, 2014; Rickerson, 2014). Finally, several books and papers have described alternative regulated utility business models with varying degrees of specificity (Fox-Penner, 2010; Hanser and Van Horn, 2014).

In this study, we focus more attention on the link between regulatory/utility business models and the end goals of policymakers; a topic that in our view has received insufficient attention in previous studies. A more holistic assessment and consistent framework for depicting utility profit motivation and achievement aligned with public policy goals and customer technologies may be useful to industry stakeholders in order to provide a lens through which to evaluate specific proposed changes to current practices. Additionally, the implications of changes to existing regulatory paradigms and business models should be included in assessing the viability of new approaches.

To help frame such discussions, we develop a framework to represent the broad spectrum of regulatory paradigms and utility business models that exist today and may develop in the United States over the next 10 to 20 years. The work is based on a series of public presentations (e.g., Goldman et al., 2013; Satchwell, 2014). In this paper we add further specificity, discussion, and more recent examples. The framework and resulting typology highlights ratemaking tools that can be used in tandem with traditional cost of service (COS) regulation, as well as fundamental changes intended to more closely align utility profits with achievement of societal goals for clean energy through utilization of distributed resources (i.e., "clean energy public policy goals"), including energy efficiency, demand response (DR), renewable resources, customer-sited generation, energy storage, and microgrids.

Our framework is based on two fundamental utility business model characteristics: profit motivation and profit achievement. While these are the characteristics of any profitable enterprise and are thus not particular to regulated electric utilities, we use the terms to describe a spectrum of attributes for different regulatory approaches.

We use the framework to highlight issues raised as state regulators consider adapting COS regulation to include either incremental or more fundamental changes to better align utilities' profit motivation and achievement with public policy goals for facilitation of clean distributed energy resources. We discuss the regulated utility's role in providing value-added services that relate to increased market penetration of DERs; specifically whether these changes necessitate or suggest a changing role for the utility in delivering DER. Based on that role, we identify the "openness" of utility information, communication and advanced metering infrastructure (AMI) networks. We also discuss relative risks, and the shifting of risks, for utilities and customers. We identify regulatory changes required under each set of changes to facilitate delivery of these services by utilities and/or third-party providers. Where possible, we also provide actual and theoretical examples to illustrate the variety of possible regulatory and utility business models in a high DER future.

2. Background on Cost of Service Regulation

In this section, we describe the process for establishing retail electricity rates, how regulated utilities collect revenues, and the profit motivation for electric utilities under the traditional cost of service (COS) regulatory model, which is the dominant regulatory paradigm in the United States. The conceptual background will serve as the foundation and point of comparison for describing alternative regulatory and utility business models.

The primary role of state utility commissions is establishing retail electricity rates for utility services. In doing so, they must balance a number of goals—among them, stable revenue for the utility, stable retail rates for customers, efficient use of energy and capital, and retail rates that are fair, equitable and understandable to customers (Bonbright, 1961). Additionally, regulators must consider the alignment of rates with public policy goals (e.g., energy savings goals, air quality standards). Beyond the balance of goals, some have suggested that regulators should also explicitly account for future risk in their decisions (Binz et al., 2012).

The actual process for setting rates occurs through a formal administrative process called a rate case. This process allows for regulators, utilities, and other interested stakeholders to establish the fair and reasonable rate amount that allows the utility to collect revenues to cover its fixed and variable costs and an opportunity to earn a profit commensurate with that earned by firms facing similar risks. Because many utilities are owned by investors, the profitability component, either as the authorized return-on equity (ROE) or amount of earnings, is a top priority for utility management.[2]

The specific elements of rate designs are also an important element under the purview of state utility commissions. Rate designs for small residential customers in the 1880s, at the dawn of the electric industry were largely based on fixed charge amounts reflecting the full cost of providing electric service. (Hausman and Neufeld, 1984). The merits of time-based rates, intended to increase electric generation utilization rates and to direct the timing of electricity consumption for power purposes, were discussed at length at that time but the cost of metering was too much to justify such rate designs. More recent rate designs, particularly in response to energy price spikes in the 1970s and clean energy public policy goals in the 1990s and 2000s, were intended to encourage energy conservation.

While today's rate designs often include some small fixed charge amount, a typical residential or small commercial customer's bill in the United States is largely based on volumetric consumption, often with retail prices that increase as monthly consumption increases (e.g., inclining block rates) or rates that increase during particular hours when electricity provision is most expensive (e.g., time-of-use [TOU]

[2] From the investor perspective, profits are important but not the only variable they take into account when deciding on making an investment in a company. The manner in which profitability relates to stock prices, which is the ultimate concern of investors, is beyond the scope of this report.

rates).[3] And, if the customer's bill is largely based on volumetric consumption, then the utility's revenue collection is also largely based on volumetric retail sales.

2.1 Incentives in Cost of Service Regulation

Under COS regulation, state regulators set just and reasonable electric rates by determining the utility's prudently incurred cost of providing service to customers in a test year. This "revenue requirement" is based on the utility's accounting costs and is the sum of fixed and variable operating costs, return of (i.e., depreciation) and return on investment,[4] and taxes during the test year.

Revenue Requirement = (Rate Base[5] X Rate of Return) + Power Production Operating Expenses[6] + Non-Power Production Operating Expenses[7] + Annual Depreciation Cost + Taxes

In the rate case, the regulator and other stakeholders inspect the utility's proposed cost of service. Traditionally, the prudence process for capital projects is a *post hoc* review that determines whether it was reasonable for the utility to make the investment under the circumstances at the time.[8] Rates are set to recover the approved revenue requirement as allocated to each customer class based on the number of customers, sales, and demand.

Profit Motivation

The utility industry is capital intensive as the generation, transmission, and delivery of electricity requires significant investment in assets. Regulated network industries, in which a single entity owns and operates a utility system, are predicated on economies of scale where the costs of large, central station production with a transmission and distribution network are spread over an increasing customer and sales base. General economic theory indicates natural monopoly conditions of a set of network services (e.g., distribution of electricity) provided by a regulated utility are considered preferable to several competing entities that may not be able to achieve necessary economies of scale or be financially viable in the long-run.

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[3] Default TOU rates are less common among residential and small commercial customers in the US.

[4] The rate of return is based on the utility's cost of debt and equity and a set debt to equity ratio. The amount of the utility's rate of return is intended to be set at a level sufficient to attract capital under efficient management and equal to the return of other businesses facing similar risks.

[5] Rate base is the utility's total "used and useful" plant in service, at original cost, minus accumulated depreciation and deferred income taxes. Rate base also includes "working capital"—cash the utility must have available to meet the current cost of operations given the lag between customers receiving electric service and when they pay their electric bills. Regulators may allow other adjustments.

[6] Includes costs that vary with levels of power produced or purchased (e.g., fuel, variable O&M, spot market purchases).

[7] Includes costs that do not vary with levels of power produced, sometimes called "fixed" costs (e.g., property, taxes, debt interest, fixed labor and pension).

[8] Some states require *ex ante* review of large capital projects, in particular generating plants, and utilities in those states must receive a Certificate of Public Convenience and Necessity (CPCN) authorizing the project

Authorized Profit = Equity Portion of Rate Base X Authorized Return on Equity

COS regulation provides utilities with a return of and on capital investments as an incentive to drive utilities towards building and maintaining their systems in order to provide customers with reliable and affordable electric service. This authorized profit is the product of the utility's equity portion of rate base and the authorized return on equity. The profit motivation for utilities, therefore, is to build assets, and COS regulation largely limit the types of investments in ratebase to generation plants, transmission facilities, and distribution equipment. Some contend that because a utility's authorized return on equity is typically above the cost of capital, a utility may have an incentive to over-invest in capital compared to other inputs (Averch and Johnson, 1962).

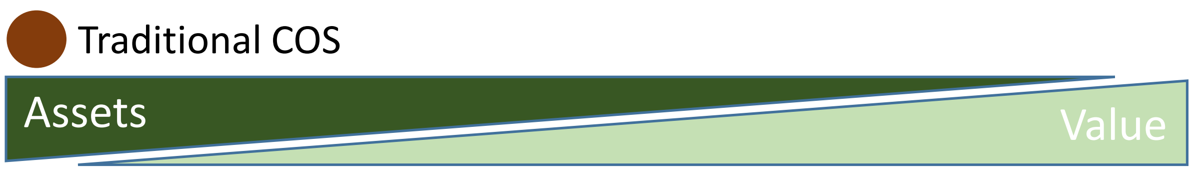

Figure 1. Spectrum of regulated utility profit motivation

At one end of the spectrum, profit motivation is defined by a utility's motivation to build incremental assets for the primary purpose of expanding its ratebase (e.g., expand/upgrade the distribution network to improve distribution system reliability).[9] At the other end of the profit motivation spectrum, a utility may focus on extracting the maximum value through the efficient use of existing assets (e.g., use a customer's distributed generation system to improve distribution system reliability in lieu of expanding/upgrading the distribution network) or build incremental assets that maximize creation of value (e.g., replace aged distribution infrastructure with "smart" distribution automation technologies that has the ability to better integrate distributed generation). Figure 1 depicts where traditional COS regulatory models fall along the spectrum of regulated utility profit motivation. In between, utility profit motivation combines elements of these two motivation "extremes".

Profit Achievement

While the utility's authorized profits are based on its rate base and authorized rate of return, a utility's actual profits between rate cases are the difference between its collected revenues and costs. There are two fundamental aspects of profit achievement under COS regulation:[10]

[9] Technically, the incentive to invest in assets only exists when the rate of return exceeds the cost of capital. In the current environment of a relatively low cost of equity (e.g., 5% to 6%), utilities are likely to be earning rates of return in excess of that.

[10] See Appendix A for a more detailed mathematical derivation of a utility's profit motivation and achievement under traditional COS and how it changes given different changes in costs and billing determinants.

Profit = (Retail Rate X Billing Determinants) – (Power Production Operating Expenses + Non-Power Production Operating Expenses + Annual Depreciation Cost + Taxes)

First, the utility's actual costs may deviate from the revenue requirement established in the rate case and the utility has an incentive for cost control under COS regulation if it can maintain costs that are less than used in setting the revenue requirement. In reality, some non-fuel costs are not easily influenced by utility management. For example, many labor and pension costs (i.e., non-power production operating expenses) are based on negotiated contracts and cannot easily be changed in the short term. Also, back-office infrastructure costs (e.g., IT, billing) are fixed based on the initial investment and changing from one system to another every year-or-two may incur greater costs in the long-run. Though it is true from an economics standpoint that all costs are variable in the long-run, some utility non-fuel costs are fixed between rate cases.

Second, utility collected revenues may not equal the revenue requirement (in fact, they rarely—if ever—do). Actual collected revenues are based on incurred billing determinant (i.e., sales, customer count, and demand) levels in a given year, which may be very different than those used in the test year to set rates. Therefore, utility profit achievement is also driven by changes in billing determinants. These may be considered factors largely outside the utility's control, as the number of customers in a utility service territory and their particular consumption levels are strongly influenced by macroeconomic factors (e.g., employment, income, building stock).

As discussed earlier, the largest component of collected revenues comes from volumetric sales. Thus, any decrease in sales between rate cases due to economic conditions, weather, or energy conservation negatively impacts utility profitability -- this concept is referred to as the *throughput incentive* (Moskovitz, 1989).

Figure 2. Spectrum of regulated utility profit achievement

Profit achievement establishes the second dimension of our framework. At one end of the spectrum, electric utilities can achieve higher profit levels by promoting increases in sales of the electricity commodity. At the other end of the profit achievement spectrum, a utility can increase profits through greater provision of services. We define the ends of this spectrum by profit achievement exclusively through commodity sales and profit achievement exclusively through services provision (see Figure 2). The regulatory framework for utilities may also allow the regulated utility to earn profits through a combination of sales and services. Within our framework, traditional COS regulation provides incentives for profit achievement through commodity sales.

Figure 3 shows the position of traditional COS regulation along both spectrums of profit motivation and profit achievement. Our framework is based on these two spectrums and the quadrants they form. We explore movement from the traditional COS regulatory model in our discussions of incremental and fundamental changes.

