EISPC

EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

Utility Involvement in Distributed Generation: Regulatory Considerations White Paper

February 2015

National Regulatory Research Institute

For EISPC and NARUC

Funded by the U.S. Department of Energy

Acknowledgement:

This material is based upon work supported by the Department of Energy, National Energy Technology Laboratory, under Award Number DE-OE0000316.

Disclaimer:

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

The information and studies discussed in this report are intended to provide general information to policy-makers and stakeholders but are not a specific plan of action and are not intended to be used in any State electric facility approval or planning processes. The work of the Eastern Interconnection States' Planning Council or the Stakeholder Steering Committee does not bind any State agency or Regulator in any State proceeding.

Rajnish Barua, Ph.D.
Executive Director
National Regulatory Research Institute
8611 Second Avenue, Suite 2C
Silver Spring, MD 20910

Utility Involvement in Distributed Generation: Regulatory Considerations

Ken Costello
Principal Researcher
National Regulatory Research Institute

NRRI Report No. 15-01
February 2015

8611 Second Avenue, Suite 2C
Silver Spring, MD 20910
Tel: 301-588-5385
www.nrri.org

About the Author

Mr. Ken Costello is Principal Researcher, Energy and Environment, at the National Regulatory Research Institute. Mr. Costello previously worked for the Illinois Commerce Commission, the Argonne National Laboratory, Commonwealth Edison Company, and as an independent consultant. Mr. Costello has conducted extensive research and written widely on topics related to the energy industries and public utility regulation. His research has appeared in numerous books, technical reports and monographs, and scholarly and trade publications. Mr. Costello has also provided training and consulting services to several foreign countries. He received B.S. and M.A. degrees from Marquette University and completed two years of doctoral work in economics at the University of Chicago.

Author's Acknowledgments

The author thanks Dr. Douglas J. Gotham (Purdue University); Denis Bergeron (Maine Public Utilities Commission); and my NRRI colleagues, Dr. Rajnish Barua and Tom Stanton. Any errors in the paper remain the responsibility of the author.

National Regulatory Research Institute

About NRRI

NRRI was founded in 1976 by the National Association of Regulatory Utility Commissioners (NARUC). While corporately independent, NARUC and NRRI are linked in multiple ways to ensure accountability. NARUC, as the association of all state regulators, is invested in quality research serving its members. NRRI coordinates its activities to support NARUC's policy, research, educational and member-support service to state commissions.

Mission Statement

To serve state utility regulators by producing and disseminating relevant, high-quality applied research that provides the analytical framework and practical tools necessary to improve their public interest decision-making. In all its activities, NRRI embodies the following values: relevance, excellence, objectivity, creativity, independence, fiscal prudence, ethics, timeliness and continuous improvement.

Board of Directors

Executive Summary

The rapid growth of distributed generation (DG) over the past two years with the expectation of continuation through this decade has the potential to transform the U.S. electric industry. It has stimulated a dialogue, sometimes of a spirited nature, on core topics that relate to both utility operations and state utility regulation. The recent narrative on the electric utility of the future includes the efficacy of the existing utility business model and current ratemaking practices in financially sustaining utilities and DG providers, as well as in advancing societal goals. A new business model, for example, could enable DG to compete on a more equal basis with utility generation. Alternatively, existing or newly erected regulatory barriers and obstacles could prevent DG from reaching its full economic potential. The question also arises as to whether and how utilities might go beyond simply accommodating DG, to becoming active agents in growing DG for long-term profit.

One caveat is that states will vary on their efforts to exploit new technologies like DG and the smart grid. Some states will aggressively foster these technologies while others will perceive little or even negative benefits from encouraging them. Each state faces unique economic and political conditions that would rationally lead them to pursue a different path for their electric utilities.

At this time, the future growth of DG is unknown. For example, although the cost of solar PV has sharply dropped, it faces serious challenges. One challenge derives from its non-dispatchability. Another challenge is that, in the not-too-distant future, DG may have to operate without subsidies. Federal, state, and utility incentives provide substantial impetus to solar PV systems. A third challenge is the lowering of what the industry calls “soft” costs. Some experts contend that the key factor in making solar more competitive in the future is to manage “soft” costs.

Smart technologies could assist in allowing DG to reach its full potential by (1) facilitating grid integration and (2) achieving accurate valuation of the benefits that the grid offers DG providers, and vice versa. If DG actually assumes a large role in the electric industry, as many observers predict or hope for, then state utility regulators might support more-than-incremental changes in both utility business models and their own practices, especially in defining the utility’s function and in ratemaking. After all, the appropriate business model and regulation are inseparable, as each relies on the other for fostering predetermined objectives. For example, a business model with the dual objectives of financially sustainable utilities and fairness to all utility customers calls for compensatory and symmetrical rates that accurately account for both the grid services required by DG customers and the benefits they provide to the grid.

This paper explores the challenges facing electric utilities and their state regulators as they grapple with the various questions inherent in advancing the public interest during a transition to higher reliance on DG. It begins by highlighting DG’s recent developments and

future prospects, and enumerating: (1) DG's unique features as a source of electric power and related grid services; (2) concerns it has raised; and (3) its relationship to the smart grid.

One area of interest is the implications of DG for both electric utilities and regulators. Specifically, what are available options for realigning or revamping the utility business model? A popular view today is that that utilities will have to operate under a new business model to thrive, perhaps even just to survive, in a market environment with DG playing a prominent role. Major or even incremental changes in utility business models could require all participating parties, including state utility regulators, to contemplate new practices that place more emphasis on utility performance while minimizing barriers to DG. It becomes imperative for regulators to eliminate any artificial barriers that might stifle DG development. Regulators might also support some ratemaking reforms to better advance regulatory objectives, even if utilities make no changes in their business model. Current ratemaking practices leave much to be desired, especially in view of smart technologies that enable utilities to execute more economically rational pricing (e.g., real-time pricing, pricing of DG energy and other services exported to the local utility, demand charges for residential service).

This paper covers the following topics:

1. Recent developments in DG, focusing on rooftop solar PV;

2. Rationales for a new utility business model in view of increased DG growth;

3. Functions that utilities could perform in facilitating or stimulating DG growth under different future business models;

4. The likelihood of and conditions that might result in a death spiral for utilities;

5. How current ratemaking and other regulatory practices affect DG development and the public interest;

6. The benefits that smart technologies could offer for integrating DG into the utility grid; and

7. The potential positive and negative outcomes from direct utility participation in the DG sector.

Stakeholders in the regulatory process disagree over what actions state utility regulators should pursue in promoting DG. This paper provides regulators with basic information to help guide their decisions about DG and the various actions that utilities can take in its development.

Table of Contents

Distributed Generation: Utility and Regulatory Challenges

This paper explores the challenges facing electric utilities and their state regulators as they grapple with the various questions surrounding the growth of distributed generation (DG). It begins by highlighting DG's recent developments and future prospects with regard to rooftop solar. It then enumerates: (1) DG's unique features as a source of electric power, (2) concerns it has raised and (3) its added benefits from deployment of the smart grid.

This paper also discusses the implications of DG for both electric utilities and regulators. A popular view today is that that utilities will have to operate under a new business model in a market environment with DG playing a prominent role. One outcome of a new business model is the elimination of artificial barriers that might stifle DG development. Regulators might also want to consider ratemaking reforms to better advance regulatory objectives, even if utilities make only incremental changes in their business model. Finally, this paper discusses the effects from direct utility participation in the DG sector. The difficult task for regulators is to weigh the potential upside of direct utility involvement against the risk of abuses that could stifle third-party investments and fair competition.

I. Background on Rooftop Solar PV

A. Falling costs and rapid growth

DG refers to small-scale generation largely directed at self-consumption on the site of customers, who are connected to the distribution system for backup power and the sale of surplus energy not internally consumed.[1] DG installations typically range in size from 3 kilowatts (kW) to 10 megawatts (MW) or larger. Since a typical household's peak demand is about 3.5 kW, installations for residential customers lie within the lower part of the range. The larger installations are mostly for commercial and industrial customers. In addition to solar PV, DG includes small wind turbines, combined heat and power (CHP), fuel cells, microturbines, as well as other sources. Because more than 90 percent of installed distributed generation in the United States today is solar PV, it is the primary focus of this paper.[2]

[1] The definition of DG has transformed over time. When the Public Utility Regulatory Policies Act (PURPA) was enacted in 1978, utilities became statutorily obligated to purchase power from qualifying facilities (QFs) at the utility's "avoided cost. These QFs included combined heat and power (CHP) facilities and small power production facilities with 80 MW or less of installed renewable generation capacity. These QFs were generally thought of as DG facilities.

[2] Solar PV systems consist of arrays of modules that absorb solar radiation and cause current to flow between oppositely charged layers of the module. PV systems use semiconductors to convert sunlight directly to electricity, and an inverter to transform DC of PV modules into AC (McGarvey et al.

DG customers continuously rely on the utility distribution system either for exporting or importing power;[3] that is, DG generation needs grid support. The two-way flow of power from and to DG facilities requires additional utility capital expenditures and sophisticated operational support.

DG has favorable attributes from both a customer and societal perspective, but it also has costs.[4] From the public-interest perspective, regulators, utilities and policymakers should then evaluate both the aggregated benefits and costs of DG to determine its desirability. Distributional effects (e.g., who gains, who loses) should also enter into policy decisions.[5] Policies on DG could fail a cost-effectiveness or cost-benefit test besides creating perverse incentives and adverse "fairness" consequences that could jeopardize the public interest.

The economics of rooftop solar PV varies 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. As of late 2012, 10 utilities had 70 percent of the DG capacity in the U.S.[6] 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

2007). PV systems have the benefit of being highly modular. PV systems also have the advantage of being able to produce electricity anywhere: deserts, cities or suburbs. All PV systems require short construction times and even utility-scale solar projects can start operating within 6-12 months of the start of construction.

Analysts usually divide solar systems into two size groups: Rooftop and utility-scale. They classify rooftop systems as either residential or commercial. Residential PV systems are generally 2-10 kW P DC and installed on sloped roofs, while commercial systems may be between 10 kWP DC and multi-MW and are most often installed on a flat or low-slope roof. Minimum size thresholds for utility-scale systems are either 1 or 2 MW or even larger, according to some definitions. All utility-scale systems are ground-mounted. Economies of scale are a feature of PV solar systems. One study calculated, for example, that large commercial rooftop systems (>1 MW) cost 42 percent less than residential rooftop systems on average, and utility-scale systems cost, even less per kW and kWh (Barbose et al. 2013). Favorable costs for larger PV solar systems have persisted over time (Stanton et al. 2014).

[3] Because residential load and solar PV systems do not synchronize, DG customers require the distribution system for purchasing or selling energy during most periods.

[4] Utility-scale PV is about 50 percent cheaper per kWh. If RPS requires carve-out for rooftop solar PV, it could push out more cost-effective renewable energy.

[5] Distributional effects have played an important part in the current, and often heated dialogue on solar PV. One interpretation of recent events is that solar advocates are rent-seekers who are motivated either by ideology or economic interests to promote this technology without the slightest concern for taxpayers, utility ratepayers or the societal interest. Rent-seekers in a larger context often try to shape the future to their advantage.

[6] Kind 2013, 4.

Jersey and Pennsylvania (Stanton 2013, 5). Consequently, at least so far, development of solar PV has concentrated in a relatively few areas across the country.[7]

According to the National Renewable Energy Laboratory, about one-quarter of residential and commercial rooftops in America are suitable for solar.[8] 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.[9] Although the current penetration of solar PV in the residential and commercial markets is extremely low, projections call for high growth in the coming years across the country.[10]

The cost of solar PV systems has fallen dramatically over time (Stanton et al. 2014).[11] The average price of a residential solar PV system, for example, fell by over 40 percent between 2010 and the second quarter of 2014. As noted by Moody's Investor Service, this favorable trend could substantially increase solar PV's presence behind-the-meter with potentially adverse outcomes:

> It is easy to imagine a scenario where a mass-market adoption of a disruptive technology can destroy the traditional utility business model. As solar-power installation costs continue to fall, more residential customers will be incentivized to install solar technology. Combined with storage, energy efficiency and conservation efforts, we can see why some customers might opt to drop off the grid -- assuming it can be done safely and with a cost-effective alternative. But

---

[7] The two states with the highest number of solar PV installations over the past two years are Arizona and California.

[8] Lacey 2013. According to some observers, this creates a greater need for community and other forms of shared solar.

[9] The U.S. Energy Information Administration reports that rooftop solar electricity accounts for less than a quarter of 1 percent of the nation's power generation (EIA 2013).

[10] The general belief is that with additional production, installation and operation of solar systems, system costs should decline in the future. That is, the past decrease in solar costs reflects a learning curve or what analysts call an experience curve should continue in the future. One prediction derives from what is called Swanson's Law: the cost of PV cells decreases by 20 percent for a 100 percent increase in cumulative production (Pethokoukis 2013). Such a downward trend in cost could trigger a "growth spiral," as increased production lowers price leading to higher demand and higher production, which repeats the cycle bolstering growth in the solar industry. Not everyone, however, subscribes to the prediction that past trends (e.g., Swanson's Law) will hold in the future. One argument is that using past trends is overly simplistic in capturing the multiple, complex drivers of cost reductions. They cannot, for example, predict discontinuities in learning due to technology breakthroughs, market structural changes, and possible future barriers to further development (Candelise et al. 2013).

[11] Besides lower cost for producing solar PV systems, subsidies of various kinds and third-party financing have contributed to the recent high growth of solar.

this scenario goes way beyond just rooftop solar installations, so although we see the threat as possible, we do not view it as probable, at least not now...Still, distributed generation can impose significant cost shifts on non-adopters and in an extreme scenario threaten the utility industry's profitability and undermine its business model.[12]

B. Challenges faced by rooftop solar PV

Although the cost of solar PV has sharply dropped, it faces serious challenges. One challenge derives from its non-dispatchability: An intermittent generating technology such as solar could have lower economic value than a dispatchable generating technology even with similar levelized cost.[13] Intermittency also requires a utility to have increasing amounts of flexible generating capacity; for example, to accommodate incremental amounts of solar generation by ramping down its other generating facilities in the morning when solar generation starts, and ramping up in the afternoon as solar generation decreases while the evening peak increases.

Another challenge is that in the not-too-distant future, DG may have to operate without subsidies.[14] Federal, state, and utility incentives provide substantial impetus to solar PV systems. They enjoy a federal investment tax credit (ITC), which provides an income tax credit for residential and commercial PV installations. The ITC was revised in 2009 as part of the American Recovery and Reinvestment Act (ARRA).[15] In addition 48 states give tax incentives. As discussed later, increasingly industry stakeholders have voiced their concerns over the favorable treatment given to solar PV systems from net energy metering (hereafter "net metering") and the Renewable Portfolio Standard (RPS).[16] Some states are addressing whether

[12] Moody's Investors Service 2013, 2.

[13] The inherent variability of solar generation, for example, could lead to mismatches between generation and demand, which in turn could cause voltage and frequency to deviate from tolerable levels (Borenstein 2011; Joskow 2011). This outcome could result in grid instability and failure. One utility response is to add system reserves and back-up generation to maintain system reliability. A bigger challenge is integrating additional solar capacity into a grid once it has reached high levels of penetration (Massachusetts Institute of Technology 2011).

[14] As costs for solar PV installation continue to fall, unsubsidized solar will move closer to parity with other electric-generation technologies. At parity or even earlier, policymakers should consider eliminating subsidies, or at least phasing them out.

[15] ITC provisions in the ARRA that specifically relate to solar PV include a 30 percent ITC extended through the end of 2016 for both residential and commercial solar installations. As of this writing, solar proponents are lobbying to extend the existing tax credit that is otherwise scheduled to drop to 10 percent at the end of 2016.

