Traditionally-Structured Electric Utilities in a Distributed Generation World

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## I. INTRODUCTION

To hear electric utilities tell the story, the end is nigh. Their chief worry is symbolized by the simple rooftop solar panel. Of course, a homeowner’s installation of rooftop solar, in and of itself, is little or no cause for concern. After all, property owners have every legal right to generate their own power. Rooftop solar, however, is significant for what it

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represents more broadly—distributed generation (“DG”). This broader concept of DG means that central power stations can lose market share of their electricity sales by a range of technologies including solar, wind, fuel cells, micro-grids, and the like. Fortunately for electric utilities, at this point, distributed solar electricity constitutes only one to two percent of the total electricity load and, therefore, DG is not an immediately significant contributor to load loss. However, the signs on the horizon are not necessarily rosy for investor owned electric utilities (“IOUs”) that provide seventy-five percent of the nation’s electricity.

The reality is that the electricity market is changing. The market is more competitive today than it has been historically and, consequently, traditionally structured IOUs face real financial challenges as new technologies with decreasing costs “directly threaten the centralized utility model.” This article argues that the twenty-first century challenge to the

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3. See ELEC. POWER RESEARCH INST., supra note 2, at 10.


5. Electric Utility Industry Worldwide Directory: Electric Utility Industry Overview, MIDWEST PUBLISHING COMPANY, http://www.midwestpub.com/electricutility_overview.php (last visited Mar. 30, 2014). The [United States] electric industry includes over 3,100 electric utilities. Investor owned electric utilities are privately owned, represent [eight] percent of the total, approximately [seventy-five] percent of utility generating capability, generation, sales, and revenue. Historically, most investor owned electric utilities were operating companies that provide basic services for the generation, transmission, and distribution of electricity.

Id.


electric industry is different in kind from previous challenges. Further, past responses to past challenges are inadequate to meet the convergence of demands posed on IOUs by new technologies, new markets, and new regulations.8 Instead, the twenty-first century challenge requires a dramatic new response as electric utilities face a new economic order and as they seek revenue protection and assurances of financial stability from their regulators.

Now, what to do? Two responses are readily available. Electric utilities can either fight or switch.9 The first response is the one given by incumbents: Stay the course, tweak the regulatory system, and continue doing business as usual (“BAU”).10 The BAU strategy relies on maintaining cost-of-service ratemaking as central to the regulatory compact between utilities and regulators.11 The second—and smarter—is that IOUs must change their business models in significant—if not dramatic—ways.12 The country is making a revolutionary transition to a clean energy economy13 and...
there are several drivers to that transition, including: (1) a developing policy consensus;\textsuperscript{14} (2) positive economic indicators;\textsuperscript{15} (3) the need to diversify fuel resources; (4) new financing techniques; and, (5) regulatory proposals at the state and federal levels.\textsuperscript{16} Quite simply, electric utilities should behave as key actors in that transition. Today, however, utility efforts have been lacking as they seek solace in old ways of doing business.

This article will first explore current industry characteristics and challenges in Part II. Part III will then discuss the current situation of the electricity market and IOU participation in that market. Part IV will analyze the fundamental legal claim available to utilities that the regulatory environment is devaluing their property and may constitute a constitutional taking. In Part V, a test case involving solar distributed generation and net metering will be presented to examine the types of challenges facing IOUs as well as available responses to those challenges.

Starting with Part VI, the article more broadly discusses the need to change the current regulatory compact between utilities and their regulators. Then, Part VII examines new forms of ratemaking that can be employed to implement the regulatory compact. The article concludes in Part VIII with a discussion of the shape that the utility of the future ought to take.

II. INDUSTRY CHALLENGES

The electricity industry has been roiling for over three decades. For the first two-thirds of the twentieth century, the industry continued to realize growth and, with it, increasing sales and profits.\textsuperscript{17} Utility executives were aided in their expansion by a cost-of-service rate formula that rewarded them for their capital investments.\textsuperscript{18} During that period, as the industry expanded, economies of scale were realized and consumers enjoyed relatively low and stable prices while producers reaped their rewards.\textsuperscript{19}
By the mid-to-late 1960s, however, things began to change: A national electricity infrastructure was completed; electric generation plants reached a technological plateau; and, the cost of electricity from traditionally structured electric plants began to rise.\(^\text{20}\) These events, among others, shook the industry from its complacency and presented real challenges both to industry actors and to their regulators.

This once staid industry began encountering a series of challenges beginning in the late 1970s as electricity prices began to rise and as the financial stability of the industry was threatened by two major events.\(^\text{21}\) The first financial shockwave came with the collapse of commercial nuclear power.\(^\text{22}\) From the mid-1970s through the 1980s, utilities that had invested in nuclear power found themselves with excess capacity, canceled plants, or the costly conversions of nuclear plants to coal-fired plants.\(^\text{23}\) These nuclear investments ran into the billions of dollars and those costs had to be apportioned in some way.\(^\text{24}\) The question “Who pays?” was a real one for utilities, for regulators, and for consumers. The response to the question was generally some form of cost allocation between ratepayers and shareholders.\(^\text{25}\) In some instances, regulators simply amortized the investment and allowed the utilities to recover their principal but did not allow them to either earn a return on their investment or to recover their costs of capital.\(^\text{26}\) In brief, the regulatory response to the nuclear crisis was to


\(^{22}\) See McDermott, supra note 17, at 24; Pierce, supra note 21, at 503–04.

\(^{23}\) McDermott, supra note 17, at 24; Pierce, supra note 21, at 503–05.

\(^{24}\) Pierce, supra note 21, at 504.

\(^{25}\) See Tomain, Nuclear Power Transformation, supra note 20, at 3; Pierce, supra note 21, at 505–06.

\(^{26}\) See Jersey Cent. Power & Light Co. v. Fed. Energy Regulatory Comm’n, 810 F.2d 1168, 1171–72 (D.C. Cir. 1987). In this case, an en banc panel of the United States Court of Appeals for the District of Columbia upheld a Federal Energy Regulatory Commission (“FERC”) ruling that allowed Jersey Central to recover a $397 million investment in a failed nuclear power plant over a fifteen-year period. Id. at 1170–71, 1187–88. Jersey Central wanted to place the unamortized portion that remained each year into the rate base. FERC allowed the fifteen-year amortization—i.e., allowed the utility to recover $26.4 million as an expense for fifteen years—but disallowed including the unamortized portion in the rate base, and that ruling was upheld by the Circuit Court. Id. at 1171, 1187–88.

Regulators applied other rules as well. Some regulators, for example, applied the prudent investment test, which held that investments that were prudent when made should be recovered from ratepayers. See United Illuminating Co., 55 P.U.R. 4th 252, 267 (Conn. Dept. Pub. Util. Control Aug. 22, 1983); Rochester Gas & Elec. Corp., 45 P.U.R. 4th 386, 400 (N.Y. Pub. Serv. Comm’n 1982). And others applied a used and useful test that held that ratepayers were not to be saddled with the cost of an investment that produced no electricity. See
protect some of a utility’s investment, and to maintain their financial stability while not overburdening consumers.27

The second financial shockwave came in the 1990s with efforts to deregulate the electric industry, and when that failed, then to restructure it.28 Complete deregulation failed due to its complexity and the inability to develop either a policy or political consensus to fully deregulate.29 At the wholesale level, deregulation looked promising and has occurred to a significant degree.30 At the retail level, however, the continued natural monopoly characteristics of the transmission and distribution (“T&D”) segments prevented across-the-board deregulation from occurring.31 Many states, however, did attempt retail competition,32 but California’s notable failure threw two major utilities into financial distress with Pacific Gas and Electric declaring bankruptcy.33 With that failed experiment, restructuring effectively ended.34 Still, restructuring efforts threatened the financial integrity of IOUs.35 The regulatory response to this problem, however, was to provide some mechanism for utilities to recover any stranded costs that resulted from (1) prudent investment and (2) reliance on regulatory requirements.36

The nuclear power collapse and the failure of restructuring were one-off events. In other words, once an investment in a nuclear plant was unproductive for any of the reasons cited above, then the financially threatening event was over and it needed to be resolved in some way. Similarly, once an investment in a restructured environment was also seen to

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27. See Pierce, supra note 21, at 518.
29. See id. at 36.
30. See id. at 28, 31.
34. Tomain & Cudahy, supra note 32, at 408.
be unproductive, then it too needed resolution. The regulatory responses to both events were essentially cost-based. Regulators looked to the prudence of a utility’s capital investment and they looked to the overall effect of those investments on the utility’s financial integrity. Regulators then did what they could to ensure the continued financial existence of the utilities. The current challenge, however, is not one-off. Instead, it is long-term and developing slowly, and also requires a more creative response than shoring up past investments. Instead, a forward-looking response is needed to maintain a healthy electric market for IOUs.

In order to better understand the nature of the twenty-first century challenge, let’s briefly first look at changes in the market and then examine some of the reasons for those changes. The electricity market in the twenty-first century is dramatically different from what it was during the twentieth century. For most of last century, electric utilities enjoyed a growing market and, therefore, regularly enjoyed increasing sales. Today, however, things are different.

Demand for electricity has slowed each decade from the post-World War II golden age until now. In the decade of 1949 to 1959, electric utilities enjoyed an annual growth of 9.8%. That growth has declined to an annual rate of 0.7% in the first decade of the twenty-first century. In fact, electricity demand has declined every year except two since 1996. Further, for the last two years demand has fallen, and in 2012, demand was down 1.7% compared with 2011. According to recent Energy Information

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37. See McDermott, Edison Elec. Inst., supra note 17, at viii–ix tbl.1, x, 17–40. In addition to nuclear power and restructuring, McDermott notes other periods of stress including the rise of inflation during the 1970s, excess capacity in the 1980s, and a current challenge to restore customer and investor confidence in the industry. Id.
38. Id. at viii, 25–26.
39. See id. at 33.
40. See Ebinger & Banks, supra note 6.
41. See id.
42. See Leonard S. Hyman et al., America’s Electric Utilities: Past, Present and Future 151 (8th ed. 2005). From 1945 through 1965, electric utilities enjoyed an annual growth rate of approximately seven percent. Id. “No doubt what helped most was the dramatic and continuing drop in the real price of electricity, compared to the price of other fuels.” Id.
44. Id.
45. Amory B. Lovins, Amory’s Angle: Three Major Energy Trends to Watch, Solutions J. Online (Summer 2013), http://www.rmi.org/summer_2013_esj_amorys_angle_three_major_energy_trends_main.
Administration estimates, demand is scheduled to decline for the third year in a row and hit the lowest level since 2001.47 Nevertheless, the Department of Energy projects that for the next three decades, from 2011 to 2040, overall demand will increase by twenty-eight percent.48 Even with such modest growth in overall demand, individual consumers are, in fact, consuming less electricity.49 More problematic for traditional IOUs, however, is that projected demand for central power station electricity is predicted to fall “dramatically due to a combination of energy efficiency and competition from new technologies, which collectively could impact their addressable markets by 50% over the next two decades.”50 To add to these troubles, significant investment is needed in the electricity infrastructure, both to upgrade the current grid and to promote interconnections with renewable resources, as well as to make investments in new technologies.51

According to the Energy Information Administration, electricity demand declined due to reduced retail sales and a lack of demand growth in the commercial and industrial sectors as a result a soft economy.52 A slow economy, though, is only one reason among many. Technological and market reasons include increased energy efficiency in appliances and buildings; smarter meters and temperature controls; smarter consumer choices about using cheaper off-peak energy; growth of DG so that consumers can obtain power on-site; and an increase of inexpensive shale gas for home heating.53 These technological and market changes, however, did not come about on their own. They were aided by state and federal regulations that were intentionally designed to increase competition and change the fuel mix in the electricity sector largely because cleaner, cheaper

47. Fahey, supra note 46.
53. See KIND, supra note 4, at 3, 5, 11.
power was available than that generated by IOUs. Further, these regulatory demands clearly point to a clean energy future rather than to a continued expansion of coal-fired—or even nuclear generated—electricity.

