In defense of the grid

Remaking the utility business model

BOB FESMIRE – The traditional regulated utility business model is under siege. Demand growth is on the decline at the same time that costs, customer expectations and regulatory scrutiny are increasing. As the industry and its regulators search for an alternative to cost-of-service regulation, new technologies and a re-thinking of the value of the grid could change the game.

Reliability has always been the prime directive of the power industry. Now a confluence of changes in technology, regulation and public policy has produced a mortal threat to the traditional cost-of-service model that has sustained the industry for more than a century.

Whatever replaces this approach must take into account the value the grid delivers, specifically with regard to:

- Reliability - ensuring the power supply remains reliable and affordable
- Efficiency – reducing energy losses, keeping costs down and reducing resource consumption
- Flexibility - providing a platform for a wide range of new products, services and businesses
- Policy and customer demands - facilitating the shift to cleaner sources of energy

Accordingly, the grid must not just be preserved, but modernized. That will require not only enormous investment, but also reconsideration of the most basic elements of the industry: what is the definition of a customer? What is a utility? What do we expect the power industry to provide? Anything being contemplated as a replacement for the cost-of-service model must address all of these questions.

Regardless of what comes next, industry revenues are likely to remain constrained just as customer expectations for reliability and renewables integration are increasing and prices for delivered energy remain low. New, unregulated lines of business present intriguing opportunities, but the bulk of the investor-owned utility's (IOU) business will remain tied to legacy business (i.e., reliable delivery of electric power). Utilities operating distribution networks, therefore, will be faced with several imperatives over the next five to ten years:

- Manage the health of existing assets and extend their life
- Minimize non-recoverable investments (i.e., those not included in rate case or in deregulated service areas)
- Optimize operations to maximize capital utilization and minimize costs

There are solutions—technological and otherwise—to address the challenges facing IOUs, but perhaps the biggest challenge will be finding a way to pay for them. In short, the industry and its counterparts in government must find a way to "monetize" the grid aside from volumetric sales of electricity.

The cap ex conundrum

The American Society of Civil Engineers estimates that $673 billion must be invested in the US power infrastructure by 2020 just to maintain the level of service to which we've become accustomed. The market capitalization of the entire utility industry is only $464 billion.

Investor owned utilities (IOUs) make up the bulk of the power industry, serving 70 percent of all electricity customers. In regulated service areas, these firms operate under a regulatory compact that allows them to retain their monopoly status and receive a set percentage on prudent investments they make as long as they operate in the public interest and their rates are "just and reasonable." Retail rates are determined via a quasi-judicial process in which the utility must justify its expenditures before they are added to the ratebase.

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The utility business relies on more capital expenditures per unit of output than any other industry, but it also spends more in absolute dollars. Deloitte estimates that in 2013 the industry spent $85 billion in ca-

Booming natural gas supplies have contributed to a continued downard trend in electricity prices

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pex in the US alone. However, despite this extreme level of capital intensity, the average asset utilization rate for a typical IOU is below 50 percent according to a recent report published by GE.

Of course, much of this seemingly counter-intuitive relationship between capital expenditures and asset utilization can be attributed to the nature of electricity and the wide range in demand over the course of a day. In short, utilities must invest and maintain assets for the worst case scenario—the proverbial hot summer day—but most of the time they operate far below the system's physical constraints.

The utility industry's high level of capital expenditure is not a problem in and of itself, and during the postwar years of grid expansion a continuing cycle of new-build construction kept the revenue flowing. However, the nature of the cost-of-service model includes a built-in disincentive for utilities to invest in systems and equipment that might lower costs. The problem lies in the regulatory review cycle.

If a utility invests, for example, in a new outage management system, the company faces a conundrum. On one hand, it's possible that the cost of the system will be disallowed to become part of the ratebase if it doesn't perform to the level anticipated. On the other hand, if it performs well, the utility's cost savings will be short-lived as the "new normal" of service is applied at the next rate review.