[16] Some RPS mechanisms have carve-outs, which designate a mix of renewable generation requiring, for example, a specified share of distributed generation or a level of an emerging technology.

to undo net metering and replace it with a pricing mechanism that corresponds closer to the real value of solar energy to the utility grid and society as a whole.[17]

A third challenge is the lowering of what the industry calls "soft" costs.[18] Some experts contend that the key factor in making solar more competitive in the future is to manage "soft" costs. With PV module prices declining rapidly, "soft" costs have accounted for an increasing portion of the average installed PV system costs. "Soft" costs vary widely across projects.[19] Permitting costs can be much higher for utility-scale systems. These systems have a large footprint on land and water use.

C. Is rooftop solar PV a disruptive technology?

Some experts regard solar as a disruptive technology that will change the landscape of utility retail markets. For example, one study warns that:

> A surge in rooftop solar installations leads a wave of innovation in energy markets that manifests as disruptive competition for electric utilities. These innovations are emerging not only in technology but in public policy, social preferences, and business practices as well. Risks to the stability of current arrangements in the power sector are real, but regulatory protections cannot entirely insulate utilities from all such challenges…The characterization of renewable energy innovations, such as rooftop solar, as a 'mortal threat' or 'radical threat' to utilities and utilities themselves as in a 'death spiral' reflects an awareness that unconventional risks have emerged.[20]

By definition, disruptive technologies make new or existing products and services more affordable to a broader population. They have a direct effect on how businesses operate and their internal organization. Often, they require firms to give up their old business practices and reinvent themselves to better compete and survive. Historically, monopoly utilities have always faced some forms of competition: benchmark competition, inter-fuel competition, competition by service area (businesses choosing to locate or relocate in the most favorable territories), independent power producers, PURPA QFs, and in some service areas retail-customer choice.

[17] The paper later addresses this topic.

[18] "Soft" costs include customer acquisition costs, marketing, insurance, financing and contracting, permitting, interconnection and inspection, installation labor, and O&M expenses.

[19] *See*, for example, U.S. Department of Energy 2012; and Stanton et al. 2014. When compared with solar systems in other countries, especially those with an active solar market, the U.S. has high solar costs. One explanation is the relatively high "soft" cost of U.S. solar installers. According to one study, nearly two-thirds of the total installation costs for a residential solar PV system are "soft" costs. The DOE's SunShot Initiative has targeted research at reducing "soft" costs to make solar more cost competitive.

[20] Graffy and Kihm 2014,1-2.

As one study noted, these pre-existing forms of competition did not constitute what the authors describe as "disruptive competition that challenges the status quo of the regulated monopoly arrangement," but DG potentially poses "disruptive competition" for utilities.[21] Nevertheless, in its infancy, the jury is still out on whether rooftop solar PV will have a disruptive effect or, instead, have a "boutique" or "niche" effect on retail markets. The prospects for solar PV may well fall short of the projections being made by solar advocates and others. One policy implication for this ambiguity, which seems to have been ignored so far, is envisioning electric utilities to perform radically different functions than currently. The consequent transition costs may overwhelm any benefits from a disappointing level of DG acceptance by utility customers.[22]

D. Policy issues with DG

Various concerns over DG have emerged as its presence has rapidly grown in some markets:

1. The costs associated with utilities revamping their distribution systems to accommodate DG;

2. Incompatibility of the current utility business model in a heightened DG world;[23]

3. Obstacles to utility customers and third parties in developing DG;[24]

---

[21] Ibid.

[22] Another way of saying this is that the pretense of knowledge in leaving no doubt of the large-scale penetration of DG may have unintended consequences (i.e., regrettable outcomes). Just as those who believe that nothing will change much over the next several years seem extreme, those who convey sureness that the electric utility industry will undergo major transformation seem to be extreme as well. A rational approach would be to (a) recognize the *possibility* of major changes in the electric industry and (b) take cautious action now that would limit its cost in the event of unexpected developments.

[23] 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. While recognizing the effects on individual stakeholders, regulators have the duty to focus on the collective or public interest.

[24] Stakeholders often petition state regulators to redress what they consider unfair or excessive obstacles to their agenda. Their advocacy might involve subsidies or other forms of financial incentives, or the lifting of certain restrictions. In their duty to promote the public interest, regulators should distinguish between what we call here "artificial obstacles" and "natural obstacles." Examples of a *natural obstacle* are a customer's rational response to risk and customer uncertainty over the future price of utility electricity. An *artificial obstacle* could originate from regulatory rules that unduly discourage utilities from accommodating DG, from entry barriers to DG providers, or from improper price signals to consumers that make DG less economically attractive. As a policy matter, regulators should try to mitigate artificial obstacles, which by definition stem from market imperfections or flawed regulatory practices and policies, as long as the benefits exceed the costs of mitigation.

4. The financial effect on electric utilities, conceivably a possible "death spiral" outcome; and

5. An alignment of ratemaking and other regulatory practices affecting DG with the public interest.

Overall, the status quo in terms of utility functions and behavior, and regulatory practices is under scrutiny. As an example, some stakeholders have criticized current ratemaking for (1) not allowing utilities sufficient revenues to cover the cost of serving DG customers (via grid services) and (2) deficiently compensating DG customers for the value they offer the grid. These are two issues that many state regulators will face soon if they have not already. As discussed later, a smart grid can help support socially desirable DG. First, it can improve the ability of a utility to integrate DG into its distribution grid. Second, the smart grid can more accurately measure the benefits of DG to the distribution grid, and vice versa.

Another issue is whether utilities should take on a broader and proactive role in bolstering DG development. They could, for example, invest in DG systems and rate-base them to help offset the revenue losses from full-requirements customers converting to DG customers. Perhaps more important, utilities can redesign their distribution systems and operate them differently to accommodate third-party DG generation.[25]

II. The Smart Grid and DG

A. The utility distribution network

The focus of this paper is on utility distribution systems accommodating third-party DG operators. Key questions are: What is a distribution system? How does its planning and operations have to change, if at all, to accommodate DG? How do new technologies like the smart grid improve the effectiveness of the distribution system in creating value for both DG and full requirements customers?

A network is a collection of compatible products/services that share a common technical platform. The network operator (e.g., utility or third party) is a matchmaker who connects producers and consumers. An electric distribution system is an example of a network. It consists of three major components: (1) *Distribution substations* that have transformers to step voltage down to the primary distribution level (typically in the 4 to 35 kV range); they also have circuit breakers and monitoring equipment; (2) *distribution transformers* typically mounted on a pole or located underground near the customer; they step voltage down to the secondary distribution level for safe use by most retail customers; and (3) *primary distribution lines or*

[25] *See*, for example, Electric Power Research Institute 2014; and Rocky Mountain Institute 2013.

feeders that leave a distribution substation; these lines carry three-phase AC voltage; the network operator separates the individual phases to feed different neighborhoods.[26]

As a greater number of entities (DG producers and consumers) use the utility distribution system, the more it becomes a network. An essential feature of networks is the complementary linkage between the various nodes and links.[27] Networks consist of links that connect nodes (e.g., points of electricity production connected to the distribution system).[28] Classical networks have nodes, for example, that represent physical locations and links to physical connections between the nodes. Inherent in the structure of a network are many components that provide a typical service.[29]

Engineers define networks where services AB and BA are distinct as "two-way" networks.[30] They include railroads, roads, many telecommunications systems, and more recently electric distribution systems.[31] Network in this context refers to an open, multi-directional electric distribution system that accommodates connected customers and distributed energy resources. Such a network enables interaction between market participants and increases the value they receive from the network.[32] The distribution system is a radial network where only one path exists between two nodes (i.e., no loop flow exists).

Power distribution networks are occasionally congested and users exhibit non-cooperative behavior.[33] The operator's role is to coordinate activities on the distribution network so as to maximize the grid's value to all parties collectively. For many networks,

[26] *See*, for example, Massachusetts Institute of Technology 2011.

[27] A service delivered over a network requires the use of two or more network components. That is, network components are complementary to each other.

[28] As defined by one expert, "A 'node' is a more general mathematical term applied to the intersection of connecting paths in any type of network." (Stoft 2002, 390)

[29] The distribution network consists of *links* (lines), *flows* over time and space (electricity) and *nodes* (substations, generators or points of receipt or delivery of electricity).

[30] When power flows in the opposite direction, voltage management and thermal rating problems can arise.

[31] As discussed below, the smart grid uses two-way flows of electricity and information to create an automated and advanced distribution network. Data is essential for successful connections and distinguishes platforms from other physical structures.

[32] The distribution network, as some analysts would describe it, should be an enabling platform for a dynamic energy network that is flexible and responsive to the needs of all users, including DG customers. It represents the foundation for new products and services that users might require and for which they are willing to pay.

[33] Analysts refer to the congestion on a network as a negative externality. Given an aging distribution network along with rapidly growing DG, congestion and outages become more than a remote possibility.

however, new participants may actually benefit existing ones, known as a positive externality or network effect.[34] Additional DG customers, for example, can enhance the value of the network by diversifying the fuel and generation-technology mix, avoiding energy losses from power transmitted from centralized plants over long distances, and deferring utility distribution, transmission, and generation upgrades. On the downside, the network effect can spread the damage of problems (e.g., severe congestion) on one part of the grid to all customers.[35]

One challenge facing utility operators is to integrate rising levels of DG into their system.[36] They need to calculate the cost effects of DG on a distribution network;[37] they also need to comprehend the potential benefits of DG from active utility management of distribution networks. Some observers contend that distribution-system operators have little incentive, or are even averse, toward facilitating the integration of DG facilities through active network management practices. Sticking with passive network management, however, could lead to unnecessary network costs and less-than optimal network value for users.[38] As one study noted:

> The increase in distributed generation and electric vehicle charging will change the operational characteristics of distribution systems, requiring additional investment, more active management, and increasingly heavy data gathering and complex pricing, all at a time when some consumers are leaving the grid. There may be a time when storage and distributed generation will be cheap enough for homes to leave the distribution grid entirely. The end game will probably be a conversion of distribution services from energy supply to infrastructure, load balancing, and backup services, and for distribution services to be priced accordingly. In many cases, it may make sense for distribution systems to be built, managed, and paid for as infrastructure rather than energy.[39]

The California Public Utilities Commission has articulated the need for an integrated grid:

---

[34] With a network effect, the value of a product or service depends on the number of users. Good examples of a network effect are telephones, fax machines and the Internet where the value of service for individual users depends on the number of other users on the network.

[35] For example, since network effects arise from interconnections, blackouts from a supplier failing to meet its customers' demand can affect the whole grid. This is why economists consider reliability a public good.

[36] 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* Electric Power Research Institute 2014, 30.

[37] From the utility's perspective, DG poses risks and costs because of uncertain production levels, times of production and locations of production.

[38] *See*, for example, Scheepers 2007.

[39] Shrimali 2014.

> California needs to consider a more advanced and highly integrated electric system than originally conceived in many smart grid plans. This integrated grid will evolve in complexity and scale over time as the richness of systems functionality will increase and the distributed reach will extend to millions of intelligent utility, customer and merchant devices.[40]

The policy question that California[41] and other states are grappling with is how to increase the number of network users, and do it so as to maximize the network's value to society. The dynamics of coordinating new market players, technologies and business models makes this a daunting challenge.[42]

B. Benefits from the smart grid

The smart grid[43] has the potential to benefit electricity customers by contributing toward cheaper, cleaner and higher-quality power.[44] An important factor is real-time information received and sent from and to various parts of the grid to improve operations efficiency.

In one of several ways, the smart grid can improve valuation calculations for two-way power flows and the integration of DG. They include:

1. Time-sensitive pricing of grid services provided to the DG customer;

2. Time-sensitive measurement of the utility's avoided costs from DG;

---

[40] California Public Utilities Commission 2014, 24.

[41] In California, new legislation requires all investor-owned utilities (IOUs) to submit a distribution resource plan by July 1, 2015. Among other things, the plans must identify optimal locations for distributed energy resources to meet system requirements. There are also mandates for the three largest IOUs to procure 1,325 MW of energy storage.

[42] The distribution network must keep the system in balance and confine voltage and frequency levels within a tolerable band. It must also respect contingency limits, meaning no violation of a line's physical limit if some other line or generator goes out of service unexpectedly. The network carries out these basic functions by purchasing "ancillary services." The operation of an interconnected electric network has to be monitored in real time to assure that: (a) production always matches consumption, and (b) power can flow across the network within established reliability and security constraints. The integration of DG makes these tasks more difficult.

[43] The smart grid represents the integration of software, hardware, data management and analytics.

[44] Potential benefits are contingent on different factors and conditions, including the degree of utility exploitation of the technology's potential benefits. One such benefit would come from customers shifting power consumption to lower-cost, off-peak periods. This has generally not happened as real-time pricing has met with strong opposition from some state utility regulators, consumer groups and even utilities. Less than 1 percent of residential customers in the U.S. presently are under real-time prices.

3. Two-way communications capability;

4. Facilitation of multidirectional and unpredictable power flows (e.g., load balancing);

5. Mitigation of voltage and frequency fluctuations (e.g., from rapid changes in supply and demand);[45]

6. Remote real-time monitoring of grid activities (e.g., loads, voltage);[46] and

7. Remote and automatic control of facilities on the central grid (e.g., automatic breakers and switches).

Overall, the smart grid can better accommodate DG by integrating it with the distribution network. Smart meters can enhance both passive and active network management strategies. For example, it allows the distribution-network operator to handle fluctuations in the energy supply of DG by making customers more sensitive to changes in energy prices.

III. Should Electric Utilities Adopt a New Business Model?

A. The functions of a business model

A business model focuses on the utility's products and services, their value relative to their cost, and how efficiently and effectively the utility creates, produces, delivers and supports those products and services in their franchised area. The utility business model should have three qualities. First, it should respond to new technological and market developments. For example, utilities as "platform"[47] operator should accommodate DG that technological changes have made economical to utility customers.

Second, a business model should support traditional regulatory objectives; they include cost-based rates, fairness across different customer groups, highly reliable service, and, more

[45] This outcome reduces the probability of power quality lapses. It does this by eliminating any disruption in frequency or voltage. Power quality refers to the fitness of electrical power to appliances and other consumer devices (e.g., synchronization of voltage, frequency and phase).

[46] In other words, the smart grid can better monitor system operations and customer activities (e.g., electricity usage and savings).

[47] A "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) permitting the operator to offer unbundled distribution services, (c) increasing transparency, and (d) enabling integration benefits to grow with more diverse suppliers and new technologies (e.g., storage, plugged-in electric vehicles). Industry observers label this role of utilities as a "smart integrator", "facilitator" or "orchestra leader." *See*, for example, Rocky Mountain Institute 2013; New York State Department of Public Service, April 24, 2014; and Fox-Penner 2013.

broadly, "just and reasonable rates." Notwithstanding major changes that might take place in the electric utility sector, long-held regulatory goals still hold a high standing.

Third, the business model should satisfy predetermined broad social objectives (e.g., affordable electricity to low-income households, clean energy). For example, changed conditions might require a different business model in which utilities would have more opportunities to exploit the benefits for themselves and society from the improved economics of DG and other technologies that would otherwise threaten their long-term financial viability.

B. Rationales for a new business model

Firms may have various reasons to reorganize or create a new business model. They include: (1) Trying to find the greatest growth expectations for their investors; (2) strategic repositioning to become more competitive in a restructured industry; (3) "blowing the company to bits," meaning tearing apart elements of transactions (via unbundling), and then rebundling them into something that consumers find more valuable, ask for, and get; and (4) prospective investors looking for growth opportunities in the market. As one study noted, "New business models are likely to be required that better align the interests of customers, regulators, energy suppliers, and manufacturers of [DG] technology."[48]

The recent dialogue on the electric utility of the future has focused on whether the existing business model is sustainable, given the prospects for the rapid development of solar PV and other DG technologies.[49] A threat to utilities can start with sales losses to DG and, subsequently, inexorably struggling to recover their fixed costs from fewer customers. Price increases aggravate utilities' problem of yet more customers switching to DG.

