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Creating a Smarter U.S. Electricity Grid

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Starting in the late 1980s, federal and state governments began to restructure and deregulate some segments of the U.S. electric power industry. The basic idea was that the generation, transmission, physical distribution, and retail supply of electricity would be "unbundled" from one another. The physical distribution of electricity and the transmission of electricity would continue to be subject to state (distribution) and federal (transmission) regulation, while generation (wholesale competition) and retail supply (retail competition) would become competitive. To support this restructuring program, a number of regulatory and organizational changes were made or planned to create and manage wholesale power markets, transmission networks, and retail competition in an efficient manner.

These reforms spread quickly during the late 1990s. Then came the California Electricity Crisis (or the Western Electricity Crisis) of 2000–2001 (Joskow 2001; Borenstein 2002). The political reaction to this crisis put a virtual halt on additional states adopting restructuring and associated retail competition reforms. It also slowed efforts by the Federal Energy Regulatory Commission (FERC) to push forward its agenda to bring organized wholesale markets, integrating the efficient dispatch and pricing of generation supplied at different locations with the efficient allocation of scarce transmission capacity, to the entire country. FERC's efforts to rationalize the balkanized ownership and operation of transmission facilities by creating Regional Transmission Authorities (RTO) managed by Independent System Operators (ISOs) were also constrained. Today about one-third of the population has access to competitive retail supply alternatives, and

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about half of the generating capacity in the country is located in regions with organized competitive wholesale markets and transmission networks managed by independent system operators (Joskow 2006).

While efforts to refine the wholesale and retail competitive market reforms continue, public policy interest has now shifted to modernizing and expanding transmission and distribution networks. In particular, this paper focuses on efforts to build what policymakers call the "smart grid" by 1) stimulating investment to improve the remote monitoring and automatic and remote control of facilities on high-voltage transmission networks; 2) stimulating investment to improve the remote monitoring, two-way communications, and automatic and remote control of local distribution networks; and 3) installing "smart" metering and associated communications capabilities on customer premises so that customers can receive real-time price information and/or take advantage of opportunities to contract with their retail supplier to manage the consumer's demands remotely in response to wholesale prices and network congestion. While the smart grid is the focus of this paper, there are other important areas for modernizing and expanding transmission networks, including stimulating investment in new transmission capacity, especially "long distance" transmission facilities that span multiple states, and better integrating electricity demand into wholesale power markets.

A recent Electric Power Research Institute (2011a, p. 1-1) report uses the following definition of the smart grid:

> The term "Smart Grid" refers to the modernization of the electricity delivery system so that it monitors, protects, and automatically optimizes the operation of its interconnected elements—from the central and distributed generator through the high-voltage transmission network and the distribution system, to industrial users and building automation systems, to energy storage installations, and to end-use consumers, and their thermostats, electric vehicles, appliances, and other household devices.

Current "smart grid" initiatives are driven by a number of potential benefits. The EPRI (2011a, p. 1-1) report correctly notes: "The present electric power delivery infrastructure was not designed to meet the needs of a restructured electricity marketplace, . . . or the increased use of renewable power production." The reference to a "restructured marketplace" emphasizes that a smarter grid can facilitate wholesale and retail competition in the supply of power, as well as the need to accelerate replacement of an aging transmission and distribution infrastructure and to conserve on meter reading and other network operating costs. The reference to renewable power points out that a smart grid may be needed if solar, wind, geothermal, and other renewable energy technologies are to make a sizable contribution to national electricity needs as well as engage with demand-side issues like charging electric vehicle batteries or encouraging consumers to use electricity more efficiently.

The American Recovery and Reinvestment Act of 2009 (ARRA) provided $4.5 billion in funds for smart grid demonstration and technology deployment projects, including various analyses of consumer behavior in response to the installation of "smart meters," discussed at ⟨http://www.smartgrid.gov/federal_initiatives⟩, a website sponsored by U.S. Department of Energy. About 140 projects have been funded under these programs with about $5.5 billon of matching funds from utilities and their customers. Several states have adopted regulations that require utilities to install smart meters and make other smart grid investments, while others have started more modestly with pilot programs. The costs of these efforts are typically recovered through regulated prices for physical distribution services. The federal funds have certainly accelerated activity on smart grid projects around the country, and these financial incentives have been reinforced by state mandates and pilot programs. Since it is unlikely that federal subsidies for smart grid investments will be sustained at their recent ARRA level, the performance of the projects supported with these funds and the experience with state mandates and pilot programs will be a powerful influence on whether and how fast smart grid investments continue in the future.