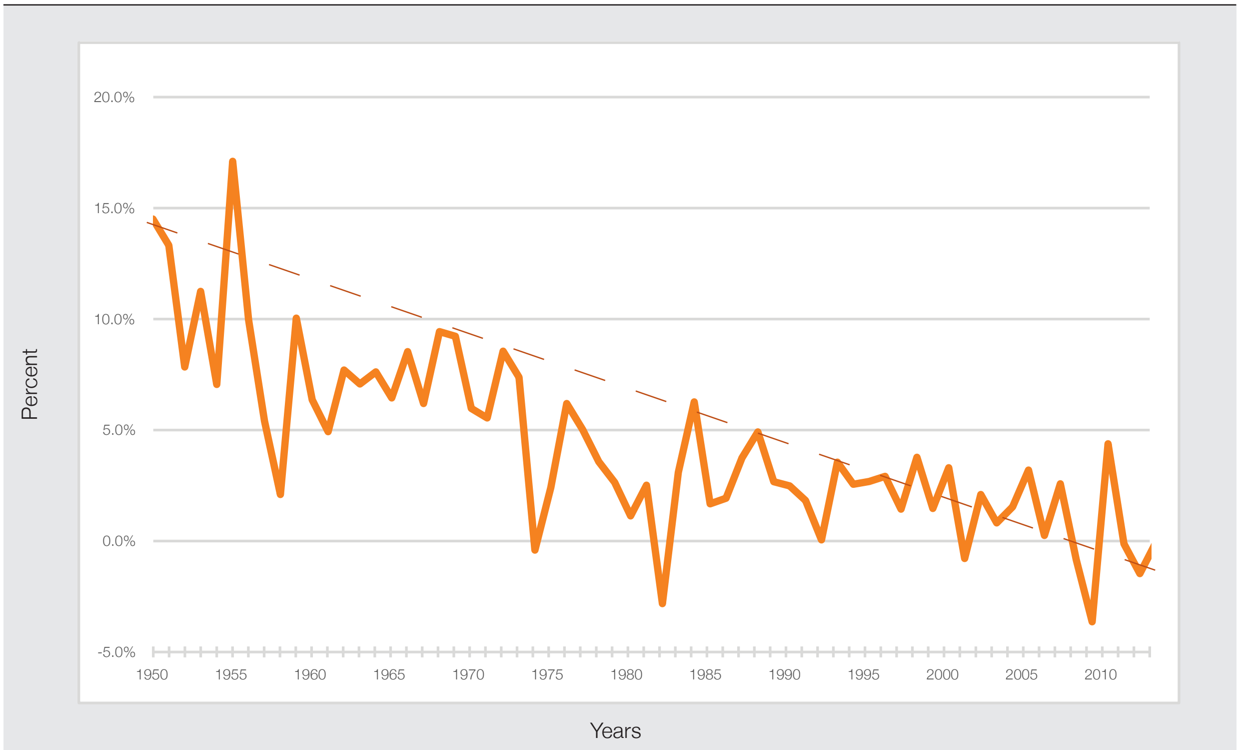
What's wrong with traditional utility regulation

The problem with cost-of-service is that there is a lag between when the utility invests in a given project and when they might see a return. This is particularly challenging with newer technologies like energy storage, microgrids and renewable integration projects that might go through proof-of-concept and pilot phases before being rolled out. In the case of efficiency-boosting projects, even if a utility does recover the initial investment, there is no mechanism to offset the hit the utility will take in subsequent years resulting from foregone sales of delivered energy.

Cost-of-service regulation is fundamentally backward-looking, and this is apparent in two ways. First, the nature of the ratemaking process itself: Rates are made by examining historical costs or near-term projections and determining whether and how they should be recouped. Second, the traditional ratemaking process operates on the assumption that the utility will keep on providing exactly the same service it always had before.

Customers today expect far more than reliable electric service from their utility, but they are not consuming electricity at a growing rate, which means utility revenues are not growing either. Meanwhile, customers want to know where their power comes from. They want the option of buying renewable energy or generating their own power (while remaining connected to the grid). They want the grid to be protected from physical or cyber attack. They want to know that their personal data is secure. All of these carry significant implications for utility budgets, but do not easily lend themselves to a conventional ratemaking process. The result is that in terms of adopting new technologies that can enhance reliability, make the grid more flexible and meet customer demands, the industry is being held back by an outdated business model.