Some analysts consider the *assumptions* underlying the current utility business model outdated:

1. One-way power flow;[50]

2. Limited communications between the utility and customers;

3. Natural monopoly services behind-the-meter;[51]

---

[48] IHS Energy 2014, ES-18.

[49] The author observes that some utilities would prefer, at least initially, to take a defensive stance by erecting barriers to DG development and advocating for ratemaking reforms that assure their financial viability. The latter action could include charging DG customers a special fee, implementing revenue decoupling, and shifting recovery of fixed costs to the customer or demand charge.

[50] Utilities usually design distribution systems assuming power flow in one direction. Two-way flows that would result from DG require changes in both design and operations. *See*, for example Electric Power Research Institute 2014.

4. Economical for utilities to both operate the grid and own the physical assets;

5. Passive utility customers with limited choices, rather than empowered customers;

6. At the minimum, modest growth in sales;[52]

7. Utility profitability from increasing the rate base and sales, rather than financial gains from selling integration services valued by DG customers; and

8. DG as a threat rather than a potential revenue source.

One kind of new business model recognizes the utility's distribution system as a network or platform rather than as simply part of a supply chain. In other words, the utility would view its business model as nonlinear in which it simply creates value upstream with its services consumed downstream.

C. Elements of a business model

According to Johnson et al. (2008), business models contain four broad elements:

1. A customer value proposition (i.e., how customers benefit from utility service or how the utility can create value for customers);

2. A profit formula (i.e., how the utility creates value for itself while delivering value to customers);

3. Key resources (e.g., staff, capital); and

4. Key processes (operational and managerial processes).

The last two describe how the utility will deliver value for customers and itself. The first element is most essential, as it requires the utility to sell products or services for which customers are willing to pay. The second element says that, as a for-profit entity, a utility must manage its costs and generate sufficient revenues to earn a return for its investors. A good business model links these elements in consistent and complementary ways. Anything that changes the value proposition, the profit formula and key resources and processes for a utility might warrant a new business model. The new model could better accommodate new

[51] The traditional structure of the electric industry presumes that the generation and delivery of electricity is a natural monopoly and, thus, best served by a regulated franchise.

[52] Since around 2010, residential usage per customer has declined, which can have implications for ratemaking and the funding of new utility investments.

technologies (e.g., smart grid, storage[53]), expand utility services and justify a redesign of the utility's distribution network.

An appropriate business model is important for the utility's financial stability and even survival. It could contribute toward a utility's revenue growth or prevention of revenue erosion. The business model could also affect the utility's ability to achieve social objectives, which have increasingly become an integral part of utilities' responsibility. Most important, it could grow the value of utility services to customers (both full requirements and DG). For example, a responsive utility to changing conditions might require it to take on a different role, such as a "platform" operator for serving customers who produce their own electricity. Industry analysts sometimes refer to these customers as "prosumers."

A utility business model encompasses several facets of a utility's strategy and operations, including:

1. Utility objectives and goals (e.g., financial, policy-determined, fairness, economic efficiency);

2. Utility logic to achieve objectives and goals (e.g., weighing different objectives, time sequence);

3. Utility role (e.g., platform operator, provider of new services);

4. Assumptions about market conditions (e.g., competitors' tactics, willingness of customers to pay for offered products and services); and

5. Pricing practices (e.g., discount rates for certain services, rate design).

D. Factors affecting the business model

In achieving predetermined objectives, utilities must consider different factors. The first is technology. If technology changes, for example, in favor of small generating facilities, the utility should expect its monopoly position to erode and competitive forces to grow.

Market conditions are a second factor. If the utility's core product becomes less in demand, for example, it must expand its product line to prevent material losses in revenues.

[53] Electricity storage is drawing increased attention as costs have decreased, utilities have begun to conduct pilots and state regulators have initiated discussion on policy matters. Storage has great potential for mitigating power outages, reducing delivery costs, shifting consumption away from expensive peak periods, and providing ancillary services. Storage would seem to have greater value in conjunction with wind energy than with solar. Wind energy production frequently occurs at times least valuable for the utility grid, sometimes with a zero or even a negative value. Electricity storage is presently not competitive with other technologies and resources that can provide similar services. *See*, for example, Chang et al. 2014.

Public utility regulation is also a consideration in what business model to adopt. Regulatory support for, or opposition to, certain new technologies could affect a utility's business strategy. Energy and environmental policies, at both the federal and state level, may mandate certain utility actions and restrict others.

Under the structure-conduct-performance (SCP) paradigm often used by economists, the business model forms the core of how a utility's internal structure and conduct affect its performance.[54] Structure includes vertical integration, technology, product substitution and differentiation, geographic scope of the market, market and buyer concentrations and entry barriers. Conduct refers to pricing behavior and responses to increased competitive conditions. Performance covers price, service quality, technical progress, profits and economic efficiency. A new business model may entail a change in a utility's internal organizational structure and conduct to sustain financial viability and achieve other objectives in the long term. A utility sticking with the current business model could jeopardize its performance by (1) losing the competitive struggle with, or failing to accommodate, DG, (2) unfairly burdening full-requirements customers, (3) encountering serious financial problems.

A feedback loop exists in which the business model affects some of the factors in turn. Regulation, for example, responds to the market environment, policy objectives and the business model adopted by a utility.[55] In turn, regulatory practices affect market outcomes. This dynamic process makes it difficult to predict the condition under which the business model and its factors together settle to a final state (i.e., achieve equilibrium).[56]

The changes in the utility business model being most discussed today originate from recent developments in the electric industry. They include: (1) the utility as "platform" operator (traffic cop), (2) broadened utility objectives, (3) new pricing practices, (4) new value-added services,[57] (5) a modified utility role, and (6) utility strategies to achieve objectives.

E. Questions for regulators

Within the confines of a utility business model, regulators should, first, ask what value utilities could create for their customers. How, for example, can utilities provide the services

---

[54] For a discussion of SCP, s*ee* Cabral 2000, 156-59.

[55] Actual market activities also affect regulation. If, for example, the penetration of DG rises unexpectedly, it may become imperative for regulators to modify their policies to accommodate it. One reason is that the consequences of inertia or an inadequate response may carry a higher social cost that regulators would want to avoid.

[56] As one reviewer noted, there may be no final state and the role of regulators is then to ensure that the continual evolution is orderly.

[57] Some analysts believe that the business model should recognize the need for utilities to provide customized energy services in addition to electricity. These services, for example, can help customers to produce their own electricity.

needed by DG customers? With new technologies, regulators should expect utilities to offer more services. Second, regulators should ask how utilities will deliver added value to customers. For DG customers, utilities might have to create a "platform" that will allow those customers to purchase required distribution services. The last question is how utility shareholders can benefit. They benefit only when DG customers value utility services more than the costs for delivering those services. Unless regulators allow utilities to profit from additional services, they will be reluctant to provide them. How a utility prices those services for DG customers becomes crucial in determining its profits.

F. Utility role

Utilities can take on different functions in growing DG. They could provide services, for example, to both their full-requirements customers and DG customers. Regulators have discretion over what products and services utilities can sell. Their decision rests on what functions they want utilities to perform. Three alternatives are "platform" facilitator ("traffic cop"), service provider[58] and "wires" provider.

One middle-of-the-road option is for utilities to interact with DG customers as a partner with third parties. In this role, utilities primarily act as a facilitator of new technologies and service offerings by exploiting their engineering and other expertise. 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.

Utilities could invest in DG facilities and rate-base them to earn a profit.[59] Alternatively, utility shareholders could initially fund these investments and recover the costs from DG customers over time. Another option is for utilities to form an affiliate that provides DG services.

G. Avoiding the wrong business model

Pursuing a new business model that offers little benefits could be costly and futile. Adapting the current business model to new conditions might suffice for achieving the objectives set out by the utility, its regulator and other policymakers. As long as the utility could meet the

---

[58] Some utilities have already invested in solar PV to improve their earnings. Others are considering additional services to offer their DG customers.

[59] One rationale for utility investments in electric-vehicle recharging stations, for example, is market failure; that is, the private sector, for whatever reasons, would under-invest in recharging stations. In a more facilitative role, a utility could help stimulate electric vehicles by expediting permitting and installation, in addition to offering time-of-use rates for electric-vehicle charging. The market-failure argument would seem to hold less for the DG market, which has attracted a large number of vendors, installers and other market providers.

needs of its customers at a profit and with current resources and processes, it can avoid the high transition cost of developing and executing a new business model.

A misjudgment or error in selecting a business model is more likely with greater uncertainty of the future. The public policy discourse so far has focused more on not doing enough than on going too far in reshaping the utility business model. Utilities and their regulators should consider the risks associated with both over-reacting and under-reacting to the expected changes for the electric industry.[60]

H. Choices of business models

One factor in selecting a business model is the regulatory context. A regulatory regime that supports DG and a smart grid, for example, would affect a utility's structure and strategy. Two broad options include passive network management and active network management. The latter option involves the utility taking bold action to coordinate the different DG systems so as to maximize the value of integration. As noted in one study:

> The active network management philosophy is based on the concept of intelligent networks where technological innovations on power equipment and information and communication technology (ICT) are combined to allow for a more efficient use of distribution network capacity. In addition, it involves the active involvement of both consumers and distributed generators: load and generation characteristics are taken into account in network operations and planning.[61]

Business models need to have the flexibility to change in their early years. It is common for firms to experience initial failure and realize the need for corrected action; firms need to learn and adjust.

A final question relates to whether a utility is able to build on its existing business model rather than creating a new one. Because of its natural competence in producing and delivering electricity, a utility could adapt its existing model to accommodate "prosumers", maintain financial solvency, and protect full-requirements customers from cost-shifting. The utility's new business as a "platform" operator has the potential to complement and reinforce its core business. The ultimate question is: *Can a business model integrate all the essential elements to achieve the predetermined objectives most efficiently?* Actions should involve more than simply

[60] One suggestion for regulators and utilities is to evaluate their existing policies and practices (e.g., ratemaking, the scope of utility functions) in a new market environment. Decision making under uncertainty can easily lead to regrettable outcomes. They originate from policies that assume a different state of affairs than what actually transpired. In other words, a mismatch exists between policies and actual conditions for which utility customers might bear the brunt. These policies relate to the utility business model, ratemaking, rules for fair competition and financial incentives for DG technologies.

[61] Scheepers et al. 2007, 20.

achieving objectives: The utility should do so at the lowest possible cost. Otherwise, the utility fails to manage its resources more efficiently in reaching those objectives.[62]

IV. Ratemaking Concerns

A. Criticisms of current ratemaking practices

The regulator's task of approving rates and rate designs is essential in engendering an efficient and socially desirable DG market. Ratemaking affects the utility's incentive to accommodate or promote DG, the economics of third-party DG investments, and the well-being of full-requirements customers.[63] Analysts and others have raised concerns about current ratemaking practices.[64] Some of them are driven by self-interest while others have more legitimacy from a public-interest perspective. Even in those jurisdictions not anticipating radical industry reform, utilities along with their regulators are contemplating changes in ratemaking.

1. Examples of concerns

Specific concerns with retail utility ratemaking are as follows:

1. **Harm to utilities from lower sales given the current rate design of recovering most fixed costs through volumetric charges:** Prior to the introduction of smart meters, the inclusion of demand charges in the bills of residential and small business customers was not feasible.[65] That barrier no longer exists. As some analysts have proposed, the ideal retail tariff would include a demand charge that accounts for customers' contribution to the peak demands in both the wholesale and distribution markets.[66]

2. **Inappropriate rates and rate design for DG and full-requirements customers:** For example, the utility might under-recover its costs from DG customers and over-recover them from full requirements customers.[67] As DG grows, it becomes

[62] In other words, the utility is wasting resources whose value is higher in an alternative use.

[63] Rates affect both the cost and benefit side of emerging technologies such as DG.

[64] Ratemaking generally has implications for the ability of utilities to recover their costs, allocate costs between customer groups and achieve predetermined regulatory/social objectives. These objectives include the financial viability of utilities, the efficient use of electricity and the accelerated penetration of socially desirable new and emerging technologies.

[65] The utility would set the demand charge on the basis of a customer's maximum demand over some specified time period, for example over a 15-minute period. Under most current rate structures, customers with relatively low demand are subsidizing other customers. *See*, for example, Hledik 2014.

[66] *See*, for example, Blank and Gegax 2014.

[67] An acute example is in California where the high-tail inverted block rates increasingly became less sustainable as solar got cheaper. The current rate structure results in residential solar customers

increasingly urgent for regulators to consider separating energy costs and capacity and related grid-services costs for ratemaking.[68] DG customers should pay their fair share of the cost of the grid because pushing any of this cost onto non-DG customers raises serious economic efficiency and fairness questions.[69] Indeed this is one of the key issues in the current debate over net metering.

3. **Pricing of surplus power (i.e., the net metering rate[70]) is not cost-based like with CHP:[71]** 43 states and the District of Columbia, and hundreds of utilities use a net

---

receiving a subsidy funded by all other non-solar customers in higher tiers (via net metering); this outcome is a good example of a "death spiral" cycle in which over time as higher tiered customers absorb higher rates, they would more likely invest in solar PV facilities. Although it has become economical for some customers to invest in solar systems, those decisions may be inefficient because of a rate structure that exhibits large intra-class subsidies. Consequently, in California it is hard to say with any certainty whether the increased penetration of solar reflects efficient entry into the retail electricity market.

As one study noted, although regulators have been willing to accept a relatively limited amount of cost shifting to promote utility investments in energy efficiency (about 2-3 percent of rates, on average), they are unlikely to accept the magnitude of cost shifting associated with the high growth of net-metered DG (Brown and Lund 2013).

[68] One state utility regulator, the Arizona Corporation Commission, voted in December 2013 to allow Arizona Public Service Company to impose a $0.70 per kilowatt (kW) per month adjustment for all residential DG installations beginning December 31, 2013. Dissenters of the decision argued that the $0.70 does little to address the problem of cost-shifting.

[69] Because solar generation is both time- and weather related, for example, the utility needs to provide backup generation (e.g., operating reserves) or demand resources to meet grid-reliability standards.

[70] The 2005 Energy Policy Act required state regulators to consider net metering. Most state regulators adopted net metering partially because of its intuitive appeal and simplicity. Crediting customers at the full retail rate is a strong financial incentive for investing in DG.

Under most net-metering programs, the utility's full retail rate applies to both the DG customer's generation and consumption. The meter simply records how much energy the DG customer consumed on-site and then how much it produced, with the difference in kilowatt-hours either charged or credited to the customer. Since net metering rarely accounts for time of usage, it wrongly compensates the DG customer, both on the upside and downside, during various hours, based on the avoided-cost criterion.

[71] The Public Utility Regulatory Policies Act (PURPA) required utilities to provide QFs with reasonable standby and back-up charges, and to purchase excess electricity from these facilities at the utilities' avoided costs. It also contains a simultaneous purchase-sale provision that allows the CHP operator to purchase all of its electricity demand at the applicable utility retail rate, while selling all of its electricity output to the utility at avoided cost. (Costello 2014, 10).

metering policy to credit DG facilities for their power. Many analysts consider net metering as an unfair cross-subsidy. [72]

4. **Cost-shifting to full-requirements customers:** One prime example are California full-requirements customers subsidizing PV solar customers at the tune of the difference between the high-tier retail rates (> 30 cents per kWh) and the avoided generation cost. [73]

5. **Deficient utility compensation to DG customers for the value they contribute to the utility grid:** The potential benefits include avoided generation energy, capacity and ancillary costs, frequency support, loss reduction, transmission/distribution avoided capacity, and voltage support.

