Recent Developments in the U.S. Electric Industry: Options for State Utility Regulators

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National Regulatory Research Institute

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Executive Summary

The growing consensus is that the U.S. electric industry is undergoing a transformation over the next several years. Major developments in technology and energy policy point to important changes in the electric industry. While even this favored policy narrative among experts is no guarantee of the future, it is dictating the ongoing dialogue across the country about possible new actions at both the state and federal levels. This paper does not predict that transformation of the electric industry will occur on a broad scale. In fact, it projects that the degree of transformation will vary across states, just as the electric industry saw a diversity of state responses toward retail and wholesale restructuring in the 1990s.

This paper outlines the topics and issues that state utility regulators should examine in line with a changing electric industry. It does not delve deeply into the myriad topics that utilities and regulators will need to address in contemplating a transformed electric industry. Assuming interest from state regulators, NRRI proposes conducting more in-depth analyses of individual topics in future papers. We have seen initial and sometimes heated dialogue on these topics and expect it to continue over the next several years. What NRRI offers in this dialogue is a public-interest perspective that is fundamental for good public policymaking.

This paper starts off by listing the salient features of the electric industry. It discusses, for example, how the industry has a large footprint on society, playing a vital role in economic growth and the environment, among other things. This wide influence makes the electric industry susceptible to interest-group politics and serious disagreement over its future direction.

The paper then lays out a vision of the future electric industry that is compatible with the views expressed by many industry experts. This vision includes the marked growth of new, and what some observers call disruptive, technologies, such as distributed generation, the smart grid, storage, electric vehicles, the slowing of demand growth, rising costs, the increased penetration of renewable energy, an aging infrastructure and rising physical and cyber threats. Along with policy mandates that will increase their costs, electric utilities are likely to face daunting challenges in the years ahead. How they will fare in securing needed investment capital and maintaining shareholder interest, in addition to advancing their customers' welfare and broader societal objectives, hinges to an important extent on state utility regulation.

This paper addresses two fundamental questions about a transformed electric industry: (1) What roles should utilities play? and (2) How should state utility commissions regulate utilities fulfilling those roles? Many experts believe that utilities will have to operate under new business models to prosper, and even survive, in the new market environment. The new business models should converge on achieving maximum value of the central grid to electricity consumers, which includes both core and distributed generation (DG) utility customers. The result might be a reconfiguration of the utility distribution system as a platform for efficiently and fairly integrating distributed resources and centralized resources. Fairness would involve creating fair opportunities for all generation resources. The business model along with reformed ratemaking could create incentives for steering utility efforts toward predetermined social goals.

The business model, whether fundamentally different from the existing one or only changed by a few minor tweaks, will dictate the goals and scope of regulation.

One question is whether policymakers (e.g., state legislatures and utility regulators) should shape the utility business model. The alternative is for the market to dictate the model with minimal outside intervention. The business model spells out the role of the utility, which can range from a wires provider or a facilitator to an energy-service provider. It should have the primary goal of maximizing long-term customer welfare while keeping prudent utilities financially viable. In a transformed electric industry, this goal requires customer empowerment, with utilities offering value-added services, customers making well-informed decisions about their use of utility facilities and resources, and new technologies enabling customers to minimize their associated transaction costs.

The main part of this paper focuses on the challenges facing state utility regulators in adapting to a transformed electric industry. Many observers contend that the *status quo* or traditional regulation is not compatible in an environment in which distributed resources, the smart grid, rising average costs, high investment requirements, and energy storage prevail. Under a reshaped utility business model, regulators might want to consider a new ratemaking paradigm that, first, rewards exceptional performance and, second, gives utilities incentives to promote customer and societal interests. In arriving at a final resolution, regulation will likely need adjusting, so that it corresponds with the business model under which utilities will operate.

A basic question is what posture state public utility commissions will take: Will they lead, follow or rationally resist change? Commissions may have to revisit their interpretation of "just and reasonable" rates and redefine the public interest. They may have to grapple with advancing additional objectives, either mandated by the outside or self-imposed. In serving the public interest, smart regulation would achieve these objectives, some of which are conflicting, at the lowest total cost to and engendering the greatest total benefits for society.

In considering reforms, commissions should ask four basic questions:

1. What functions do electric utilities serve in advancing society's interest and which, if any, of those functions possess the essential characteristics of natural monopolies?

2. What specific actions should utilities take to perform those functions?

3. What incentives or protections should regulation provide?

4. How should regulators reform or change their present policies and practices?

The sphere of electric utilities responsibilities has expanded beyond providing reliable service at "just and reasonable" prices. Increasingly, policymakers require utilities to expand their sphere beyond a for-profit business by assisting low-income households, accommodating, facilitating and even subsidizing their competitors (e.g., distribution generation) and renewable energy, adopting non-profitable new technologies, promoting energy efficiency, achieving clean-air targets beyond federal and local mandates, and empowering their customers to make more economical decisions. A major topic in the policy debate is the extent to which utilities should broaden their functions to address society's needs. No unambiguous answer exists at this time. The vague answer is that it depends on what functions policymakers assign to utilities. An expansive role for utilities could place upward pressure on electricity prices, at least in the near term, and potentially conflict with traditional regulatory objectives (e.g., cost-based rates, consumer protection, least-cost utility operations, adequate service reliability).

One of the most serious challenges for regulators in a transformed electric industry is to provide utilities with financial incentives to achieve cost-effectively both utility financial stability and society's broader policy goals. Constructing regulatory incentives that are compatible with achieving the goals assigned to utilities has always challenged regulators. Attempts have sometimes led to unintended, counterproductive outcomes. Without financial inducements, however, regulators would have to take an alternate, heavy-handed path of closely monitoring utilities to ensure that their performance coincides with societal goals.

Regulators will also need to address whether to engage in any major reinventing, or a much more modest incremental reshaping. For example, will performance-based regulation, new rate designs, and modest expansions of the utility's role in a revamped industry satisfactorily accomplish regulatory goals? Will regulators, instead, have to resort to more drastic steps? It is not too soon to think about how the electric industry will evolve and how regulation will have to adapt. Regulators, operating under the assumption that the future electric industry will change fundamentally, should begin to study innovative regulatory approaches.

The last part of this paper raises the question of how likely is it that the radical changes predicted by many industry observers will actually transpire. Some of these predictions reflect less of objective assessments of the future and more of self-serving scenarios, a quasi-religious mission, and parochial wishful thinking. It is easy to imagine that that the future will actually turn out differently from what many observers are now projecting; after all experience demonstrates that predictions often miss the mark. Planning today based solely on a single future scenario, even one that represents a best guess given the information presently available, is risky. If that scenario fails to materialize as imagined, society could suffer large adverse consequences, from well-meaning actions that turn out to have been misguided. Put simply, today's popular policies may take us down a primrose path to arduous transitional problems, inefficient and unreliable utility service, and excessive electricity prices.

This paper also recognizes the inherent conflict between regulators obligating electric utilities to advance an expanding number of social objectives while simultaneously expecting investor-owned utilities to carry out their fiduciary responsibilities to shareholders. More than almost any other private entities, society expects electric utilities to integrate social goals into their decision-making process. Regulators themselves face the difficulty of balancing the objectives of keeping prudent utilities financially healthy while achieving a broadened social agenda. One can reasonably ask whether electric utilities more resemble public agencies than private entities driven to serving only their shareholders and customers. One can also question whether funding each specific social mandate through utility rates is in the best interest of electricity customers. This paper recommends that regulators as well as other policymakers do a thorough reality check when contemplating the proper roles for electric utilities.

This paper ends by observing that policymakers might be slighting the capability of the free market to direct the future path of the electric industry. In an ideal market, for example, clean energy technologies would compete with one another and with the technologies they seek to replace, not for government handouts or regulatory or legislative favors that effectively function as inefficient, rent-seeking actions. In addition to minimal subsidies, essential conditions for well-functioning markets include consumer empowerment, robust incentives for innovation and economically rational pricing.

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Options for State Utility Regulators

I. Where We Are Today

No one wants to be guilty of being backward or reactive about the future of the electric industry. The favored position as of today is that the utility of the future will have a radically different role and business model than what exists today. If that is true, then state utility regulation will have to reshape its policies and practices to align with the new industry. A contrarian position is that it is presumptuous to say for sure that the industry will change dramatically, notwithstanding the trend toward so-called game changers in the form of renewable and distributed energy, power storage and the inexorable movement toward clean energy. This position has credibility as we have learned from the past that expected events, for various reasons, often fail to transpire. A transformed industry, as we have seen for electric-industry restructuring that initiated in the 1990s, may occur in a number of states but not in others.

While a few states, such as California and New York, are preparing for this new world in a dramatic way, most so far have exhibited more caution. Many questions still remain before we can say with certainty that the electric industry will see a transformation over the next several years. There is no denying that the prospect for big changes is a real possibility. Whether these changes will penetrate the industry in a large way across the majority of states remains to be seen. After all, many who are projecting change either have ideological, even bordering on a quasi-religious mission, or monetary interests in promoting such a path. Regulators should, therefore, not just accept these optimistic[1] or rent-seeking[2] claims for new technologies on face

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[1] One area of optimism is that a massive number of residential customers will invest in solar PV systems. It is plausible that only a small minority of households care enough about lowering their electricity bills to spend a large amount of dollars upfront or even allow a third party to make the investment and install a system on their rooftop. After all, the average residential customer spends only about 2.7 percent of its before-tax income on electricity. (Bureau of Labor Statistics, *Annual Expenditure Survey*, 2012.) Experiences with retail choice has also shown that the vast majority of residential customers would prefer staying with their current utility rather than switching to a third party even at the lost opportunity to lower their electricity bill.

[2] Some analysts contend that the same condition accounts for both the recent push for distributed generation and support for retail competition in the 1990s; namely, that average cost exceeds marginal cost in both periods, meaning that utility customers benefit from bypassing utility service (priced at average cost) and switching to another source (priced at marginal cost). Because of this pricing discrepancy, it is difficult to know whether bypass improves net economic welfare (i.e., economic efficiency). The effect is cost-shifting between electricity customers, rather than real cost savings. In both instances, lost utility revenues typically pass through to remaining full-requirements customers in the

value but act accordingly to a future that may, but not with certainty, turn out much differently than what the consensus projects as of today. This posture has implications for what actions regulators should take today and in the immediate future versus waiting to see what evolves over the next few years.

The overall question for state utility regulators is what actions they should pursue in view of these prospects for dramatic change in the electric industry. Should they take the lead in proposing changes in utility operations and the business model, and how they regulate? Should they, instead, wait longer to see what transpires in technology development, and regulatory and energy/environmental policies in other states and at the federal level? What are the costs of staying with the current utility business model and regulatory practices if radical changes occur? At the other extreme, what are the costs of reshaping regulation and the utility business model when the expected changes fail to transpire? Will an explosion in distributed generation, for example, be confined to a few geographical areas or will it permeate across most states?

We know from experiences in the 1990s and early 2000s the difficulties of transforming the U.S. electric industry from a highly regulated to a market-driven sector.[3] Compared to other industries that have taken the deregulation route, namely, natural gas, financial services, trucking, railroad, telecommunications, and airlines, the transition to a restructured electric industry has been afflicted with myriad stumbling blocks. For restructured states, a major obstacle rested was the divergent visions that interest groups held about the future direction of the electric industry. There was no solidarity of views about where the industry should be heading. For the other states, restructuring was not even a topic of discussion or stakeholders reached a consensus of "no change." The present situation is similar in that the dialogue over the utility of the future involves several interest groups with varying views about what path the electric industry should pursue. Political and economic conditions also make it rational for states to take dissimilar decisions on the future of the electric industry.

Policymakers should not underestimate the transitional problems and difficulties in going from today's electric industry to the future industry envisioned by many observers. From the restructuring efforts of the 1990s, we discovered that flawed policies, notably in California, can have serious counterproductive outcomes.[4] Some of the problems were not cyclical and short-lived; instead, they were more structural in nature. Germany is another example where transforming the electric industry has met with serious and unexpected transitional difficulties.

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form of increased rates. This contention basically says that customers wanted to avoid utilities' sunk costs by having the right to choose another supplier. The logical remedy is to set utility retail rates based on marginal or incremental cost. *See*, for example, Borenstein and Bushnell (2014).

[3] *See*, for example, Navigant Consulting (2013); and Joskow (2006).

[4] Policymakers also neglected to adopt new practices that would have aligned with the restructured industry and led to improved outcomes. These practices included marginal-cost pricing for retail services and robust incentives for productive efficiency and innovations.

Because, among other things, electricity has significant environmental and other economy-wide effects, consumes large amounts of energy in production, and is essential for businesses and households, interest groups engaged in these matters are vocal and active participants in the dialogue over the future electric industry. Selling major changes on the idea that it will lead to a cleaner, more socially responsible and efficient industry may reach a political consensus only after much effort and compromise.

The electric industry has several features that make it highly visible and susceptible to politics and interest-group lobbying. Table 1 highlights these features, grouped by utility regulation, market and economy-wide. The electric industry affects many aspects of society in a profound way.

Features of the longstanding traditional electric industry include the following: centralized power generation, economies of scale, one-way power flow, limited customer and system operating information, passive small retail customers, almost nonexistent power storage, analog systems, and centralized control centers. As discussed later, all of these features, largely because of new technologies, may erode in the coming years.

Many observers contend that the *status quo* or traditional regulation is not compatible in an environment where distributed resources, the smart grid, rising average costs, high investment requirements, and energy storage prevail. In reaching a balance, regulators should try to match the business model under which utilities will operate. They might, for example, want to contemplate a new ratemaking paradigm that (1) rewards exceptional utility performance and (2) gives utilities incentives to advance customer and societal interests.

This paper will not delve deeply into the myriad topics that utilities and regulators will need to address in contemplating a transformed electric industry. Assuming interest from state regulators, NRRI will propose conducting more in-depth analyses of individual topics in future papers. We have seen initial and sometimes heated dialogue on these topics and expect this to continue over the next several years. What NRRI offers in this dialogue is a public-interest perspective that is fundamental for good public policymaking.