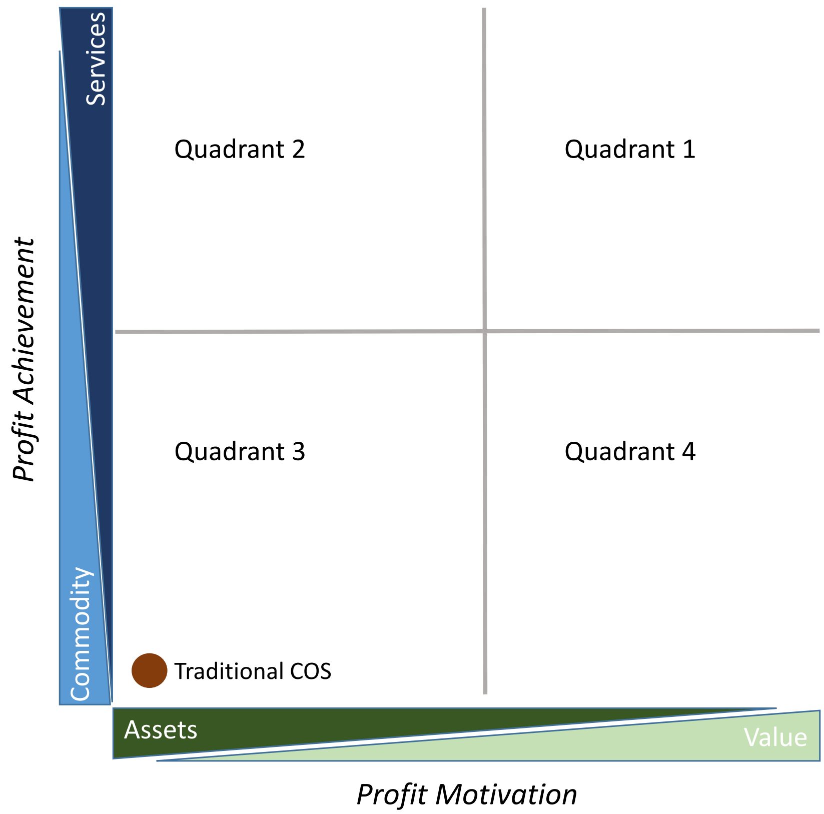

Figure 3. Profit motivation and profit achievement framework

3. Assumptions about Changes to Regulatory and Business Models

The traditional COS regulatory model, and resulting utility business model, has evolved over the past century. Changes have largely been incremental, although regulators have in the past and likely will in the future contemplate more fundamental changes to the regulatory paradigm which will likely have implications for the utility's business model. The possible combinations and permutations of changes to utility regulation are immense. Using the simplified framework discussed in previous section, we focus on a core set of issues that will inform those setting policy.

In this section we limit our discussion to *regulated utility* market structures because we are focused on primarily on the evolution of regulatory models in the electricity sector in this study. This is a narrower scope than utility asset ownership at the parent or holding company level where the company may own unregulated subsidiaries with generation or transmission assets.

3.1 Changes in market structure and utility roles

Market structure and, in parallel, asset ownership define the type of assets owned by a utility and are foundational decisions that policymakers make about the utility's role. Through the 20th century, *Vertically Integrated Utilities* (VIUs) provided all aspects of traditional electricity service and were the monopoly suppliers of the electricity commodity for their retail customers.[11] Thus, they owned generating plants as well as transmission and distribution system assets.

With the advent of restructured electricity markets in the 1990s, regulators in many states required utilities to divest some or all of their generating assets, leaving them to own only distribution (and occasionally transmission) system assets. In some states, retail customers were able to choose their electricity supplier from competing sellers, receiving delivery over the power lines from their *distribution-only utilities*. In all states with retail competition (except Texas), utilities are required to provide default electricity commodity service to all customer classes.[12]

Market structure and asset ownership define utility roles in providing value-added services because they encompass the types of assets owned, managed, and operated by the utility. For example, VIUs that own generating assets may be able to offer generation services to customers (e.g., community or solar gardens, distributed generation) as opposed to distribution-only utilities who are sometimes precluded by state statutes from owning generation, including distributed generation. Additionally, distribution-only utilities that typically pass-through commodity and transmission access costs to default service customers may be closer aligned with operating the distribution system and integrating DERs than a VIU who would also be competing with distributed generators and third-party DER providers.

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[11] Even where the utility is the monopoly provider of electric service, regulators in some states require or encourage utilities to consider offers from independent power producers through a competitive solicitation process.

[12] Typically, the actual commodity cost is passed through to retail customers, providing no impact on utility profits.

Although retail competition represents a very fundamental change in the role of the distribution utility and services that can be provided by the regulated firm (i.e., narrowing the range of services), our framework is not affected by such changes because there is little to no difference between a vertically integrated utility (VIU) and a distribution-only utility with respect to the changes a regulator could consider making to affect profit motivation and profit achievement under high penetration level of DERs. For example, a distribution-only utility would typically be limited to invest in distribution assets only, but would have a similar profit motivation as a VIU to make incremental investments in these assets under traditional COS regulation.

3.2 Access to customer information and utility networks

Over the past 20 years, customer information and utility networks have been expanding. These networks are traditionally comprised of the customer load data (based on either statistical sampling or hourly/sub-hourly data collected from all digital service meters) used by utility system planners and operators. Utilities have also invested in distribution system technologies as part of their distribution system networks. AMI networks have more recently evolved as the foundational structure for the modern delivery and operation of electric service. Depending on the AMI system design, they typically include two-way communications networks, which are able to send information and price signals to and from customers' digital meter, as well as enhanced back-office IT networks. DERs and other energy services are enabled, to a great degree, by these networks, including the ability of third-parties to provide services (under a formal relationship with the utility or absent one). For example, third parties may want access to the AMI network in order to send pricing and control signals to the home and obtain access to outbound meter data. Third parties may also want access to utility distribution networks in order to send or sell net generation from solar PV to the utility. Many states have established standards, procedures and agreements that specify interconnection requirements for access to utility distribution networks with the objective of making the interconnection process transparent, timely and at a reasonable cost.

We make a simplifying assumption that, under traditional COS regulation and ratemaking alternatives, customer information and utility networks are not typically open to third-party providers. Because regulatory approaches under traditional COS regulation and ratemaking alternatives make use of the utility's assets to provide basic commodity, transmission and distribution services, there is no need or incentive to open customer information and utility networks to third-party providers because it is the utility who is ultimately delivering all services to customers. We acknowledge that there are no clear-cut definitions across the myriad of regulatory approaches in the United States, but our simplification establishes a straightforward comparison point for our later discussions of how changing the utility and third-party role in providing value-added services has implications for the openness of customer information and utility networks.

3.3 Risk sharing among utilities, customers, and society

While risks are an inevitable occurrence, they can be largely identified and allocated among various parties based on certain principles and policies. For example, risks can be identified as cost overruns and stranded assets, and earnings and returns less than necessary to attract capital. These risks can be allocated to utilities and classified as operating risks, investment risks, and profitability risks, respectively. Furthermore, risk assessment primarily depends on perspective. For example, these risks to utilities affect the company's financial health, value to shareholders, and potential growth and competitiveness.

Because of the way traditional COS regulation and ratemaking alternatives are predicated on natural monopolies with captive markets, the risks mentioned above could also be allocated to or borne by utility ratepayers (rather than utility shareholders) who could be asked to bear some of the cost responsibility for poor utility management. These risks may impact profitability of private sector businesses and percentage of income that households spend on electricity bills, as well as comfort (Binz et al., 2012).

In addition to the typical balancing of risks between utilities and ratepayers, some regulators consider risks to society. These societal risks include pecuniary and non-quantifiable risks of electric utility operations and regulatory and policy decisions. They include environmental impacts of utility generation sources affecting customers within and outside utility service territories, inefficient use of natural resources (e.g., water and land) affecting society at-large and also future generations, and impacts to macroeconomic gains (e.g., job creation) as either construction projects are approved or not approved by regulators.

Among the jobs of state public utility commissions is creating a regulatory climate that leads to stable, predictable regulatory outcomes. Regulators must balance risks appropriately and may incorporate risk assessment in ratesetting and other regulatory decisions (Binz et al., 2012). Unlike asset ownership, utility role, and network openness, we chose not to simplify the assessment and management of risk for the purposes of providing a comparison point for fundamental changes to regulatory and utility business models. We instead generally describe risks from the perspective of utilities and ratepayers and potential approaches to assess risks of future utility business models.[13] However, this is not always a zero-sum game in which the total amount of risk does not change but merely shifts from one group to the next. The amount of risk may change under different regulatory and utility business model and depends upon the subtle details of how these changes are implemented.

[13] We do not detail societal risks of future regulatory and utility business models because they are largely dependent on the relative success of policies, a discussion outside the scope of this paper.

4. Incremental Changes to the Regulatory Paradigm

Our characterization of COS regulation, up to this point, serves as a conceptual foundation. In reality, the past 100 years of utility regulation in individual states have resulted in a patchwork of changes to better align utility profitability with policies and technologies. We discuss current approaches regulators take with a basis in traditional COS regulation to illustrate the spectrum of such changes.

Since the inception of the modern electric utility industry, incremental changes to COS regulation have sought to address specific challenges to the utility industry, including (but not limited to) the decommissioning and waste disposal costs for nuclear generating plants, volatile fuel prices, and major cost overruns for large capital projects. There are numerous “ratemaking alternatives” that could be considered incremental changes ranging from mechanisms for more timely recovery of fuel costs (e.g., fuel adjustment clause [FAC]) and capital expenditure costs (e.g., construction work in progress [CWIP] and accumulated funds used during construction [AFUDC]), to bill “riders” or “trackers” recovering costs associated with particular projects or programs (e.g., nuclear decommissioning funds, carrying costs, public purpose programs), to broader alternative regulatory approaches (e.g., forward test years for setting retail rates in a rate case proceeding). We limit our discussion of incremental changes to those ratemaking alternatives that address profit motivation and profit achievement in the present environment of low load growth and increasing penetration of DERs.

4.1 Impacts of DERs on Profit Achievement and Profit Motivation

Profit achievement for electric utilities between rate cases is driven by revenue collection largely based on volumetric, commodity sales (i.e., $/kWh) and demand (i.e., $/kW). Figure 4 shows the proportion of a typical residential utility bill based on a sample of southwestern and northeastern electric utilities (Satchwell et al., 2014). The percent of a residential customer’s bill that is fixed ranges from less than 2% to almost 20%, resulting in their volumetric consumption driving the vast majority of their bill.

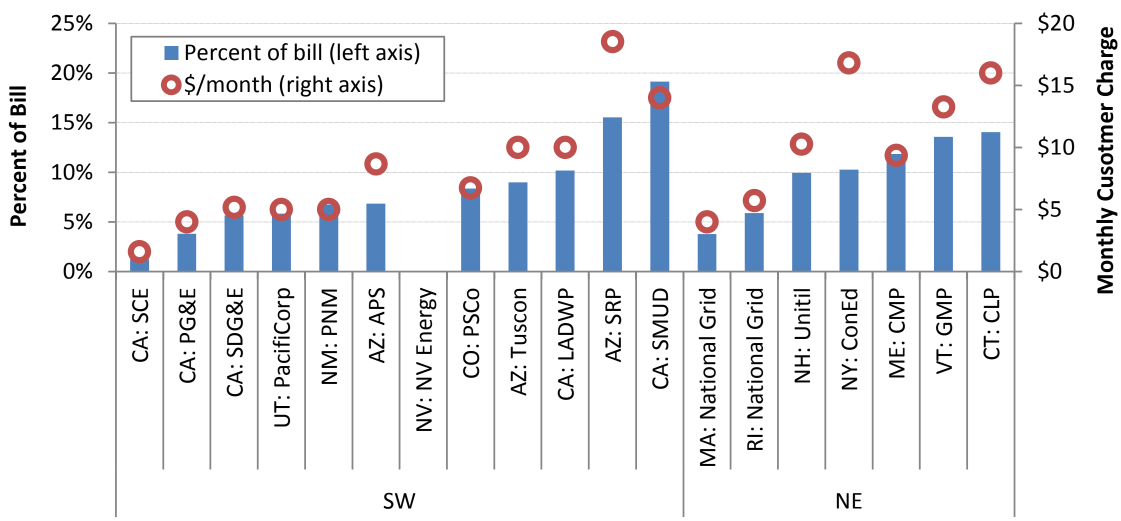

Figure 4. Proportion of fixed charges on typical residential utility bills in the southwestern and northeastern United States.

