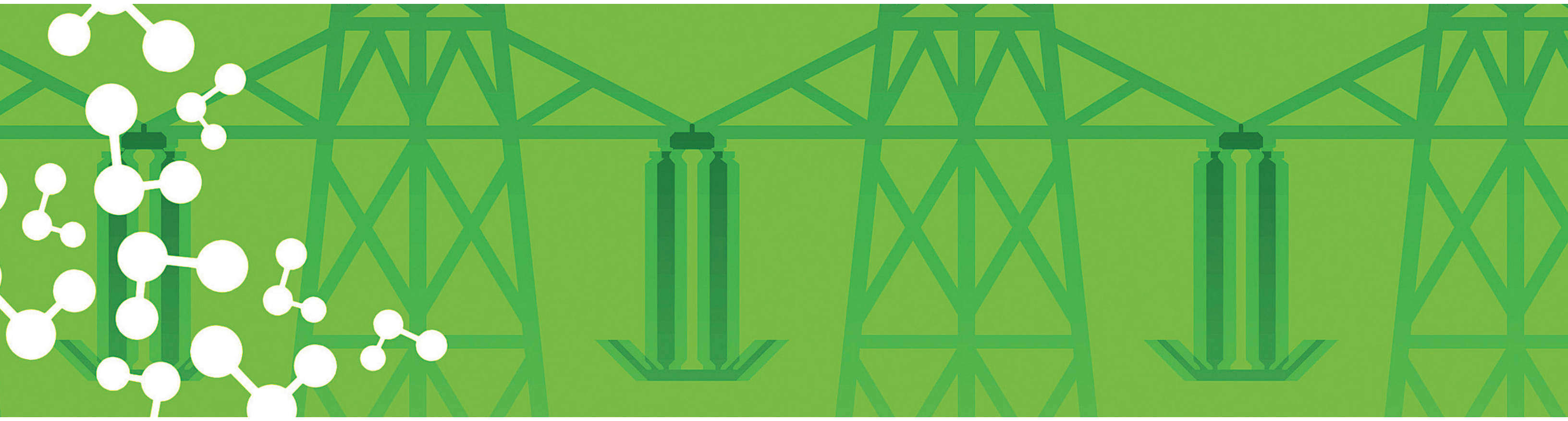


U.S. smart grid value at stake: The $130 billion question

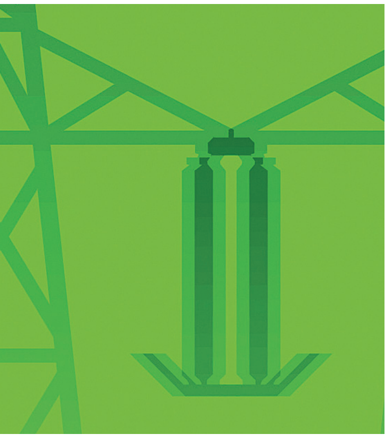
The strategic stance that utilities adopt during the development of the smart grid in the United States will help determine how much value is captured and who captures it.

Adrian Booth, Mike Greene, and Humayun Tai

The development path for the smart grid has reached an inflection point in the United States. More than 50 million smart meters are slated to be installed by 2015 and deployment of new grid and customer applications is accelerating, driven in part by an infusion of federal government stimulus funds. Before these technologies mature and their benefits become clear, however, utilities will have to develop estimates of the evolution of the smart grid and strategies to address its overall value proposition.

The stakes will be enormous, with the total potential value generated in the United States from a fully deployed smart grid reaching as high as $130 billion annually by 2019. Electricity customers, utilities, technology providers, service providers, and society at large will each receive a share in the form of improved utility operations, improved utilization of the electric grid, reduced power consumption, improved ability for customers to manage electricity, and reduced economic losses from power interruptions.

