

# Demand Response: Promise and Reality



**THE CASE FOR DEMAND RESPONSE (DR)** initiatives has been made for many years. Looking forward, peak demand for electricity is projected to rise by 19 percent nationally over the next decade, but capital committed to electric power generation, transmission, and distribution is expected to grow by only 6 percent during the same period according to the North American Electric Reliability Council. DR has the potential to play a significant role in closing that gap and easing the strain on North America's power delivery infrastructure. In fact, many in the electric power industry view DR as a potential solution to mitigate growing peak demand, enhance grid reliability, and defer new power generation and delivery capacity development. When DR is implemented via technologies with broader energy management capabilities, the result can be a cost-effective solution with a wide array of benefits, including reduction of carbon-emitting generation.

However, there is increasing concern that unless the advances being made in enabling technologies are matched with rate changes, regulations, and customer acceptance of programmatic solutions, the benefits of DR will be diluted. DR is more likely to realize substantial benefits if all interested stakeholders involved in the generation, delivery, and consumption of electricity have reached a workable understanding of the true implications and costs.

## TECHNOLOGY

Pilot studies and existing programs indicate that so-called "Smart Grid" technology provides significant potential to expand the capability and participation of DR. Through digital monitoring and control of the power delivery network and two-way communication with consumers and market participants, this intelligent infrastructure can increase consumer participation in DR programs by automating their choices. It also will allow for a multitude of energy services, markets, integrated distributed energy resources, and control programs.

The Smart Grid will enable electric utilities in real time to collect and analyze power supply and usage data from distribution network elements and from millions of end-user devices, thereby increasing distribution grid efficiency. A Smart Grid infrastructure will allow such data collection as often as every minute or "on demand," providing much more granular information and control capability. This capability in turn could enable the utility to coordinate and manage demand-side resources more effectively, taking into account distribution system conditions and power delivery requirements. A Smart Grid's potential capability would permit utilities and end users to become partners in shaving peak loads and reducing the need for expensive new generation plants or transmission and distribution infrastructure.

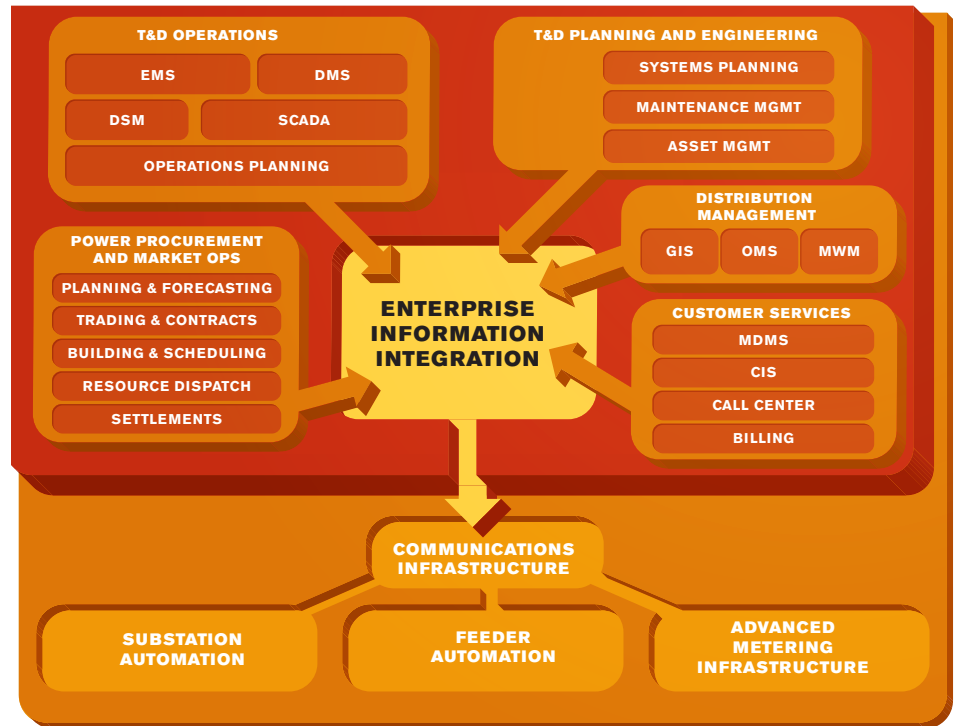
**DEMAND RESPONSE SUCCESS HINGES ON ADEQUATELY ADDRESSING AN INTERRELATED SET OF TECHNOLOGY, REGULATORY, COST, AND ACCEPTANCE ISSUES.**

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As utilities upgrade substations and communications networks in different ways, many are considering how such capabilities can be integrated with back-office and control center systems to deliver an end-to-end solution. *Figure 7* illustrates how an Advanced Metering Infrastructure (AMI) becomes an integral part of the utility operational infrastructure. AMI enables two-way communications between the utility and the consumer, and is often the foundation for a range of expanded technological improvements.