II. One Vision of the Future Electric Industry

A. Expected developments for the future

Table 2 shows future developments that many experts project for the U.S. electric industry. Many of these developments pose serious financial challenges to utilities. One is that they will lower the ability of utilities to fund increased investments from revenue growth.[5] Customers will also likely impose greater demands on utilities (e.g., quicker utility response time

[5] The reader may correctly argue that over time utilities should invest less because of slower sales growth. While this is true, many of the future utility investments will not be correlated with sales

Table 1: Three Broad Features of the U.S. Electric Industry and Its Regulation

Utility Regulation	Market Characteristics	Economy-wide Effects
State-by-state balkanization	Wholesale power prices in restructured markets highly vulnerable to demand and supply shocks	Substantial environmental footprint
Many stakeholders involved	Essential input for many energy services	High social costs from outages or supply shortages
Highly visible and politicized	Large capital requirements with long lead times	Vulnerable to cyber and physical terrorist attacks
Tight price control over natural-monopoly services	Competitive conditions in restructured wholesale markets	Large user of energy
Federal/state jurisdictional disputes	Some retail competition that includes residential customers	Important driver of economic growth
State jurisdiction over transmission siting	High regret from unexpected events or poor public policies*	

* Examples include prolonged service outages, large overruns of generation construction costs, PURPA payments far above avoided costs, manipulation of the California wholesale power market.

to outages). As perhaps the most serious challenge, utilities will face greater competition behind-the-meter.

The inherent nature of new technologies or innovations poses five challenges for utilities and regulators:[6] High costs, uncertain costs, uncertain benefits, often minimal short-term

growth (e.g., grid improvements to accommodate DG, environmentally-driven) but with energy and regulatory policies.

[6] New technologies include solar, wind and other renewable energy resources, storage, the smart grid and electric vehicles. Not all of these technologies are economical presently and will require further technical improvements or changing economic conditions, which may be several years down the road, before they are. Some enjoy large tax subsidies with uncertain futures. The benefit-cost performance of these technologies will also vary by state. In certain states, some of these technologies will fail to pass muster, both politically and economically. The smart grid is an amalgamation of technologies that makes possible remote monitoring, two-way communication, and automatic control of facilities on the

benefits, and difficulty in measuring public benefits (e.g., cleaner environment, job creation). If a new technology, for example, performs poorly, and if it provides minimal benefits to utility customers, regulators might declare that the technology is not "used and useful." The consequence might be less-than-full cost recovery by the utility. As another example, short-term benefits from new technologies and other changes may be small, relative to the long-term benefits. As well, benefits to existing customers may be conjectural, or they may not flow directly to the utility's customers.[7] Finally, future benefits may depend on other developments. For example, customer benefits from the smart grid hinge on new rate structures, smart appliances and active customers. Benefits also depend on whether customers find plug-in electric vehicles and distributed generation (DG) attractive.[8] The public understandably tends to resist technologies that have unfavorable short-term benefit-cost ratios or uncertain or indirect benefits.

In sum, utilities will see tougher times in the years ahead that may require them to revamp their business model. Accordingly, regulators may have to accommodate new developments through new ratemaking mechanisms and other innovative practices.

B. Inevitable uncertainty and implications for policymakers

Because no one knows for certain about the future, it is unclear how regulators should respond to the technological and policy developments (e.g., CO_2 regulations, incentives for distributed generation) that we are seeing today. Regulators have different options, which include assigning staff to investigate the issues, proposing rule changes, conducting workshops and educational forums, and advocating for legislative change.

As of now, regulators and other policymakers have more questions than answers. We may be at the threshold of a revolution in the electric industry; at least that is what many people (e.g., some state utility regulators, smart grid and renewable energy advocates, new technology vendors, management consultants) are conveying. Yet, changes, if they do occur, may concentrate in a few geographical locations or be not as radical as many observers are projecting.

transmission and distribution networks. It includes "smart" metering and associated communications capabilities. [See Joskow (2012)]

[7] Uncertain benefits may require utilities to express them qualitatively rather than numerically. It is unclear how a cost-benefit analysis would consider those benefits in combination with quantifiable benefits in the overall review of a technology.

[8] The smart grid can also more accurately measure the value of the central grid to a DG customer as well as the value of DG resources to the grid. This increased accuracy should improve both the economic efficiency and fairness of the multidirectional flow of electric power and capacity between the utility and DG customers.

Unlike past transformations of the electric industry, the projected one is more technology-driven,[9] not from a single technology but from a number of them. The 1990s, for example, were a time of more government policy-driven change (e.g., open access rules for wholesale and retail power, lifting of barriers to independent power producers) while the present

Table 2: Three Categories of Expected Developments in the Future U.S. Electric Industry

Demand-side	Supply-side	Technological Developments
Lower sales growth	Increased emphasis on grid resilience	Distributed resources
Greater customer demands for reliability and value added services	Continued increasing average cost	Intermittent renewable energy
More informed customers	Continuously growing DG penetration increasing the complexity of distribution operations	Power storage
Enabling technology for customer decisions	Generation relocation from high voltage to low voltage	Broader application of the smart grid
Broader application of time-varying prices	Increased (reduced) dependence on natural gas (coal) for new generation	Real-time information for market participants (e.g., DG operators, retail customers)
Growing dependency on electricity by digital economy	Increased pressure for clean energy	Plug-in electric vehicles
Customers supply electricity to the grid ("prosumers")		

[9] Although distributed generation, for example, has benefitted from technological improvements, government subsides and other policies have contributed to its rapid growth up to now.

situation reflects more technology-driven change.[10] Past restructuring of the electric industry also called for radical change in utility operations and utility regulation.[11]

We see a confluence of events that could promote competition, improve the environment and increase industry efficiency, while also straining utility finances. The best guess, as of today, is that we are on that path, but with an unknown degree of uncertainty over the timing and geographical dissemination of radical industry changes. For example, for good reason many states may not want to pursue a transformed-industry future.[12]

One suggestion for regulators is that it would be prudent if they and utilities evaluate their existing policies and practices (e.g., ratemaking, the scope of utility functions) in a transformed electric-industry world. Decision making under uncertainty often accounts for what analysts call *Type I* and *Type II* errors (*see* Table 3).[13] These errors originate from policies that assume a certain state of affairs rather than what actually transpired. In other words, a mismatch exists between policies and actual conditions. In the context of electric-industry transformation, utility customers can suffer losses from the wrong policy. Policies might involve the utility business model, ratemaking, rules for fair competition and financial incentives for clean technologies.

In deciding on the appropriate policy, a Type I error can cause a dead-weight loss to customers from transforming the industry when a more incremental regulatory strategy would be more appropriate. Presuming that utilities face robust competition from DG, for example, to warrant light-handed price regulation when competition in fact remains weak could mean higher

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[10] *See* Joskow (1986); and Binz and Mullen (2012). This statement is not strictly true as the advent of combined-cycle gas turbines together with low natural gas prices drastically changed the economics, for example, by widening the gap between the marginal cost of new generation and the embedded cost of existing generation. Many buyers of electricity, especially industrial and other large consumers, wanted the opportunity to avoid paying the relatively high price of utility electricity.

[11] Electric industry restructuring that started in the 1990s dramatically changed the structure of the industry, as well as the conduct of suppliers. The restructured industry had: (a) less vertically-integrated utilities, (b) for some states, retail access in the form of unbundled service offerings, (c) more new generation facilities being owned by non-utilities with electricity sold at unregulated prices, (d) open transmission access for wholesale transactions, (e) several new categories of players, including aggregators, marketers, and energy service providers, and (f) large-scale, regional transmission organizations that control the flow of electricity.

[12] Although their initial preference might be to avoid it, they may ultimately be overtaken by external events (e.g., technological changes).

[13] Type I and II errors are frequently applied by economists and other analysts in situations where the policymaker evaluates the risks associated with a particular decision given that his projections of the future and other assumptions turned out to be wrong.

rates for utility customers.[14] A second adverse outcome could come from placing excessive optimism on DG to ultimately become a major force in the industry. By over-relying on DG and encouraging its development, for example, the utility and its customers risk subpar service reliability and higher rates from poor (and more realistic) performance.

A Type II error can derive from policies that under-compensate for actual technological, policy and market changes. One cost stems from obsolete regulatory practices and the utility business model[15] depriving utility customers of the benefits that new technologies and competition can deliver to them. Utilities could also suffer financial difficulties from robust competition behind-the-meter when regulators fail to adopt new ratemaking methods that allow them to recover their costs for still serving DG providers, although on a more limited scale (e.g., standby service). Inadequate regulatory changes can also lead to excessive central generation and pollution, suboptimal integration of DG into the utility grid, and unfair/exclusionary practices by utilities to keep out potential competitors.[16]

In sum, the mismatch between regulation and actual market and utility operating conditions can have profound negative repercussions on the public interest. A regulator must trade off the two types of error in decision-making: Reducing one type of error compromises the other. For example, in reducing the risk from an overzealous policy (Type I error), the regulator takes the chance of responding inadequately to the technological and other changes that are actually occurring. Similarly, avoidance of an inadequate response to a radically different future electric industry risks over-reaction by executing mismatched regulatory practices and utility business models. One example is to rely heavily on renewable energy to meet future electricity demand when adequate service reliability would require additional central station generation and fuel diversity.

[14] Utilities could then charge a price that reflects their market power. This price would presumably exceed the price under tight regulation.

[15] The existing business model, for example, may poorly integrate DG into the utility grid. The result is that the value received by utility customers from DG is less than optimal.

[16] The last outcome might derive from outdated code of conduct rules that fail to prevent a utility from favoring its own affiliate that competes with third-party providers.

Table 3: The Risk of Choosing the Wrong Strategy

Regulatory Strategy	Risk	
	Stable conditions	*Dynamic conditions*
Status Quo / Incremental	Preferred	***Type II error***
Radical	***Type I error***	Preferred

What strategy regulators pursue comes down to their perception of the relative risk of being wrong. For example, if regulators see higher costs to utility customers from the *status quo* than from an overreaction to events, they would tend to look more favorably upon radical changes. On the other side, some states may view radical changes in a negative light: They are less tolerant of a Type I error and more likely reason that major actions will have a negative benefit-cost outcome. Interest groups and the actual circumstances faced by utilities would also influence regulators' strategy. If a regulator sees a long and arduous transition period along with uncertain outcomes, it would lean toward more incremental policies (e.g., rate design reform).

III. Intense Pressures on Electric Utilities

One problem facing electric utilities is that more of their capital expenditures produce no incremental revenues from increased sales. These investments include those mitigating CO_2 and other pollutants, and replacing an aging infrastructure. To aggravate this problem, most forecasts call for revenue growth to decline, reducing the likelihood that utilities will be able to fund new investments from their revenues.[17] One widely-cited estimate places needed electric utility investments over the next 20 years at $2 trillion.[18]

The dialogue on future developments in the electric industry usually includes speculation on how disruptive technologies and other factors will affect the finances of electric utilities. By definition, disruptive technologies make alternative products and services more affordable to a

[17] When revenues fall short of needed capital investments, utilities can borrow from the capital markets or sell stock. These sources of capital, however, place upward pressure on rates from new utility debt and other financial obligations. Historically utilities have funded capital projects that include these sources.

[18] This number comes from various documents (papers, reports and presentations) authored by The Brattle Group.

broader population. From experiences in other industries, they have a direct effect on how incumbent businesses operate and their internal organization. Typically, they require firms to scrape their old business model and revamp themselves to better compete and survive.[19]

A. Developments inimical to utility financial interests

Challenging times for the electric industry may lie ahead given the confluence of several events that have the propensity to threaten utilities' finances. The major ones include:

1. *Recent growth of DG and their continued improved prospects for increased market share in the electric retail market*: Unknown at this time is whether DG will become a disruptive technology with mass appeal or just a "boutique" technology.[20] In any event, DG increases competition behind-the-meter, eroding utilities' monopoly power;

2. *Expansive role of utilities to address social issues*: For example, more actively promote energy efficiency and adopt clean energy, even when uneconomical and detrimental to short- or long-term utilities' finances;

3. *Long-term slowdown in demand growth*: Reasons include stagnant or falling demand from full requirements ("core") customers and customers who switched their primary electricity source to DG;[21]

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[19] A business model concerns how a firm creates value for its customers and sustains financial success.

[20] For example, the economics of rooftop solar vary by region and depends on a number of factors, including solar radiation, the price of utility electricity, the physical capability of a rooftop to handle a solar system, and local, state and federal financial incentives. According to the National Renewable Energy Laboratory, about one-quarter of residential and commercial rooftops in America are suitable for solar. In California, which has by far the most solar PV installations in the country, only about one percent of residential customers have rooftop solar. Throughout the country, about half a million homes and businesses have installed a solar PV system. Although the current penetration of solar PV in the residential and commercial markets is extremely low, projections call for high growth over the coming years in several states.

Currently, 10 utilities have 70 percent of the DG capacity in the U.S. [Kind (2013), 4]. During the period 1998-2011, more than 80 percent of all solar PV installations in the U.S. occurred in just three states, California, New Jersey and Pennsylvania. [Stanton (2013), 5]

[21] Most experts, as of today, see the recent slowdown in electricity demand growth as a long-term phenomenon, rather than as cyclical. One analyst [Ahmad Faruqui (August 14, 2012)] identifies five factors accounting for this lower growth: (a) a weak economy, (b) demand-side management programs, (c) building and appliance codes and standards, (d) distributed generation and (e) fuel switching. Many analysts now project a drop in annual sales growth to less than one percent as a long-term phenomenon.

4. *Public policies providing subsidies and incentives for less electricity usage and non-utility generation*: These policies have the effect of both negatively affecting utilities' finances and placing upward pressure on short-term electricity rates;

5. *Rising costs placing pressure on utilities to increase their rates*: For example, new environmental regulations could substantially increase utilities' costs;[22] replacing aging infrastructure and modernizing their grids[23] will also escalate utility costs;

6. *Free riding by PV rooftop solar generators when they pay less than their fair share of utilities' fixed costs*: This is a ratemaking matter that has drawn much attention; the debate is over what is a compensatory rate that keeps utilities and their core customers harmless while being fair to the DG host;

7. *Increased customer demands for reliability and higher quality service*: For example, the public and politicians will expect more prompt utility response to super storms and other disasters; and

8. *Higher ratio of fixed to variable costs that limits short-term cost savings from reduced sales*: As another problem for utilities, with a higher share of fixed costs recovered in the volumetric charge, the utility's earnings decline more for a given decrease in sales.

In sum, electric utilities may face difficult times ahead to maintain their financial viability. The future calls for stagnant-to-declining revenues and increasing expenses, conditions conducive to daunting challenges and a less-than-optimistic outlook for electric utilities. Expected changes include: (1) new technologies threatening utilities' financial position, (2) a permanent slowdown in demand growth, (3) escalating costs from new investments, (4) increased competition behind-the-meter, (5) increased customer demands for new services and higher service reliability, and (6) policies that emphasize nonutility generation and energy efficiency. All of these factors tend to weaken utilities' monopoly and financial status.