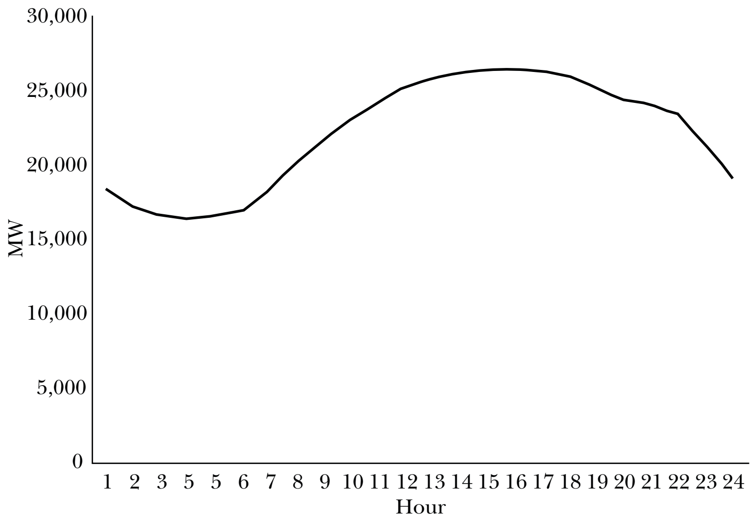
In what follows, I will examine the opportunities, challenges, and uncertainties associated with investments in "smart grid" technologies at each of the traditional components of the grid. I start by discussing some basic electricity supply and demand, pricing, and physical network attributes that are critical for understanding the opportunities and challenges associated with expanding deployment of smart grid technologies. I then discuss issues associated with the deployment of these technologies at the high voltage transmission, local distribution, and end-use metering levels. I will not discuss "behind the meter" technologies that may be installed inside of homes and businesses in response to the availability of smart grid capabilities, smart metering, and variable pricing.

Attributes of Electricity Markets

The demand for electricity varies widely from hour to hour, day to day, and month to month. Electricity demand is typically highest during the daytime hours and lowest at night. It tends to be very high on unusually hot or unusually cold days and is lowest at night on mild spring and fall days. Demand typically reaches its highest levels during only a few hours each year. There is also a minimum "base" aggregate demand that is sustained through the entire year. Figure 1 displays the levels of demand or "load" at different times of the day in New England on July 7, 2010. The peak demand is 60 percent higher than the lowest demand on that day. Figure 2 depicts the associated spot prices for electricity at each hour on that day, which I will discuss presently.

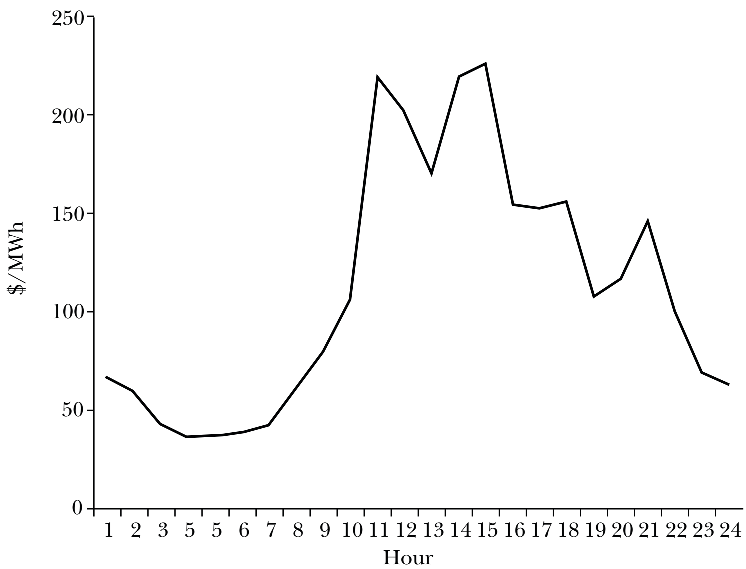
Electricity cannot be stored economically for most uses with current technologies (except in special applications where batteries, pumped storage, compressed air, and the like may be economically attractive). In electricity markets, physical

Figure 1
Real-Time Demand for Electricity, July 7, 2010
(in megawatts)



Source: Constructed from data from the New England ISO at ⟨http://www.iso-ne.com⟩.

