The Future of the Utility Industry and the Role of Energy Efficiency

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Acknowledgments

This study is one of many on the future of energy utilities. Rather than repeat what others have done, we build on the work of more than 50 previous reports, papers, and articles, each of which is summarized in Appendix B. We thank the many people too numerous to mention by name who gave us suggestions on material to include as well as their insights into a variety of issues on the future of utilities and the many specific topics we explored. Funding for this work was provided by Consolidated Edison (Con Ed), Energy Trust of Oregon (ETO), National Grid USA, and Pacific Gas & Electric Company (PG&E). Each of the funders also took time to give us their insights into these issues. We particularly thank Fred Gordon (ETO), Marisa Uchin (PG&E), Steve Almeida (Con Ed) and Lynn Westerlind (National Grid). Additional supplemental funding was provided by the Energy Foundation. Helpful comments on drafts of this report were provided by ACEEE staff (Jim Barrett, Neal Elliott, Marty Kushler, Maggie Molina, and Dan York) as well as by outside reviewers including Peter Cappers (LBNL), Sheryl Carter (NRDC), Peter Fox-Penner (Brattle Group), Chuck Goldman (LBNL), John Jimison (Energy Future Coalition), Ron Lehr (former chair, Colorado Public Utilities Commission), Elizabeth Noll (AGA), Ellen Petrell (EPRI), Andy Satchwell (LBNL), Rich Sedano (RAP), and Rick Tempchin (EEI). To all of them we are grateful. While we appreciate their help, the opinions expressed here are our own and are not necessarily endorsed by any of the people who helped us. Finally, we wish to thank Fred Grossberg and Eric Schwass at ACEEE for their help in editing and producing this report.

Executive Summary

The energy utility industry is facing many challenges, with sales stagnating, use of distributed generation growing, infrastructure aging, and environmental regulations tightening. In the past, utilities could make money by serving growing loads and earning returns on the large capital investments they had made to serve those loads. Now, with loads barely growing, they will likely need new strategies to meet their fiduciary obligation to provide returns to shareholders. Some observers inside and outside the utility industry have suggested that utilities could enter a "death spiral." In this scenario, increases in distributed generation and energy efficiency reduce sales, causing utilities to raise rates to cover fixed costs, thereby driving more customers to reduce their purchases.

Dozens of studies and papers have been written on these issues and on how to structure utilities and regulation to best serve the interests of society and shareholders. This study attempts to complement the work of others by addressing three specific questions:

1. What might future electricity sales be (and to a much lesser extent future natural gas sales)? Future sales very much affect the model of the future that utilities might choose. Viable models may well be different if sales are increasing, decreasing modestly, or decreasing rapidly.

2. What is the range of options proposed by other writers, researchers, and utility industry experts on the future role of utilities?

3. How will these options affect energy efficiency? Energy efficiency has played a critical role in keeping costs to consumers down, and a great deal of additional efficiency savings is available to be harvested.

SCENARIOS FOR FUTURE SALES

In order to estimate a range of possibilities, we constructed three scenarios for future electricity sales while more briefly examining natural gas sales. For electric sales we used as our medium-change scenario the *2014 Annual Energy Outlook Early Release* published in December 2013 by the Energy Information Administration (EIA). However we felt that EIA may have been too conservative in its assumptions about these specific resources, due in part to legal constraints on what it could include in its forecasts. Therefore we modified the EIA forecast using more aggressive assumptions, including greater use of energy efficiency programs, solar photovoltaics, combined heat and power systems, and electric vehicles. Based on these assumptions, we developed (1) a medium-high-change scenario, which is designed to be highly plausible but more aggressive than the EIA reference case, and (2) a high-change scenario that is even more aggressive and, while clearly plausible, includes changes that many observers would consider unlikely. We conducted our analysis for each of the 20 electric regions in the lower 48 states and then summed the results.

On a national basis (the sum of all 20 regions), EIA projects that electricity sales will grow an average of 0.70% per year over the 2014-2040 period. In our medium-high-change scenario, sales decline to an average annual growth of 0.04%—essentially flat consumption. In our high-change scenario, national-level electricity consumption declines about 10% over the 2013-2040 period (i.e., an average annual growth rate of -0.39%). The three scenarios are illustrated in figure ES1.

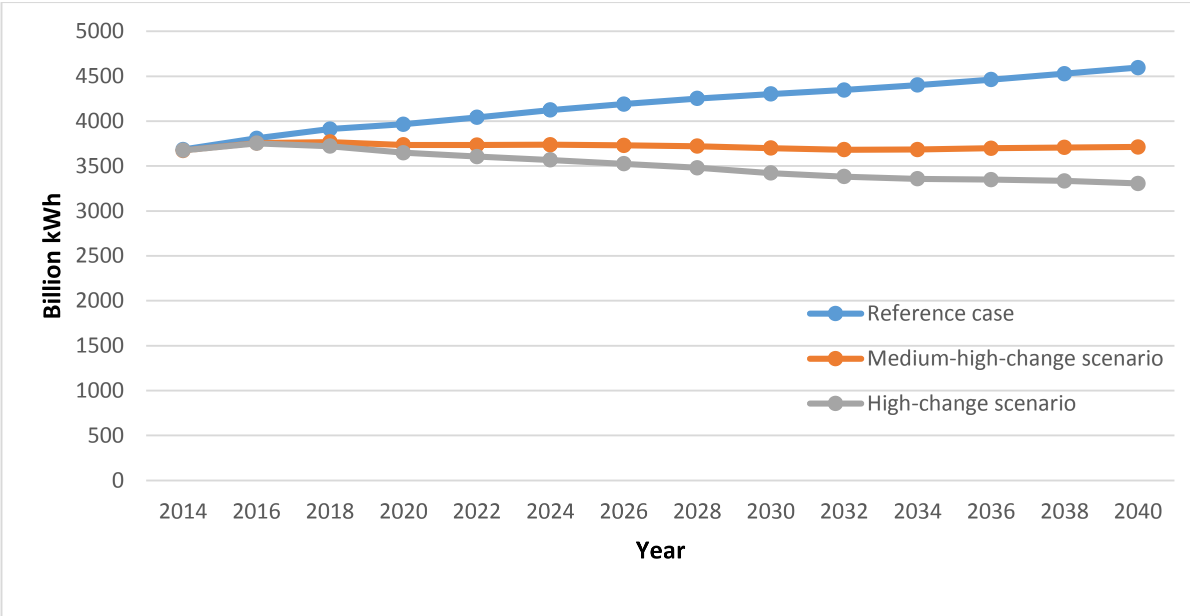

Figure ES1. Electricity sales in the lower 48 states over the 2014-2040 period under three scenarios

It is clear that, while national-level sales are unlikely to grow as they have in the past, even the high-change scenario has less dire results than some observers have suggested. A sales decline of 10% over nearly 30 years cannot be called a death spiral. On the other hand, such a decline in sales would be very significant for an industry that has historically relied on load growth to fuel profits. Therefore the industry does need to rethink the best ways to earn a return on investments going forward.

In the medium-high-change scenario, energy efficiency is the biggest contributor to the reduced national-level sales relative to the reference case, with photovoltaics second. Electric vehicles cause a modest increase in sales, and the contribution of combined heat and power (CHP) is negligible because the reference case includes a good deal of CHP and other distributed generation. In the high-change scenario, energy efficiency is again the largest cause of the sales decline relative to the reference case, followed closely by photovoltaics. The sales increase caused by electric vehicles is more substantial in this case than in the medium-high-change case, but even still, electricity used by electric vehicles only offsets about half the electricity produced by photovoltaic systems. Again, CHP makes a very small contribution.

Results at the regional level are generally similar to the national results in most regions, although some vary substantially. Thus, even at the regional level, there is no death spiral.

We also more briefly examined natural gas sales. Projections by EIA in their 2014 reference case show natural gas use increasing by 20% over the 2012-2040 period. Comparing consumption in 2012 with projections for 2040, we find the largest increases in natural gas use in the power and industrial sectors, followed by the transportation and commercial sectors. Residential-sector consumption is forecast to decline slightly. The high gas resource case estimates substantial increases in consumption for power generation and modest increases in the other sectors.

OPTIONS FOR THE UTILITY OF THE FUTURE

We examined more than 60 reports, papers, and articles related to the utility of the future, and we also conducted interviews with about a dozen utility industry participants and observers. Based on these sources, we summarize suggested changes to the utility system, grouping them into 19 options that utilities and regulators should consider in their short-, medium-, and long-term planning:

- Better management
- Regulation
  - Reassess the role of regulation
  - Expand decoupling and shareholder incentives
  - Reform electricity pricing
  - Institute performance-based regulation
  - Foster innovation, R&D, and more competition
  - Establish long-term climate policy
  - Improve utility ability to invest and recover costs
  - Consider an energy efficiency utility model
- Energy resources and infrastructure
  - Expand energy efficiency and renewable energy
  - Expand demand response and customer options
  - Improve infrastructure
  - Expand transmission system
  - Limit generation expansion
  - Engage in long-term planning
- Services
  - Expand utility services
  - Consider the utility as "FinanceCo" model
- Long-term models
  - Consider the utility as smart integrator
  - Consider the energy services utility

THE ROLE OF ENERGY EFFICIENCY

Energy efficiency typically costs less than half the cost of other electricity resources. Efficiency is also generally less expensive than natural gas supplies, although not to quite the same degree. In addition, in some cases energy efficiency can be used to defer transmission and distribution investments.

Energy efficiency can also be a low-cost emissions-reduction strategy, which will likely be important as EPA sets (and states implement) new carbon dioxide emissions rules for existing power plants. Energy efficiency is also likely to play a large role if and when a more comprehensive climate change policy is enacted. Furthermore, by lowering consumption, energy efficiency lowers bills, making rate increases to pay for new infrastructure more affordable. Thus, investing in energy efficiency is an important tool that utilities can use as they seek to manage costs and risks. Moreover, since it is a service valued by many customers, utilities can use energy efficiency to increase customer engagement by providing efficiency services and by using efficiency as a gateway to other offerings.

On the other hand, if utility fixed-cost recovery is not decoupled from sales, energy efficiency does lead to a decline in sales and so does affect utility profits. For energy efficiency to flourish, the use of decoupling needs to be expanded so that utilities can recover their fixed costs even if sales decline. Shareholder incentives for achieving efficiency goals will also need to be expanded so utilities can earn some return on energy efficiency investments just as they earn a return on investments in power plants and infrastructure.

Energy efficiency programs funded by utilities have saved a substantial amount of energy—nearly 4% of U.S. electricity use. These programs can dramatically increase savings over what can be achieved just by relying on markets. At the same time, they can help to overcome market barriers and to create stronger markets including contractors hired by utilities and an increased demand for energy efficiency services. Without such programs, efficiency savings will be lower and needed investments in generation, transmission, and distribution will be higher, yielding higher rates and bills.

To be most useful for the utility of the future, energy efficiency programs should be well integrated with demand-response and distributed-generation efforts. Such integration includes the possibility of utilities' directly investing in CHP and other distributed generation at customer sites or in communities, using low-cost utility capital, and leveraging utility expertise in power-plant development and operation.

Power prices need to be fair to all as utilities invest in energy efficiency. A particular issue is how to balance fixed monthly charges with variable rates based on energy consumption and peak demand. In our view, variable prices should be based on long-run marginal costs, including the costs of new generation, transmission, and distribution investments that will be needed. We prefer recovering grid costs through time-of-use rates, variable demand charges, or minimum bills rather than through high fixed charges. The higher the fixed charge and the lower the variable charge, the less incentive customers have to invest in energy efficiency.

PATHS FORWARD

The road from the present to the utility of the future is likely to be winding and bumpy. In particular, we note that since the utility industry is at core a regulated monopoly, regulations and business practices must evolve in tandem for progress to be made. Furthermore, there is no single answer. It is likely that each state and each utility will pursue its own path, although many of those paths will be similar and ultimately will likely evolve into a few primary routes.

Using timing as our organizing principle, we suggest some primary paths forward for the short, medium, and long terms. Short-term means the next three years, medium-term the following five years, and long-term eight years or more away.

As the need for change is becoming more apparent, utilities and policymakers should consider the following ways forward over the next few years:

- Reassess the role of regulation and how regulation can best be structured to meet both consumer and utility needs in a period of change.
- Expand the use of energy efficiency as a way to replace retiring generation, minimize rate increases, meet environmental requirements, and provide a valued customer service.
- Institute decoupling and shareholder incentives to meet energy efficiency goals in the states (roughly half) that have not presently done so.
- Increase the use of demand response and smart pricing, and better integrate these mechanisms with energy efficiency programs and policies so the grid can be managed more effectively and at lower cost.
- Establish fair pricing to pay for fixed costs without unfairly discouraging investments in energy efficiency and distributed generation.
- Look at infrastructure needs and prioritize them so that key projects with significant net benefits can move forward.
- Experiment with new utility services to see what works in particular situations and what does not.
- Manage well.
- Experiment with performance-based regulation (PBR).
- Effectively manage a diverse grid with large contributions from distributed generation and variable resources.
- Reduce uncertainty about future environmental regulations by completing a variety of pending rulemakings that affect the power sector.
- Think very carefully before proceeding with decisions to build new generation.

Over the medium term, utilities and policymakers will increasingly need to pursue the following options:

- Develop and offer optional services, moving from pilots into broader-scale offerings.
- Develop and implement new systems and capital plans for managing increasingly complex grids.
- Establish and implement best practices for performance-based regulation, building on initial experiences that show which practices work and which do not.

In the medium term, many of the efforts begun in the near term will continue, including expanding energy efficiency and demand-response efforts and prioritizing needed infrastructure improvements. This period should also be used to experiment with new long-term models for utilities' involvement in generation, transmission, and services. Climate-change policy may also become clearer during these years, both through government action and through the actions of consumers and businesses. If so, the utility industry will need to adjust accordingly.

By the mid-2020s, each state and utility will likely have to choose a long-term model. All such models show a clear need for a single company to operate the wires and a system integrator to assure reliability. Together, these are core functions of "the utility." In our view, this entity should play an important role in funding and implementing energy efficiency investments, as these help to lower costs for all customers. Without such programs, the rate of energy efficiency adoption will be lower, and demand and costs higher.

A key question will be whether the system integrator also owns generation. In some states, utilities have already divested their power plants and there is wholesale competition. In others, integrated utilities are required to plan for generation needs and to acquire generation through open bidding. Still other states have vertically integrated utilities that own generation. These states and companies will have to decide whether to continue with exclusive utility control of new-generation additions and vertical integration, or to open the market for new plants to the utility's competitors.

Conclusion

The future of the utility industry is far from clear, with uncertainties regarding future sales, the role of distributed generation, environmental regulations, and business and regulatory models. The next few decades will probably be challenging for the utility industry as utilities and regulators grapple with roughly level demand, increasing use of distributed generation, and a more complex grid. Our key finding is that a utility industry with substantially increasing sales is unlikely, but a death spiral is also unlikely.

To maintain profits in this environment, utilities should pursue new services, good management, decoupling and incentives for achieving energy efficiency, and other key public goals. We believe that energy efficiency should and will play a strong role. Utilities can help their customers use energy more efficiently as a way to moderate utility risks and customer bills while also providing valued customer services and protecting the environment.

In order to prepare for a strong utility of the future while also meeting public goals, utilities and policymakers should provide consumers value for their money, get regulatory rules right, and establish fair policies and robust systems in several areas. These include power pricing, decoupling profits from sales, incentive regulation, and coordinating a more complex grid. Fair rules will mean that utilities can offer new services and that other service providers can enter markets without undue advantages or constraints.

To get on this path, utilities and policymakers need to make important decisions in the short term and build on them over the medium and long terms. These decisions will address such issues as decoupling, performance measurement and metrics that provide appropriate financial incentives for utilities, the role of rate-payer funded programs in promoting energy efficiency, opportunities for utilities and their competitors to offer new services, and how best to structure rates to recover costs. If we can get these rules and systems right, utilities will maintain profitability, customers will receive the services they need, bills will be kept to reasonable levels, and we will all enjoy a clean environment.

Introduction

The environment in which electric utilities operate is going through a fundamental change. For the first time since Thomas Edison, demand for their product is no longer growing.[1] While electricity sales before 1970 grew at 5% or more per year, since the turn of the 21st century sales growth has been more in the neighborhood of 1.5% per annum, and since 2007 sales have actually declined. This latter decline was driven in part by the Great Recession of 2008-2009, but since then electricity sales have continued to decline, even as gross domestic product (GDP) increased. The Energy Information Administration (EIA) projects that sales will resume growing in coming years, but at much more modest levels than in the past. Figure 1 illustrates historic trends and EIA projections.

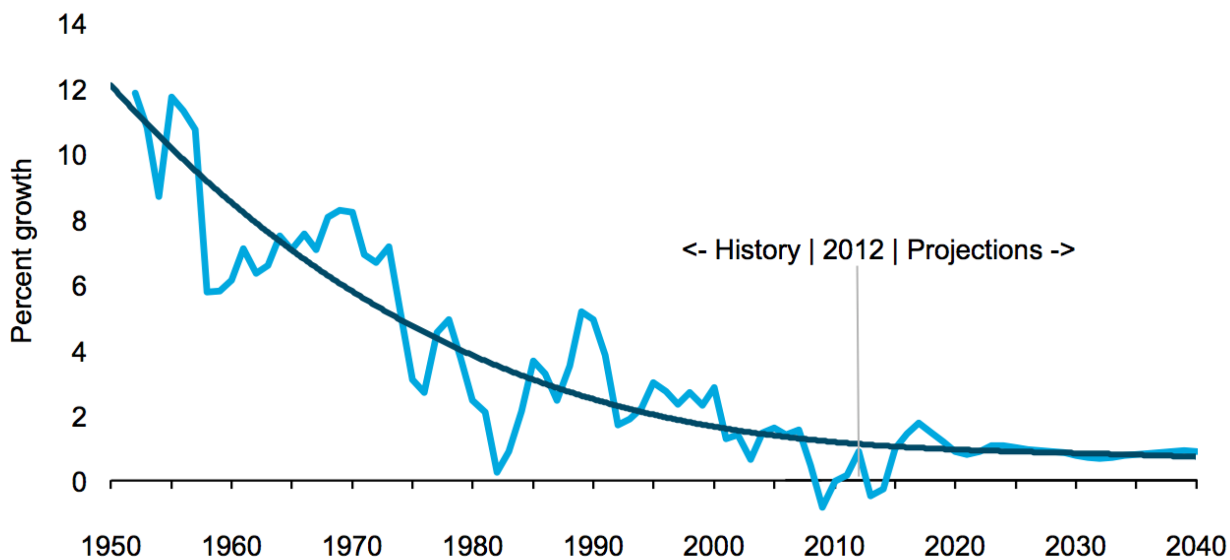

Figure 1. U.S. electricity demand growth, 1950-2040 (percent, 3-year moving average). Figures beyond 2012 are projections and not actual data. *Source:* EIA 2013a.

Nadel and Young (2014) found that savings from energy efficiency programs and policies are a significant contributor to slowing electricity sales. Utilities have increasingly adopted energy efficiency programs for end-use customers in recent years. Spending on these programs totaled about $7.2 billion in 2012 (Downs et al. 2013), with total annual energy savings of about 140 billion kWh in 2012, amounting to about 3.7% of total 2012 electricity sales (EIA 2014a).[2] As shown in figure 2, these savings represents a substantial increase over earlier years, driven by such factors as state energy efficiency portfolio standards (Downs

[1] According to Energy Information Administration (EIA) data, there were very small declines in U.S. electricity use in 1974, 1982 and 2001, but the first multiyear decline has been in the period after 2007 (EIA 2014a).

[2] This latter figure includes measures installed in 2012 as well as measures installed in earlier years that were still in place and saving in 2012.

2014) and steps regulators have taken to make efficiency investments more attractive to utilities (York et al. 2013). At the high end, in Vermont, energy efficiency savings in 2012 totaled about 12% of 2012 sales, and this figure is increasing by about 2% each year (Efficiency Vermont 2013).

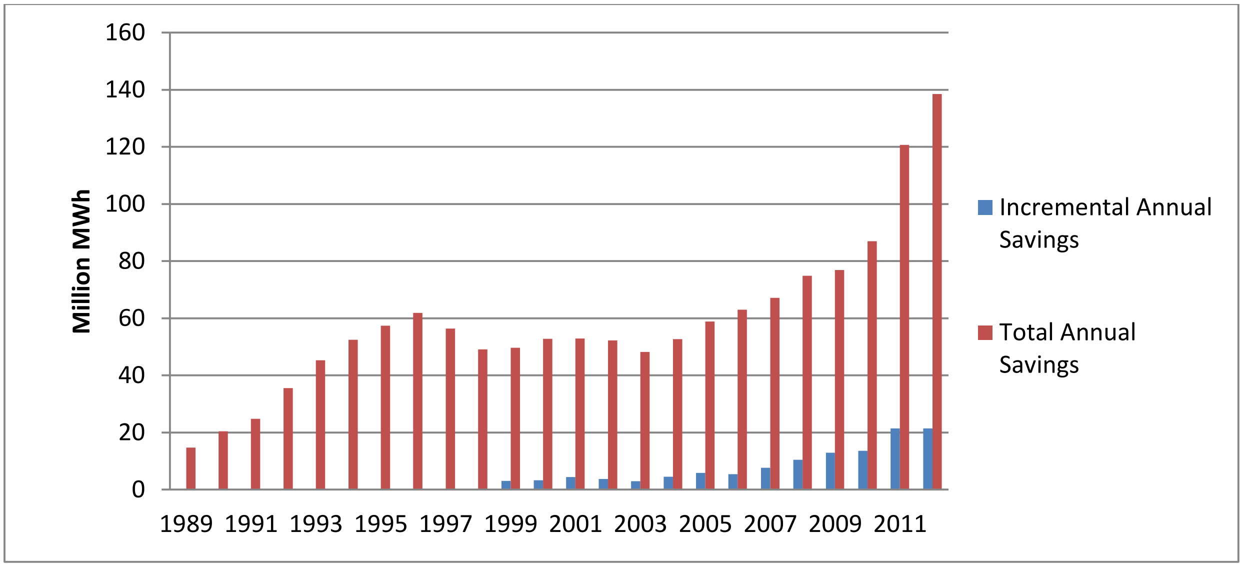

Figure 2. Energy efficiency savings by year. "Incremental annual savings" are the savings from energy-saving measures installed that year. "Total annual savings" include savings from all measures in place in a given year, regardless of when the measures were installed. The latter measure accounts for the fact that the typical energy-efficiency measure has a service life of multiple years. These figures only include savings from programs operated by electric utilities that report to the Energy Information Administration. Programs operated by non-utility entities (e.g. the New York State Energy Research and Development Authority) were not included prior to 2012, but are included in the 2012 figures. *Source:* ACEEE analysis using data from EIA 2014a and Nadel and Young 2014.

Energy efficiency savings generally cost much less per kWh saved than the cost of building and operating a new power plant, as illustrated in figure 3.