Figure 1: YOY Growth in Electricity Sales 1950 - 2013



Reliability, then and now

Historically, the reliability of the US power system has been among the best in the world. Equally important, though, is the less-known fact that the cost to the end user to receive this highly reliable supply of energy has declined steadily over time. The average inflation-adjusted retail price of residential electricity in 2012 was 28 percent lower than it was 30 years earlier according to a Deloitte study.

However, utilities are experiencing major outages today far more frequently than the historical average. Most of these outages are weather-related. According to Deloitte, US utilities experienced between 5 and 20 major outages per year caused by weather in the 1990s compared to 50-135 per year between 2008 and 2013. This dramatic increase in outages has turned up the pressure on utilities to improve reliability, specifically in terms of their ability to recover quickly from storms.

Perhaps the most vivid example of where customers' expectations with regard to reliability have come can be seen in the aftermath of superstorm Sandy. The storm itself was exceptional to be sure, but that did little to mitigate people's expectations about when their power would be restored. Even those who had seemingly reduced or eliminated their dependence on the grid by installing rooftop solar were left wondering why their systems weren't working.

The answer of course was simple. Despite having the ability to self-generate, these customers' homes were still part of the interconnected grid and subject to all the safety and control measures that any other generating facility must adhere to.

Customer expectations of the grid have clearly evolved. Electricity has long been essential to maintaining modern society, but it has reached a point now where it underpins every aspect of our lives. Land line phones, to take one example, have been traded for cell phones, but what do you do when you can't charge your phone? The land line comes with its own power supply so that communication can go on during a power outage, but mobile phones (and the networks they rely on) are utterly dependent on the same power network that every other household appliance uses.

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Electronic devices continue to proliferate, driving perceptions that the grid must be advancing as quickly as the technologies it supports.

Moore’s law doesn’t apply to power systems

Meanwhile electronic devices continue to proliferate, driving perceptions that the grid must be advancing as quickly as the technologies it supports. Customer expectations are now bumping up against the limits of an aging network, both in terms of primary equipment and the IT systems that monitor and control it. However, the limitations of the cost-of-service model are being highlighted even more thanks to a decline in revenue growth that is the culmination of a trend decades in the making but is only now being felt by the industry.