Figure 2
Real-Time Energy Prices, July 7, 2010
(dollars per megawatt hour)



Source: Constructed from data from the New England ISO at ⟨http://www.ne-iso.com⟩.

inventories are not generally available to balance supply and demand in real time, and "stockouts" mean rolling blackouts or a larger uncontrolled system collapse (Joskow and Tirole 2007). On an electricity grid, supply and demand must be balanced continuously to maintain a variety of physical network criteria—like frequency, voltage, and capacity constraints—within narrow bounds. Electricity is the ultimate "just in time" manufacturing process, where supply must be produced to meet demand in real time.

These considerations have implications for the variations in the spot price of electricity in an unregulated wholesale electricity market and the shadow price of electricity in a traditional regulated environment that relies on an economic dispatch curve based on estimates of marginal generating costs. As demand increases, "dispatchable" generating capacity—first "base load," then "intermediate," then "peaking" capacity—with higher and higher marginal operating costs, is called to balance supply and demand (Turvey 1968; Boiteux 1964a; Joskow and Tirole 2007). As a result, wholesale market prices that reflect short-run marginal costs of generation are generally high when demand is high and low when demand is low, reflecting the marginal cost of the generation supplies needed to meet demand at different points in time. During unusually high-demand periods, supply and demand may (theoretically) be rationed on the demand side. When unexpected outages occur due to generation supply constraints or network failures, electricity consumers bear costs typically measured as the Value of Lost Load or VOLL (Stoft 2002; Joskow and Tirole 2007).

As noted, Figure 2 displays the variations in wholesale spot prices in New England associated with the variations in demand displayed in Figure 1 for a hot day in July 2010. The highest price is five times the lowest price on that day. More extreme price variability has been observed under more extreme weather conditions, though there is a $1,000 per megawatt hour cap placed on spot prices for energy in most areas ($3,000 in Texas).[1]

The prices in Figure 2 are *wholesale* spot prices. However, most *retail* residential and small commercial consumers are charged a retail price per kilowatt hour that does not vary dynamically with the time they consume electricity. As a result it does not reflect the wide variations in wholesale prices and the marginal cost of generating electricity. This is the case because traditional residential and small commercial users of electricity have meters that record only aggregate consumption between monthly or semi-monthly readings.[2] In some states, residential and small commercial consumers can opt for time-of-use meters, which charge different pre-set prices during predetermined "peak" and "off-peak" periods (for example, daytime and nighttime prices), based on averages of historical prices. While these

[1] The price caps are generally thought to be well below the Value of Lost Load in most circumstances and this raises other issues for efficient short-run and long-run performance of competitive wholesale markets (Joskow 2005).

[2] In a few cases, the largest retail consumers were billed based on prices that did vary more or less with variations in wholesale market prices (Mitchell, Manning, and Acton 1978, pp. 9–16).

time-of-use retail prices somewhat more accurately reflect variations in marginal generation costs and wholesale market prices, the relationship between actual retail prices and actual wholesale prices is necessarily very rough indeed, and penetration of time-use retail pricing has been low.

Enhancing High Voltage Transmission Systems

High voltage transmission networks are central to the operation of a modern electric power system: they make it possible to meet locationally dispersed demand with locationally dispersed generation in an efficient and reliable manner. High voltage alternating current (AC) networks are not switched networks—like a traditional railroad or telephone network—that is, power generated at point A does not flow to a specific customer located at point B. Electricity flows on an AC power network according to physical laws known as Kirchoff's laws and Ohm's law (Clayton 2001; Stoft 2002; Hogan 1992; Joskow and Tirole 2000). To drastically oversimplify, electricity produced on an AC electric power network distributes itself to follow the paths of least resistance. Transmission networks can also become congested in multiple locations, which may not lie on the "path" between buyer B and seller A, as suppliers of relatively low-cost generation seek to use the network to sell power to areas with higher cost generation. Network congestion is reflected in differences in wholesale market prices for electricity (or in shadow prices where wholesale markets with locational pricing have not been created) at different locations on the network (Hogan 1992; Joskow and Tirole 2000).