As DERs are introduced, they will generally reduce the volume of the utility's electricity sales. For example, EE, through building codes, appliance and equipment standards, programs funded by utility customers, and other programs results in lower levels of electricity consumption. That, in turn, reduces the utility's collected revenues and achieved profits resulting in a "revenue erosion effect." As another example, generation at the customer-site reduces utility sales and impacts utility profit achievement in a similar fashion. This reduction in collected revenues is especially pronounced between rate cases when the retail rate (i.e., price) is fixed.

Profit motivation is largely driven by investing in assets, like generating plants and transmission and distribution systems. The electric utility industry is a capital intensive industry predicated on central station generation with large delivery systems to transport the electricity to customers. A proportion of a utility's capital expenditures are growth-related because they are driven by increasing demands and new customers in its service territory. Customer investments in EE, DR, distributed generation (DG) and energy storage reduce growth in utility sales and peak demand, reducing the proportion of growth-related capital expenditures. Under these conditions, the only portion of incremental capital expenditures for the utility would be those associated with replacing aging infrastructure or to meet new system requirements not associated with increasing loads. DERs, therefore, impact utility profit motivation by reducing the opportunities for the utility to invest in assets (i.e., "lost future earnings opportunity effect").

4.2 Ratemaking Mechanisms to Address Profit Achievement

Ratemaking mechanisms to address profit achievement are intended to make the utility indifferent to resources that negatively impact revenue collection between rate cases. Such ratemaking approaches better align utility business models with public policy goals for increased EE and DER deployments as the utility is no longer incented to oppose such clean energy public policy goals, but the approaches do not necessarily incent the utility to pursue clean energy resources or incent the utility to be successful in achieving public policy goals (Kihm, 2009).

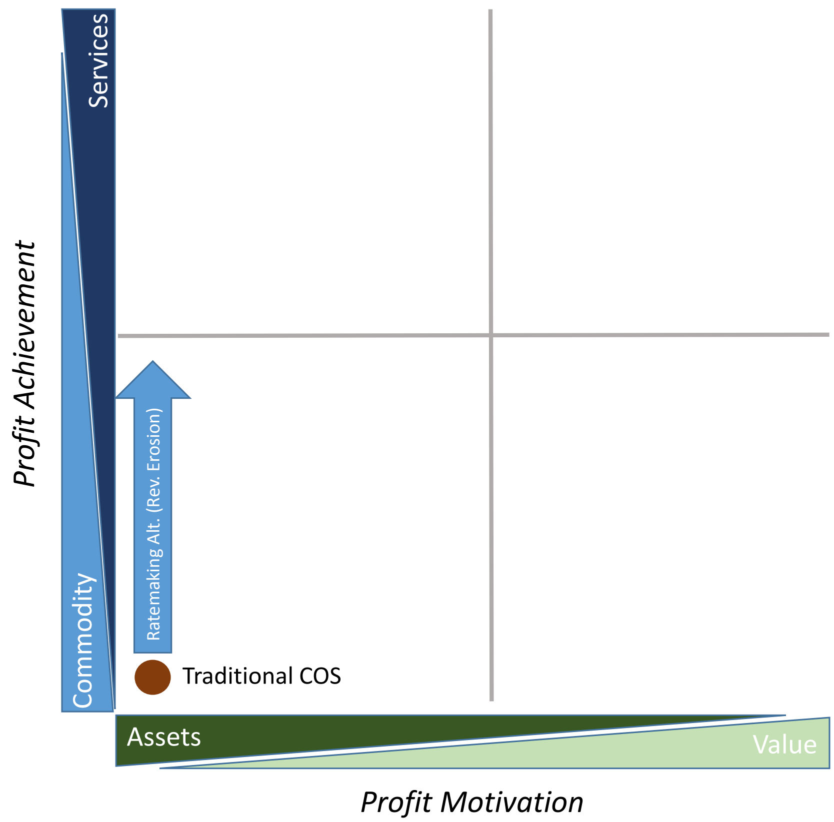

Figure 5. Movement along profit achievement spectrum with incremental changes to address revenue erosion

A variety of mechanisms exist to address the revenue erosion effect, including compensating the utility for "lost revenues" with revenue decoupling, lost revenue adjustment mechanisms (LRAM) and customer bills that rely on a higher proportion of fixed costs. These ratemaking alternatives were introduced several decades ago (Eto et al., 1994) as a way to mitigate the real or potential negative financial impacts from increased deployment of energy efficiency and continue to be pursued as DER technology costs decline, customer interest increases and states broadly consider policies to support more aggressive DER penetration. They are each discussed in more detail below.

Profit = (Retail Rate X Billing Determinants) – (Power Production Operating Expenses + Non-Power Production Operating Expenses + Annual Depreciation Cost + Taxes) **+ Recovered Lost Revenues**

Decoupling is a ratemaking tool intended to address the revenue erosion effect by breaking the link between how much energy a utility sells and the revenue it collects to cover fixed costs. The rate case process remains the same whereby the utility regulator establishes the amount of revenue a utility should collect if it experiences the assumed financial, business, and sales conditions. A utility's actual collected revenues and profits, however, are a function of actual sales and expenses, which, in reality, may not achieve the forecasted revenue requirement or achieve the authorized rate of return) set by the regulator in the rate case.

Under decoupling, the utility uses an accounting mechanism to "true-up" its actual revenues to the amount authorized in the rate case. In effect, a decoupling mechanism functions like a revenue cap and compensates the utility for all short-run fixed costs thereby ensuring the utility collects its non-fuel revenue requirement regardless of the level of sales, demand, and customers. There are design options for decoupling mechanisms that only allow a portion of utility revenues to be decoupled, or that "recouple" utility revenues to growth in customers (i.e., revenue-per-customer [RPC] decoupling) (Shirley et al., 2008). RPC decoupling allows revenues to increase or decrease between rate cases, based on the number of utility customers, which more explicitly ties short-run costs, and the collection of revenues to cover those costs, to changes in number of customers.

As of July 2013, 14 states had approved revenue decoupling mechanisms for at least one utility (IEE, 2013). A comprehensive study found that decoupling adjustments for electric utilities changed rates by less than 2 percent (surcharge or refund) 65 percent of the time for decoupling mechanisms that adjusted monthly, and 85 percent of the time for mechanisms that adjusted annually (Morgan, 2012).[14]

Decoupling mechanisms are typically designed symmetrically, whereby customers may see a surcharge or refund on their bills that "trues-up" collected revenues to equal the amount authorized for the decoupling mechanism. If the adoption of energy efficiency increases over time, which in turn will reduce utility sales growth, it is likely that decoupling mechanisms will produce more surcharges to customers than refunds, thus the increase because of decoupling surcharges which add to rates and thus increase customer bills will reduce some, but not all, customer bill savings from participating in energy efficiency programs.

Like decoupling, a **Lost Revenue Adjustment Mechanism** (LRAM) is designed to address the incentive for the utility to increase electricity sales between rate cases and is widely used in the United States (Morgan, 2012; Edison Foundation, 2013). Unlike decoupling, an LRAM compensates the utility only for lost revenues associated with lost sales from specific DER programs. Thus, an LRAM compensates only for short run fixed costs that are recovered through the volumetric component of the retail rate. To the degree the existing retail rate design includes some short-run fixed costs in the volumetric rate, an LRAM can be a successful lost revenue mechanism. Historically, these mechanisms have been applied to ratepayer-funded energy efficiency programs but they could be extended to other utility-administered DER programs. For example, customer-sited generation output can be metered in a fairly straightforward manner by the utility, thereby allowing for the lost revenue impact of customer-sited generation to be calculated in a manner that may be easier than measuring and verifying energy savings attributed to energy efficiency programs.

[14] Should there be concerns about the volatility of these rate adjustments, regulators may impose caps on decoupling adjustments.

Under an LRAM, regulators authorize an adjustment to customer bills, typically on an annual basis, to compensate the utility for the incremental loss of revenue from the designated causes. Implementation of a LRAM requires properly estimating the lost sales—a potentially contentious process—in order to determine the revenue losses for which the utility should be reimbursed (Shirley et al., 2008). From the customer perspective, an LRAM collects additional revenues and increases customer bills. Like a decoupling mechanism surcharge, an LRAM may reduce some, but not all, of the customer bill savings from energy efficiency program participation.

An alternative to decoupling or LRAM is a change in retail rate design to **increase the fixed charge** amount. Typically, some fixed costs—those that do not change with changes in retail electricity sales—are included in volumetric charges for residential and small nonresidential customers in order to limit fixed customer charges. However, regulators in a few states have modified this practice to include a greater share of fixed costs in fixed customer charges (Lowry et al., 2013). With a high fixed charge, the utility recovers more, or all, of its fixed costs through non-volumetric charges. A "Straight Fixed Variable" (SFV) rate design recovers *all* short-run fixed costs through fixed charges and only short-run variable costs (costs that vary by usage) through variable (per unit) charges. As such, some types of SFV rate design reduce the link between electricity sales and recovery of fixed costs. However, a high fixed charge reduces the customer's incentive for energy conservation and investments in energy efficiency and other distributed energy resources as a result of a smaller proportion of the customer's total bill that can be reduced through decreases in consumption.[15]

While the particular design of these mechanisms varies, the intent is to address profit achievement concerns for the utility and help align the utility business model with achievement of DER goals and targets. Alternative ratemaking approaches move the regulatory model along the profit achievement spectrum from profit achieved entirely from commodity sales towards profit achieved based on combination of sales and the provision of services, such as energy efficiency programs (see Figure 8). Incremental changes to ratemaking move the utility's profit achievement upwards in our conceptual framework, but are not significant enough to fundamentally shift earnings on incremental investment from volumetric commodity sales to provision of services.

[15] An alternative to SFV intended to address utility revenue sufficiency is a "minimum bill" that guarantees the utility a minimum amount of monthly revenue from each customer. Instead of that minimum amount billed as a fixed, customer charge, customers pay a volumetric rate and the bill is effectively trued-up to ensure each customer is paying the minimum amount. Supporters of this approach argue that the approach preserves the incentive for energy conservation as the customer continues to face a volumetric charge without a fixed customer charge (see Lazar, 2014).

4.3 Ratemaking Mechanisms to Address Profit Motivation

While decoupling and other similar mechanisms are intended to address the revenue erosion effect, there are separate mechanisms intended to mitigate the lost earnings opportunity effect. For example, targeted shareholder incentives can provide positive earnings opportunities for utilities to facilitate the achievement of energy savings and other clean energy public policy goals that may stand counter to a traditional utility business model.

Profit = (Retail Rate X Billing Determinants) – (Power Production Operating Expenses + Non-Power Production Operating Expenses + Annual Depreciation Cost + Taxes) **+ Shareholder Incentives**

Shareholder incentive mechanisms can be designed in numerous ways and have been used for more than 30 years to provide financial rewards for the successful achievement of energy savings goals from ratepayer funded EE programs. These mechanisms typically fall into three general categories (Cappers et al., 2009; Shirley and Schwartz, 2009). First, shared savings mechanisms are based on a percentage of "net" benefits (i.e., resource savings minus costs) or avoided costs of EE, often tied to a minimum threshold of kilowatt-hour (kWh)/kilowatt (kW) reduction. Second, other performance-based incentive mechanisms, typically called "bonus" mechanisms, provide earnings based on a set percentage of EE program costs, often on an inclining scale based on meeting targets (e.g., bonus of X% of program costs for 80% of target and bonus of Y% of program costs for 100% of target). Third, "cost-capitalization" mechanisms authorize a utility to include EE program costs in the utility's ratebase and, in some cases, a bonus rate of return. Any of these shareholder incentive mechanism designs could be applied more broadly to utility-administered DER programs.