6. **Deficient DG customer compensation to the utility for standby and other grid services:** Reasonable standby rates would compensate the utility for: (a) the costs associated with preparing for contingencies (e.g., forced outage) in which the DG facility is unable to generate at a normal or expected level; and (b) the costs of providing any supplemental power that the customer requires beyond the capacity of his DG facility. [74]

7. **Uniform prices across all time periods:** When a solar facility is available during peak periods, the avoided cost to the utility would be higher than if it only operates

[72] Specifically, analysts, consumer groups and utilities have criticized net metering for: (a) disconnecting retail rates from utility avoided costs and other benefits to the utility grid, (b) being contrary to PURPA principles, (c) paying the DG customer a retail price for essentially wholesale energy, (d) not accounting for the time-dependent value of DG energy, and (e) overall, being an unfair and regressive cross-subsidy. It is regressive because customers who install solar PV systems, on average, have higher incomes than full-requirements customers who fund the subsidy. Net metering seems to have been implemented for convenience if for no other reason: The retail price is accurately measured with little contention, and the DG needs only a single meter. Net metering undoubtedly promotes DG but the question is whether it does so in an efficient and socially desirable manner.

[73] The ironic development in California is that one objective of the steep tiered rates was to protect low-usage, and presumably low-income, residential customers. What has happened, instead, is that the above-cost, higher-tiered rates have induced customers to install solar PV systems in large numbers. This outcome has become a “double whammy” for low-usage customers: The utility loses revenues from solar PV customers who were subsidizing other customers, and the utility has a net-metering rate that exceeds its avoided costs. In effect, the high-usage customers who previously subsidized lower usage, and, on average, lower income customers, are now being subsidized by other customers, including low-income households. The result is gross economic inefficiency and a redistribution of wealth that favors higher income customers.

[74] For a review of issues surrounding standby rates, *see* Selecky et al. 2014 and Costello 2014.

during off-peak periods. Therefore, because solar has its highest (lowest) value during the peak (off-peak) periods, the DG customer should be compensated accordingly.[75]

8. **Impeding progress toward meeting traditional and new regulatory objectives:** Examples include unfairness to full requirements customers from net metering rates, weak incentives for utility innovation,[76] excessive risk allocation to customers (e.g., from surcharges and trackers), revenue instability (e.g., from inverted rates), utility disincentive for energy efficiency and DG (e.g., from standard two-part tariffs), and profit instability (e.g., from inverted rates and standard two-part tariffs)

B. The lessons of infant-industry subsidies for net metering

Net metering rates and other subsidies have parallels to the idea of infant-industry favors.[77] Partiality toward new entrants or new technologies, such as rooftop solar PV, is analogous to the infant-industry argument in international trade.[78] According to this argument, during its infancy a domestic industry may require protection against foreign competition. The underlying premise is that new domestic entrants in a developing country would face high costs during the initial period, but they could compete in the long run. Without immediate protection, new entrants would presumably find it extremely difficult to compete and might even decide to exit the market. Consequently, in the absence of the protection, the long-run benefits that the country would otherwise realize from more competition would be foregone.

Critics of the infant-industry argument offer cogent counterpoints that are applicable to net metering and other subsidies for DG. First, once protection occurs it is difficult to terminate. Those who benefit would strongly oppose any change in policy; they would expend substantial resources, in what economists call rent-maintenance costs, to argue that protection should continue because the industry has not “grown up.”

---

[75] Nonuniform pricing (e.g., real-time pricing) can also bolster the development of energy storage, which has the potential to contribute to the growth of intermittent DG in the long run. For example, storage could greatly increase the value of solar PV from a reliability perspective. As of today, only a tiny percentage of residential customers with smart meters are subject to real-time pricing.

[76] Traditional ratemaking has focused on preventing utilities from using market power to charge unreasonable or discriminatory prices or provide inadequate service. While minimizing the exercise of market power is a core regulatory function, encouraging utilities to innovate and discover more efficient ways to deliver value to their customers can produce large economic benefits. The problem with traditional ratemaking is that it socializes both the benefits and costs of innovation, which translates into weak incentives for utilities.

[77] Even if one argues that net metering is not a subsidy, it is hard to deny that it is an arbitrary approach for calculating the compensation that a DG customer should receive on grounds of both fairness and economic efficiency.

[78] *See*, for example, Baldwin 1969 and Krueger 1997.

Second, policymakers would find it difficult to know the appropriate time to end the protection. Opponents of termination would invariably argue that since they are still infant, even after several years, assistance is necessary for them to stay in business.

Third, policymakers lack the necessary information to quantify or estimate the size of the potential benefits from protection. In the context of retail electricity markets, how much more competitive would retail markets be with short-run protection to new entrants? What would be the benefits to retail customers in the long run?

Fourth, protection of new entrants represents an inferior way to address the problem of incumbents holding a market advantage if indeed they do. If artificial barriers to entry actually exist, policymakers should identify them and then find an appropriate remedy. (Artificial barriers to entry by definition mean that their elimination would improve consumer welfare in the long run.) As a policy, protection for new entrants is as likely to inflict losses on society as it is to benefit society. Extended protection may keep inefficient firms in the market, for example, at the expense of a more efficient incumbent.

Finally, the presumption is that new entrants cannot compete with an incumbent. In the context of this paper, this translates into new entrants (i.e., third parties) being unable to compete with a utility or its affiliate. If policymakers eliminate or mitigate artificial barriers to entry, no reason exists for concern by policymakers. The dynamics of well-functioning markets allow new entrants to compete successfully when they are more efficient, innovative, and customer responsive than incumbents. We observe this phenomenon across a broad range of industries — computer, telecommunications and financial services are conspicuous examples. We expect this to also hold for retail electricity markets so long as regulators eliminate artificial barriers; for example, distorted prices, onerous entry costs, utility favoritism toward its affiliate.

C. Alternatives to net metering

Three alternative approaches to net metering are under review across the country, each of which seeks to ensure that DG customers using grid services pay their fair share of the costs of those services while still receiving fair compensation from the utility for the energy produced. [79] The first approach is to redesign retail tariffs so that they are more cost-based; for example, by the inclusion of one or more demand charges in rates to reflect system-wide capacity costs.[80] With smart meters, utilities can calculate demand charges based on the maximum amount of electricity consumed over a short time period (e.g., 15-minutes). Some analysts view such charges fairer than imputing the same fixed charge for all customers within a particular class.[81]

[79] Other possible approaches are feed-in tariffs and auctions to determine the market-driven price for solar PV energy.

[80] *See*, for example, Blank and Gegax 2014.

[81] The reason is the apparent correlation between energy usage and demand. It would then seem unfair to recover the same fixed costs from both low-usage and high-usage customers. Part of a utility's

The second approach is to charge DG customers for their gross consumption under the utility's retail tariff and separately compensate them for their on-site generation. A prime example is value of solar tariffs (VOST). Under VOST, the utility bills customers separately for all electricity usage under the applicable tariff and then credits them for all solar energy production under the approved VOST.[82] The intent of VOST is to provide fair compensation to solar customers that avoids overpayment by non-solar customers, while also rewarding solar generation for its economic and other designated benefits.

VOST, in theory, would end the subsidy and related cost shifting under net metering.[83] This assumes that the price paid for solar energy truly reflects the utility's avoided cost. For example, the DG customer buys all of the energy consumed on-site through the retail tariff and sells all of the energy produced on-site at prices that reflect the utility's avoided cost.[84]

As an illustration, assume that the DG customer's monthly consumption of electricity is 1,000 kWhs and that he produces 600 kWhs. Assume also that the retail price of electricity is 10 cents per kWh and that the utility's avoided cost is 7 cents per kWh. The utility' fixed cost is then 3 cents per kWh. Under net metering, the customer's net bill would be $40 [(1,000 kWhs – 600 kWhs)·10 cents]. Under VOST based on the utility's avoided cost, the customer pays $100 for the electricity consumed[85] but receives a credit of $42 for the electricity he produces.[86] His net bill is then $58. The problem, as utilities view it, is that prior to installing the PV solar system, the customer contributed $30 [(10 cents – 7 cents)·1,000kWhs] toward the utility's fixed costs. VOST allows the utility to recover the same amount of fixed costs from the DG customer as before, because the lost revenues to the utility equal its avoided cost; that is, the utility loses $42 of revenue but its cost also declines by $42 (600 kWhs·7 cents). Under net-metering pricing the utility recovers $18 less from the customer for recovery of fixed costs. The explanation is that the utility's revenues decrease by $60, which is $18 more than its avoided cost of $42. Consequently, the revenue loss allows the utility to recover only $12 of its fixed costs from the customer, or a reduction of 60 percent.

---

fixed costs is customer-specific, like metering and billing. But another part represents system-wide distribution costs, such as maintenance costs for main distribution lines, which depend on total usage. A demand charge would better reflect cost causation as a primary principle of pricing.

[82] In other words, unlike net metering VOST treats generation and consumption as two independent functions. *See*, for example, Blackburn et al. 2014.

[83] VOST also has the advantage of being more transparent than net metering rates, because of the breakdown of its components.

[84] Studies have shown that the largest avoided-cost component relates to generation (e.g., fuel and capacity costs) rather than distribution and transmission. (*See*, for example, Satchwell et al. 2014.) The current debate in some states about the "value of solar" centers on the inclusion of adders in the utility's avoided cost to account for environmental and other external effects (e.g., job creation).

[85] 1,000 kWhs·10 cents.

[86] 600 kWhs·7 cents.

The third approach is to set (1) standby rates for DG customers who purchase electricity from the utility and (2) PURPA-type (avoided cost) rates for electricity sold to the utility.[87] The avoided-cost criterion under PURPA attempts to strike a balance between encouraging CHP electricity production and imposing no burden on the utility and its other customers.[88] Setting a purchased price at avoided cost[89] would tend to have a neutral economic effect on the utility and its customers (i.e., avoid any cross-subsidization); and benefit the DG operator when it could produce electricity below the avoided cost.[90] Avoided cost corresponds closely to the utility's marginal cost. One outcome of just-and-reasonable standby rates is that they do not discourage economical DG while avoiding a subsidy funded by non-DG customers: Less-than-full cost recovery by the utility requires funding by non-DG 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 customers operators and non-DG utility customers, and not discourage good DG projects or encourage bad DG projects. One reasonable approach is for utilities to set standby rates with the same pricing principles that they apply to full-requirements service. Although this does not infer that the rate levels are the same, it supports allocating common and capital costs to non-DG and DG customers based on the same criteria.[91]

D. Valuing benefits to the utility grid from DG

DG can provide benefits external to the customer who directly benefits from lower electricity bills. The utility can increase these benefits by sound integration planning and

[87] This approach requires a separate meter for on-site generation.

[88] One avoided-cost proposal for utilities operating in organized markets is to compensate DG customers for their surplus energy at the wholesale price during different periods of delivery (e.g., the real-time energy price), plus any transmission or distribution avoided costs. (*See* Brown and Lund 2013) This approach reflects more accurately the economic value of the offered energy compared to the uniform retail price under net energy metering. This proposal also avoids some of the other problems with net metering, such as regressive cross-subsidization and disincentives for efficient technologies.

[89] One interpretation of the avoided cost to the utility is that it represents the economic value of the electricity produced from a DG facility; that is, it measures the long-run cost of the electricity that the utility need not produce, measured in terms of the economic opportunity cost of the resources saved.

[90] This condition would tend to align the DG customer's economic interest with an improvement in economic efficiency. The reason is that if the cost of producing solar electricity is less than the avoided cost of utility electricity, a customer would have an incentive to invest in lower-cost solar. Both the customer would benefit and economic efficiency would increase. Instead, when the solar customer's benefits relate to the retail price of electricity, the customer could have an incentive to self-generate even when solar has a higher cost than what the utility avoids. Consequently, economic efficiency diminishes or uneconomic bypass occurs. This problem stems from the retail price of electricity set above the utility's marginal cost.

[91] In other words, the utility charging different rates for standby and full-requirements service would not be discriminatory.

strategic operation. Potential benefits include diversity of the fuel and generation-technology mix, reduction of the carbon-emissions intensity of the local grid, avoidance of energy losses from the long-distance delivery of power from centralized generating plants, and deferral of utility distribution, transmission, and generation upgrades.[92] Smart inverters on solar systems, for example, can enhance grid stability by providing voltage and frequency control.[93]

It is also true that DG imposes costs on the utility grid. The grid may require some upgrades to handle the two-way flow of power on the local distribution circuit and the intermittency of generation. Depending on existing rate structures, net metering or other approaches may also allow DG customers to avoid paying for the utility's physical assets that they still rely on for reliability (or backup) purposes. This situation could result in general rate increases that shift some of the utility's fixed costs to full-requirements customers.

In applying VOST, for example, questions remain over the benefits that DG can provide to the distribution grid and other customers. With smart meters and real-time pricing, utilities can more accurately compensate DG customers for the value they provide to the utility system during different periods.[94]

VOST raises several questions:

1. What are the real cost savings (e.g., energy and capacity cost savings)?[95] Savings in transmission costs are utility-specific, for example, dependent on DG operation during utility system peaks. To the extent the VOST equates with the utility's avoided cost, no cost-shifting would occur.
2. What benefits are pecuniary in that they represent a reallocation of benefits rather than a net benefit? One example is lower wholesale power prices that could result from DG.[96]
3. What benefits are speculative versus definitive in nature? Accurate valuation of these benefits in dollars requires the combination of sound analytics and empirical

---

[92] Although solar can reduce carbon dioxide emissions, cheaper alternatives to DG may exist.

[93] It is another matter, though, trying to quantify this value in monetary terms within a tolerable degree of error.

[94] There is the fundamental question of why utilities and their core customers should compensate DG customers at all on the basis of the value of DG to the utility grid, other than for the utility's avoided energy and capital costs. It seems then that VOST bestows special treatment upon solar PV when utility compensation goes beyond avoided costs.

[95] The timing of solar availability on an electric grid affects its value. For example, when solar is available during peak periods, the avoided cost to the utility would be higher than if a solar system only operates during off-peak periods. In other words, solar would have its highest value during the peak periods.

[96] Although lower power prices benefit electricity consumers, they represent an economic loss to generators that analysts must account for in calculating net benefits. In other words, pecuniary benefits tend to produce a zero-sum outcome, rather than a net benefit for society.

evidence. For some benefits, monetization becomes infeasible or is simply not appropriate (e.g., physical hedging,[97] fuel diversity).[98] As one study noted:

> While some consensus exists on the estimation of energy value and capacity value of distributed solar, there is significantly less agreement on the valuation of distributed solar as it relates to the distribution system, grid services, and environmental externalities. Even a calculation for avoided fuel cost can vary significantly among. In general, variations in benefit-cost calculations for solar DG may be attributed to location; the means of market price determination; whether pricing is estimated according to a short-term or long-term basis; sensitivity to solar penetration levels; or the ability of a given feeder to accommodate intermittency.[99]

4. Does net metering or VOST reflect undue favoritism toward DG relative to other generation sources (including other clean energy sources) and energy efficiency?[100]

5. Are the external benefits of DG to full-requirements customers commensurate with the increased electricity prices that result from compensating DG customers? The issue here is one of "fairness" in which utility customers are paying more than their share of DG costs relative to the benefits they receive.

---

[97] The major beneficiary of hedging is the DG customer himself, rather than all the customers on the utility system. One presumed reason why households and businesses invest in solar is to stabilize, and make more predictable, their electricity costs over time.