Many major utilities in the United States (and abroad) are pursuing either pilots or full deployment of AMI technology. For example, PG&E has begun a five-year effort to install SmartMeter™ devices for its 4.2 million gas and 5.1 million electric customers. The Energy Information Administration reports that 50 percent of U.S. states have AMI/Smart Grid pilot projects and installations in progress. However, while there is indeed significant activity in the market, such reports can be somewhat misleading. Pilots typically take place among a small set of customers, and proceed in advance of receiving regulatory approval for a broader effort. Currently, full-scale deployments are the exception. A number of utilities are still pursuing a “surgical” approach, in which they first target their most expensive or hard-to-read meters.

Nevertheless, pilot activity should be seen as an important step toward eventual development of a broader capability. Pilots enable technology and design concepts to be field proven, while gaining immediate synergistic benefit. They also can concretely identify technical, economic, and regulatory challenges to be resolved prior to full deployment. In the process, they help provide the experience and insight needed to resolve these issues.



**FIGURE 1** “Smart Grid.” Infrastructure facilitates demand response through an Advanced Metering Infrastructure and provides information and benefits across the utility enterprise.

### REGULATION

The slow adoption of Smart Grid technology can be partly explained by the piecemeal approach states and utilities are taking to comply with the Energy Policy Act of 2005 (EPAct) requirement to evaluate DR. Furthermore, without standards for smart networks, there is an increased risk associated with being an early adopter. The U.S. House Energy and Commerce committee has proposed a measure to create a new nine-member Grid Modernization Commission within the Department of Energy. If created, the commission would facilitate the adoption of Smart Grid standards, technologies, and practices across the nation’s electricity grid to the point of general adoption. How well policy decisions will keep pace with the decisions utilities must make to meet growing demand is still an unanswered question that poses a regulatory risk.

Smart Grid technologies will have limited value for DR without accompanying rate structures that take advantage of technology to provide short-term price signals. Yet dynamic rate structures will not be put into place on a broad scale without an established implementing technology. This “chicken and egg” conundrum has no easy fix.

The ultimate questions remain: how much consumer benefit will come from DR initiatives and how long it will take to achieve these benefits? Regulators across the country continue to face this issue. The long-term benefits of AMI/Smart Grid technology are typically dispersed among a wide range of customers, and may take years to be achieved. In addition, there are direct and indirect benefits for utility operations – from workforce reductions, to greater efficiencies in outage management, enhanced reliability, and customer services – that can only be approximated unless a system is fully implemented. Until the benefits can be quantified in terms that justify the economics, regulatory reluctance to approve technology implementation will not change.

EPAct Section 1252 requires utilities and state regulators to consider adopting policies that require time-based rates and smart meters for customers who request them. However, almost every state is looking at the substantive issues around advanced technology in a different way. Some states (e.g., Illinois, Oregon, Pennsylvania, and Texas) have been considering smart metering questions as part of rate cases and/or resource planning discussions. Other states (e.g., Kentucky, Louisiana, Ohio, and Virginia) have initiated Section 1252 inquiries separately from other proceedings.

Within its 2003 Energy Action Plan, California identified DR as a top energy policy and specified that 5 percent of peak load should be met by DR in 2007. Although actual results will likely fall short of the objective this year, the California Public Utilities Commission has approved AMI/Smart Grid programs among the state's three investor-owned utilities. Most large consumers in California already have advanced meters and participate in a number of DR programs, but residential and small business customers in the state will not have advanced meters until 2011. Even with the enabling technology to imple-

ment dynamic pricing and expand DR participation, price signals may produce limited benefits. A California law known as AB1X, passed in an emergency session after the last energy crisis, protects residential and small commercial customers from rate changes, so options for responding to price signals may be limited in these sectors. California programs are still ahead of many states and will provide important lessons and business insights for future DR and Smart Grid deployments.

Despite the flurry of concentrated activity in certain states, there is no industry consensus on the need for DR, and by extension AMI/Smart Grid technology. In response to EPAct directives, some states have concluded that no action needs to be taken, even while utilities in those states may continue to include advanced metering and DR in their future business plans. Utilities may need to take new regulatory approaches in the technology adoption plans to overcome potential regulatory hurdles. Early-stage regulatory involvement, along with thorough assessments, evaluations, and quantification of projected economic value, will go a long way in winning approval for cost recovery.