As of July 2013, 28 states had approved a shareholder incentive mechanism for at least one utility, specifically: 8 states with incentives based on a percentage of EE program costs, 13 states with incentives based on shared net benefits, 4 states with incentives based on a percentage of avoided costs, and 3 states with incentive mechanisms approved but specifics yet to be determined (IEE, 2013). Shareholder incentive mechanisms are ultimately a cost to all ratepayers. Thus, from the ratepayer's perspective, this additional cost reduces some of the bill

Changes to Address Utility Role in Delivering DER

Because of the way traditional COS regulation motivates utilities for profit and the way they achieve profits, attainment of DER penetration, type, size and location goals may be adversely impacted. This misalignment between utility incentives under traditional COS regulation and the pursuit of DER goals has resulted in some policymakers, regulators and stakeholders preferring to administer DER programs through third parties.

Third-party administrators operate most effectively when they have access to the utility and customer data on costs and consumption, are able to coordinate projects with the utility (e.g., to reduce load on distribution circuits where the reduction has the greatest value), and can present themselves to customers as a partner with the utility.

Further, while an independent administrator for DER programs reduces the utility's *ability* to take action to prevent program-induced reductions in electricity sales, it does not necessarily remove the utility's *disincentive*. The utility still faces revenue erosion and lost earnings opportunity effects (Schwartz, 2009). Thus the incremental changes to traditional COS regulation discussed here may still need to be addressed in some fashion.

savings derived from energy efficiency programs.

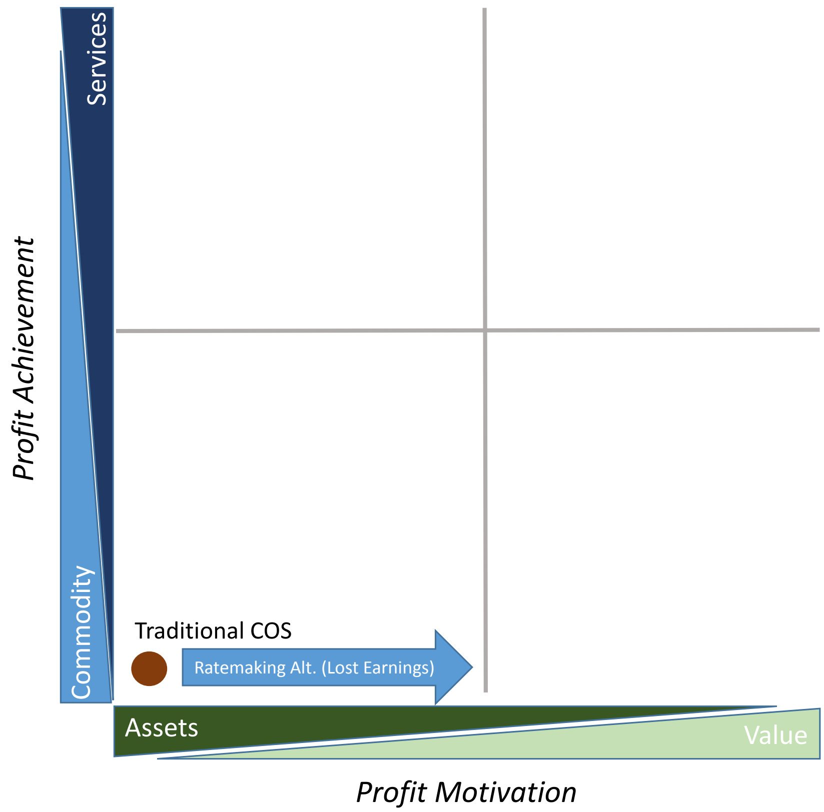

Figure 6. Moving along profit motivation spectrum with incremental changes to address lost earnings opportunities

Figure 6 shows the movement of the regulatory model along the profit motivation spectrum when ratemaking alternatives are implemented to address the lost earnings opportunities effect. Shareholder incentive mechanisms, as an example, are intended to incent utilities to pursue clean energy resources that would otherwise reduce their future earnings opportunities or incent the utility to successfully achieve clean energy public policy goals. Such changes to the utility's regulatory model reflect a profit motivation based on a combination of assets and extraction of value from those assets, but do not represent a fundamental change to motivate regulated utilities toward profits based predominantly or exclusively on value extraction from existing and new (including non-utility-owned) assets. While this approach better aligns regulatory and utility business models with clean energy public policy, shareholder incentive mechanisms in isolation do not address the core of utility profit achievement.

4.4 Representation of incremental changes to traditional COS regulation

Today's regulation of electric utilities, as applied in practice, is not a "pure," traditional COS paradigm. For the purposes of our framework, we place the ratemaking mechanisms described here as incremental changes in a single quadrant bounded by profit motivation dominantly through assets and profit achievement dominantly through commodity sales (see Figure 7).

Experience with ratemaking mechanisms in the context of customer-funded EE programs shows that they can be effective in delivering significant benefits to ratepayers. Of the top 15 states in the 2014 ACEEE State Energy Efficiency Scorecard, 13 states have either a lost revenue recovery or shareholder incentive mechanism in place (e.g., Oregon, Washington), or both (e.g., California, Massachusetts). Two states (i.e., Iowa and Illinois) that rank in the top-15 states have neither mechanism in place (Gilleo et al., 2014).

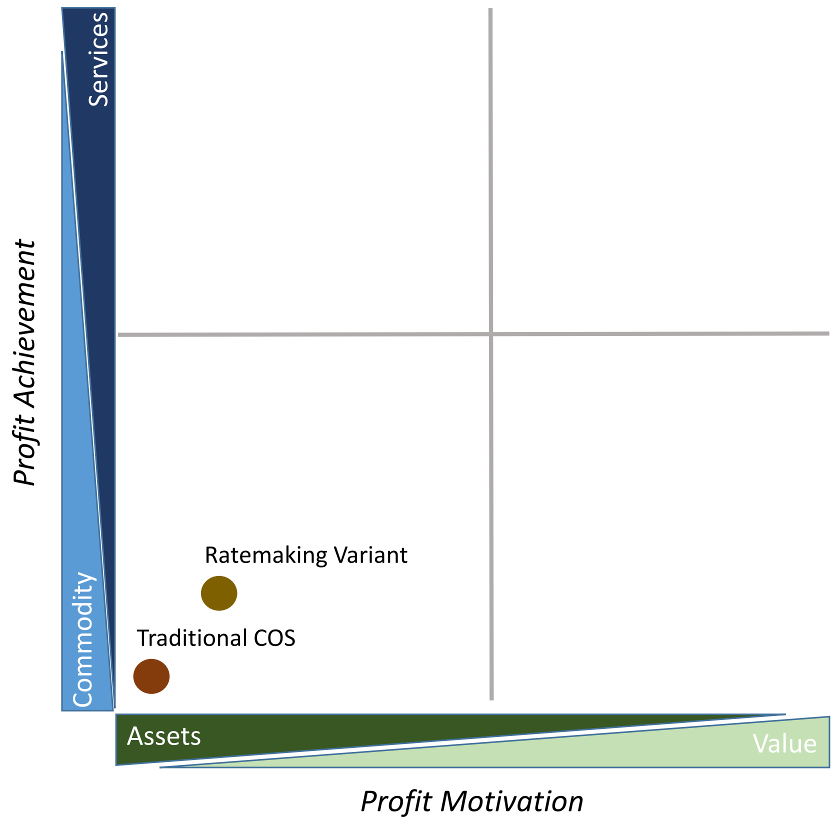

Figure 7. Position of traditional COS regulatory model and ratemaking variants within framework

Incremental changes to traditional COS regulation are often made by regulators and policymakers in isolation to address a particular policy (e.g., energy efficiency resource standard) or particular utility investment (e.g., advanced metering infrastructure) and may be applied by layering various ratemaking mechanisms. However, these changes are not, in our framework, comprehensive enough as to make support for cost-effective DERs a core function of the utility. A more holistic and integrated approach by regulators may be necessary to make clean energy public policy goals complementary with, rather than competitive towards, the utility's profit motivation and profit achievement.

5. Fundamental Changes in the Regulatory and Utility Business Model

Increasing penetrations of DERs due to costs declines, supported by public policies, relative to existing retail rate levels, reduced growth in electricity consumption, and large investments to replace and upgrade the electric system infrastructure are among the drivers for considering more fundamental changes to regulatory and utility business models. While the general topics of discussions are similar (e.g., future role of utilities, asset ownership), the particular context for revisiting or reimagining these models is different. For example, in Hawaii, more fundamental changes are being considered to mitigate the impacts of high penetrations of customer-sited generation. New York is considering a changing role for the distribution utilities in ownership, management, and operation of the delivery system in order to facilitate and integrate desired future increases in DERs.

We use our framework to characterize fundamental changes in profit motivation and profit achievement. Moving beyond profit achievement predominantly through commodity sales, and profit motivation predominantly through asset investments, suggests possible implications for utility roles; risk sharing among utilities, customers, and society; and customer information and utility network access. We use current approaches (i.e., traditional COS regulation with additional ratemaking mechanisms) as a comparison point to discuss these implications.

The intent of possible future regulatory and utility business models within our framework is to align utility profit achievement and profit motivation with clean energy public policy goals. We recognize that there has been little experience in the United States with the fundamental changes necessary to develop these future models. Furthermore, given the diversity in legislation, regulations and approaches among the states, as well as diversity in public policy goals and history and experience in achieving those goals, we expect that jurisdictions will continue to pursue diverse strategies. To advance the discussion, we identify comprehensive options that state regulators could consider for implementation in the future.

5.1 Creating a Services-Driven Utility

Rapid developments in technology, information processing and communications are improving the prospect for increased utility customer engagement, choice, and control and at the same time increasing reliance on customer resources. Electric, natural gas and telecommunications utilities increasingly are offering value-added services—those in addition to, and billed separately from, basic commodity service—including bundling products and packages (Graffy and Kihm, 2014). Some utilities use common infrastructure to provide these services. For example, electric utilities may use a communications backbone for smart grid as well as internet services.[16]

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[16] The Electric Power Board, Chattanooga, Tenn., installed a fiber optic network for smart grid and other city services. See https://www.smartgrid.gov/project/epb_smart_grid_project and http://www.perfectpowerinstitute.org/sites/default/files/PPI%20ChattanoogaCaseStudy%20%20Final.pdf.

Value-added services that electric utilities and third parties offer today for distributed energy resources[17] include the following:[18]

- Energy efficiency programs
- Demand response programs
- Green power options
- Installation, ownership or leasing, operation and maintenance of distributed generation systems at customer sites or in communities, such as solar PV, combined heat and power systems and microgrids
- Energy storage services
- Energy system management
- Home automation
- Energy usage information
- Financing
- Backup generators
- Electric vehicle charging at individual customer sites, for fleets and for the public
- Aggregation and other services to facilitate DER transactions in wholesale or retail markets

If regulators want utilities to increasingly play a role in delivering such value-added services, regulatory and utility business models are likely to move away from sales-driven profits toward profits tied to providing services (see Figure 8). The utility would still be motivated to make profits on existing and incremental capital investments (i.e., assets). The particular capital investments, however, will likely be made to drive profit achievement from services enabled or delivered by utilities and third-party service providers.

Profit = {(Retail Rate X Billing Determinants) **+ (Service Rate X Services Delivered)**} – (Power Production Operating Expenses + Non-Power Production Operating Expenses + Annual Depreciation Cost + Taxes)

[17] For a description of potential value-added services beyond those directly related to DER, see Advanced Energy Economy (2014).

[18] For a more detailed assessment of particular value-added services related to DER that re currently being offered by utilities and third parties, see Appendix B.