[98] Solar has inherent environmental benefits when compared with fossil fuels. PV arrays avoid negative externalities like fuel wastes, air pollution, or greenhouse gasses. Some studies have shown that quantifying the environmental benefits (in dollars) of solar would elevate its standing (e.g., make solar achieve parity) relative to fossil-fuel and other generation technologies (Sinha et al. 2013).

Other public benefits attributed to solar include job creation, national security and contributing to the country's overall growth. Some of these benefits are dubious in theory while others are difficult to quantify (Borenstein 2011). One justification for financial incentives to bolster solar technology is the premise of public benefits. These incentives include RPS solar set-asides, tax credits, net metering, rebates, sales tax exemptions, and property tax exemptions.

[99] Blackburn et al. 2014, 23.

[100] Compared with energy efficiency, CHP and other instances where a customer action creates benefits to the utility external to the customer, solar PV operators receive an added reward under net metering. In creating a properly functioning market for DG, the utility's retail price should correspond to marginal cost. When that condition holds, a "producer" of energy efficiency or a DG "prosumer", in his capacity as a consumer, receives benefits in the form of a cost savings equal to the value of the resources not used. The consumer, arguably, should realize no additional benefit, as that would over-incent him to curtail his electricity usage. The exception to this rule is when the "prosumer" has surplus electricity to sell back to the utility: He should at the minimum receive the utility's avoided cost and, in certain instances, other benefits deemed relevant and measurable.

6. How should regulators treat measurable benefits (in dollars) versus difficult-to-measure and non-measurable benefits in determining utility compensation to DG customers?[101]

7. How should regulators apportion the benefits from solar between the utility, full-requirements customers, and DG customers? VOST represents a buy-all, sell-all approach whereby solar customers pay the same amount to the utility for the electricity they consume. To the extent that VOST equates to the utility's avoided cost, full-requirement customers and the utility are held harmless. In other words, VOST passes a net-burden test. But if the principal reason for the installation of the solar system was to lower the customer's electricity bill, VOST does not accomplish that. In effect, the solar customer's sole economic gain comes from being a producer and selling power it produces back to the local utility.

A critical policy question relates to the distribution of benefits from DG, such as the utility's avoided costs, to the connected utility and its full-requirements customers. Assume that a DG operator has no surplus electricity to sell back to the utility. Assume also that DG production defers utility investments in generation, transmission and distribution. Should the operator receive some compensation from the local utility, for example, in the form of a subsidized standby rate or should the utility and its full-requirements customers retain all of the benefits? One argument for the latter scenario is that the DG operator already benefits from lower electricity cost, which is its main reason for investing in DG in the first place. The external benefits are incidental or simply fall out of the DG operations. The situation is similar to when a utility customer uses less electricity: She benefits from lowering her utility bill. Should she receive additional compensation from lowering the utility's cost? Other than possibly receiving a financial incentive *ex ante* from her utility to use less electricity because of alleged market barriers, the common practice is for the utility not to separately compensate her for actual electricity saved. Normally, the avoided costs transfer into lower future revenue requirements and general rates, other things held constant, benefitting other customers in the long term.

E. Valuing benefits of the utility grid to DG customers

The utility continues to incur costs in serving DG customers in various ways. These costs arise from the utility providing voltage and frequency stability, reverse power flow reactive power balance, increasing re-dispatch transmission constraints, protection, interconnection and ancillary services.

[101] As mentioned earlier, some of the benefits may be highly speculative. Because paying for these benefits ultimately comes from full-requirements customers, their rates increase. Some analysts have argued that reliability benefits largely accrue to the DG customers, rather than to the distribution system. (*See*, for example, Brown and Lund 2013) Although solar PV on-site produces zero pollutants, the net effect of solar may actually be to increase pollutants. The reason is that solar is intermittent and has a relatively low capacity factor that requires back-up capacity that emits it own pollutants.

The utility's fixed costs relevant to the provision of grid services relate to transmission, distribution, generation capacity, and the costs of ancillary and balancing services that the grid continuously provides to the DG customer. As one study noted:

> [T]he customer's consumption and generation are almost never equal; consequently, most of the time the customer is using the external power system to offset the difference between the customer's consumption of electric energy and its on-site production. In most cases the customer will be taking energy from the grid during many hours of the day…Clearly, even if the customer's total energy production over some time interval (*e.g.*, a monthly billing cycle) exactly equals its consumption over that same interval, that customer is still utilizing at least some, if not all, of the above grid services during that time interval.[102]

F. Additional required utility investments

Utilities will require additional capital expenditures to support two-way flows created by DG, energy storage and EVs. A Massachusetts Institute of Technology study (2011) on the future of the electric grid explains that low levels of DG penetration reduce load at the nearby substation, but high DG penetration could create excess load at the substation. The outcome is power flowing from the substation to the transmission grid, creating a reverse power flow that grids might find difficult to handle and causing high voltage swings and other stress on electric equipment. These potential strains on the distribution network will require utilities to make further capital investments in system upgrades, which might include distribution automation, system interoperability, data management and analytics, and cybersecurity to address new network dynamics. As noted in one article:

> The distributed generator's contribution to the cost of distribution facilities arguably might increase on a relative basis because investments must be made in the distribution system to accommodate two-way flows that include the output of distributed generation. In addition, the variability of solar energy (without adequate storage) may increase the utility's cost to supply balancing services because, as variable energy is added to the system, utilities must invest in or acquire a larger proportion of balancing resources relative to their total load.[103]

[102] Wood and Borlick 2013, 1-2.

[103] Raskin 2014, 278.

V. The Linkage between Utility Objectives, Business Strategies and Regulatory Practices

A. Coordinating regulatory policy with the utility business model

Regulators should try to coordinate their policies on what they intend utilities to achieve with the utility business model. That is, the utility business model and regulation should evolve together. A key factor is aligning regulation with predetermined social priorities.[104] Three general approaches are regulatory mandates,[105] oversight and incentives.[106]

One option is for regulation to align its policies with the selected business model. The regulator together with the utility and other stakeholders, for example, could agree on the preferred business model. The connection between policy objectives, utility strategies and regulatory practices should follow a logical sequence: Objectives lay the foundation for how a utility plans and operates, and the regulator provides incentives, imposes mandates and oversees utility activities. The ideal outcome is a regulatory solution that best promotes the public interest and achieves the predetermined objectives.[107]

When regulatory policies fail to align with the business model, the utility may deviate from its strategy to achieve the predetermined objectives. One example is a business model that accommodates DG but regulation gives no incentive other than to penalize a utility if it falls short of expected performance. A second example is an attempt to achieve fair competition for

[104] Some analysts have argued that policymakers require too much of electric utilities. They expect utilities to maintain financial viability, make electricity affordable to all customers, adopt, accommodate and even subsidize new technologies that compete with their core business, decarbonize their generation portfolio, promote less usage of their product (electricity), and increase consumer empowerment. Society requires few if any other private businesses to commit to such a wide social agenda.

[105] If regulators had good information about how utilities should perform, they could readily 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. These opportunities differ across utilities, depending on the inherent features of their production technology, exogenous input costs, and other factors that cause costs to vary by location because of their attributes. *See* Costello 2010.

[106] The regulator might want to establish, for example, special incentives that would elicit utility performance to achieve some target by a specified future date. The regulator should first decide the merits of the utility achieving the target from the perspective of consumers and the general public. An improvement in system reliability, for example, could produce smaller benefits to consumers than the additional costs they will have to pay.

[107] The term "the public interest" has different facets. A regulatory review of alternative rate mechanisms, for example, requires consideration of fairness, economic efficiency, utility financial condition, and other outcomes. A narrow definition of "the public interest," more in line with traditional regulation, is the long-term interests of utility customers.

DG in the absence of any code of conduct rules that would prohibit a utility from favoring affiliates over third-party DG providers.

A complexity arises from the regulatory goal of balancing different objectives, some of which are non-quantifiable or conflict with other objectives. The balancing act of regulation, with the goal of trading-off stakeholder interests or objectives, resists a "corner solution" where regulators ignore certain objectives at the expense of the general public.

B. Illustrations of linkages

Table 1 (p.33) identifies real-world policy objectives, utility strategies to achieve them, supporting regulatory practices, and indicators of their achievement. State utility regulators initiate some of these objectives while federal and state policymakers require others in line with broad social mandates. Indicators are evidence of whether a utility has satisfied policy objectives. They reflect a utility's performance, affected by both management decisions and external factors beyond its control. Performance is the "proof of the pudding," in determining how a utility's actions affect its customers and the public. Performance is multi-dimensional, embracing cost and dynamic efficiency, promotion of certain technologies, reliability and service quality, all of which affect consumer welfare and the public good. Regulators can take appropriate action when a utility achieves, falls short or exceeds expectations.[108]

One can view utility strategies as a roadmap for achieving the predetermined objectives. They represent one element of a utility business model that encompasses general utility actions. Strategies focus on how the utility can (1) serve customers by offering them value, (2) comply with policy mandates, and (3) make profits for its shareholders.

With regard to DG, Table 1(p.33) makes the following points:

1. "Just and reasonable" rates have expanded to include utility services provided to DG customers as well to the benefits that those customers offer the utility grid.[109]

2. In promoting renewable energy, and in particular DG, regulators could either mandate utilities to create the proper platform for integration or offer utilities an incentive (e.g., a pecuniary reward) for creating the platform. For example, utilities could

[108] The action may affect cost recovery by the utility, lead to a more detailed investigation of management decisions, such as a retrospective management audit, or induce the regulator to institute a mechanism that would motivate higher utility performance. For example, the regulator might reward the utility for above-average performance deemed to reflect exceptional management actions.

[109] New services to DG customers raise several questions: (a) who should provide the services, (b) how should they be priced (tariff, contract, market based), (c) how are they distinct from other utility services, (d) how should they be defined, and (e) should they be placed in a separate category?

receive incentives for transforming their management practices from passive to active in terms of integrating the various DG facilities into their distribution network.[110]

3. Regulators could consider utility incentives to DG customers for providing ancillary services to assist the utility distributor in enhancing operations, for example by providing voltage control, reactive power support, and frequency reserve.

4. Regulators should eliminate all artificial barriers to DG growth. Such barriers (a) produce uneconomic and socially-damaging outcomes and (b) their mitigation passes a cost-benefit test and, therefore, their amenability to policy intervention.[111] On the other hand, some barriers alleged by analysts and others may derive from natural market forces and would, most surely, fail a cost-benefit test to mitigate.

5. If regulators find grid modernization or the smart grid cost-beneficial,[112] they should consider pre-approving investments and reducing delays for cost recovery through a surcharge.[113]

6. In empowering customers, regulators should consider encouraging utilities to offer new services and invest in new technologies.[114] They should also ensure no utility discrimination against DG customers.

7. In promoting DG, regulators should consider allowing direct utility involvement with rules erected to prevent undue favoritism to the utility or its affiliate. Regulators should stress the importance of "fair competition" to achieve optimal outcomes that best serve the public interest.

---

[110] Another incentive would be to reward utilities for connecting more DG operators and reducing their connection cost.

[111] Economists label these barriers as "market/regulatory failures."

[112] Positive outcomes from grid modernization include: (a) lower outage costs, (b) higher operational efficiency, (c) protection against cyber and physical threats and (d) integration of DG into the central grid. *See*, for example, Massachusetts Department of Public Utilities 2014.

[113] Regulators might also require an *ex post* review that evaluates whether the utility was prudent in managing the grid-modernization project.

[114] In a transformed electric industry, customer empowerment requires utilities to offer value-added services, customers to make well-informed decisions about their use of utility facilities and resources, and new technologies to enable customers to minimize their associated transaction costs.

Table 1: Linkage between Policy Objectives, Utility Strategies and Utility Regulation

Policy Objective	Utility Strategy	Supporting Regulatory Practice	Indicator
Just and reasonable rates	Efficient operations Promotion of profitable sales Pursuit of financially profitable activities Minimal or no cross-subsidies, with the possible exception of assisting low-income households Fair utility pricing to competitors	Incentives for prudent activities Utility recovery of prudent costs Opportunity for utility financial viability Prohibition of undue price discrimination Consideration of special assistance to low-income households Cost-based ratemaking as the core method When justified, pricing linked to value of service	Prudent costs recovered in rates Financially healthy utility Affordable utility service "Fair" allocation of costs Compensatory pricing of utility services to DG customers Fair compensation of DG customers for their value to the utility grid
Clean energy	Generation diversity Commitment toward reducing CO_2 Accommodation of renewable energy Evaluation of different technologies on an equal basis	Integrated resource planning process Accounting for environmental effects of different generation technologies Mandatory utility "platform" that integrates DG and other resources Incentives for utility activities to reduce CO_2 and other pollutants	Phasing out of "dirty" technologies Increased market share of renewable energy Balanced mix of generation technologies
Cost-effective energy efficiency	Aggressive promotion of cost-effective energy efficiency Energy efficiency as core utility activity "Equal footing" of energy efficiency with supply-side resources	Profit neutrality or gains for utilities Cost-benefit test Monitoring of utility energy-efficiency activities for evaluating performance	Benefits of energy efficiency exceeding costs Absence of utility disincentive to promote cost-effective energy efficiency Utility committed to energy efficiency

Policy Objective	Utility Strategy	Supporting Regulatory Practice	Indicator
DG growth	Development of a ”platform” that integrates DG into the utility grid Proper ratemaking of grid services and DG services to the utility grid	Elimination of obstacles to socially desirable DG Mandatory DG-friendly utility “platform” Economically rational pricing of grid services and DG services benefitting the utility grid	No artificial barriers Utility accommodation reflected in interconnection requirements and cost, reasonable pricing of grid services and other actions
Grid moderni-zation	Investment plan and schedule for installation of the smart grid Customer education, marketing and outreach Monitoring of benefits	Review of utility proposals No second-guessing of investments Consideration of preapproval and surcharge for utility cost recovery *Ex post* review of actual benefits	Installation of smart grid when cost-beneficial Utility financial support Full exploitation of grid-modernization benefits over time
Grid resilience	Deployment of the latest information and communications technologies Plan for efficient and prompt service restoration Support for microgrids and DG	Mandatory utility plans on service restoration Encouragement of grid modernization, microgrids and DG Consideration of utility ownership/operation of microgrids and DG	Prompt utility response time Utility anticipatory actions Rare interrupted electric service Microgrid and DG development Grid modernization
Cyber and physical security	Utility-wide commitment Coordination and information sharing Grid physical security standards or benchmarks Surveillance and monitoring	Mandatory utility cyber security plan Rules for access to private information Mandatory standards for grid security Informed commission on security technologies and issues Annual utility reporting requirements	Coordinated effort between utilities and other entities Upfront commission support Utility training Protection of confidential information AMI deployment

Policy Objective	Utility Strategy	Supporting Regulatory Practice	Indicator
Grid reliability	Continuity of electric power under foreseeable circumstances Adequate operating reserves to handle short-term contingencies Adequate planning reserves for meeting annual peak demands Proper design and operation of the power system to withstand sudden, unexpected disturbances	Regulatory rules for reliability Monitoring of utility performance Disincentives for utilities to fall short of reliability standards Positive utility environment for attracting required capital	System security (in the traditional sense) Resource adequacy Reasonable outage costs to customers Minimal reliability problems from DG integration
Efficient markets	Proactive utility in adopting socially desirable innovations Management of inefficiencies Cost-based pricing No erection of artificial barriers to competitors	Incentives for utility innovations and short-term productive efficiency Cost-based pricing as the core method Prohibition of undue price discrimination	Economically rational pricing Operations and investment efficiencies Fair competition Socially desirable innovations
Customer empower-ment	Focus on delivering benefits to customers Commitment to customer education Exploration of new services to DG customers Commitment to serving DG customers on par with full-requirements customers	Mandate for utilities to invest in technologies benefitting DG customers Mandate for utilities to consider new services for DG customers Mandate for utilities to not discriminate against DG customers Opportunity for utilities to profit from new services offered to DG customers	Offering of new value added services Availability of real-time information Utility investments in enabled technologies Utility education initiatives

Policy Objective	Utility Strategy	Supporting Regulatory Practice	Indicator
Maximum long-term consumer welfare	Setting of economically rational rates Offering of new services Commitment to high service quality Investment in customer-enabled technologies Investments for assuring reliable, resilient and secured service	Regulatory mandates for investments with long-term benefits Regulatory incentives for long-term utility performance Exploration of emerging issues that affect utility customers	Setting of cost-based rates Offering of value-added services Reliable, resilient and secured service High service quality
Optimal integration of distributed resources	Role as system integrator and network operator Proactive utility-management posture Investment in grid modernization Communications standards and interconnection rules Integrated planning and operations	Regulatory mandate on the utility's responsibility to coordinate and integrate DG facilities on its distribution system Regulatory incentives for essential utility investments and other actions Affiliate rules for maintaining neutrality and fairness to all DG providers	Achievement of maximum value from the utility grid Availability of real-time information Utility integration activities Active utility monitoring of integration activities

VI. The "Death Spiral"[115]

Firms face serious challenges when they try to raise prices in the face of growing competition. A death spiral relates to an existential crisis whereby a firm has limited ability to raise its prices to sustain financial viability in response to adverse events (e.g., inexorable fall in demand for its product, new competitors). In a competitive environment, individual firms have no control over the price and will experience financial disaster if they tried to raise their price above the market price. In non-competitive situations, like the retail electric sector, firms can exercise some control over the price they receive, but even then they would encounter lower profits when they price their product or service too high.[116] These firms face a downward-sloping demand curve in which consumers will buy less at higher prices.