Decreasing demand

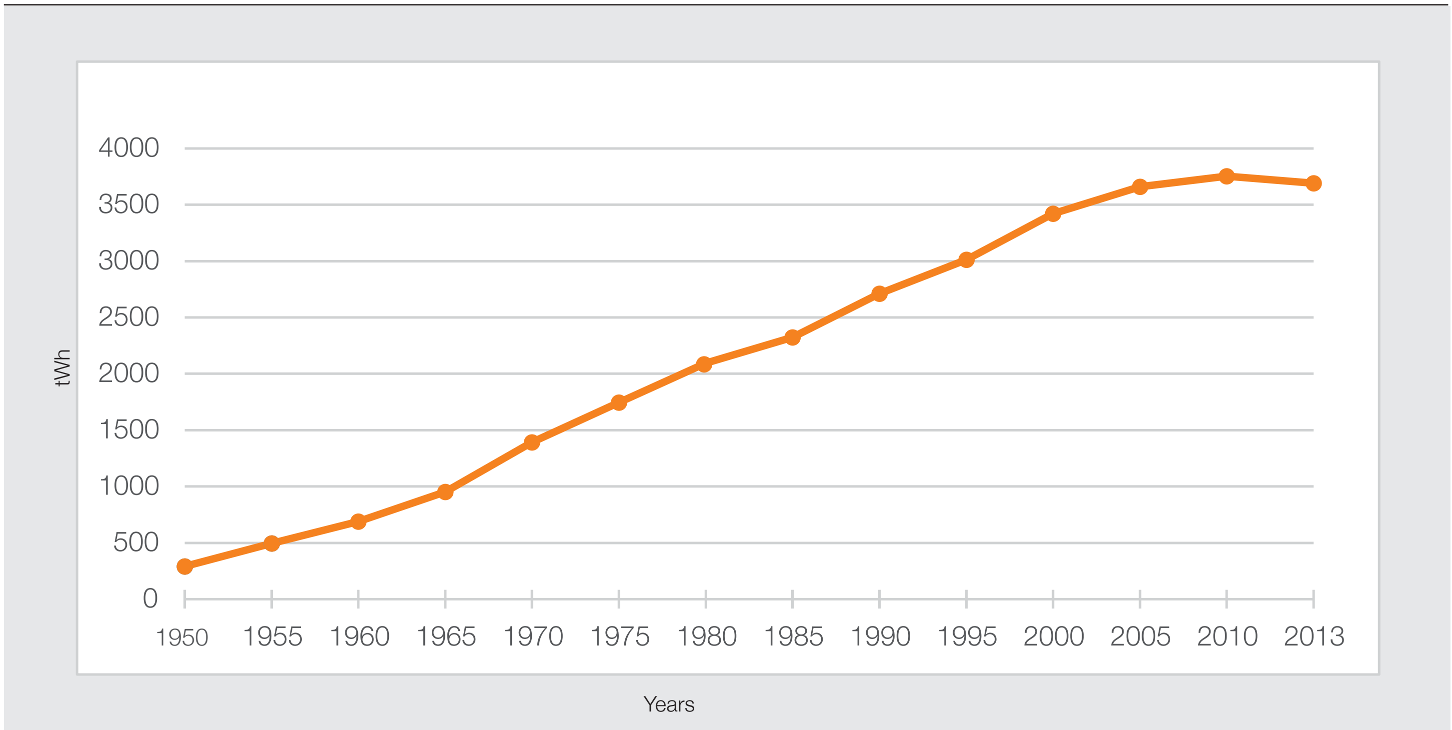
The growth rate of electricity sales has been trending downward for over sixty years. In fact, according to the Energy Information Administration, total US electricity sales have seen negative growth in five of the last six years.

A strong resurgence in demand seems unlikely. The US economy is set to continue a downward trend in energy per unit of GDP (see chart), largely as a result of a shift away from heavy manufacturing toward service industries. Meanwhile, according to Deloitte, 83 percent of power customers in 2012 said they were taking steps to cut electricity usage vs. 68 percent just two years earlier. The figures for businesses generating some portion of their own power were 35 percent in 2012, up from 21 percent in 2010. The same study showed commercial and industrial customers targeting a 23 percent reduction in power use over the coming 3 to 4 years.

These figures are significant, but they represent the beginning of a much wider trend. On the residential side, rooftop solar continues to proliferate, particularly in states with legislation favorable to the development of renewable energy sources and/or self-generation. States such as California, Massachusetts, New Jersey and Maryland top a ScottMadden list of the most conducive to solar based on retail prices, the cost of distributed generation, metering and interconnect policies, and provisions allowing third party sales of electricity. While solar still accounts for only a fraction of total generating capacity, it is growing rapidly thanks to declining costs, policy incentives and wider consumer acceptance. Expect to see more PV panels on more rooftops.

From the utility’s perspective, we are now at the end of a long downward curve that began in the postwar boom years when utility revenues were growing at 8 percent per year. By contrast, the EIA projects demand growth to remain essentially flat through 2040. That single fact, more than any other, signals the obsolescence of the cost-of-service model, but there are other factors at work too.

Figure 2: Electricity Sales 1950 - 2013



Regulatory changes

State commissions make the rules for how utilities operate, but there are some important regulatory considerations at the federal level. Some impact the industry directly, such as environmental standards like the Mercury and Air Toxics Standards (MATS) that govern power plant emissions. Carbon regulations seem to be increasingly likely, but for the moment they remain in the wings.

There are also policies that affect the power industry indirectly. Incentives for electric vehicles, for example, encourage more plug-in vehicles that in turn can dramatically increase the demand level of a given home. These incentives are likely to remain available for at least a few more years as carmakers work their way toward a cap of 200,000 vehicles per manufacturer.

Despite being broadly reported when initially put in place, reliability standards have receded from the headlines in recent years, but they set very clear boundaries for utility performance.