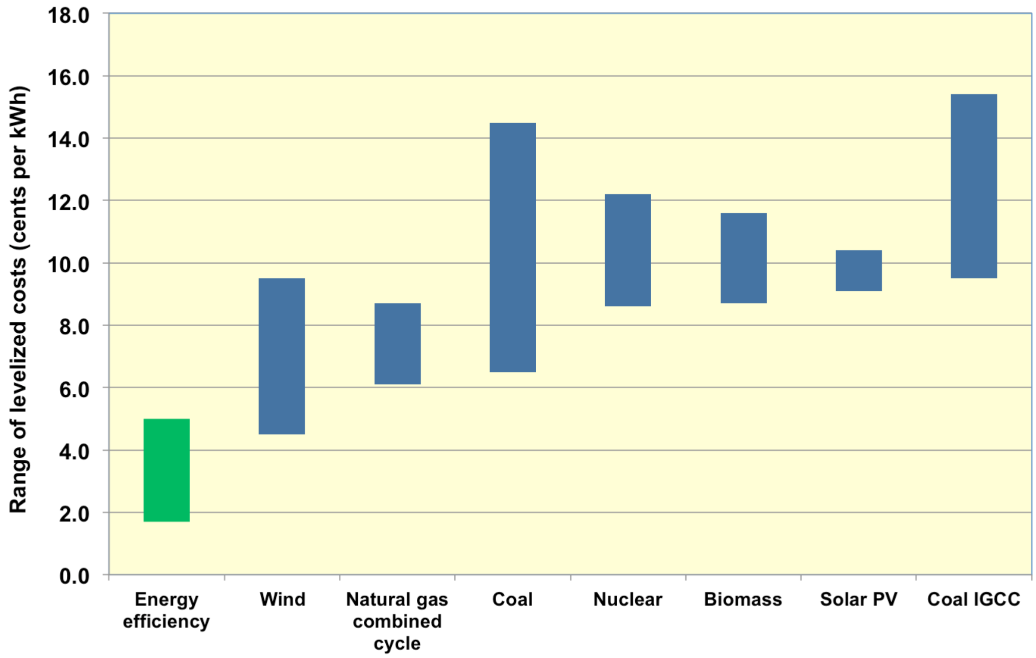

Figure 3. Cost per lifetime kWh of various electric resources. High-end range of coal includes 90% carbon capture and compression. *PV* stands for *photovoltaics*. *IGCC* stands for *integrated gasification combined cycle*, a technology that converts coal into a synthesis gas and produces steam. *Source:* Energy efficiency portfolio data from Molina 2014; all other data from Lazard 2013.

As an order of magnitude approximation, the net savings to ratepayers in 2012 (benefits minus costs) is more than $4 billion. This figure assumes that the 140 billion kWh of savings achieved in 2012 cost utilities and other program operators an average of 3 cents per kWh (Molina 2014), and that displaced generation costs 6 cents per kWh. This latter cost (the low end shown in figure 3) allows for the fact that old, depreciated power plants are generally less expensive per kWh.

Furthermore, additional large cost-effective savings appear to be available. For example, a 2010 National Academy of Sciences study estimated that the energy efficiency technologies that exist today or that are likely to be developed in the near future could save considerable money and energy. Fully adopting these technologies could lower projected U.S. energy use by 17% to 20% by 2020, and 25% to 31% by 2030 (National Research Council 2010). Likewise, a 2009 study by McKinsey Global estimates a cost-effective opportunity to reduce U.S. 2020 energy use by 26% (Granade et al. 2009). These savings are achieved as a result of more than 100 different energy efficiency measures.

Looking over a longer time frame, the American Council for an Energy-Efficient Economy (ACEEE) estimated in 2012 that energy efficiency could reduce overall U.S. energy use by 42% to 59% in 2050 relative to a business-as-usual scenario based on the EIA reference case (Laitner et al. 2012). The longer time frame in the ACEEE analysis leads to higher savings than in 2020 or 2030, because by 2050 a larger portion of buildings, factories, and vehicles will be either new or substantially renovated, providing additional opportunities for cost-effective energy savings. Technology development over the 2020–2050 period also plays a role. Studies by the Rocky Mountain Institute (Lovins 2011) and the California Council on Science and Technology (2011) make similar savings estimates.

At the same time as electricity sales are declining, the electric grid is aging and many observers have called for major new investments in transmission and distribution (for example, see MIT 2011). New power plant emission standards are taking effect, the cost of solar photovoltaics continues to decline, and natural gas prices have come down, putting pressure on the economics of coal plants, and even nuclear plants in some cases. EIA (2014b) estimates that 60,000 MW of coal-fired power plants will retire by 2020, and the closure of four nuclear plants has been announced in recent months with more retirements possible (Northey 2014). Furthermore, some of the plants that are not being retired need to upgrade pollution control and other systems.

Traditional power plants are also facing competition from new sources. These include energy efficiency programs run by utilities and third parties, and distributed generation (DG) systems ranging from large combined heat and power (CHP) systems at major facilities to small residential rooftop solar systems. While the amount of DG added each year has been small, installations picked up in 2012, and incremental generation relative to 2011 totaled nearly 8 billion kWh. This is about 0.2% of 2012 sales, driven by such factors as declining costs for solar and low natural gas prices. In 2013 DG grew by 0.2% of total sales relative to 2012. While 0.2% of sales annual growth is modest, DG could have a significant impact on sales if the upward trend continues. Hawaii is perhaps a harbinger of things to come, with distributed generation totaling about 10% of generation on Oahu, the most populous island (Wesoff 2014).

Utilities are very concerned about the impact of DG on sales. When asked in a poll what technology provided the most disruptive potential to their business model, 53% of utility respondents listed distributed generation, followed by 28% listing demand-side management (Utility Dive 2014). Recent-year DG trends are summarized in table 1.

Table 1. Electricity generation from distributed resources in the industrial, commercial, and residential sectors, 2007-2013 (billion kWh)

					Change	
	Industrial	Commercial	Residential	Total	From prior year	From 2007
2007	143.1	8.3	7	158.4	-4.6	-
2008	137.1	7.9	8.1	153.1	-5.3	-5.3
2009	132.3	8.2	9.1	149.6	-3.5	-8.8
2010	144.1	8.6	11.7	164.4	14.8	6
2011	141.9	10.1	15.8	167.8	3.4	9.3
2012	145.2	10.6	19.9	175.7	7.9	17.2
2013	147.9	11.5	24.4	183.8	8.1	25.4

Source: EIA Monthly Energy Review 2013a; industrial and commercial data from table 8.2d; residential data derived by ACEEE from tables 10.2a and A6 in EIA 2013a.

To sum up, while electric sales are declining and could continue to decline, needed investments are increasing, which will likely cause rates to go up. Some utility industry observers are worried that as rates go up, more customers will seek to self-generate, further reducing sales and causing a "death spiral" as fewer customers are left to pay the cost of the grid (see, for example, Martin et al. 2013). On the other hand, Moody's Investors Service believes that "rooftop solar [and] distributed generation [are] not expected to pose [a] threat to U.S. utilities" because Moody's "expect[s] regulators to intervene should it ever begin to have a significant [financial impact]" (Moody's 2013). There are also intermediate viewpoints such as Dinning (2013). Writing in the *Wall Street Journal*, he argues that talk of a looming death spiral for utilities is "hyperbole… but only up to a point." In his view, "mass adoption [of DG] is likely years away, but it is no longer over the horizon."

Natural gas utilities also face substantial changes, although significantly different in kind from those affecting electric utilities. Due to the fracking revolution, supplies of natural gas are increasing, and prices are lower than price peaks reached during the first years of the 21st century, making gas more attractive relative to many other energy sources. At the same time, gas sales per household have been declining, primarily due to energy efficiency improvements. Gas utilities are looking to grow loads, particularly in increased market share for gas space heating (e.g., displacing oil in the northeast), distributed generation (including cogeneration and small-scale generation), industry, and transportation (IHS CERA 2014).

The challenge, then, is how to re-envision the utility industry so it can provide important and needed services in a changing environment. Many other observers have described their vision of the utility of the future. Our study aims to complement the work of others by addressing three specific questions:

1. What might future electricity sales be (and to a much lesser extent future natural gas sales)? Future sales very much affect the choice of model for the future. Viable models may well be different if sales are increasing, decreasing modestly, or decreasing rapidly. Given the rhetoric about a death spiral generated by reduced sales, it will be useful to explore how probable such an outcome might be.

2. What are the range of options proposed by other writers, researchers, and utility industry experts on the future role of utilities? With so much already written on this topic, it will be helpful to summarize the range of options to make sense of the dozens of suggestions that have been made.

3. How will these options affect energy efficiency? As discussed above, energy efficiency has played a critical role in keeping costs to consumers down, and a great deal of additional efficiency savings is available to be harvested. Efficiency is only one of many factors to consider in evaluating future options; however, given our expertise in this area, we pay special attention to the role of energy efficiency while also considering a variety of other factors. These include each option's effect on cost and quality of service, utility profits, and the environment.

In the next sections we discuss scenarios for future electricity sales and (more briefly) natural gas sales. After that we make a brief digression to review recent experience in the telecommunications industry and whether there are useful lessons to be learned. Then we discuss 19 options for the future role of utilities, drawing from the results of more than 50 studies we reviewed and assessing the pros and cons of these options. After summarizing our analysis of the role of energy efficiency, we conclude by discussing pathways to the utility of the future over the short, medium, and long terms, including recommendations for utilities and policymakers.

Scenarios for Electricity Sales

As noted in the introduction, the direction and magnitude of future electricity sales can have an important impact on which models of the future to pursue. Major changes in the structure of the industry will be more necessary if sales are decreasing rapidly than if they are increasing or decreasing modestly. It is also worth examining the likelihood of a death spiral, as we mention above. Of course the future is unknown, and any one forecast is likely to be wrong. Therefore we explore three scenarios to help bound the more likely range of possible futures, while also recognizing that futures outside our range are possible as well. Since the situation is likely to differ from region to region, we analyze separately each of 20 electric market regions in the lower 48 U.S. states.

METHODOLOGY

Our analysis is based on the 2014 Annual Energy Outlook Early Release prepared by the EIA and published in December 2013 (EIA 2013a).[3] We used as one scenario the reference case published by EIA for each region, covering the period 2014-2040. We then prepared two enhanced scenarios for each region based on a consideration of four factors where we thought EIA might be too conservative: enhanced energy efficiency investments, increased use of distributed photovoltaic (PV) systems, increased use of CHP systems, and increased use of electric vehicles (EVs). The EIA has some legal constraints that make it difficult for them to fully consider these factors.

Taking the reference case scenario as a medium-change scenario, we then developed medium-high-change and high-change scenarios for each of the four factors. For energy efficiency, photovoltaics, and CHP, we subtracted additional savings or generation beyond the reference case. For EVs, we added additional use beyond the reference case.

The medium-high-change scenario is designed to be highly plausible but more aggressive than the reference case. The high-change scenario is even more aggressive, and while clearly plausible, the changes included are at a level that many observers would consider unlikely. In the paragraphs below, we discuss each of the four factors and how we created the medium-high- and high-change cases.

Energy Efficiency

EIA does not explicitly incorporate savings from utility-sector energy efficiency programs into its forecast. However, its methodology uses historic sales as a key input, and to the extent historic sales are influenced by utility-sector programs, program results at these historic levels are incorporated into the EIA forecast. To estimate to what extent the EIA forecast does incorporate efficiency programs, we calculated the average efficiency program savings in each region over the past five years using the savings data in the annual ACEEE *State Energy Efficiency Scorecard* (Eldridge et al. 2009; Molina et al. 2010; Sciortino et al. 2011; Foster et al. 2012; Downs et al. 2013).

For the medium-high-change case, we started with historical average savings for each region over the past five years and ramped them up to 1.5% incremental savings as a percentage of total sales over a three-year period, beginning in 2016. Thus if historical savings averaged 0.6% of sales, we assumed 0.9% savings in 2016, 1.2% savings in 2017, and 1.5% savings in 2018 and thereafter. We delayed the start of increased savings until 2016 in order to allow time for programs to be planned and regulations to be put in place. Savings from efficiency measures are estimated to last an average of 11 years (Molina 2014), but some measures have shorter lives and others have longer lives. Each year we calculated savings by taking 10.5/11 of the savings from the prior year and adding in savings from

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[3] The final version of the *2014 Annual Energy Outlook* was published just a few weeks before this report was released, much too late to use as the basis for our analysis.

measures installed in the current year. In this way, half the savings from a measure are in place in the eleventh year, with some deterioration of savings in earlier years and a counterbalancing amount of savings persisting beyond the eleventh year. For the high-change case, we used the same methodology but ramped up to 2.0% annual incremental savings.

The 1.5% savings level is clearly feasible: four states exceeded it in 2012 (Arizona, Massachusetts, Rhode Island, and Vermont). In addition, five other states—Colorado, Maine, Maryland, Minnesota, and New York—are targeting this level of savings in the near term. The 2.0% savings level has also been achieved by Vermont for multiple years and is a level targeted in the near future by Arizona, Massachusetts, New York, and Rhode Island (Downs et al. 2013).

EIA does directly incorporate future appliance and equipment standards as well as building codes into its forecast. We did not make any adjustments to EIA's treatment of these policies.

Photovoltaic Systems

PV systems use a photoelectric process to generate electricity directly from sunlight. Sunlight excites electrons in the cells; electricity is essentially flowing electrons. PV systems can be placed on rooftops or next to buildings, and the electricity generated is used in the building, thereby reducing the amount of electricity that needs to be purchased from the utility. When the electricity generated is more than the building needs at a point in time, the excess is most frequently sold back to the utility, but at times it is stored (e.g., in batteries) for later use.

For PV systems, we started with a forecast by the Solar Energy Industries Association (SEIA) on projected sales for 2013-2016 (SEIA 2013). These projections are similar to those by the National Renewable Energy Laboratory (NREL 2008) and the European Photovoltaic Industry Association (EPIA 2012). On a national level, the SEIA forecast for new solar systems is about three to four times higher than the EIA forecast, a large difference. We applied the SEIA figures to each of the regions by multiplying each regional forecast by the ratio of the national SEIA forecast to national totals in the EIA reference case. In this way we maintained the distribution of PV sales among the regions as estimated by EIA.

We could not find any published forecasts of year-by-year sales after 2016, as there is much uncertainty as to whether the federal renewable energy tax credits will be extended after their current expiration in that year, and also as to how the market will respond when and if they do end. To estimate sales after 2016, we had discussions with experts at SEIA, NREL, and the U.S. Department of Energy (DOE). Based on these discussions, for the medium-high-change scenario we assume a 50% drop in sales in 2017 (many sales will be accelerated into 2016 to take advantage of the tax credit) and then 10% annual growth thereafter through 2040. For the high-change scenario, we assume only a 25% drop in sales in 2017 and then 15% per year growth.

In the high-change scenario, however, we constrained total sales to be no more than 80% of the technical potential estimated by NREL for rooftop solar by state based on their review of detailed aerial photographs and other data (Lopez et al. 2012). The 80% figure is our own estimate; it allows for the fact that some portion of the potential will not be economic and that some building owners will not be interested in solar even if the economics are favorable. We reached this limit in the high-change case in 8 out of the 20 regions, and therefore we modified our growth rate from 20% down to an annual rate that would exactly reach the 80% technical potential by 2040. In these regions, the high-change scenario is constrained by such factors as tree cover and available roof area.

It should be noted that the photovoltaics included in our scenario are capped by the available rooftop area suitable for solar energy and implicitly assume that any surplus energy is either stored or sold to the grid. The addition of storage will affect how much is sold to the grid but will not affect total production. Also, we did not include utility-scale solar in our analysis since such systems are merely another way utilities can meet customer energy demands. The NREL study we used (Lopez et al. 2012) considers community solar to be utility-scale solar since these systems are frequently owned by utilities. For example, National Grid has recently proposed to build 20 MW of such systems in Massachusetts (Massachusetts DPU 2014). To the extent end users build systems that are not on buildings, photovoltaics could have a larger impact on utility sales than indicated in our scenarios.

Although our assumptions are very rough, they do serve to bound the more likely range of possibilities. We are not the only scenario builders who have had difficulty grappling with solar sales: in its recent global scenarios, the World Energy Council regards solar penetration as a key uncertainty up to 2050 (World Energy Council 2013). Just as we were completing our analysis, Morgan Stanley (2014) published a research note estimating solar market share under bullish, bearish, and mid-range scenarios. They do not provide a timeframe for their estimates and express them in terms of peak gigawatts of power output. Under their mid-range scenario, in the long term solar would account for 15% of U.S. residential and commercial *peak* power use. This would increase to about 25% under their bullish scenario. Our medium-high-change case estimates that photovoltaic systems would displace 8% of *annual* residential and commercial power use, increasing to 17% in our high-change case. Since photovoltaic output is higher at very sunny times (the focus of the Morgan Stanley estimates) than at average times (the focus of our estimates), these two estimates are broadly consistent with each other.

Combined Heat and Power

CHP is the production of both heat and electricity in the same system, a process that reduces energy waste relative to having separate systems for generating power and for providing heat to institutions and industrial processes. In a study prepared for the American Gas Association (AGA), Hedman et al. (2013) estimate a technical potential for additional CHP systems of about 123,000 MW of electric generating capacity nationwide.

For the medium-high-change case, our CHP analysis used a policy scenario developed for a recent ACEEE report that estimates highly achievable CHP potential by state (Hayes et al.

2014). This report estimates state-specific CHP potential based on the Hedman study which reported the technical and economic potential for CHP by state, sector, system size, and project simple payback period. Hayes et al. then assigned an acceptance rate for each payback period range, with high acceptance (75%) for paybacks of less than five years, gradating down to 3% acceptance for paybacks of more than ten years.

For the high-change case we used the same AGA report (Hedman et al. 2013) but included all applications with a simple payback of ten years or less. In other words, our high-change case assumes much higher implementation of CHP systems with a payback of 5 to 10 years.

For both the medium-high and high-change cases, we then compared the additional CHP from our cases with the CHP and non-photovoltaic-distributed generation in the EIA forecast. In most instances, the EIA forecast was more aggressive for CHP and distributed generation, and we therefore just used the EIA values, but in a few regions there was additional CHP potential beyond what EIA forecast. Although there is substantial CHP potential, the 2014 EIA forecast assumes that much of this potential will be implemented, leaving only modest additional CHP for our medium-high- and high-change scenarios.

The aggressiveness of the EIA 2014 forecast is illustrated by a recent study by General Electric called *The Rise of Distributed Power* (Owens 2014). In this study GE estimates that distributed generation worldwide will grow at an annual rate of 4.4%, substantially greater than the 3.3% annual growth rate they project for electricity consumption. In fact they see distributed generation taking market share from centralized generation. Likewise, EIA (2013a) projects a 1.7% annual growth in power from combustion turbines and diesel, much more than their estimate of 0.9% annual growth in electricity consumption. EIA also sees distributed generation taking market share from centralized generation, since coal, nuclear, and combined-cycle gas are projected to grow only 0.3% per year.

Electric Vehicles

To generate our alternative scenarios, we used year-by-year vehicle-stock figures from the "optimistic PEV technology estimates" in a recent National Research Council report on future vehicles and fuels (NRC 2013).[4] We created a high-change case by multiplying each of the EIA regional projections by the ratio of the NRC projection to the EIA (national) reference case projection for each year. This resulted in much higher growth in EVs in, say, California than in Alabama. We generated the medium-high-change case for plug-in vehicles using a national vehicle-stock number equal to one third the NRC "optimistic" values used in the high case. This choice was based on a 2010 NRC study which judged "probable" penetration of plug-in hybrids to be on the order of one third of "maximum practical" penetration (NRC 2010b).[5] Relative to the EIA reference case, the stock of EVs in

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[4] These are approximate stock values by vehicle technology read from a graph; small values will not be accurate.

[5] See Figure 4.6 in NRC 2010b.

our medium-high- and high-change cases is about a factor of three and eight higher than the EIA estimate.

NATIONAL RESULTS

On a national basis (the sum of all regions in the lower 48 states), EIA projects that electricity sales will grow an average of 0.70% per year over the 2014-2040 period. In our medium-high-change scenario, this declines to an average annual growth of 0.04%—essentially flat consumption. In our high-change scenario, national-level electricity consumption declines about 10% over the 2013-2040 period (an average annual growth rate of -0.39%). Thus, while national-level sales are unlikely to grow as they have in the past, even our high-change scenario does not confirm some observers' alarmist projections. A sales decline of 10% over nearly 30 years cannot be called a death spiral. We do not attempt to pinpoint the level at which the industry could rightly be said to be entering a death spiral, but by way of reference, we do note that in the telecommunications industry, talk of a death spiral is underway with 36% of households having "cut the cord" as of the end of 2012 (Caperton and Hernandez 2013). On the other hand, a sales decline of 10% would be very significant for an industry that has historically relied on load growth to fuel profits. Thus the industry does need to rethink the best ways to earn a return on investments going forward.

Figure 4 shows electricity sales under our three scenarios.

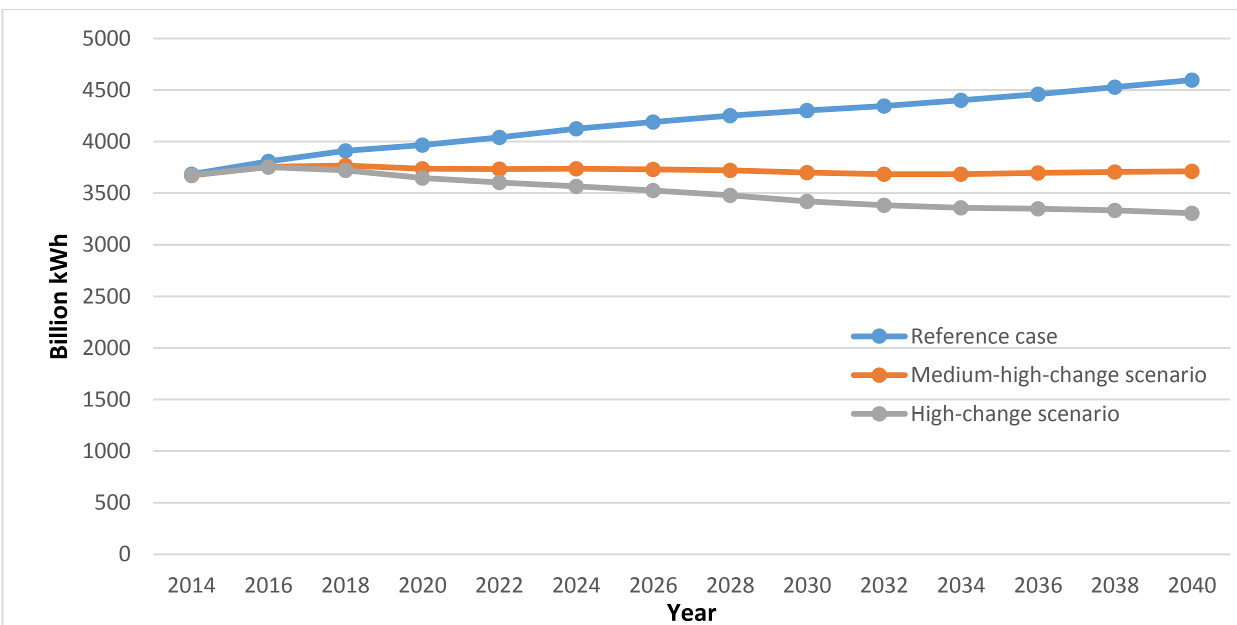


Figure 4. Electricity sales in the lower 48 states, 2014-2040, under the 3 ACEEE scenarios

It is also useful to look at the factors causing the differences between the EIA reference case and our two alternative scenarios. At the national level, in the medium-high-change scenario, energy efficiency is the biggest contributor to reduced sales relative to the reference case, with photovoltaics second. Electric vehicles cause a modest increase in sales, and the contribution of CHP is negligible since the reference case includes a good deal of CHP and other distributed generation. These trends are shown in figure 5.