[115] This section draws heavily on an article co-written by the author, Costello and Hemphill 2014.

[116] The optimal output for these firms is where marginal revenue equals marginal cost.

A. The dynamics of a "death spiral"

The recent dialogue on the electric utility of the future has included the question of whether the existing utility business model is sustainable, given the rapid growth in the development of DG, especially solar PV. A threat to utilities could start with sales losses to DG and, subsequently, struggling to recover their fixed costs from increasingly fewer customers. Price increases aggravate utilities' problem of yet more customers switching to DG.[117]

The threat of a death spiral has shown up previously in times of dramatic changes in the electric industry. Starting in the late 1960s, emerging conditions posed serious challenges for electric utilities in maintaining their financial stability.[118] Later in the 1970s and 1980s, some observers believed that the expensive construction programs of electric utilities would inevitably lead to high rate increases repressing sales enough to place utilities in permanent financial distress. A few argued that new power plants are uneconomical and unaffordable to utility customers.[119] Consequently, they concluded that the "overbuilding" in the industry would inevitably lead to a "self-perpetuating" cycle of excess capacity and escalating rates.[120] The death spiral would be the outcome of the futile effort by a utility to avert financial disaster by increasing its rates. In other words, the death spiral reflects an unstable dynamic process with bankruptcy as the inevitable outcome.[121] In the 1990s, some observers predicted that industry restructuring and increased competition would doom electric utilities unless they could recover stranded costs or actively compete themselves or through an affiliate.[122]

---

[117] In other words, the dynamics is that continuously higher prices would motivate an increasing number of full-requirements customers to switch to DG with the subsequent effect of yet higher prices triggering more customers to migrate.

[118] Joskow 1974.

[119] Lovins (1985), for example, remarked that:

> The long-run own-price elasticity of demand for electricity is extremely large; so large that higher prices will probably reduce utility revenues. A utility which raises its rates will probably lose more on the number of kilowatt-hours it sells than it makes up by charging more than kilowatt-hour. If so, new construction will require more revenue but yield less -- recipe for bankruptcy. Long-run revenue can be increased only by lower price, not by higher price (at 21).

[120] Ford 1997.

[121] An unstable condition exists when the utility market fails to gravitate toward equilibrium where price equals average cost after an external shock.

[122] Graffy and Kihm 2014.

B. The likelihood of a "death spiral"

The current dialogue on the death spiral for the electric industry has shifted to how potentially disruptive technologies, such as solar PV, and other factors could affect electric utilities. A death-spiral cycle for the electric industry, at least on the surface, does not seem so remote given the confluence of several recent developments that tend to have a negative financial effect on utilities.[123] Other industries have encountered new technologies and negative market developments, with some firms adapting well and achieving success while others suffering permanent financial difficulties.[124] Since electric utilities are regulated, state utility regulators will have a say in what future path they pursue.

With hindsight, past death-spiral claims for the electric industry were exaggerated. Although utilities endured difficult financial times, both utilities and their regulators reacted by undertaking actions that prevented more serious problems. Today, the relevant questions are: Is the current concern over a death spiral also exaggerated? What conditions are necessary for a death spiral? How likely are they to occur?

History has shown that regulators would tend to support regulatory policies that avert a death-spiral outcome for utilities. After all, a financially struggling utility would find it difficult to fund new investments. Regulators will be as intent to avoid financial disaster for a utility as they have in the past: From experience, regulators seek to minimize extreme financial outcomes for utilities. Besides, they are subject to legal constraints imposed by legislatures and the courts. Most regulators view a financially distressed utility as inimical to the public good. Utilities will need large investments to upgrade their systems to accommodate DG, to install smart grid technologies and to meet the demands of their customers.[125]

In sum, a death spiral outcome would hurt customers in the long term since they will still rely on the utility grid as a platform for delivery and services to both DG and full-requirements customers. One essential policy benefiting utility customers as a whole would be to fairly allocate past utility capital expenditures between full-requirements and DG customers.

Yet, it is clear that regulators overprotecting utilities from inevitable competition is not good public policy. If DG becomes economical, regulators should demand that utilities

---

[123] The major developments are: (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 non-utility generation and energy efficiency. All of these factors tend to erode utilities' monopoly and financial positions.

[124] Examples of firms, other entities and industries enduring disruptions or events that threaten their financial viability include Kodak, newspapers, small colleges, cable companies, urban transit (trolley cars and streetcars), manufacturers of mainframe computers, the U.S. Postal Service, telecommunication companies, and natural gas in the 1980s.

[125] *See*, for example, Raskin 2014.

transition to the new environment by accommodating or even encouraging nonutility generation behind-the-meter. In the interim, regulators should treat utilities fairly, but they should also incentivize them to move ahead in accommodating those developments that best benefit their customers in the long term.

C. Adaptive utility and regulatory actions

According to some analysts, a death spiral becomes inevitable unless utilities take a proactive stance by exploiting the value of DG to their financial benefit rather than simply protecting their current physical assets from financial depreciation.[126] Regulators could also help avert a death spiral through their authority over utility ratemaking and the domain of utility activities in a transformed market environment. Accordingly, ratemaking reforms as well as a new business model are key factors in sustaining utilities' financial viability in a future where DG takes on a prominent role.

Two particular actions could go a long way in avoiding a death-spiral outcome for utilities. In the short term, regulators could make sure that customers who turn to DG pay their fair share of the costs incurred by a utility in providing them with required grid and standby services. As discussed earlier, regulators should revisit utility ratemaking practices to assess whether they meet their objectives in a new market environment. In the longer term, regulators should contemplate whether the current utility business model allows utilities to remain financially sustainable.[127] For example, changed conditions might warrant a different business model; namely, 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.

Four specific actions that regulators could take in averting a "death spiral" are as follows:

1. *Approve new ratemaking practices to mitigate financial threats to utilities:* For example, regulators might attempt to end cross-subsidies that motivate certain customers to uneconomically bypass the utility system,[128] although beneficial to

---

[126] A proactive utility would anticipate, shape and drive market and policy agendas, instead of just responding to proposed regulations, market or policy changes or regarding DG as the enemy. *See,* for example, Graffy and Kihm 2014.

[127] One comparable example is the car-service industry where Uber has applied new technologies (namely, "mobile apps") to develop a business model that has disrupted the financial viability of traditional taxi companies. Three possible scenarios come to mind: Either Uber would be subject to the same heavy regulations as taxi companies, the taxi companies would have to scrap their old business model to better compete with Uber, or regulations on taxi companies would lighten.

[128] Bypass could have a more serious effect on the utility as the former customer would no longer pay fixed charges. If instead, the customer merely cuts back on electricity usage but remains on the utility as a full-requirements customer the utility would still recover some of its fixed costs. One mitigating factor is that the utility could still recover at least a portion of the fixed charge by providing

those customers.[129] Another action would be to move all or more of the utility's fixed costs out of the volumetric charge.[130] While ratemaking reforms by themselves may not fully head off all future financial problems, regulators should consider them a good place to start.[131]

2. *Support for a new utility business model:* The new model could allow utilities, for example, to profit from offering distributed generation services or owning solar PV systems, while maintaining a competitive marketplace that gives utilities and their affiliates no unfair advantage.

3. *Determination of whether the problem is a bad business model or bad utility management:* The current business model might still be appropriate, but utility management itself might fail to adapt adequately to an increasingly competitive and more challenging environment. Scrapping the current business model when not warranted could lead to avoidable transitional costs.

4. *Avoidance of excessive costs imposed on utilities:* In coping with the challenges that electric utilities face, regulators could help protect utilities from unnecessary costs. Regulators might want to also provide utilities with stronger incentives for cost efficiency and innovations.[132] If utilities lack incentives for adopting new technologies, then they are less able to fare well with solar PV providers and other behind-the-meter competitors.

---

standby service or other service to the bypassed customer. At least over the next few years, storage will unlikely be cost-effective for DG customers to completely bypass the utility system (Chang et al. 2014). Even if it is, DG customers placing a high value on reliability may still be hesitant to wean themselves off the utility grid.

[129] Analysts sometimes used the term "uneconomic bypass" to describe this condition. Such bypass produces a decline in aggregate economic welfare: Output shifts to firms that have higher costs (but lower prices) than the local utility. Distorted pricing is a major source of uneconomic bypass.

[130] A utility may mitigate sales losses if a rate increase affects only the inframarginal "blocks" of consumption. For example, if the entire rate increase (needed to cover revenue requirement) goes into the customer or service charge, the effect on electricity usage would presumably be smaller. As long as consumer surplus *post* rate increase is still positive, customers would not discontinue service from the utility. Alternatively, customers would be more inclined to leave the utility system if the fixed charge exceeds consumer surplus at a price equal to marginal cost. *See* Felder and Athawale 2014; and Wenders 1984.

[131] One article expressed the view that "the current rate design cannot economically or politically support a large cross subsidy from non-DG to DG customers." (Felder and Athawale 2014, 14)

[132] *See*, for example, Costello 2012.

VII. The Classic Problem: Should Regulators Allow Expanded Utility Activities at the Risk of Competition?

The debate over utility involvement entails three basic questions that regulators will need to answer. First, what are the criteria for determining whether a utility or its affiliate can participate in a market that is workably competitive?[133] Second, if the regulator approves utility participation, what limitations should the regulator place on the utility to compete? Third, should utility core customers pay for any of the utility investments in the non-regulated market or should utility shareholders fund the investments? This Part will address some of these questions.

A. The benefits

The Straw Proposal authored by the staff of the New York Department of Public Service enunciates the benefits from direct utility involvement in the distributed energy-resource market:

> The advantage of utility DER [distributed energy resources] ownership is that utilities are well-positioned to accomplish or at least contribute to this growth with their own DER products and services. They have direct access to customers, credibility as a familiar energy provider, and knowledge about their distribution systems to identify where and how DER can be integrated with the greatest effect. Direct utility participation in DER can accelerate the transformation to a more fully distributed electric grid. Utilities can achieve these ends by leveraging existing ratepayer-funded assets and in-house expertise related to system planning, design and operations, and customer communications. Utilities can identify and demonstrate new DER technologies that are reliable and effective, thereby helping customers adapt to and exploit these technologies…Utilities can also act to promote development of DER technologies and, in turn, markets, by providing financing at relatively low cost.[134] In this way, utilities can take advantage of their economies of scale, with concomitant lower production costs that can establish market viability.[135]

1. Economies of scale and scope

In the context of our discussion, economies of scope measure the difference between the sum of the cost for providing regulated and unregulated service by separate entities and the cost

[133] Workably competitive markets lack all the text book requirements for perfect competition but produce similar outcomes, for example individual firms have limited market power and the market price tends to settle near marginal cost.

[134] In some states, including Ohio, Florida, Georgia, and California, utilities themselves have sought to act as third-party providers, either directly or through unregulated affiliates and as investors in third-party firms.

[135] New York Department of Public Service, August 22, 2014, 68.

to one firm providing both services. By providing a new service to DG customers, for example, a utility might more efficiently use its internal resources. As an illustration, by serving DG customers, a utility might lower its average cost for information technology activities, general personnel, billing, and metering. The result is a lowering of the utility's average cost, which benefits all customers, both full-requirements and DG customers. We assume that providing one service is distinct from providing the other. As long as the utility recovers from DG customers sufficient revenues to cover its incremental costs, no burden falls on existing customers. From the perspective of existing customers, the prices are compensatory.[136]

2. Stimulant for further DG development

Utility ownership of DG facilities has at least three benefits. First, the utility is able to recoup some of its lost revenues[137] when a customer switches from full-requirements service to partial service. The utility itself (e.g., in a division or department) or an affiliate can provide DG services.[138]

Second, the customer does not have to pay the upfront capital cost for the DG system. Even when cost-effective, some utility customers might shy away from investing in DG because of high initial capital costs or the higher priority they place on alternate home investments.

A third benefit is that the utility could exercise greater control over the operation of the DG facility and its integration with its distribution system, for example, through its contract with the customer. According to power engineers, optimal location and sizing of DG is essential to maximize the benefits of DG and avoid wasteful capital and operating expenditures.[139]

Overall, the utility can exploit its expertise in generation to DG. A proactive utility can act as a promoter, rather than as an obstructionist of DG development. Some industry observers consider active involvement as a game-changer in the development of DG. As an example, the utility (rather than customers) paying the upfront capital cost for the DG facility could lift a major barrier to DG development.

[136] As a rule, when a utility receives revenues from new services equal to or greater than the incremental cost, existing customers are either no worse off or better off. The revenues from new customers can filter through general rates.

[137] It is assumed here that the utility has a conventional rate design, with some of its fixed costs recovered in the volumetric charge, and no revenue decoupling mechanism.

[138] A utility can transform itself into an ambidextrous organization: One part of it operates as before while another attempts to combine the best aspects of a small, flexible firm and also benefiting from being part of a more established company (i.e., taking advantage of existing competencies and assets).

[139] *See*, for example, Scheepers 2007.

3. Avoidance of a **"**death spiral**"**

Regulators should consider whether the current utility business model allows utilities to remain financially sustainable. For example, the new environment may require expanding the scope of utility activities (the topic of this Part) which would improve the ability of utilities to exploit the potential financial gain from the improved economics of DG and other technologies that would otherwise threaten their financial viability.[140]

B. Regulatory concerns

1. The fundamental problems

The utility's presence in the DG market could discourage the entry of third-parties. The utility might have cost advantages because of economies of scale or scope, or, instead, have a contrived foothold from erecting barriers to third-party participation.[141] These barriers could originate from several sources: the pricing of utility-affiliate transactions, cost-shifting, cross-subsidization, discriminatory regulated service from "essential facilities," mandatory tying of "essential facilities" service and unregulated service, and discriminatory release of information from a utility to its unregulated affiliates. Cost shifting could involve, for example, the utility allocating DG-related costs to core utility services. As another example, the utility could sell information and computer services to an affiliate at below-cost.