III. THE NEW NORMAL

The constrained electricity market now represents the new normal for privately-owned electric utilities. This new normal must be recognized as different in kind from the threats posed by the nuclear collapse and the restructuring failure. Today’s challenge is structural, long-term, and driven by multiple events. Consequently, to meet the challenge, structural changes are necessary on the regulatory side to renegotiate the regulatory compact and redesign traditional cost-of-service ratemaking. Additionally, there must be structural changes in the business model of utilities as well. The needed regulatory and business model responses presented by the new

54. See McDermott, supra note 17, at ix–x, 33.


56. See Ahmad Faruqui & Eric Shultz, Demand Growth and the New Normal, PUB. UTIL. FORT., Dec. 2012, at 22, 23. Demand side management (“DSM”) is comprised of “programs and technologies [that] enable consumers to reduce peak demand and electric energy consumption by providing customers with incentives to buy more energy efficient technologies and to shift demand from peak hours—where the power grid is stressed due to high demand—to off-peak hours.” Id. at 24; see also Kind, supra note 4, at 1–2. Among the factors contributing to the challenge, Kind lists: (1) falling cost of distributed generation; (2) new technologies; (3) consumer and regulator interest in demand side management; (4) declining natural gas prices; (5) slow economic growth; (6) rising electricity prices in some sections of the country; and (7) investment need for system improvements. Kind, supra note 4, at 1–3.


[We all have to realize that real progress can only be made by state utility commissions, many of which seemed unwilling to seriously consider moving beyond regulatory compacts in states that for decades have rewarded utilities only, or mostly, for selling more kilowatt hours. Now that electricity demand nationally is flattening and may be declining, the time has come for tradition-bound states to reengineer the traditional regulatory compact.

Id.
normal electricity market can be uncovered by first examining the economic and policy assumptions behind the traditional regulatory model, and then by examining the regulatory climate that has significantly contributed to the current market.

A. Traditional Economic Assumptions

In the early years of utility regulation, the relationship between utility and regulator was based upon what—in 1898—the infamous Samuel Insull proposed as “a grand bargain in which local electric companies would receive exclusive franchise service territories, ‘…coupled with the conditions of public control, requiring all charges for services fixed by public bodies to be based on cost plus a reasonable profit.’” 58 Nearly one hundred years later, then Judge Kenneth Starr defined that grand bargain as a regulatory compact that has been prevailing since electricity regulation began. 59 In short, the regulatory compact was indeed a grand bargain for the utility. As it turns out, the regulatory compact also served as something of a bargain to consumers and to regulators for most of last century.

Utilities greatly benefited from the regulatory compact essentially because by having been granted an exclusive service territory, utilities could block out competition from new entrants simply because they were now operating under a government protected monopoly. 60 Further, utilities also benefitted from a ratemaking formula that operated like a cost-plus contract. Utilities would receive all of their reasonably incurred expenses on a dollar-for-dollar basis and they would be able to earn a return on invested capital. 61


The utility business represents a compact of sorts; a monopoly on service in a particular geographical area—coupled with state-conferred rights of eminent domain or condemnation—is granted to the utility in exchange for a regime of intensive regulation, including price regulation, quite alien to the free market. Each party to the compact gets something in the bargain. As a general rule, utility investors are provided a level of stability in earnings and value less likely to be attained in the unregulated or moderately regulated sector; in turn, ratepayers are afforded universal, non-discriminatory service and protection from monopolistic profits through political control over an economic enterprise. Whether this regime is wise or not is, needless to say, not before us.

Jersey Cent. Power & Light Co., 810 F.2d at 1189 (citation omitted).

60. See MCDERMOTT, EDISON ELEC. INST., supra note 17, at vii; Electric Utility Industry Worldwide Directory: Electric Utility Industry Overview, supra note 5.

61. See MCDERMOTT, EDISON ELEC. INST., supra note 17, at vii, 2.
While it is inaccurate to say that utilities were guaranteed a profit, in effect though, as long as they operated prudently, profit was assured.62 Consumers also benefitted to the extent that rates were set at more or less competitive levels rather than at monopoly levels.63 Regulators benefited as well because as the industry was expanding and as utilities were realizing economies of scale, rates stayed relatively flat and in some instances, declined. In other words, rate hearings followed well-established and well understood rules and methodologies and the life of a regulator was fairly easy.64

The regulatory compact was implemented through the application of a traditional cost-of-service ratemaking formula that required regulators to balance the interests of the utility and its shareholders in earning a reasonable return on their investments against the interests of ratepayers in not being charged confiscatory or discriminatory rates.65 The balance was intended to satisfy the Fifth Amendment constitutional prohibition against takings of private property without just compensation.66

Cost-of-service ratemaking, quite simply, works well in an expanding economy. As long as electric demand continues to grow and as long as utilities continue to make technological improvements and achieve scale economies, utilities can be rewarded for their prudent capital investments and customers do not suffer rate increases due to a "virtuous growth cycle in which increasing electricity consumption was viewed as synonymous with the public good."67

The danger in such a formula, however, should be apparent. As long as utilities received a return on capital expenditures, they had an incentive to build.68 Again, during a period of economic expansion and growth in electricity demand, building is a necessary and economically valuable strategy. Today, however, the industry is experiencing a "paradigm shift" caused by the need for large new capital additions at a time of declining sales growth and reduced credit worthiness.69 If the economy slows or demand falls, capital investments may not be economically valuable because the
market is saturated and electricity sales flatten, meaning revenues decline for IOUs. Today, IOUs in fact face just such a slow economy, weak demand, and nervous regulators.70

B. Traditional Policy Assumptions

Generally, energy policy—more specifically electricity policy—was grounded on the central and important idea that the more energy that a country produces and consumes, then the more vibrant its economy would be.71 Indeed, the twentieth century witnessed unprecedented economic growth for the United States as well as any developing country with a robust energy infrastructure.

There are other policy ideas associated with this belief in the direct positive relationship between energy and the economy. First, it is more efficient to use cheaper inputs to produce a product such as electricity than more expensive ones.72 In this way, then, the electric industry has relied predominantly on cheap, but dirty, fossil fuels—particularly coal.73 Second, scale economies could be realized through larger plants and greater centralization.74 Therefore, the utility industry should capitalize on those improvements—to a point. Parenthetically, this principle was exactly the reason that utilities invested in nuclear power—to realize scale economies. Unfortunately, that strategy often proved to be quite costly. Third, as utilities moved from local to regional, and, ultimately, to interstate T&D, industry regulation similarly moved from municipal to state and then to federal authorities.75 In short, the development and the structure of the industry and its regulation moved in tandem as industry actors and regulators mimicked how each conducted its business, thus reinforcing the traditional energy paradigm.76

As a result of these assumptions, the industry and its regulation developed a pattern that exists today and is a pattern that has witnessed the investment of trillions of dollars over the century. Unfortunately, the traditionally structured industry and its regulation do not fit with current

70. See id.
71. See id. at ix, 17.
74. Tomain, Nuclear Power Transformation, supra note 20, at 11.
76. See id. at 374.
economic policy nor are they aligned with contemporary energy policy assumptions.

Most notably, today we have significant reasons to question the underlying assumption about the direct relationship between energy and the economy. Most particularly, even though electricity demand is projected to increase overall, albeit slowly, individual consumption is declining.\(^{77}\) In other words, the traditional belief in the direct linkage between energy and the economy is now experiencing a reversal. Individual consumers can continue to enjoy the lifestyles they have while consuming less electricity. Further, industrial and commercial, as well as residential, consumers are less dependent on the local utility for their electricity. Additionally, energy policy—more specifically electricity policy—is concerned not only with the relationship between energy and the economy; it is also concerned about environmental consequences and about the energy reliability and national security issues in the realm of geopolitics.\(^{78}\)

Consequently, given the dramatic nature of changes in the electricity market and in energy policy, it is time to reconsider, reevaluate and redesign both the regulatory compact and the traditional approach to ratemaking—particularly given the changes that have been made in energy regulation—to which we now turn.

C. Regulatory Changes

The regulatory landscape for the electricity industry and its markets has been undergoing dramatic change for over forty years at both the federal and state levels.\(^{79}\) It is this regulatory twist that has given IOUs cause for concern and it is something that they must now confront.

Although, as noted above, the electric market began changing in the mid-1960s, no major regulatory changes occurred until the passage of the Public Utility Regulatory Policies Act of 1978 ("PURPA").\(^{80}\) In brief, large IOUs seemed to reach a technological plateau in the mid-1960s, yet they had committed capital to expansion projects. In doing so, IOUs overbuilt and, as a consequence of the traditional ratemaking formula, they were charging customers for that capital expansion. To inside observers, it was clear that cheaper electricity was available but could not get to market because T&D

\(^{77}\) Sioshansi, *Why the Time Has Arrived to Rethink the Electric Business Model*, supra note 1, at 65–66.
\(^{78}\) See Tomain, *Building the iUtility*, supra note 8, at 29.
was privately owned by IOUs. As it turned out, PURPA proved the very point that cheaper electricity was available.81

As economic dislocations occurred in world energy markets and in the domestic economy, President Carter proposed, and Congress enacted, the National Energy Act82 with the intent of stabilizing domestic energy policy and markets.83 PURPA was intended to encourage states to move away from electricity rate designs that encouraged consumption and move toward marginal cost pricing because it would promote more accurate price signals and achieve greater efficiencies.84 In addition, PURPA promoted independent power production, co-generation and small power generation.85 Known as qualifying facilities (“QFs”), these non-utility generators were able to produce electricity that was less expensive than electricity generated from traditional IOUs and they were more successful than policymakers imagined.86 QFs demonstrated that non-utility generation could be delivered safely and reliably and, as it turned out, there were more generating facilities, sometimes referred to as PURPA-machines, than anticipated.87 Consequently, it was revealed that cheaper power was available for electric markets.88

QFs had a very attractive economic incentive to generate electricity up to the maximum amount allowed under law.89 Not only could QFs generate cheaper power for a firm’s own use, any excess power could be sold back to the local utility at the “utility’s full avoided costs.”90 The local utility

88. See What is a Qualifying Facility?, supra note 86.
90. Id. at 404.
had to allow access to QFs, and it was obligated to purchase their excess electricity at the local utility’s marginal cost of electricity. The local utility had to pay the cost that it would incur to generate one more kilowatt-hour of electricity. In other words, the utility had to pay the generator not at the prevailing market value, but at the utility’s own higher cost of producing electricity. Thus, PURPA discovered a new generation market.