Each of the three high voltage AC networks covering the continental United States experiences significant congestion during certain hours of the year, including many "off-peak" hours, although as far I know the costs of congestion have never been quantified systematically for the entire country.[3] A natural approach to measuring the magnitude and costs of congestion is to use the differences in locational wholesale prices over time. For example, Table 1 displays the average spot wholesale prices during peak hours at different locations on the Eastern Interconnection on that same day in July 2010. It should be clear that on July 7, 2010, power was not flowing from one location to another on the Eastern Interconnection to arbitrage away large differences in wholesale spot prices; the ability of the network to transfer power from one location to another was constrained by scarce transmission capacity.

This congestion and lack of wholesale locational price arbitrage arises for three primary reasons: First, the transactions costs for moving power from the North,

[3] These costs, or at least the congestion rents, are quantified for the Regional Transmission Organizations (RTO) and Independent System Operators that have markets based on a locational marginal price market design. For example, in the PJM RTO, region, the independent market monitor estimated congestion costs to be as high as $2 billion in 2005, with substantial year-to-year variation, in his State of the Market Report for 2006 (PJM 2007, p. 39).

Table 1
Day-Ahead Peak Period Prices for Delivery July 7, 2010

Location	*$/MWh*
Boston (Massachusetts Hub)	117.75
New York City (Zone J)	138.50
Buffalo (Zone A)	79.00
Virginia (Dominion Hub)	107.75
Chicago (Illinois Hub)	68.75
Minneapolis (Minnesota Hub)	42.50
Florida	37.00

Source: Megawatt Daily, July 7, 2010, p. 2.

West, and South to New York City are high, requiring transactions with multiple Regional Transmission Organizations, Independent System Operators, and other balancing authorities with different market designs, settlement rules, and transmission service prices. Second, system operators place a very high value on reliability, which means maintaining "contingency" margins to be prepared for unanticipated events in neighboring areas which might affect their area. Third, most system operators have inadequate monitoring, communication, and control equipment on their high voltage network—an inadequate ability to "see" the state of neighboring networks—so they enforce higher contingency margins than would be necessary if they had better information and a wider span of control.

The benefit of these high contingency margins is that the U.S. electric transmission system is presently very reliable. While good comprehensive numbers are not available, it is extremely rare that retail consumers lose power because of failures of equipment or operating errors on the high voltage transmission system. EPRI (2011a, p. 2.1) estimates that U.S. power systems achieve 99.999 percent reliability at the high voltage (bulk) transmission network level and that over 90 percent of the outages experienced by retail customers are due to failures on the distribution system, not the transmission system (p. 6.1). However, when a rare major failure does occur on the high voltage transmission network, as with the 2003 Northeast Blackout when 50 million customers suffered power outages that lasted up to a couple of days, the associated costs can be high. (The 2003 Northeast Blackout was due in part to poor communications between system operators of interconnected control areas.)

It is widely accepted that there has been underinvestment in monitoring, communications, and control equipment on the high voltage transmission network to meet the needs of supporting efficient wholesale power markets, squeezing more effective capacity from existing transmission facilities, and achieving policy goals for renewable energy from grid-based wind and solar generating systems (for discussion, see EPRI, 2011a, chap. 5; New York ISO, ⟨http://www.nyiso.com/public/energy_future/issues_trends/smart_grid/index.jsp⟩; U.S. Department of Energy ⟨http://www.oe.energy.gov/⟩). EPRI (2011a, p. 5.1) recognizes that while it is hard to estimate with precison the costs of upgrading the high voltage transmission system with this "smart" equipment, EPRI estimates that the total investment cost is $56–$64 billion. EPRI also concludes the investments in improved monitoring of high voltage transmission networks represent the most cost-effective category of smart grid investments. Investments in this category also represent about 20 percent of the total cost of EPRI's defined Smart Grid program. This is qualitatively consistent with my own assessment.