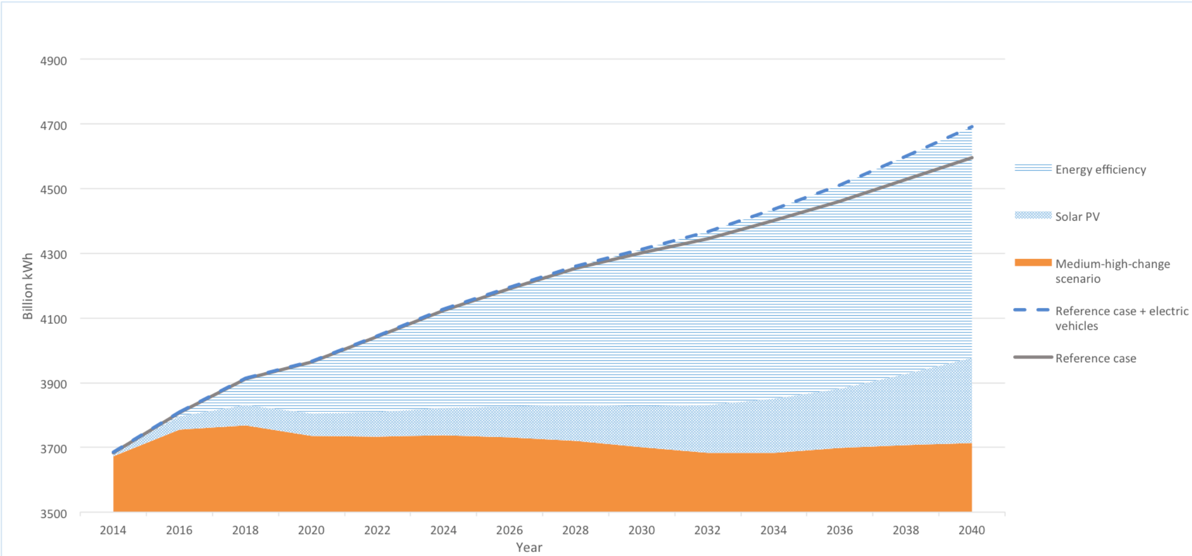


Figure 5. Increases and decreases in electricity consumption in the medium-high-change scenario in the lower 48 states relative to the reference case.

In the high-change scenario, energy efficiency is again the largest cause of sales decline relative to the reference case, again followed by photovoltaics. The sales increase from electric vehicles is more substantial in this case than in the medium-high-change case, but even still, electricity used by electric vehicles only offsets about half the electricity produced by PV systems. Again, CHP makes a very small contribution in this case since so much CHP and other distributed generation are included in the reference case. These trends are illustrated in figure 6.

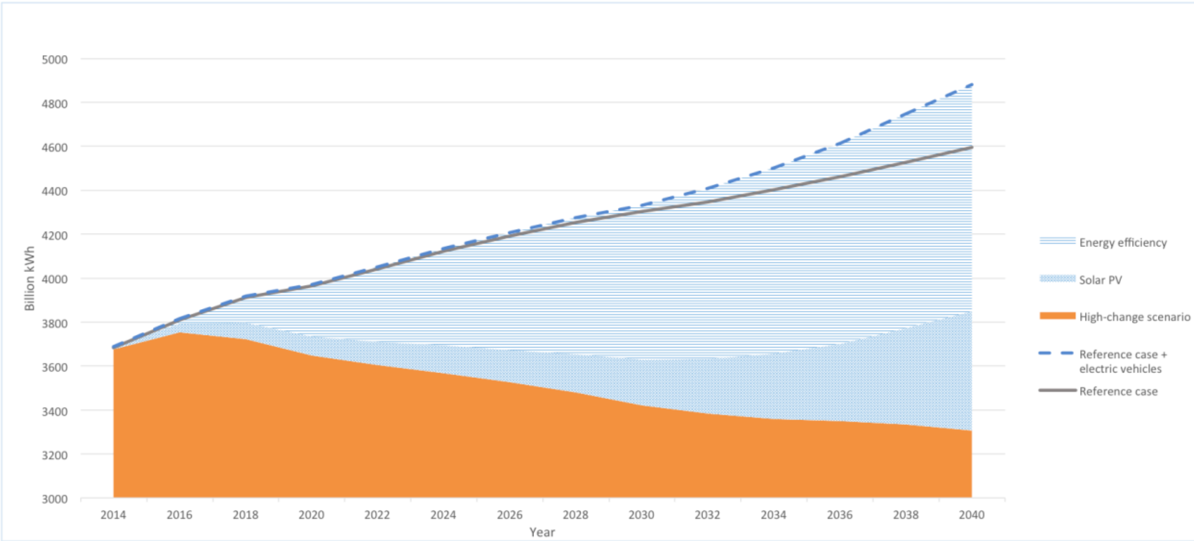
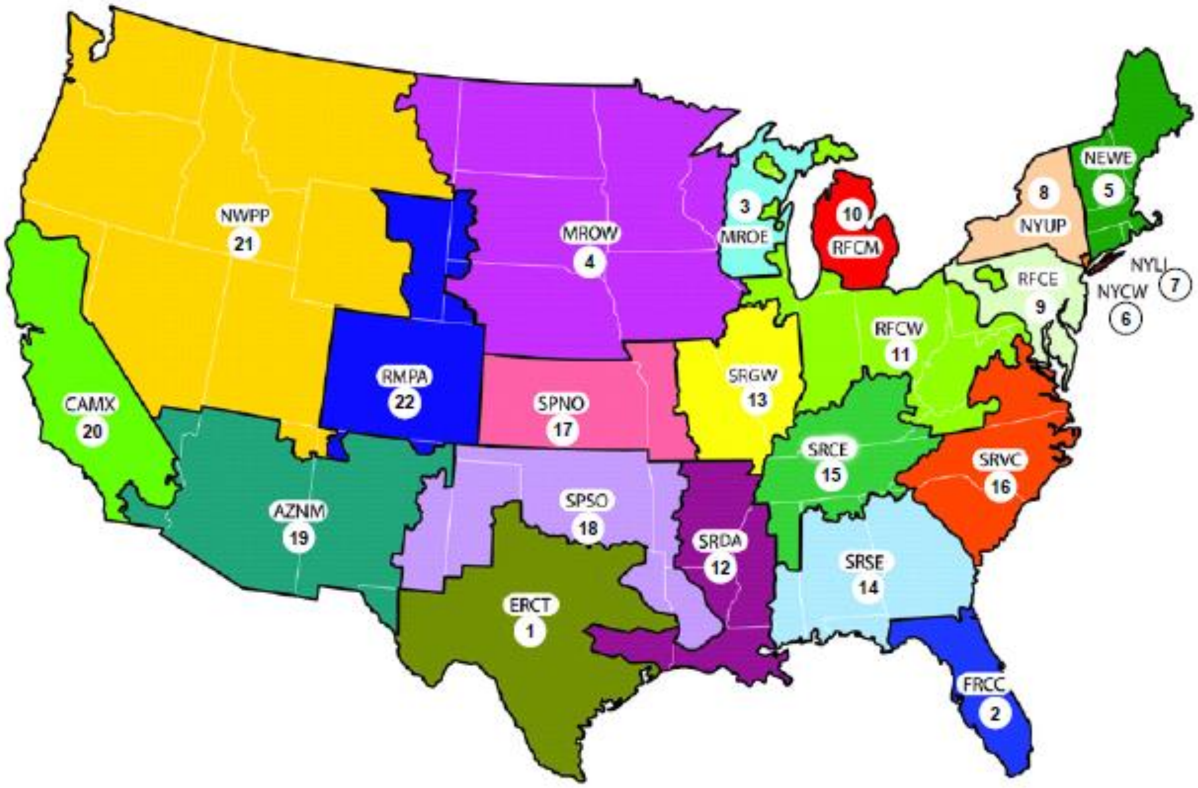


Figure 6. Increases and decreases in electricity consumption in the lower 48 states in the high-change scenario relative to the reference case

Regional Analysis

Regions Used

Figure 7 illustrates the regions that EIA models and that we also used. Since the electric grid does not generally follow state lines, neither do the regions. Some regions are rough approximations of states, others include multiple states, and in a few cases states are split among two regions. New York state is split into three regions, but we combined them into a single region for our analysis.



1.	ERCT	TRE All	12.	SRDA	SERC Delta
2.	FRCC	FRCC All	13.	SRGW	SERC Gateway
3.	MROE	MRO East	14.	SRSE	SERC Southeastern
4.	MROW	MRO West	15.	SRCE	SERC Central
5.	NEWE	NPCC New England	16.	SRVC	SERC VACAR
6.	NYCW	NPCC NYC/Westchester	17.	SPNO	SPP North
7.	NYLI	NPCC Long Island	18.	SPSO	SPP South
8.	NYUP	NPCC Upstate NY	19.	AZNM	WECC Southwest
9.	RFCE	RFC East	20.	CAMX	WECC California
10.	RFCM	RFC Michigan	21.	NWPP	WECC Northwest
11.	RFCW	RFC West	22.	RMPA	WECC Rockies

Figure 7. EIA electric module regions

Regional Results

Results in some regions are very similar to the national results, but other regions vary substantially. For example, in the medium-high-change scenario, electricity consumption grows modestly over the 2014-2040 period in the majority of regions, with sales growth at less than 0.5% per year. However, in eight regions, consumption decreases (see table 2 below).

In the high-change scenario, electricity consumption falls modestly in most regions, but there is only one region (MRO East) where sales decline by more than 1% per year. In this scenario there is still modest growth (less than 0.5% per year) in three regions: SPP South, WECC Southwest, and WECC Northwest.

Thus even at the regional level, there is no death spiral. However, as with our national results, in regions with declining sales, companies will need to rethink how they provide a return on investment to their shareholders. It is also worth noting that impacts will likely be greater in some subregions than is shown by our regional analysis. Compound growth rates by region, as well as which primary states make up each region, are summarized in table 2.

Table 2. Compound annual growth rates for electricity consumption by region over the 2014-2040 period

Region	Primary states included	Reference case	Medium-high change scenario	High change scenario
New York State	NY	0.10%	-0.35%	-0.73%
TRE All	TX	0.89%	0.02%	-0.66%
FRCC All	FL	0.84%	0.10%	-0.74%
MRO East	WI	0.46%	-0.48%	-1.44%
MRO West	MN, IA, NE, ND, SD	0.58%	0.06%	-0.47%
NPCC New England	ME,NH,VT,MA,RI,CT	0.21%	-0.13%	-0.37%
RFC East	East PA, MD, DE, NJ	0.40%	-0.55%	-0.54%
RFC Michigan	MI	0.41%	-0.12%	-0.58%
RFC West	North IL, West PA, IN, OH, WV	0.48%	-0.10%	-0.46%
SERC Delta	AR, LA, West MS	0.85%	0.04%	-0.44%
SERC Gateway	East MO, South IL	0.49%	-0.42%	-0.92%
SERC Southeastern	AL, GA, Southeast MS	0.86%	0.19%	-0.04%
SERC Central	KY, TN, Northeast MS	0.86%	0.08%	-0.49%
SERC VACAR	VA, NC, SC	0.86%	0.12%	-0.53%
SPP North	KS, West MO	0.57%	-0.11%	-0.38%
SPP South	OK	0.88%	0.23%	0.03%
WECC Southwest	AZ, NM, South NV	1.15%	0.34%	0.01%
WECC California	CA	0.74%	0.23%	-0.21%
WECC Northwest	WA, OR, ID, MT, UT, West WY, North NV	0.87%	0.63%	0.32%
WECC Rockies	CO, East WY	1.15%	0.41%	-0.04%
United States	All states, excluding AK and HI	**0.70%**	**0.04%**	**-0.39%**

There are also significant differences between the regions in the impacts of energy efficiency, photovoltaics, and electric vehicles. Energy efficiency effects are particularly strong in regions that have not historically done much energy efficiency, since these regions have relatively little efficiency embedded in the reference case. Photovoltaics are particularly strong in the medium-high scenario in California, MRO East, RFC East, and WECC Southwest. This list expands to other regions in the high scenario. Electric vehicles are strong in the medium-high scenario in New York, New England, RFC East, and California. The regional differences for photovoltaics and electric vehicles all reflect trends in the EIA reference case. Table 3 summarizes further details on these findings. CHP is not shown in this table because EIA includes extensive DG and CHP in its reference case, although some CHP makes our scenarios in California and SERC Central. Additional details on each region can be found in the figures in Appendix A.

Table 3. Impact of energy efficiency, solar PV and electric vehicles on electricity consumption by region and scenario

2040 consumption/generation as a percent relative to AEO 2014 reference case for 2040						
Region	Medium-high-change scenario			High-change scenario		
	Energy efficiency	Solar PV	Electric vehicles	Energy efficiency	Solar PV	Electric vehicles
New York State	-14.67%	-4.73%	4.86%	-21.93%	-15.30%	14.59%
TRE All	-17.87%	-6.34%	1.25%	-24.70%	-15.07%	3.76%
FRCC All	-17.76%	-5.78%	1.85%	-24.49%	-18.56%	5.54%
MRO East	-10.96%	-15.98%	1.76%	-18.08%	-29.55%	5.29%
MRO West	-11.63%	-5.09%	1.33%	-18.71%	-11.84%	4.00%
NPCC New England	-6.77%	-9.37%	4.31%	-14.04%	-16.11%	12.93%
RFC East	-16.27%	-13.85%	3.69%	-23.34%	-13.79%	11.08%
RFC Michigan	-15.32%	-2.54%	1.79%	-22.43%	-8.84%	5.37%
RFC West	-16.96%	-1.86%	1.98%	-24.08%	-6.48%	5.93%
SERC Delta	-20.16%	-2.62%	1.23%	-27.07%	-7.59%	3.70%
SERC Gateway	-17.84%	-7.86%	1.51%	-24.90%	-13.43%	4.54%
SERC Southeastern	-19.99%	-0.44%	1.53%	-26.87%	-1.52%	4.58%
SERC Central	-19.15%	-2.48%	1.02%	-26.13%	-8.90%	3.06%
SERC VACAR	-19.02%	-4.11%	1.84%	-25.84%	-13.54%	5.52%
SPP North	-19.54%	-0.57%	1.30%	-26.55%	-1.97%	3.89%
SPP South	-19.29%	-0.03%	1.29%	-26.15%	-0.10%	3.88%
WECC Southwest	-12.47%	-13.26%	1.86%	-19.09%	-16.73%	5.58%
WECC California	-2.90%	-17.82%	3.05%	-9.73%	-26.39%	9.15%

2040 consumption/generation as a percent relative to AEO 2014 reference case for 2040						
Region	Medium-high-change scenario			High-change scenario		
	Energy efficiency	Solar PV	Electric vehicles	Energy efficiency	Solar PV	Electric vehicles
WECC Northwest	-10.57%	-2.35%	2.58%	-17.41%	-7.77%	7.74%
WECC Rockies	-14.14%	-9.27%	1.84%	-20.82%	-15.25%	5.53%
United States	-15.52%	-5.76%	2.07%	-22.46%	-11.79%	6.20%

Scenarios for Natural Gas Utility Sales

The future of natural gas sales will be very much affected by the price of natural gas, which in turn is affected by the supply. In 2009, natural gas average wellhead prices fell by more than 50%, and since then they have fluctuated in a band of about $3 to $5 per thousand cubic feet, with occasional excursions higher and lower. Wellhead prices do not include the cost of interstate pipelines and local distribution and also do not include any hedging costs to manage price volatility. These costs can be substantial. Prices paid by residential and commercial consumers have fallen more gradually, with 2013 average residential prices 15% below 2009 prices. Over the 2009-2013 period, U.S. natural gas consumption has increased 14%, including a 19% increase in the power sector, a 21% increase in the industrial and transportation sectors, 6% in the commercial sector, and 3% in the residential sector (EIA 2014a).

Projections by EIA in their 2014 reference case show natural gas use increasing 20% over the 2012-2040 period. EIA is more bullish on natural gas consumption in their 2014 forecast than in their 2013 forecast, with their 2014 projection of 2040 consumption 9% higher than their 2013 projection (EIA 2013a, 2013b). EIA also prepares a high oil/gas resource case. In this case, in the 2014 forecast, 2040 consumption is 17% higher than in the reference case. These trends are shown in figure 8. All of these scenarios assume the continuation of current trends and, with the exception of increased natural gas availability, no major disruptive changes.

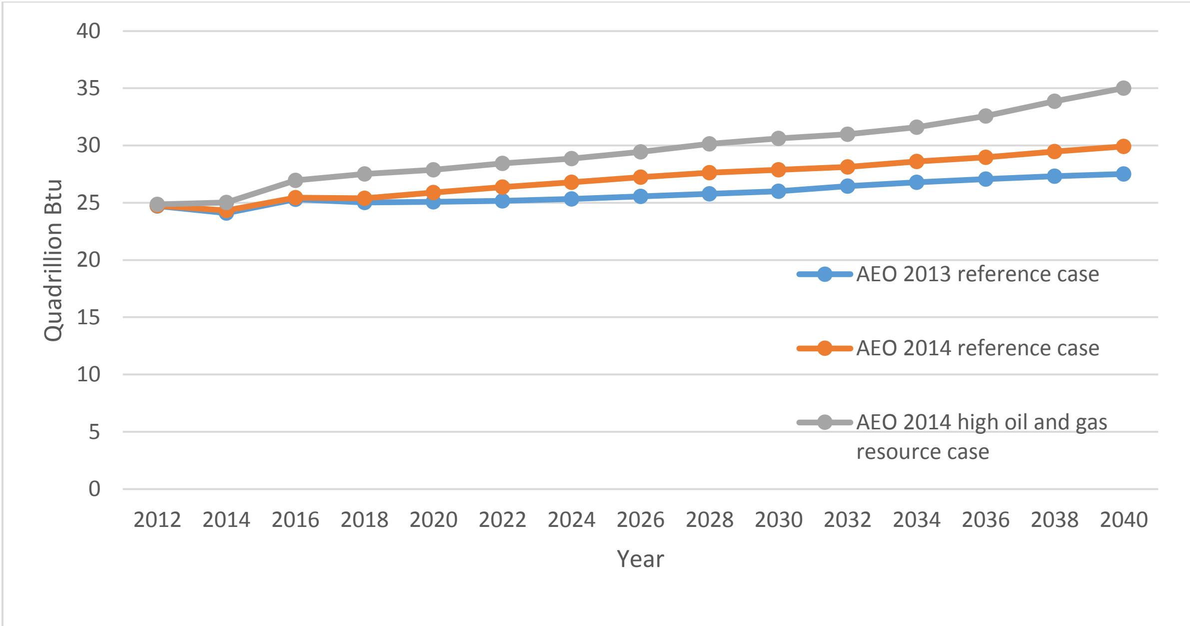


Figure 8. U.S. natural gas consumption in various forecasts

Comparing consumption in 2012 and 2040, the largest increases in natural gas use in the EIA 2014 reference case are in the power and industrial sectors, followed by the transportation and commercial sectors. Residential sector consumption is forecast to decline slightly. The high gas case includes dramatically higher consumption in the power sector and modestly higher consumption in each of the other sectors. These trends are illustrated in figure 9.

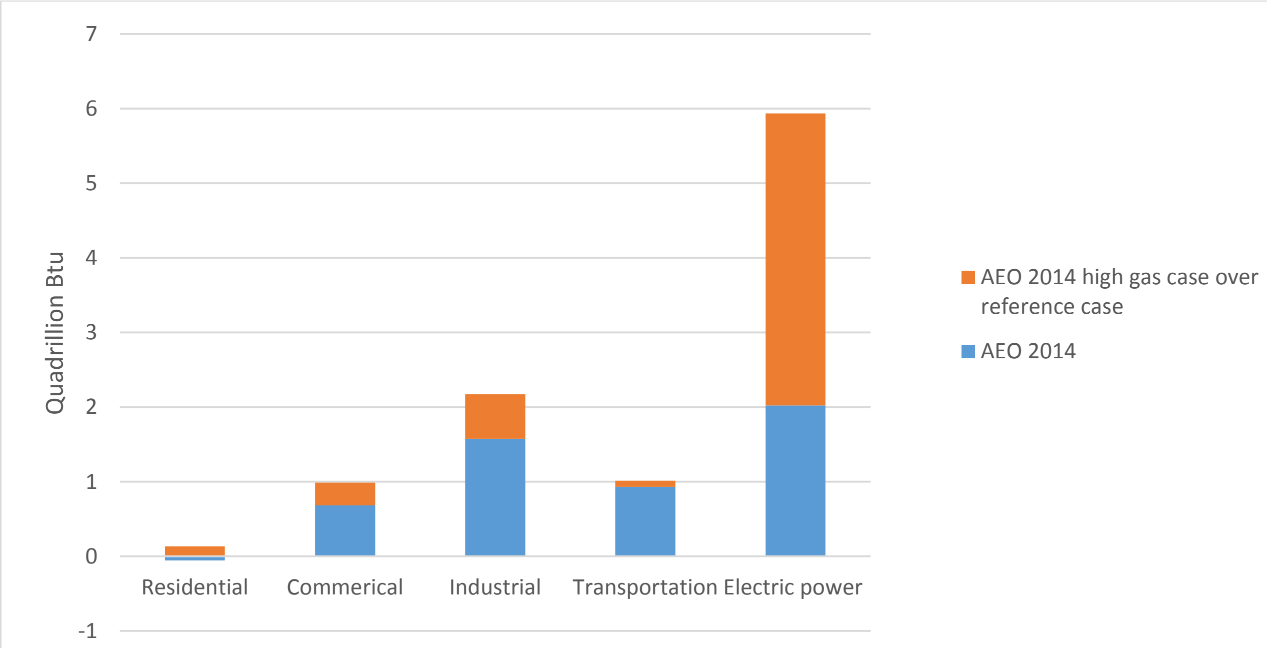


Figure 9. Change in natural gas consumption over the 2012-2040 period in various forecasts. *Source:* EIA 2013a and 2014c.

We did not prepare additional natural gas scenarios, but given the increase in consumption between EIA 2013 and 2014 forecasts, we surmise that even higher natural gas consumption is possible than is estimated in the 2014 high gas/oil supply case.

Lessons from the Telecommunications Industry

Analogies have been made between the evolution of the telecommunications industry over the past 30 years and what could happen to electric and gas utilities. There are both important similarities and significant differences, and it is unclear what lessons from telecommunications might apply to energy. We summarize some of the major issues in the paragraphs below.

Traditionally, telecommunications was considered a natural monopoly, just like electric and natural gas service. At one point, AT&T served most of the U.S., but in the 1980s AT&T was broken up into "Baby Bells," giving birth to such companies as Bell Atlantic (now part of Verizon) and US West (now part of CenturyLink). Even with this breakup, each region had a single service provider. In the 1970s and 1980s, new long-distance companies emerged (e.g., Sprint and MCI) to compete with AT&T, facilitated in part by technology that allowed communications to be sent over long distances by microwaves. In the 1990s, cell phone service became widely available, providing an alternative to wire-based service. The Internet took off around the same time, providing new ways to communicate and, ultimately, voice over internet protocol (VoIP) service (e.g., Skype). Then Congress passed the Telecommunications Act of 1996, which undertook a major restructuring of the sector, in particular opening it up to more competition. Other changes in the telecommunications industry at the same time included dramatic reductions in the costs of transmission and switching, digitization, increased communications via computers and other multifunction devices, and the reallocation of the electromagnetic spectrum, creating more room for wireless competition (Economides 1998).

As a result of these regulatory and technical changes, the telecommunications industry expanded the services it offered. While the cost of some individual services such as long distance went down, total revenues generally went up through 2001 and then flattened since then as illustrated in figure 10.