These mandatory standards come with financial penalties and replace the self-policing regime that was in place since the dawn of the industry. What is notable in retrospect about the shift to mandatory standards is how it seems like just one more of a growing number of constraints, however warranted, on utility operations.

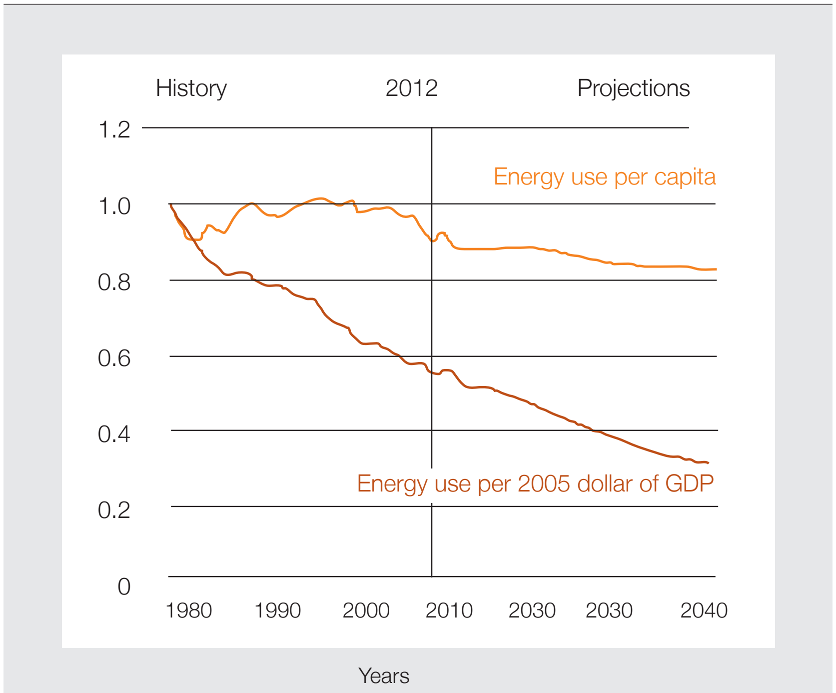
There are more at the state level, and they span a variety of policy objectives that tend to focus on environmental objectives or industry structure.

Environmental – Twenty-nine states and the District of Columbia now have some form of mandatory renewable portfolio standard in place, and another eight have voluntary standards. California and Puerto Rico have also implemented mandates for energy storage. It's worth noting, however, that some utility customers (e.g., Apple, Wal-Mart) are moving to 100% renewable power with or without the utility, signaling the potential for a rising demand for green power that may eventually overtake RPS mandates. States are also promoting energy efficiency. Deloitte projects funding for state efficiency programs to grow at 4-10 percent CAGR by 2025

Industry structure – Wholesale power market restructuring brought change to the generation and transmission markets serving 60 percent of all US electricity customers according to GE. The same is poised to occur at the retail level. Net metering, where electricity customers can sell power back to their utility, now exists in 44 states following a 2005 federal mandate to establish appropriate standards. Utilities, however, receive no compensation for providing what is essentially 24/7 backup power capacity for grid-connected facilities using on-site generation. Twenty states currently allow third party ownership of renewable generation resources and 14 states have implemented "decoupled" rates in which utilities are compensated on metrics other than simple volumetric sales of power.

The changes in market rules are particularly interesting. In a recent paper, IBM noted that there are now "reciprocal value exchanges" in which value, like power itself, flows in multiple directions. Gone are the days when the utility sent power out and customers sent dollars back. Not only can customers also become suppliers, but a host of new players are seeking to intermediate the utility-customer relationship. A variety of industry observers have likened this trend to what happened in the telecom industry whereby the incumbent "utility" built out a network that was then

Figure 3: AEO2014 Market Trends - Figure data - May 7, 2014



Energy use per capita and per dollar of gross domestic product in the Reference case, 1980-2040 (index, 1980 = 1)

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used by third-party service providers as a platform for myriad new businesses (e.g., Amazon, Netflix).