A large and new set of opportunities—worth some $59 billion—is in customer applications, which comprises packages of pricing, in-home displays, smart appliances, and information portals, all aimed at encouraging customers to smooth and reduce consumption. Taken together, these demand-management programs should lead to improved ability to manage electricity and



substantially lower energy consumption. Grid applications and advanced metering could yield an additional $63 billion and $9 billion respectively, mostly in the form of improved grid efficiency and reliability.

The estimated value at stake includes hard cost savings such as reduced operational expenses and reduced power consumption for utilities and soft cost savings like deferred capital expenditures and societal benefits such as improved reliability and lower greenhouse gas emissions. In addition to the value at stake estimated here, there are other future opportunities that are hard to value at this time (e.g., the value of data) or are in adjacent value pools that are potentially influenced by smart grid (e.g., energy efficiency, renewable generation, electric vehicles). The estimates in this article are based on the total surplus the technological and policy innovations in question are expected to generate. No assumptions are being made about which customers, utilities, and smart grid providers shall actually capture the value. Furthermore, only the gross annual benefits available are calculated here, without taking account of the cost to capture. In order to realize the value, substantial investment will be required in equipment, software, installation, management, and other services. Given the rapid evolution of technology and standards, the costs are expected to decline although it is not yet clear how fast and by how much.

Development of the smart grid and its potential value remain uncertain. Will customers want it? How much value will be captured, and by whom? What role will utilities play in unlocking the value? What regulatory framework will optimize the roles of key stakeholders? One thing is certain: utilities, and particularly those that own and operate distribution assets, are at the center of the debate. They have important strategic choices to make, which will determine the total value realized as well as who captures it.

Value of smart grid applications

Smart grid applications can be grouped into three broad categories: advanced metering, grid applications, and customer applications. Exhibit 1 on the following page shows the relative value of these categories and the discrete value levers that make up the $131 billion in estimated annual value in 2019.

Customer applications—$59 billion

Smart grid customer applications can enable demand response (DR) programs that shift demand from peak to off-peak times based on voluntary customer behavior. In addition to peak shifting, a second advantage of DR is the opportunity to reduce overall energy consumption by increasing information to customers and customer awareness thereby. Broadly defined, these programs use technology, education, and tariffs to manage demand. As with other high-tech products that influence consumer behavior, attributing the appeal and effectiveness of energy management solutions to specific components or design features can be difficult. It is therefore more useful to talk about the effectiveness of whole customer application packages, rather than individual applications such as TOU (time-of-use) pricing or in-home displays. These packages could include:

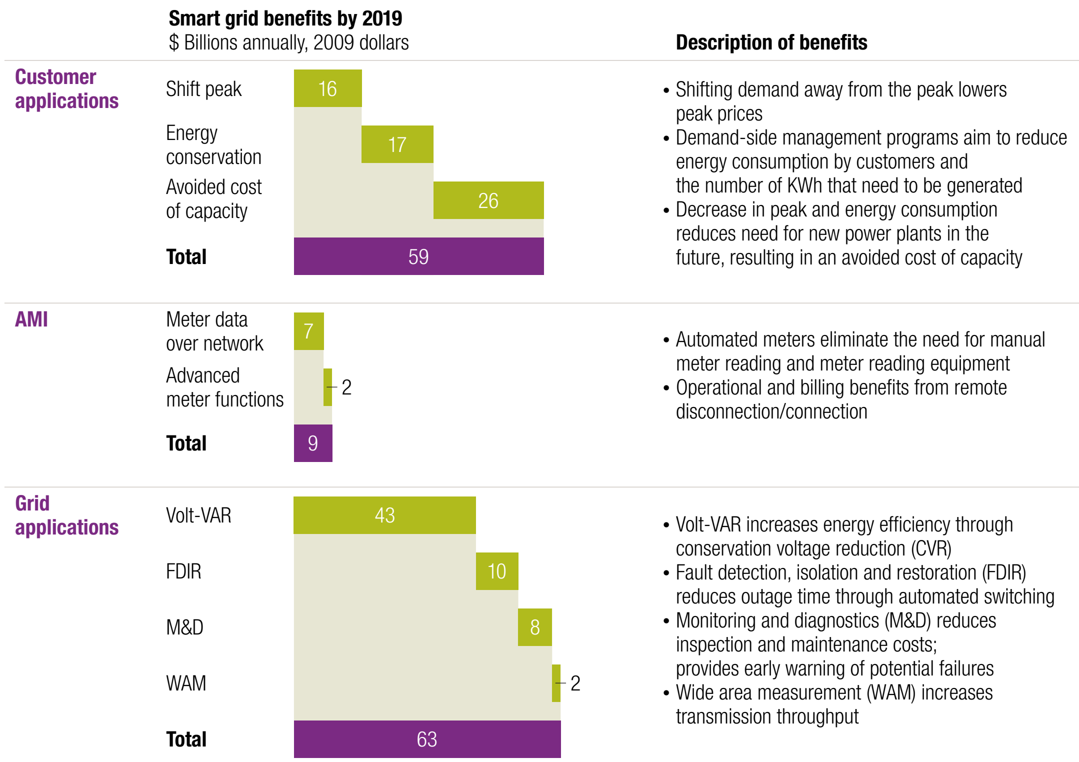
- *Tariffs and rate structures,* such as time-of-use pricing, critical-peak pricing, real-time pricing, and other financial incentives