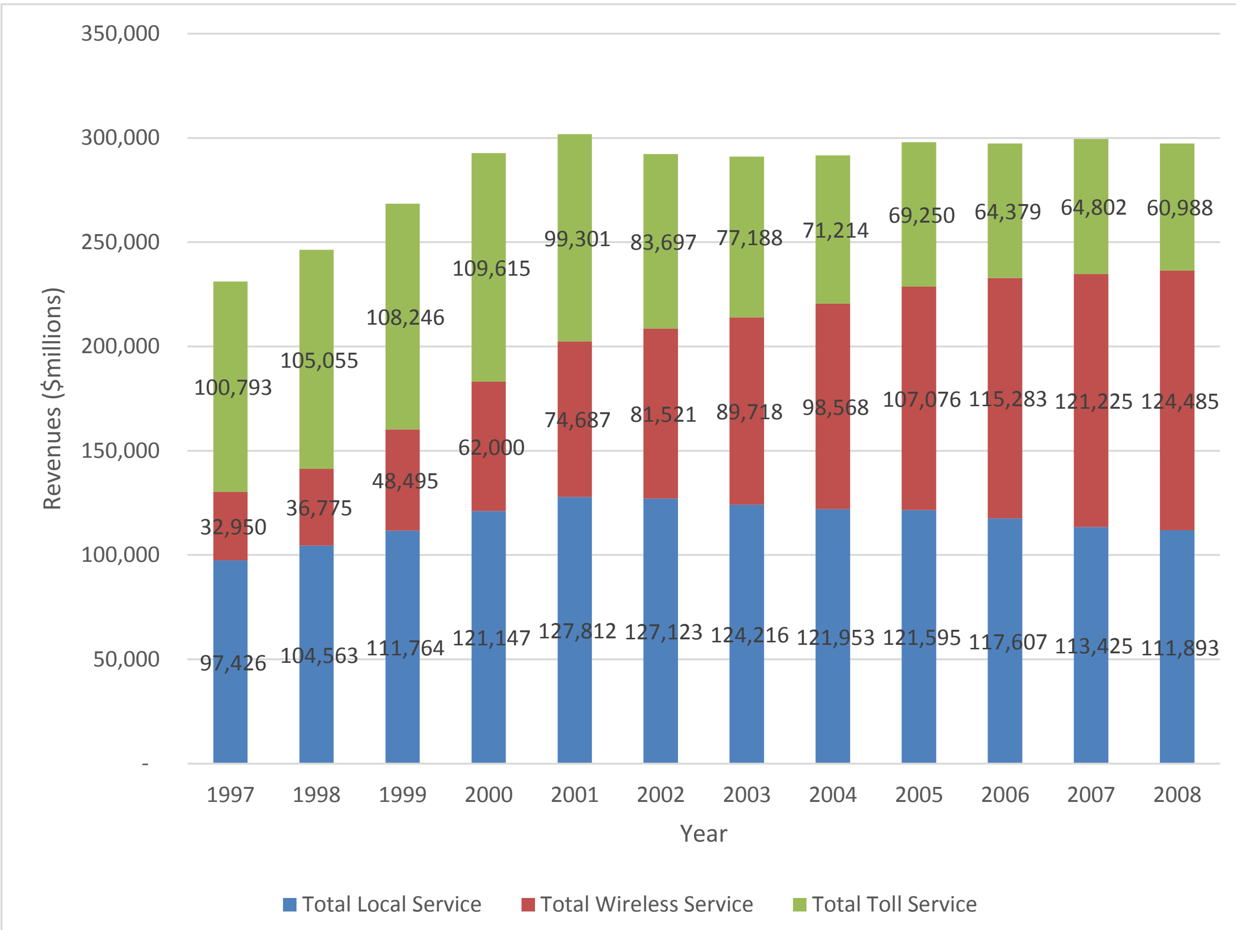


Figure 10. Telecommunications revenue by type of service, 1997-2008. *Source:* ACEEE analysis using data from FCC 2010 and 2002.

As summed up by Advanced Energy Economy (AEE) in one of their forums on the utility of the future, "massive gains from innovation [in telecommunications] created new value for customers as well as for a wide range of independent actors" (AEE 2013).

More recently, some phone companies have asked for permission to gradually phase out their old wires-based systems, arguing that they are expensive to maintain and that most wire-system customers have access to other forms of communication. For example, in 2012, just 9% of customers had access only to landlines, while 36% used only wireless (i.e., had "cut the cord"), with the remaining 55% having both land and wireless service. As wires-only service has declined substantially, questions are now being raised whether it is cost effective to maintain landline service, a situation that some observers have called a death spiral. The debate is complicated by equity issues, as those who rely on telephone wires tend to be rural and poor (Caperton and Hernandez 2013, Svensson 2013).

How much of this experience is applicable to electric and gas utilities? A number of points are relevant.

- Many of the changes in the telecommunications field relied on new technologies such as wireless service for which there is currently no parallel in the energy field. For example, there is no serious discussion of beaming electricity via microwaves.
- The telecommunications industry prospered on new, largely unregulated services such as cellular phones and broadband internet and entertainment. Companies have made their profits on these new services, not on traditional regulated land lines. There are certainly opportunities for new energy services, but it is not clear that they could eventually surpass traditional services as has happened with telecommunications.
- The price of entry for new telecommunications firms was generally modest (Clavenna 2013). The cost of building energy infrastructure is typically much greater.
- The environmental impact of expanding telecommunications infrastructure is generally much lower than that of expanding energy infrastructure. Unlike increased energy use, increased use of telecommunications generally has little environmental impact.
- There are many fewer key players in the telecommunications industry than in the utility industry. A significant majority of telecom service is provided by a handful of companies (e.g., AT&T, Verizon, Sprint, T-Mobile, Comcast, and Time Warner). There are more than 100 large utilities, not to mention thousands of smaller ones.
- Bankruptcies played a substantial role in writing off some of the legacy costs in telecom, a situation that few would advocate as a course of action for the energy sector.

In sum, although utilities may find some opportunities to create value and financial returns from new services, many aspects of the telecommunications model are unlikely to apply to the energy sector.

Options for the Future

Dozens of articles, papers and reports have been written about the future of the utility industry and about the ways in which it can or should adapt. We summarize more than 50 of these pieces in Appendix B. Most of them focus on electric utilities, but some apply to natural gas utilities. We also conducted interviews with about a dozen utility industry participants and observers to get their insights into these issues. Considered together, these materials and sources show that there is a wide range of opinions on where the utility industry is or should be heading. Some observers such as Peter Fox-Penner (2010) and the

Rocky Mountain Institute (2013) suggest that radical change is needed, while others suggest only incremental changes. Many observers suggest substantial but not radical changes.

In this section we summarize the many changes to the utility system that observers have suggested. These range from incremental changes in current business practices to major long-term models that would fundamentally restructure the utility industry. For ease of presentation and understanding, we group the suggestions into five categories and discuss each of them in turn:

1. Better management
2. Regulation
3. Energy resources and infrastructure
4. Services
5. Long-term models

Within each category, we order the suggestions from the least to the most controversial, although these are just approximations: opinions about the relative controversy of each option are likely to vary. We focus on investor-owned electric utilities, although many of the options also apply to other utilities. We discuss implications for public and natural gas utilities at the end of this section. Readers interested in just our analysis of the options and not a detailed description of them should go to the section called "Impacts of the Options" that begins on page 58.

We should note that we do not necessarily endorse all of the options we discuss. We present our recommendations near the end of the report, sorted by short-, medium-, and long-term changes.

Better Management

When income is threatened, a standard response is to improve the management of the enterprise to reduce costs. For example, Scalise and Zech (2013) from Bain and Company suggest that "given the squeeze between mandated investments and flat-line growth, cutting costs is no longer an option but a requirement for survival." They describe four strategies that offer the greatest potential for cost reduction:

- *Raise productivity at the front line*. Improve field services and call centers. For example, optimize scheduling of field service (instead of making one stop and then returning to base). Improve communication between field crews, foremen, and planners so proper equipment is on board and problems can be solved in real time.
- *Reduce external spending*, for example by instituting comprehensive, cross-company purchasing programs to gain more bargaining power and steeper volume discounts.
- *Restructure and streamline organizations*. Identify "shadow functions" where remote sites have staff that replicate work at the main office. Standardize common processes and eliminate custom, one-off initiatives. Streamline the managerial layer and overhead resources.

- *Manage the portfolio and prune assets*. Periodic reviews of costs and performance can reveal opportunities to rebalance operations or pare the organization. Examples include shifting more operations to low-cost fuels, locking in long-term fuel supply controls when prices are low, and integrating into upstream natural gas supplies.

Similarly, in a special issue of the *Electricity Journal* on the utility of the future, Hogan (2013) makes the following suggestions for the larger grid:

- *Reduce market area fragmentation*. The benefits of balancing supply and demand over larger regions far outweigh the costs of integration. These benefits include better access to high-quality sources of renewables, less aggregate variability in supply and demand, lower integration costs due to better use of transmission, and risk mitigation from both resource and market diversification.
- *Improve operational flexibility.* Flexibility can reduce the need for backup capacity and transmission expansion. Also, operational flexibility reduces the need to curtail renewable production during periods of low demand and high renewable supply.
- *Upgrade grid operations to unlock flexibility in the short term.* Upgrade grid scheduling, dispatch, and weather forecasting to allow for more flexible and reliable system operations. Consolidate balancing areas and expand the role of demand response.

In the same special issue, Jimison and White (2013) suggest dynamic transfers between balancing areas (allowing transfers in real time rather than according to a previous static schedule), real-time path ratings (adjusting allowed ratings for transmission based on local conditions at a moment in time), improved reserve sharing, and improved wind and solar forecasting. Again in the same issue, Harvey and Aggarwal (2013), suggest improving coordination between balancing areas, dispatching on shorter intervals, and using dynamic line rating to make the most of existing transmission lines. More generally, the MIT report on *The Future of the Electric Grid* (2011) discusses many opportunities for improving the functioning and reliability of the grid that are made possible by technical developments in sensing, communications, control, and power electronics.

The electric industry has already begun to implement some of these approaches, as documented in a recent e-book published by the Institute for Electric Innovation (IEI), an educational affiliate of the Edison Electric Institute (IEI 2013a). This book provides case studies of the following:

1. *Grid edge optimization*. Increasing visibility at the edges of the traditional electricity distribution network to improve service reliability and increase grid efficiency. Includes Volt/VAR optimization (optimizing voltage and reactive power) and conservation voltage reduction.
2. *Grid resiliency, reliability, and restoration*. Making the grid less vulnerable to weather-related outages, and reducing the time it takes to restore power after an outage does occur. Includes distribution automation equipment that reroutes the flow of electricity and isolates an outage to a small line section so that fewer customers are disrupted.

3. *Grid visibility and asset management*. Deploying distribution automation and advanced metering infrastructure, and linking systems to improve asset management and the operational efficiency of electric distribution systems.
4. *Grid analytics*. Using information from smart meters, grid sensing devices, and asset monitoring for end-to-end data analytics to optimize transmission and distribution systems and improve grid performance.
5. *Renewable energy, distributed generation, and storage integration*. Integrating distributed generation resources into the power grid, deploying micro-grids, and using electrical energy storage devices in a robust, flexible, and reliable grid.
6. *Demand response and energy management*. Using technology to simplify and automate customer involvement in peak demand response events, and using demand response to manage renewable energy integration.
7. *Customer engagement*. Educating and empowering customers to manage their energy use more strategically and efficiently.

Management also includes mergers. We have seen extensive merger activity in the utility industry as companies seek to gain economies of scale and increase returns on investment. Such activity is likely to continue.

REGULATION

All investor-owned utilities (IOUs) are subject to regulatory oversight by state public utility commissions (PUCs), as are a few public utilities. Since regulators set rates and the various rules that guide utility actions, the future of utilities depends in part on their decisions. In addition, environmental and other agencies establish other regulations that affect utilities. In our review of the literature, we identified eight options that fall under the broad topic of regulation:

- The proper role of regulation
- Decoupling and shareholder incentives
- Reform of rate design
- Performance-based regulation
- Fostering innovation including expanded R&D and more competition
- Long-term climate policy
- Investment and cost recovery
- Energy efficiency utilities

We discuss each option in turn, and then we briefly mention a few other regulatory options at the end of this section. We should also note that there is interest by utilities in increasing the services they offer. We discuss this topic later in the report in a section on services (page 47), but note here that any new services will involve some regulatory oversight.

The Proper Role of Regulation

If the role of utilities may be changing, several observers suggest that it is time to carefully consider the role of regulation so that it can aid rather than hinder desirable changes. Most prominently, Ron Lehr (2013a), the former chair of the Colorado Public Utilities

Commission, suggests that regulators need to align regulatory incentives so utilities can pursue broader societal policy goals in ways that also benefit customers and shareholders. In terms of specific policy recommendations, Lehr (2013b) provides further details, suggesting that regulators first consider fundamental questions:

- What outcomes does society want from the electric utility industry?
- What role should utilities fulfill in the future?
- What incentives should law and regulation provide?
- How must regulation be modified to provide these incentives?
- Can utilities' clean energy strategies become their most profitable courses of action?

More specifically, Lehr suggests that regulators assess whether current approaches to regulation are sufficient to support new utility business models that address current challenges, asking such questions as:

- Will regulatory business as usual be able to provide comprehensive and coordinated solutions across issues facing utilities today and in the future?
- Even if workable today, could regulation provide better incentives for utility performance on traditional goals such as cost, environmental performance, and the adequacy and reliability of service; lead utilities toward constructive responses to new challenges that require innovation, such as new technology, cybersecurity, and storm-damage repairs; and improve utility response to rapidly changing consumer preferences?
- What policy, financial, market, and operational considerations, constraints, and opportunities need to be analyzed to determine an appropriate role for utilities going forward? What trends are evident that suggest the potential for progress toward new utility business models and regulation that supports them?
- What are the planning considerations now used by regulated utilities? Could consumers be spared future risks if these considerations and utility planning were more comprehensive or focused more on risk management?
- What do consumers want? Has consumer research segmented consumer requirements beyond residential, commercial, and industrial, or beyond firm and non-firm service classes?
- Have required utility outputs been defined? Have they been linked to metrics and measurements, and to incentives?
- What metrics and measurements are used in regulating utilities? Does consumer satisfaction play a role in utility profitability? Are utility profits linked to consumer requirements? How?
- Who are the stakeholders, i.e., those with enough of a stake in regulatory outcomes to require that they be included in discussions and consensus about changing the ways of achieving those outcomes? What are the opportunities to add more and higher-quality communications to the regulatory process?

Lehr (2013a) outlines several regulatory systems already in place which may serve as examples for the regulatory scheme of the future. These include performance-based regulation as now being implemented in the United Kingdom, the "Iowa Model," which he describes as a settlement process between MidAmerican (a major electric utility) and the Iowa Utilities Board that lessened the transaction costs associated with a typically adversarial process, and a "Grand Bargain" to produce, through negotiation, a thorough regulatory regime that would address a broad set of issues in a consistent manner. We discuss the U.K. model later in this report.

Other observers also suggest that the fundamentals of regulation be reassessed. For example, Advanced Energy Economy (AEE 2014), in a report on *Creating a 21st Century Electricity System for New York State*, suggests "advancing to an increasingly flexible and performance-oriented regulatory system" based on several guiding principles:

- Maintain effective aspects of the current regulatory approach that will serve as the foundation for the future.
- Modify the regulatory approach to realize the future model by measures such as supplementing traditional cost-of-service regulation with symmetric performance incentives, aligning utility investments to the achievement of state policy objectives, and creating greater clarity for long-term investments and cost recovery.
- Adjust ratemaking, including rate design, to allocate costs equitably, reflect the true value of the grid, and address structural changes in utility load profiles.
- Improve rate design to allow customers to make informed choices to enhance their value of service, aligned with policy objectives.

We pick up on many of these themes in subsequent sections of this report.

Finally, we note that regulatory rules will need to continue to evolve, and reviewing them is not a one-time event. As Creyts and Newcomb (2014) put it, "the rules governing the network must be adaptive to constantly shifting asset configurations, operations and other factors."

Decoupling and Shareholder Incentives

Electricity sales may decline and utilities become concerned that they may not be able to fully recover their fixed costs. Decoupling is a strategy that can ensure full cost recovery. It involves making small upward or downward adjustments to rates so that authorized fixed costs are fully recovered but not over-recovered. When sales are growing, decoupling will often result in rate decreases, while the reverse is true when sales are declining. As of October 2013, decoupling has been adopted for some or all utilities (electric and/or gas) in 16 states (Downs et al. 2013). In a survey of utility personnel by Utility Dive (2014), when asked how they would react if there were low-to-no growth in electric sales in coming years, 33% of respondents said they would seek decoupling of electricity sales from profits, and an additional 26% would seek undefined "rate loss recovery mechanisms." Further information on decoupling and its impacts can be found in Morgan (2013).

Similarly, under traditional regulation, utilities earn money by increasing their rate base and then earning a return authorized by regulators on this rate base. If the future brings more energy efficiency and distributed generation, then the need for new utility investments will be lower, reducing opportunities for utilities to earn profits. To address this concern, as of October 2013, 29 states have adopted some form of shareholder incentive that rewards utilities for achieving energy efficiency goals, and sometimes other goals as well (Downs et al. 2013). Further information on shareholder incentives and their impacts can be found in Hayes et al. (2011) and York et al. (2013).

Decoupling and shareholder incentives are two separate items, and while many states have done both, some states have only done one or the other. In order to simplify our subsequent discussion, we group these two options together, while acknowledging that they can and often are considered separately.

Given the already substantial incidence of decoupling and shareholder incentives, quite a few utility observers have suggested expanding their use as part of a utility-of-the-future strategy. For example, the Rocky Mountain Institute (RMI), in its 2013 report called *New Business Models for the Distribution Edge*, discusses four possible models for the utility of the future. The least radical of these is to "reduce disincentives and reward performance within the existing model"(RMI 2013). This model includes such measures as decoupling revenues from sales so fixed costs are recovered, as well as developing new pricing models and cost allocation methods. These are discussed in the next section.

Similarly, Scalise (2013) from Bain and Company discusses a "decoupled monopoly" as the middle of three possible models for the future. (His two others are traditional vertical integration and retail competition). A decoupled monopoly would be a distribution company, with wholesale competition at the generation level. Decoupling and incentives are also mentioned in various ways by Bazilian et al. (2013), Goldman et al (2013), and Ceres (2010).

The Edison Electric Institute (EEI) has also weighed in on decoupling and incentives in several publications. First, a 2007 report called *Making a Business of Energy Efficiency: Sustainable Business Models for Utilities* discusses three families of regulatory incentives, one of which is the "conventional regulatory incentives family." (We discuss the other EEI families later.) The regulatory incentives family encompasses two particular business models: (1) a shared savings model in which a utility earns a share of the net benefits from its efficiency efforts, and (2) a capitalization model in which a utility can earn a rate of return on its efficiency investments. This report goes on to argue that these mechanisms are "the least likely to be sustainable, as they rely upon the continuity of regulatory favor for their sustainability" (EEI 2007).

More recently, a 2013 IEI paper (2013b) notes that revenue decoupling promptly restores utility net revenues that would otherwise be lost due to declining electricity sales, but it goes on to argue that DG impacts are much greater than the energy efficiency impacts typically covered by decoupling. The paper then suggests that decoupling to address the costs of net metering would shift costs to non-DG customers. In other words (to summarize a conversation with an EEI manager speaking off the record), decoupling can help utilities, but it does not fully and fairly solve the problem of fixed cost recovery.

Reform of Rate Design

The literature features a variety of proposals to reform electricity pricing so that all customers pay their fair share of systems costs, although there are likely to be differences of opinion on the definition of "fair." In the sections below, we discuss three issues relating to the reform of rate design.

RECOVERING FIXED NETWORK COSTS VIA CUSTOMER CHARGES THAT DO NOT VARY WITH THE VOLUME OF ELECTRICITY CONSUMPTION This is another option besides decoupling; the phrasing comes from the MIT *Future of the Electric Grid* report (MIT 2011). The grid provides important benefits to all customers and all customers need to help pay for the grid. There are several ways this can be done. First, EEI suggests "institut[ing] a monthly customer service charge to all tariffs [rates] in all states in order to recover fixed costs" (EEI 2013). IEI (2013b) adds demand charges to this list. AEE cautions that in designing such charges, it is important not to deter customer energy efficiency or distributed resource investments (AEE 2013).

On the other hand, in a proposal to the Sacramento Municipal Utility District, NRDC (2013) suggests that high fixed monthly fees reduce customers' incentive to adopt clean energy technologies (including efficient technologies). NRDC further argues that a planned $20 fixed monthly fee (significantly higher than typical fixed fees which are commonly in the $5-$10 range) combines what are effectively about $10 of truly fixed costs with about $10 of monthly costs that can vary over the long term due to changes in customer demand. To address these problems, NRDC suggests two charges that would each average about $10 per month per customer:

1. Convert the truly fixed charge into a minimum bill requirement. Such a charge will ensure that all customers help pay the cost of the system, but for the vast majority of customers (those who use more than $10 of electricity per month), a minimum bill requirement will incentivize energy efficiency and consumption reductions.

2. Institute a variable-demand charge that recovers an average of at least $10 per month from customers based on their peak demand for electricity measured in kW of power. This variable charge would change based on a customer's demand and would help recover long-run variable costs such as the costs of improved infrastructure.

According to NRDC, this latter charge could be based on a variety of options:

- *Maximum demand charge*. Variable demand charge based on the customer's highest level of demand throughout a month. This charge format would incentivize off-peak charging of electric vehicles and reduced electricity consumption in general.

- *Average maximum demand charge*. Variable demand charge based on an average of several meter readings.
- *Restrictions to on-peak hours*. A utility could restrict the designation of either a maximum demand charge or an average demand charge to demand that coincides with peak hours. This would more closely align the charge with stress on the grid.
- *Capping the variable demand charge*. A maximum cap on monthly demand charges.

More recently, in February, 2014, EEI and NRDC released a statement on a variety of issues including rate design. Among other provisions, it states:

> Utilities deserve assurances that recovery of their authorized non-fuel costs will not vary with fluctuations in electricity use. Customers deserve assurances that costs will not be shifted unreasonably to them from other customers. Rate designs will continue to develop that reward customers for using electricity more efficiently. Examples include, but are not limited to real-time pricing and variable demand charges that take advantage of digital meter capabilities where available. (NRDC 2014)

On the other hand, high fixed charges, demand charges, real-time-pricing, and minimum bills lack broad support at this point. One utility executive we interviewed off the record noted that there may be consumer and regulator resistance to residential demand charges. He also noted that minimum bills bring in little revenue and therefore do not do much to address the need to recover fixed costs in new way.

Utilities must be careful not to raise fixed charges so much that they encourage customers to fully disconnect from the grid. As Morgan Stanley stated in a recent research note, "higher fixed charges to distributed generation customers are likely to drive more battery purchases and exits from the grid" (2014). As indications of this possible trend, NRG Energy is now investing in small distributed generation systems using Stirling engines that it believes may be attractive to consumers for photovoltaic systems backup (LaMonica 2013). Likewise, RMI (2014) recently looked at opportunities to combine photovoltaics with battery storage to allow full disconnection from the grid; they found favorable economics in quite a few regions and applications in the 2020s and 2030s.

REFORM OF NET METERING Another issue that comes up in several discussions about the utility of the future is net metering. Net metering allows some customers, typically those with small renewable energy systems such as photovoltaics, to effectively run their meters in reverse when they supply extra power to the grid. In other words, net metering typically allows these customers to be paid for extra electricity at the retail rate rather than at the wholesale rate more commonly used for power purchases. According to the Solar Energy Industry Association, 43 states plus the District of Columbia had some type of net metering policy as of January 2014, although details vary significantly from state to state (SEIA 2013). Net metering policies are designed to jump start the market for qualifying resources by improving the economics for would-be purchasers. The solar industry also argues that its systems provide tremendous value to the grid and that being paid at retail prices is fair (SEIA 2012).

A review by RMI (2014) of 16 studies on the economics of net metering was inconclusive: the value of net metering varied across studies due to differences in local context, input assumptions, and methodologies. In addition, these studies implicitly assume a historically low penetration of distributed photovoltaics. As photovoltaics' penetration of the electric system increases, RMI says that more sophisticated and granular analytical approaches will be needed, and the total value is likely to change.

Still, it is widely acknowledged that you cannot have 99% of customers on net metering and leave the remaining 1% to pay for the system. For example, when California established net metering, the legislature capped the number of qualifying installations at 2.5% of aggregate customer peak demand. The California Public Utilities Commission (CPUC) subsequently changed the cap to 5%. Many other states have caps, which vary widely.