In effect, PURPA set the stage for competition. Traditionally regulated IOUs, following the traditional regulatory structure and rate formula, earned favorable rates, but they had overbuilt. The excess capacity raised utilities’ fixed costs, which had to be recovered from ratepayers. Consumers were aware of these market developments. They did not want to pay for higher cost electricity and sought lower-cost options. While the existence of lower cost electricity did not surprise large customers, the market was surprised by how much new non-utility generated electricity was available, and how eager new generators were to enter the market. These new unregulated producers were willing to supply the market with electricity at prices lower than those charged by incumbent IOUs, and they now provide over one-third of the country’s electricity.

PURPA opened electricity markets and other state and federal legislation entered that arena and expanded competition. Under the Energy Policy Act of 1992, Congress created a category of exempt wholesale generators. These entities generated electricity to be sold at wholesale, and they were exempt from some of the regulatory provisions contained in the Public Utilities Holding Company Act of 1935, which was later repealed.

92. See id. § 210(d).
93. See id.
95. Id.
96. Id. at 231.
97. See MCDERMOTT, EDISON ELEC. INST., supra note 17, at X; Tomain, The iUtility, supra note 94, at 226–27.
by the Energy Policy Act of 2005.\textsuperscript{101} That repeal was deemed to be a significant boost to independent power production because it opened the electricity market to a wider variety of business activities.\textsuperscript{102} Also under the Energy Policy Act of 2005, Congress required electric utilities, under certain restrictions, to offer net metering services to electricity consumers.\textsuperscript{103} To date, forty-three states and the District of Columbia have adopted some form of net metering.\textsuperscript{104} Additionally, for over three decades federal tax incentives in the form of production tax credits and investment tax credits, among others, have spurred production of electricity from renewable resources.\textsuperscript{105} Finally, federal regulators, pursuant to enacted legislation, are pursuing methods of pollution control.\textsuperscript{106} Proposed EPA rules will strengthen Clean Air Act protections and they will have a negative impact on coal-fired power plants.\textsuperscript{107}

Federal regulation was a boon to independent power production. State regulation, however, was more varied and went quite a bit further. State regulatory actions that contribute to declining electricity demand include demand side management planning requirements; integrated resource planning requirements; renewable portfolio standards (“RPS”); and energy efficiency standards as well as net metering laws.\textsuperscript{108} Additionally, in an effort to stimulate non-fossil fuel generation, thirty-seven states and the

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\textsuperscript{102.} See id.

\textsuperscript{103.} Energy Policy Act of 2005, Pub. L. No. 109–58, § 1251, 119 Stat. 594 (codified as amended in 16 U.S.C. § 2621(d)). “Each electric utility shall make available upon request net metering service to any electric consumer that the electric utility serves.” Id. The section contains qualifications that allow Public Utility Commissions (“PUCs”) to fashion net metering rules: (1) consumer must be an “eligible on-site generating facility” and (2) that electricity “may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.” Id.


\textsuperscript{106.} See Massachusetts v. EPA, 549 U.S. 497, 532–33 (2007) (holding that the EPA does have the authority and the responsibility under the Clean Air Act to regulate greenhouse gas emissions).


\textsuperscript{108.} See, e.g., Faruqui & Shultz, supra note 56, at 24–28.
\end{flushleft}
District of Columbia have adopted RPS that impose requirements of varying strictness on local utilities to sell electricity generated by renewable resources.109 These standards vary throughout the country but are comprised of essentially two elements.110 First, a resource such as solar, wind, hydropower, or geothermal must qualify for inclusion under the terms of the RPS.111 Second, a percentage goal and timetable is established for each utility to satisfy the requirement.112 RPS programs have a significant impact on developing renewable resources over the last decade or so.113

States have also been involved in an array of other regulations that are aimed at having electricity produced by non-utility generators using renewable resources.114 Feed-in tariffs, for example, are long-term contracts

that utilities enter into with renewable resource providers, which enable the providers to have an assured income stream enabling them to provide renewable energy.\textsuperscript{115} Energy efficiency standards and zero net building standards are intended to reduce consumption by capturing energy efficiencies.\textsuperscript{116} States also have tax credits available that have made the installation of photo-voltaic ("PV") solar and other alternatives more affordable for more consumers.\textsuperscript{117}

Consequently, an array of federal and state legislation has had two dramatic consequences for the industry.\textsuperscript{118} First, competition in the electricity market has been encouraged.\textsuperscript{119} Second, regulations have promoted renewable resources and energy efficiency that have had the effect of reducing demand for IOU electricity.\textsuperscript{120} This new regulatory scheme has caused a reevaluation of regulation at both ends of the fuel cycle.\textsuperscript{121} At the generation end, we have seen that the market is more competitive than once assumed.\textsuperscript{122} At the consumption end, buyers wanted cheaper electricity.\textsuperscript{123}

Since the late 1970s we have been trying to restructure the electric industry with only partial success. We continue to struggle with the problems of: (1) getting cheaper electricity to consumers; (2) continuing to diversify generation sources; (3) dealing with intermittent sources such as wind and solar power; (4) redesigning electricity markets; and (5) encouraging traditional IOUs to rethink their business models. This last issue—encouraging traditional IOUs to reformulate their business models—raises a legal question of constitutional dimension. To the extent that a privately owned firm has invested capital in reliance on government regulations, is the firm entitled to compensation when those regulations change? That question will be addressed in the next section and will then be followed by the test case for the matter of DG that has been promoted

\begin{thebibliography}{99}
\bibitem{116} See \textit{ROCKY MOUNTAIN INST., NET ENERGY METERING}, supra note 114, at 11.
\bibitem{117} See id. at 7, 9.
\bibitem{118} Cudahy, supra note 87, at 423.
\bibitem{119} Id.
\bibitem{120} See \textit{CHANNELL ET. AL., supra} note 50, at 74–75; Cudahy, \textit{supra} note 87, at 423.
\bibitem{121} MCDERMOTT, \textit{EDISON ELEC. INST., supra} note 17, at 21; Cudahy, \textit{supra} note 87, at 425.
\bibitem{122} Cudahy, \textit{supra} note 87, at 425.
\bibitem{123} MCDERMOTT, \textit{EDISON ELEC. INST., supra} note 17, at 21.
\end{thebibliography}
through government regulation and that now competes with the IOU market share.

The electricity market is indeed changing. As the Edison Electric Institute—the trade association for IOUs—puts the issue: “While every market-driven business is subject to competitive forces, public policy programs that provide for subsidized growth of competing technologies and/or participant economic incentives do not provide a level playing field upon which generators can compete fairly against new entrants.” It is important to distinguish between technologically driven changes that result in increased competition and competition that results from regulatory requirements on incumbent utilities and on regulatory incentives that promote new entrants. It is equally, if not more, important to realize that the dividing line between markets and their regulation is fuzzy at best.

Edison, thus, is partially correct to distinguish between market-driven technological change and public policies that promote competition. This distinction, though, fails to recognize that the electric industry has been a regulated industry and has enjoyed the fruits of that regulation for over a century. In other words, the divide between market changes and government regulation is not a particularly neat one. The fact that the electric industry has been the beneficiary of regulation and is now in a posture of contesting competition that has come about through regulation reveals that a solution or response to the industry’s concerns involves political as well as economic considerations.

IV. Takings and Electric Utilities

As noted in Part II, the issue of costs from failed nuclear power investments or from failed restructuring investments can also arise as regulators adopt rules that increase competition for IOUs. Each of these issues raises the same constitutional question. Is an IOU entitled to recover such costs because of regulations that devalue its property? In other words, has a regulation effectuated a taking of utility property?

Any legal transition generates economic winners and losers. In the energy sector, subsidies and financial supports to wind and solar providers, for example, reduce their cost of doing business and may open up clean energy markets. Similarly, the under payment of royalties or tax incentives and subsidies for fossil fuel companies reduce their cost of doing

business, thus giving them a competitive advantage over clean energy providers.\textsuperscript{127} In short, any regulation has economic consequences including reducing the value of an owner’s property. It is generally true, though, that regulations occur on a regular basis without giving rise to a takings claim. “Government hardly could go on if to some extent values incident to property could not be diminished without paying for every such change in the general law.”\textsuperscript{128}

However, as Justice Oliver Wendell Holmes has also said, “[t]he general rule at least is, that while property may be regulated to a certain extent, if regulation goes too far it will be recognized as a [constitutional] taking.”\textsuperscript{129} Holmes’ Delphic pronouncement would seem to settle the matter that a regulation can constitute a taking necessitating just compensation.\textsuperscript{130} However, the definition of a taking, let alone a regulatory or a deregulatory taking,\textsuperscript{131} remains unsettled and takings jurisprudence has been seen by the Supreme Court of the United States as essentially ad hoc.\textsuperscript{132} More problematically, takings jurisprudence, as a whole, has been said to be in vast disarray.\textsuperscript{133}

Consequently, takings law is best understood on a case-by-case basis with three or four general principles.\textsuperscript{134} First, a court is most likely to find a taking when a property owner has suffered a permanent physical invasion of

\begin{itemize}
  \item \textsuperscript{127} See Cong. Budget Office, Federal Financial Support for the Development and Production of Fuels and Energy Technologies 2 (2012), \textit{available at} http://www.cbo.gov/sites/default/files/efiles/attachments/03-06-FuelsandEnergy_Brief.pdf (while most energy resources receive some financial incentives “tax preferences for fossil fuels continued to make up the bulk of all energy-related tax incentives through 2007, typically accounting for more than two-thirds of the total cost”); U.S. Gov’t Accountability Office, GAO-14-140, Coal Leasing: BLM Could Enhance Appraisal Process, More Explicitly Consider Coal Exports, and Provide More Public Information 24 (2013), \textit{available at} http://www.gao.gov/assets/660/659801.pdf (undervaluing royalty payments on public lands); David Kocieniewski, \textit{As Oil Industry Fights a Tax, It Reaps Subsidies}, N.Y. Times, July 4, 2010, at A1 (“[A]n examination of the American tax code indicates that oil production is among the most heavily subsidized businesses, with tax breaks available at virtually every stage of the exploration and extraction process.”).
  \item \textsuperscript{128} Pa. Coal Co. v. Mahon, 260 U.S. 393, 413 (1922).
  \item \textsuperscript{129} \textit{Id.} at 415.
  \item \textsuperscript{130} \textit{Id.}
  \item \textsuperscript{131} See, e.g., Sidak & Spulber, \textit{supra} note 65, at 222–26, 427. Regulatory takings are discussed at 222–26. Deregulatory takings are discussed at chapter 13.
  \item \textsuperscript{134} See, e.g., Loretto v. Teleprompter Manhattan CATV Corp., 458 U.S. 419, 426 (1982).
\end{itemize}
his or her property. Second, a property owner who can demonstrate that a regulation deprives him or her of all economically beneficial use of his or her property may successfully assert a takings claim. Third, a regulatory taking may be found when a regulation has frustrated the property owner’s investment-backed expectations. These three reasons are the standard tests developed by the Court for identifying takings. There appears, though, that a fourth requirement is most often applied. Specifically, all of the cases just cited deal with real property rather than with the value of a corporate enterprise. Thus, “major regulatory initiatives rarely require a penny in compensation for millions of dollars in economic losses.”