- *Technology,* such as in-home displays that provide pricing, consumption, environmental and billing

Exhibit 1

The $130 billion question

The U.S. smart grid value at stake is over $130 billion annually.



information, as well as load-control devices and programmable communicating thermostats that allow a utility to shift peak demand without significant impact to customers

- *Analytics,* such as current load vs. average or current load vs. a neighbor's

- *Education and marketing* about the new packages and ways to use energy more efficiently.

Future customer applications will also likely integrate distributed generation, electric vehicles, and more sophisticated energy management systems. Effective combinations will provide customers with the transparency, tools, and incentives needed to reduce the burden they place on their finances, the grid, and the environment.

Customer applications could provide $59 billion in annual benefits by 2019:

- *Energy conservation—$17 billion.* Pilots suggest that providing customers with detailed, up-to-date information about their energy use and its cost results in an overall reduction in electricity consumption for two reasons. First, customers can make effective trade-offs in how they use energy, given information about what devices use energy and the price of energy. Second, the information they receive allows them to make targeted energy efficiency investments—for example, a residential customer could use granular energy usage data to better understand the return on investment resulting from upgrad-ing an old refrigerator.

- *Smoothing daily demand profiles—$16 billion.* Electricity grids typically have prominent daily peaks that carry strong ramifications for the required generation types and capacity, boosting wholesale prices during peaks. Persuading customers to shift some peak-time consumption to off-peak hours by waiting to run energy-intensive appliances or, in years to come, charging of electric vehicles, would cause the average cost of generation—and the overall average price of energy to customers—to decline.

- *Smoothing critical peaks—$26 billion.* Grids experience critical peaks several times per year, typically during heat waves in areas and times of high air-conditioner use. These peaks of just a dozen or so critical hours a year set the capacity requirements of the entire distribution grid. If demand reduction measures such as the application of higher prices or the cycling of selected customers' air conditioning can be agreed upon and applied, then total grid capacity could be significantly lower.

The willingness of customers to implement these solutions or change behavior to capture the conservation and efficiency gains is currently unknown. Many pilots have shown significant impact—from 5 to 14 percent consumption reduction relative to baseline consumption. Few if any of these have been conducted in a manner that would robustly test the applicability and scalability of the benefits to a broader population, however. Many of these pilots, for example, have been criticized for allowing biases of self-selection and/or novelty. The real question is what the impact of customer applications could be, given the right level of information, pricing, control, user interface, and automation tailored to an individual customer's needs (see accompanying article, "The Smart Grid and the Promise of Demand-Side Management," pp. 38–44).