These smart grid investments at the high voltage transmission level are likely to have even higher returns as "intermittent" generating capacity like high voltage grid-connected wind and solar generating capacity grows (local photovoltaic facilities on the roofs of homes create related challenges for distribution networks—see below). High voltage grid-based wind and solar installations supply electricity intermittently. This means that their output is driven by wind speed, wind direction, cloud cover, haze, and other weather characteristics rather than by supply and demand conditions and wholesale market prices. As a result, their output typically cannot be controlled or economically dispatched by system operators based on economic criteria in the same way as traditional electricity generation technologies (Joskow 2011a, b). Since wind and sun intensity vary widely and quickly, output of intermittent generating units can vary widely from day to day, hour to hour, minute to minute, and location to location. To balance supply and demand continuously when there is significant intermittent generation on the high voltage network requires that system operators have the capability to respond very quickly to rapid changes in power flows at different locations on the network by holding more dispatchable generation in operating reserve status and having the capability to monitor and adjust the configuration of power flows on the transmission network to balance supply and demand continuously while minimizing costs.[4]

Smart grid investment on the high voltage network has only a limited ability to increase the effective capacity of transmission networks. A large increase in transmission capacity, especially if it involves accessing generating capacity at new locations remote from load centers, requires building new physical transmission capacity. However, building major new transmission lines is extremely difficult. The U.S. transmission system was not built to facilitate large movements between interconnected control areas or over long distances; rather, it was built to balance supply and demand reliably within individual utility (or holding company) service areas. While the capacity of interconnections have expanded over time, the bulk of the price differences in Table 1 are due to the fact that there is insufficient transmission capacity to move large amounts of power from, for example, Chicago to New York City. The regulatory process that determines how high voltage transmission capacity (and smart grid investments in the transmission network) is sited and paid

[4] These network issues associated with intermittent generating capacity are different from issues related to the proper comparative valuation of intermittent and dispatchable generating technologies (Joskow 2011a, b); Borenstein (2008) applies methods compatible with those in Joskow (2011a, b) to derive the cost per kilowatt hour supplied and the cost per ton of CO_2 displaced by substituting solar for fossil-fuel generation expected to result from California's rooftop solar energy subsidy program.

for in regulated transmission prices is of byzantine complexity (Joskow 2005). It is clear, however, that the combination of FERC cost allocation policies, the requirement to receive siting permits from each state in which a new transmission line is located, and not-in-my-backyard political constraints hinder efficient investment in long distance transmission lines. FERC has been trying to resolve the issue of "who pays" and "how much" for new transmission lines for years, most recently promulgating Order 1000 in July 2011. This rule has many constructive features, but it will take several years to see how and to what extent it is implemented. Nor does that rule address state siting requirements or NIMBY constraints. Congress gave the Department of Energy authority to designate National Interest Electric Transmission Corridors to respond to the diffusion of siting authority among many states, but the DOE's procedures have been rejected by the courts (Watkiss 2011). The best solution to the siting problems would be to move regional transmission planning authority from the states to FERC. However, the political barriers to such a change are enormous. Thus, underinvestment in multistate high voltage transmission facilities is likely to continue to be a problem for many years.

Automating Local Distribution Networks

The smart grid technologies being deployed on local distribution systems include enhanced remote monitoring and data acquisition of feeder loads, voltage, and disturbances; automatic switches and breakers; enhanced communications with "smart" distribution substations, transformers, and protective devices; and supporting communications infrastructure and information processing systems. Smart grid investments in local distribution networks offer a variety of potential gains: to reduce operation and maintenance costs (goodbye meter readers, manual disconnects, and responses to nonexistent network outages); to improve reliability and responses to outages; to improve power quality (for example, to eliminate very short disruptions in voltage or frequency); to integrate distributed renewable energy sources, especially solar photovoltaic systems installed at customer locations that produce power intermittently and can lead to rapid and wide variations in the (net) demand placed on the distribution network; to accommodate demands for recharging of the electric vehicle of the future; to deploy "smart meters" that can measure customers' real-time consumption and allow for dynamic pricing that reflects wholesale prices; and to expand the range of products that competing retail suppliers of electricity can offer to customers in those states that have adopted retail competition models.

The U.S. Department of Energy has supported about 70 smart grid projects involving local distribution systems on a roughly 50/50 cost sharing basis, with details available at ⟨http://www.smartgrid.gov/recovery_act/tracking_deployment/distribution⟩. However, a full transformation of local distribution systems will take many years and a lot of capital investment. Are the benefits likely to exceed the costs?

In the only comprehensive and publicly available effort at cost–benefit analysis in this area, the Electric Power Research Institute (2011a) estimates that deployment (to about 55 percent of distribution feeders) would cost between $120–$170 billion, and claims that the benefits in terms of greater reliability of the electricity supply would be about $600 billion (both in net present value).[5] Unfortunately, I found the benefit analyses to be speculative and impossible to reproduce given the information made available in EPRI's report.