Nevertheless, the takings argument is far from fanciful for utilities. Indeed, the constitutional requirement that regulators cannot take property without just compensation is at the heart of the regulatory compact. As noted by the Supreme Court:

A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments [and] other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its

135. Id. at 441. The laying of cable TV lines across an owner’s property is a physical occupation of real property and is, therefore, a taking. Id. at 421–26. “We affirm the traditional rule that a permanent physical occupation of property is a taking.” Id. at 441.

136. Lucas v. S.C. Coastal Council, 505 U.S. 1003, 1019 (1992). We think, in short, that there are good reasons for our frequently expressed belief that when the owner of real property has been called upon to sacrifice all economically beneficial uses in the name of the common good, that is, to leave his property economically idle, he has suffered a taking.

137. Penn Cent. Transp. Co., 438 U.S. at 124 (“The economic impact of the regulation on the claimant and, particularly, the extent to which the regulation has interfered with distinct investment-backed expectations are, of course, relevant considerations.”).


141. Epstein, supra note 133, at 101.
credit and enable it to raise the money necessary for the proper discharge of its public duties.\textsuperscript{142}

Over ninety years ago, then, the Supreme Court established the principle that a public utility is entitled to earn a return on its prudently incurred capital investments at a level sufficient for the utility to be financially sound and to attract investors.\textsuperscript{143} The problem for a regulated entity, such as an electric utility, is that regulations can affect the value of those investments.\textsuperscript{144} Indeed, electric utilities have raised the takings issue in a number of settings: Environmental regulations,\textsuperscript{145} restructuring orders,\textsuperscript{146} low rates of return,\textsuperscript{147} and the like,\textsuperscript{148} have all generated takings claims. None, however, have resulted in direct monetary damages paid in compensation to a utility although financial relief from burdensome regulations has been made available as discussed below.\textsuperscript{149}

Substantive takings jurisprudence appears to provide electric utilities grounds for claiming that when a regulation goes too far it then becomes a taking.\textsuperscript{150} Yet, electric utilities’ regulatory takings claims have not been

\begin{itemize}
\item \textsuperscript{143} \textit{Id.}
\item \textsuperscript{144} \textit{See id. at 689–90, 693.}
\item \textsuperscript{145} \textit{See, e.g., Integration of Greenhouse Gas Emissions Standards into Procurement Policies, Rulemaking Proceeding No. 06-04-009, 2007 WL 2579525 (Cal. Pub. Utils. Comm’n Sept. 6, 2007). The regulatory takings claim that GHG regulations may devalue property or cause a sale of the property is denied. \textit{Id.} Indeed, the PUC noted that claimant failed to cite “any cases holding that there is a regulatory taking if a pollution control requirement causes an owner of a plant to shut it down entirely.” \textit{Id.}
\item \textsuperscript{146} \textit{See, e.g., Provision of Elec. Servs., 175 P.U.R. 4th 1, Docket No. U-0000-94-165, 1966 WL 787623 (Ariz. Corp. Comm’n Dec. 26, 1996) (utility’s regulatory takings claim that Arizona’s restructuring orders may result in uncompensated stranded costs denied, because the rules provided a mechanism for at least some stranded cost recovery).}
\item \textsuperscript{147} \textit{See PacifiCorp, Case No. PAC-E-10-07, 2011 WL 1525191 (Idaho Pub. Utils. Comm’n Apr. 18, 2011); Niagara Mohawk Power Corp., 286 P.U.R. 4th 401, Case No. 10-E-0050, 2011 WL 286478 (N.Y. Pub. Serv. Comm’n Jan. 24, 2011) (9.3% return on equity not a taking even though it was below the rate set by other PUCs for similarly structured utilities). PUC’s decision that the 27% of a transmission line that is not used and useful can be excluded from the rate base is not a taking. PacifiCorp, \textit{supra} note 147. The PUC also noted that when the line is fully integrated into the system, it will put it into the rate base. \textit{Id.}
\item \textsuperscript{148} \textit{See, e.g., In re Citizens Utils. Co., 769 A.2d 19, 23 (Vt. 2000) (takings claim denied when the Public Services Board reduced the rate of return from 10.5% to 5.25% because of the poor management of the utility).}
\item \textsuperscript{149} \textit{See id. at 22–23, 32–33; Provision of Elec. Servs., \textit{supra} note 146; Integration of Greenhouse Gas Emissions Standards into Procurement Policies, \textit{supra} note 145; PacifiCorp, \textit{supra} note 147; Niagara Mohawk Power Corp., \textit{supra} note 147.}
\item \textsuperscript{150} \textit{See Pa. Coal Co. v. Mahon, 260 U.S. 393, 415 (1922).}
\end{itemize}
successful. In part, the lack of success can be attributed to a narrow application of takings doctrine as revealed by the four substantive law principles listed above.

In addition to a narrow reading of substantive takings law, utilities must also confront procedural challenges to the successful assertion of a takings claim. According to the letter of the law, if property is taken for public use then compensation is required. However, compensation in the form of damages for regulatory takings is rare if not impossible. First, if a utility asserts that a regulatory taking has occurred as a result of an onerous regulation, then the most likely remedy will be an invalidation of the regulation, not damages. Second, courts are reluctant to award damages if a utility asserts a facial claim of an unconstitutional regulation because, most often, courts require a showing that actual damage has occurred.

There is another subtlety to takings jurisprudence that electric utilities must face. Regulation, for example, may very well reduce, even destroy, a valuable portion of electric utility’s property. However, before a takings claim can be successful, the property as a whole must be evaluated and not just portion of it. A utility, for example, that argues that a portion of its property was denied a return on investment, cannot successfully claim that a portion of its property has been taken if, looking at the utility’s total financial situation, the utility’s property still has value. Another way of characterizing this issue of partial or full evaluation of a utility’s property is to ask the question: How much damage has the utility suffered?

Utilities, for example, that have claimed that a portion of their property has been excluded from rate base treatment and, therefore, denied a return on investment, have not succeeded with their takings claim when the
remaining property is treated as a capital investment for which a return is due. States that have passed legislation requiring that only property that is used and useful can earn a return on investment have seen that legislation upheld as constitutional. Finally, to the extent that the regulated entity can take steps to mitigate any damages that might occur as a result of a regulation, they must do so, and failure to do so will negate the takings claim.

As the electricity market undergoes its current transformation and as IOUs confront their current challenges, the issue of costs imposed on IOUs due to government regulation is ever present as revealed by the test case next discussed.

V. A DG TEST CASE

IOUs have become concerned about the growth of solar power, other renewables, and energy efficiency because of the consequent loss of load attributed to those activities. The use of solar power is expanding for three predominant reasons. First, the cost of solar panels is declining noticeably. Second, third party financing options make the installation of solar panels attractive to individual homeowners. And, third, existing state

\[\text{161. } \text{See, e.g., id.} \]
\[\text{162. } \text{See, e.g., id.} \]
\[\text{163. } \text{See infra Part V.} \]
\[\text{164. } \text{BLOOMBERG NEW ENERGY FIN. \& BUS. COUNCIL FOR SUSTAINABLE ENERGY, supra note 13, at 3, 31.} \]
\[\text{165. } \text{See id.} \]
\[\text{167. } \text{BLOOMBERG NEW ENERGY FIN. \& BUS. COUNCIL FOR SUSTAINABLE ENERGY, supra note 13, at 3.} \]
\[\text{168. } \text{ROCKY MOUNTAIN INST., NET ENERGY METERING, supra note 114. Third-party financing essentially leases solar installations to individual homeowners or businesses under long-term contracts but retains ownership. Id. at 23–24. The third parties also operate the solar system. See, e.g., Solar Power for Your Home, supra note 166. These third-party owners can do so because in exchange for selling solar installation, they receive tax credits and other financial incentives as the nominal owner. See, e.g., ROCKY MOUNTAIN INST., NET ENERGY METERING, supra note 114, at 23–24. The use of third-party financing and third-party ownership has not gone unchallenged. See, e.g., Ruling on Petition for Judicial Review at 3–4, SZ Enter., LLC v. Iowa Util. Bd., No. CVCV009166 (Iowa 5th Dist. Mar. 29, 2013). From the perspective of the regulated utility, to the extent that third parties are financing a number of residential and commercial installations, those actors are invading the service territories of the incumbent utilities. See, e.g., id. at 18. The utility’s argument then, is that these third parties should be regulated as public utilities. See, e.g., id. at 5. This matter is currently under consideration by the Iowa Supreme Court. Appellate Court Case Details for SZ Enterprises v. Iowa Utilities Board, Docket No. 13-0642, IOWA CT. ONLINE SEARCH, https://} \]
and federal regulations provide financial incentives for solar installations.\textsuperscript{169} To an incumbent IOU, reduced electricity sales are a financial threat.

On December 3, 2013, the Arizona Corporation Commission issued a ruling that brings together the several issues in this article.\textsuperscript{170} The Arizona Public Service Company (“APS”), the local IOU, sought relief from regulatory obligations and petitioned the Commission to reduce the burdens imposed upon it by net metering regulations that required the utility to pay rooftop solar users for their excess electricity.\textsuperscript{171}

Arizona’s net metering law “allows electric utility customers to be compensated for generating their own electric[ity] . . . from [identified] renewable [behind-the-meter] resources,” such as solar power.\textsuperscript{172} “If [a] customer’s energy production exceeds the energy supplied by the electric utility during a billing period, [then] the customer’s bill for subsequent periods is credited for the excess generation.”\textsuperscript{173} The credit is based upon the IOU’s avoided cost or the customer’s retail rate.\textsuperscript{174} The avoided cost rate—sometimes referred to as a bundled rate—means the marginal cost to the utility of producing its next unit of electricity.\textsuperscript{175}

To better understand the impact of avoided cost as defined by the Supreme Court of the United States and in the Arizona Code, it is necessary

\textsuperscript{169} BLOOMBERG NEW ENERGY FIN. & BUS. COUNCIL FOR SUSTAINABLE ENERGY, supra note 13, at 31.


\textsuperscript{171} Id.

\textsuperscript{172} Id.

\textsuperscript{173} Id.

\textsuperscript{174} Id. The law does provide a safety valve and limits the size of the customers distributed generation system to a maximum of 125% of that customer’s total load. Ariz. Pub. Serv. Co., supra note 170. This limitation is not unproblematic. From a utility standpoint, this 125% maximum helps limit the amount of revenue loss. Regulators, mindful of the need to protect the utility’s revenue requirement together with their service obligation, have adopted such limitations. See generally SOLAR ELEC. POWER ASS’N, RATEMAKING, SOLAR VALUE AND SOLAR NET ENERGY METERING—A PRIMER (2013), available at http://www.solarelectricpower.org/media/51299/sepa-nem-report-0713-print.pdf. The problem, however, is that, to the extent that solar rooftop in particular or DG in general is either a desirable or inevitable direction for the future of the electric industry, the transition is being delayed. Id.