All of this will only be accelerated by the capture and analysis of the ever-expanding amount of data being generated by customer and supplier alike. Indeed, IBM says "the grow-and-build years are back," only now the infrastructure being built is virtual, and the benefits of such growth won't necessarily flow to the utility.

So, the cost-of-service model is outmoded on several points:

- It relies on a perpetual growth cycle that no longer reflects reality
- It is fundamentally backward-looking and provides limited, if any, means for utilities to fund projects prospectively even if they have the potential to reduce costs in the long term
- It fails to account for the broad range of services (e.g., green power options) and assurances (e.g., vis-à-vis grid security, data privacy) that the modern utility is expected to provide
- At its worst, it can act as a disincentive to innovation

Compounding these issues is the fact that the ratemaking process, owing to its provenance as a judicial proceeding, often creates an adversarial relationship between the utility and the PUC, not to mention utility customers. Going forward, replacing the cost-of-service model should extend to changing the nature of the working relationship between regulator and utility.

Alternative regulatory schemes

Following are some approaches to cost recovery that offer various alternatives to the cost-of-service model, but each works best in a cooperative environment.

Prospective rate cases – These are similar to existing cost-of-service, but are based on forward-looking estimates of investment rather than backward-looking accounting of investments already made.

New rate components – This refers to the creation of mechanisms separate from conventional rates that allow utilities to recover costs on an accelerated basis. For example, some utilities now receive payment for grid capacity (kW) as opposed to actual delivered energy (kWh).

The view from Wall Street

Utility stocks have long been considered part of the "widows and orphans" portfolio—safe, dividend-producing shares that provide a steady income with relatively low risk. Today, even firms that remain fully integrated (i.e., owning the entire electricity supply chain) are facing a very different set of investor expectations. Quarterly earnings are being scrutinized in the same way that the earnings of companies in other, more competitive industries are. Utility investors increasingly want to see growth, not simply a dividend.

Meanwhile, utility revenues are flattening. This is due to a combination of factors but it's a trend that has been decades in the making. The result, from an investor's viewpoint, is a much less attractive sector. GE reports that 58 percent of utilities have credit ratings of BBB or lower from S&P. In the early 90s, only around 20 percent had such low ratings. More recently, utility stocks have gone from substantially outperforming the S&P 500 during the 2000s to dramatically underperforming the broader market since 2009.

Formula rates – These are pre-set "no haggle" rates derived from the utility's submission of cost data in a standardized format. Costs can be subject to review after the fact.

Multi-year rates – These rates take a longer-term view, for example by being indexed to inflation. They might include requirements for cost reductions and for any resulting savings to be shared with customers. They might also provide the utility with a mechanism to address unforeseen exceptional costs. This approach comes with a potential downside in that it could lead to a cutback in Op Ex spending, which in turn would erode reliability.

Price caps – As the name implies, the idea here is to set a kind of "out of pocket maximum" for utility customers, thus encouraging utilities to find ways to reduce costs.

Technology changes

Advancing technology has produced a variety of products that impact utilities in different ways. Some improve reliability while others enhance efficiency of the grid or reduce demand. Many show results in more than one of these areas.

Reliability-enhancing technologies

Advanced metering infrastructure is probably the most immediate example of a technology that can have a direct impact on reliability. AMI is often portrayed as a convenience for the utility but aside from reducing the cost of meter reads and improving the quality of billing data, having a network of smart meters in place allows the utility to know when power goes out and when it is restored with a high degree of accuracy. This is vital in reducing the time to restoration during major storms, not to mention reducing associated costs.

Feeder automation is another low-hanging fruit with regard to reliability. The US Department of Energy's recent grant program with four utilities showed a reduction in the frequency of customer outages of 11-49 percent and a reduction in the average outage duration of up to 56 percent. The technology also can be scaled easily from a single feeder to thousands and utilities can realize a benefit from the outset.

Microgrids are not a specific technology per se, but they are gaining a lot of attention now as a way to improve on the reliability of the grid. Some microgrids aim to exploit local renewable energy sources, but their appeal stems primarily from

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the assurance that even if the grid goes down, the microgrid will continue to operate in island mode. Obviously, when coupled with full-time on-site generation, microgrids can be seen as "part of the problem" of declining demand, but while the number of projects under way today is small, utilities may ultimately find new revenue in microgrid related services.