Advanced metering—$9 billion

Advanced metering infrastructure (AMI), sometimes referred to as "smart metering," consists of digital electricity meters equipped with bi-directional communication capabilities that will enable utility operational benefits estimated at $9 billion by 2019. As of 2005, fewer than 2 million of an estimated 150 million meters in the United States were smart meters. As of 2009, numerous large-scale projects had been initiated that will upgrade 50 million meters within next 5 years. Smart meters will generate $9 billion in direct benefits by eliminating the need for manual meter reading, but they will also enable many new customer applications that will generate indirect benefits (discussed later in the article). The direct benefit breaks down as follows:

- *Meter data over network—$7 billion.* Automated metering eliminates the need for manual meter reading and meter reading equipment.

- *Advanced meter functions—$2 billion.* Advanced metering sends more and better information directly to the utility. Utilities will thereby know almost instantly the location and extent of outages, enabling them to restore power and resume selling electricity more quickly. In the absence of smart meters, utilities must rely primarily on contact with customers for information about outages. Advanced metering, with its remote disconnection and reconnection capabilities, will also increase revenue assurance by reducing theft and enforcing disconnection policies.

Grid applications—$63 billion

Grid applications involve monitoring, controlling, and automating operation of the distribution and transmission networks. The four main applications that provide the most benefit to the grid are 1) volt-var optimization (sometimes called integrated volt var control or IVVC); 2) fault detection, isolation, and restoration (FDIR, sometimes called fault location, isolation and service restoration FLISR); 3) wide-area measurement (WAM); and 4) remote substation and feeder monitoring and diagnostics. Together, these applications can provide over $63 billion in annual value to society by 2019.

- *Volt-var optimization (VVO) and conservation voltage reduction (CVR)—$43 billion.* Smart technologies such as tap changers and capacitor banks that can respond to grid- and meter-based systems could enable real-time management and control of the voltage level and power factor throughout the grid. The majority of the benefit comes from conservation voltage reduction (CVR), an action in which utilities lower the endpoint voltage in order to reduce overall power consumption.[1] (Smart grid technologies permit significantly more precise voltage control than is possible without dynamic, real-time monitoring of and response to conditions in the grid, making it possible to achieve this voltage reduction while staying within regulated power quality guidelines). This voltage reduction lowers the need for total electricity delivered—and also reduces grid capacity needs, all on the order of a few percent. In many jurisdictions, a new or modified regulatory framework will be needed to encourage utilities to capture these benefits, as most utilities currently have little financial incentive to implement CVR. Additionally, the ability of VVO systems dynamically to correct power voltage reduces reactive line losses that would otherwise cause a percentage of power to be lost en route from the generator to the meter. The result is reduced emissions and lower electricity bills.

- *Fault Detection, Isolation, and Restoration (FDIR)—$10 billion.* These systems enable the utility remotely or automatically to reconfigure the grid in response to unplanned or planned outages. Smart substation relays are the most prominant example of this reconfiguration, although other components may include fault sensors and mid-circuit reclosers and ties. The benefits begin with detection. Depending on the nature of the fault, FDIR systems may be able to estimate its location and type and automatically dispatch an appropriately equipped work crew to the exact location. Careful activation of reclosers and ties could provide a second benefit, by isolating the fault to a smaller section of the grid, potentially including re-routing power from adjacent feeders to continue service to all but those immediately around the fault. The primary benefit of this capability is improved reliability (often measured using the System Average Interruption Duration Index [SAIDI][2]), but utilities will also benefit from the ability to streamline their repair operations.