\textsuperscript{175} SOLAR ELEC. POWER ASS’N, supra note 174, at 10. Arizona more specifically defines avoided costs as “the incremental costs to an [e]lectric [u]tility for electric energy or capacity or both which, but for the purchase from the Net Metering Facility, such utility would generate itself or purchase from another source.” ARIZ. ADMIN. CODE § 14-2-2302 (2013).
to understand how a utility bill is designed. By way of simplification, a utility serves basically three types, or classes, of customers—residential, commercial, and industrial. 176 Each class, in turn, has different energy needs and is charged accordingly. 177 By way of example, residential customers consume less electricity than industrial customers; however, residential customers, as a class, consume more customer service for their homes in contrast with a large manufacturing company that requires less customer service for its plant relative to the amount of electricity consumed. 178

In the attempt to even out charges to each class of customers, a utility bill is generally comprised of three components—a demand charge, an energy or volumetric charge, and a customer service charge. 179 The service charge represents the costs, such as billing, metering and some investments, to provide electricity service to each consumer. 180 These charges remain flat relative to the amount of electricity that a user consumes, but the total cost varies with the number of customers. 181 The energy charge represents the amount of electricity consumed by each user. 182 And, finally, the demand charge represents the utility’s capital investment in plant and equipment that is allocated to each consumer based on the consumer’s maximum rate of usage. 183 A rough way of differentiating these costs is to say that the energy charge and the service charge represent a utility’s variable costs while the demand charge represents the utility’s fixed costs. Usually, residential consumers do not pay a separate demand charge. 184 Instead, the fixed costs are embedded in the volumetric portion of the bill. 185 This embeddedness, or bundling, gives rise to the problem litigated in this test case. 186

In its regulatory filing, APS argues that as participation in DG grows, it becomes increasingly concerned about the cross-subsidization between customer classes. 187 DG customers, APS argues, are partially subsidized by non-DG customers because, it asserts, DG customers do not

176. SOLAR ELEC. POWER ASS’N, supra note 174, at 11.
177. Id.
178. See id. at 13.
179. Id. at 15–17. PUCs often add other charges such as a surcharge for a specific investment. Nonetheless, these three charges illustrate the distinction between fixed and variable costs. See, e.g., id.
180. SOLAR ELEC. POWER ASS’N, supra note 174, at 3, 15.
181. Id. at 15.
182. Id.
183. Id. at 17.
184. Id. at 15.
185. SOLAR ELEC. POWER ASS’N, supra note 174, at 15.
186. See ROCKY MOUNTAIN INST., NET ENERGY METERING, supra note 114, at 28–29.
bear their fair share of fixed costs. Instead, they offload those costs to non-DG customers. Parenthetically, in addition to an unfair allocation of fixed costs, DG shows some income bias. Quite simply, higher income consumers have more options available to them, including installing rooftop solar, than lower income consumers. Consequently, rate designs that may apportion costs across all residential consumers will be regressive and unfairly burden low-income users.

The issue of cross-subsidization is problematic. The real concerns of APS, however, are that: (1) Arizona’s net metering obligations became increasingly costly; (2) it was losing market share even though in its filing it asserted that revenue loss was not part of its case; (3) that non-DG users are paying a disproportionate share of the fixed costs; and, (4) most disconcerting for the utility, the cost increase to non-DG customers will effectively drive more people to DG thus resulting in greater revenue losses. This phenomenon of losing customers to DG because of increased costs is sometimes referred to as a death spiral, which is a situation that prompts/forces more ratepayers to install solar on their rooftop to avoid rising utility rates as a result of the spreading out of those fixed costs to a lower base. In the end, the utility could be left with fewer revenues to support already installed (and future) infrastructure investments with long useful lives (i.e. transformers, low and high-voltage transmission lines, distribution assets).

To gather information and formulate a proposal to the Commission, APS held a series of conferences. APS then proposed solutions that fell into two broad classes. To simplify, the first option for new DG

188. Id.
189. Id.
190. See id.
191. See id. (Burns, Comm’r, dissenting).
195. Citi, Rising Sun: Implications for US Utilities, supra note 4, at 11–12; see also KIND, supra note 4, at 12 (“When investors realize that a business model has been stung by systemic disruptive forces, they likely will retreat.”).
197. Id.
customers.\(^{198}\) Existing customers would be grandfathered into the rate schemes in existence, for twenty years. \(^{Id.}\) After that time, however, APS posed that the new rates would be imposed. \(^{Id.}\) The problem with this proposal, however, is that the rates should attach to the property rather than to the customer. \(^{Id.}\)

198. Existing customers would be grandfathered into the rate schemes in existence, for twenty years. Id. After that time, however, APS posed that the new rates would be imposed. Id. The problem with this proposal, however, is that the rates should attach to the property rather than to the customer. Id.

200. Id.
201. Id.
202. Id.
203. Id.
205. Id.
206. Id.; see also KIND, supra note 4, at 17.
208. Id. The LFCR is a surcharge allowed by regulators that is intended to offset the revenue that results from customers who reduce their bills through conservation and other renewable energy programs. Id.
209. Id.
210. Id.
fuel costs and avoid making certain capital investments in plant transmission or distribution. Non-quantifiable benefits include “increased grid security and air quality improvements,” improved system reliability, load balancing, improved forecasting and planning, environmental improvement, and meeting regulatory requirements such as renewable portfolio mandates. To be sure, accurately valuing the benefits of DG is difficult and—according to one study—most analyses had failed to comprehensively evaluate the benefits and costs of DG. Still, such benefits may well be accounted for through a smart rate design.

Staff concluded that both options offered by APS should be rejected and that the Commission should open a separate docket to more fully study the issue, taking into account the benefits, as well as the costs, of DG. The Commission, then, should develop a new rate design to account for DG penetration.

The Commission concluded that the proliferation of DG installations did result in a cost shift from DG customers to non-DG residential customers; therefore, rate design changes were warranted. As an interim measure, the Commission imposed a seventy-cent per kilowatt monthly

211. Ariz. Pub. Serv. Co., supra note 170. Because distributed generation is closer to its end users—sometimes located on exactly the same property—the need for extensive transmission and distribution lines is mitigated. Id.

212. Id.

213. LENA HANSEN & VIRGINIA LACY, ROCKY MOUNTAIN INST., A REVIEW OF SOLAR PV BENEFIT & COST STUDIES 37 (2d ed. 2013), available at http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue. System reliability can be improved by distributed generation as it reduces congestion, reduces large-scale outages, and can provide backup power during outages. Id.

214. Id. at 15; see also ROCKY MOUNTAIN INST., NET ENERGY METERING, supra note 114, at 32–33.


216. STERLING ET AL., NAT’L RENEWABLE ENERGY LAB., supra note 7, at ix, 27–28; see also SOLAR ELEC. POWER ASS’N, supra note 174, at 25, 28.

217. HANSEN & LACY, ROCKY MOUNTAIN INST., supra note 213, at 4.


220. Id.

221. See SOLAR ELEC. POWER ASS’N, supra note 174, at 11, 18.

222. See id. at 20.
charge for all residential DG customers until the Commission more fully addressed the issues raised in the underlying proceeding. 223 The goal of the interim measure, then, is to not raise the amount of fixed costs APS collects from residential non-DG customers due to reduced payments by DG customers. 224

The advantage of the seventy-cent fixed cost charge—also sometimes referred to as an access fee, solar rider, or standby charge—is its simplicity. 225 New DG customers will know what the charge is and why it is imposed. 226 Further, such charges are intended “to recover a portion of the utility fixed costs that have typically been embedded in volumetric [electricity] rates.” 227 In principle, this approach allows those fixed costs to be fairly allocated among all customers, and specifically, DG customers. 228

The test case raises exactly the correct issues and suggests a direction for a correct solution as long as all benefits and costs are taken into account. 229 While the Arizona case is an important one to watch, a series of studies and other actions are occurring throughout the industry and in many states including California, Colorado, Michigan, Ohio, New York, Texas,


225. See id. at 3.

226. See id.


228. SOLAR ELEC. POWER ASS’N, supra note 174, at 3.

229. See CITI, RISING SUN: IMPLICATIONS FOR US UTILITIES, supra note 4, at 11–12.

There is a middle ground solution on the compensation issue for DG, in our view. Either: (1) a set fixed charge for T&D or (2) a credit that only reflects the utilities replacement power cost of generation. Eventually, for DG to work at a larger scale with the support of the utilities, we expect changes to the compensation structure for the off grid solar providers in the near future. These changes more specifically could include: (1) a bill credit that is lowered from the current avoidance of full retail rates to one that resembles the utilities replace cost of power (i.e. gas peaker) and/or (2) a demand charge (fixed charge for T&D) to be tacked on to the off grid solar homeowners electric bills. These items provide a middle ground solution, in our viewpoint, with net metering battles clearly evident in several states like CA and AZ.

Id. at 12. See also KIND, supra note 4, at 12 (“When investors realize that a business model has been stung by systemic disruptive forces, they likely will retreat.”).
Vermont, and others. In California, for example, legislation was passed directing the California PUC to study the costs and benefits of net metering and calculate the ratepayer impacts and cost of service to solar customers.

Not to put too fine a point on the matter, IOUs have been experiencing increased competition from technological innovations as well as from innovative regulatory strategies. On the positive side, the electricity market is becoming more competitive; consumers are enjoying a wider array of choices; and, energy policy is moving towards a clean energy economy. Incumbents, however, must deal with the negative side of a changing electric industry. More precisely, the challenge is to address the matter of past investments made by incumbents. Now that consumers are leaving the grid in whole or in part, which, if any, of the capital investments should be recouped by IOUs?

Fortunately, DG penetration into electricity markets at this time in history is relatively low and warnings about a death spiral for IOUs is premature and alarmist. The amount of penetration by DG, at this time, is minimal and manageable. A smart electric utility, like the smart telecommunications firm, can get ahead of the technology and it can certainly manage it to their advantage even if that necessitates changing the


235. See id. at 20.

236. Id. at 16.

237. See id.

238. See id.

An alarmist interpretation suggests that revolutionary technology could throw the sector into a death spiral where customer migration off the grid results in higher rates for those customers remaining—first creating a cross subsidy from wealthier to poor[] customers, and eventually fueling a self-perpetuating cycle of further erosion as rising costs drive more customers to seek off-grid alternatives.


firm’s business model. But then, that is what smart businesses do. DG penetration, however, is expanding and therefore caution is warranted.\textsuperscript{240} Regulators must provide a mechanism that compensates IOUs for their investments and they must design a new regulatory regime for a clean energy future. Additionally, regulators must insure that customers are treated fairly, that cross-subsidization is minimized or justified on sound policy bases, and that the proper balance between shareholder and ratepayers is realized.\textsuperscript{241} In short, rates must respond to the legitimate concerns of the utility and to the value provided by DG customers.\textsuperscript{242} Those responses will come from a renegotiated regulatory compact, new rate designs, and new business models for IOUs.\textsuperscript{243} Each of those issues is addressed in the following Parts.