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[22] One example is section 111(d) of the Clean Air Act. Some concerns exist over (a) fugitive emissions for natural gas, especially methane and volatile organic compounds (VOC); and (b) water quality and quantity impacts for natural gas production using hydraulic fracturing. Although not directly affecting a utility's cost, they can increase the price that utilities pay for natural gas or the price for wholesale power produced by gas-fired generating facilities.

[23] In its Notice of Inquiry, the Massachusetts Department of Public Utilities (2014) remarked that grid modernization by electric distribution companies, although costly, will: (a) enhance the reliability of electricity services; (b) reduce electricity costs; (c) empower customers to better manage their use of electricity; (d) develop a more efficient electricity system; (e) promote clean energy resources; and (f) provide new customer service offerings.

B. The "death spiral" threat

1. An unstable condition

The recent dialogue on the electric utility of the future has provoked the question of whether the existing utility business model is sustainable, given the surge in the development of solar PV and other DG technologies.[24] A threat to utilities can start with sales losses to DG and, subsequently, a struggle by utilities to recover their fixed costs from increasingly fewer customers. Price increases aggravate utilities' problem of yet more customers induced to switch to DG.

Specifically, a death spiral represents an unstable market condition that arises from the utility recalculating prices to recover the same amount of fixed costs. This process causes even higher rates and an eventual collapse of demand. The presumption is that at a given level of demand, customers are willing to pay less than the average cost of the utility. Thus, as the utility tries to increase its rates to recover their fixed costs, the quantity of electricity demand will fall enough to lower profits. Eventually a price set at average cost will cause demand to drop toward zero. A utility will be unable to recover its revenue requirement.

Historically, the death spiral related to price increases resulting from radically higher utility costs. Back in the 1980s, for example, the term "death spiral" was part of the lexicon over the growing public discontent over the sharp rise in electricity prices from large utility construction programs. The worry was that the sharp rise in prices would cause electric utilities to suffer enduring financial distress.[25] The death spiral today refers to retail customers migrating from full-requirements utility service to the combination of self-generation and partial-requirements service.[26]

Necessary conditions for a death spiral include a non-responsive utility and regulator to its threat, a high price elasticity of demand facing a utility[27] and a high fixed-to-variable utility cost ratio.[28] Erecting entry barriers to avert a death spiral for a utility creates the problem of depriving customers of the potential benefits from competitive supplies (e.g., DG).

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[24] *See*, for example, Deloitte Center for Energy Solutions (2014); Felder and Athawale (2014); Graffy and Kihm (2014); Kind (2013); and ScottMadden (2013).

[25] *See*, for example, Ford (1997); and Lovins (1985).

[26] The presumption is even if a customer invests in distributed generation he will still need standby service from the utility.

[27] By increasing the price elasticity facing a utility, competition behind-the-meter, DG has increased the prospects of declining demand for utility electricity.

[28] Most electric utilities recover a large portion of their fixed costs in the volumetric charge. When sales decline, this rate design causes utilities to (a) recover less of their fixed costs, even those

2. Empirical evidence

The limited empirical information suggests that a death spiral is unlikely unless a massive migration of utility customers to DG occurs and other conditions exist. If regulators want to know the likelihood of a death spiral for utilities in their state, they need to examine the specific information for individual utilities. This information includes demand growth, the ratio of fixed costs to variable costs, rate design, ratemaking procedures (e.g., regulatory lag, test year), peak demand and utility structure (e.g., vertically integration, wires-only).[29]

One report estimated that for Hawaii Electric in 2012, which has a DG penetration of 8 percent, which is by far the highest in the country, lost recovery of fixed cost (i.e., cost-shifting) was about $12 million, or only about 0.39 percent of the utility's total annual revenue or a miniscule increase in rates of $0.001/kWh. For California, which has the second-highest penetration rate of residential rooftop solar at about 1 percent, cost-shifting in 2012 was about $254 million, or only 0.7 percent of the total revenue of the three investor-owned utilities in California.[30] Another study remarked that a 10-percent decline in load, which includes some customers leaving the utility grid, could cause utility prices to rise by at least 20 percent.[31]

A third, and the most thorough study done to date, conducted by Ernest Orlando Lawrence Berkeley National Laboratory, applied a pro-forma financial model to quantify the effects of PV penetration on the customers and shareholders of two prototypical utilities. The study's major finding was that:

> [E]ven at 10% PV penetration levels, which are substantially higher than exist today, the impact of customer-sited PV on average retail rates may be relatively modest (at least from the perspective of all ratepayers, in aggregate). At a minimum, the magnitude of the rate impacts estimated within our analysis suggest that, in many cases, utilities and regulators may have sufficient time to address concerns about the rate impacts of PV in a measured and deliberate manner. Second and by comparison, the impacts of customer-sited PV on utility shareholder profitability are potentially much more pronounced, though they are highly dependent upon the specifics of the utility operating and regulatory environment, and therefore warrant utility-specific analysis. Finally, we find that the shareholder (and, to a lesser extent, ratepayer) impacts of customer-sited PV may be mitigated through various "incremental" changes to utility business or regulatory models, though the potential efficacy of those measures varies

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previously approved by regulators as prudent and (b) lose more revenues than what they save in costs. Most U.S. electric utilities operate under this rate design.

[29] Satchwell et al. (2014).

[30] Moody's Investors Service (2013).

[31] Kind (2013), 5.

considerably depending upon both their design and upon the specific utility circumstances. Importantly, however, these mitigation strategies entail tradeoffs – either between ratepayers and shareholders or among competing policy objectives – which may ultimately necessitate resolution within the context of broader policy- and rate-making processes, rather than on a stand-alone basis.[32]

IV. Fundamental Policy Questions

A. The utility business model

Three fundamental questions underlie a utility business model: (1) What value do utilities create, (2) how can they deliver that value to their customers and society as a whole and (3) how can utility shareholders benefit? The confluence of events evolving in the U.S. electric industry has called into question the efficacy of current practices and the utility business model in serving the public interest. These events are broad, covering technology, the marketplace, energy and environmental policies, and public utility regulation itself. The relationship is two-way: These events determine the preferred business model, which in turn affects the outcomes of these events. As an illustration, the improved economics of DG technologies (i.e., the event) justifies a business model that better accommodates them. The actual model itself would help influence the future growth of DG. Events and the business model should go hand in hand.

Regulators should begin by asking two basic questions. The first relates to what role utilities should play in a transformed electric industry: What markets should they serve? What products and services should regulators allow them to sell? What functions should they perform? Should regulators determine the utility business model? Should, the utility with minimal regulatory intervention dictate the model?[33]

If technological developments are occurring so rapidly, as some experts are projecting, it becomes highly unlikely that regulators and other policymakers will find the "right model" or have the ability to choose winning technologies or market structures that maximize societal welfare.

B. Regulatory actions

The second set of general questions relates to whether the current practices and policies of regulators in controlling and overseeing utility activities are still appropriate. Have recent developments, for example, made obsolete and socially injurious the traditional ratemaking

[32] Satchwell et al. (2014), xiii-xxiv.

[33] One argument for regulators' involvement is that some utilities would prefer the *status quo* to maintain their monopoly power. A new business model, as one of its objectives, would accommodate DG suppliers and other competitors of utilities behind-the-meter. This accommodation might lie contrary to utility interests.

paradigm that regulators have depended on for decades?[34] Unless regulation changes in line with the utility business model, disappointing outcomes become inevitable.[35] Specifically, electric industry transformation could make the guiding regulatory standard of balancing various interests more difficult to achieve.[36] Regulators might have to take into account the interests of additional stakeholders (e.g., DG advocates) and consider more objectives, whether mandated externally or initiated by the regulators themselves. The tasks of regulators will ostensibly become more complex in a transformed electric industry.

V. Discussion on Utility Business Models

According to one definition, a business model is the conceptual structure supporting the viability of a business, including its purpose, its goals and its strategy for achieving them. In other words, a business model specifies how an organization fulfills its purpose. Management experts sometimes refer to the business model as the theory of business or the conceptual structure that supports the sustainability of a business.[37] A business model, for example, could represent a framework for how a utility achieves the outcomes that society wants; namely, the delivery of valuable services to customers and society at large. A business model may include a vision statement: Financial goals are normally the main focus, at least from the firm's perspective, with other goals such as business sustainability and corporate culture increasing in importance in recent years.

Utilities face no shortages of options for business models. They need to find, with approval and input from their regulators, the model that best fits their objectives and operational conditions. Business models are dynamic in that they need to be fine-tuned or overhauled when technological or market conditions, or public policies warrant change.

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[34] Traditional ratemaking provides utilities with weak incentives for innovation and with disincentives for accommodating DG and other socially desirable actions (e.g., energy efficiency) that would reduce their sales. It also tends to base utility revenues on past costs rather than on the value to customers from the activities that underlie the costs. Finally traditional ratemaking sets retail prices based on average cost rather than incremental cost, distorting price signal to consumers.

[35] This statement does not imply that a single best regulatory paradigm exists for each business model. The two should coincide, however, in achieving the same objectives in the most efficient manner.

[36] State utility regulators attempt to balance the rights of utilities and their customers by considering three major factors: (1) *legal constraints*—for example, utilities have a right to be given a reasonable opportunity to be financially viable, and customers have a right to just and reasonable prices; (2) *the regulator's perception of fairness*; and (3) *compatibility with a broader interest.* Regulators try to balance the interests of the different stakeholders with the overall objective of promoting the general good; at least, that is the premise behind the public-interest theory of regulation.

[37] *See*, for example, Drucker (1954).

A. Rationales for a new business model

The late management guru Peter Drucker (1954) commented that a business model answers the following questions: Who is your customer, what does the customer value, and how do you deliver value at an appropriate cost and at an acceptable profit? A business model, therefore, concerns how a firm (1) creates value for its customers through its operations, products and services and (2) generates sustainable operating and financial performance.[38] One rationale for electric utilities to adopt a new business model is that technological, public policy and economic changes have affected utility sales and revenues such that doing nothing inevitably will lead to an unsustainable financial situation for utilities. The *status quo* may also deprive electric consumers and third-party providers the value they would otherwise receive from the utility grid.[39] Of primary interest to regulators is the value that DG customers would receive as both consumers and producers when connected to the utility grid.

The prime rule behind the business model is that it should conform with the underlying assumptions relating to society's demands through public policies, market conditions, current technologies, and customer behavior and wants. The lesson learned across different industries is that three primary factors exist for why firms are more likely to experience financial stress in a dynamic world, for example, with the presence of a disruptive technology. They are, inertia and complacency, poor management strategies, and unstoppable market trends (e.g., inexorable falling demand for a firm's product or service). Sometimes a firm, for example, encounters a sudden collapse in demand for the product or service that it has been providing for years (i.e., a structural demand crisis). Other times firms err by staying the course when events dictate that they revamp their business model and take other drastic steps.[40]

At the other end of the spectrum, firms that successfully overcome a death-spiral (i.e., existential) threat exploit new technologies, change their management practices, and eliminate or modify old operating, pricing, marketing and other practices.[41] A firm may not necessarily have

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[38] Drucker advised that in reviewing whether to change their business model or other aspects of their business, firms should start by asking five basic questions: "What is our mission? Who is our customer? What does the customer value? What are our results? What is our plan?" As discussed elsewhere in this paper, electric utilities, in addition to satisfying their customers and shareholders, must also appease policymakers who prescribe their broader social responsibility.

[39] It is assumed that utilities providing these benefits are fairly compensated. Determining "fair compensation", of course, is not a straightforward exercise.

[40] Analysts sometimes refer to firms that are nonresponsive to change as "dinosaurs" or "elephants."

[41] Consistent with Schumpeter's process of "creative destruction", the scenario described above suggests that the traditional business model for electricity distribution is unsustainable; thus, incumbents will need to transform themselves if they are to adapt and survive the paradigm shift in the generation and delivery of electricity to retail customers. [Schumpeter (1950)]

to embrace new technologies; often it can instead improve its financial performance by adapting old technologies to a more competitive environment.

Since the future is uncertain and the social environment is constantly changing, even the soundest business model inevitably becomes obsolete. Regulators and public policy in general have imposed an expanded social agenda on utilities that complicates their strategies and tactics. Change often requires firms to review whether the underlying assumptions behind their business model still hold. This advice seems especially relevant for electric utilities as they face technological, economic and public-policy shifts.

B. Outdated assumptions underlying the current business model

The prevailing business model in use today assumes different market, consumer and technological attributes of the electric industry that may not hold in the future.[42] They include:

- Traditional-only utility objectives (e.g., reliable and safe service, and "just and reasonable" rates)
- Utility profitability tied to electricity sales and rate basing[43]
- Predominately central station generation
- One-way power flow
- Limited communications between the utility and customers (e.g., monthly billing and usage information, and occasional outage communications)
- Utility natural monopoly behind-the-meter
- Economies of scale and scope in utility operations
- Economical for utilities to both operate the grid and own the physical assets
- Passive utility customers
- Sales growth financing new investments
- New investments creating additional utility profits

[42] *See*, for example, Aspen Institute (2013); Binz (2013); Brown (2013); Dion (2013); Energy Industry Working Group (2014); Fox-Penner (2013); Goldman et al. (2013); Lehr (2013); Rocky Mountain Institute (2013); Shultz-Stephenson Task Force on Energy Policy (2013); Tai (2013); and Zarakas (2013).

[43] A mantra for utilities is "build, sell, profit." That is, build new physical facilities to place in rate base and sell more power to earn higher profits.

- Uniform service reliability
- Closed distribution grid
- Restricted customer desires
- Limited integration of third-parties providers into the planning and operation of the distribution grid[44]
- Minor problems from utility recovery of fixed cost through the commodity charge
- Minimal utility customer bypass either completely or partially

A business model for utilities should (1) respond to new technological and market developments (2) support traditional regulatory objectives (e.g., cost-based rates, fairness across different customer groups) underlying "just and reasonable rates" and (3) satisfy predetermined broad public-policy goals. By operating under a new business model, for example, utilities could embrace, accommodate or invest in new technologies, in addition to better serving their customers. One rationale for a new business model is that technological and economic changes (as discussed earlier) have adversely affected utilities' future financial situation. Another rationale is that both federal and state policymakers have mandated utilities to take on broad social responsibilities. Despite these serious challenges, utilities possess many relevant resources and capabilities placing them in a favorable position to adapt and survive in the new competitive landscape. But, utilities may have to reorient their strategies and tactics to achieve financial viability in a transformed electric industry.