Some utilities have become concerned that since net metering customers do not contribute to the cost of building and maintaining the grid, other customers are subsidizing them. EEI and IEE are promoting three possible models to address this issue:

1. Redesign retail tariffs to make them more cost reflective (including adopting one or more demand charges).
2. Charge distributed generation customers for their gross consumption under their current retail tariff and separately compensate them for their gross (i.e., total on-site) generation.
3. Impose transmission and distribution (T&D) "standby" charges on distributed generation customers. These are typically fixed charges, but other options may be possible. (IEI 2013)

Net metering has recently been a major issue in Arizona and California, and it is likely to become so in other states. In California, the legislature passed a bill in October 2013 that directs the CPUC to establish a new tariff for net metering customers, covering connections after January 1, 2017 or earlier if any utility reaches the 5% cap on peak load subject to net metering (California Legislative Information 2013). In other words, the bill lifts the 5% cap, but requires the California Public Service Commission to set a tariff that is fair to all and in the public interest.

In Arizona, Arizona Public Service proposed either requiring net metering customers to pay a charge "for their use of the grid, based on how much electricity they use," or paying new system owners for power they sell to the grid "based on the market rates APS pays other generators for power" (i.e., at wholesale rather than retail rates) (Trabish 2013a). The Arizona Corporation Commission, the state regulator, ultimately decided to impose a small monthly charge of $0.70 per kW on net metering customers (Trabish 2013b). Thus the monthly charge would be $3.50 for a 5 kW system (a typical size).

A variation on this theme is to establish a "value-of-solar" tariff that explicitly estimates the value to the grid of renewable energy production, considering an array of costs and benefits. The Minnesota Public Utilities Commission recently set such a tariff, and it lets utilities determine whether they prefer to pay for solar electricity by paying the retail rate or the value-of-solar tariff (Haugen 2014).

The issue of tariffs for photovoltaics is closely related to broader tariff issues, and some solutions may be situated on the boundary between them. For example, Sedano (2014) suggests reclassifying a utility customer who implements an on-site PV system as one taking "connection" service. Such a "connection" customer would "be distinct from a 'requirements' customer and would see a tariff reflecting the costs of service assigned to it." Another option that is sometimes mentioned is charging some type of exit fee to current customers who totally disconnect from the grid, so that the cost of investments made to help serve those customers are not passed on to others. These and other concepts related to net metering are discussed by Linvill et al. (2013).

NEW TARIFF STRUCTURES Discussions about recovering fixed network costs and addressing net metering are likely to result in new tariff structures. These structures would recover fixed costs from customers in ways that regulators consider fair; i.e., they would promote outcomes seen as desirable while minimizing cross-subsidies. For example, Harvey and Aggarwal (2013) discuss "charging customers a fair price for grid services and pay[ing] customers a fair price for the grid benefits they create." MIT (2011) calls for developing "pricing regimes in which customers pay rates that reflect the time-varying costs of supplying power." And EEI (2013) suggests developing "a tariff structure to reflect the cost of service and value provided to DER customers," including off-peak service, backup interruptible service, and the pathway to sell distributed electric resources to the utility or other energy supply providers.

A variety of options should be considered when new tariff structures are developed, including time-differentiated rates (which vary the charge as the cost of service varies through the day and year), fees to provide basic grid services (as discussed in the section above on recovering fixed network costs), and buyback rates (the price paid to distributed power generators for their extra power). MIT (2011) also adds one other issue: developing price structures for electric vehicles to encourage charging during off-peak periods and discourage it during peak periods.

As noted in the section above, the California PSC is about to embark on a new rate design effort to address these various issues, and other states are likely to follow.

Performance-Based Regulation

Performance-based regulation (PBR) has been defined as "the implementation of rules, including explicit financial incentives that encourage a regulated firm to achieve certain performance goals, while affording the firm significant discretion in how the goals are achieved." Exercising this discretion, the firm uses its knowledge of its operating environment to achieve the desired goals. PBR also allows regulators and utilities to be forward looking and to identify and focus on key goals. It differs from cost-of-service regulation by relying more on explicit financial incentives and by affording more discretion to the regulated firm. Thus it tends to involve lighter regulatory burdens than traditional regulation. States have used PBR to regulate the telephone industry since 1985, and there are multiple examples of its use in the energy industry, including shareholder incentives for achieving energy-efficiency goals (Sappington et al. 2001).

Multiple observers have proposed PBR as a useful strategy for the utility industry in order to encourage innovation and give incentives to improve operational efficiency and service quality. For example, GE Digital Energy and the Analysis Group (2013) suggest a form of PBR they call "results-based regulation." This strategy is designed to support investments that deliver long-term value to customers, reward utilities for exceptional performance, and stay affordable by encouraging operational efficiencies and sharing cost savings with customers. As an example, these analysts describe the United Kingdom's newly-adopted RIIO model ("Revenue set to deliver strong Incentives, Innovation, and Output"). Under this model, utility revenues are determined by regulatory review of forward-looking utility business plans. RIIO sets a multiyear revenue cap that gives utilities an incentive to reduce their costs, as well as an earnings-sharing mechanism that lets customers benefit from utility cost savings. Utility rewards are determined by clearly defined metrics based on performance, with incentives for delivering value to customers. Additionally, funding is set aside to inspire innovation.

EEI (2007) also discusses PBR as an incentive model. It notes that a PBR plan can include multiyear versions of the conventional regulatory incentives for energy efficiency. Likewise, the Energy Future Coalition (2013) suggests that regulatory frameworks should reward utility performance, not necessarily sales volume, in order to incentivize reliability, quality, and security. They further suggest that "emphasis should be on reliable, measureable metrics for rating utility performance," based on customer satisfaction in particular. They recommend varying return on investment by plus or minus 1% based on performance using the chosen metrics.

Harvey and Aggarwal (2013) also support a move away from rate-of-return regulation. They suggest using performance-based regulation that gives utilities the freedom to innovate or call on others for specific services. And Goldman et al. (2013) also consider PBR to be an option, noting that "economists perceive it as better than cost of service/rate of return because of stronger incentives for cost containment and innovation." However, Goldman et al. note that PBR "can lead to dissatisfaction with audits, prudence and used and useful reviews" and also that it "can take many forms and has a variety of design issues that make creating a system time-consuming and challenging for the uninitiated."

Aggarwal and Burgess (2014) provide some concrete examples of how PBR can work in a report called *New Regulatory Models*. Although they do discuss the RIIO model, all their other examples involve just a single goal including incentives for nuclear plant performance at the Fort St. Vrain plant, revenue sharing for off-system sales involving Xcel Colorado and

Mid-American Energy, performance incentives for energy efficiency in Massachusetts, and smart-grid investment incentives in Illinois.

Fostering Innovation Including Expanded R&D and More Competition

Many observers recommend that the utility system of the future should encourage innovation. For example, accelerating innovation and advanced energy deployment was the overarching theme of a series of CEO forums convened by Advanced Energy Economy and MIT (AEE 2013).

The literature on accelerating innovation calls for utilities to expand R&D, competition, and partnerships with more innovative firms in other fields. Although the second area clearly relates to regulation and the other two are on the cusp between regulation and other topics such as services, we group them together here for simplicity. The three areas overlap, but each of them can also be pursued independently.

R&D The MIT *Future of the Electric Grid* report (2011) calls for expanding R&D in key areas including computational tools for bulk power system operation, methods for wide-area transmission planning, procedures for response to and recovery from cyber-attacks, and models of consumer response to real-time pricing. It also suggests that detailed data should be compiled and shared. The Executive Office of the President's *Policy Framework for a 21st Century Grid* suggests sharing information from smart-grid R&D and demonstration projects, catalyzing the development and adoption of open standards, developing consumer-facing devices and applications to make it easier for users to manage energy consumption, and developing adequate consumer and privacy protections (Executive Office of the President 2013). DOE (2012) discusses its R&D work in seven areas: renewables integration, smart grid, advanced modeling, cyber security, energy storage, power electronics and materials, and institutional and market analysis.

Analysts at EPRI (2014) also discuss the need for R&D as part of their action plan for achieving an integrated grid of central and distributed energy resources. They suggest research in areas such as communications technologies, smart inverters, distribution management systems, and ubiquitous sensors. They also recommend a modeling and demonstration program to prepare for the system-wide implementation of integrated-grid technologies in the most cost-effective manner. They note that they plan to develop a framework for assessing the costs and benefits of combinations of technologies that lead to an integrated grid.

COMPETITION Hogan (2013) suggests adapting forward investment mechanisms to capture the value of certain resource capabilities. Also, forward markets for specific system services and time shifting services should be adopted, and new market entrants should be encouraged whenever possible. Harvey and Aggarwal (2013) suggest opening long-term markets for new services such as fast-start or fast-ramping services to meet sudden needs for power, for example when the wind suddenly dies.

PARTNERING In their paper, "Distributed Energy: Disrupting the Utility Business Model," Hannes and Abbott (2013) from Bain and Company suggest several strategies that utilities can pursue to survive the growing use of distributed generation. One of these is to "explore partnerships, joint ventures and acquisitions," using these to "build up distributed energy capabilities and to tap into entrepreneurial activity in this area." (We discuss their other strategies later.) The AEE CEO Forums (AEE 2013) also recommended promoting more opportunities for profitable partnerships between incumbents and innovators, including risk-sharing between load-serving entities and providers of new technologies and services, and possible ways for new ventures to access low-cost utility capital.

Long-Term Climate Policy

In years past, there was substantial interest in having the federal government establish a long-term climate policy so that utilities would know the rules of the road and could make long-term business decisions based on this knowledge. For example, in a report called *Climate Policy Uncertainty and Investment Risk*, IEA (2007) finds that "in some cases business decisions [on power sector investment] will be different under conditions of policy uncertainty." IEA further finds that in the short term, climate-policy uncertainty will have an effect on investment risk, but this risk will gradually decrease as a market for climate solutions and pollution mitigation investment is created.

Long-term U.S. climate policy is very unclear at present, as one political party wants to establish such a policy and the other questions whether climate change is real and hence whether any policy is needed. Some states are starting to fill this gap, establishing their own policies to help drive their decisions. In California, for example, many decisions are being driven by their climate law, AB32. Other public and private parties are also setting their own policies, including quite a few cities, universities, and private companies who have made climate commitments of various types. Given the uncertainty as to future policies, utilities need to make decisions that are flexible or anticipate decisions they think are most likely.

We found one recent study on the future of the utility industry that called for the establishment of climate policy (CSIRO 2013), but that was in the Australian context. Recent U.S. studies on the utility industry generally do not mention the need for climate policy. That could very well indicate that in the current political environment, long-term policy is unlikely to be established in the near future. Still, since power plants have lives of many decades, possible future regulations are a consideration. For example, Jim Rogers, former CEO of Duke Energy, noted at a recent forum that Duke routinely includes a price for carbon (often involving several scenarios) in their analyses of potential construction projects. He stated, "A prudent operator and a prudent builder need to assume a price on carbon" (Rogers 2014).

While not a comprehensive long-term policy, we also note that an issue receiving extensive attention is a rulemaking now being conducted by EPA to set carbon dioxide emission standards for existing power plants. Scheduled for completion in mid-2016, these rules will require each state to prepare an implementation plan detailing how it will comply with the EPA standards. Depending on the details of the rules, they could have an impact on decisions to upgrade or retire many existing power plants, particularly coal-fired plants. A major issue in establishing these rules is the role of energy efficiency, including (1) whether end-use energy efficiency savings can be credited as part of compliance efforts (since lower consumption can mean lower emissions from generation), and (2) whether EPA should consider the savings available from end-use energy efficiency when it sets emissions targets. For further discussion of this issue, see Hayes and Herndon (2013).

While a strong long-term climate policy would allow utilities to better plan their future, it would also have a more direct impact on utility plans and business models. For example, in our review of the literature and our interviews, a particular issue related to long-term climate policy is the role of natural gas. On the one hand, natural gas has lower greenhouse gas emissions than coal-fired electricity, and thus it is often promoted as a clean fuel. And the fact is that in some applications, natural gas end use can be more efficient and have lower carbon emissions than electricity, given today's generation mix.[6]

On the other hand, a study by California Council on Science and Technology (2011) finds that if more than about a 50% reduction in California greenhouse gas emissions relative to 2005 levels is needed, then California will have to pursue "aggressive electrification to avoid fossil fuel use where technically feasible." According to this study, substantial emissions reductions can result from replacing natural gas use in homes and businesses with the use of electricity from renewable and other zero-carbon energy sources. Similar findings appear in a paper published in *Science* on how California can reduce emissions by more than 80%. The paper states that "technically feasible levels of energy efficiency and decarbonized energy supply alone are not sufficient; widespread electrification of transportation and other sectors is required" (Williams et al. 2012). In this study's scenario, 28% of the ultimate emissions reductions come from energy efficiency, 27% from electricity decarbonization, 16% from electrification, 15% from non-energy, non-CO_2 measures, and 14% from the sum of biofuels, smart growth, and rooftop photovoltaics. Similar suggestions are made by Environment Northeast (2014), who see electrifying buildings and cars as part of a strategy for a "modern sustainable, low carbon economic future."

Thus the long-term goals of climate policy could affect decisions on whether to promote the use of high-efficiency natural gas equipment and whether to promote fuel switching (electricity to gas or gas to electricity).

[6] For example, gas furnaces with 95% efficiency are widely available today. The typical high-efficiency heat pump has a coefficient of performance of about 2.0, which, when mated with a typical combined-cycle power plant with 45% efficiency, makes for a total system efficiency of about 90% (2 * 45%). The gas heating system is more efficient, but, if zero-carbon generation is used, the electric heating system is cleaner. And the very best heat pumps and combined-cycle plants are more efficient than these typical values indicate.

Investment and Cost Recovery

Some electric utilities are concerned that if they invest money in their systems, they may not be able to fully recover their costs. EEI (2013) suggests the following options to address this concern:

- Assess the appropriateness of depreciation recovery lives based on the economic useful life of the investment, factoring in the potential for disruptive loss of customers.
- Consider a stranded cost charge in all states to be paid by distributed energy resources and fully departing customers to recognize the portion of investment deemed stranded as customers depart.
- Consider a customer advance in aid of construction in all states to recover upfront the cost of adding new customers and, thus, mitigate future stranded cost risk.
- Apply more stringent capital expenditure evaluation tools to factor in potential investment that may be subject to stranded cost risk, including the potential to recover such investment through a customer hook-up charge or over a shorter depreciable life.
- Factor the threat of disruptive forces into the requested cost of capital being sought.

Many of these proposals are likely to be opposed by consumer advocates and some regulators and customer groups who think that that utilities are fairly compensated for the risks they take and that these changes could transfer too much risk from utilities to ratepayers.

Energy Efficiency Utilities

The Vermont Energy Investment Corporation (VEIC) operates the first energy efficiency utility in the United States, Efficiency Vermont. An efficiency utility is a utility with a mandate just to operate cost-effective energy efficiency programs, often statewide. It is largely unencumbered by the need to balance other considerations such as the effect of these programs on a utility's sales. VEIC wrote a recent report called *What's a Utility to Do? Next Generation Energy Services and a New Partnership to Serve Customers* (VEIC 2013). They suggest that if we start by asking, "How will the utility survive?" rather than, "What energy future do we really need?" we will come up with answers that are "at best incomplete, and at worst deeply flawed."

They further note that although most energy efficiency efforts are currently delivered by distribution utilities, energy efficiency and other customer-focused services are not inherently utility functions. They suggest that energy efficiency services "can be effectively delivered in a new way, specifically with a separately chartered and regulated Sustainable Energy Utility (SEU), focused on consumers and on facilitating the markets." In their view, an SEU would work closely with a refocused energy investment utility (EIU).

While they acknowledge that SEU and EIU functions may be combined, they argue that this would create several challenges. First, combining the functions may limit the SEU's ability to explore innovative sources of public benefit, an essential aspect of its mandate. Second, the SEU function should not be a way for the incumbent utility to gain market advantage in other energy sectors beyond the base service it provides, nor should the focus be on sales volume. Third, although it is not clear how an SEU function could be a truly independent function of an incumbent utility, there may be actual value to the EIU in being complemented by an independent SEU. This relationship could increase trust between the EIU and its customers and allow it to evolve to provide services in new ways.

On the other hand, a few of the utility executives we interviewed noted that efficiency utilities might not have access to all the detailed customer billing data that utilities have, and might also have more difficulty integrating energy efficiency efforts with utility-operated demand-response programs.

Besides Vermont, several other states have emphasized non-utility models, including Delaware, the District of Columbia, Indiana, Maine, New Jersey, New York, Oregon, and Wisconsin. Some states use hybrid models, with utilities implementing some programs and non-utilities other programs. These states include Maryland and Illinois, where the non-utility role is secondary, and Wisconsin and New Jersey, where it is the utilities that play a secondary role. New York includes major roles for both utilities and a state agency. In other states, thus far, the option of non-utility administration either has not come up (probably the most common case), has been opposed by the incumbent utilities, or has been rejected, sometimes because there was no logical organization to become the SEU.

Other Regulatory Options

Of course many other regulatory options are possible. We came across brief mentions of two of them, although neither was discussed in depth, implying that they are not among the more likely options.

First, in their listing of various options, Goldman et al. (2013) include “municipalization,” i.e., the conversion of investor-owned utilities to municipal utilities. Such acquisitions tend to be expensive and contentious, as illustrated by the City of Boulder’s attempt to create a municipal utility (Jaffe 2014).

Second, Joseph Scalise (2013) at Bain and Company, in testimony before the California Public Utilities Commission, lists full wholesale and retail competition as one model. While wholesale competition is now widespread in the utility industry, retail competition has been controversial. A few states enacted it in the 1990s. Joskow (2003) summarizes initial experience with wholesale and retail competition, finding that wholesale competition has resulted in substantial investments in new generating capacity completed by merchant generating companies, as well as in a shifting of construction costs, operating performance, and market risks to suppliers instead of consumers. On the other hand, he finds that “the performance of retail competition programs has been disappointing almost everywhere, especially for residential and small commercial customers.” This characterization is reinforced by a recent report by the Connecticut Office of the Consumer Counsel. They found that the majority of customers served by non-utility suppliers pay more for electricity than they would if they bought power under the standard offer from their local regulated utility. Specifically, they found that 42% of Connecticut electricity customers purchase power from non-utility suppliers, and of these, 70% to 87% pay more for power than the standard offer, varying by utility (Koenig 2014).

Kushler and Witte (2001) provide an added caution regarding retail competition in a report entitled *Can We Just "Rely on the Market" to Provide Energy Efficiency?* They interview market actors most likely to offer energy efficiency services in nine states undergoing restructuring. In summary, they find

> little evidence to support the premise that relying on private market actors to provide energy efficiency would be a superior approach and that government/regulatory policies and funding for energy efficiency can be phased out or eliminated. Indeed, after focusing on nine states that were early adopters of electric restructuring and gathering data from the three private market actors most prominently mentioned as entities that would "pick up the ball" and deliver energy efficiency in a restructured marketplace, this study supports conclusions contrary to that premise. Those private market actors each face significant limitations in their interest and ability to deliver energy efficiency and have thus far demonstrated no realistic capability to replace government/regulatory policies and programs to provide energy efficiency.

ENERGY RESOURCES AND INFRASTRUCTURE

Utilities have an obligation to meet the energy demands of their customers, which means having the requisite generation, transmission, distribution, and other infrastructure to provide reliable service. This requirement is tempered by the need to keep rates and bills to levels that are just, reasonable, and affordable to customers. In order to balance the need for reliable service and reasonable cost, utilities must decide on the optimal investment mix, including generation, transmission, distribution, energy efficiency, demand-response programs, and other infrastructure. To a significant extent, these resources compete to provide reliable service at the best value to consumers. In our review of the literature, we found a variety of suggestions to expand the use of various resource and infrastructure options and to improve planning for them. In the sections below we discuss six of these topics:

- Expand energy efficiency and renewable energy
- Expand customer options and response
- Improve infrastructure
- Expand transmission system
- Limit generation expansion
- Engage in long-term planning

Expand Energy Efficiency and Renewable Energy

Quite a few of the sources we reviewed recommend expanding programs to encourage energy efficiency and renewable energy. For example, Hogan (2013) suggests that low-cost energy efficiency measures will help drive down the costs of renewable energy implementation, both because "the potential for efficiency gains is available at lower cost than supply-side measures" and because, with reduced consumption, less power will need to come from variable sources and more can come from "more dispatchable options such as biomass." He notes that in order to be effective, energy efficiency must be driven by both policy and programs. Similarly, Bazilian et al. (2013) suggest using a variety of policies to promote energy efficiency and renewable energy, including energy efficiency resource standards, white certificates, government-run programs, and renewable energy standards. Ceres (2010) says that successful, financially solvent U.S. utilities will need to undertake five strategies in the 21st century, one of which is pursuing all cost-effective energy efficiency.

Energy efficiency generally costs less than other electric resources, saving both utilities and ratepayers money (recall figure 3 on page 3). Also, by lowering consumption, energy efficiency lowers bills, making rate increases to pay for new infrastructure or other needs more affordable. One California utility executive noted that his company is using energy efficiency and demand-response programs to help customers lower their bills, even as the costs of California's cap-and-trade system for greenhouse gas emissions begin to be reflected in the cost of power.

According to Peter Fox-Penner, the senior utility executives he spoke with noted that energy efficiency programs were very popular with customers (pers. comm., December 2013). In the future, utilities are likely to face more competition from other service providers, and offering valued energy efficiency programs can be one way to maintain customer loyalty. Support for this view is provided by several recent examples in the literature as summarized in a paper for the SEE Action Network (2011). This study cites data from utility customer satisfaction surveys conducted by J.D. Power and Associates as well as case studies on DTE Energy and MidAmerican Energy. For example, a J.D. Power 2011 survey on customer satisfaction with gas utility companies found that 32% of business customers overall were familiar with their gas utility's energy efficiency programs, and that those who were familiar were significantly more satisfied with gas prices than those who were not. A similar correlation can be gleaned from a 2010 J.D. Power study of residential gas and electric utility customers. In another instance, when faced with low customer satisfaction levels, DTE Energy began implementing targeted energy efficiency programs in 2008. They found that targeted customers were more likely to view their electric and gas rates as reasonable, with customer satisfaction rising by 11% in some groups.

Frankel and Tai (2013) from McKinsey & Co. suggest there are significant opportunities to scale up energy efficiency activities and to capture savings cost effectively through smarter targeting of consumer segments. However they caution that as the market for energy-efficiency-related technology product offerings matures, a growing number of sophisticated and well-funded players are entering the space and will provide a further challenge to existing players. They conclude that "While utilities are at present best positioned to provide energy-efficiency-related services and information, consumers are increasingly open to other parties. Utilities are facing significant competition from energy retailers, home-improvement and construction-materials retailers, and technology companies."

A utility executive we interviewed reinforced several of these observations, noting that not only does energy efficiency generally cost less than the alternatives, it can also help mitigate risks. This is because less investment is needed for generation as well as T&D, and less variable renewable energy is ultimately needed to meet remaining loads, whether utility-scale or at the customer site. The executive noted that energy efficiency is an important customer engagement strategy, and that in the future engagement will combine pricing, demand response, and energy efficiency. Furthermore, she suggested that in providing services, utilities increasingly will need to partner with companies that are expert in particular areas such as data analytics, since companies that specialize in these areas do better at them than utilities could ever expect to. In other words, utilities and third parties can be partners and not necessarily competitors.