- *Wide Area Measurement (WAM)—$2 billion.* WAM provides real-time information about the state of the transmission grid using a network of precisely timed monitoring devices variously called synchrophasors or phasor measurement units (PMUs). By aggregating synchronized measurements, a utility can obtain a real-time picture of network conditions, allowing the safe operation of the transmission grid closer to its true capacity, thereby reducing congestion costs. As one grid operator explained, “You can stand closer to the edge of a table if you know where

[1] The exact ratio between reductions in voltage and consumption is a matter of some debate and will depend heavily on the mix of end-customer devices connected to the grid, as well as on customer behavior. Hence the estimates here are approximate, based on a “middle-of-the-pack” value for this ratio.

[2] Other applicable metrics for reliability include the System Average Interruption Duration Index (SAIFI) and the Customer Average Interruption Duration Index (CAIDI).

the edge of the table is." By alerting utilities quickly to developing conditions on the grid, WAM also reduces the likelihood of major cascading blackouts, such as the one experienced in the U.S. Northeast in 2003.

- *Substation and Feeder Monitoring and Diagnostics (M&D)—$8 billion.* Smart technologies can provide utilities with a wealth of nearly real-time operational data about substation and feeder equipment. This data can be used quickly to address impending failures, optimize inspection and maintenance schedules, and generally improve asset lifetimes and utilization. The majority of this benefit is due to transformer monitoring systems, which can warn of an impending failure, allowing preventive rather than corrective maintenance and avoiding collateral damage.

Implications for utilities

The magnitude of the value at stake raises strategic questions for all interested parties, but particularly for utilities. While ratepayers, regulators, technology providers and service providers stand to capture portions of the value, utilities—specifically those that own and operate distribution assets—lie at the center of smart grid deployments. They are uniquely positioned to set the tone for deployments, which in turn will influence the total value realized as well as who captures it.

For a distribution operator, for example, the most significant strategic determinations are which pools of value to pursue, under what business model. The answers depend on the scope of operations the operator decides to target and the range of customer services it decides to offer. At one end of a spectrum of choices, a utility might focus on being an infrastructure provider. At the other end, it might operate as an energy services provider.

Infrastructure provider

The role of infrastructure provider is one option for utilities anticipating an evolutionary path for the industry, albeit it may limit total potential value capture. In this approach, the utility would remain more supply-oriented and focus on building or assuring enough generation and grid capacity to meet demand. For infrastructure providers, grid-side applications offer a valuable way to continue investing capital in the grid, while streamlining operations and improving asset management.

Infrastructure providers will be primarily concerned with supporting the power infrastructure to ensure reliable service and generate operational benefits through enhanced visibility into grid conditions, better controls, and improved meter functionality. An infrastructure provider will typically roll out advanced metering first, capitalizing on the trend toward smart metering and achieving an effective trade-off between capital and operating expenses.

Grid applications may leverage AMI communications and/or IT assets. They are a natural next step for the improvement of overall reliability and realization of operational savings. An infrastructure provider is likely to evaluate its investments in a traditional way, looking at the net present value of the resulting savings.

The implied business model of an infrastructure provider resembles that of utilities today: a rate of return related to the amount of prudently invested capital that is "used and useful." While some regulatory changes will be needed fully to deploy grid applications, the regulatory challenges will be relatively familiar in nature. As for capabilities, infrastructure providers will need to make significant organizational investments to ensure

A greater share of the value created through customer applications will be available for a utility that adopts a stance more akin to an energy services provider

successful deployment and management of such grid applications as next-generation distribution management systems. Power and IT engineers will need to work more closely together and be cross-trained. Many core business processes, such as outage management, field force management and asset management, will ultimately be completely redefined.

The role of infrastructure provider may be a more attractive one for many utilities concerned with managing their exposure to technological and market risks. However, this approach will limit value-creation opportunities from customer applications, which otherwise could account for more than half the total potential value from the smart grid. An added drawback to the choice of infrastructure provision is that the customer applications which are on the horizon could threaten the traditional utility business model by lowering overall energy consumption (or reducing the rate of increase that would otherwise occur).