Since the U.S. electric industry operates under federalism, utility business models will likely differ across states and conceivably within an individual state. Thus, we will unlikely see a standard or uniform future utility model, since we have 50 different states and little prospect for federal legislation that will send all states in a common new direction. Some observers may frown upon this development, while others see it positively in allowing states to exercise more control over the future course of the electric industry. What seems best for a state, after all, depends upon its unique political and economic conditions.

One topical area of discussion is whether a transformed electric industry should allow utilities to expand their scope of activities so that they can share in the economic gains from DG and other technologies; otherwise utilities would tend to view them as threats and, thus, motivated to stifle their development.[45] In other words, a new business model can allow utilities

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[44] Integration involves more than just mere connection of a DG operator to the grid. Integration can provide distribution voltage support, optimize distribution operations, improve voltage quality and reduce system losses and improve grid resiliency. *See* EPRI (2014), 30.

[45] The question utilities would ask is: "As opposed to fighting solar and other forms of DG, how can we exploit new technologies to better serve both our customers and shareholders at the same time?"

to profit from offering distributed generation services or owning PV solar systems, while nurturing a competitive environment that mitigates utilities' potential monopoly power as the distributor operator.

C. First-order questions for regulators on business models

Basic questions that regulators can ask in reviewing electric utility business models are:

- What is a business model?
- Why is it important?
- What are the major components of a business model?
- What is the typical business model for electric utilities?
- Why has a public dialogue begun over its relevance and usefulness?
- What are some of the problems with the current business model?
- What are the changes under discussion?
- What are the underlying assumptions for each proposed business model?
- Is the current business model the problem or, instead, is it outdated regulatory practices or inept utility management?[46]
- What are the benefits and costs of a new business model?
- What should regulators do now, if anything, about the utility business model?
- How should regulators achieve a balancing of stakeholder interests and the public interest in approving a business model?[47]

For utilities, new technologies can present either new opportunities or threats. Often, major new technologies result in more competitors and make existing business practices obsolete.

[46] The current business model might still be appropriate, but management itself might fail to adapt to an increasingly competitive and more challenging environment. Scrapping the current business model when unwarranted can lead to unnecessary transitional costs. Ten to fifteen years ago many experts thought that traditional utilities retaining their long-held business models would not survive in the new more competitive power business; to the contrary, many utilities did not change their business model and adapted well to the more competitive environment.

[47] Different groups have expressed concerns over the current business model, namely, clean and renewable energy advocates, DG advocates, energy efficiency advocates and utility customer groups.

One common perspective is that utilities need to make fundamental shifts in defining their purpose and structure (i.e., their business model) in response to the financial threat posed by DG. Merely addressing this problem through rate design or through other incremental means, according to this view, falls short of serving the public interest.

D. Minimalist or expansive role for utilities

Possible utility roles range from a facilitator, minimally involved in transactions, to providers of energy services.[48] Two distinct business models have so far emerged: (1) Utilities providing new value-added services[49] to make money; exploiting new technologies for profit (e.g., utility ownership of rooftop solar panels and electric car plug-in charging stations)[50]; and (2) utilities providing a platform for new services.[51]

One option that represents a "middle" course for utilities in their interaction with DG is to partner with third parties.[52] In this role, utilities primarily act as a facilitator of technology and service changes. They would apply their engineering and reliability standards by adapting them to new technologies and service offerings.[53]

While considering the effects on the individual stakeholders, regulators have the duty to maximize the collective interest.

[48] *See*, for example, Deloitte Center for Energy Solutions (2014); Fox-Penner (2013); Kind (2013); Lehr (2013); New York State Department of Public Service (2014); ScottMadden (2013); and Shultz-Stephenson Task Force on Energy Policy (2013).

[49] Some utilities have already invested in solar and energy efficiency to improve their earnings. Others are considering additional services to offer their customers.

[50] One argument against utilities playing this role is that they lack incentives to innovate and change in general.

[51] "Platform" refers to a system that supports interactions among multiple parties and a set of rules that facilitates transactions among multiple parties. A platform can increase innovation and competition by: (a) reducing transaction costs, (b) increasing transparency, and (c) enabling the enhancement of integration benefits that will grow as more diverse suppliers and new technologies (e.g., storage, plugged-in electric vehicles) enter the market. Industry observers label this role of utilities as a "smart integrator", "facilitator" or "orchestra leader". *See,* for example, Rocky Mountain Institute (2013).

[52] An example of a partnership is the utility entering into a commercial arrangement with a third-party, who would develop and build a DG facility. The utility then could sign a long-term lease or operating agreement with the third party. A second example would relegate the utility's role to working with a vendor or customer to facilitate the application of a DG technology.

[53] One vision of the new business model would have a third party (e.g., an independent system operator) managing the operation of the distribution system. The rationale for this model is that the utility

VI. New Regulatory Duties and Challenges

In a transformed electric industry, state utility regulators will face new challenges that will steer them away from their current practices and policies. Some industry observers advise that regulators should replace the old ratemaking paradigm for a new one that is (1) more compatible with prevailing conditions, (2) flexible enough to adapt to an ever increasingly dynamic sector, and (3) supportive of the evolving roles for utilities, non-utility providers and consumers in the electric industry.

Many analysts believe that regulation will be more effective in serving the public interest by moving away from short-term price considerations and toward the practice of developing long-term goals. They also suggest that regulation should shift and broaden its focus from monopoly-era economic issues, to a larger and more generalized set of issues. They contend that regulation can best address them, for example, by setting utility revenues based on performance so that utilities have incentives to modify their behavior toward serving the public good.[54] One behavioral change would be for utilities to direct their innovations and other investments toward predetermined policy objectives.[55] Another suggested action would have regulators reviewing their current ratemaking mechanisms to determine whether they are still fair and commensurate with the public interest.

This paper takes the position that an expansion of regulator's role in expanding social policy can create problems. State utility regulators have limited resources, frequently overextended in performing their traditional functions in such areas as ratemaking and utility planning. There is also the question of whether the regulators themselves or the state legislature should set policy. One view is that legislatures should set policy with regulators relegated to executing it.

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would have a conflict of interest and favor increasing its physical assets rather than advancing the development of third-party distributed energy resources. *See* Tong and Wellinghoff (2014).

[54] *See*, for example, Binz and Mullen (2012); Costello (2010); Lehr (2013); Malkin (2014); and New York State Department of Public Service (2014).

[55] A cardinal principle of establishing good incentives is to harmonize a utility's financial interest with the public interest or social objectives. This principle relates to what is called the "principal/agent problem;" namely, how to motivate a utility to achieve the objectives set out by the policymaker (e.g., the regulator). Assume that a regulator wants a utility to aggressively promote energy efficiency. At the minimum, the utility hopes to avoid any negative financial consequences; this outcome could require a revenue-decoupling rider, a lost revenue adjustment mechanism, or a rate design that protects the utility against unexpected sales declines (e.g., straight fixed-variable rates). The regulator could pursue further action by allowing the utility to profit from cost-effective initiatives comparable to profits for supply-side alternatives. Profits can come from shared savings, performance target incentives, and a rate-of-return adder. Without financial inducements, the regulator would have to more closely monitor the utility to make sure it carries out its goal for energy efficiency.

A. General considerations

One certainty is that regulators cannot avoid making tradeoffs among an increasing number of objectives, some of which are conflicting (e.g., promoting DG that may impose a burden on non-DG customers or utilities). Advocates of industry change hope to achieve a nonzero sum outcome where everyone comes out better. As argued by two advocates:

> We need to align regulatory incentives so that healthy utilities can pursue society's broader policy goals in ways that also benefit customers and shareholders…The time is ripe to explore a revised compact among utilities, regulators and the consumers they serve.[56]

A second matter is how regulators should interpret "just and reasonable" rates, and more generally the public interest, in a transformed electric industry. In its most basic form, regulation strives to assure adequate, reliable electric service at rates that are just and reasonable. Thus, regulation recognizes that financially healthy utilities are essential for the long-term economic welfare of customers. At the same time, customer protection against the exercise of utility monopoly power is a core principle of ratemaking. In a transformed electric sector, because utility rates affect utility competitors and a greater variety of technologies, the definition of "just and reasonable" rates need to consider these new players and elements of the industry.[57] Rates would need to recognize (1) non-utilities wanting a fair opportunity to compete, (2) utility customers wanting lower prices and reliable service, (3) utilities wanting rates that allow them to be financially healthy and compete with non-utilities, (4) utilities wanting special incentive rates to innovate and (5) environmentalists and conservationists wanting clean energy and energy efficiency. Trying to accommodate these varied and somewhat conflicting objectives in maximizing the public interest poses a tough challenge for regulators.

A final matter relates to how regulators can achieve the prespecified objectives laid out by society at the lowest cost. Some analysts refer to such an outcome as "smart regulation." A regretful regulatory legacy is the achievement of specific regulatory objectives at higher than least cost.[58]

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[56] The quote gives the impression that satisfying broad policy objectives has higher priority over customer and utility shareholder welfare. *See* Ron Binz and Ron Lehr at http://www.rbinz.com/Utilities%202020.pdf.

[57] Terms like "fairness" and "just and reasonable prices" have subjective connotations that challenge regulators, for example, to balance the dual objectives of fairness and economic efficiency in addition to other objectives.

[58] For example, many utility programs to assist low-income households have resulted in excessive dollars spent to achieve a given level of benefits. Excessive cost expenditure in the administration and implementation of utility programs is one source of waste. Another source is non-poor households receiving assistance, thereby deducting the assistance available to financially needy households. A non-targeted lifeline rate or a discounted rate with broad eligibility rules that includes non-

B. Logical questions for regulators

In contemplating reforms, regulators should start by asking themselves a few basic questions. The first relates to what society should expect from utilities. Other than reliable utility service at "just and reasonable" rates, what else should utilities achieve and be held accountable? A second question is the role that utilities should play in meeting societal objectives. The answer lies with the business model under which the utility operates. A third question relates to incentives that regulators should provide utilities so that they can fulfill their social obligations. Today's regulatory structure offers few incentives for efficiency throughout a utility. This has serious consequences because increased profitability, derived from eliminating inefficiencies, could offset at least some of the anticipated cost increases for utilities. Utility efficiency could potentially "fund" desirable utility activities, such as shifting toward cleaner generation resources and new consumer services. Uncertainties exist over the size of existing inefficiencies and the dollar value of potential efficiency gains.

Finally, regulators should ask whether and how they should change their present policies and practices. Does regulation need to reinvent itself, for example, adopt a new ratemaking paradigm, or just make incremental changes? Examples are multiyear rate plans, new rate designs and the requirement of a new utility role. For some states, new rate design and economically rational ratemaking may suffice given the circumstances they face. Some regulators may decide to reward utilities for efficient integration of disparate resources (e.g., DG) and achieving targeted social goals, rather than for growing their rate base through new assets that may not be economical and socially desirable. We will later discuss some options available to regulators.

C. Areas of regulatory review

1. Topics to consider

Regulators may want to review a number of topics over the coming few years. They include:

- New rate design (e.g., straight fixed-variable rates)
- Sorting out of cost allocation for DG providers
- Selection of the appropriate utility business model[59]
- Incentives for utility innovation

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needy customers are examples of this type of inefficiency. A third source of inefficiency stems from assistance not going to the neediest low-income households (e.g., the poorest of the poor). *See* Costello (2009)

[59] *See* the earlier discussion.

- Evaluation of utility performance in different functional areas
- Likelihood of a "death spiral" threat for utilities
- New ratemaking paradigm for calculating revenue requirements (e.g., multi-year rate mechanism)
- Cost recovery and funding for expensive new investments (e.g., grid modernization), in terms of who should pay and how should utilities recover their costs
- Integration of renewable energy into the power grid
- Creation of "fair competition" among generation technologies[60]
- Increased resiliency of power system (especially in the East and other areas with violent storms)[61]
- Power system security from cyber and physical terrorism

2. Elaboration on three topics receiving wide attention

a. Incentives for utility innovation

Innovation broadly refers to the creation of better products, operating processes, technologies, or even ideas that enhance a utility's performance. Innovation improves both economic and noneconomic matters over what they were previously. Put another way, innovation is a social-welfare-enhancing investment. Innovation has enormous potential for enhancing the performance of public utilities: It can help improve utility services and lower the cost of existing services. Innovation can also advance regulatory objectives. New technologies, for example, have increased utility reliability and safety or achieved them at a lower cost. Technology improvements have made new nuclear and coal generating plants more efficient, cleaner, and safer.

[60] Does creating "fair competition" require more or less regulation? This was an issue in the old telephone industry. A balance needs to be reached between not overburdening the incumbent and not discriminating against new entrants. It is also conceptually not straightforward to define "fair competition" when the local utility has an obligation to provide service to anyone who wants it. This service includes both full-requirements and standby service. The utility, for example, would still have to invest in infrastructure and maintain its system even as more customers switch to DG.

[61] Resiliency refers to: (a) withstanding small or moderate external disturbances without loss of service; (b) maintaining minimum service loss during severe disturbance; and (c) quickly returning to normal service after a disturbance.

Unregulated firms innovate and invest in new technologies to improve their prospects for earning handsome profits. Incentives are essential to induce firms to innovate. Because innovative investments activities are intrinsically risky, firms expect a higher return from them over conventional investments. Unregulated firms also innovate to compete with their rivals, a fact that tends to disperse innovation throughout unregulated industries. One firm's innovation or investment in new technology will often require other firms to innovate as well, if they want to survive.

It is wrong to generalize that utility regulation always gives utilities meager incentives to innovate. Regulation, in fact, oftentimes encourages innovation, sometimes with poor results. Electric utilities historically invested aggressively in new technologies when their economic incentives were strong (i.e., a high expected return-to-risk ratio[62]). In the past, some of those new technologies have performed poorly, burdening utility customers with the recovery of excessive costs.

New technologies inherently create several risks for utilities. These risks include regulatory, demand, cost, and performance. Regulatory risk can arise in different ways. One example is when a new technology performs poorly, and if it provides minimal benefits to utility customers in the short term, regulators might declare that the technology is not "used and useful." The consequence might be less-than-full cost recovery by the utility. Another example is when utilities face a long delay in recovering costs. This delay aggravates the uncertainty that already exists and poses a cash-flow problem for utilities. Because of the unique risk associated with new technologies, regulators might want to consider allowing utilities to earn a higher return on those investments.

A primary objective of regulation should be to create incentives for utilities to invest in new technologies that benefit their customers and society at large. The challenge for regulators is to overcome the "principal/agent problem"; namely, how to motivate a utility to invest in socially desirable new technologies.[63] In the absence of financial inducements, the regulator would have to mandate that utilities adopt certain new technologies or evaluate whether they were prudent in their decision whether or not to adopt them.