Utilities may even have opportunities to earn financial returns from energy efficiency services beyond shareholder incentives for reaching savings goals. For example, Ralph Izzo, chairman and CEO of Public Service Enterprise Group (the utility serving Northern New Jersey), recently said, "I think we could make more money by selling less" (Kuckro 2014). He suggests that utilities invest in energy-saving improvements in customer facilities such as factories and hospitals, earning a return on those investments just as they do on power plants. The customer may still hold legal title to the property, but the utility investments would be treated as a "regulatory asset" upon which returns could be earned. He acknowledges that utility investments in smart grid and distributed generation may be sexier, but he sees energy efficiency investments as smarter.

Finally, it is notable that in a recent survey by Utility Dive (2014) of more than 500 utility professionals and staff, 83% of respondents said their utility is planning to grow its energy efficiency programs over the next five years.

Expand Customer Options and Response

The same Utility Dive survey found that 81% of respondents said their utility is planning to grow its demand-response programs over the next five years, just slightly lower than the percentage saying the same thing about energy efficiency programs. Demand response involves a variety of possible strategies to encourage the shifting of demand from high-cost and high-demand periods to lower-demand periods. The term typically encompasses load-management programs that shift loads from one period to another, as well as various pricing strategies (such as time-of-use-rates) to encourage shifts from some periods to others. Demand response can be an alternative to building new peaking power plants.

Some studies we reviewed recommend increasing demand-response efforts, while others suggest broader efforts to expand customer options. For example, in their *Utility 2.0* report for the state of Maryland, the Energy Future Coalition (2013) include residential-customer and larger-customer optionality as two out of six categories "in which progress will be essential." By "optionality" they appear to mean making optional choices available to customers. Under residential-customer optionality, they include increasing the options, control, and information available to residential customers through the use of smart technologies, as well as facilitating the implementation of distributed-generation technologies, increased energy efficiency, and customer self-monitoring of energy usage.

For larger-customer optionality, they suggest increasing the islanding ability of large customers and groups of small customers through microgrids, demand response, distributed generation technologies for economic and reliability benefits, and support for electric vehicle infrastructure for customers with large parking lots.

Similarly, in their *Policy Framework for the 21st Century Grid*, analysts for the Executive Office of the President (2013) feature "empowering consumers and enabling them to make informed decisions" as one of four key pillars. They suggest that state and federal policymakers should determine the best ways to ensure that consumers receive meaningful information and education about smart-grid technologies and options. Policies and strategies should also be developed to ensure that consumers receive timely access to, and have control over, machine-readable information about their energy consumption in a standard format. Furthermore, they suggest that regulators should consider ways of ensuring that consumer-facing devices and applications make it easier for users to manage energy consumption.

The Commonwealth Scientific and Industrial Research Organization (CSIRO, Australia's national science agency) released a report entitled *The Future Grid Forum's Analysis of Australia's Potential Electricity Pathways to 2050.* CSIRO examine four scenarios, including one called "set and forget" that emphasizes the widespread use of automated load management where consumers choose their settings. Under this scenario, appliances are automated to adjust their power use when certain conditions determined by the consumer are met, e.g., when a specific price point is reached or when the electrical system is under great stress. After choosing their settings, consumers do not play an active role in demand control but rely on utilities to operate demand-control schemes based on the set points the consumers have selected (CSIRO 2013).

David Crane, CEO of NRG Energy, a firm providing wholesale and retail power, sees the future of the utility industry in distributed generation, clean energy, individual choice, and the empowerment of the American energy consumer. He writes, "we are in the process of reorganizing ourselves from the customer's perspective." The retail part of NRG's business is focused on "ensuring that we remain a first mover in bringing technological innovation aimed at the home energy consumer to our customers, on terms that they find attractive." He notes NRG's marketing relationship with Nest (a company making smart thermostats) and their plans to offer rooftop solar and other forms of sustainable and clean generation to homes and businesses. NRG will offer storage and "sophisticated localized automation to balance production and load." The company is also exploring fresh-water production, waste disposal, and electrified transportation in its effort to be "a leader in the area of renewables-driven ecosystems" (Crane 2014).

Finally, Creyts and Newcomb (2014) from the Rocky Mountain Institute go a step farther, saying that in the future the customer *must* be empowered. They write, "the services of the grid must de-commoditize to deliver against exact customer needs for reliability, 'green-ness,' and other attributes. Failure to do so will result in customers finding higher-value alternatives."

Improve Infrastructure

A variety of observers note that although the U.S. electric grid is a major feat of engineering, it needs modernization to address 21st century needs. For example, DOE (2003) states that

> America's electric system, "the supreme engineering achievement of the 20th century," is aging, inefficient, and congested, and incapable of meeting the future energy needs of the Information Economy without operational changes and substantial capital investment over the next several decades.

More recently, the hurricane dubbed Superstorm Sandy that struck New York and New Jersey in October 2012 was a loud wake-up call that infrastructure improvements are needed to make the grid more resilient.

EPRI (2014) recently published a report called *The Integrated Grid* that discusses a variety of steps to better integrate distributed energy resources. We discuss their recommendations at more length in the section below on the smart integrator; here we note that an integrated grid includes hardware and software that requires investment (e.g., smart inverters, distribution management systems, and distributed energy storage) as well as improved interconnection rules, planning, and enabling policies. Many of these needs involve building intelligence into the system so the infrastructure can better handle loads.

To illustrate what can be done, the Massachusetts Department of Public Utilities (DPU) is undertaking a large proceeding on the modernization of the electric grid. A draft decision was issued in December 2013 (DPU 2013). The DPU finds that evaluating and investing in technologies that further grid modernization should be integral to electric distribution companies' ongoing and routine investment and operational plans. However the DPU recognizes that, initially, modernization will involve some changes to the companies' traditional planning and practices. The draft also notes that "to advance grid modernization we must address certain existing barriers, consider potential benefits and costs to customers and the distribution companies, and balance the interests of competitive suppliers, clean energy companies, and technology innovators." The DPU concludes that "we must take a comprehensive approach to addressing the various, interrelated aspects of modernizing the electric grid."

Based on recommendations from a stakeholder working group, the DPU suggests four broad objectives for grid modernization:

- Reduce the effect of outages
- Optimize demand, including reducing system and customer costs
- Integrate distributed resources
- Improve workforce and asset management

The DPU proposal has two main components: (1) a requirement that electric distribution companies prepare and file with the DPU ten-year grid modernization plans (GMPs) that describe the companies' investment and operational strategies for achieving grid modernization, and (2) a decision to address a number of grid modernization topics in separate proceedings, including (a) time varying rates, (b) cybersecurity, privacy, and access to meter data, and (c) electric vehicles.

New York and New Jersey are also beginning to address these issues. The largest utility in New Jersey, Public Service Electric and Gas (PSE&G), has proposed a $4 billion set of investments called Energy Strong (Tweed 2013). Part of the plan involves old-fashioned hardening, including proposed floodwalls for some assets, targeted undergrounding, and replacing old wooden utility poles with heavier-duty poles. Cutting-edge technology also gets a substantial chunk of the money, including

- fault location
- isolation and service restoration
- a new distribution management system (DMS)
- a high-speed fiber-optic network to connect information coming off distribution feeders to the DMS
- substation automation and remote control and monitoring of every distribution circuit
- enhancements to storm management systems, including mobile systems that could be used across first-responder networks
- reconfiguring the current electrical system using more smart switches and smart fuses and adding redundancy

In New York, the blue-ribbon Moreland Commission on Utility Storm Preparation and Response issued a report in June 2013 (Moreland Commission 2013). They recommend improving infrastructure to improve resiliency, but subject to a cost constraint. They note that New York already has high electric rates and suggest several possible funding mechanisms that would not require rate increases. They recommend that utilities prepare plans that prioritize and maximize the effectiveness of capital expenditures within whatever budget is ultimately determined to be available. The New York Commission has opened a docket to explore these issues in more detail.

Reinforcement for the idea of cost constraints comes from Australia. As noted by CSIRO (2013), Australia has experienced large electric rate increases in recent years, with household electricity prices increasing from about 15 cents per kWh in 2007 to over 25 cents in 2012, both expressed in real 2013 Australian dollars. The primary contributing factor has been large investments in the electricity distribution system to replace and refurbish it and improve reliability. As the report states:

> While reliability has become more important over time as Australia's lifestyle and industry have come to depend more on electricity, the contribution to the recent electricity price rises of infrastructure spending to meet reliability standards led many to question whether reliability standards are now set too high or too prescriptively in some jurisdictions.

Likewise, the Gratton Institute of Australia provides similar figures on Australian electricity price increases and goes on to recommend several steps, including "ensur[ing] that network companies make investments that better match future power needs" and "review[ing] the value of network assets to decide who should pay for any write-down of surplus infrastructure" (Wood and Carter 2013).

All this is not to say that the grid should not be modernized, but several of the studies we reviewed suggest that a balance will need to be found between the reliability we may want and the cost we can afford.

Expand Transmission System

A number of observers also suggest that the transmission system should be expanded. For example, Jimison and White (2013) state that "high-voltage transmission lines make the grid more efficient and reliable by alleviating congestion, promoting bulk-power competition, reducing generation costs, and allowing grid operators to balance supply and demand over larger regions. And these considerations will be ever more important in a high-renewable energy scenario." They go on to suggest that the "primary barriers to building new high-voltage lines and optimizing the grid aren't so much technical or economic but rather bureaucratic. Inefficient *institutions* and insufficient *policies* are the key factors preventing the United States from accessing its rich resources of clean energy, and spreading that wealth throughout the economy." These obstacles include:

- Disputes over how to allocate or share costs for new lines among ratepayers in different sub-regions of the electric grid
- Concerns over whether the costs of new high-voltage transmission lines will outweigh benefits for ratepayers, and whether the cost of new lines will be unfairly allocated to customers who will not benefit from them
- Concerns related to the impact of siting the lines, including environmental and cultural impacts, and compensation to landowners, as well as inconsistent and uncoordinated state policies on transmission line siting
- Failure to accord proper weight to the clean nature of renewable energy in much of the country

Jimison and White suggest prioritizing inter-regional lines that link balancing areas, increasing competition in transmission, slashing the timeline for planning, building and siting transmission, and then making the most of lines once they are built.

In terms of policy, DOE (2003) recommends clarifying intergovernmental jurisdiction, establishing rules of the road for workable competitive markets wherever they can be established, ensuring mechanisms for universal service and public purpose programs, and supporting a stable business climate that encourages long-term investment. DOE also discusses a variety of new technologies that can enhance the transmission system, including advanced conductors, high-temperature superconducting materials and advanced electric storage systems, distributed intelligence and smart controls, and power electronics. MIT

(2011) suggests giving the Federal Energy Regulatory Commission (FERC) enhanced authority to site transmission lines.

UBS Utilities (2013), who are stock equity analysts, observe that

> the most consistent theme across the latest annual EEI Financial Conference [in December 2013] was continued growing focus in electric transmission opportunities. Across almost all companies, there was either a consistent focus on execution around an existing plan for transmission execution, or nascent plants to expand disproportionately into the sector through competitive ventures later in the decade.

A recent article by Utility Dive (Howland 2014) expands on this theme, noting that FERC is currently allowing higher returns on invested capital than many states. The article goes on to discuss five large utilities that, collectively, are planning to invest more than $20 billion in transmission. Many utilities and stock analysts essentially see transmission investments as an opportunity for utilities to earn good financial returns.

On the other hand, Harvey and Aggarwal (2013) caution that before investing in technical fixes to the grid, utilities should first make operational changes that reduce system costs, enable more renewables, and maintain reliability. Neme and Sedano (2012) from the Regulatory Assistance Project (RAP) go a step farther, saying that efficiency programs can often defer transmission and distribution investments either passively or actively. Passive deferrals arise from efficiency programs that were not undertaken primarily for the purpose of deferring transmission and distribution (i.e., system-wide efficiency programs). Active deferrals are those that result from efficiency programs that are geographically targeted for the express purpose of deferring the need for upgrading specific elements of the transmission and distribution infrastructure.

Neme and Sedano (2012) discuss various instances where utilities have used energy efficiency to defer the need for upgrades for a few years to a decade or more. Their examples include Pacific Gas and Electric, Portland General Electric, Bonneville Power Administration, Green Mountain Power, Consolidated Edison, and NV Energy.

Limit Generation Expansion

One potentially controversial issue is how much central generation will be needed in the future. A Citi report, *Energy Darwinism: The Evolution of the Energy Industry*, finds that for utilities in developed markets, "Large, capitally intensive, long-life conventional generation assets are in our view unlikely to be built (under current remuneration systems) given that developed market utilities can have little confidence in either the utilization rates of those facilities, or indeed the price which they will receive" (Citi 2013).

Some participants in AEE's CEO Forums (AEE 2013) suggested that

> utilities' basic dilemma [is one] of escalating costs and declining sales. In this view, what is needed is a "right-sized" (i.e., smaller) core of regulated assets—

> primarily network assets—that can ensure universal service and enable the development of a vibrant competitive market in DER. In this model, utilities will retain opportunities for growth through their unregulated arms-length affiliates.

Similarly, a study for Ceres called *Practicing Risk-Aware Electricity Regulation* by Binz et al. (2012) looks at seven major risk categories and finds that "the riskiest resources—the ones that could cause the most financial harm—are large base load fossil and nuclear plants." To address this the authors recommend that regulators practice "risk-aware regulation" that first exhausts lower-risk investment options like energy efficiency before allowing utilities to commit huge sums to higher-risk projects. They further note that

> ratepayer funding is a precious resource. Large investment requirements coupled with flat or decreasing load growth will mean higher utility rates for consumers. Increased consumer and political resistance to rising electricity bills, and especially to paying for expensive mistakes, leaves much less room for error in resource investment decisions and could pose a threat to utility earnings.

In another study, Kihm et al. (2014) examine finance theory and find that a utility profits from new investments only when the return on its investment is higher than its cost of capital. This situation did not apply in the late 1970s (a period of high inflation), and the book value of utilities declined. The authors note that cost of capital includes allowances for risk, and the cost of capital to utilities could increase if markets perceive investments to be risky.

Quite a few expensive power plants became "stranded"—their market value was lower than their book value—during utility restructuring in the 1990s when multiple states moved to market-based power generation. These plants could only be sold in the market for a fraction of their book value (see for example Martin 2001). Stockholders and ratepayers absorbed the losses, with the proportions varying by state. This is probably a situation that nobody wants to repeat. In other words, the First Law of Holes might apply: "If you find yourself in a hole, stop digging."[7]

Support for this view comes from a blog about the European experience called "The Economic and Political Consequences of the Last 10 Years of Renewable Energy Development" (a Paris 2013). The author argues that in the early years high subsidies helped jump start the renewable energy market in Europe, but as subsidies were dropped, the industry was able to lower costs through new technology and a brutal price war. More recently, the costs of increased renewables have largely been absorbed by incumbent utilities who are finding that their conventional power plants are being dispatched much less often. This is due to the widespread presence of renewables which have low operating costs and thus tend to set spot-market prices. The author notes that many intermediate and

[7] A proverb attributed to British politician Denis Healey. http://en.wikipedia.org/wiki/First_law_of_holes .

even base-load plants used to make money during the daytime when spot-market prices were high, but now that spot prices are lower, the economics of conventional plants are weaker. He suggests that many utilities underestimated the amount of renewables available when they made decisions to build base-load or mid-load plants, and now they may be holding uneconomic assets. In other words, the market changed in ways utilities did not foresee when they made decisions to build these plants. Denning (2013), writing in the *Wall Street Journal*, makes a similar point, observing that several traditional German utilities have had difficulty adapting to the rising use of solar panels: their combined market value has slumped 56% over the past four years in a rising German stock market.

On the other hand, some fast-ramp-up generation is probably needed to help balance a system with substantial intermittent generation resources. For example, David Crane (2014), CEO of NRG Energy, a wholesale and retail power provider that owns 50,000 MW of generation, wrote in a letter to shareholders that NRG would be "repowering select plants with flexible fast-start units located in advantageous positions on the grid." Regions that have lost a substantial proportion of existing generating capacity may also feel a need for some new generation. For example, in March, 2014, the California PUC approved a plan to replace the retired San Onofre Nuclear Generating Station (SONGS) with 600 MW of power from "preferred resources" (energy efficiency, renewable energy, storage and conservation) and up to 800 MW from "any source" (meaning natural gas or additional use of preferred resources) (Mulkern 2014).

Engage in Long-Term Planning

Given the need to balance a variety of potential distribution, transmission, generation and energy efficiency resources, several observers see long-term planning as an important element of the future utility system. For example, in their report called *Practicing Risk-Aware Electricity Regulation,* Binz et al. (2012) suggest promoting an "inclusive and transparent planning process" and diversifying resource portfolios.

Planning is also an important element for the "integrated distributed resource manager" model, one of four possible models suggested by RMI in their *New Business Models for the Distribution Edge* report discussed above. In this model, an integrated utility develops a least-cost integrated plan (with a good deal of input from interested parties) that includes energy efficiency and distributed generation. The utility then offers incentives, RFPs, financing, and direct investments to implement the plan, and receives performance incentives based on results. This model is particularly appropriate for vertically-integrated utilities who will conduct a comprehensive and fair planning and implementation process based on regulatory oversight and incentives for meeting regulatory goals.

The plans envisioned by these authors are more robust than typical integrated resource planning (IRP) processes, as they are likely to involve more scenario analysis and more input from interested stakeholders than is typical in IRP. Think of them as IRP on steroids. Also, these plans need to have extensive input from interested parties, more so than most traditional utility plans. It might be best to think of these as utility-facilitated plans rather than utility-prepared plans.

SERVICES

The literature features many calls for utilities to expand the services they offer. Sometimes these are regulated services, but more frequently the suggestions are for optional unregulated (or lightly-regulated) services in which utilities have an opportunity to earn a profit. We start by describing the broad range of suggestions made for new services, and at the end of this section we focus on one specific suggested model labeled the "FinanceCo."

Expand Utility Services

If revenues from electricity sales are less robust than utilities are used to, many of them will consider offering new services to increase their revenues while providing value to customers. For example, in a survey of utility staff by Utility Dive (2014), when asked how they would respond to low to no growth in electric sales in coming years, 65% of respondents said they would develop a new business model. In general, for new services to make sense, they must be part of a viable business model that renders them profitable. This is more likely when new services build on a utility's current strengths.

By far the most common suggestion was for utilities to invest in distributed generation. In the Utility Dive survey, when asked their views on distributed generation, 57% of utility respondents saw an opportunity for utilities, while 38% saw a threat. Hannes and Abbott (2013) from Bain and Company discuss several models for utility involvement in distributed generation including:

- *Preserve and extend core capabilities*. Manage the supply and demand balance of distributed energy systems through sophisticated control techniques. Manage large engineering projects. Optimize the use of operational assets.
- *Expand existing capabilities*. Take "no-regret" decisions to make the most of new opportunities. This particularly means improving customer loyalty and getting a better sense of customer needs and preferences.
- *Identify new businesses*. One option is integrated contracting, where the utility offers services such as planning, installation, operations and maintenance, and load and demand management.
- *Explore partnerships, joint ventures, and acquisitions*. Use these to build up distributed energy capabilities and to tap into entrepreneurial activity.

In this last regard, an illustrative example is the recent announcement by OPower that they are having conversations with several utilities on how they can play in distributed generation. For example, OPower analyzes more than 100 billion meter reads each year and can potentially use this information to help identify good opportunities for distributed generation, battery storage, or electric vehicle integration (Lacey 2014). Another example is a partnership by Nest and NRG Energy to use Nest thermostats to help NRG Energy retail customers participate in demand-response programs (Davis 2014).

Regarding utility investments in solar and combined heat and power, Mendelsohn (2013) from NREL discusses ways utilities can invest in distributed solar and storage technologies. He argues that utilities are uniquely positioned for three reasons: (1) access to low-cost capital, (2) a need for capital investment to ensure shareholder returns, and (3) the potential for increased grid resiliency from investments. He goes on to categorize potential utility investments:

1. *Short-term.* The utility invests for a limited period (typically one year) until construction is completed or the asset is sold into a secondary market.
2. *Medium-term*. The utility provides equity for a period of five years. After this period, it sells off the remaining interest to third parties or into secondary markets.
3. *Long-term*. The utility invests and holds the asset for the expected life. Projects provide long-term rate-based and shareholder returns. The utility and the customer split the savings, with the utility receiving ancillary benefits in the form of carbon offsets and improved grid resiliency.

Bird et al. (2013) also discuss opportunities for utility investments in solar power, including:

1. *Utility build-own-operated or utility turnkey systems*. Examples: Duke Energy and Dominion Virginia Power.
2. *Utility-led community solar projects*. Systems that can serve dozens or hundreds of homes but that are smaller than traditional utility-scale projects.[8]
3. *Utility partnership and investments in third-party leasing companies*. Example: PG&E Corporation, the parent company of the PG&E retail utility.
4. *Value-added consulting services*
5. *Virtual power plant operator*. The utility aggregates the generation from many distributed units on its system and uses them to help manage its distribution system. Example: Arizona Public Service.

Other examples of utilities investing in end-user solar systems include Edison International (parent of Southern California Edison), NextEra Energy (affiliate of Florida Power & Light), and Duke Energy (Pernick et al. 2014).

Similarly, Chittum (2013) discusses how utilities are uniquely positioned to make CHP investments due to their familiarity with long-term capital expenditures, as well as their access to better bond ratings and cheaper capital than other third party investors. She argues that CHP investments are relatively low risk and present unique benefits to utilities in the form of improved grid reliability, creditable emissions reductions, and a potentially reliable rate of return.

One utility executive we interviewed noted that many of his company's customers feel they lack the expertise to construct and operate CHP systems, but they might be open to a

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[8] National Grid has recently proposed to build 20 MW of such projects in Massachusetts (Massachusetts DPU 2014). In a recent forum at the Brookings Institute, Chesser (2014), the former CEO of Great Plains Energy, endorsed utility investments in community-scale solar in particular.

utility's using its expertise to do so. Chittum (2013) notes three possible approaches with examples:

- *Rate-basing the asset.* For utilities that own CHP themselves or enter into power purchase agreements for CHP-produced power, the costs of the CHP system are aggregated and embedded into the utility's rate base. Traditionally regulated utilities enjoy an economic benefit from a satisfactory rate of return to reach their revenue requirement. Both Southern Company and Austin Energy own CHP systems which are built into their rate base, with power purchase agreements in place that allow excess CHP-produced power to be sold off to the grid.

- *Using CHP to meet efficiency goals*. The efficiency benefits of CHP can be factored into overall system efficiency and emissions levels in order to meet state goals. In Massachusetts, specific portfolio standards for the implementation of all cost-effective CHP signal its priority among resource options.

- *CHP as a for-profit business arm*. Electric utilities that may not own generation directly may engage third-party owners. Connecticut-based United Illuminating is exploring a zero-capital program to help third parties adopt CHP on site with power-purchase agreements of five to ten years between the utility and system owner.

Chittum and Farley (2013) also discuss the opportunity for CHP investments by gas utilities, repeating the same three options as for electric utilities but also adding two more:

- *Providing direct assistance and incentives*. For example, Philadelphia Gas Works (PGW) pays for customers' initial CHP feasibility assessments. If the project moves forward, PGW pays the initial upfront costs. The customer then pays PGW back via on-bill financing.

- *Offering special gas rates for CHP systems*. Among many examples, local distribution companies (LDCs) in Connecticut offer rebates to CHP-using customers equal to the gas delivery charge. Also, California LDCs are required to charge CHP systems the same price for gas as they charge electric utilities.

David Crane, CEO of NRG Energy, builds on these opportunities and notes that NRG is expanding its wholesale business in on-site generation for industry and large-scale commercial customers. In his view, the "cost to our business customer of maintaining localized generation will be defrayed by our ability to sell excess capacity and generation, on behalf of that customer, back into the traditional grid" (Crane 2014).