VI. THE NEW REGULATORY COMPACT

The core of the regulatory compact is that the government sets the utility’s rates—and consequently, its profits—in exchange for protecting the IOU’s service territory.\textsuperscript{244} As long as the IOU operates prudently, it is virtually guaranteed a return on its capital investment. When the compact was made, the exclusive business of the IOU was to sell as much electricity as it could.\textsuperscript{245} As we have seen, the electric market is changing in significant ways, such that a new regulatory compact must be considered.\textsuperscript{246}

We can start with certain concrete assumptions. First, large-scale central power stations will continue to be important generators in the electricity market, although on a diminishing scale. Second, the T&D segments of the industry will continue to be regulated as long as they exhibit natural monopoly characteristics. Third, IOUs can no longer be devoted

\begin{footnotes}
\item[240.] See, e.g., id. at 23.
\item[241.] See Sciacca, supra note 192, at 33–34. The rate design issues that plague rooftop solar and other DG strategies also complicate a utility’s smart grid investments. Id.
\item[242.] More specifically, \\
[do] individual end users save enough money on their bills with AMI, for instance, \\
to offset the increase in rates necessary to pay for that infrastructure? If so, how \\
long does it take to achieve payback, or ROI? If the benefits [are not] direct and \\
quantifiable, then what reasoning in metrics justify such a project? \\
Id. at 33; see Press Release, Elizabeth Heyd & Patrick Remick, Natural Res. Def. Council, 
EEI/NRDG Agreement Supports Policies to Benefit Electricity Consumers (Feb. 12, 2014), 
http://www.nrdc.org/media/2014/140212.asp.
\item[243.] Id. at 36.
\item[244.] Tomain, The iUtility, supra note 94, at 223, 231.
\item[245.] See id.
\item[246.] See TOMAIN, ENDING DIRTY ENERGY POLICY, supra note 14, at 5; Tomain, 
The iUtility, supra note 94, at 234; Joseph P. Tomain, “Steel in the Ground”: Greening the 
Grid with the iUtility, 39 ENVTL. L. 931, 933 (2009) [hereinafter Tomain, “Steel in the 
Ground”].
\end{footnotes}
exclusively to electricity sales. Instead, IOUs must be seen as actors in a broader energy business that provides a wider array of energy services and products as discussed in Part III. \textsuperscript{247} Finally, because IOUs will continue to be regulated, the regulatory compact will continue. However, given these assumptions a new set of regulatory principles will be necessary and we can identify five.

A. Stranded Costs

First, utilities should not be put in a position of incurring excess costs that, due to regulatory or policy changes, may become stranded and may then give rise to a regulatory takings claim. This principle is actually a two-edged sword. On the one hand, investors should not be deprived of a return on their investments due to regulatory or policy changes.\textsuperscript{248} On the other hand, regulators must be careful when imposing requirements on IOUs.\textsuperscript{249} As discussed in Part I, regulators and legislators in the past have provided relief to utilities from previous financial challenges.\textsuperscript{250} Thus, to the extent that IOUs invest in reliance on regulatory requirements, then some protection must be provided.\textsuperscript{251} Nevertheless, as contemporary energy policy changes, the problem of stranded costs should be anticipated and, if possible, avoided.\textsuperscript{252}

The stranded cost problem in the context of an energy transition is distinct from the problem of nuclear power cancellations and the like, and from government ordered divestment. First, in the nuclear power and divestment situations, the stranded costs were more or less identifiable and occurred at a very time-specific point.\textsuperscript{253} A clean energy transition is distinguishable in that it will not occur at a point in time, but will most likely occur over decades. This fact alone should allow utilities to plan for changes in the industry and changes in their own business models. Next, as a utility’s

\textsuperscript{247} See supra Part III.

\textsuperscript{248} SIDAK & SPULBER, supra note 65, at 29; see David B. Raskin, The Regulatory Challenge of Distributed Generation, 4 HARV. BUS. L. REV. ONLINE 38, 47 (2013), http://www.hblr.org/?p=3673. “[The] inability of utility shareholders to secure the return of, and a competitive rate of return on, their investment gives rise to the condition known as stranded investment or stranded costs.” SIDAK & SPULBER, supra note 65, at 29.

\textsuperscript{249} See id.; Raskin, supra note 248, at 47.

\textsuperscript{250} Raskin, supra note 248, at 47; see supra Part I.

\textsuperscript{251} See Raskin, supra note 248, at 47. Raskin also writes: “The differential was known as ‘stranded costs.’” Id.

\textsuperscript{252} KIND, supra note 4, at 17–18. One suggestion for addressing the stranded cost problem is to impose a stranded cost charge on all DER customers to recoup that portion of the investment that might otherwise become stranded due to departures from the grid. Id. at 18.

\textsuperscript{253} See id. at 8.
customer base declines, the downward spiral in lost sales will mean that there will be a smaller group of ratepayers to pick up increasing costs. That is a scenario that is obviously not sustainable.

Nevertheless, although the law regarding regulatory or deregulatory takings remains opaque, the risks are real. Investors will be reluctant to invest without reasonable assurances of a return on their investment that will not be negated by prudence hearings, regulatory changes, or legislation that diminishes the value of their property to the point at which their investment-backed expectations go uncompensated. Indeed, such financial risk is reflected in the downward movement of credit ratings for the electric industry. Thus, the issue of distributed generation, particularly coupled with net metering, can pose a real risk to capital unless the utility recalibrates the way it does business and regulators rethink their rules.

B. Legacy Financing

Second, regulators should avoid legacy financing. Quite simply, traditionally structured utilities should not continue to be rewarded as they have in the past. Any argument that utilities should continue to earn revenue because demand is down must be scrutinized quite closely. Decreased demand alone is no cause for continuing to allow a regulated firm to earn a return on investment. The problem, of course, is complicated because the current challenge to IOUs is the consequence of both market and technological changes, as well as regulatory requirements. Nevertheless, no utility has any legal claim to continue to maintain its revenue requirement just because it loses sales. The idea that the revenue requirement must be

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254. See Kosnaski & Shankar, supra note 234, at 16; Raskin, supra note 248, at 48.

An alarmist interpretation suggests that revolutionary technology could throw the sector into a death spiral where customer migration off the grid results in higher rates for those customers remaining—first creating a cross subsidy from wealthier to poor[ ] customers, and eventually fueling a self-perpetuating cycle of further erosion as rising costs drive more customers to seek off-grid alternatives. Kosnaski & Shankar, supra note 234, at 16.


256. See KIND, supra note 4, at 10 fig.2.

257. See Robert E. Curry, Jr., The Law of Unintended Consequences: The Transition to Distributed Generation Calls for a New Regulatory Model, PUB. UTIL. FORT., Mar. 2013, at 44, 47. “As [distributed generation] grows, such under-recovery has the potential to materially weaken the utility’s financial integrity and its ability to attract investor capital, which in turn can lead to higher rates.” Id.


259. See id.
maintained as embedded in a cost-of-service mentality to cover a utility’s costs, regardless of the amount of service, is no longer tenable.

Cost-of-service ratemaking may have had its place; nevertheless, it should not be used to allow utilities to continue to build dirty coal-fired plants, nor should it be used to reward utilities for embarking on financially risky nuclear projects precisely because “investment in conventional generation [is] hard to justify” in the new market.260 Indeed, financial analyses indicate that solar, wind, and natural gas generated electricity are showing increasingly positive cost signals, particularly against nuclear power.261 As a result, continued investments in coal and nuclear power will be viewed skeptically by the market while investments in new fuels and technologies are becoming increasingly attractive.262 Those investments must also be viewed skeptically by regulators. Thus, instead of maintaining the status quo, regulators must manage the changing role of IOUs and encourage alterations in their business models.263

C. Innovation & Competition

Third, the new regulatory compact should encourage—rather than inhibit—competition and the development of innovative energy technologies including sales reducing technologies such as DG. Indeed, the alternative energy market is attracting significant investments and will only expand.264 DG is becoming an increasingly important actor in electricity markets. In the test case, APS argued that it needed to revise net metering rates in order to avoid unfair cross-subsidization.265 Behind that argument,

260. CHANNELL ET AL., supra note 50, at 73 (a report for Citi GPS).
262. See, e.g., id.
however, APS was concerned about loss of sales volume.\textsuperscript{266} To the extent that net metering rates do generate an unfair cross-subsidization, then they should be changed. However, net metering benefits must also be accounted for,\textsuperscript{267} and to the extent that net metering rates may slow DG penetration and therefore, act as a drag on innovation and competition, then that argument should be rejected. The smart utility will become actively involved with DG as well as with the development of utility-scale solar, wind, and other renewable projects.\textsuperscript{268}

D. \textit{Universal Service & Reliability}

Next, regulators must be attentive to maintaining universal electric service. With the expansion of distributed generation and energy-efficient improvements, some customers will be placed at a disadvantage such that distributed generation and energy-efficient customers will be using less electricity which puts pressure on utilities to raise rates to the customers that remain in that territory. Similarly, regulators must assure energy/electricity reliability. Electricity must remain available at the flip of a switch for most consumers. To be sure, those consumers that have access to other sources of electricity, such as distributed generation and the like, may be able to negotiate for interruptible rates. Most consumers, however, will need firm service contracts.

The provision of universal reliable service presents challenges all of its own.\textsuperscript{269} However, an increase in electricity providers does have the potential for bringing significant benefits to a utility’s T&D segments.\textsuperscript{270} Reduced load can, at times, reduce congestion and improve balancing, and a larger number of providers should lower cyber security risks. To be sure, the issue of reliability will be an argument to be made against DG and that

\begin{footnotesize}
\begin{itemize}
\item \textsuperscript{266} See Ariz. Pub. Serv. Co., \textit{supra} note 265; NAVIGANT CONSULTING, INC., \textit{supra} note 265, at 7.
\item \textsuperscript{268} See, e.g., Brad Copithorne, 4 Utilities Thinking Beyond ‘Wires and Poles,’ \textsc{GREENBIZ.COM} (Oct. 9, 2013), http://www.greenbiz.com/blog/2013/10/09/4-utilities-think-beyond-wirespoles.
\item \textsuperscript{269} See Amory Lovins, Amory Lovins: Don’t Cry for the Electric Utilities, \textsc{GREENBIZ.COM} (Feb. 12, 2014), http://www.greenbiz.com/blog/2014/02/12/dont-lament-renewables-disruption-electric-utilities.
\item \textsuperscript{270} See id.
\end{itemize}
\end{footnotesize}
argument should be recognized for what it is—a political argument not necessarily a technical nor economic one.271

E. Mitigation

The Arizona test case, and others like it, as well as the reports of the dire threats to electric utilities, clearly demonstrate that IOUs are well aware of changing electricity market conditions as well as aware of a change in the policy landscape towards clean energy. As a consequence, utilities cannot rely on past practices for future revenue. Instead, since IOUs are well aware of the political economy of a changing energy market, they cannot continue to do business as usual; to the extent that they can avoid incurring expenditures based upon past assumptions, they must do so in an effort to mitigate damages as is required by any contract.