A theoretically preferred approach would be to design a general regulatory framework that balances utility incentives to innovate and fair risk-allocation to customers. This framework

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[62] During those periods regulators rarely conducted prudence reviews and disallowed cost recovery, while extended regulatory lag allowed utilities to retain the benefits of a new technology over several years. Typical ratemaking spreads most of the benefits and costs of new investment to all customers. This allocation tends to make utilities indifferent toward new technologies. Overall, today's regulatory environment lacks giving utilities any strong inclinations to invest in new technologies. *See*, for example Costello (2012); and Malkin (2014).

[63] The regulator is the principal calling on the utility as the agent to carry out its mandates and advance the objectives that it has predetermined for the utility.

would consider depreciation rules,[64] regulatory commitment,[65] targeted incentives,[66] mitigation of asymmetric information, and abolition of "undue barriers." A holistic approach could help create a new regulatory paradigm for stimulating utility innovation. One caveat is that some stakeholders would likely oppose rewarding utilities for something that they feel the utilities should do in the absence of any additional incentive.

b. Mitigation of a death spiral

(1) A two-edge sword

Regulatory protection of utilities facing more competition is a double-edge sword. Regulators will be as intent to avoid financial disaster for a utility as they have in the past.[67] Most regulators view a financially distressed utility as not serving the general public. Utility

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[64] The typical book-depreciation practices can discourage utilities from replacing existing physical assets with new technologies because they can lead to "stranded costs." When depreciation rates are too low, the depreciation period can extend beyond the economic life of an asset. In such an instance, the utility encounters "technology risk" by suffering a financial loss if it were to replace the asset at the end of its economic life. This frequently happens to utility assets depreciated using straight-line book methods. One response to this problem is to allow the utility to use accelerated depreciation. This allows the utility to improve its cash flow in the early years of an asset's life, which can help to finance a new technology. Accelerated depreciation, though, increases the burden on customers by increasing their rates. In other words, accelerated depreciation passes the risk of unrecovered depreciation entirely to customers, a transfer that some regulators might oppose.

[65] Over the past several years, regulators have been under intense pressure from utilities to approve cost-recovery mechanisms that shift more of the risks to customers. In many instances, the utility request is for pre-approval (sometimes called "full commitment") of both an investment and its costs. The broadness of a regulatory commitment affects the scope and nature of later retrospective review of the utility's performance. Regulatory commitments are controversial because they can assign to customers virtually all the risks of a costly new investment with uncertain benefits. Regulators are understandably reluctant to bet "customer" money on an innovation when they know the chances for failure are high. The challenge for regulators is to strike a balance between credibility to investors and fairness to customers so as to best serve the public interest. In the extreme, a commitment to utility investors that the utility will recover all of its costs for a new technology would certainly be credible from the perspective of investors, but utility customers along with regulators likely would perceive it as unfair.

[66] A well-designed incentive mechanism would have several components. First, it would have a cost-overrun protection. If actual capital costs exceed the projected level by a certain percentage, the utility would absorb a specified portion of the "cost overruns." Conversely, if actual costs fall below the projected level, the utility might be allowed to keep a part of the "cost savings." Targeted incentives can also lead to a sharing of the benefits from a new technology. Traditional ratemaking generally provides utilities with minimal benefits from new technologies, even when they are successful.

[67] From experience, regulators seek to minimize extreme financial outcomes for utilities. They are also subject to legal constraints imposed by legislatures and the courts.

financial burdens can translate into long-term harm to customers: If a utility expects not to recover its full costs for an investment, it will tend not to voluntarily offer to make the investment, even when it is socially desirable.[68]

On the other hand, regulators may decide not to protect utilities for political or "public interest" reasons. The public may view traditional regulatory solutions to insulate utilities from competition as exemplifying a one-sided approach that harms the long-term interests of customers and society at large. Some analysts would even argue such an approach increases the utilities' risk where a more proactive strategy would improve the position of utilities by replacing risk with opportunities to benefit from change.[69] As the magazine *The Economist* has remarked, "The utilities have a stark choice: sit back and be disrupted, or embrace the shock of the new."[70]

(2) Regulatory options

Regulators have different options to mitigate the chances of a death spiral for utilities. Regulators can help avert a death spiral through their authority over ratemaking practices, their general policies[71] and the scope of utility activities allowed in the transformed market environment. Ratemaking reforms[72] as well as a new business model are, therefore, key factors in sustaining utilities' financial viability in a future where DG assumes a prominent role.

Specifically, regulators can approve new ratemaking practices to mitigate financial challenges for utilities and unfairness for full-requirements customers. For example, they might attempt to end cross-subsidies that motivate certain customers to uneconomically bypass the utility system.[73] Regulators should first look at ratemaking reforms for avoiding any death-spiral tendencies.[74]

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[68] A breakeven constraint (i.e., total revenues equal total costs) is a necessary condition for assurance of adequate service utility service in the long run.

[69] One good example is cable companies that exploited new technologies to expand their services and bundle them profitably. *See* Graffy and Kihm (2014).

[70] "Adapting to Plug-Ins," *The Economist*, October 4th - 10th, 2014, 74.

[71] Some people might argue that net energy metering rules that require utilities to pay the retail price for surplus solar PV power can contribute to a death- spiral threat.

[72] While ratemaking reforms by themselves may not fully head off all future financial problems, they are a logical place to start.

[73] Bypass could have an especially harmful effect on utilities as the former customer would no longer pay a fixed charge. If instead, the customer merely cuts back on electricity usage but remains on the utility system as a full-requirements customer the utility would still recover most of its fixed costs. One mitigating factor is that the utility could still recover at least a portion of the fixed charge by providing standby service or other grid services to the "bypassed" customer. At least over the next few years, storage will unlikely be economical for DG customers to completely bypass the utility system.

As discussed earlier, regulators can support a new utility business model. It can allow utilities, for example, to profit from offering distributed generation services or owning PV solar systems, while maintaining a competitive marketplace that prevents them from having an unfair advantage.[75] Put simply, utilities would become an energy service provider[76] rather than just being an electricity provider or grid integrator, so that they can compensate for revenue losses from increased competition.[77] Changed circumstances might justify a different business model in which utilities would have more liberty to exploit the benefits for themselves from the improved economics of DG and other technologies that would otherwise threaten their long-term financial viability and existence. The underlying business model approved by the regulators would, therefore, allow the utility to compete with third-party providers of electricity and energy services in general. As said earlier, circumstances have changed that would seemingly warrant utilities to consider a new business model.[78]

Even if it is, DG customers who place a high value on reliability would still hesitate to wean themselves off the utility grid.

[74] One article by Felder and Athawale (2014) expressed the view that "the current rate design cannot economically or politically support a large cross subsidy from non-DG to DG customers." Another article by Lively and Cifuentes (2014) supports adding a demand charge to residential rates.

[75] As discussed later, expanding the utility role can lead to a potential market-power problem that regulators will need to address.

[76] Energy service extends beyond kWhs of electricity to include, among other things, energy management, advice and software support. Put simply, the utility would view its role from the perspective of adding value to customers' consumption of heating, cooling and other services requiring electricity as an input.

[77] One study also notes other benefits from utilities owning combined heat and power (CHP) facilities:

> Utility ownership has at least three benefits. First, the utility is able to recoup some of its lost revenues when a customer switches from full-requirements service to partial service. Second, the customer does not have to pay the upfront capital cost for the CHP system. Even when cost-effective, some companies may shy away from investing in CHP because of high initial capital costs or the higher priority they place on revenue-producing investments. A third possible benefit is that the utility could exercise greater control over the operation of the CHP facility and its integration with its distribution system, for example, through its contact with the customer. [Costello (2014), 40]

[78] *See*, for example, Ernst and Young, Global Power and Utilities Center (2014). The paper lists five proactive, or what it calls "no regrets", actions that electric utilities can take to control their destiny (e.g., avoid financial calamity): (a) manage their operation and maintenance (O&M) costs, (b) transform the central grid to accommodate DG, (c) manage the regulatory transition, (d) understand their customers better, and (e) start exploring a new business model.

Regulators can also determine whether any death-spiral threat reflects a bad business model, bad utility management, or bad regulation. The current business model might still be appropriate or require tweaking, but management itself might fail to adapt well to an increasingly competitive and more challenging environment. Scraping the current business model when untenable can lead to avoidable transitional costs.

Finally, regulators can avoid imposing excessive costs imposed on utilities. In coping with the challenges that electric utilities face, regulators can help protect utilities from superfluous costs. Regulators might want to provide utilities with stronger incentives for cost efficiency and innovative activities. If utilities lack incentives for adopting new technologies, then it would be less likely to fare well with DG and other retail competitors.

c. Evaluation of utility performance

Regulation's central purpose is to induce high-quality performance from utilities. To achieve this objective, regulators need to measure and evaluate utility decisions and activities, then inject the evaluation's results into regulatory decisions. Measurement can strengthen regulatory incentives so that utilities perform better. Improved performance, in turn, can lead to lower rates over time, higher quality of service, fewer rate cases, a cleaner environment at lower cost, better integration of DG with the central grid, more energy efficiency and lower overall utility costs.

Performance measurement can detect subpar utility management that could lead to further investigation, cost disallowances, or a modification of regulatory incentives. It can also assist regulators in determining whether utilities have satisfied stated objectives or targets. Performance measurement can also help regulators reward utilities for superior performance that benefits customers, for example, through lower rates or higher quality of service.

If regulators had good information about how utilities should perform, they could simply set performance standards that the utility would have to meet or suffer the consequences. In the real world, however, the regulator faces the problem of less-than-perfect information about the efforts of utility management and the utility's cost opportunities. Cost-saving opportunities differ across utilities, depending on the unique features of their production technology, input costs, and other factors that cause costs to vary by location beyond the control of utilities. Rural utilities, for example, tend to have higher average costs than urban utilities.

Regulators observe outcome (e.g., power plant reliability) but lack a utility's expertise in assessing how management influenced it. Since the required information to identify optimal performance is absent, regulators have to resort to alternative actions, such as explicit incentives or judgment of a utility's performance based on the information provided to them by the utility and other sources.

In the transformed electric industry, utilities will have an expanded role and responsibilities for which regulators might want to measure and evaluate their performance. For example, regulators might want to evaluate utilities' performance in reducing greenhouse gas emissions, empowering customers, improving system resiliency and integrating the grid. The challenge for regulators is to determine what constitutes a well-performing utility. What do they consider acceptable performance? These are questions that regulators would need to address if they are to exploit fully the information embedded in performance measures (i.e., metrics) for regulatory decisions relating to utility prudence, rate setting and other matters. The measurement of performance trends in the absence of a standard, for example, might limit regulatory action to further investigation, not to a direct determination of cost recovery and judgment of utility-management performance. Even in this limited capacity, performance measures can help regulators make better informed decisions.

VII. How Should Regulation Change? Two Distinct Views

A. Reinvention of regulation

A radical regulatory response presumes a transformed electric industry in which utilities have a new business model that defines their new role, objectives and strategies. The regulatory compact between a utility and its regulators might also undergo a major change.[79] The utility, for example, may have less retail monopoly power, disrupting the utility's geographical franchise, and the regulator might allow the utility's rate of return to vary within a larger range, based on the utility's performance and a longer regulatory-lag period.

Even with a new compact, utilities would still have to adhere to certain restrictions and conditions. "Just and reasonable" rates will continue to be a regulatory criterion with the following features: (1) the provision of affordable service to utility customers, (2) rates reflecting only the prudent costs of a utility, (3) rates reflecting the utility's cost of serving different classes of customers and of providing different services, (4) sufficient utility revenues to attract new capital and satisfy minimum financial standards, (5) prohibition of undue discrimination against any customer class or service (e.g., rates should never fall below short-run marginal cost), and (6) in competitive markets, approval of any price voluntarily transacted between a buyer and a seller. But the utility in a transformed industry would likely have different functions and obligations.

1. New York: Reforming the Energy Vision

The staff of the New York State Public Service has proposed a bold approach, called Reforming the Energy Vision ("REV") to better align regulation and the utility business model with the state's energy, environmental, and economic policy objectives.[80] The proposal,

[79] The oft-cited "regulatory compact" connotes an implied agreement between the utility and the regulator: The utility will provide affordable, reliable, universal service in exchange for the exclusive right to serve customers in a geographic territory at an authorized rate of return.

[80] The staff proposed two phases: The first phase would focus on the duties and functions of the Distributed System Platform Providers, with the utilities submitting a proposal based on its system requirements and resources; the second phase addresses necessary ratemaking and other regulatory

contained in a report, would broaden the responsibilities and reach of the electric utilities in the state's economy. Although other states may follow suit, most are likely to take a more measured strategy in reshaping regulation and utility operations, finding the New York staff proposal too extreme given the prevailing uncertainties.[81]

Traditionally, the relationship between utilities and regulators presumes that the physical delivery of electricity across a service area is a natural monopoly; the REV vision shifts the focus of the natural monopoly from pure physical delivery to utility management of an increasingly complex distribution network because of the smart grid and DG, with the core goal of maintaining reliability.[82] One alternative is for distribution utilities to function as orchestra leaders or traffic cops with a multidirectional flow of power.[83] Utilities would act as regulated platforms[84] for selling energy services. The proposal labels the new role of utilities as Distributed Services Platform Providers (DSPP). It envisions DSPPs would "identify, plan, design, construct, operate, and maintain the needed modifications to existing distribution facilities to allow wide deployment of distributed energy resources."[85]

a. Objectives and issues

The proposed plan has five policy objectives:

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changes. The day after the issuance of the staff report, the Public Service Commission ordered parties to review the staff proposal. [New York State Department of Public Service (2014)].

81 Most states might also hesitate to impose radical changes on utilities on an accelerated schedule because of transitional difficulties, like those in Germany, and additional costs that exceed the perceived benefits. They might view the benefits, for example, as minimal. In other words, they might judge that a transformation of the electric industry, especially when done with less-than-complete information on future technological and policy developments, would fail a cost-benefit test and be contrary to the public interest.

82 As an EPRI (2014) paper points out, the value of the grid would increase with the *integration* of the DG with grid operation, rather than just a connection of the DG to the grid. The paper identifies four essential components of an integrated grid: (a) Grid modernization, (b) communication standards and interconnection rules, (c) integrated planning and operations, and (d) informed policy and regulation.

83 For example, utilities would coordinate distribution of electricity produced by a multiple of small entities (e.g., control points) and flowing in all directions. Basically, the role of utilities would change from power supplier and deliverer to system integrator and network operator.