Another possible area for expanded services is electric-vehicle charging ports. Citi (2013) and Utility Dive (2014) mention this opportunity. Citi suggests that utilities consider getting involved in the maintenance of e-vehicle charging ports. Utility Dive (2014) finds that 46% of their utility respondents think utilities are missing an opportunity to deploy public charging stations, while 37% feel that the opportunity is there and will not be missed. In pursuing this option, however, utilities should either use smart charging strategies that largely charge vehicles off peak or include the cost of peak daytime power into charging-service rates.

Another possible focus area in the literature is energy and energy efficiency services. Citi (2013) suggests that utilities can provide energy solutions, or manage energy efficiency as a contractor. Harvey and Aggarwal (2013) add ancillary services as another possibility. And EEI (2007) lists several possible business models as part of their energy services model family, one of several families they discuss. (The other two are the conventional directing incentives family and the performance model family.) The energy services family includes:

- *Customer infrastructure business model*. The utility contracts with a customer for delivery of specified energy services such as heating or cooling.
- *Fee-for-service business model*. The utility sells efficiency services to customers.
- *Green power business model*. A variation on fee-for-service in which the utility offers green power to consumers who are willing to pay the full incremental cost of green power or offsets.

EEI argues that the energy services model family is more sustainable than the others since it relies on markets and not regulators.

Finally, AEE (2013 and 2014) has been exploring still other services that utilities could offer including:

- Innovation in retail services to meet differentiated customer needs. For example, will some customers pay more for higher-quality power, reduced risk of interruptions, or reduced emissions?
- Services based on access to real-time customer end-use data
- Billing services for third parties such as ESCOs
- Metering services and associated data
- Enhanced customer and grid management services
- Commodity supply services and behind-the-meter supplies
- Customer-sited energy storage facilities
- Emergency and non-emergency operational services
- Distribution-level ancillary services

This is just a compilation of the options we have found in our review of the literature. There are sure to be additional possibilities. The field is not wide open, however. As noted by Rogers (2014), some regulators and competitors are concerned that utilities could have an unfair advantage over competitors in certain markets. As a result, many states require a wall between a utility's regulated monopoly and unregulated competitive operations. Some states may put additional restrictions on what utilities can do. To address this problem, Bird et al. (2013) suggest several business model considerations for regulators. These include codes of conduct requiring separate offices and communications so the competitive affiliate does not benefit by having access to information denied to its competitors. Another possibility is operating rules and perhaps contracts between the parent utility and the competitors so that all competitors are treated fairly.

Other cautions were raised at a November 2013 National Association of Regulatory Utility Commissioners (NARUC) meeting in Orlando and an April 2014 Infocast meeting in San Francisco. For example, Carol Choi, vice president of integrated planning and environmental affairs for Southern California Edison, said that bundling electricity with home security and other services “sounds very compelling to a consumer, but it’s much more challenging to achieve” (RTO Insider 2013). David Shuford, vice president for policy and business evaluation, Alternative Energy Solutions, Dominion suggested that consumers do not want utilities getting into the solar sales and installation business. He said that solar and distributed generation customers want to be free of the utility (Wesoff 2013). And Margaret Jolly, director of research and development for Consolidated Edison of New York noted that "The investment community is a little uncomfortable with the sort of proportion of the utility getting into more risky business," and “The proportions shouldn't be too much; that's the message we're getting from the investment community" (Kahn 2014).

Continuing along these lines, if utilities invest too heavily in non-core businesses, they could pass on risks to captive core customers in ways that are unfair to them. This was the situation with Montana Power, which sold off generation and other assets so it could invest heavily in telecommunications, renaming the company Touch America. The new owner of these generation assets found that it could make more money selling this power out of state, and the price of power in Montana more than doubled. Ultimately the telecommunications investments did not pay off and Montana Power/Touch America went bankrupt (Kohn 2003).

On the other hand, utilities need the flexibility to adjust service offerings so they can compete with non-utility service providers. Utilities should not be at a competitive disadvantage because they need regulatory approval for every change in their offering while their competitors have no such constraint. For example, Paulos (2013), reporting on a California PSC hearing, suggests that for utilities to expand their service offerings, the relationship between regulators and utilities must be more flexible. The typically adversarial utility commission proceeding is not well suited to figuring out new approaches. He notes how four utility leaders at the hearing expressed a desire for flexibility, simple regulation, and the opportunity to experiment, all of which could help leverage new business opportunities in the power sector.

At the same hearing, Greg Guthridge of Accenture argued that “what consumers really want is control, which is different than choice.” According to Guthridge’s research, about one in three customers is interested and ready to buy new products and services today—and that number is growing. The rest he puts in the “less is best” group, who want less cost, less choice, and less interaction with their power company.

The results of a recent E-Source/Nielson survey of more than 30,000 consumers underscores the growing interest in new utility services. When asked, “If your electric utility was given a grant to improve part of their business, which would you most like to see them invest in?”

49% of consumers suggested more programs and services to help customers lower their energy use, 26% suggested cleaner power, 19% answered improved reliability, and 6% suggested better customer service (LeBlanc 2014).

In sum, it is hard to say in the abstract which services customers will most want and which of them utilities will do a good job of providing. But these questions must be addressed by utilities and their regulators who would like to see utilities find successful new business enterprises. Giving customers what they want is the key indicator of business success, so finding out what they want is a first-order endeavor. Much experimentation will be needed, and for utilities to experiment, they need some regulatory flexibility.

Utility as "FinanceCo"

One of the four utility models discussed by RMI (2013) is called the "distributed resource finance aggregator" or "FinanceCo." In this model the distribution utility provides on-bill financing for customers to invest in efficiency and distributed generation, working with approved third-party service providers. The utility pays service providers based on verified performance for installing and managing resources. Participating customers are under a rate structure that covers the full cost of distribution services to them. Thus the utility is a source of capital but leaves it to the market as to which resources are acquired. Presumably, however, projects that utilities finance need to be bankable, i.e., their risks are low or manageable. According to RMI, this model could operate within the conventional structure of integrated utilities and could be especially attractive to municipal utilities.

EFC (2013) also includes on-bill finance as an important part of their Utility 2.0 model. As they see it, the utility would provide access to up-front capital for customers eager to embrace new smart-grid options or improve their energy efficiency, despite lacking the capital to invest. Such loans would reflect the utility's own low cost of capital and would be recorded against the property where installations are made, thus providing repayment security that would help justify the low-cost capital. Direct utility investments in distributed generation are also considered by Mendelsohn (2013) and Chittum (Chittum 2013, Chittum and Farley 2013) as discussed above.

Despite these models, many utilities are reluctant to function as a bank, because they see that role as beyond their core expertise. In many states, moreover, serving as a FinanceCo could expose utilities to a whole new set of banking and consumer protection regulations.

LONG-TERM MODELS

The options we have discussed to this point can be considered partial models for the future, as each deals with one or a few aspects of the utility business but does not present an integrated vision for the future of the industry. Now we turn to two long-term integrated models described by several authors: the smart integrator model and the energy services utility. Of course the choice of a model is not a black-versus-white decision, and this section also discusses a variety of in-between options.

Utility as Smart Integrator

In his 2010 book, *Smart Power: Climate Change, the Smart Grid, and the Future of Electric Utilities*, Peter Fox-Penner suggests two possible utility models. One he calls the smart integrator. A smart integrator is a utility that operates the power grid and its information and control systems but does not actually own or sell grid-delivered power. The role of the smart integrator utility will be to deliver electricity from a multitude of sources (traditional generators, distributed generators, renewables) at prices set by regulator-approved market mechanisms, to customers who have been empowered through smart-grid technologies to alter their personal energy demand based on price signals. Smart integrator utilities will own and maintain the physical elements necessary for transmission and distribution, upgrading them so that they can respond to a plethora of information gathered through advanced system-monitoring technologies. In Fox-Penner's formulation, a smart integrator will not own generation but will be an honest broker who manages the grid. In a January 2014 personal communication, he said he thought this model was the most likely and noted that several utilities have expressed interest in it.

Similarly, Ron Lehr (2013a), in a paper in the *Electricity Journal* (which summarizes a longer report), discusses a "middle way" scenario, where utilities act as the smart integrator or orchestrator of energy efficiency investments and the shift to a renewable-energy-driven power sector. In this scenario, utilities have productive partnerships with third-party innovator firms and use demonstration-project findings to inspire new investment at a lower risk to shareholders. Like Fox-Penner, Lehr sees this as the most likely scenario. He also argues that this model would best facilitate the transitions necessary for survival in an ever-evolving electric power industry.

RMI analysts also includes this approach among their major options. In *New Business Models for the Distribution Edge* (RMI 2013), they discuss an "independent distribution network operator model" in which a company would operate just wires and not electricity supply. Such a wires company would be a regulated monopoly subject to performance-based regulation. The distribution utility would be encouraged to come up with pricing mechanisms and incentives for customers and resource developers that would encourage them to develop resources in ways that reduced distribution-system costs. Similarly, an RMI report for Pacific Gas & Electric discusses a "network utility approach with highly differentiated price signals" (Lacy et al. 2012). RMI adds some points in a 2014 blog post, noting that the future grid will be highly transactive and suggesting that asset and service value will be differentiated by location and timing of availability (Creyts and Newcomb 2014).

With these models there is a separate choice to be made about utilities' role in delivering other services such as energy efficiency, demand response, value-added services, and technical and investment assistance for the development of distributed generation. Utilities could provide these related services in some situations; in others, more reliance on competitive forces and separate providers might be desirable. Many of the observers we spoke to believe that there is room for a smart integrator to provide such services, but a few believe that competitive forces will be better at encouraging innovation than utilities under regulation. In this latter view, to be a truly honest broker, a smart integrator should operate the grid and nothing more.

Taking a more technical view, EPRI (2014) suggests that an integrated grid will require grid reinforcement and modernization as well as updated interconnection rules and wholesale market and retail rate structures that adequately value both capacity and energy. Secure communications systems will be needed to connect distributed-generation providers and system operators. EPRI concludes that "as distributed resources penetrate the power system more fully, a failure to plan for these needs could lead to higher costs and lower reliability."

A recent example of a utility's beginning to embrace the smart integrator model is National Grid USA which serves large parts of Massachusetts, New York, and Rhode Island. Its new Connect21 strategy combines a "resilient backbone" that can address extreme weather events and growing demand for renewable energy sources, a "market enabler" function that provides customers with price and other information they can act on, and "customized solutions" for customers including technical and financing assistance (King 2014). The smart integrator model is also central to a report by Advanced Energy Economy called *Creating a 21st Century Electricity System for New York State* that includes an important role for value-added services (AEE 2014).

Energy Services Utility

Fox-Penner (2010) also discusses the energy services utility (ESU) model. An ESU is a regulated electricity-producing entity whose prices and financial returns are controlled. It is responsible for supplying all retail generation customers' demand as reliably as possible while also providing demand response, energy efficiency, and smart-grid services and technologies to its customers. It can own the generators that provide its supply, whether large upstream plants or small local ones, but it is also required to purchase or transmit power from others attached to its wires. ESUs are often incentivized to cooperate with local generators who want to connect and sell power into their smart systems through measures such as energy efficiency profit incentives or revenue decoupling. An ESU is essentially a smart integrator that also owns generation, and because it needs to manage both its own and third-party generation without showing favoritism, it is subject to more regulatory oversight than a smart integrator. It evolves from today's vertically-integrated utility that owns generation, transmission, and distribution.

Lehr (2013a) also discusses this option. He sees it as a maximum utility role where electric utilities act as "energy services utilities," particularly in circumstances where exigent demands require utilities to respond. The New York Moorland Commission's recommendations for restructuring the Long Island Power Authority (LIPA) are one example. Hurricane Sandy blacked out portions of Long Island, some for weeks. In response, the governor and the Assembly mandated significant changes to LIPA's business structure and operations. According to Lehr, such a scenario requires a widespread political consensus that allows a state legislature to mandate a structure in which utilities are primarily in charge but required to meet certain targets for renewables and energy efficiency.

RMI (2013) has a similar discussion of an "integrated distributed resource manager"; we referred to it earlier in the section on long-term planning. In RMI's view, a key function of the integrated utility is to develop (with plenty of input from interested parties) a least-cost integrated plan that includes energy efficiency and distributed generation. The utility offers incentives, RFPs, financing, and direct investments to implement the plan and receives performance incentives based on results.

Goldman et al. (2013) also discuss this model, but in their formulation, it includes a move away from commodity energy sales (e.g., selling kWh) and towards selling services (e.g., cooling).

Taking a broad view, we can see that there is a continuum of long-term options, at one end of which is a smart integrator that only operates the grid, does not own generation, and offers no services beyond grid integration, and at the other end, an energy-service utility that owns generation and provides many services. The former leaves all these latter functions to other firms. In between are a variety of options in which a firm providing grid-integration functions also offers some services (regulated and unregulated) and may own some generation, particularly moderate amounts of distributed generation. There are many plausible options along this continuum.

PUBLIC UTILITIES

The preceding discussion focused on options for investor-owned utilities (IOUs), who provide about 55% of the power consumed by end users in the United States. On the other hand, about 26% of our power comes from publically-owned utilities, including municipal utilities and electric cooperatives (APPA 2013a).[9] Public utilities have many of the same concerns as IOUs but also show some important differences.

In terms of similarities, public utilities may be concerned about declining electricity sales and may wish to have pricing structures that allow them to fully recover the costs of running their systems. For example, the Sacramento Municipal Utility District (SMUD) is steadily increasing its residential monthly fixed charge to recover more of its system costs. A monthly charge of $7.20 per month will increase steadily until it reaches $20 per month in 2017 (SMUD 2011). Public utilities, too, will have to manage a grid with increasing participation from distributed generators. Public utilities care very much about customer service and sometimes claim that, because they ultimately respond to public officials and voters and not to shareholders, they are more service-oriented than IOUs (see, for example, APPA 2013b).

On the other hand, although they do need to cover their debt financing and operating costs and avoid losing money, public utilities generally do not emphasize profits. In some cases,

[9] These figures are for kWh sales to ultimate customers. In addition to investor-owned utilities and public utilities, 18% of sales are by power markers, and 1% by federal power agencies.

though, public utilities that are part of municipal and other government agencies are in fact profit centers whose surplus of revenues over expenses keeps taxes and other public exactions lower than they would be otherwise.

Another consideration is that public utilities generally do not need to satisfy outside regulators such as a public service commission (PSC), although in a few states the PSC does have some authority over them. Instead, public utilities are accountable to their boards or to local governments. As a result, they have somewhat more control over their situation than do IOUs, and they are generally not looking for performance-based ratemaking or for improving the investment climate.[10] There are no shareholder incentives for public utilities, but performance-based compensation for management is fairly common. Although decoupling has been rare in the past, public utilities in Los Angeles and Glendale, California recently adopted it (Cavanagh 2012 and email to author, February 13, 2014).

Perhaps the biggest difference between public utilities and IOUs is one of size and scope. While there are some small IOUs, most are large companies. The reverse is true for public utilities: while there are a few large ones, most are much smaller.[11] As a result, most of them have less staff, perhaps making it more difficult to offer new services or manage a more complex grid. On the other hand, public utilities can work together, often through state municipal utility or electric cooperative associations, to develop new services that each member can offer. In a few situations, they have struck creative deals with IOUs to gain scale economies and overcome their size-related deficiencies. Still (to over-generalize), smaller public utilities tend to be traditional in their outlook and may be slow to embrace and adapt to change. As a result, many of them will likely hang on to their current structure and services until such time as changes in the utility industry force them to change as well.

Gas Utilities

The preceding sections have focused on electric utilities, but there are some points to note about gas utilities. Gas distribution utilities are also concerned about stagnant sales. As homes are becoming more efficient, consumption per household has been declining (EIA 2010). In the 2014 Annual Energy Outlook, EIA (2013a) projects that residential natural gas sales will be flat through 2040, with new customers and new loads compensating for the declining loads among existing customers. EIA projects only modest growth for commercial and industrial sales (both increasing 0.7% per year through to 2040). The big upside sales opportunity for natural gas distribution utilities will be in transportation, including compressed and liquefied natural gas. The gas industry has been promoting increased use of gas for transportation (see for example IHS CERA 2014), and EIA projects that this use will increase by 11% annually, albeit from a very small base.

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[10] However one regulator with whom we communicated thought performance-based regulation could also work for public utilities.

[11] Examples of larges ones include Austin, Jacksonville, Los Angeles, Memphis, Nebraska, Omaha, Salt River Project in Arizona, Santee Cooper in South Carolina, Seattle, San Antonio, and Sacramento.

Faced with stagnant sales for a longer time, natural gas distribution utilities have been quicker to embrace decoupling than electric utilities. To better ensure that fixed costs could be recovered, the American Gas Association (AGA) began supporting decoupling in 2004 (AGA and NRDC 2004). As of Fall 2013, 36 states had decoupling or a lost revenue adjustment mechanism for at least one natural gas utility (Downs et al. 2013).

The natural gas industry sees distributed generation as an opportunity to sell more gas, since the vast majority of nonrenewable distributed generation being built is fueled with it.[12] Thus natural gas utilities can be leaders in promoting distributed generation. They are also interested in converting more customers to natural gas (from fuel oil, propane, and electricity) and in enticing new customers to install gas service and equipment. Natural gas and electric utilities compete intensely to serve new developments, particularly in the South where mild winters can make electric heat an attractive option.

Concerns about climate change are a double-edged sword for natural gas utilities. As discussed above in the section on climate change, the use of natural gas can save energy in some applications, and it can emit less pollution than today’s electrical generation mix. But if emissions reductions of more than 50% are contemplated, several reports suggest that we should promote electrification rather than natural gas.

In addition to decoupling, expanding service offerings, and establishing long-term climate goals, many of the options discussed above for electric utilities also should apply to gas utilities. These include

- better management
- expanding customer options and response (e.g., winter peak-load management)
- pricing reform
- fostering innovation
- improving infrastructure (the gas infrastructure is also aging)
- long-term planning
- expanding energy efficiency
- expanding the transmission system (e.g., interstate pipelines)
- performance-based regulation

Some options like the smart integrator model probably will not apply to gas utilities. Others, although not as compelling for gas utilities as for electric utilities, could still potentially apply. These include improving the ability to recover costs, the energy efficiency utility, the utility as FinanceCo, and the energy services utility.

[12] For example, of the 54 GW of new end-use generation that EIA forecasts will be added over the 2013-2040 period, they estimate that 57% will be powered by renewable energy, 42% by natural gas, and 1% by other fuels (EIA 2013a).

Regarding energy efficiency, recent analyses (e.g., Young et al. 2012) indicate there are still substantial cost-effective opportunities to save energy, but the recent declines in natural gas prices have affected the size of the efficiency resource for gas more than for electricity. As a result, natural gas utilities and others who work on natural gas efficiency programs are increasingly interested in better documenting the non-energy benefits of efficiency investments (e.g., improved comfort and home value) and incorporating them in cost-benefit analyses (Noll 2014).

Impacts of These Options

We discussed 19 options for the future in the section above, many of which can be combined in a comprehensive overall strategy. Each option has both strengths and weaknesses. To help make sense of them, in this section we assess their effect on

1. energy efficiency
2. cost of service (energy bills, which in turn depend on both consumption and rates)
3. quality of service
4. utility profits[13]
5. the environment

In many cases, these effects will depend on the particulars, and therefore we have tried to indicate key decisions that will push an option one way or another. Tables 4 to 7 present our analysis:

- Table 4: Management and service options
- Table 5: Regulatory options
- Table 6: Resource and infrastructure options
- Table 7: Long-term options

In these tables we evaluate each option on each criterion, assessing whether it will cause the metric to increase (+), decrease (-), stay approximately the same (=), or have no effect (0). "EE" means energy efficiency and "RE" means renewable energy. A minus under costs means costs go down.

[13] Kihm et al. (2014) suggest that a better metric would be shareholder value. While profits and shareholder value can diverge (as discussed previously in the section on generating plants), profits are more intuitive for many readers. Additionally, for the high-level analysis conducted here, profits and shareholder value are generally correlated. Hence we use profits but note this caution.

Table 4. Impact of management and service options on key metrics for utility service and value

Option	Effect on:				
	Energy efficiency	Cost of service (bills)	Quality of service	Utility profits	Environment
Better management	+ if seeks to minimize cost of service. - if seeks to eliminate costs not deemed essential.	-	= if seeks to operate services more efficiently. - if seeks to cut costs by reducing service.	+	= if does not cut environmental protection. - if seeks to cut costs by reducing environmental protection.
Expand utility services	0 for most services. + if EE services included. -if replaces EE programs and services now available to all customers.	= generally, as those who want new services will pay for them. + if some costs are passed on to regulated customers.	+ generally, since services need to provide value or there will be no demand for them. - if utility neglects core business.	+ if services profitable. - if services lose money.	+ if environmental services such as green power included.
Utility as FinanceCo	+ if finances EE. - if displaces other EE programs.	- if promotes cost-effective EE.	+ if allows new services; = otherwise.	+ if financing profitable.	+ if allows environmentally preferable resources to prosper.

Key: + means increase; -means decrease; = means stays the same; 0 means little effect. EE means energy efficiency; RE means renewable energy. Minus under costs means costs go down.

Table 5. Impact of regulatory options on key metrics for utility service and value

Option	Effect on:				
	Energy efficiency	Cost of service (bills)	Quality of service	Utility profits	Environment
Reassess the role of regulation	+ more likely as EE helps to reduce bills.	- more likely as regulators will generally look to reduce bills.	+ more likely as service quality important to regulators.	= most likely but could go up or down.	+ more likely as regulators generally look to protect environment.
Decoupling and shareholder incentives	+	- if allows cost-effective EE programs to expand; = otherwise.*	+ if prevents cuts in services that could take place without this policy.	+ for decoupling if sales declining. - for decoupling if sales increasing. + for incentives	+ if allows EE and RE to expand.
Reform electricity pricing	-if reduces variable energy charges or moves to decreasing block rates; + if increasing block rates; = otherwise.	+ to DG customers who benefit from special deals now. - to non-DG customers if they now subsidize DG deals.	+ if prevents cuts in services that could take place in absence of this policy.	+ generally since leads to fuller recovery of costs.	+ if leads to more EE and RE. - if leads to less EE and DG.
Performance-based regulation	+ if EE a key metric; =/- otherwise.	- if done well; =/+ otherwise.	+ if service quality a key metric; =/- otherwise.	+ since utility can manage to improve metrics.	+ if environment a key metric; =/- otherwise.

Option	Effect on:				
	Energy efficiency	Cost of service (bills)	Quality of service	Utility profits	Environment
Foster innovation including expanded R&D and more competition	+ as long as EE included. 0 generally if EE not included.	Varies, depending on whether innovations save money or provide new services but at a cost.	+ generally from innovations. Varies with competition as depends on whether competition is robust or not.	+ for someone, but not necessarily incumbent utilities.	+ generally.
Establish long-term climate policy	+ since EE is generally least cost.	+ but probably modest.	= generally.	+ if costs recovered and investments included in rate base. - if old dirty plants need to be written off and these costs not passed on to ratepayers.	+
Improve ability of utilities to invest and to recover costs	- if enables generation that is more expensive than EE.	+ more likely. =/- if done well.	+ to extent that added investments improve reliability.	+	+/- depending on particulars.
Energy efficiency utility	+ if EEU does a good job.	- if promotes cost-effective programs.	+ if offer additional services; = otherwise.	+ if shareholder incentive for helping. 0 if decoupling but no incentive.; - if neither decoupling nor incentive.	+ generally.

Key: + means increase; -means decrease; = means stays the same; 0 means little effect. EE means energy efficiency; RE means renewable energy. Minus under costs means costs go down. * Morgan (2013) found impact on rates to be very small.