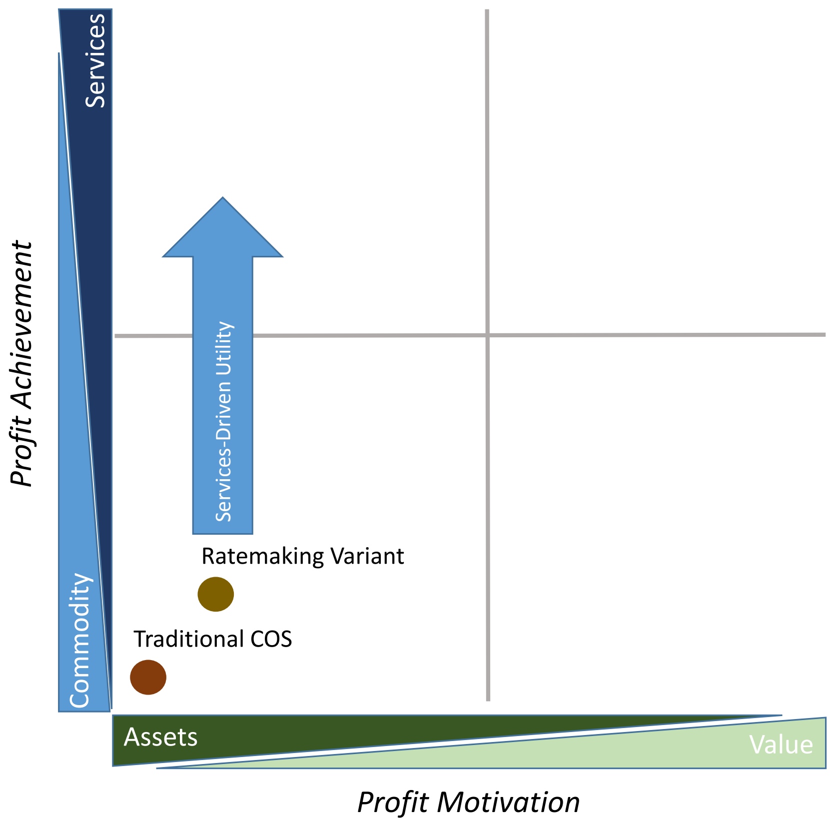

Figure 8. Movement along spectrum of profit achievement for a services-driven utility

Services-driven utility models

A "Smart Integrator" utility (Fox-Penner, 2010) would create and manage a robust distribution network to integrate distributed energy resources and "provide the most open architecture possible for power sources of all types." Its open and accessible network would facilitate third-party providers to offer value-added electricity services to utility customers.

Another example is an independent distribution system operator (IDSO) model which would employ a non-utility operator of the distribution system. An IDSO would be responsible for reliability, maintaining open network access, facilitating market mechanisms, system planning and dispatch of energy resources (Rahimi and Mokhtari, 2014; Tong and Wellinghoff, 2014).

In both cases, the utility's profit achievement would be focused, in part, on services the utility enabled but were delivered by third parties, while its profit motivation would largely remain asset-focused.

Regulatory and utility business models in this upper-left quadrant do not necessarily suggest a change in market structure, since VIUs and distribution-only utilities can equally and effectively provide services to customers (albeit, a different range of services). However, the role of the utility in delivering these services (monopoly vs. competitively) must be defined. Among the fundamental issues regulators must address when evaluating the utility's role in providing value-added services—and setting prices for them—are the impacts on competitive markets for those services, to the degree they already exist or could develop, and risks to ratepayers of expanding utility investments into new areas.[19] To the extent utilities compete with other entities to deliver value-added services, regulators will likely need to provide a level playing field for third-party providers by setting utility rates for these services using market-based pricing and granting third parties ready access to customer information and utility networks. As an alternative to direct competition, which is used in parts of the country for the successful delivery of

[19] For early work analyzing the potential benefits of retail electric competition for a variety of value-added services for nonresidential customers, see Golove et al. (2000).

demand response and energy efficiency programs, utilities may partner with third parties to provide such value-added services to customers (Advanced Energy Economy 2014).

Regulators may also view the utility's role as a catalyst for nascent services important to public policy goals—for example, by providing public charging stations for electric vehicles to reduce transportation sector air emissions and dependence on fossil fuels. Or regulators may determine that investments in non-core electricity services may preempt competition, along with innovation and lower costs, and pose undue risk for ratepayers.

From the perspective of utilities, customers, and society, risks of such a regulatory and utility business model will be different than under COS regulation. Utilities will face new risks as they largely move planning and operational functions towards delivering and providing particular value-added services. Customers may face new risks from needing to manage electricity consumption in different ways, including choosing between utility and third-party providers for desired services. Additionally, paying separately for energy services may change customer decision making and customer economics impacting the adoption of DERs. PV adoption is driven, in large part, by federal and state tax policy as well as net-energy metering (NEM) which compensates PV generation with all energy services costs. If utility services (e.g., system reliability, billing services) are separated, then the portion of the bill that compensates PV may be smaller. While increased competition for services may lower prices, the increased choices may pose additional risks for customers—especially in nascent services.

Another implication of this shift towards profit achievement based much more substantially on services is a change in pricing, particularly for value-added services. Like other electricity services the utility offers, pricing value-added services requires both quantifying the costs associated with the service and determining the proper unit for measuring its use. Under a COS regulatory regime, regulators set the price for the service at a level designed to collect the total cost of providing it—including any utility profit or incentive for offering the service—accounting for the estimated total consumption of the service by all participants.

Determining the costs of the energy service requires properly attributing cost factors such as capital, labor, fuel, materials, outside services, maintenance, depreciation and taxes. Also required is assigning to the service an appropriate share of costs for infrastructure and services—for example, customer billing, IT and communication networks—that the utility uses to provide other energy services. Utilities have a long history of using COS studies to functionalize and allocate costs. However, COS studies traditionally have not assigned costs for value-added services.

In contrast to traditional electricity service, where a utility's revenues are based on energy sales, energy demand and delivery, utility revenue for value-added services in the future may be based on such metrics as lumens of light, heat delivered for hot water service, and size of a solar PV system installed at the customer's site (Sant, 1980; Reister and Devine Jr., 1981; Fox-Penner, 2010). This would explicitly allow the utility to move away from focusing on selling more of the input (e.g., electricity) in order to focus on selling more of the output (e.g., lumens). As Fox-Penner (2010) describes, "Under this approach, if a more efficient light source came along, so that the bulb and input power were cheaper for the utility to provide together than the existing, less efficient combination, the utility would automatically have the incentive to install the more efficient technologies." Such pricing is common in other industries, including telecommunications and insurance. For example, mobile phone carriers charge for phone, text messaging, and data services separately instead of charging a flat rate.

Regulatory and business models focused on utilities providing services, rather than selling a commodity, are largely conceptual. However, proposals are emerging that would change the role of electric utilities and fit within the assets motivation and services achievement quadrant in our framework (see text box, "Services-driven utility models"). Many of these models would change the asset ownership of the utility and, therefore, profit motivation to build assets. The models also suggest a different set of roles than the traditional utility and may require alternative approaches for how the utility recovers revenues to cover costs of an open network. Importantly, aligning utility profit achievement with clean energy public policy goals does not necessarily result in meeting the goals. Therefore, utility regulators will continue to play an important role in monitoring performance and enforcing compliance.

5.2 Creating a Value-Driven Utility

Traditional COS regulation motivates a utility to expend capital to solve a problem (e.g., to meet new customer loads by building a new substation), not to maximize the value it can extract from existing assets to solve it (e.g., optimize DERs and existing EE programs to reduce or shift customer loads to avoid building a new distribution substation). Regulators have long been frustrated by this misalignment and have sought over time to implement various incremental changes to the regulatory and business model in order to focus the utilities' efforts on improving the degree of value extraction. Activities like integrated resource planning enable the utility to consider a myriad of different resources, not just traditional generation assets but demand side resources (e.g., energy efficiency, demand response), to meet reliability needs in the future. However, these incremental changes have not always compelled the utility to pursue specific goals that the regulators want them to achieve. In response, a fundamental change in the regulatory model was conceived by economists in the 1970s that focused on "outcomes" and not inputs (Laffont and Tirole, 1993).

Performance-based regulation (PBR) is a form of incentive regulation in which a utility's revenues are tied directly to performance (i.e., value),[20] sometimes called "outcomes-based regulation" or "performance-based ratemaking." Under PBR (and its named variants), regulators set specific targets on a variety of different categories for utility performance that determine the level of the utility's profits. By contrast, in COS regulation, the difference between costs and revenues determine the utility's

[20] We apply the term "incentive regulation" more broadly than in the common academic literature, which typically uses the term to describe alternatives to traditional cost of service regulation (e.g., Joskow, 2006). The difference may ultimately be a semantic one as incentive regulation, applied to either COS regulation or PBR, is primarily about the types of incentives provided to utilities and the power of those incentives to drive desired regulatory outcomes (see Laffont and Tirole, 1993; Comnes et al., 1995).

profits.

PBR can promote cost containment by including price caps, revenue caps, and multi-year rate plans. PBR mechanisms may be "targeted," with incentives limited to specific aspects of utility performance (e.g., fuel purchases, power plant performance), or "comprehensive," in which PBR covers all aspects of the utility's rates or revenues. Several key elements for implementation of comprehensive PBR approaches include long-term plans and lengthy cycles for resetting rates, as well as pricing mechanisms that include flexibility to adjust to cost increases or other exigent circumstances between rate cases.

Some view PBR to be a preferable regulatory model than COS regulation in terms of economic efficiency because it provides greater incentives for cost containment and innovation. This viewpoint is largely predicated on the belief that targets and goals (i.e., outputs) drive a firm's behavior better than an accounting framework focused on costs (i.e., inputs) (Woolf and Michals, 1995; Lowry and Kaufmann, 2002).

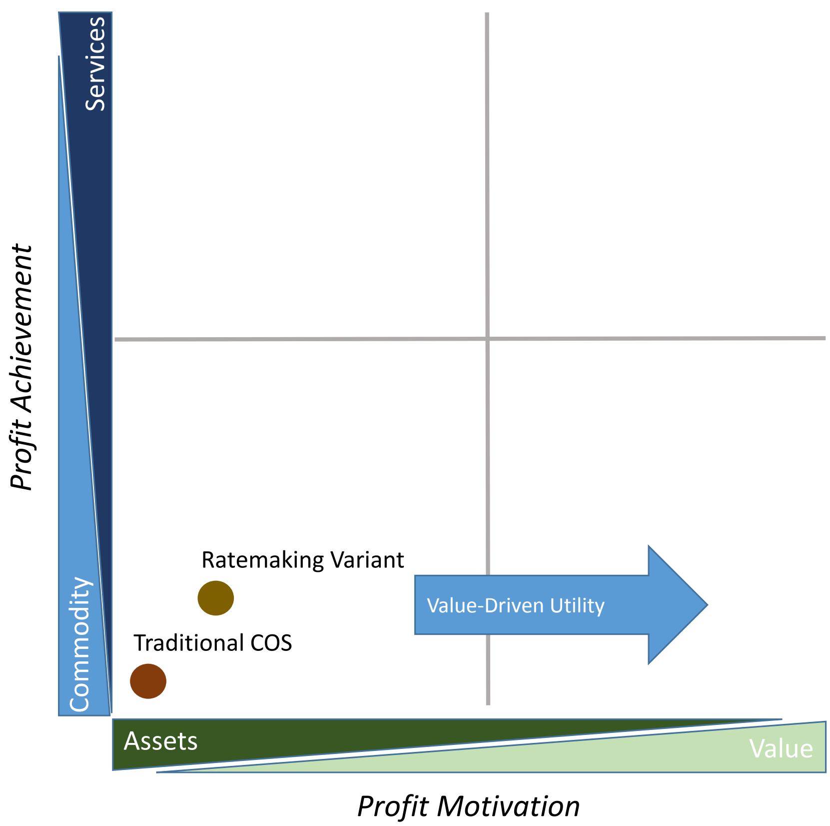

Figure 9. Fundamental changes to profit motivation towards value creation

Great Britain's RIIO Model

The regulatory authority in Great Britain that oversees electric and gas distribution companies is implementing a new regulatory approach known as RIIO (Fox-Penner et al., 2013). Short for "Revenue = Incentives + Innovation + Outputs," RIIO is a performance-based regulatory model using revenue caps.

RIIO's objectives include addressing challenges of large future investment costs, maintaining reliable and secure delivery networks, and meeting low carbon and other environmental objectives. RIIO also enables investments in innovation projects (Ofgem, 2013).