During the period of electric industry restructuring, for example, New Hampshire passed legislation intended to introduce competition into retail electric markets.272 As part of those efforts, independent system operators controlled the transmission grid by accepting bilateral contracts and operating a power exchange with spot markets.273 The New Hampshire restructuring plan would treat generation and retail marketing as functionally separate from T&D services.274 The legislation expressed a preference for the divestiture of a utility’s generation and transportation assets.275 Utilities operating under the previous statutory scheme were concerned about stranded assets.276 More specifically, regulators recognized the fact that if retail customers could purchase lower-priced electricity from sources other than the IOU, then a portion of the IOU’s investments may be unrecoverable.277

The New Hampshire PUC recognized this possibility and made provisions that would allow the utility to recover its stranded costs if those costs were found to have resulted from a government regulation.278 The utility, however, would not be able to recover stranded costs if they were imprudently incurred.279 Concomitantly, the legislation required utilities to

271. See id.
274. Id.
275. Id.
276. Id.
277. Id.
279. Id.
mitigate their stranded costs. Moreover, the commission took a fairly aggressive approach regarding mitigation efforts that the utility should undertake. Those steps included, among other efforts, “the sale of . . . excess generating capacity” and the renegotiation of service contracts.

By adopting these principles, then, the regulatory compact will continue to balance utility/shareholder interests with customer/ratepayer interests while maintaining reasonable and fair rates. At the same time, the new regulatory compact will encourage utilities to adopt new business models; promote technological innovation and competition; expand market opportunities; and, increase consumer choice. The regulatory compact, however, is not self-executing. Instead, PUCs must adopt a forward-looking approach to ratemaking.

VII. RATEMAKING

Ratemaking is the mechanism that drives the regulatory compact. Historically, cost-of-service ratemaking has had remarkable persistence even though regulators have been experimenting with performance-based rates and with market-based rates for decades. As noted earlier, when the electric industry was challenged by nuclear and restructuring failures, regulators relied on cost-based ratemaking. In times of financial stress, when utilities confronted volatile costs for fuel or wrestled with inflation, they sought refuge behind automatic fuel adjustment clauses that allowed rates to escalate in tandem with those rising costs. Similarly, regulators have relied on this formula and, in some instances, have expanded its use. Such devices as forward test years, multi-year rate structures, cost trackers, and the like, are all cost-based.

280. Id.
281. Id.
282. Id.
284. See McDermott, Edison Elec. Inst., supra note 17, at 18–19.
285. LOWRY ET AL., PAC. ECON. GRP. RESEARCH L.L.C., supra note 186, at 5 (a report for the Edison Electric Institute on cost trackers); McDermott, Edison Elec. Inst., supra note 17, at 18–19 (fuel adjustment mechanisms). Another mechanism for recovering costs during construction periods is to include construction costs while they are ongoing. LOWRY ET AL., PAC. ECON. GRP. RESEARCH L.L.C., supra note 186, at 5. This mechanism is known as construction work in progress. Id.
286. See McDermott, Edison Elec. Inst., supra note 17, at 23.
287. LOWRY ET AL., PAC. ECON. GRP. RESEARCH L.L.C., supra note 223, at 27.
288. Id. at 31.
289. See id. at 5, 27, 31.
In brief, cost-based ratemaking functions well when the market is expanding and demand continues to grow. Once the market slows or stalls, then cost-based ratemaking may contribute to excess capacity and other economic dislocations. Further, “cost of service regulation can slow the pace of innovation and may offer little incentive for utilities to improve operational efficiency or service quality beyond the minimum levels set by regulators.”

Nevertheless, cost-of-service ratemaking has a strong hold on the regulatory structure. “The regulatory framework has been resilient in the face of the flux brought about by economic, technical, and financial shocks that often nullified one or more of the assumptions underlying the original framework, precisely because of the willingness to adopt incremental changes to the process.” However, another way of analyzing cost-of-service ratemaking is to argue that it has not been resistant to change and that the ratemaking formula must adapt to today’s changing market conditions.

The most immediate problem, then, is that cost-of-service ratemaking was dedicated to covering a utility’s prudently incurred costs. Now the problem is that utilities cannot continue to make the same types of investments that they have in the past particularly in light of falling sales that can threaten a utility’s of financial stability. In brief, the traditionally structured electric utility, as well as its regulators, must figure out how to earn money by selling less electricity while promoting other energy services and products.

Fortunately, there is no shortage of new rate designs including: (1) performance-based ratemaking; (2) incentive rates; (3) alternative regulation; (4) market-based rates; (5) decoupling; (6) feed-in-tariffs.

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290. See Malkin & Centolella, supra note 58, at 3. This tendency to invest and expand is also known as the A-J effect or the Averch-Johnson effect, based upon the seminal paper by Harvey Averch and Leland L. Johnson. Harvey Averch & Leland L. Johnson, Behavior of the Firm Under Regulatory Constraint, 52 Am. Econ. Rev. 1052, 1052 (1962).

291. Malkin & Centolella, supra note 58, at 3.

292. MCDERMOTT, EDISON ELEC. INST., supra note 17, at 1.

293. Burr, supra note 9, at 30.


and, (7) results-based regulation as examples. In choosing among new rate designs, regulators must “address the fact that in an efficient, modern utility, conventional revenue recovery may no longer keep pace with utility system costs, investment needs, and the changing dynamics of customers which have a growing range of energy related choices ranging from DG to demand response.” Further, rates should be seen as “a means by which energy companies communicate their value proposition to their customers—[and] not merely the process by which they collect revenues.” Thus, while a wide variety of approaches can be adapted for a new electricity market, any choice should be based upon a set of principles.

A. Costs

While costs will most likely play some role in any new rate design, the move away from using historically embedded costs—or even future tests year costs—as the central element of utilities revenue requirement must be changed. A key move away from cost-based ratemaking is decoupling. At its simplest form, decoupling means that rates will not be based on the volume of electricity sales; instead, rates will be based on other indicators such as the number of customers served. Another basic element of decoupling is that it allows for periodic rate adjustments. Still, there are a variety of decoupling mechanisms. “Some mechanisms use the revenue authorized in the utility’s last general rate case; others adjust that for specific cost changes or according to a

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300. MALKIN & CENTOLELLO, supra note 58, at 14.

301. SOLAR ELEC. POWER ASS’N, supra note 174, at 14.


303. MALKIN & CENTOLELLO, supra note 58, at 3.

304. REGULATORY ASSISTANCE PROJECT, supra note 298, at 2.


306. MORGAN, GRACEFUL SYS. L.L.C., supra note 305, at 5.
formula, and still others calculate revenue on a per-customer account basis rather than as a single dollar amount.\textsuperscript{307}

B. \textit{Innovation and Transition}

Rate designs can promote innovation and assist in the clean energy transition by allowing utilities to recover investments in innovation, energy efficiency, or renewable resources.\textsuperscript{308} Smart grid investments should be recouped, for example.\textsuperscript{309} Similarly, investments in smart meters, energy savings appliances, energy audits, and the like should be encouraged and included in any utilities revenue requirement. Regulators, of course, will have a great degree of discretion. Some investments can be included in rate base, and therefore can earn a return for shareholders. Other investments can be treated as costs and recouped dollar-for-dollar.

In the United Kingdom, for example, the utility regulator has adopted a Revenue set to deliver strong Incentives, Innovation, and Outputs (“RIIO”) rate design.\textsuperscript{310} The intent is to have “utilities . . . focus on delivering long-term value to customers.”\textsuperscript{311} “Revenues [will be] set based [up]on a review of the utility’s business plan,” including planned operating expenses as well as an assessment of future capital investment.\textsuperscript{312} The rates are then set on a multi-year basis and are intended to “provide[ ] an incentive for the utility to pursue efficiency improvements by [allowing a] utility . . . to retain [some] of [the] cost savings.”\textsuperscript{313} Indeed, cost sharing is a principal that should incentivize utilities to earn savings that can then be shared with customers.\textsuperscript{314} Again, regulators will have discretion on the proportion of cost sharing between the parties, but the idea is to create incentives for innovation and efficiency.\textsuperscript{315}

In the same way that revenue decoupling and shared savings policies together can provide strong incentives for utilities to invest in energy efficiency, a similar approach could strengthen incentives for utilities to invest in distributed generation, storage, microgrids, smart electric vehicle charging, smart inverters, or other distributed technologies to reduce operating costs and/or [to]

\begin{itemize}
\item \textsuperscript{307} Id. at 6.
\item \textsuperscript{308} MALKIN & CENTOLELLA, supra note 58, at 13.
\item \textsuperscript{309} Id. at 5.
\item \textsuperscript{310} Id. at 16.
\item \textsuperscript{311} Id.
\item \textsuperscript{312} Id.
\item \textsuperscript{313} MALKIN & CENTOLELLA, supra note 58, at 16.
\item \textsuperscript{314} Id.
\item \textsuperscript{315} Id. at 14–16.
\end{itemize}
defer or avoid the need for investments to expand capacity of distribution feeders or invest[ed] in . . . other electricity supply, transmission, or distribution assets.316

A smart rate design, then, may require hybrid pricing models that apply to different investments and to different expenses. Electricity rates can be unbundled for different purposes such as “unbundled pricing for reliability, standby, and power quality services; temporally or locationally differentiated prices for energy or distribution services; price structures that reflect how costs are incurred—e.g. fixed, demand-based, energy-based, etc.—and incentive payments for dispatchable demand response or ancillary services to the grid.”317

Smart rate designs, then, “may ultimately create a nimble system that pays for required services, maximizes value, and allows for effective implementation.”318 The core idea behind moving away from cost-based ratemaking to rate designs that are more sensitive to the market and technological developments is to encourage competition and enable utilities to capitalize on new opportunities.319

C. **Balance of Interests**

Shareholders, of course, will only invest if they earn a reasonable return on their investment. That return must be comparable with investments of similar risk. Nevertheless, shareholders do take on some investment risk and they should not be guaranteed a return at the expense of customers who may receive little or no benefit.320 The trick, of course, is in clearly identifying the risks to shareholders, as well as the costs and benefits to consumers. Rates should send clear price signals that account for both fixed and variable costs,321 avoid cross-subsidization as much as possible,322 and represent the value of services provided to the customer by the utility.323 “Building a shared understanding among stakeholders and regulators in the electricity sector about the full range of costs and benefits of distributed energy resources and the implications of net energy metering is an essential

316. **ROCKY MOUNTAIN INST., NET ENERGY METERING,** supra note 114, at 46.
317. **ELEC. INNOVATION LAB, ROCKY MOUNTAIN INST., supra** note 263, at 14.
318. **ROCKY MOUNTAIN INST., NET ENERGY METERING,** supra note 114, at 43.
319. **ELEC. INNOVATION LAB, ROCKY MOUNTAIN INST., supra** note 263, at 13–14.
320. **MALKIN & CENTOLELLA,** supra note 58, at 11.
321. **ELEC. INNOVATION LAB, ROCKY MOUNTAIN INST., supra** note 263, at 10.
322. See id.
323. **ROCKY MOUNTAIN INST., NET ENERGY METERING,** supra note 114, at 41.
first step toward devising rates and incentives that will create the greatest benefit for all.324

D. Prudence and Needs Reviews

Prudence reviews became a matter of concern to utilities with the collapse of the nuclear power industry. The possibility of a prudence review constitutes a risk to investors; however, all risk cannot and should not be eliminated.325 The fact that utility’s capital investment will be reviewed for prudence should be considered simply a matter of bringing business discipline into the electricity market. A prudence review should work hand-in-hand with the obligation of a utility to mitigate the costs of unwise investments.