Efficiency-enhancing technologies

At the transmission level, significant improvements in grid efficiency can be realized through the application of advanced power electronics to move more power over existing lines. These devices can forestall major investments in new generating capacity while also greatly enhancing grid resilience. However, the opportunities for transmission-level improvements are relatively few compared to those at the distribution level.

Distribution automation includes a number of particular technologies, but one good example is the practice of volt-vAR optimization (VVO). With appropriate monitoring and control, distribution grids can automatically adjust voltage levels to optimize their throughput dynamically. This would be impossible without automation, but when it is put in place, VVO can yield improvements in distribution grid efficiency of 2 to 4 percent. One utility, Oklahoma Gas & Electric, is using VVO to reduce peak demand levels and expects a savings of around 80 MW, the equivalent of a gas-fired power plant.

Microgrids, as noted above, are seen primarily as reliability-enhancing but by placing generation close to the point of use they also drastically reduce line losses associated with serving disparate loads from centralized power plants. Even in the US, transmission and distribution losses amount to around 6 percent of all power generated, so eliminating most of them has a substantial impact on overall efficiency. Perhaps more importantly, locating more generation close to load defers the need to upgrade transmission and distribution lines.

Demand-reducing technologies

Perhaps the most visible technology in this category is rooftop solar. The cost of photovoltaic (PV) panels has dropped precipitously in recent years and with tax incentives in place at least through 2016, we should expect to see more solar in the near term. However, their impact on overall demand levels will likely lag the hype surrounding their proliferation.

Energy efficiency, on the other hand, is improving across a wide range of end-use applications, from residential appliances to energy-intensive industrial processes. This trend is attributable to essentially building better mousetraps (e.g., the shift from incandescent light bulbs to compact fluorescents to LEDs). The gains realized from these more efficient products are fixed and permanent, driven by a desire to reduce energy costs. However, the same motivation underlies demand response programs that by nature seek to reduce demand for a specific period of time, typically a few hours during peak periods.

DR has been around in one form or another for decades, but a variety of technologies is now poised to take it to the next level. From smart devices to systems that allow third party service providers to aggregate reductions in demand and sell them on the wholesale power market, demand response is finally on solid ground at least technologically. More favorable regulations regarding how DR is treated and who has the authority to sell it will only encourage further adoption. For utilities, especially those operating in deregulated markets, the rise of DR is more complicated. As with efficiency technologies, the utility may find itself funding the creation of a new service that will permanently reduce its revenue from power sales.

What's next?

Modern, industrial societies will not tolerate an unreliable power supply, and if for no other reason than this, the industry and its regulators must come together. The grid, as such, is not what utility customers pay for. They pay for a reliable supply of electric power, along with a host of newer expectations outlined above (e.g., the ability to go 100 percent renewable).

The traditional utility business model must therefore adapt to meet these requirements, but where does that leave utilities? What can they do?

If they're vertically integrated, they can defer large capital projects (i.e., power plants) by investing in technologies like VVO that also reduce operating costs. Still, regardless of the regulatory environment, utilities will have to look beyond their core business to specialized services that produce a higher return. For example, they can embrace distributed generation and (eventually) microgrids and position themselves as the supplier of choice. They can do the same with demand response.

On the regulatory side, utilities can push for rate systems that recognize the value of the grid and support long investment cycles, and they can engage in public relations to educate customers. Ultimately, though, it is the state PUCs that need to deliver an alternative regulatory model. They must recognize the obsolescence of traditional cost of service and they must adopt alternatives that bring utility and customer needs into alignment.

That, after all, is what this industry transformation is all about. Power customers are evolving, not only in how they use energy but in how they acquire it. That change is already happening. Now it's up to utilities to adapt, but it will require bold action on both sides—business and regulatory—to build a new utility business model that can succeed going forward.

ABB Inc.
+1 800 HELP 365
12040 Regency parkway
Cary, NC 27518

Reference

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