Under RIIO, each electric and gas distribution company develops a business plan for negotiation and approval by the regulator (Ofgem). The plan serves as a regulatory contract and contains two key elements: 1) "outputs and deliverables" that detail how performance of the distribution company will be assessed by Ofgem and 2) an eight-year forecast of costs and revenues that include incentives for meeting and exceeding performance goals, as well as penalties for under-performance. By tying revenues to performance, the RIIO model moves the utility's profit motivation from creating assets to creating value.

Within our framework, PBR moves the utility considerably along the profit motivation spectrum (see Figure 9) where the utility's profits are largely if not exclusively based on targets and goals set by regulators, and the utility is motivated to maximize the value it extracts from assets (e.g., labor, equipment, customer service representatives, customer-sited DER). Incremental capital investments are made to meet or exceed targets and goals, but do not drive overall authorized profit levels.

Profit = **(Retail Rate X Billing Determinants at Capped Prices or Revenues)** – (Power Production Operating Expenses + Non-Power Production Operating Expenses + Annual Depreciation Cost + Taxes)
+ Performance-based profit provisions

Under PBR, the utility continues to plan, operate, and maintain transmission, distribution and, in the case of VIUs, generation systems. Thus, PBR can be applied to all aspects of electric service, though the range of performance targets and goals would be broader for VIUs than distribution-only utilities. For example, PBR for a VIU could be used to drive the types and quantities of power purchases or for long-term fuel contracting, whereas for distribution-only utilities, PBR targets and goals would be limited to energy delivery and distribution system services (e.g., distribution planning, operation, and interconnection).

PBR does not suggest a necessary change in utility or third-party roles for the delivery of value-added services like DER, although it is possible that regulators could use the opportunity of goal setting to re-assess roles and responsibilities. If the utility is going to compete for the delivery of such value-added services, various customer information and utility networks would need to be open to third parties.

From the perspective of the utility, risk of financial performance would be different under PBR but not necessarily more or less than COS regulation. Profit risk for the utility under PBR is contingent on meeting goals, not on levels of sales and costs between rate cases. It is possible that the utility would be better able to manage risk since it would know whether or not it would be on track for meeting targets and goals, and such foresight would be more predictable than revenues driven by sales fluctuations. From the perspective of customers, risk would also be different under PBR than COS regulation. Potentially, if a utility under-achieves its target and goals, then customers would likely pay less in total than if the utility completely achieved its goals, because PBR compensates utilities only for successful performance. Whereas under COS regulation, the utility's profit is not directly tied to performance. The impact of PBR, or another value-driven regulatory model, on the customer economics for DER adoption will largely depend on the particular design and elements and whether the customer will be able to reduce their bill via lower consumption or peak demand.

There has been limited experience with comprehensive PBR approaches in the United States (Comnes et al., 1995), though there are many and more recent examples of targeted PBR mechanisms focused on particular areas of utility performance (Aggarwal and Burgess, 2014). Experience with more comprehensive PBR may be drawn internationally (see text box titled “Great Britain’s RIIO Model”).

5.3 Creating a Services-Driven and Value-Driven Utility

Building on, and ultimately combining, the previously identified fundamental changes results in a services- and value- -driven utility where profit motivation is based more on value than assets and profit achievement is based more on services than commodity (see Figure 10). This fundamental and comprehensive change may result in the utility competitively or exclusively offering value-added services under a PBR model. This approach may present a complete paradigm shift in the way utilities are regulated, what a utility offers to customers particularly “behind-the-meter,” and how a utility measures the services it provides to customers. For example, under a PBR model, utilities would be regulated based on the value they create for customers, not on the assets they invest in to serve customers. Such regulatory and utility business models within this upper right quadrant of our framework also require a fundamental shift in pricing away from commodity sales (e.g., $ per kWh consumed) towards services offered (e.g., $ per kWh of solar-generated electricity).

Profit = **(Services Rate X Services Delivered at Capped Prices or Revenues)** – (Power Production Operating Expense + Non-Power Production Operating Expenses + Annual Depreciation Cost + Taxes) + **Performance-based profit provisions**

New York’s “Reforming the Energy Vision”

In April 2014, New York’s Department of Public Service opened the “Reforming the Energy Vision” proceeding (Case 14-M-101). The Commission laid out a vision for the state’s distribution utilities to establish a platform which will enable greater penetration of DER by monetizing products and services that will provide value to both the distribution system and customers who invest in DER (NYS Department of Public Service Staff, 2014). In order to achieve this goal, the Commission will shift the focus of regulation away from historic incurred costs to the pursuit of long-term customer value.

Initial decisions associated with the role of the utility as the distributed system platform provider (DSPP) are expected in 2015 with more fundamental regulatory reforms coming.

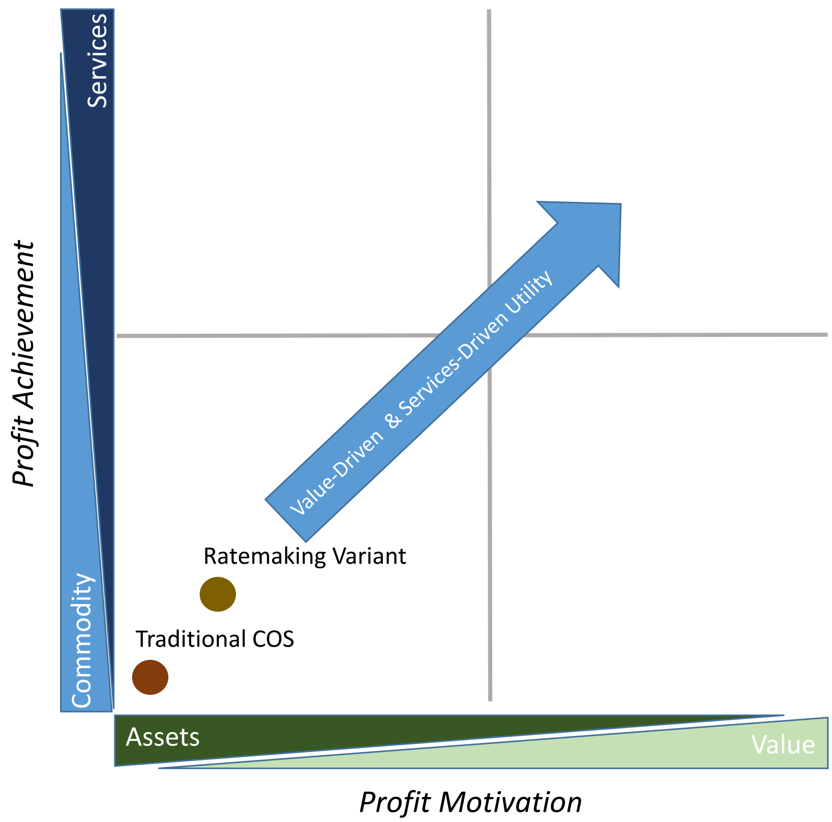

Figure 10. A paradigm shift in how utilities price and offer services

A shift in which the utility competitively or exclusively offers services does not suggest a change in market structure or asset ownership, though VIUs would be competing to provide or exclusively offering a wider range of services than a distribution-only utility. The role of the utility may move "behind-the-meter" in which they offer services tied to end-uses at the customer premise. This would be a significant departure from current roles for the utility that often stop at the meter base outside the home. Utilities have historically eschewed owning assets behind the customer's meter because of the potential liability and high transaction costs. Regardless of whether utilities venture into the customer-side of the meter, in the case where a utility remains the exclusive provider of services, customer information and utility networks are likely to stay closed to provide a competitive advantage for the utility.

With respect to risk, it is likely greater for a utility under this regulatory regime as it must compete directly with others in the market to provide services and create value, with profits dependent on both. Customer risk may be different than under traditional COS depending on a utility's ability to meet performance targets and goals and whether any costs of poor performance are passed through to ratepayers or remain with shareholders.

Regulatory and utility business models within this quadrant of the framework are largely conceptual at present. However, in New York, in 2014, the Department of Public Service commenced a proceeding

(NYDPS Case 14-M-101) to fundamentally change the roles and responsibilities of the distribution utility in order to create a Distributed System Platform (DSP) (see textbox titled “New York’s ‘Reforming the Energy Vision’”). This may be the first example in the United States of such a comprehensive change that includes aspects of performance-based regulation and the competitive delivery of a variety of value-added services.

6. Transitioning to New Utility Business Models

The pace of DER adoption will continue to vary by region in the United States, driven by such factors as retail rates, installed technology costs, customer preferences and policy frameworks. Regulatory models also will continue to vary by state, largely dependent on electric industry market structure and associated asset ownership, as well as history and experience with ratemaking approaches and policy decisions in the state.

Most utilities in the United States today have fuel and purchased power adjustment clauses that place much of the commodity price risk on ratepayers. Other cost trackers and pass-through mechanisms have added to that trend. Further, in order to mitigate the throughput incentive that directly conflicts with public policy goals for EE, customer-sited generation and other distributed resources, regulators in many parts of the country have adopted decoupling or a lost revenue adjustment mechanism. A few states have moved to future test years to more directly address anticipated changes in loads (and resources), and others are experimenting with multi-year rate plans and performance-based incentives.

Many states have adopted shareholder incentive mechanisms or other approaches to provide the utility with a profit motive to pursue greater adoption of DERs. Many of these mechanisms have evolved from initial simple designs to encompass a variety of public policy goals. For example, Connecticut's energy efficiency incentive mechanism includes goals for market transformation programs, EE investments for low-income households, and overall savings from utility-administered programs. Such changes to the utility's business model seek to facilitate customer investments in DER.

Conversely, other incremental changes to COS regulation under discussion today, such as high fixed customer charges, may at least initially frustrate customer investments in distributed energy resources. Ultimately, however, that approach may hasten customers' departure from the grid altogether as DERs may be paired with energy storage systems that free customers from needing grid service from the utility (Graffy and Kihm, 2014).

The past may be a helpful predictor of changes to the regulatory paradigm. For example, states that have embraced decoupling may tend to move more quickly to innovative regulatory models that facilitate greater utility service offerings. On the other hand, states that have had poor experience to date with energy efficiency incentives for utility shareholders may be more cautious about performance-based ratemaking. States' disparate experiences and market structures will continue to drive, at least in part, the diverse set of approaches we have in the United States today.

6.1 Transition Strategies

Regardless of where each state may be heading, effective transition strategies can mitigate risk to utility shareholders, customers, third-party providers of DER services, and achievement of DER public policy goals. Ultimately, some utility services and roles will naturally lend themselves to economies of scale and thus some form of regulation. Others do not, suggesting a more competitive market opportunity may exist. Among the key issues that must be addressed during the transition to new regulatory and utility business models are the following:

- **Market structure and asset ownership** - We assume for the purpose of our utility business model typology that state policymakers already have made their decisions about market structure and asset ownership—vertical integration (generation, transmission and distribution) vs. "restructured" (distribution only). In reality, these issues may not be entirely settled. Recent calls for a distribution system network operator (Rahimi and Mokhtari, 2014; Tong and Wellinghoff, 2014), for example, are squarely challenging utilities' traditional roles for planning, acquiring and controlling electric system assets in a future with a high penetration of distributed technologies, including those that enable customers to disconnect from the grid entirely.

  At the same time, with rapid technology change, increasing customer adoption of distributed resources and low load forecasts, regulators may be particularly cautious about utility investments in large assets, especially considering typical useful lives of 30 years or more. While ratemaking tools such as accelerated depreciation can be used to address utility risk and help avoid inter-generational customer equity issues, these tools transfer risk from utility shareholders to customers.

  Still, states with restructured electricity markets will tend to evolve in ways that are different than states that have maintained vertically integrated utilities.

- **Planning and operational responsibilities** - To ensure safe and reliable operation of the grid, utilities will need to determine how to plan for and operate the grid with utility-, customer- and third-party-owned assets. Regulators in California, Hawaii, Massachusetts and New York are among those actively exploring these issues.