According to EPRI (2011a, page 6.1), over 90 percent of the electricity supply outages experienced by retail electricity consumers occur because of failures on the local distribution network rather than the transmission network. These failures may be caused by wind and storms, tree limbs falling on overhead distribution lines, icing up of distribution equipment, overloads of the local distribution network, failures of low-voltage transformers and breakers due to age or poor maintenance, cars that crash into poles and knock down distribution equipment, flooding of underground distribution, excessive heat, natural aging, and so on. No matter how smart we make local distribution systems, power outages will arise from many of the natural causes on this list, especially in areas that rely on overhead (rather than underground) distribution lines. Using standard measurement criteria from the IEEE (Institute of Electrical and Electronics Engineers), which exclude certain planned and weather-related outages, the average residential household has (rounding to simplify the calculation) 1.5 unplanned outages per year with an average outage duration of about 100 minutes per year (Power Engineering Society, 2006). Accordingly, the average residential customer experiences about 150 minutes of unexpected outages per year or 10.5 percent of one day per year. When I compare EPRI's estimates of the benefits from greater reliability with typical estimates of Value of Lost Load—for example, $5,000 to $10,000 per megawatt hour lost—the EPRI estimates of reliability benefits appear much too high.

Very short voltage drops and electrical transients that appear almost as flickers of lights (poor "power quality")—potentially create significant problems for very sensitive digital equipment. Investments in smart distribution grid technology can reduce these transients, but at significant cost. The value of reducing these transients also varies widely among customers. Having to reset one's clock is less costly than maintaining backup facilities for a critical server or data storage system in the event of disruption or damage from a voltage spike, as a financial management firm might have to do. In crafting a response, we must address the question of whether investments to improve power quality should be made for everyone, or whether they should be made "behind the meter" by those who value power quality highly? This issue would benefit from more independent empirical evidence and analysis.

[5] More specifically, nearly half of the overall benefits ($445 billion in net present value) for EPRI's (2011a) entire smart grid program are attributed to "reliability," which appears to be shorthand for reliability and power quality. There is another benefit category called "security" (benefits of $151 billion in net present value), which seems to be a subset of "reliability." Adding these gives the total of roughly $600 billion in the text.

Of more pressing concern are the new demands that may be placed on at least some distribution systems by distributed generation, primarily solar photovoltaic systems, and by the potential future need to recharge plug-in electric vehicle batteries. Several states are promoting solar photovoltaic technology with large subsidies (Borenstein 2008). Due to the wide variability in the output of photovoltaic technologies, sometimes over short time periods (NERC 2009, pp. 27–29), and related variability of net demand (which could be net *supply* if there are enough photovoltaic facilities and it is very sunny) that consumers place on the distribution system, photovoltaic technologies will place new stresses on local distribution feeders where they are installed. Better remote real-time monitoring and remote and automatic control capabilities, data acquisition and analysis of the state of the distribution system, and automatic breakers and switches will be required to accommodate significant quantities of these resources efficiently and safely.

The rate of new photovoltaic installations will vary widely from distribution feeder to distribution feeder and from state to state because of differences in subsidy policies and the relative economic attractiveness of photovoltaic investments. This variation suggests a targeted approach to local distribution system automation: focus first on areas where distributed generation, and the related stress on specific distribution feeders, will happen sooner.

The potential future demands placed on the local electric distribution system by plug-in electric vehicles raise similar issues. In 2010, out of 11.6 million total car sales, there were at most 3,000 pure electric plug-in electric vehicles sold and about 275,000 plug-in hybrids. The future path of electric vehicle sales depends on many factors: the price of gasoline, subsidies for electric vehicles, technological change affecting battery life and costs, new emissions standards, reductions in electric vehicle costs, and consumer behavior. Forecasts of the fraction of new vehicles that will be electric plug-ins by 2035 varies from less than 10 percent to over 80 percent. The U.S. Energy Information Administration (EIA 2011a, p.72; see also EPRI 2011b, chap. 4) forecasts a market share of light-duty vehicles of only 5 percent for plug-in and all-electric vehicles in 2035 in its reference case. The National Research Council (Committee on Assessment of Resource Needs for Fuel Cell and Hydrogen Technologies, 2010, p. 2) concludes that a realistic estimate is that by 2030 about 4.5 percent of the national light duty vehicle fleet will be plug-in electrics—with a maximum possibility of about 13 percent.