The pertinent policy question then becomes: How could regulators assure a "level playing field" between utility-owned and third-party DG facilities? Utility ownership (or via affiliate) would require regulatory rules to ensure non-discriminatory access by third parties wanting to compete with the local utility. Cost-shifting[142] and other problems could arise that regulators will have to address in regulatory rules. Regulators will want to first assure that core customers are not subsidizing the DG facility; that is, the benefits they receive at least equal the added costs they pay to help fund the facility. Protections can include ring fencing and prohibitions against information and employee sharing with an unregulated affiliate. On the other hand, imposing undue restrictions on the utility or its affiliate could prevent them from investing in DG even when they are the least-cost provider.

---

[140] One study (Satchwell et al. 2014), for example, conducted a numerical analysis of the potential for utility ownership of solar PV to offset the earnings losses from customer migration to DG. With a utility owning a substantial portion of rooftop solar PV, the study concluded that "Utility ownership of customer-sited PV may offer sizable earnings opportunities, potentially offsetting much of the earnings impacts from PV that otherwise occur (at 56).

[141] Because of its status as a monopoly, a utility can exercise unfair competitive advantages over third-party providers of the same services.

[142] Cost shifting is not necessarily anticompetitive. It always has the effect of raising the prices of regulated services. Yet it might have minimal effect on the unregulated market: It might simply allow the utility to increase its profits by cost manipulation, rather than predation or other strategies giving its affiliate an unfair advantage over competitors.

One justification for proactive regulatory action is to discourage evasion of regulation through discrimination against competitors in the quality, timeliness, or availability of access to the regulated facility (e.g., the distribution network). Discrimination creates an artificial advantage in the competitive market, in effect tying the competitive service to the regulated service. This allows a vertically integrated firm to receive the profit from its monopoly status that regulation intends to preclude. The other justification for proactive regulation is to prevent cross-subsidization, here defined as misallocating costs of the competitive service (e.g., DG service) to the regulated side's books. If a vertically integrated utility could evade detection of such behavior, it would be able to raise rates for the regulated service closer to the monopoly level and possibly make credible predatory pricing threats in the competitive market.

The Straw Proposal authored by the staff of the New York Department of Public Service summarizes some of these misgivings with direct utility participation in the DG market:

> Market power concerns arise from utility's direct commercial involvement with distributed energy resources, from utility control of platform functions including scheduling and dispatch, and from utility control of access to its network, including interconnection and access to both system and customer data. These concerns include (1) the potential for a utility-provided platform to maintain barriers, such as burdensome interconnection requirements and outmoded tariffs, to robust entry into the market by DER providers; (2) potential reluctance of a utility-provided platform to provide the system or customer data needed by DER providers to succeed; and (3) the potential for functional competitive advantage on the part of the utility/platform regardless of utility behavior.[143]

2. Leveraging market power

The *leverage theory* supports the idea that a firm with power in one market (e.g., a public utility with a franchised service area) could exploit that power to acquire or preserve power in a second market. This behavior has the potential to harm competitors and create monopoly power in a market that is otherwise competitive. This theory reflects what analysts call a *vertical-control problem*, in which an electric utility, for example, providing local distribution service under regulated and monopolistic conditions could misuse its position to attain market power for an affiliate selling electricity and other competitive (e.g., DG) services.

The concern of state utility regulators, non-affiliate DG providers, and consumer groups generally is that the local utility or its parent company might leverage the monopoly power it enjoys in the delivery components of its operations to gain undue advantages in its lines of business that are workably competitive. The local utility might then have the ability to foreclose or impede the development of competition in markets for unbundled electric services. This is a classic example of a vertical-control problem.

---

[143] New York Department of Public Service, August 22, 2014, 67.

Many economists would argue that the majority of attempts to leverage would be unsuccessful in expanding market power. They assume that most markets are workably competitive and regulation is able to prevent monopoly profits. Certain situations, such as when a firm operates under rate-of-return regulation in one market, however, could potentially cause leveraging that leads to an anticompetitive outcome in an unregulated market. Specifically, a regulated firm could evade a regulatory constraint by operating in an unregulated market. Although different from traditional leverage theory, this hypothesis has a linkage.[144]

3. The absence of fair competition

Fair competition requires that all incumbent and prospective firms have equal opportunities to compete for customers. Equal opportunities have different interpretations among the different interest groups, as well as among economists. For example, a utility may interpret standard-of-conduct rules as overly restrictive, placing its affiliate at a disadvantage, while non-affiliates might consider these rules as essential to avoid what they perceive as inherent favoritism toward the utility affiliate. What is considered fair by some interest groups might well be viewed as unfair by others.

In the context of competitive sports, fair rules reflect no partiality toward any team or individual. They should produce outcomes that depend solely on the skills of the participants — that is, the best should always win. In the marketplace, fair rules should produce winners on the basis of their ability to satisfy consumers, nothing else. This means that new entrants should have the same opportunities as incumbents to succeed while, at the same time, incumbents are not unduly restricted in their ability to compete. Of course, most individuals would tend to define fair rules in terms of their self-interests. Social policy driven to serve the general population should ignore this perception as it would frequently harm the public. The basic task for policymakers is to strike a balance between regulating the utility-affiliate interaction to avoid abuses but not to excessively regulate so as to discourage or prohibit economical interaction.

4. Entry barrier to non-utility providers

Economists often disagree on whether certain "barriers" are actually anti-competitive or merely normal, pro-competitive market activities. Critics of a liberal definition of entry barriers (e.g., the Chicago School) contend that many of the alleged barriers are simply market efficiencies that serve to improve consumer welfare. Policymakers often mistake them for obstacles to competition that require mitigation.[145] As an example, when motivated by

[144] *See*, for example, Timothy J. Brennan 1987.

[145] As one economist has expressed, "The discussion of barriers in economic literature hardly reflects consensus. . .[The] differing definitions allow their authors to hold different opinions about specific sources of barriers." (Demsetz 1982, 47) Demsetz criticizes the conventional definitions of a barrier to entry for focusing only on the differential opportunities of incumbents and potential entrants. He uses the example of some legal barriers, such as taxi medallions, whose opportunity costs to incumbents and potential entrants are the same.

competitive forces, strategic pricing can reflect pro-competitive, rather than anti-competitive, behavior. By definition, pro-competitive activities benefit both consumers and society-at-large; in contrast, anti-competitive activities violate socially welfare-enhancing market practices by making a firm or group of firms better off at the expense of consumers. On net, society is worse off.

C. Analysis and policy options

1. General discussion

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.[146] It is also conceptually not straightforward to define "fair competition" when the local utility (1) has an obligation to provide service (e.g., both full-requirements and standby service) to anyone who wants it and (2) has social obligations (e.g., promoter of clean air) mandated by regulators or other governmental entities. The utility, for example, would still have to invest in infrastructure and maintain its system even as more customers switch to DG.

The risks associated with decision-making under uncertainty are sometimes labeled T*ype I* and *Type II* errors.[147] A Type I error would result from disallowing a particular action that is actually beneficial; one example would be the prohibition of a utility directly participating in the DG market that would otherwise benefit customers. A Type II error occurs when a particular action is allowed but the action results in a net cost to consumers or society. An example would be to allow sharing of a utility and affiliate resources when the resultant cost-shifting overwhelms any integration gains that may ensue.

From a political-economy perspective, governmental decision-makers such as state regulators and antitrust authorities have a propensity for avoiding Type II errors: They would prefer too many rules prohibiting certain activities than too few rules. In the example of utility-affiliate rules, based on casual observation regulators tend to be more concerned with the possibility of an incumbent utility or affiliate to exercise market power than with the loss of integration or scope economies from overly restricted rules.

Specifically, state regulators seem bent toward preventing market abuses such as cost-shifting and cross-subsidization even when forgoing integration and other efficiencies. Implicit is their belief that sacrificing some unknown, hard-to-measure efficiencies, or improvement in

[146] Some states such as California refer to this trade-off as a "balancing test" in which the regulator weighs the potential benefits of utility involvement against the potential anticompetitive effect. One benefit might derive from a market failure in which non-utility investments in (say) DG is deficient.

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

customer welfare, is a small price to pay to mitigate the possibility of market abuses. This asymmetric position, if in fact true (which seems consistent with actual regulatory policies and practices), is not at all surprising for risk averse regulators:[148] Market abuses or anticompetitive actions could be embarrassing and even damaging to regulators, while forgoing as of yet unseen, unrealized integration and other economies would likely have little or no political repercussions[149]

2. *Rule of reason* versus *per se* test

A *rule of reason* test involves the balancing of an activity's anticompetitive tendencies against the expected pro-competitive benefits. By presuming that efficiency is a possible determinant of the motivation behind an action, it calls for a benefit-cost test that places an equal burden on opposing parties to provide evidence. In practice, this standard would be difficult to apply precisely because of the non-quantification of some benefit-cost parameters.[150]

The *per se* test presumes that a particular activity is either inherently good or bad, thereby eliminating any need to weigh the evidence.[151] Applying a *per se* standard that approves all actions with potential efficiency gains is highly unlikely because of its negative political ramifications for regulators. Besides, it reflects bad policy as potential efficiency gains may be diminutive compared to the expected anticompetitive effect.

The strongest case for allowing a utility to make an efficiency argument occurs when anticompetitive effects are highly uncertain and efficiency gains are imminent. A seemingly extreme position would entail prohibiting all actions that could potentially be anticompetitive, no matter how small the probability is and how large foregone efficiency gains are. Decision-making under this rule violates a benefit-cost test, with the exception where society places an extremely high value on preventing anticompetitive actions relative to the expected efficiency

---

[148] Regulators' aversion to practices with potential anticompetitive consequences might arise from misperceptions of risk. For example, regulators might overestimate the probability of an anticompetitive outcome or its actual harm to consumers. Errors on risk perceptions might cause regulators to make decisions that fail to maximize social or consumer welfare.

[149] This partiality might also derive from the fact that anticompetitive effects (i.e., higher prices) often show up prior to the pro-competitive effects (i.e., production efficiencies). Consequently, regulators would tend to discount the pro-competitive aspects of an act relative to its anticompetitive aspects.

[150] A decision-maker could immediately reject an activity that would almost surely lead to less competition and has no prospects for efficiency improvements. In accordance with the *rule of reason* test, this activity would be prohibited when the pro-competitive (or positive) effects are either non-existent or fall short of the potential anticompetitive effect.

[151] The test says that an activity is always good or bad, with no exceptions. For example, the regulator can use the test to impose a blanket prohibition against utility involvement in markets with non-utility competitors.

gains.[152] This *per se* illegality standard seems to be embodied in some state regulatory actions reflecting a position of "throwing out the baby with the bath water."

As an alternative, regulators could apply a truncated-like rule of reason standard that places the burden of proof on one party. For example, regulators could view as desirable any action that produces potential efficiency gains with the burden of proof placed on those who predict anticompetitive effects. From observation, it is rare for state regulators to apply this particular standard.

The behavior of many regulators reflects their adherence to the standard that any action with the potential to be anticompetitive should be prohibited, unless evidence demonstrates that efficiency gains are likely to be more than offsetting from the perspective of consumer interests. This policy may in effect transform into a *per se* standard: It is highly difficult to quantify the efficiency gains if regulators in fact require it to satisfy the "demonstrated" criterion. Less than rigorous demonstration of economies or other sources of efficiencies would probably fall short of regulators' standard for acceptance. A reality is that claims of efficiency are easy to assert but real efficiencies are hard to prove and specious efficiencies to disprove.[153]

3. Four major factors for regulators to consider

Regulators might want to consider the following factors in deciding how to deal with potential utility abuse in providing DG services:

1. **Under rate-of-return regulation, a utility has a strong incentive for cost-shifting and overpayment of goods and services purchased from an affiliate**.[154] Consequently, regulators might have to institute a monitoring mechanism along with prescribed accounting and affiliate rules to prevent cost-shifting.[155]

2. **A "utility's ability" relates to the opportunities for market abuses.** For example, in a monopoly market where the utility can pass through higher prices with little effect on demand, the utility would have greater ability to engage in cost-shifting and other abuses.

---

[152] For example, the decision hinges on weights assigned to the two opposing effects on utility customers. The weights depend on the probability of occurrence and the value (positive or negative) attached to a specific event.

[153] It is difficult to demonstrate empirically that a particular action would improve efficiencies or rebut a false argument.

[154] Overpayment reflects a price above the market price or the stand-alone cost of the utility.

[155] The idea here is that enforcing rules on utilities that have an incentive to violate the rules would be hard, especially in light of the difficulties associated with knowing whether utilities actually broke the rules (i.e., information asymmetry).

3. **The monitoring and oversight effectiveness of regulators should influence the decision as to whether their policy should focus on developing the right incentive or rules.** With ineffective oversight capabilities, an agency should lean toward putting the correct incentive in place. For example, price caps relative to rate-of-return regulation should reduce the need of an agency to oversee certain utility activities.[156]

4. **A regulator's policy should understand the tradeoffs of different efficiencies that sometimes occur.** A good example involves an action that might produce scope or integration economies but at the cost of eliciting fewer suppliers in a market. Although fewer suppliers might mean higher productive efficiencies, it could result in suppliers acquiring an increased ability to exercise market power.[157]

4. Structural separation or behavioral rules?

a. Structural separation

Corporate restructuring such as structural separation and divestiture would sever financial or accounting ties between different functions within a firm. One intended effect is to reduce the ability of a utility to engage in certain abuses.[158] Thus, a benefit of separation is to lessen the likelihood of anticompetitive practices that might arise from an unregulated affiliate gaining an unfair advantage over its competitors. Structural separation, by placing a "Chinese Wall" between regulated and nonregulated activities, allows regulators to better track the actual costs

[156] By severing prices from a utility's reported costs, price caps give the utility or its parent company little or no incentive to shift costs and transfer excessive prices from self-dealing to the regulated utility. For example, under a pure price-cap mechanism, a utility simply could not pass through an inflated price for electricity purchased from its DG affiliate. The reason is that price changes do not necessarily correlate with the utility's change in reported cost.

[157] In economics parlance, the efficiency (or "deadweight") loss from the exercise of market power reflects the triangular area accounting for the decrease in consumer surplus minus the firm's cost savings, both attributable to lower output. The rectangular area measuring the reduction in marginal cost multiplied by total output represents the efficiency gain from scope economies or other sources of production efficiencies. Under most conditions, the net efficiency change would likely be positive; that is, the efficiency gains from small reductions in marginal cost or cost per unit likely dominate the deadweight loss from the exercise of market power. An example of this outcome for which goals of economic efficiency and consumer welfare are sometimes conflicting is a merger that results in lower costs but also a greater potential for the exercise of market power.

[158] Some electricity industry observers have raised the following question: Should structural separation be an absolute or should it be mandatory only after the demonstration of abuses?

incurred by the regulated segment.[159] Offsetting this benefit is the potential loss of economies of scope that may exist between regulated and unregulated services.

Structural separation does not eliminate the concern that a utility would have an incentive to engage in certain abuses relating to self-dealing and preferential local distribution access and information disclosure. Consequently, behavioral rules (e.g., standard-of-conduct rules) would need to accompany a structural-separation mandate. Taking everything into account, the social attractiveness of structural separation hinges on (1) the ability and incentive of a regulated utility to pursue anticompetitive practices in unregulated markets, and (2) the degree of economies of scope between the regulated and unregulated lines of business.

b. Codes of conduct

Codes of conduct are rules for restricting or prohibiting a utility's practices in its interactions with an affiliate.[160] Regulators execute these rules to protect the consumers of regulated services from certain abuses and sometimes to promote competition during the initial period of restructuring. More intense competition would presumably benefit consumers in their purchases of non-regulated goods or services. For example, codes of conduct try to prevent an incumbent utility from exploiting its position at the detriment of consumers; for example, by subsidizing a non-regulated affiliate, or by erecting artificial entry barriers favoring an affiliate and stifling the development of competition. This exploitation results in what this paper has referred to as anticompetitive practices.