- **Utility role in providing value-added services** - Non-regulated utility affiliates—including other subsidiaries owned by the parent corporation, the parent corporation itself, or another company in some way involved with the utility—may compete even more directly with third-party providers than the utility itself. State regulatory commissions have rules in place governing affiliate transactions to prevent "self-dealing," where the utility pays above-market prices for affiliate services or provides services at below-market prices to affiliates. Such rules also are intended to protect the utility's customers from risky actions by affiliates. Whether and how utilities offer value-added services that are otherwise available in the marketplace is a fundamental question regulators will increasingly face. Appendix B provides summaries of utilities providing certain value-added services.

- **Openness of utility networks** - Public policy goals for distributed energy resources rely on innovation through competition that increases adoption and reduces costs of technologies and practices. Openness of utility networks may play a significant role in determining the pace and nature of these changes.

  There are many examples today where independent service providers are challenged in, or have raised concerns about, their ability to access utility networks. For example, the utility's AMI communications system may not be open to demand response providers, or interconnection procedures for rooftop solar or industrial combined heat and power systems may be difficult to navigate. To the extent regulators do not remedy these conditions, service providers will need to partner with utilities in ways that provide advantages to utilities or "leapfrog" the status quo and thrive outside of utility networks.

- **Regulatory processes** - It will take years of thoughtful testimony and deliberation, experimentation, evaluation, and refining to address changes in regulatory regimes and business models through policy, rulemaking and ratemaking dockets by state regulatory commissions and potentially statutory changes by state legislatures. Meantime, commissions will need to continue to make decisions in more narrowly focused general rate cases and other proceedings. State commissions will need to decide if they want to pursue incremental changes to current regimes or consider more comprehensive and fundamental changes to electric utility regulatory models (e.g., New York, Minnesota).

  While Great Britain has used performance-based regulation for electric utilities for decades, and it may appear straightforward to import the model directly, some important considerations may limit implementation of RIIO-type regulation in the United States. First, such a mechanism would require a change in regulatory thinking and approach. RIIO builds on more than 20 years of experience in Great Britain with revenue cap regulation. Second, Ofgem has a staff of more than 750, many of whom are economists trained in incentive regulation (Ofgem, 2014). Regulatory staffs in many U.S. states have little or no experience in these areas and generally have fewer trained economists. Also, the population and cultural differences between the Unites States and Great Britain may affect public acceptance of a regulatory approach here that shifts from historical accounting-based costs and pricing to an approach that attempts to create customer value determined by a regulatory authority. As regulators in the United States consider broader performance-based regulation, pilot programs may be useful for exploring how performance metrics tied to a portion of the utility's revenues may lead to better outcomes and may help overcome some of these identified challenges.

- **Leverage experience** - There has been considerable experience in the Unites States with tracking, rewarding and penalizing utility performance for energy efficiency, as well as service quality measures related to reliability and customer services. There also has been a fair amount of experimentation with performance-based ratemaking in the United States and abroad in other utility sectors. Lessons learned from these experiences over the decades should be collected and analyzed, including assessments tailored by market structure and for representative regulatory regimes.

- **Incremental changes to COS regulation** - To the extent that state regulators have not yet adopted incremental changes to COS regulation as described in this paper (e.g., decoupling, shareholder incentives), these may be appropriate transition steps before considering more significant modifications to regulatory regimes that affect a utility's profit motivation and profit achievement.

- **Assessing and ensuring customer benefits** - Regulators will need to evaluate the potential customer benefits and risks of any proposed regulatory changes, develop performance metrics for key desired outcomes, and set mandates as well as incentives and penalties to align the utility's performance with those metrics. Depending on the nature of the regulatory changes, state commissions should consider built-in customer protections such as annual reviews, price caps, sharing mechanisms and off-ramps.

7. Implications for Future Research

Many state policymakers and regulators are keenly interested in quantitative analysis of potential future impacts of distributed energy resources on utilities and customers. These impacts are dependent on various conditions—electric industry market structure, regulatory environment, state and federal policy goals, rate design, ratemaking practices, tax credits and other customer incentives, among others. Of particular interest to states are the combined effects of a suite of distributed energy technologies and multiple policies and regulations on costs, benefits, and risks for utilities and customers.

Several states are exploring these issues in formal proceedings initiated via regulatory or legislative directives or in response to utility proposals. Some of these proceedings are focused on specific policy tools such as net energy metering or decoupling, while others are broadly reviewing rate design for all customers or fundamental changes to traditional regulation and utility roles.

Among the key issues to address in future research are the following:

- Application of financial principles in assessing utility returns and risk that may provide different rates of return for different types of utility investments, as well as assessing approaches to reduce risk for successful achievement of clean energy public policy goals;
- Transition strategies and options for performance-based regulation that tie utility profits to meeting particular outcomes for customers and society;
- Design of performance incentive mechanisms related to grid modernization objectives (e.g., resiliency, reduced outages, improved customer choice);
- Openness of customer information and utility networks that will be predicated on developing customer data access standards for utilities and third-party service providers; and
- Development of proper and fair pricing of energy services beyond cost per kWh (e.g., $ per lumen, $ per kWh of solar-generated electricity).

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Appendix A. Mathematical Representation of COS Models

We developed general form equations to algebraically represent the various business models discussed in the paper and to represent the change in how different models achieve, and therefore motivate, profits for a regulated electric utility. A regulated utility's profits (and the profits for any firm) are based on the difference between collected revenues and incurred costs during a given period, such that:

(1) $P = R - C$

Where,

P = Profits

R = Revenues

C = Costs

The actual calculation of revenues and costs will differ among utilities based on the particular regulatory and ratemaking environment in which the utility operates. Some of those differences include: test year used for revenue requirement calculation (e.g., historical versus future test years), period of time between when a utility files a rate case and new rates take effect (i.e., regulatory lag), use of balancing accounts to "pass through" certain costs (e.g., fuel adjustment clause, bill riders or trackers), and the approved rate design that determines how the utility collects revenues among customers based on their volumetric energy and demand consumption, as well as the use of fixed (i.e., customer) charges. Likewise, utilities can differ substantially in the costs they incur: financing costs (e.g., cost of debt, cost of equity), non-fuel operations (e.g., salaries, pension) and maintenance (e.g., newer vs. older equipment), fuel costs (e.g., age and efficiency of generation fleet, fuel type). The algebraic representations, therefore, generalize the different idiosyncrasies of utility revenues and costs and would be applicable in most U.S. regulatory jurisdictions. Notwithstanding our generalization above, we differentiate below among commodity and non-commodity costs (i.e., fuel and non-fuel costs) in the equations because those costs are typically incurred and treated in different ways from a revenue collection standpoint.

Traditional Model for a Regulated Electric Utility

The profit of the regulated electric utility under a traditional model (i.e., cost of service approach) is based on collection of revenues set at "fair and reasonable" prices by a regulatory authority. Prices are based on revenues that match the utility's test year revenue requirement. The profit of a regulated electric utility, therefore, can increase or decrease in between rate cases based on changes to actual collected revenues and/or actual costs that may differ from test year revenue requirements.

The total costs of a regulated electric utility are calculated as:

(2) $C = (VCC * Q) + (VNCC * Q) + FNCC + (r * RB)$

Where,

VCC = Variable commodity costs

VNCC = Variable non-commodity costs

FNCC = Fixed non-commodity costs (includes taxes on net income, and depreciation costs, and debt service costs for rate base assets)

r = Overall rate of return

RB = Ratebase (i.e., net investment in assets to provide electric service)
Q=Quantity of retail electric sales

And, the average retail price[21] of electricity is:

(3) $$P = \frac{C}{Q} = \frac{(VCC*Q)}{Q} + \frac{(VNCC*Q)}{Q} + \frac{FNCC}{Q} + \frac{(r*RB)}{Q}$$

Where,
P = Price of retail electric sales (i.e., revenue requirement per unit electricity sales)

The profit, or net income (NI), of the regulated electric utility is therefore:

(4) $$NI = (P * Q) - \big((VCC * Q) + (VNCC * Q) + FNCC + (r * RB)\big)$$

Where,
Q = Quantity of electric sales

Incremental Changes to the Traditional Business Model: Fuel-Adjustment Clause

Over the past several decades, regulators have increasingly been willing to allow regulated electric utilities to fully collect their commodity costs regardless of the revenue collected via the commodity portion of the retail rate. This is commonly called a Fuel Adjustment Clause (FAC). Thus, if we characterize the commodity and non-commodity portion of the collected revenue in similar manner as we do the costs, then the commodity revenues and costs cancel out due to the FAC, leaving us with:

(5) $$NI = \left\{\left[\frac{(VNCC*Q)}{Q}\right] * Q\right\} + \left\{\left[\frac{FNCC}{Q}\right] * Q\right\} + \left\{\left[\frac{(r*RB)}{Q}\right] * Q\right\} - (VNCC * Q) - FNCC - (r * RB)$$

We can take the total differential to see what can impact net income in the short-run, assuming the non-commodity portion of the retail rate is set.

(6) $$\Delta NI = \left\{\left[\frac{(VNCC*Q)}{Q}\right] * \Delta Q\right\} + \left\{\left[\frac{FNCC}{Q}\right] * \Delta Q\right\} + \left\{\left[\frac{(r*RB)}{Q}\right] * \Delta Q\right\} - (VNCC * \Delta Q) - (\Delta VNCC * Q) - \Delta FNCC - (\Delta r * RB) - (r * \Delta RB)$$

In the short-run, the utility has relatively constant unit variable costs, so ΔVNCC=0. Additionally, the utility's authorized return on equity as well as rate base asset levels are set during rate cases and so likewise are invariant in the short run , so Δr=0 and ΔRB=0. Thus, after cancelling out a few terms, the equation (5) reduces to:

(7) $$\Delta NI = \left\{\left[\frac{FNCC}{Q}\right] * \Delta Q\right\} + \left\{\left[\frac{(r*RB)}{Q}\right] * \Delta Q\right\} - \Delta FNCC$$

The regulated electric utility in this case is motivated in the short-run to increase retail commodity sales (Q), reduce fixed non-commodity costs (FNCC), reduce capital investments (RB), or any combination of the three.[22] Thus, any efforts to reduce Q can have negative financial implications for the utility, including under-recovery of fixed costs due to reductions in commodity sales below what was expected

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[21] Though there are differences in the actual price (or prices) of electric service a particular customer faces, we use the average retail electricity price throughout the appendix as a way to simplify and generalize the equations.

[22] Reducing capital investments between rate cases may increase short-run profits, but it will lower the level of rate base used in the next rate case from what it otherwise would have been. This will result in lower authorized return on the equity portion of financed capital investments (i.e., profit) due to the smaller rate base in the long-run.

during the rate-setting period.

Incremental Changes to the Traditional Business Model: Lost Revenue Mechanism

Historically, regulators and policymakers have dealt with this under-recovery of fixed costs via some sort of auxiliary revenue collection mechanism. A lost revenue recovery mechanism (LRRM) can come in many forms[23] but invariably attempts to ensure the utility's lost revenues can be recaptured to sufficiently cover these allowed fixed non-commodity costs and not adversely impact achieved net income by compensating the utility with additional revenues.

(8) $$\Delta NI = \left\{\left[\frac{FNCC}{Q}\right] * \Delta Q\right\} + \left\{\left[\frac{(r*RB)}{Q}\right] * \Delta Q\right\} - \Delta FNCC + LRRM$$

Incremental Changes to the Traditional Business Model: Shareholder Incentive Mechanism

As noted above, a utility's authorized after-tax net income (i.e., profit) level is defined by its authorized return on equity and the amount of equity used to finance its book of rate base assets. This means the utility's profit levels are predicated on the size of its book of rate base assets, which are investments made by the utility deemed "used and useful" by regulators. If reductions in commodity sales defer the need to invest in capital assets down the road, the utility's expected profit level will be lower than it otherwise would have been. This may create a barrier to utility managers, whose financial compensation may be based in part on the level of profits, from more vigorously pursuing opportunities that may reduce commodity sales levels (e.g., energy efficiency, solar PV). In the energy efficiency arena, this is commonly counteracted by providing the utility with a shareholder incentive (SI), a financial compensation mechanism, often based on meeting or exceeding energy savings goals, as a way to partially offset some of those lost earnings opportunities (e.g., Cappers et al., 2010). Such an approach has also been discussed concerning solar PV (e.g., Satchwell et al., 2014).