Along with the number of plug-in cars, the load placed on the distribution system will depend on the attributes of the car batteries and charge-up time selected by vehicle owners. Shorter charging times at higher voltages can place very significant loads on local distribution networks even with modest electric vehicle penetration (Browermaster 2011). An interesting possibility arises here. The demand on portions of the *local distribution system* in areas where electric vehicle sales may be concentrated—say, in places like Berkeley, California or Cambridge, Massachusetts—could peak at night, even when prices in the much broader wholesale power market are low. The possibility that the marginal cost of electricity distribution service on some distribution feeders could peak at times when aggregate system demand for power and associated power prices in the wholesale market are low suggests that more thought should be given to altering the pricing of electricity distribution service. Distribution service prices are now based on a flat per kilowatt hour rate and do not vary with the marginal costs of distribution service, which is driven largely by the peak demand on distribution feeders. Distribution service prices would more closely reflect the associated marginal cost of this service if we moved, instead, to a distribution charge based at least partially on individual customers' peak load on the local distribution system.

These considerations all lead to the conclusion that phasing in the installation of smart grid technology, targeting investment where it is likely to be most needed quickly, and collecting data using a controlled experimental framework to evaluate its costs and benefits would be a sensible strategy.

I offer one caveat to this conclusion. Many U.S. distribution systems are aging, and utilities are embarking on large distribution network replacement programs. These investments are long-lived, and it makes sense for these programs to take advantage of the most economical modern distribution technologies. In many cases, forward-looking investment optimally should deploy much more automation and communication technologies than immediately needed, even if deployment of distributed generation and electric vehicles is expected to be slow.

Smart Meters and Dynamic Pricing Incentives

It is not unusual for the incremental generating capacity held by a utility or RTO to meet the peak demand on its system during the 100 highest demand hours each year (1.1 percent of the total hours) to account for 10 to 15 percent of the generating capacity on its system. This is the direct consequence of the wide variability of demand (especially in response to extreme weather conditions), the failure of retail prices to reflect the true marginal cost of supply under these extreme conditions, and the utility practice of building enough generating capacity to meet demand even under very extreme low-probability demand states. Accordingly, using appropriate prices to provide consumers with an incentive to cut peak demand during a small number of hours can reduce generating costs significantly in the long run. Retail prices that are not tied to variations in wholesale prices inefficiently increase the level of peak demand by underpricing it, and may also discourage increased demand during off-peak hours by overpricing it.

The idea of moving from time-invariant electricity prices to "peak-load" pricing where prices are more closely tied to variations in marginal cost has been around for at least 50 years (Boiteux 1964b, c; Turvey 1968; Steiner 1957; Kahn 1970, pp. 63–123). The application of the theory in practice has lagged far behind, especially in the United States. (Mitchel, Manning, and Acton (1978) discuss early developments in other countries.) There is evidence from the well-designed experiments with time-of-use pricing of electricity in the 1970s showing consumers do respond more or less as expected to price incentives (Aigner 1985), in the sense that higher prices lead to less consumption. The magnitude of the estimated responses varies widely though and does not reflect potential adaptations in the attributes of the appliance stock resulting from widespread deployment. Moreover, a 2010 survey indicated that only about 1 percent of residential customers were on time-of-use rates (FERC 2011, pp. 28, 99).

"Smart meters" can record *real-time* consumption of electricity. They also can have two-way communications capabilities allowing for real-time retail prices tied to variations in wholesale prices (and a number of variations on this theme), and could lead to remote control of customer demand by allowing the retail supplier or the customer to adjust appliance utilization inside the customer's home or business. For example, a customer might program the air conditioning (or have the utility program it) to turn off, at least intermittently, when electricity prices reach a certain level. Real-time pricing to reflect variations in wholesale market prices can increase efficiency, at least when it is applied to larger customers (Borenstein 2005). In addition, real-time pricing can stimulate innovations in appliances and equipment inside the home or in business to make them capable of responding more easily to changes in real-time prices and load management arrangements made with retail suppliers.

The traditional arguments for not introducing real-time pricing were: 1) the meters and billing costs would be so costly that residential and small commercial customers would not benefit from them; 2) retail consumers would not understand or effectively utilize complex rate designs; and 3) changing rate designs would lead to large redistributions of income reflecting the wide variations in consumption patterns across individuals and decades-old mechanisms for allocating costs among types of customers and within customer classes (Borenstein 2007a, b).