84 The staff considers the platform as a natural monopoly that cannot be economically replicated. It defines the "platform" as a system that supports value-based interactions among multiple parties and a set of rules that standardizes and facilitates transactions among multiple parties.

85 New York State Department of Public Service (2014), 25.

1. Customer knowledge and tools to support effective management of the total energy bill

2. Market activism (e.g., responsiveness of suppliers and consumers to prices)[86]

3. System wide efficiency

4. Fuel and resource diversity

5. System reliability and resiliency

The REV identifies several topics that the Commission would have to address in executing the plan effectively. The eight major ones are:

1. Technology and system requirements

2. Utility roles vis-à-vis other market participants

3. Benefit/cost standards for utility investment

4. Ratemaking incentives for innovations and other desirable utility activities

5. A new transaction model for customer decisions, markets and tariffs

6. Barriers and opportunities related to customer engagement

7. Alignment of wholesale markets with distribution-level markets

8. Time horizon of implementation – short, medium and long-term measures

b. Emphasis on utility performance

The staff proposal elevates the role of utility performance and highlights the importance of utility earnings being tied to how well utilities serve their customers and society as a whole.[87] As said earlier, an important function of regulation is to measure and evaluate the performance of public utilities. Effective regulation requires measurement of performance if utilities are to be held accountable for their obligation to serve customers. After all, if regulators hope to set regulatory standards, determine "just and reasonable" rates or make other decisions integral to their duties, they need to measure utility performance and acquire supplemental information to evaluate utility performance. Compared to their foreign counterparts (especially European

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[86] One way to heighten customer activism in the marketplace is to enable them through technology (e.g., an automated thermostat, real-time communications) to respond to dynamic rates.

[87] The proposal, for example, includes performance reviews of utilities in their role as the Distributed System Platform Provider.

countries),[88] U.S. regulators have relied less on performance measures as a benchmarking tool to set rates and make other decisions. In most U.S. applications, benchmarking has focused on service reliability and operation and maintenance expenses, rather than on a utility's total cost.

c. Ratemaking reforms

The staff plan would revamp ratemaking to account for innovations in the information technology sector, to promote energy efficiency and renewable energy resources such as wind and solar, and to support wider deployment of distributed energy resources, such as microgrids, on-site power supplies, and storage.[89] An energy industry group in New York recommended:

> …a more innovative approach to regulation that would start with the evaluation of the current regulatory model, and consider changes that will provide alignment with state energy policy, provide long-term financial viability for the distribution companies by continuing to attract investors, build a platform for a dynamic energy market, and provide more customer options.[90]

Staff proposed for consideration a new regulatory framework,[91] namely, the multiyear rate plan.[92] Supporters of multiyear rate plans point to five potential benefits: (1) more predictable revenues for utilities, bolstering their financial condition, (2) spreading rate increases over a longer period, (3) more predictable rates for customers, (4) timely recovery of costs for new capital projects, (5) fewer general rate cases over time, and (6) strong incentives for operational efficiency when allowed rate changes link to external indices. These benefits,

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[88] *See*, for example, Cambridge Economic Policy Associates (2003).

[89] Distributed energy resources can supply energy and capacity in addition to ancillary services such as reserves, reactive power and voltage control.

[90] Energy Industry Working Group (2014), 28.

[91] The Commission presently allows revenue decoupling, future test years, multi-year plans in ratemaking and performance incentives for reliability and customer service. These non-traditional ratemaking approaches, although applied in other states, are not typical.

[92] As expressed by one expert,

> Multiyear rate plans ("MYRPs") are designed to compensate a utility for changing business conditions without frequent, full true-ups to its actual cost of service. Rate cases are held infrequently, most often at three to five year intervals. Any rate escalations that are made between rate cases are based in whole or in part on automatic attrition relief mechanisms ("ARMs"). The rate adjustments provided by ARMs are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth. [Pacific Economics Group Research (2013), 35]

although perhaps viewed by some observers to be minimal from the perspective of utility customers, may dominate any downsides, making multiyear rate plans worth considering.[93]

Multiyear rate plans provide utilities with differing performance incentives, contingent on whether allowed rate adjustments derive from forecasted costs for a utility or on indexes that are exogenous to an individual utility's actual costs.[94] Most of the real-world plans have "stay out" provisions that provide an additional utility incentive for cost management.

To avoid wide financial swings, multiyear rate plans can include an earnings-sharing component that restricts the utility's actual rate of return to a narrower range. Although this feature may diminish a utility's incentive for cost management, it allows utility customers to reap the benefits of unexpected efficiency gains prior to the next general rate case. It also tempers the extreme effects that could result from large forecasting errors (e.g., exorbitantly high or excessively low utility profits).

d. Expected outcomes

The staff expects its proposal to produce several positive outcomes. Efficiency improvements would come from higher system capacity utilization, better price signals for consumers and providers, and more competition in the retail market. Higher system capacity utilization, for example, would result from less demand for reserve capacity. A second expected outcome is consumer empowerment from better (e.g., real-time) information, additional value-added services,[95] lowering of transaction costs and less reliance on utility generation. Other expected outcomes include (1) utility investments that enhance customer value (e.g., metering, communications and customer technologies),[96] (2) utility incentives aligned with fostering innovation[97] and achieving social objectives, (3) ratemaking mechanisms targeted at regulatory

[93] An inherent problem with multiyear rate plans is the need to derive reasonably accurate forecasts over a three- or five-year period. Poor forecasts can lead to extreme utility earnings, either on the high side or low side. The consequences of wrong forecasts are potentially greater than those under a conventional test-year approach. These plans also require more time by commission staff and other parties to evaluate them, in addition to increasing the complexity of rate cases.

[94] Pacific Economics Group Research (2013).

[95] Questions relating to value-added services include: (a) who should provide the services, (b) how should they be priced (tariff, contract, market based), (c) distinguishing them from core services, (d) defining those services, and (e) whether to place them in a separate category.

[96] The authors of REV acknowledge that utilities would have to undertake major investment in metering, communications and customer technologies. For example, the utility system would require a communications network to transmit meter data and price signals to customers.

[97] The general perception is that regulated utilities are slow to innovate. They may be more risk averse by nature and therefore less willing to invest in innovation. As one study noted:

objectives and utility outputs,[98] (4) the promotion of energy efficiency and distributed resources[99] (especially wind and solar, and to a lesser extent CHP[100]), (5) fuel and resource diversity, (6) utility resiliency, and (7) explicit standards for utility investments.

e. Observations

So far, the proposal has received several reviews with the following general observations: (1) it could be good for utilities if they are able to take advantage of new market opportunities, or it could be a threat (e.g., utilities losing substantial revenues); ((2) uncertainty exists over how much DG will grow and over what time period; (3) economic efficiency may not improve as long as DG continue to receive subsidies; (4) the proposal faces major implementation hurdles, for example integration of DG into wholesale markets;[101] (5) the Commission may be overreaching if it accepts the radical proposed changes for the utility business model and regulation; (6) whether regulation should allow utilities and independent power producers to own and operate DG, or just stick to wires and traditional power plants, respectively, needs to be addressed; (7) whether utilities, rather than a third party, should manage and control the distribution grid also requires regulatory consideration; (8) utility market-power concerns are legitimate; (9) performance-base regulation, with less reliance on prudence reviews, would probably be well-received by investors; (10) utilities would have to invest a massive amount of dollars to develop the required infrastructure; (11) utilities may disagree on the preferred business model to adopt; and (12) customers may fail to actively participate in the new regime.

> Although new technologies have been introduced, long equipment lifecycles, standardization and utilities' aversion to risk have tended to limit the implementation of innovative transmission and distribution system technology. [Navigant Consulting (2010), v.]

The allocation of risk and benefit is a key factor in utility incentives for innovation. Typical ratemaking socializes most of the benefits and costs of new investment: Customers capture most of the benefits as well as bear most of the risks. This traditional allocation tends to make utilities less-than-enthusiastic about investing in new technologies.

[98] A results-based model shifts the emphasis of regulation from the reasonableness of historically incurred costs to the pursuit of long-term customer value. Regulatory incentive plans allow for focusing on outputs rather than inputs. Outcome-based regulation, however, can lead to greater financial variability, which increases utility risk.

[99] As defined in the report, "distributed resources" refers to distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

[100] The proposal calls for clean energy to move up in priority relative to other technologies.

[101] Incidentally, New York is only one of three states (the other two being California and Texas) where the wholesale market operator or RTO that sets prices and balances load with supply lies entirely within its borders.

2. Hawaii: Comprehensive energy policies and guidelines

On April 28, 2014, the Hawaii Public Utilities Commission issued four major orders requiring the Hawaiian Electric Companies (HECO Companies) to adopt major improvement action plans for the purposes of (1) pursuing energy cost reductions, (2) proactively responding to emerging renewable energy integration challenges, (3) improving the interconnection process for customer-sited solar photovoltaic systems, and (4) embracing customer demand response programs.[102] On that date, the Commission also issued a white paper, titled "Commission's Inclinations on the Future of Hawaii's Electric Utilities." The paper stresses the importance of "leaping ahead" of other states to create a 21st century generation system, and modern transmission and distribution grids. The Commission sees the objectives of lower, more stable electric bills and expanding customer energy options, while maintaining reliable energy service in a dynamic environment, as essential features of a utility strategic plan.

The Commission contends that the old regulatory compact is broken and no longer relevant for utility planning and operation, and utility regulation. It made a strong statement to the HECO Companies that if its current business model did not align with public policy goals and the needs of Hawaii's electricity customers, it would "employ arduous regulatory scrutiny and oversight of utility expenditures, operations and investments to attempt to achieve the desired performance levels and customer satisfaction." The Commission rejected the utility's initial integrated resource plan in failing to reflect progress toward what it calls a "sustainable business model."

The Commission highlighted that Hawaii has "entered a new paradigm" where "the best path to lower electricity costs includes an aggressive pursuit of new clean energy sources." Specifically, the Commission recommended that the HECO Companies "expeditiously" pursue the following strategies:

- Seek high penetrations of lower-cost, new utility-scale renewable resources;
- Modernize the generation system to accommodate a future with a high penetration of renewable resources (e.g., invest in smart meters, and communications and data systems);
- Exhaust all opportunities to achieve operational efficiencies in existing power plants; and
- Pursue opportunities to lower fuel costs in existing power plants and to retire or scale down old-inefficient fossil generating facilities.

The Commission considers continued utility ownership of generation as a barrier to the HECO Companies becoming a "world-class operator of a high renewables grid."

[102] Hawaii Public Utilities Commission (2014)

The Commission said it will examine whether the HECO Companies should own new generation facilities.

The Commission remarked that the HECO Companies' future functions in power generation could include generation resource planning, third-party generation capacity procurement, fuel supply management and procurement, and power supply dispatch and operational optimization. The Commission added that it will redesign the regulatory model to properly compensate the HECO Companies for undertaking these functions.

Rather than being a monopolist of electricity generation, the utility would become the facilitator, integrator and operator of a grid with high penetrations of third-party, utility-scale renewable energy and distributed energy resources. Although this new role deviates from the traditional utility business model, the HECO Companies will have profit opportunities from performing well as the system integrator.

The Commission recommends new rate structures, calling the current ones "not well suited" to Hawaii's future grid. The new rate structures include:

- Unbundling rate structures to accommodate customer preferences for varying levels of electricity service
- Greater use of capacity-based, fixed-cost based pricing
- Time-of-use and dynamic pricing structures that better match customers' demand with renewable electricity supplies
- New incentives to reduce the curtailment of renewables in the state
- A supplemental power supply pricing structure

The Commission acknowledges that the regulatory paradigm and ratemaking in particular should align with the new business model in which the utility will act primarily as grid operator and facilitator. Thus, it views regulatory reform as an essential part of their energy policy.

Finally, the Commission believes that other jurisdictions can learn from its bold approach. It hopes to become a model for the rest of the country. Hawaii is not a typical state in many ways, however: it has the highest electricity rates in the country, unusually high use of oil for power generation, and relatively uniform electricity usage across months of the year. Other states faced with much different conditions would likely not find Hawaii's comprehensive approach as appealing.

3. California: The Development of Distribution Resources Plans

Section 769 of the AB 327 requires the state's electric utilities to file Distribution Resources Plan Proposals (DRPs) before the Public Utilities Commission.[103] The plans should recognize, among other things, the need for (1) investing in distribution facilities to integrate cost-effective distributed energy resources (DERs) with the central grid and (2) identifying barriers to the deployment of DERs, such as safety standards related to technology or operation of the distribution circuit.

The Commission initiated the rulemaking proceeding to:

> [E]stablish policies, procedures, and rules to guide California investor-owned electric utilities (IOUs) in developing their Distribution Resources Plan Proposals, which they are required by Public Utilities Code Section 7691 to file by July 1, 2015. This rulemaking also will evaluate the IOUs' existing and future electric distribution infrastructure and planning procedures with respect to incorporating Distributed Energy Resources into the planning and operation of their electric distribution systems.[104]

The scope of the proceeding includes the following topics:

- Definition of principles to guide the DRPs;
- Development of a calculation methodology for assessing locational value of a particular DER;
- Description of how utilities can more fully integrate DERs into distribution planning;
- Identification of methodologies for assessing whether DERs provide distribution reliability benefits;
- Integration of DERs into distribution system planning and operations;

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[103] The Act requires the state's privately-owned utilities to file, by June 2015, new models for planning distribution grid investments that integrate cost-effectively distributed energy resources into their system.

[104] California Public Utilities Commission (2014), 1. The Commission Order appends a white paper, titled "More Than Smart: A Framework to Make the Distribution Grid More Open, Efficient and Resilient." The paper includes a four-step process for transforming from today's distribution system to a DER-integrated grid future. The Commission remarked that the paper is "a basis for questions to be asked in this rulemaking and a useful framework from which this rulemaking will establish policies, procedures, and rules."

- Specification of scenarios or guidelines, or both, that will test whether a specific DER integration strategy will work;

- Identification of any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of producing net benefits to electricity consumers; and

- Identification of barriers to the deployment of distributed resources.

The Commission has the authority to modify and approve a utility's DRP "as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources." The primary objective of the plans is to have utilities integrate DERs into their distribution systems. Unlike many of the other states, California expects to have a high penetration of DG and other distributed resources (e.g., storage) over the next several years.