While general agreement exists over the need for codes of conduct, it is accurate to say that they are highly contested in an environment where the participating interest groups hope to manipulate the political or regulatory process to gain preferential treatment.[161] Although certainly understandable from a single-group's perspective, these rent-seeking motives place regulators in the difficult position of sorting out conflicting information. The unprecedented challenge they face with codes of conduct is to evaluate and characterize individual practices as either pro-competitive or anticompetitive. To put it differently, regulators need to identify those practices compatible with a well-functioning market.[162]

[159] An example of a nonregulated activity is the utility forming an affiliate to install solar PV facilities on rooftops and servicing them.

[160] Sometimes industry observers refer to them as "safe harbor" rules.

[161] For example, a utility may interpret code-of-conduct rules as overly restrictive, placing its affiliate at a disadvantage. Non-affiliates, on the other hand, may regard these rules as necessary to avoid what they perceive as inherent favoritism toward the utility affiliate.

[162] Characteristics of a well-functioning market addressed by codes of conduct include (a) no exercise of market power by any one supplier, (b) no cost-shifting or cross-subsidization, and (c) suppliers having equal opportunities to compete.

This issue lies at the heart of the debate over whether regulators should encourage, prohibit or limit utility-affiliate interactions. Codes of conduct may "go too far" by misidentifying certain practices as anticompetitive or potentially anticompetitive when they are actually pro-competitive. This is probably the biggest risk associated with codes of conduct and one that will be difficult to avoid because of political realities.[163]

For codes of conduct to be effective, regulators must vigorously monitor them for compliance since a utility would have an incentive to violate the provisions. Regulators should then be able to detect actual abuses in addition to punishing the guilty party. In the worst case scenario, where regulators lack monitoring capabilities, utilities could easily evade the rules. We can reasonably assume that they would do so since it would be in their self-interest.

VIII. Conclusion

Historically, distributed generation in most U.S. jurisdictions was a marginal issue that did not require proactive regulatory action. Net metering is a case in point: Rooftop solar PV customers receive the utility's applicable retail price for the power they produce. While one could argue the merits of the methodology, the small volumes were immaterial. In the future, regulators might want to consider more intelligent pricing mechanisms for crediting solar PV customers. The major reasons for pricing reform are the advent of smart meters, solar PV's growing presence in the retail market, and a better balancing of regulatory objectives that include fairness to a utility's non-DG customers.

With the increased growth of DG, largely motivated by carbon concerns, improved economics and substantial subsidies, the issues associated with DG are no longer on the edge. They require bold regulatory actions that are aligned with the public interest. Other than new rate mechanisms, regulators might consider whether utilities should adopt a new business model to integrate DG into their distribution systems in a way that stimulates socially desirable DG.

Specific challenges for regulators include ratemaking to reflect smart grid technology, mitigating artificial barriers to the development of DG, and identifying the appropriate role for electric utilities in the development of DG. One important task for regulators is to weigh the potential upside of direct utility involvement against the risk of abuse that could stifle third-party investments and competition.

Regulators face strong pressures from interest groups to take certain courses of action. Their job is to balance these interests so as to best serve the public good. This paper provides regulators with basic information to help guide their decisions about DG and the various actions that utilities can take in its development.

[163] A possible source of this problem is regulators' short-term interests diverging from consumers' long-term interests. For example, risk-averse regulators may prefer the avoidance of potential anticompetitive outcomes over potential efficiency gains from integration. Conceivably, this preference may work counter to advancing the long-term interest of utility customers.

Bibliography

Ackerman, Eric. "Altreg and the Challenge of Distributed Energy." Presentation before the EUCI Conference on Alternative Regulation for Emerging Utility Challenges, April 23, 2014.

Aggarwal, Sonia, and Eddie Burgess. "New Regulatory Models." Prepared for the State-Provincial Steering Committee and the Committee on Regional Electric Power Cooperation, March 2014.

Ardani, Kristen et al. *Benchmarking Non-Hardware Balance of System (Soft) Costs for U.S. Photovoltaic Systems Using a Data-Driven Analysis from PV Installer Survey Results*. November 2012.

Aspen Institute. "The Future of the U.S. Electricity Sector." 2013 Energy Policy Forum, 2013.

Baldwin, Robert E. "The Case Against Infant-Industry Tariff Protection." *Journal of Political Economy* 77:3 (May/June 1969): 295-305.

Barbose Galen et al. "Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012." Report Summary, July 2013.

Binz, Ron. "Ron Binz's Perspective." Rocky Mountain Institute, 2014.

Binz, Ron. "New Utility Business Models: Response to a High Penetration Renewables Future." Presentation before the ACORE Northeast Roundtable, June 24, 2013.

Binz, Ron, and Dan Mullen. "Risk-Aware Planning and a New Model for the Utility-Regulator Relationship." *ElectricityPolicy.com.*, 2012.

Blackburn, Griselda et al. "Solar Valuation and the Modern Utility's Expansion into Distributed Generation." *The Electricity Journal*, Vol. 27, Issue 1 (January/February 2014): 18-32.

Blank, Larry, and Doug Gegax. "Residential Winners and Losers behind the Energy Versus Customer Charge Debate." *The Electricity Journal*, Vol. 27, Issue 4 (May 2014): 31-9.

Borenstein, Severin. "The Private and Public Economics of Renewable Electricity Generation." EI@ Hass WP 221R, Revised December 2011.

Brennan, Timothy J. "Why Regulated Firms Should Be Kept Out of Unregulated Markets: Understanding the Divestiture of AT&T." *The Antitrust Bulletin* 32 (Fall 1987): 741-93.

Brown, Ashley C. "The Utility Business Model Going Forward: Policy, Perception, and Risk Considerations." Presentation before the Harvard Electricity Policy Group, December 12, 2013.

Brown, Ashley, and Louisa Lund. "Distributed Generation: How Green? How Efficient? How Well-Priced?" *The Electricity Journal*, Vol. 26, Issue 3 (April 2013): 28-34.

Cabral, Luis M. B. *Introduction to Industrial Organization* (Cambridge, MA: MIT Press, 2000).

California Public Utilities Commission. "Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769." *Order Instituting Rulemaking*, August 14, 2014.

Candelise, Chiara et al. "The Dynamics of Solar PV Costs and Prices as a Challenge for Technology Forecasting." *Renewable and Sustainable Energy Reviews*, Vol. 26 (2013): 96-107.

CEPA LLP. *RIIO-ED1: Review of the DNO's Business Plans.* Report prepared for Centrica, August 2013.

Chang, Judy et al. "The Value of Distributed Electricity Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments." Prepared for Oncor, November 2014.

Costello, Kenneth W., and Ross C. Hemphill. "A 'Death Spiral' for Electric Utilities: A Hyperbole or a Reality?" *The Electricity Journal*, Vol. 27, Issue 10 (December 2014): 7-26.

Costello, Ken. "Gas-Fired Combined Heat and Power Going Forward: What Can State Utility Commissions Do? NRRI 14-06, June 2014.

Costello, Ken. "New Technologies: Challenges for State Utility Regulators and What They Should Ask," NRRI 12-01, January 2012.

Costello, Ken. "How Performance Measures Can Improve Regulation." NRRI 10-09, June 2010.

Deloitte Center for Energy Solutions. "The New Math: Solving the Equation for Disruption to the U.S. Electric Power Industry." 2014.

Demsetz, Harold. "Barriers to Entry." *American Economic Review* 72:1 (March 1982): 47-57.

Dion, Philip J. "The Electric Utility Business Model Going Forward: Maximalist, Minimalist or Somewhere in Between?" Presentation before the Harvard Electricity Policy Group, December 12, 2013.

Drucker, Peter. *The Practice of Management* (New York: Harper and Row Publishers, 1954).

Electric Power Research Institute. "The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources." February 2014.

Energy Industry Working Group. "Creating a 21st Century Electric System for New York State." Position Paper, February 26, 2014.

Ernst and Young, Global Power and Utilities Center. "From Defense to Offense: Distributed Energy and the Challenge of Transformation in the Utilities Sector." 2014.

Felder, Frank A., and Rasika Athawale. "The Life and Death of the Utility Death Spiral." *The Electricity Journal*, Vol. 27, Issue 6 (July 2014): 9-16.

Ford, Andrew. "System Dynamics and the Electric Power Industry." *System Dynamics Review*, Vol. 13, No.1 (Spring 1997): 57-85.

Fox-Penner, Peter. "The Future of Electric Utility Business Models: The View from 2013." Presentation before the Minnesota Rural Electric Association at the Energy Issues Summit, July 31, 2013.

Frankel, David et al. "The Disruptive Potential of Solar Power." *McKinsey Quarterly*, April 2014: 1-7.

Frantzis, Lisa. "Creating a 21st Century Electricity System." Presentation before the Symposium on Reforming the Energy Vision, May 22, 2014.

Goldman, Charles et al. "Utility Business Models in a Low Load Growth/High DG Future." Presentation before the National Association of Regulatory Utility Commissioners, July 23, 2013.

Graffy Elisabeth, and Steven Kihm. "Does Disruptive Competition Mean a Death Spiral for Electric Utilities?" *Energy Law Journal*, Vol. 31, No.1 (2014): 1-44.

Hawaii Public Utilities Commission. "PUC Orders Action Plans to Achieve State's Energy Goals." *News Release*, April 29, 2014.

Hledik, Ryan. "Rediscovering Residential Demand Charges." *The Electricity Journal*, Vol. 27, Issue 7 (August/September 2014): 82-96.

IHS CERA. *Fueling the Future with Natural Gas: Bringing It Home*. Prepared for the American Gas Foundation, January 2014.

Johnson, Mark W., Clayton M. Christensen, and Henning Kagermann. "Reinventing Your Business Model." *Harvard Business Review* 86, no. 12 (December 2008): 50-9.

Joskow, Paul L. "Creating a Smarter U.S. Electricity Grid." *Journal of Economic Perspective*, Vol. 26, No. 1 (Winter 2012): 29-48.

Joskow, Paul L. "Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies." Discussion draft, revised February 9, 2011.

Joskow, Paul L. "Inflation and Environmental Concern: Structural Changes in the Process of Public Utility Regulation." *Journal of Law and Economics,* Vol. 17, No.2 (October 1974): 291-327.

Kind, Peter. *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*. Prepared for the Edison Electric Institute, January 2013.

Krueger, Anne O. "Trade Policy and Economic Development: How We Learn." *American Economic Review* 87:1 (March 1997): 1-22.

Lacey, Stephen. "The Most Important Solar Statistics of 2013." GreenTechSolar, December 17, 2013 at http://www.greentechmedia.com/articles/read/the-most-important-solar-statistics-of-2013.

Lehr, Ronald L. "New Utility Business Models: Utility and Regulatory Models for the Modern Era." *The Electricity Journal*, Vol. 26, Issue 8 (October 2013): 35-53.

Lively, Mark, and Lorraine Cifuentes. "Curing the Death Spiral." *Public Utilities Fortnightly,* August 2014: 14-7.

Lovins, Amory B. "Saving Gigabucks with Megawatts." Public Utilities Fortnightly, March 21, 1985.

Massachusetts Department of Public Utilities. *Investigation By the Department of Public Utilities on Its Own Motion into the Modernization of the Electric Grid*, *D.P.U. 12-76-B,* June 12, 2014.

Massachusetts Institute of Technology. *The Future of the Electric Grid: An Interdisciplinary MIT Study* (Cambridge, MA: Massachusetts Institute of Technology, 2011).

McGarvey, Joe et al. *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria*, NRRI 07-03 (Columbus, OH: National Regulatory Research Institute, February 14, 2007).

Moody's Investors Service. "Arizona Public Service: Getting a Jump on Rooftop Solar Distributed Generation." *Credit Focus*, May 16, 2014.

Moody's Investors Service. "Rooftop Solar, Distributed Generation Not Expected to Pose Threat to Utilities." *Special Comment*, November 8, 2013.

New York State Department of Public Service. *Reforming the Energy Vision*. Staff Straw Proposal on Track One Issues, Case 14-M-0101, August 22, 2014.

New York State Department of Public Service. Reforming the Energy Vision. Staff Report and Proposal, Case 14-M-0101, April 24, 2014.

New York State Public Service Commission. *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Instituting Proceeding, Case 14-M-0101*. April 25, 2014.

Pethokoukis, James. "Swanson's Law and the Stunning Drop in the Cost of Solar Cells." *AEIdeas*, May 30, 2013.

Raskin, David. "Getting Distributed Generation Right: A Response To 'Does Disruptive Competition Mean A Death Spiral For Electric Utilities?'" *Energy Law Journal*, Vol. 35, No. 2 (2014): 263-82.

Raskin, David B. "The Regulatory Challenge of Distributed Generation." *Harvard Business Law Review Online*, Vol. 4 (2013): 38-51.

Rocky Mountain Institute. *New Business Models for the Distribution Edge: The Transition from Value Chain to Value Constellation* (Boulder, Co: Rocky Mountain Institute, April 2013).

Satchwell, Andrew et al. *Financial Impacts of Net-Metered PV on Utilities and Ratepayers: A Scoping Study of Two Prototypical U.S. Utilities*. Report by the Ernest Orlando Lawrence Berkeley National Laboratory, September 2014.

Scheepers, Martin et al. *Regulatory Improvements for Effective Integration of Distributed Generation into Electricity Distribution Networks*. Summary of the DG-GRID Project Results, ECN-E-07-083, November 2007.

ScottMadden. "Distributed Resources and Utility Business Models □ The Chronicle of a Death Foretold." 2013.

Selecky, James et al. "Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States." Prepared for Oak Ridge Laboratory, February 2014.

Shrimali, Gireesh. "A Low-Carbon Electricity System Roadmap." *Stanford Energy Club*, Issue 5, October 21, 2014.

Shultz-Stephenson Task Force on Energy Policy. "California's Electricity Policy Future Beyond 2020." April 2014.

Shultz-Stephenson Task Force on Energy Policy. "Renewable and Distributed Power in California: Simplifying the Regulatory Maze □ Making the Path for the Future." 2013.

Sinha, Parikhit et al. "Total Cost Electricity Pricing of Photovoltaic." Proceedings of the 28th European Photovoltaic Solar Energy Conference, October 2013.

Slocum, John. "Threat from Behind the Meter: The Case for Utilities To Compete Directly with Distributed Resources." *Public Utilities Fortnightly*, July 2013: 46-57.

Stanton, Tom et al.. "A Review of Cost Comparisons and Policies in Utility-Scale and Rooftop Solar Photovoltaic Projects." NRRI Paper 14-05, June 2014.

Stanton, Tom. "State and Utility Solar Energy Programs: Recommended Approaches for Growing Markets." NRRI 13-07, July 2013.

Stoft, Steven. *Power System Economics: Designing Markets for Electricity* (Piscataway, NJ: IEEE Press, 2002).

Tai, Humayun. "New Utility Business Models." Presentation before the Harvard Electricity Policy Group, December 12, 2013.

Tong, James, and Jon Wellinghoff. "Rooftop Parity: Solar for Everyone, Including Utilities." *Public Utilities Fortnightly*, August 2014: 18-23.

U.S. Department of Energy. *SunShot Vision Study*, February 2012.

U.S. Energy Information Administration. "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants." April 2013.

Wenders, John T. "Two-Part Tariffs and the 'Spiral of Impossibility' in the Market for Electricity." *The Energy Journal*, Vol. 5, No. 1 (1984): 177-79.

Wood, Lisa, and Robert Borlick. "Value of the Grid to DG Customers." *IEE Issue Brief*, September 2013.

Zarakas, William. "The Utility of the Future: Distributed or Not?" Presentation before the Advanced Energy 2013, April 30, 2013.