(9) $$\Delta NI = \left\{\left[\frac{FNCC}{Q}\right] * \Delta Q\right\} + \left\{\left[\frac{(r*RB)}{Q}\right] * \Delta Q\right\} - \Delta FNCC + LRRM + SI$$

Fundamental Change to the Traditional Business Model: Services-Driven Utility

One way to alter the business model is to move the utility's attention away from promoting sales of the electric commodity and rather getting them to focus on offering value-added services. Under this business model, the utility's revenue is collected based on a combination of retail electric commodity sales and value-added services (S) it provides. The price for each service would be set in such a way that it would cover some fraction of the utility's fixed non-commodity costs (α) and return on investment of existing infrastructure (β) as well as variable costs needed to provide the value-added services. The remainder of the utility's fixed non-commodity costs and return on investment of existing infrastructure would be recovered from electric commodity sales.

(10) $$NI = \left((P_Q * Q) + (P_S * S)\right) - \left((VCC * Q) + (VNCC * Q) + (VSC * S) + FNCC + (r * RB)\right)$$

[23] These mechanisms include lost revenue recovery (LRR), sales decoupling, and lost base revenue (LBR), among others.

P_Q=Price of retail electric commodity sales
P_S=Price of retail value-added services
S=Services
VSC=Variable value-added services cost
If we take the total differential of net income under this altered business model, we can see how changes in both electric commodity sales and value-added services impact the utility's bottom line.

$$(11) \quad \Delta NI = \left\{\left[\frac{(1-\alpha)*FNCC}{Q}\right]*\Delta Q\right\} + \left\{\left[\frac{((1-\beta)*r*RB)}{Q}\right]*\Delta Q\right\} + \left\{\left[\frac{\alpha*FNCC}{S}\right]*\Delta S\right\} + \left\{\left[\frac{(\beta*r*RB)}{Q}\right]*\Delta Q\right\} - (VSC*\Delta S) - \Delta FNCC + SI$$

Although demand for energy efficiency, solar PV or other value-added services may cause a reduction in commodity sales (ΔQ), the utility has found a new source of revenue in providing these value-added services (ΔS) that can be used to help cover some/all of the fixed non-commodity costs including return on rate base assets (i.e., no lost revenue requirement mechanism (LRRM) is required) lost due to lower commodity sales. If the increased pursuit of these value-added services results in an expansion of capital investment on the part of the regulated electric utility, they may pursue such opportunities on their own. However, if that is not the case, it is still likely that unless the utility is provided with some form of shareholder incentive (SI), these value-added services may not be pursued by the utility with as much vigor as policymakers and regulators would like. Hence, there is likely still a need for some sort of shareholder incentive on these value-added services.

Fundamental Change to the Traditional Business Model: Value-Driven Utility

Incentive regulation, in which firms have a direct financial reward for minimizing production costs (Laffont and Tirole, 1993), can take on many forms for regulated electric utilities. According to Comnes et al. (1995), the generalized equation for incentive regulation is as follows:

$$(12) \quad R = a + b*C$$

Where,
R = Revenue
a = fixed payment, set *ex ante*
b = *ex ante* sharing fraction, 0<b<1
C = *ex post* costs

The traditional model (i.e., cost of service) is considered a form of incentive regulation, whereby the electric utility has an incentive to manage its *ex post* costs between rate cases and make profits if costs are less than the levels used for ratesetting. Other forms of incentive regulation, known as performance-based ratemaking (PBR), tie a utility's profits to its performance (and not to costs). The viability of a PBR mechanism, however, is dependent on its pricing efficiency such that the price reflects changes in costs. Many PBR mechanisms incorporate approaches to reflect possible *ex post* changes in costs (the terms may be positive or negative changes), including annual changes in prices (e.g., change due to inflation), productivity offsets (e.g., change in firm's productivity), and adjustments for changes outside utility management's control.

A general equation for the net income under PBR is challenging given the broad spectrum of different forms of PBR. Examples include "sliding scale" regulation (e.g., earnings sharing mechanism), revenue caps, price caps, or "menu of contracts".[24] Equation 13 illustrates a general equation under price caps with PBR profit provisions tied to outcomes.

$$(13) \quad NI = \left((CapP_Q * Q) + (CapP_S * S) \right) - \left((VCC * Q) + (VNCC * Q) + (VSC * S) + FNCC + PBR\ Profit\ Provisions \right)$$

[24] For a full discussion of these types of PBR and detailed calculations, see (Comnes et al., 1995)

Appendix B – Value-Added Services Associated with Distributed Energy Resources

Utility-Owned Rooftop Solar in Arizona

In December 2014, the Arizona Corporation Commission issued decisions on proposals by two utilities, Arizona Public Service Company (APS) (ACC, 2014a) and Tucson Electric Power Company (TEP) (ACC, 2014b), to install, own and operate solar photovoltaic (PV) systems on customers' rooftops. The proposals illustrate new value-added services pursued by vertically integrated utilities under traditional COS regulation and some of the tradeoffs created.

According to the company's website, APS plans to install, own and operate solar PV systems at approximately 1,500 residential customer sites. APS stated that the program offers a way for customers who cannot afford to purchase or lease a PV system to "go solar." Participants will continue to receive 100 percent of their electricity service from APS under their original rate tariff. They will receive a $30 per month bill credit in exchange for APS' use of their roof space.

Similarly, TEP's website indicates the company will install, own and operate solar PV systems on customer rooftops. Unlike APS' program, TEP program participants switch from their current tariff to the proposed "residential solar—company owned systems" tariff for the life of the installation (25 years).[25] Participants will pay a flat monthly fee of $16.50/kW "based on the capacity of the solar equipment necessary to meet the customer's most recent 12 month historical usage" (ACC, 2014c) The monthly charge readjusts if consumption grows or declines by 15 percent or more. The charge is structured to recoup from participants directly both system costs and fixed costs (ACC, 2014c). The proposed monthly fee also will cover a portion of the capital costs of the PV systems.

Both programs maintain the utilities' current asset ownership and sales-based profit achievement. TEP's flat monthly charge slightly reduces its throughput incentive. (TEP does not earn additional revenue from the monthly PV fee if customer electricity usage increases by less than 15 percent.)

These initiatives both introduce new roles for the utility: rooftop PV system developer, financier, owner and operator. While APS and TEP plan to contract with local installers and O&M providers, third-party developers voiced concerns when the utilities proposed to move into these new roles. APS and TEP state that asset ownership is necessary for a greater understanding of the system benefits of a utility designed, optimized and operated network with solar PV generation.

[25] Customers can terminate the agreement through a system purchase provision.

Home Automation Services in Michigan and Oklahoma

Detroit Edison Company (DTE)[26] and Oklahoma Gas & Electric (OG&E) received grant funding from the U.S. Department of Energy to deploy advanced metering infrastructure and to study consumer demand-response behavior in response to information and control technology. Both the DTE and OG&E pilots are examples of vertically integrated utilities providing valued-added services under a traditional COS regulatory framework.

DTE's 2012 SmartCurrents consumer behavior study placed more than 2,000 customers on a three-tier, time-of-use (TOU) rate structure with a critical-peak pricing (CPP) overlay. Participants received an in-home display (IHD) showing energy prices, a programmable communicating thermostat (PCT) or both. The IHD allowed customers to monitor price signals and prepare for higher-priced periods by modifying consumption. The PCT responded automatically to energy prices.

Results of the study were encouraging, with some participants reducing consumption up to 44 percent during critical peak hours. In addition to lower utility bills, participants in the Smart Currents study reported "higher satisfaction with DTE overall, which may stem from positive interactions with the program or be an artifact of the self-selection process for joining the pilot" (DTE Energy, 2014).

The same year, OG&E introduced a similar pilot program to residents and businesses of Norman, Okla. The Smart Study TOGETHER pilot placed over 3,200 participants on a TOU rate with a CPP overlay or a variable peak pricing rate structure. Participants received an IHD, PCT or both. Participants also had access to a web portal where they could view consumption data and prices.

OG&E's initial results were equally positive. Some participants reduced energy use up to 43 percent during critical peak events. OG&E summed up the value to both the utility and customers: "the programs provided good business value to OG&E, and customer satisfaction is at an all-time high. It shows how … technology can really work to improve the utility-customer relationship" (Oklahoma Gas and Electric, 2011).

[26] Michigan's electric market is partially restructured, with a retail sales-based cap on customer choice of electricity suppliers. Still, it largely remains a vertically integrated utility structure.

Home Energy Reports in Washington State

In 2008, Puget Sound Energy (PSE), a vertically integrated electric and natural gas utility serving more than 1 million customers in Washington, became the second U.S. utility to include a "Home Energy Report" program as part of its energy efficiency portfolio. The program offers single-family homeowners detailed monthly or quarterly information on their energy use, a comparison to similar homes nearby, and customized tips for saving energy and money. Using Opower's software platform, the Home Energy Report program also connects participants to a web portal with energy-saving tips and to PSE's "Energy Advisors" hotline service.

PSE's program is now in its fifth year and has grown from 40,000 to more than 150,000 participants, in part due to a 2010 ruling allowing PSE to use conservation surcharge funds to expand the program. A recent evaluation found that households receiving Home Energy Reports reduced electricity use by 3 percent and natural gas use by 1.5 percent (DNV-GL, 2014; Opower, 2014a). More than two-thirds of participants report a positive experience during the program, and only 2 percent of participants have opted out (Opower, 2014b).

Energy Efficiency Performance Targets in Illinois

The 2007 Illinois Power Agency Act (20 I.L.C.S. 3855) codified the state's commitment to reduce costs to consumers through cost-effective energy efficiency and demand response measures. Under the Act, the deregulated electric utility sector must achieve annual savings targets beginning at 0.2 percent of 2008 sales and ramping up to two percent of sales in 2015 and thereafter. The Act provides for utilities to recover costs associated with meeting these goals through adjustment tariffs outside of general rate cases.

Utilities that do not meet their energy savings targets within two years are subject to fines of $335,000 to $665,000. Further, if targets are not achieved within three years, the Illinois Power Agency may take over implementation of the utility's energy efficiency activities.

Utility spending to achieve energy savings goals is limited by a rate cap that establishes the maximum rate impact allowable, compared to a 2007 baseline. The rate cap levels out in 2012 at about two percent of 2007 rates. A 2011 report found that the rate cap is likely to restrict utilities' achievement of their savings goals (Illinois Commerce Commission, 2011). Beginning in 2012, the Act allows for additional cost-effective energy efficiency, not subject to the rate cap, to be achieved through utility procurement plans submitted to the Illinois Power Agency for approval.

On-Bill Financing in New England

In its "New Business Models for the Distribution Edge" report, the Rocky Mountain Institute described the concept of the utility as a "FinanceCo" that provides loans, paid back on utility bills, for customers to install distributed energy resources (Newcomb et al., 2013a). While not a full realization of the "FinanceCo" concept, National Grid's multi-state on-bill loan programs offer an example of a distribution utility providing financing for energy efficiency improvements under the traditional COS regulatory framework. In a full FinanceCo construct, the utility also would provide loans for renewable energy systems and put participants on a special tariff that reflects the cost to serve them and provides incentives for DER deployment.

National Grid has offered on-bill financing programs to small commercial and large commercial and industrial customers in Massachusetts and Rhode Island since 1993.[27] The program uses capital from National Grid's energy efficiency program budget and from a public benefits charge to finance a range of energy efficiency improvements at eligible customer sites. The two-year, zero-interest loans are coupled with attractive rebates—up to 70 percent of project costs—to encourage participation.

In 2012 alone, National Grid distributed over $31 million through these two programs (9,800 small commercial loans and 154 large commercial and industrial loans), ranking among the highest-volume on-bill initiatives in the United States[28] The programs are oversubscribed and National Grid is considering working with a private capital provider to make loans available to more customers and expand the programs' impact.[29]

[27] In 2010, National Grid began offering small business loans in upstate New York.

[28] Some 30 on-bill utility finance programs have made more than $1.8 billion in loans (Zimring et al., 2014).

[29] For a detailed description of National Grid's programs, see Zimring et al. (2014), Technical Appendix.