4. Massachusetts: Modernization of the electric grid and time-varying rates

The Massachusetts Department of Public Utilities has mandated that electric utilities modernize their electric grid. It recognizes that recent developments have undermined the premises underlying current utility business plans and regulation.[105] The Department remarked that this modernization will have four objectives: (1) Reduce the effects of power outages, (2) optimize demand to reduce system and customer costs (via time-varying pricing), (3) integrate distributed resources into the utility grid, and (4) improve operational efficiency.[106] The Department recognizes that a modern grid has several features, some of which are new.[107] For example, a modern grid should protect against cyber and physical threats, and accommodate continuous technological change.

The Department emphasized customer education, marketing and outreach, as well as the need to move from 20th century technologies and business ideas. They include centralized economies of scale, one-way power flow, limited information, analog systems, and centralized control centers. The Commission also wants to apply infrastructure and performance metrics to gauge utility progress in achieving grid-modernization objectives.

As an important part of grid modernization, the Department endorses time-varying rates. It believes that such rates provide proper price signals that reflect system needs and costs over short- and long-term horizons. As a result, customer behavior should align with utilities making cost-effective DER investments. For example, time-varying pricing will motivate customers to

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[105] These premises include one-way power flows, central control centers and analog systems.

[106] Massachusetts Department of Public Utilities (2014).

[107] These features are affordable, safe, accessible, reliable, clean, secure, resilient and adaptable/flexible.

reduce and optimize their energy usage, stimulating innovation and new products that will further enhance customer opportunities and benefits.[108]

The Department supports pre-approval of new investments, with prudence reviews of utilities in managing those investments.[109] The benefits of pre-approval include: (1) Mitigating project risk by reducing the uncertainty of cost recovery (2) requiring the utility to prove a business case for the investment, and (3) allowing shareholders to provide advanced input into a utility investment proposal.

The Department also supports a capital cost tracker to reduce utility risk.[110] It believes that cost-of-service ratemaking provides utilities with inadequate incentives for grid modernization. The Department laid out criteria for cost recovery through the tracker: (1) Investment pre-approval, (2) prudently incurred cost (with the burden placed on the utility),[111] and (3) utility responsibility to justify any cost overruns.[112] This rate treatment reflects a balanced approach by splitting the risks between utility customers and shareholders.

5. UK: RIIO

The Office of Gas and Electricity Markets (Ofgem) is the electricity and natural gas regulator in Great Britain. It created a new regulatory regime called RIIO. RIIO is an acronym for "Revenue set to deliver strong Incentives, Innovation and Outputs." The RIIO model contains the following features: (1) A detailed set of outputs expected of the utility based on a comprehensive business plan, (2) an 8-year rate plan, (3) explicit incentives for achieving certain performance targets, (4) extensive stakeholder involvement, (5) external benchmarking of costs, (6) a total expenditure concept, and (7) uncertainty mechanisms.[113]

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[108] At least so far, throughout most of the country residential customers and regulators have opposed time-varying rates, even though empirical evidence has given them strong economic support.

[109] The Department will not second-guess a utility decision to invest, if it previously approved the investment, but it will review how the utility managed the investment (e.g., project management and oversight). The Department also added it will not apply the so-called "used and useful" standard for utility research and development (R&D) investments.

[110] Cost recovery for large capital expenditures through a general rate case can result in cash-flow problems for a utility when the lag between actual capital spending and cost recovery stretches over several years.

[111] The Department requires the utility to provide clear, cohesive and reviewable evidence to avoid the risk of cost disallowance.

[112] That is, the overrun was beyond the utility's control.

[113] *See*, for example, Fox-Penner et al (2013); Jenkins (2011); Lehr (2013); New York State Department of Public Service (2014); and Ofgem (2010).

RIIO represents a radically different ratemaking paradigm than what U.S. regulators apply to their electric utilities. It focuses less on the utility's earned rate of return and more on the utility's performance. RIIO uses the mantra "value for money."[114] It incorporates an incentive system with rewards and penalties to encourage operational efficiencies, as well as funding for innovation and opportunities for utilities to include third parties in the delivery of energy services.

As articulated by its supporters, RIIO links financial success for utilities to the achievement of public policy goals. They contend that utilities would then begin to own the policy outcomes.

Typically in the U.S., regulators view revenue adequacy solely from the perspective of utilities: Have we paid the correct amount for what the utility has spent (irrespective of the value of utility service to customers and society at large)? In other words, are utilities earning sufficient revenues to recover their costs? The RIIO phrase "value for money", in contrast, raises the ultimate question: Are utility customers and society paying for what they want? Do the revenues, or the costs incurred by a utility, correlate with the *value of utility services* to customers and society at large?[115] Are customers and society, in other words, getting what they pay for? RIIO, therefore, requires measuring the benefits of utility services, which is a major undertaking and highly contentious.

RIIO assigns primary importance to utility outputs. It defines seven performance areas for measurement: (1) Customer satisfaction, (2) reliability and availability, (3) safe network services, (4) connection terms, (5) environmental impact, (6) social obligations, and (7) price.

RIIO incorporates annual reopeners, pass-through and true up mechanisms partially to mitigate utility risk from uncontrollable costs, uncertainty, and investment shortfalls. These actions also reduce the chances of a public backlash or strong political opposition when unexpected events cause grossly abnormal outcomes, like exorbitant utility profits.

As a key feature, RIIO has a long regulatory-lag period; specifically, the basic price and revenue trajectories for utilities, along with the system of rewards and penalties, persist for eight years.[116] This means that utilities can expect with certainty to financially gain from operational

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[114] As noted by one U.S. regulation expert:

> Regulation needs to shift from its backward-looking focus on costs, to a forward-looking emphasis on value and desired societal outcomes. In this regard, the "value for money" regulatory model in the United Kingdom, with its emphasis on incentives and outcomes, might profitably be adapted for use in the United States. [Ron Binz (2014)]

[115] This perspective is more aligned with the economic notion of consumer surplus, or the difference between what value utility customers place on electricity and what they pay for it.

[116] One incentive involves rewarding a utility for achieving capital expenditures below the level approved in its business plan.

efficiency gains over a multiyear period before allocating the benefits to customers in the form of lower rates.[117]

Whether RIIO is feasible for the U.S. is doubtful at this time. Would state regulators be willing to accept a bold new approach to utility regulation, like the UK has?[118] Even if not adopted in the U.S., RIIO contains some commendable ideas that state regulators might want to consider in any new ratemaking approach that they adopt. Especially attractive is the notion that a primary criterion for utility revenue is its relationship to the value that customers receive from utility service. Benchmarking, which U.S. regulators rarely do, correctly shifts the focus from inputs to outputs and holds utilities accountable for subpar performance.

B. Incremental regulatory approach

One regulatory strategy follows a market-oriented perspective by emphasizing the role of correct prices in achieving desirable outcomes. For example, reformed rate design can foster traditional regulatory objectives, induce the appropriate utility business model, and achieve social objectives. In states that envision modest industry changes, rate reform by itself can suffice to effectuate improvements in utility performance and customer welfare.

Examples of reformed rates that are under discussion in a number of states are straight fixed-variable-type rates (e.g., three-part tariffs that include a demand charge for residential customers[119]), real-time pricing,[120] multi-year rate plans (e.g., price caps), surcharges for innovations, creation of a separate rate class for DG customers, cost-based standby rates,[121] and

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[117] One relevant question is: Are there enough inefficiencies in the utility system to have a material effect on utility profits if regulators require utilities to share the efficiency gains with their customers?

[118] Back in the 1990s when the electric industry went through dramatic restructuring, many experts believed that traditional ratemaking would not survive. They thought that price caps or more flexible ratemaking mechanisms would replace it, but it did not happen.

[119] *See*, for example, Blank and Gegax (2014).

[120] While studies on real-time pricing generally show that the benefits outweigh the costs, most of the benefits go to a small number of consumers who are relatively price-responsive. Thus, although some customers will likely benefit from such pricing, other customers will see higher bills. The fear of a large number of losers is a political obstacle to widespread adoption of real-time pricing.

[121] Most DG systems require backup, supplemental or maintenance service from a utility. The rates charged for these services can affect the economics of a DG project. Standby rates have been contentious in state regulatory proceedings since the 1980s. One outcome of appropriate standby rates is that they do not discourage economical CHP while avoiding a subsidy from full-requirements customers: Less-than-full cost recovery by the utility requires funding by other customers; more-than-full cost recovery results in excessive payment by DG customers making DG less economically attractive. In sum, a good standby rate would result in no subsidy, be fair to DG

performance-based rates for utilities.[122] As DG become more prominent, regulators will ultimately have to address how utilities should recover their actual energy cost and how they should recover their capacity and grid cost. Excessive reliance on the volumetric component of utility rates to recover both of these distinct costs will become increasingly problematic over time.[123]

Regulators can also consider reducing uncertainty over utility recovery of costs for emerging technologies whose benefits may not transpire for several years. Storage and other innovative technologies, for example, may require an upfront commitment by regulators and nontraditional cost recovery (e.g., surcharges). Regulators might consider evaluating these technologies in the context of integrated resource planning (IRP). Several states require electric utilities periodically to submit integrated resource plans. As a prospective review, IRP allows the regulator and non-utility shareholders to compare emerging technologies, before the utility commits to them, with other options.[124] IRP has particularly bolstered energy efficiency and distributed energy because it requires utilities to review, on an equal basis, these options along with traditional supply-side technologies.[125]

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customers and full-requirements utility customers, and not discourage good DG projects or encourage bad DG projects.

[122] In a general context, performance-based rates would ask: Are customers getting value for their money? Evaluation of utility revenues would consider outputs (e.g., reliability, penetration of DG, energy-efficiency savings) that benefit customers and society as a whole. The question then becomes, given utility outputs, what revenues should regulators allow utilities to earn? In this regard, performance-based rates are similar to RIIO. Performance-based rates can involve formal incentive mechanisms or simply rate adjustments by regulators based on their judgment of whether a utility performed exceptionally well or below par. The latter approach is problematic if the regulators' decision is done after-the-fact in an ad hoc fashion, rather than by applying upfront rules and criteria to the utility.

[123] One reason is that utility rates to core (or full-requirements) customers would rise faster as more customers migrate to DG.

[124] IRP can reduce a utility's risk from emerging technologies. IRP approval can represent at least a partial regulatory commitment to a utility's plan, which might include those technologies. As such, emerging technologies might be immune from later second-guessing by the regulator. The regulator could still investigate the utility later for how it managed the investment and the actual cost, especially if there were cost overruns.

[125] IRP also mitigates information asymmetry. By having a separate proceeding to evaluate emerging technologies along with other options, regulators will more likely have access to information needed for decisions that are in the public interest.

Regulators may allow utilities or their affiliates to compete with third-party DG providers in the utility's service area. If they do, they would need affiliate rules and take other actions to ensure fair competition.[126] Utility participation in DG offers the following potential benefits: (1) Utilities can identify the most beneficial sites and system sizes for their network; (2) utilities are more familiar with DG interconnection issues; (3) large-scale utility projects will help increase DG penetration and may reduce DG prices in the marketplace; (4) large-scale utility projects have economic advantages over small projects; and (5) the utility would have better control over the DG operation for grid integration.

One core task for regulators is to eliminate barriers created by market/regulatory failures, or also known as artificial barriers. An artificial barrier imposes a cost or obstacle that would prevent a more efficient entrant from competing with less efficient firms. Examples include onerous certification requirements for third-party service providers, vertical foreclosure by the regulated utility, and discriminatory transmittal of vital consumer and system-operations information by the regulated utility.[127]

VIII. Final Reflections

Is regulation up to the task of updating its policies and practices for the 21st century? There is no reason why it should not be. State utility regulators have adapted reasonably well in past years to dramatic changes in the electric industry.[128] This is not the first time that the industry has seen dramatic changes on the horizon. Some states will respond quicker than others, which should not reflect poorly on the latter states: Inertia may reflect a rational response to uncertainty over the future development of the industry. Objective observers have to concede that current projections may well turn out to be wrong. Besides, non-leading states can learn

[126] Rules such as codes of conduct produce potential benefits and costs for which interest groups disagree. Perhaps the most important benefit of codes of conduct lies with their up-front nature, which reduces uncertainty for those affected parties as well as mitigates market abuses that could otherwise lead to a costly after-the-fact investigation and litigation. Codes of conduct can provide clear and coherent signals to utilities about the propriety of their interrelationships with affiliates and independent service providers. Independent providers also benefit by knowing beforehand the prohibitions against certain utility-affiliate activities, thereby better assessing their ability to compete. In sum, codes of conduct serve as "safe harbor" rules or before-the-fact regulatory safeguards against potential utility-affiliate abuses. *See*, for example, Costello (2000).

[127] For example, the utility may provide this information only to its affiliate.

[128] *See*, for example, Joskow (1974). Joskow discusses how the combination of inflation, oil price shocks, and stricter environmental standards caused steep increases in electricity generating costs in the late 1960s and early 1970s. Utilities could not incorporate these cost increases (to a large extent beyond the control of utilities) into rates fast enough to keep profits from falling. Eventually regulators allowed fuel adjustment clauses (and, to a lesser extent, future test years) to reduce regulatory lag and avert more serious financial difficulties.

from the mistakes of early adopters, exemplifying the adage that states are "laboratories of democracy." Options theory tells us that often decision-makers should proceed incrementally in an environment of uncertainty. A radical course of action may be too risky. We can, therefore, expect uneven transformation of the electric industry across the states: DG and other technological developments will grow at a higher rate in those states with favorable economic, policy and regulatory conditions. In other states, developments will occur more incrementally; for example, regulators may tweak traditional-ratemaking practices to align with new technological and economic conditions.

Will electric utilities succeed like Verizon has or fail like Kodak[129] did in response to technological advancements and increased competitive pressures? At this time, we do not know. States can learn from the experiences of other sectors that have confronted disruptive or just new technologies, such as telecommunications,[130] higher education,[131] newspapers, the U.S. Postal Service and cable TV.[132] They should identify the key factors for incumbent survival in the face of dramatic technological and other changes.

Regulators should ask whether the current vision is less of a prediction than a scenario that represents special-interest desires or their perception of an ideal utility future. Will solar rooftop and other DG resources be nothing more than "boutique" technologies or will they assume a prominent role in retail markets?[133] Regulators need to distinguish between what will

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[129] Kodak found it difficult to compete in the emerging digital-photography market. One problem was that management continued with its old ways of doing business, which turned out disastrous. In other words, their old business model was incompatible with the new marketplace of digital photography.

[130] The telecommunications experience is analogous in the sense that incumbent providers with substantial embedded capital were under great pressure from new technologies to redefine their role.