## UTILITY COSTS

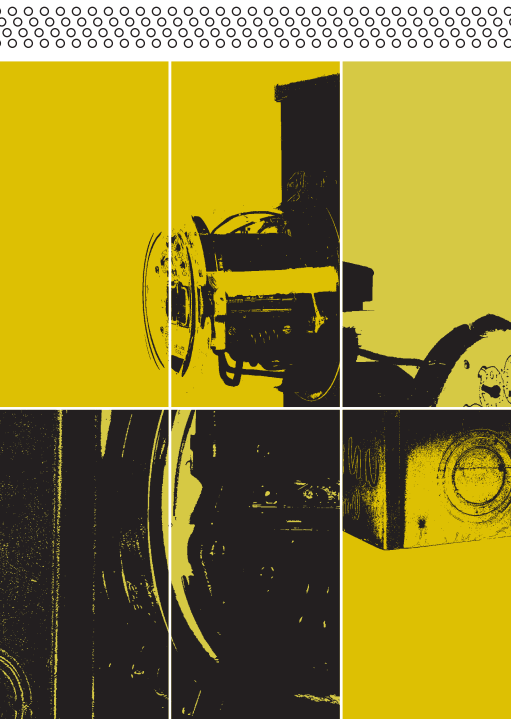
Until technology standards and regulatory policies are developed, continued reluctance to approve full cost recovery for AMI/Smart Grid technology is likely, thereby limiting expansion of DR capability. The costs are relatively straightforward; the benefits are more difficult to project.

Costs for a typical AMI system with two-way communication range from \$150 to \$250 per meter – \$500 million or more for a large utility. Capabilities for Smart Grid and DR program operation can add 20 to 100 percent depending on the scope. Broader capabilities require higher levels of investments, and provide greater potential benefits.



California Public Utilities Commission President Michael Peevey has praised the state's IOUs for making progress on their AMI plans, but he did have one complaint: “I am disappointed with the notable lack of progress in implementing tariffs demand-response programs need to capitalize on this investment.”





## CUSTOMER ACCEPTANCE

The underlying objective of DR is to more actively engage customers in modifying their consumption in response to pricing signals. The goal is to reflect supply expectations through consumer price signals or controls and enable dynamic changes in consumption relative to price. However, one inherent challenge facing DR initiatives is what appears to be a lack of consumer knowledge and interest regarding where their electricity comes from, how it is priced, and ways they can reduce consumption while maintaining lifestyle choices.

We can't blame consumers for their lack of knowledge. For decades, customers have been immune to spot energy price fluctuations, or any explicit cost for protection from those fluctuations. The public debate over how and how much to regulate electricity markets has been ongoing since the Depression era. On the Smart Grid question, one side is reluctant to approve investments that will increase consumers' costs. Another side sees the cost of Smart Grid technology as an investment with justified benefits. This debate will not be settled anytime soon, but it is important for utilities that propose such investments to adequately quantify the economic benefits, and for regulators to evaluate the proposals on the basis of a broad range of benefits.

DR proponents often point to the 2003-2006 California Statewide Pricing Pilot that involved about 2,500 customers of the state's three investor-owned utilities. These customers responded to price signals, such as time-of-use rate structures, and reduced their usage during periods of peak demand. Overall, reductions amounted to approximately 5 percent on critical days for small customers and approximately 7 percent for large customers.

Yet an often overlooked fact in this pilot is that a significant number of participants were provided smart thermostats that automatically adjusted air conditioning settings when critical peak pricing was in effect. As passive participants they did not have to take any conscious actions. The California experience suggests that when consumers are provided enabling technology that adjusts energy usage for them within predetermined limits – particularly two-way digital communications capability in smart thermostats – there is a significant drop in load.

From a regulatory perspective, this experience supports Smart Grid technology business plans. Advances in intelligent grid technology could eventually enable consumers to set the amount they want to spend each month on electricity. Appliances in the home also could be automatically adjusted. Computer programs could tell consumers at what level to set their thermostats to remain at a certain price point. These scenarios yield greater potential to support DR objectives, compared to implementing dynamic pricing tariffs alone.

To develop Smart Grid technology, a broad, long-term educational campaign also is needed. Customers need to understand how dynamic-pricing options can save them money before they will be willing to participate in such programs.

## CONCLUSION

Demand continues to rise as aging power delivery infrastructure is increasingly strained, both in quantity and quality, to meet the needs of a digital economy. AMI and the broader Smart Grid capabilities have tremendous potential to provide an infrastructure that helps better manage energy resources today and accommodate a broader diversity of new energy resources and consumer choices for the future. Beyond these technology requirements, there is a need for increased awareness of, and focus on, interactions among regulatory effects, impediments to customer acceptance, and the costs and benefits that utilities and customers will incur and realize.



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