Generally, a prudence review occurs at the time a utility wants to include specific investments in the rate base as part of a rate hearing.326 The problem with ex post reviews of investment decisions should be apparent. At Time One—for example—a utility assesses the need for a capital investment.327 Construction projects—particularly nuclear plants—take years and up to a decade or more to complete. Consequently, the decision to include that investment in the rate base will occur at a time when future market and financial conditions, as well as the need for energy, can change significantly. One way of reducing the risk of a disallowance at Time Two when the prudence review takes place is for regulators to aggressively assess the need for power before the investment is made.328 These two sets of principles, both for the regulatory compact and for new rate designs, are intended to encourage IOUs to reshape the way they do business.329

VIII. NEW UTILITY BUSINESS MODEL

One need only look at the technological advances in telephony and computers to realize that the world is changed in ways that will not return. Landlines and desktop computers have largely become things of the past. Electricity providers are proliferating, energy efficient appliances and

324. Id. at 36.
326. See id. at 21.
327. See id. at 22–23.
329. Tomain, Building the iUtility, supra note 8, at 29.
buildings are reducing per capita use, and competition and consumer choices for power providers are increasing. IOUs, whether they like it or not, are in a new market. Indeed, electric utilities should take a lesson from the telecommunications playbook and invest in change rather than continue to resist it.\textsuperscript{330}

The renegotiated regulatory compact, together with innovative rate designs, can encourage utilities to change the way they do business. More specifically, IOUs whose primary or exclusive business is to increase electricity sales cannot stay complacent in today’s changing market. Instead, utilities must offer a wider array of energy products and services, running from renewable energy and energy efficiency, to performing energy audits for its customers and broadening the array of power providers.\textsuperscript{331} In particular, utilities must act “more aggressively [by] looking at programs to use distributed assets to their benefit so that they can have a wider distribution of generation assets throughout their service areas.”\textsuperscript{332} By way of example, NRG Energy\textsuperscript{333} and NextEra Energy\textsuperscript{334} are developing utility-scale solar and other renewable projects; firms like Direct Energy\textsuperscript{335} and Veridian\textsuperscript{336} have partnered with Solar City to offer solar installations to their customers; and Duke Energy and PSE&G have been “invest[ing] in residential solar, microgrids, energy storage and smart grid technologies.”\textsuperscript{337} Indeed, opportunities abound for forward thinking utilities such as San Diego Gas & Electric, which has proposed a strategy to engage in three energy services functions: (1) generate and sell electricity to serve customers’ real-time needs; (2) provide distribution services; and (3) help customers manage

\begin{footnotes}
\item[330] See Kind, supra note 4, at 14–17.
\item[331] See Tomain, Building the iUtility, supra note 8, at 28; Tomain, “Steel in the Ground,” supra note 246, at 931–933; see also Joint Statement from Edison Elec. Inst. & Natural Res. Def. Counsel, supra note 305.
\end{footnotes}
electricity use through programs that promote efficiency, smart appliances and meters, electric vehicle charging, and the like.338

Traditionally structured, vertically integrated electric utilities served the country well for most of the twentieth century as demand continued to grow. Now with flattening demand, together with the need for investments in grid improvement, smart grid technologies, access to the grid by variable resources, reliability, cyber security, and pushes for greater use of renewable resources and energy efficiency, the utility of the future must acknowledge that the integrated utility model will not function effectively in a DG world.339 In short, as former Federal Energy Regulatory Commission (“FERC”) Chair Jon Wellinghoff has stated, “utilities are going to have to have the ability to morph into those roles of entrepreneurs and marketers and deliverers of these energy services to be able to effectively compete with all the other people in the space.”340 Further, today’s electric utilities must also recognize that the new market “does present new avenues for investment and growth in terms of grid expansion, smart grid, storage, and downstream services; the question is whether utilities grasp that opportunity and evolve themselves.”341

One way of conceptualizing the new utility model is to focus on distribution and customer service rather than on generation where the utility’s primary business is to serve as a grid operator in an environment of wholesale and retail competition.342 Innovative utilities are sensitive to customer demand.343 Studies show, for example, that consumers are responding to price information and that they are reducing consumption at peak times.344 Some of this consumer price responsiveness is due to pilot programs such as those in California, which are being operated by San Diego Gas & Electric and Southern California Edison that provide rebates to customers for electricity saved in particular peak event days.345 In addition,
behind-the-meter technologies such as home displays, programmable thermostats and other appliances, along with simple social networking, all provide information about how consumers can increase their energy efficiency to help IOUs develop their business plans.346

Thus, the utility of the future must start with the recognition that their primary business is not selling a commodity; it is providing and managing an infrastructure service.347

The entrepreneurs who put that competitive solar power on your roof with no money down can provide a portfolio of other equally unregulated products, like efficiency, demand response, storage, and so on, that could ultimately add up to a virtual utility providing the same services that utilities now provide—quite possibly with lower cost and greater reliability and resilience.348

Another, similar, way of conceptualizing the utility of the future is to see it as a network entity.

Under a network utility approach, the utility would provide highly differentiated price signals to direct investments by other service providers. In this case, the utility’s role would increasingly be focused on maintaining and operating the grid and on creating markets, managing transactions, replacing aging distribution equipment, and/or making smart grid investments and interconnecting buyers and sellers with the network. This network utility would shepherd and coordinate the network of increasingly complex transactions among [a] growing number of actors.349

Such a utility would: (1) pick a distribution area where a utility plans to expand, upgrade or modernize; (2) assess peak load demand; (3) use demand side management to target reducing loads; and (4) expand DG rather than add transportation and distribution.

Such new business approaches should be responsive to any number of issues. If large capital investments are too financially risky, then they can be scaled down. If investments in efficiency and in DG are less costly and less risky than building a new plant or making significant additions to T&D, then those investments should be made. Similarly, if the concern with upgrading and modernizing the grid is cyber security, then reducing the scale

346. See, e.g., Woods, supra note 343, at 41–42 (arguing that utilities are underutilizing social networks to inform their customers about energy consumption).
347. Burr, supra note 9, at 31 (referencing a comment by Walt Patterson).
348. Id. (quoting Amory Lovins).
349. See ROCKY MOUNTAIN INST., NET ENERGY METERING, supra note 114, at 47.
of generation and multiplying power sites rather than concentrating them will reduce those risks. Also, if natural disasters threaten the grid,\(^{350}\) then DG, microgrids,\(^{351}\) and the like may well prove to be smart alternatives.

The utility of the future, then, will adopt a new vision of the electricity business. The new utility will see itself not as a isolated actor in the market, but as part of a network “that provides a platform for the economic and operational integration of distributed resources.”\(^{352}\) The new utility will use more transparent costs and benefits of service, including technical standards, such as those needed for interconnection, as well as economic standards, such as those used in making value determinations and pricing goods and services generally.\(^{353}\) The new utility will be a value creator by serving as: (1) a distributed system operator;\(^{354}\) (2) an integrated resource planner for both large-scale distributed energy resources, and storage; (3) a provider of reliability and standby power to customers; and (4) an energy services provider and financier, through rates, of such things as energy efficiency retrofits, energy control systems, DG, storage, and the like.\(^{355}\)

As new technologies and new strategies develop, the utility of the future must integrate them into its portfolio and into its rate designs. Strategic investments as well as strategic partnerships will be necessary components of utilities’ new business model. Investments in distributed generation such as fuel cells\(^{356}\) or rooftop solar—as examples—can in some

\(^{350}\) See, e.g., Robert Uluski, Modernization Foundation: Near-Term Vision for Advanced Distribution Management, PUB. UTIL. FORT., Jan. 2014, at 44, 45 (“Recent so-called ‘storm of the century’ events in the Northeast [United States] and the lengthy power outages and customer hardships that followed have greatly elevated the need to make power delivery systems more resilient to major storm events and to provide a more effective electric utility response during such regional power grid emergencies.”).

\(^{351}\) See Sara C. Bronin & Paul R. McCary, Peaceful Coexistence: Independent Microgrids Are Coming. Will Franchised Utilities Fight Them or Foster Them?, PUB. UTIL. FORT., Mar. 2013, at 38, 39. “Generally speaking, a microgrid is a small-scale, low-voltage system for sharing distributed generation among several facilities or end users.” Id. Microgrids can be powered by conventional fuels, fuel cells, solar panels or wind turbines. Id. They may also incorporate combined heat and power. Id.

\(^{352}\) ELEC. INNOVATION LAB, ROCKY MOUNTAIN INST., supra note 263, at 9.

\(^{353}\) Id.

\(^{354}\) See, e.g., Kosnaski & Shankar, supra note 234, at 19.

\(^{355}\) See id. at 16–20.

instances produce greater efficiency, and in both instances reduce carbon emissions.357 Companies such as Bloomenergy358 and FuelCell Energy359 are actively in the market constructing fuel cells on-site as well as developing them for traditional IOUs and these are partnership opportunities.360 Fuel cells can achieve greater efficiencies and, as their costs decline, they become cost competitive in the current electricity market.361 Similarly, rooftop solar offers a low carbon alternative to baseload power and it is being offered by such companies such as Solar City that finance, install, and maintain the systems at a lower cost to the owner than traditional utility service under long-term power purchase agreements.362 This type of financial intermediation could also be adopted by the traditional IOU.363

IX. CONCLUSION

Thus, to succeed in the new electricity market, IOUs should adopt leadership roles by: (1) developing a plan for technological deployment and including DG;364 (2) engaging in strategic investments in fuel cells and in rooftop solar; (3) providing financial assistance to customers who wish to invest in alternative technologies and in energy efficiency; (4) assisting regulators in designing new rate structures; and (5) partnering with other vendors, utilities, and a variety of investors to engage all of these, and other, innovative and creative activities.365

As such, the new utility will be proactively responding to a new business environment. Utilities, however, cannot and will not act on their

more efficient than conventional heat engine approaches. CO2 is reduced, due to the high efficiency of the fuel cell, and the absence of combustion avoids the production of NOx and particulate pollutants.

Id. 357. See Kosnaski & Shankar, supra note 234, at 17.
361. See, e.g., Kosnaski & Shankar, supra note 234, at 17–18.
364. See, e.g., Jolly et al., supra note 215, at 35.
365. Kosnaski & Shankar, supra note 234, at 20; see also CHANNELL ET AL., supra note 50, at 77.
own. They must be aided and abetted by regulators who adopt new rules for their relationship with utilities that they regulate. Those new rules will be sensitive to the new market, sensitive to the demands of customers, and sensitive to the needs of utilities. The sensitivities are not only responsive to changing market conditions, they are responsive to a fundamental change in energy and electricity policy. The traditional fossil fuel policy is no longer viable. The future demands a clean energy economy and smart IOUs can play a transformative role. The clean energy future will increase their reliance on renewable resources and energy efficiency, thus increasing the diversity of inputs into electricity generation. In addition, the clean energy future should encourage competition, consumer choice, and technological innovation, as well as economic growth. Although the challenges are real, the direction of the future should be clear. IOUs can, then, play a leading role in building out the DG world.