[131] For example, small colleges face serious challenges because of: (1) Soaring student debt, (2) competition from online programs and (3) decreased college enrollment due to poor employment prospects. Some experts predict that many small colleges will likely fold in the next decade.

[132] Cable companies expanded their service offerings and competed in other markets, rather than expending substantial resources to compete with the satellite companies in the old product market. They went from being television-only providers to providers of internet and phone service, sold both individually and in bundles. One example is Comcast's Triple Play service. *See*, for example, Graffy and Kihm (2014); and Kind (2013).

[133] According to one report,

> The number of electricity customers who use net metering increased exponentially from fewer than 7,000 in 2003 to more than 450,000 in 2013…Growth has continued in 2014, with more than 75,000 additional net metered customers reported through May 2014. However, despite this growth, in 2013 these customers represented only 0.3% of the more than 145 million electricity consumers in the United States. [Heeter et al. (2014), 1]

likely happen from what should happen; that is, between unbiased, objective forecasts and scenario projections based on one's perception of an ideal world. Special interest groups are currently dominating the dialogue over the future of the electric industry. These groups stand to benefit financially or otherwise from a DG/high tech/clean energy industry future. Although flawed in their forecasts as are anyone else's, regulators and other policymakers should rely more on the analyses and forecasts of unbiased and objective groups like the U.S. Energy Information Administration (EIA).

The last decade has seen substantial changes and big surprises. Forecasters, policymakers and others should exhibit more humility by avoiding being definitive on the future electric industry and, therefore, on what utilities and regulators should do today. Have we not learned enough from the past to keep our options open because of surprises and other unexpected events? We should expect the unexpected. Regulators should recognize the real possibility of events changing course, and quickly, to make current projections of the electric industry no longer valid. As presented in an EIA conference, for example, for various reasons we may see limited growth for renewable energy.[134] We know from the past that the economics of different energy sources can rapidly change with a single event; a good example is the dramatic growth in shale gas production since 2008 because of the improved economics of hydraulic fracturing and horizontal drilling. The so-called shale gas revolution has dramatically changed the outlook for natural gas in the U.S. It has fostered industry action and governmental policies aimed at increasing the consumption of natural gas both domestically and internationally. Prior to around 2008, the biggest concern in the industry was diminishing natural gas supplies and high prices. Forecasters called for large imports of liquefied natural gas (LNG) over time. Now the issue is

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Another study reported for 2011 that over 98 percent of all net metering customers in 11 states used solar PV. [Stanton (2013), 5]

[134] The reasons include: (a) Slow electricity demand growth combined with relative surplus of existing generation capacity; (b) the increased cost of renewable increasing relative to the cost of traditional generation technologies; (c) low natural gas prices; (d) grid integration concerns; (e) the expiration of the Federal Production Tax Credit (PTC) and the decline or expiration of the Investment Tax Credit (ITC) at end of 2016; (f) no new passage of state Renewable Portfolio Standard (RPS) since 2009; instead, efforts to weaken or dismantle existing RPS policies in a number of states; and (g) considerable dialogue and debate over net metering, grid charges and other ratemaking issues. [Bredehoeft (2014)]

EIA's latest *Annual Energy Outlook* [United States Energy Information Administration (2014)] projects a sharp decline in the growth of renewable energy after 2020:

> Renewable capacity growth is supported by a variety of federal and state policies, particularly state renewable portfolio standards (RPS) and federal tax credits. However, the impact of those policies is limited later in the projection period, because individual state renewable targets stop increasing by 2025, and projects must generally be online by 2016 to qualify for currently available federal tax credits. In addition, growth in electricity demand is modest and natural gas prices are relatively low after 2025. Renewable capacity grows by an average of 0.7%/year from 2020 to 2030, compared with 3.8%/year from 2010 to 2020 [at MT-19].

how much LNG should the U.S. export. Overall, shale gas has disrupted the dynamics of the U.S. energy sector and made previous forecasts irrelevant.[135]

One professed benefit of a transformed electric industry is that it would empower utility customers to become more active participants in the marketplace. Do customers, especially residential customers, desire to be more engaged, or do they just want reliable service at reasonable rates? We know that transaction costs would have to be minimal for small customers to switch electricity supplies, including to DG. States can draw upon the experiences of both electric and natural gas retail competition where the vast majority of eligible residential customers have decided to continue receiving their total service from the local utility. The typical residential electricity consumer may have little interest in DG: The average cost savings is small relative to income, inferring that few residential customers would expend the time and effort required to collect and analyze the available DG choices.

Another uncertainty is how much DG will displace central station generation. Some industry observers project, or more accurately advocate, phasing out central station generation over the next two or three decades. Can we have an electric system with reasonable cost and high reliability sans coal and nuclear power capacity? Although highly doubtful that we can, some studies are projecting this scenario as the course the U.S. should pursue. One study shows that a lack of generation diversity can have high economy-wide costs.[136]

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[135] Low natural gas prices, among other things, have made coal, nuclear power and renewable energy less economical. They have also induced retail energy customers (e.g., residential and commercial utility customers) to switch from oil and propane to natural gas.

[136] *See* the IHS Energy (2014) study for example. The study shows that diversity is an economic winner in both reducing long-run expected costs and risk, with positive ramifications for the general economy. The major finding of the study is that:

> If the US power sector moved from its current diverse generation mix to the less diverse generating mix, power price impacts would reduce US GDP by nearly $200 billion, lead to roughly one million fewer jobs, and reduce the typical household's annual disposable income by around $2,100. These negative economic impacts are similar to an economic downturn. Additional potential negative impacts arise from reducing power supply diversity by accelerating the retirement of existing power plants before it is economic to do so. For example, a transition to the reduced diversity case within one decade would divert around $730 billion of capital from more productive applications in the economy. The size of the economic impact from accelerating power plant turnover and reducing supply diversity depends on the deviation from the pace of change dictated by the underlying economics (at 6).

Another energy expert [Binz (2014)] warned that:

> We should be agnostic about the ultimate role that distributed resources will play going forward. Undoubtedly, there will be a significant amount of decentralized resources in our energy future. On the other hand, nothing can offset the economies of scale and scope

Subsidies for all energy sources have distorted the mix of generating capacity.[137] Do we know, for example, whether renewable energy and other clean energy sources are socially desirable? When can we wean them, as well as other forms of energy, from favored governmental policies? After all, policymakers can judge the relative social desirability of various energy sources only if they compete on a "level playing field."

Another question relates to whether the expansion of long-distance transmission has become less urgent. Definitely over the past few years, the policy dialogue has shifted from transmission to distribution.

A recent comment from a CEO of a major utility [Alexander (2014)] merits some reflection:

> …at the end of the day you can't use a private company's balance sheet and its ability to bill to carry out social policy. You cannot use that capability to ultimately tax all customers for what you perceive is a benefit to certain customers.[138]

How should regulators and other policymakers react to this provocative statement? Does it have any validity or does it reflect backward thinking? The remark, if anything, reveals the heightened tension between mandating utility social obligations and sustaining utility financial viability in addition to other regulatory objectives (e.g., fairness to core utility customers). To say differently, there seems to be discordance between treating utilities as both a for-profit

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> available to larger clean energy resources. The economics of large and small resources, close and distant ones, and flexible and inflexible resources are subtle and complicated; the equilibrium state is hard to predict.

[137] One justification for financial incentives to bolster solar technology is the premise of public benefits. (These incentives can include RPS solar set-asides, tax credits, net metering, rebates, sales tax exemptions, and property tax exemptions.) For example, 43 states have established net metering for small solar PV systems, 30 states have a RPS and 48 states give tax incentives. Public benefits attributed to solar energy include job creation, a cleaner environment, national security and contributing to the country's overall growth. Some of these benefits are dubious in theory while others are difficult to quantify, making their role in decision-making suspect (Borenstein 2012).

[138] The same CEO also commented that:

> The challenges we now face from government interference in the electric business are far more intrusive and disruptive, and I believe far more significant to our industry's future…That's because whether it impacts our traditional regulated business or our competitive operations, government policy is now stifling the growth and use of electricity – and picking winners and losers in the competitive marketplace.

business and a purveyor of social services. This tension complicates efforts to achieve a political equilibrium (i.e., a consensus).[139]

That leads to the question of whether society requires too much from electric utilities. We expect utilities to maintain financial viability, make electricity affordable to all customers, adopt and accommodate new technologies that compete with their core business, decarbonizes their generation portfolio, promote less usage of electricity by their customers, and increase consumer empowerment. No other private business comes to mind in which society expects firms to address such a wide range of social issues. The primary objective of regulation is to keep utilities financially healthy while satisfying different social goals at least cost. Who should set the goals for utilities to achieve? Would outcomes be socially superior to other approaches just because stakeholders had reached a consensus? Have some stakeholders become too powerful in the regulatory arena?[140] To what extent do new objectives conflict with traditional objectives, such as fairness, economic efficiency and utility financial stability?

A follow-up question is whether a government-run utility would better satisfy all of the social objectives than what a privately own utility could. A problem of privately-owned utilities is that traditional regulation motivates them to minimize risk given the little potential for upside gain; to innovate any entity needs to be risk takers but individuals or corporations only take risk when they expect to gain, and substantially when the risk is high, when outcomes turn out well. Thus, utilities face strong incentives to minimize risk when the potential upside gains are small. Although utility management may be more risk averse than typical corporate management, utility regulation has made them reluctant to take chances and innovate even when it would be beneficial to their customers.[141] While we do not advocate government takeover of privately-owned utilities, one can rightly question how policymakers can expect utilities to perform the dual role of private corporation and social agency in advancing the public interest.

Regulators should ask themselves whether utilities' core customers are on the short end of the straw. Are customers funding the advancement of social objectives through inflated rates without compensatory benefits?[142] The term "turkey stuffing" may well describe the condition where utilities keep attaching surcharges to a typical customer's bill to fund investments and other activities whose benefits may largely accrue to others (e.g., the general public, DG

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[139] Since policy is discouraging electricity consumption and utilities have always made money by selling more electricity, good policy may dictate that regulators consider rewarding utilities for exceptional performance in satisfying societal goals related to (say) energy efficiency and greenhouse gas emissions.

[140] For example, have special interests hijacked regulation?

[141] *See* Costello (2012); and GE Digital Energy and Analysis Group (2013).

[142] These actions might also have a regressive effect by disproportionally burdening below-average income households. For example, the beneficiaries might mostly include high-income households while the funders are households of lower incomes.

customers). The dynamics work something like this: Politics and interest groups are driving change toward a clean energy/less energy consumption future; utilities are not necessarily opposed but want changes in ratemaking and regulatory rules to protect their financial interest. Regulators, pressured by utilities and advocates of clean energy, seem to acquiesce in and even exhibit enthusiasm about this development. They generally pass through costs increases and revenue losses to core utility customers. Utilities favor more cost allocation to DG customers but DG advocates fear that this would stifle DG growth. Perhaps not surprisingly, utilities have taken more of a pro-consumer position (at least in effect if not in intent) than DG advocates. DG advocates seem to want their cake and eat it too: They adamantly oppose what they consider any "unfair" action that would suppress the prospects for DG growth, including their unwillingness to surrender any subsidies or favoritism that they presently enjoy.

Broad policy options seem confined to the following three: (1) Since privately-owned utilities have assumed duties advancing a social agenda, why not make them public agencies? (2) because of the conflicts between utilities operating as a for-profit entity and advancing social objectives, why not restrict their social obligations? and (3) if we retain the *status quo* in expanding the utility role to satisfy various social needs, how can we meet the challenge of achieving a sustainable outcome for utilities and their customers?

With all the discussion about what government can and should do, have policymakers given the free market short shrift? That is, have policymakers slighted the capability of the marketplace to achieve social objectives? Markets function best when private firms receive the returns and bear the risk from investments and other activities. Moral hazard and socialization of risk are absent, as firms have the right incentive to undertake actions. Taxpayer/ratepayer subsidies (i.e., favorable treatment to certain technologies or market participants) should require rigorous cost-benefit tests.[143] Subsidies for specific technologies, for example, should continue only under special conditions; subsidies generally have negative side effects that are often non-transparent. Uneven subsidies across energy sources violate the condition of "equal opportunities" where no technology or market participant has an unfair advantage. Policies that are technology neutral are more likely to lead to the most socially desirable investments. Clean energy technologies, for example, should be competing with each other and the technologies they seek to replace in the marketplace, not in the government arena. Well-functioning markets require consumer empowerment, robust incentives for innovation and economically sound

[143] Subsidies for an energy source can distort energy and capacity markets by giving false price signals.

pricing.[144] Regulators should distinguish between normal market barriers and artificial barriers (i.e., market/regulatory failures). This distinction has definite policy implications.[145]

Policymakers should perhaps take a sobriety test. Have we gotten off the rails? Do we understand, for example, the accumulated effect of additional demands on utilities on electricity prices? Are we on the right path or we being taken down the primrose path to arduous transitional problems, inefficient and unreliable utility service, and excessive electricity prices? Have hype and ideology overridden the fundamentals of engineering, economics, risk management and good public policy in mapping out our electricity future? Who is in charge? Who should be in charge? Should it be utilities, regulators, other government entities, or shared leadership? Do we need to re-evaluate the role of electric utilities in society? As suggested earlier, an inevitable tension exists between a for-profit entity trying to achieve several and conflicting social goals. If regulators satisfy utility shareholders and the utility is meeting its prescribed social goals, the inevitable conclusion is that utility customers are picking up the tab.

Finally, the global question for utility regulators is: How should we treat utilities fairly while providing them with incentives to best serve consumers (both utility core customers and DG customers) in addition to pursuing society's broader policy goals? This is the pending $64,000 question as of today that still awaits an answer. Compare this to the past when regulation focused largely on overseeing utilities' profits, servicing growing customer demands and maintaining rate stability and service reliability. Life has definitely become more complicated for regulators. Can regulators address industry changes by rate reform and other incremental actions alone, or do they have to redefine utility social obligations and structure? It seems that, as of today, they may have to pursue a more radical course of action. But, as this paper warns, they should proceed with caution.

[144] Other features of an efficient market are well-informed customers, price transparency, customer responsiveness to price changes, low transaction costs, robust competition among suppliers and low entry barriers.

[145] Market/regulatory failures are defined here as a barrier when (a) they produce uneconomic and socially-damaging outcomes and (b) their mitigation passes a cost-benefit test and, thus, their amenability to policy intervention. In contrast, normal market barriers derive from natural market forces and would, most surely, fail a cost-benefit test to mitigate. For example, their mitigation might involve a high cost that, on net, would inevitably make matters worse. For examples of these two distinct barriers as they pertain to CHP, *see* Costello (2014).

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