Energy services provider

A greater share of the value created through customer applications will be available for a utility that adopts a stance more akin to an energy services provider (ESP). The ESP position involves a more holistic view of the value chain and considers demand-side management a core capability. The orientation of the ESP is one that sees the industry making a strategic shift toward delivering more services than simply reliable, low-cost energy. ESPs also expect that per-unit energy prices will continue to rise in the future, causing customers and public utility commissions (PUCs) increasingly to demand more effective tools to allow customers to manage their electric bills by managing the amount of electricity used. In parallel, public emphasis on green infrastructure will reward and possibly even mandate reductions in consumption for complementary non-financial reasons. Utilities acting as ESPs will be uniquely positioned to enable demand management, and will tend to pursue the supporting capabilities and incentives. As a result, the ESP utility will begin to reach behind the meter and inside the customer premises.

The ESP stance presents bigger challenges but also higher potential rewards. It will face all the same obligations and objectives of an infrastructure provider, but will also have to build new customer-facing capabilities and develop new business lines, some of which may be fast-growing, unregulated, and inclined to reward marketing and design more than pure operations. Like the infrastructure provider, the ESP will deploy smart meters as a first step, but it will view metering as a foundation on which to build future customer applications, whose benefits will furthermore help defray the costs.

For an ESP, the design of a metering system will emphasize strategy and flexibility rather than operations and cost effectiveness. As a result, the investment in smart meter capabilities for an ESP will likely be higher and more sophisticated than that of an infrastructure provider. As smart meters are deployed, the utility will need dramatic new capabilities to design, build, deploy, test, and manage customer applications, while ensuring a regulatory strategy that allows monetization of the unlocked value.

Customer applications will require a new set of institutional capabilities resembling those in consumer marketing industries. To succeed, ESP-style utilities will need to provide greater control, comfort, and convenience to customers through the right combination of customer segmentation and insights, design innovation and user-friendly technologies, meaningful marketing and messaging, and suitable interaction methods. They will also need to produce results in the form of reduced bills.

Today's utilities have few of these capabilities in-house and will need to start building or acquiring them quickly. The credit card industry offers an instructive analogy: over the past 20 years, card providers have moved from being financial engines offering a single credit card product with homogenous messaging to sophisticated marketing agents offering a range of highly customized products with meticulously refined messaging. The organizational changes that facilitated the credit card industry's transition closely parallel those that may be required for utilities to succeed as ESPs.

The ESP business model will demand innovation. ESPs will require a regulatory framework that allows for monetization of the benefits of demand-side management programs. The shareholder-incentive mechanism in place for energy efficiency programs in California is one example of this approach, although many potential alternatives exist.

Even so, many players other than utilities will likely pursue the same value pools: energy service companies (ESCOs), technology vendors, start-ups, and non-traditional players like Google and Microsoft, both of which have launched products in this space. An ESP utility must quickly decide with whom to partner and with whom to compete.

The risks of pursuing an ESP posture are real. The revenue base could decline, utilities could lose their focus on the core business of providing a reliable supply of energy, and customer applications may not catch on. Although the execution risks for an ESP are higher than those of an infrastructure provider, the latter may ultimately face a greater strategic risk. If customer applications and demand-side management become mainstream in the utility industry, the infrastructure provider may face disintermediation and confinement to a smaller market, with limited access to the value at stake in the deployment of smart grid technologies.

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Opinions diverge on how smart grid deployment will play out longer term, but its emerging dynamic poses fundamental questions for the evolution of the utilities industry. Will there be multiple sustainable business models for the "utility of the future"? Will some emerging models dominate while others die out? The strategic choices facing utilities would be difficult under any circumstances, but these choices must be made before smart grid technologies are mature and their benefits become clear. Utilities are uniquely positioned to set the tone for deployments, which in turn will influence the total value realized as well as who captures it. With $130 billion at stake, it will be important to make a sound decision.

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