Table 6. Impact of resource and infrastructure options on key metrics for utility service and value

Option	Effect on:				
	Energy efficiency	Cost of service (bills)	Quality of service	Utility profits	Environment
Expand energy efficiency and/or renewable energy	+	- for EE. + for RE in short term but could lead to lower costs in long term.	= generally. - if do not manage intermittent supply well.	+ if decoupling and incentives; - otherwise	+
Expand customer options and response	+ in most cases. - if use this as an excuse to cut EE programs.	- in most cases.	+ in most cases.	+ if utility can recover costs and earn return on investments	+ if green options included. - if current green services become optional.
Improve infrastructure	+ if raises electric price. - if utilities seek to reduce EE to better recoup infrastructure costs	+	+	+	= for most projects. + or - for some projects.
Expand transmission system	0 in most cases. - if build transmission that could have been replaced with EE.	- if helps to reduce costs; + otherwise.	= or + generally.	+ if earn return on investments	- for environmental impacts of new lines. + to extent that allows use of cleaner energy sources.
Limit generation expansion	+ if prevents overbuilding generation.	- if prevents overbuilding	= if done well. - if done poorly.	- if rate base lower. + if prevents projects that would lose money.	+ generally

Option	Effect on: Energy efficiency	Cost of service (bills)	Quality of service	Utility profits	Environment
Long-term planning	+ generally.	- if costs are a key planning metric; =/+ otherwise.	= generally. +/- if results in changes to service.	+ if helps manage risks. - if planning assumptions wrong	+ if environment a key planning metric; = otherwise.

Key: + means increase; -means decrease; = means stays the same; 0 means little effect. EE means energy efficiency; RE means renewable energy. Minus under costs means costs go down.

Table 7. Impact of long-term options on key metrics for utility service and value

Option	Effect on: Energy efficiency	Cost of service (bills)	Quality of service	Utility profits	Environment
Utility as smart integrator	0 generally. - if displaces EE programs.	= generally. - if prevents self-dealing.	+ to extent that utility now can better concentrate on integration. + if market results in new services.	- if need to divest profitable generation. + if prevents unprofitable investments.	+ generally since will tend to promote EE and DG including RE.
Energy services utility	+ if includes EE programs and services.	+/- (depends on particulars).	+/- (depends on particulars).	+ if does a good job.	+/- (depends on particulars).

Key: + means increase; -means decrease; = means stays the same; 0 means little effect. EE means energy efficiency; RE means renewable energy. Minus under costs means costs go down.

These tables show that a significant majority of the options are positive or neutral for the five criteria, particularly if done well. (Note that for cost of service, a negative sign is good because that means costs are declining.) In nearly all cases, however, it also possible to do things poorly, resulting in negative consequences. In particular, we note that the following options are generally positive or neutral if they are done well:

- Better management
- Decoupling and shareholder incentives
- Expanding customer options and response
- Fostering innovation (we treat competition separately here)
- Long-term planning

- Performance-based regulation
- Expanding utility services
- Energy-efficiency utility
- Utility as FinanceCo

A number of options involve tradeoffs, or there is a significant chance they can be done poorly. Many of these will be worth pursuing with care. These options include the following.

Reform electricity pricing. Care must be taken to make sure reforms do not unduly hinder energy efficiency and renewable energy investments by reducing variable costs below the long-term cost of new resources, or by imposing punitive charges. In addition, new pricing models need to be understandable and workable for customers or else they may not have the desired impact.

Improve infrastructure. Some infrastructure improvements will be needed, but care must be used to prioritize improvements and to keep costs in check. The Australian experience is a case in point: they invested too much in infrastructure, and electric rates skyrocketed. In some (but far from all) cases, targeted energy efficiency investments can cost less than infrastructure investments.

Expand energy efficiency and renewable energy. Energy efficiency helps reduce customer bills and can help utilities keep rates down and customer satisfaction high. Decoupling and shareholder incentives are necessary to avoid negative impacts on utility financial returns.

Expand transmission system. As with infrastructure, this option should be undertaken with care. Some projects will be needed to increase the size of balancing areas and bring renewable resources from rural areas and major load centers. But over-investment can needlessly raise the cost of service, and transmission projects do have some environmental impacts.

Limit generation expansion. With loads barely increasing (and potentially even decreasing under our high scenario), the amount of new generation needed will be limited. Some new generation will be required in rapidly growing areas or where existing generation is being retired. It may also be needed in some regions in order to quickly ramp up production to balance fluctuating renewable production. Before building new generation, it makes sense to first confirm that additional central generation will be less expensive than energy efficiency, renewable energy, or other distributed generation. At the same time, limiting new generation limits opportunities for utilities to grow their profits, so they should look for other opportunities to earn financial returns, such as shareholder incentives for energy efficiency or the marketing of additional services (primarily unregulated). In addition, if generation expansion is constrained too much, service quality can suffer. Utilities can avoid many of these problems by leaving the development of new generation to the market, with investors (including unregulated utility subsidiaries) rather than ratepayers taking the risks.

Improve the ability of utilities to invest and recover costs. While the utility industry generally supports this option, consumer advocates will be skeptical. This approach is likely to increase the amount of generation, transmission, and infrastructure that is built, increasing both costs and service quality. It could easily spur overbuilding and should be approached with great care. As discussed in some of the paragraphs above, there may well be better ways to encourage needed investments.

Establish long-term climate policy. Such a policy is good for the environment and will be generally helpful for energy efficiency and renewable energy. However climate policy is likely to raise the cost of service a little and to hurt the profits of companies owning substantial coal generation. Climate policy details should be designed in ways that permit these companies to adjust.

Utility as smart integrator. Utilities or other grid operators will need to play a smart integrator role. We believe that a smart integrator can and should continue to offer energy efficiency services. The financial returns of utilities who now own generation could decline if they are required to divest their generation resources. On the other hand, a smart-integrator role makes sense for utilities who do not own significant generation, and particularly for integrated utilities who want to avoid the risks of long-term investments in generation or who do not think that generation will be profitable in the future.[14] Unless these situations apply, integrated utilities may prefer the energy services utility model.

Energy services utility. This model may make sense for currently integrated utilities. But with loads barely growing, and with inherent incentives for capital investment in order to increase financial returns, this approach requires more regulatory oversight than most of the other options.

Competition. Competition can be useful for many services as well as at the wholesale level (including for capacity and ancillary services). However, while often positive for large customers, retail competition has performed poorly for residential and small commercial customers. Competitive companies tend to be more interested in large customers than smaller ones, and when they do serve small customers, they sometimes base their offerings on better marketing rather than lower prices or better service. It is true that market competition can be useful, but if previously successful utility and other public-purpose energy efficiency programs are discontinued to rely exclusively on the market, the result will likely be less investment in efficiency and an increased need for more expensive resources.

The Role of Energy Efficiency

The role of energy efficiency in the utility of the future is a particular focus of this report. This topic featured prominently in the discussion above, but only as one of many factors we

[14] For example, in February 2014, Duke Energy announced it was selling 13 power plants, saying that "the earnings profile is not a good strategic fit for Duke Energy" (Penty and Polson 2014).

considered. Such a broad approach is appropriate since energy efficiency cannot be considered in isolation and since it is only one of many issues that utilities and policymakers need to grapple with as they chart a path to the future. Still, it is appropriate at this stage to focus on the role of energy efficiency in particular as we weave together some of the various strands from the previous discussion.

As previously shown in figure 3 on page 3, energy efficiency typically costs less than half the cost of other electricity resources. This fact is further illustrated in figure 11, which shows the difference between wholesale market prices and the cost of energy efficiency in the Northwest. The difference between the two is money saved by consumers.

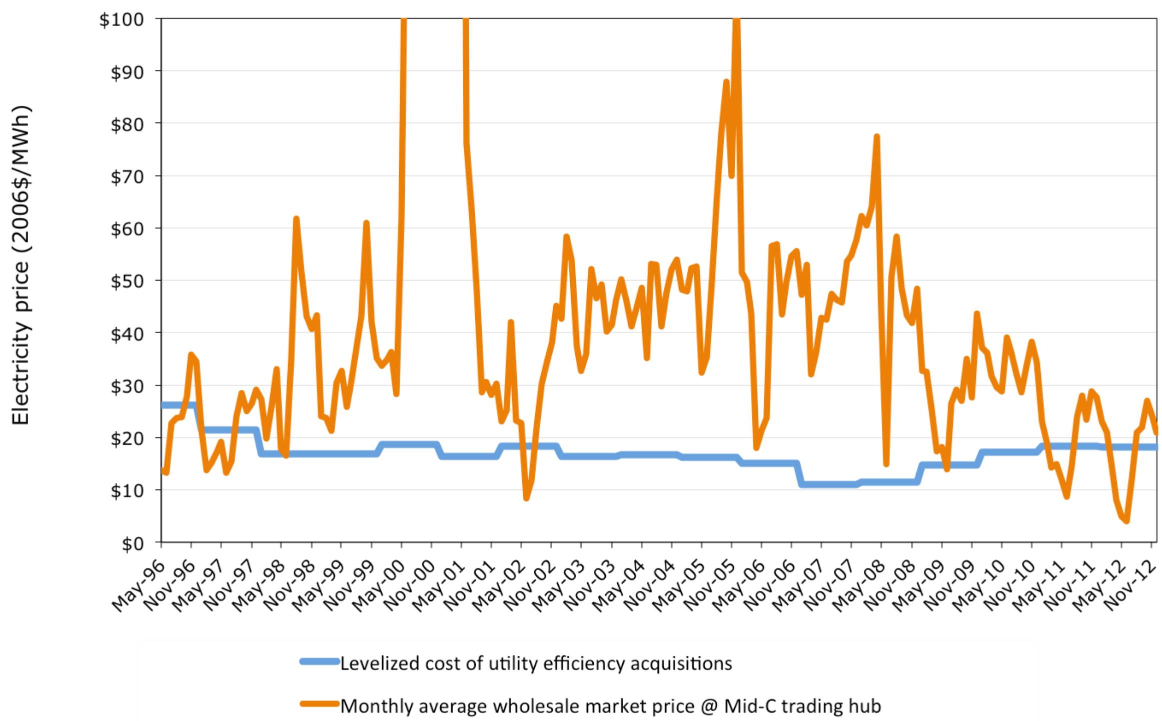

Figure 11. Comparison of the levelized cost of utility efficiency acquisitions in the Northwest with the regional average wholesale market price. ***Source:*** **Eckman 2013.**

Efficiency is also generally less expensive than natural gas supplies, although not to quite the same degree (Young et al. 2012). In addition, as we discussed above in the section on transmission, in some cases energy efficiency can be used to defer transmission and distribution investments. Consolidated Edison in New York has been a leader in this regard (Gazze et al. 2010), and Southern California Edison is about to undertake a very large energy efficiency and demand-response project as it seeks to replace the approximately 2000 MW in capacity it just lost with the retirement of the San Onofre Nuclear Generating Station (SONGS) (Mulkern 2014).

Energy efficiency can also be a low-cost emissions-reduction strategy, which will likely be important as EPA sets (and states implement) new carbon dioxide emissions rules for existing power plants (Hayes et al. 2014). Energy efficiency is also likely to play a large role if and when a more comprehensive climate change policy is enacted. Furthermore, by lowering consumption, energy efficiency lowers bills, making rate increases to pay for new infrastructure more affordable (see for example Neubauer et al. 2013). Thus investing in energy efficiency is an important tool that utilities can use as they seek to manage costs and risks. Moreover, since it is a service valued by many customers, utilities can use energy efficiency to increase customer engagement by providing efficiency services and by using efficiency as a gateway to other offerings.

On the other hand, if utility fixed-cost recovery is not decoupled from sales, energy efficiency does lead to a decline in sales and so does affect utility profits. Electricity use in the U.S. peaked in 2007, and while some of the current decline is due to the Great Recession, recent analysis indicates that increased savings from energy efficiency are also a significant factor (Nadel and Young 2014). EIA projects very modest growth in electricity consumption over the 2014-2040 period, but our scenarios for increased use of energy efficiency, photovoltaics, other distributed generation, and electric vehicles show that it is possible for consumption to level off and perhaps modestly decline. The effects of energy efficiency are the largest of these four contributing factors.

For energy efficiency to flourish, the use of decoupling needs to be expanded so that utilities can recover their fixed costs even if sales decline. Shareholder incentives for achieving efficiency goals will also need to be expanded so utilities can earn some return on energy efficiency investments just as they earn a return on investments in power plants and infrastructure. Shareholder incentives generally are structured differently from the rate of return on plant and infrastructure, but the point is that structured well, efficiency can be profitable.

As shown in figure 2 on page 2, energy efficiency programs funded by utilities have saved a substantial amount of energy—nearly 4% of U.S. electricity use. Such programs are most commonly operated in the United States by distribution utilities, although other models include operation by a state agency or state-chartered organization. All these models can work if the lead organization is motivated, has the right staff, has a reasonable budget relative to the goals to be achieved, and is not unduly impeded with red tape.[15] The fact is that proactive utility-funded energy efficiency programs can dramatically increase savings over what can be achieved just by relying on markets (Kushler and Witte 2001). At the same time, they can help to overcome market barriers (see for example Vaidyanathan et al. 2013) and to create stronger markets including contractors hired by utilities and an increased demand for energy efficiency services. Without such programs, efficiency savings will be

[15] For example, concern about government procurement practices was a key factor in the decision by the California PSC not to have the state itself administer programs. Likewise, these practices have caused substantial delays in the implementation of New Jersey's energy efficiency programs.

lower and needed investments in generation, transmission, and distribution will be higher, yielding higher rates and bills.

To be most useful for the utility of the future, energy efficiency programs should be well integrated with demand-response and distributed-generation efforts. Such integration includes the possibility of utilities' directly investing in CHP and other distributed generation at customer sites or in communities, using low-cost utility capital, and leveraging utility expertise in power-plant development and operation.

Power prices need to be fair to all as utilities invest in energy efficiency. A particular issue is how to balance fixed monthly charges with variable rates based on energy consumption and peak demand. In our view, variable prices should be based on long-run marginal costs, including the costs of new generation, transmission, and distribution investments that will be needed. The "tail block"—the price of the last increment of power purchased or saved—is particularly important, as that is the price signal consumers receive. Some reasonable level of costs, e.g., recovering the costs of billing, can be included in fixed monthly charges, but in general we prefer recovering grid costs through time-of-use rates, variable demand charges, or minimum bills rather than through high fixed charges. The higher the fixed charge and the lower the variable charge, the less incentive customers have to invest in energy efficiency.

Another important issue is performance-based ratemaking. Where this is employed, the metrics should include success in implementing cost-effective energy efficiency programs.

Utilities that use energy efficiency as their first resource can contain rate increases and risks while providing customers with valued services and lower bills. But for this to happen, regulators need to send the right signals through decoupling, shareholder incentives, and performance-based ratemaking. Without energy efficiency, customer bills will be higher, and while utilities may profit from increased sales in the short term, in the long term unhappy customers and regulators may make for weaker financial performance.

Paths Forward

The road from the present to the utility of the future is likely to be winding and bumpy. The way forward will become clearer over time as the many unknowns are resolved and as utilities and policymakers explore new approaches, see how they work, and make adjustments. In particular, we note that since the utility industry is at core a regulated monopoly, regulations and business practices must evolve in tandem for progress to be made. Both regulators and utilities will need to adapt: neither can effect most of the changes on their own. Furthermore, there is no single answer. It is likely that each state and each utility will pursue its own path, although many of those paths will be similar and ultimately will likely evolve into a few primary routes.

There is also the question of timing, with some decisions to be made soon and others a decade or more off. For example, NRG CEO David Crane suggests that it will take a while to transition from the traditional utility industry to the utility of the future, saying that NRG is positioning itself "to succeed during a prolonged period through which the traditional centralized grid-based power system co-exists with the fast-emerging high-growth distributed generation sector—much like fixed-line telephony has co-existed with the wireless world for a couple of decades" (Crane 2014). Using timing as our organizing principle, we suggest some primary paths forward for the short, medium, and long terms in the sections below. Short term means the next three years, medium term the following five years, and long term eight years or more away.

SHORT-TERM

As the need for change is becoming more apparent, utilities and policymakers should consider the following ways forward over the next few years.

Reassess the role of regulation and how regulation can best be structured to meet both consumer and utility needs in a period of change.

Expand the use of energy efficiency as a way to replace retiring generation, minimize rate increases, meet environmental requirements, and provide a valued customer service. This path includes using energy efficiency as an alternative to transmission and distribution investments where it is a viable alternative. When the value of avoided energy use, avoided peak demand, and avoided need for transmission and distribution investments are summed and compared to the costs of energy efficiency, it is clear that energy efficiency is an underutilized resource. Depending on how utilities in a particular state are structured, in some states these efforts will be led by vertically-integrated utilities, in some states by distribution utilities, and in still others by other parties.

Institute decoupling and shareholder incentives to meet energy efficiency goals in the states (roughly half) that have not presently done so.

Increase the use of demand response and smart pricing, and better integrate these mechanisms with energy efficiency programs and policies so the grid can be managed more effectively and at lower cost. For example, utilities can tap the wealth of data supplied by smart meters to identify good opportunities for energy efficiency and demand response, inform and motivate consumers about these opportunities, and optimize voltage on individual distribution circuits.

Establish fair pricing to pay for fixed costs without unfairly discouraging investments in energy efficiency and distributed generation.

Look at infrastructure needs and prioritize them so that key projects with significant net benefits can move forward. Other states should consider what Massachusetts is doing in this regard. Where balancing areas are small, operating areas should be combined.

Experiment with new utility services to see what works in particular situations and what does not. In our opinion, it is likely that utilities will ultimately have to rely more on value-added services for earning financial returns, starting with some experimentation in the near term. Many of these services will be unregulated or subject to light regulation, since they will be optional to customers. Fair rules need to be established so utilities and third parties can compete on a level playing field. These include (1) rules on affiliate transactions so utility-owned service subsidiaries do not have an unfair advantage, and (2) limited and quick utility-commission reviews so utility affiliates can be nearly as nimble as unregulated firms.

Manage well. While utilities and regulators generally seek to improve performance, good management to reduce costs and increase value is likely to take on increasing importance in coming years.

Experiment with performance-based regulation. If done well, PBR can benefit both consumers and utilities, but if done poorly, adverse consequences are likely. Initial experimentation will help utilities and regulators find out what works and what pitfalls to avoid. The metrics will differ between vertically-integrated and distribution utilities, and from state to state.

Effectively manage a diverse grid with large contributions from distributed generation and variable resources. For example, balance and schedule over shorter periods of time, upgrade weather forecasting to predict renewable energy output more accurately, deploy more extensive demand-response resources, experiment with various forms of power storage, and add fast-ramp generation where needed. These efforts will require good planning and flexible grid-management approaches that allow many decisions to be made in real time. EPRI (2014) has numerous suggestions for work in this area.

Reduce uncertainty about future environmental regulations by completing a variety of pending rulemakings that affect the power sector. We previously discussed regulations on carbon dioxide emissions for existing power plants; other pending regulations address carbon dioxide emissions from new power plants, impacts of power-plant cooling on water bodies, and proper storage and disposal of coal ash. Power-plant owners can best make decisions about how to manage their resources and systems when they know all the rules they will face. Getting air-quality and economic regulators in the same docket to address these issues proactively will result in better long-term decisions at lower costs to consumers.

Think very carefully before proceeding with decisions to build new generation. Loads are barely growing in most of the country, and future declines are possible. Before proceeding with decisions to build that will affect bills for 40 years or more, utilities and regulators should first carefully consider alternatives including energy efficiency, demand response, and encouraging distributed generation. As discussed by Binz et al. (2012), regulators should practice "risk aware regulation."

In addition to the options mentioned in this section, some of the options we discussed in prior sections may be pursued in a few states, but we do not think they will become widespread. For example, some states may improve the ability of utilities to invest and recover costs, but our sense is that more states will move to wholesale competition, and large utility investments in generation will gradually become more the exception than the rule. Some states may pursue an energy efficiency utility, but most states are likely to have distribution utilities provide energy efficiency services as long as they do a good job (which in part depends on the incentives they are given). Some utilities may establish a FinanceCo, but thus far few of them seem very interested in this approach, with the possible exception of providing financing for systems that are within their core expertise.

MEDIUM-TERM

Over the medium term, utilities and policymakers will increasingly need to pursue the following options.

Develop and offer optional services, moving from the pilots discussed above into broader-scale offerings. We see these services as an important part of future profitability. In particular, utilities can leverage their expertise in power-system and energy efficiency engineering and operations to build on their traditional core competencies. Such services should grow from customer needs, and in many cases they will compete with services offered by other non-utility service providers.

Develop and implement new systems and capital plans for managing increasingly complex grids. The growing use of renewables and other distributed generation will make new techniques for managing a complex grid increasingly essential.

Establish and implement best practices for performance-based regulation, building on initial experiences in the short term that show which practices work and which do not.

During this period, many of the efforts begun in the near term will continue, including expanding energy efficiency and demand-response efforts and prioritizing needed infrastructure improvements. This medium-term period should also be used to experiment with new long-term structures such as the utility as smart integrator and the energy services utility. Climate-change policy may also become clearer during these years, both through government action and through the actions of consumers and businesses. If so, the utility industry will need to adjust accordingly.

LONG-TERM

By the mid-2020s, each state and utility will likely have to choose a long-term model. All such models show a clear need for a single company to operate the wires and a system integrator to assure reliability. Together, these are core functions of "the utility." In our view, this entity should play an important role in funding and implementing energy efficiency investments, as these help to lower costs for all customers. Without such programs, the rate of energy efficiency adoption will be lower, and demand and costs higher.

A key question will be whether the system integrator also owns generation. In some states, utilities have already divested their power plants and there is wholesale competition. In others, integrated utilities are required to plan for generation needs and to acquire generation through open bidding. These states are more likely to employ the smart integrator utility model. Still other states have vertically integrated utilities that own generation. These states and companies will have to decide whether to continue with exclusive utility control of new-generation additions and vertical integration, or to open the market for new plants to the utilities' competitors.

The energy service utility model is likely to be used where utilities continue to own substantial generation. There are also a variety of options somewhere in between the smart integrator and energy service utility models. Furthermore, the choice as to whether a utility owns generation may not be black and white, since in either of these two models it may be possible for utilities to invest in small generation to help foster this market and provide new sources of investment return. In states with the smart integrator model, there could be caps on such generation (e.g., no more than x% of load) or requirements to spin off such investments after a defined period of time such as five years.

Conclusion

The future of the utility industry is far from clear, with uncertainties regarding future sales, the role of distributed generation, environmental regulations, and business and regulatory models. One thing that is clear is that we are likely to face the old Chinese curse: "May you live in interesting times."

The next few decades will probably be challenging for the utility industry as utilities and regulators grapple with level demand, increasing use of distributed generation, and a more complex grid. Our key finding is that a utility industry with substantially increasing sales is unlikely, but a death spiral is also unlikely.

To maintain profits in this environment, utilities should pursue new services, good management, decoupling and incentives for achieving energy efficiency, and other public goals. We believe that energy efficiency should and will play a strong role. Utilities can help their customers use energy more efficiently as a way to moderate utility risks and customer bills while also providing valued customer services and protecting the environment.

To prepare for a strong utility of the future while also meeting public goals, utilities and policymakers should provide consumers value for their money, get regulatory rules right, and establish fair policies and robust systems in several areas. These include power pricing, decoupling profits from sales, incentive regulation, and coordinating a more complex grid. Fair rules will mean that utilities can offer new services and that new suppliers can enter markets without undue advantages or constraints.

To get on this path, utilities and policymakers need to make important decisions in the short term and build on them over the medium and long terms. These decisions will address such issues as decoupling, performance measurement and metrics that provide appropriate financial incentives for utilities, the role of rate-payer funded programs in promoting energy efficiency, opportunities for utilities to offer new services, and how best to structure rates to recover costs. If we can get these rules and systems right, utilities will maintain profitability, customers will receive the services they need, bills will be kept to reasonable levels, and we will all enjoy a clean environment.

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