At least some of these arguments are increasingly being questioned, and solutions being contemplated. Metering and communications technology have moved forward with more capabilities and lower costs. Today's more advanced smart meters use two-way communication and capabilities for active real-time interaction between the distribution system and the customer: they can record consumption at least once each hour, can be turned on and off remotely, can support the introduction of dynamic retail prices that are closely tied to dynamic wholesale market prices, and can control the utilization of appliances remotely in a way that facilitates active demand-side management of the electrical grid. In addition, the information available through smart meters can inform the distribution company about variations in demand and equipment outages on the distribution grid instantly, thus creating synergies between "smart meters" and smart distribution grid investments. Variations on full real-time pricing, in particular "critical peak pricing," are easier for consumers to understand and provide much better incentives than flat rates. Nevertheless, relatively few advanced "smart meters" had been installed and used effectively in the United States, although the number is now increasing at a rapid rate (U.S. Energy Information Administration 2011b) as a result of federal subsidies and state mandates. As many as 8.7 million smart meters have now been installed at residential and small commercial locations, about 6 percent of the total—though the definition of what counts as a smart meter varies and experience with them is limited (St. John 2009).

Analysis of the costs and benefits of large-scale deployment of smart meters must look at both changes in consumer surplus and changes in the cost of supplying electricity and metering its consumption. On the demand side, one needs to be able to measure the demand elasticities and cross-elasticities for a very diverse population of consumers who have different appliance stocks, live in homes of widely varying sizes, experience different weather conditions, face different levels and structures of incumbent electricity tariffs, have different incomes, and consume different quantities of electricity each month. An added complexity is that it would be implausible to measure *long-run* demand elasticities taking the current attributes of appliances and equipment as given, because the appliance stock and opportunities to adjust energy use will change to take advantage of the new incentives if smart meters and dynamic pricing are widely used.

On the supply side, there are questions about how much all of this whizzy smart grid technology will cost and, as always, there is the need to measure the effects on generation, distribution, and transmission costs. Measuring incremental metering costs is not easy. The many different vendors of smart meters sell meters with different functionalities and different communications methods. Moreover, buying and installing the meters is only part of the cost: communications systems must be built to integrate smart meter information with automated distribution network capabilities; a new information technology infrastructure for data acquisition, analysis, and billing created and installed; customer service personnel retrained to respond to questions about more complex rate structures; and investments made in complementary distribution system upgrades. On the other hand, smart meters should also save operating costs, primarily by reducing meter-reading costs (especially for systems that have not already installed the first-generation one-way communication meters). We also know that as a theoretical matter, setting retail prices to reflect marginal supply costs will increase overall efficiency with which electricity is consumed and supplied. But is this efficiency gain large enough to cover the additional costs of smart meters and associated information and automated distribution technology, both in the aggregate and for customers with different utilization characteristics? I do not think that this question has yet been answered satisfactorily or the public adequately convinced that the answer is likely to be affirmative.

A large number of U.S. utilities began offering time-of-use and interruptible pricing options for large commercial and industrial customers during the 1980s, either as a pilot program or as an option (for example, Barbose, Goldman, Bharvirkar, Hopper, Ting, and Neenan 2005). More recently, a number of states have introduced pilot programs for residential (household) consumers that install smart meters of various kinds, charge prices that vary with wholesale prices, and observe demand. For example, Taylor, Schwarz, and Cochell (2005) estimate hourly own- and cross-price elasticities for industrial customers on Duke Power's optional real-time rates and find large net benefits for these customers. Faruqui and Sergici (2010) summarize the results of 15 earlier studies of various forms of dynamic pricing, including time-of-use pricing, peak pricing, and real-time pricing. Faruqui and Sergici (2011) analyze the results of a dynamic pricing study performed by Baltimore Gas & Electric using treatment and control groups drawn from a representative group of households. Wolak (2006) analyzes a peak pricing experiment in Anaheim, California. Wolak (2010) analyzes a pilot program using peak pricing in Washington, D.C. Allcott (2011) analyzes data from the Chicago Energy Smart Pricing Plan that began operating in 2003. Faruqui (2011) summarizes the reduction in peak load from 109 dynamic pricing studies, including those that use time-of-use pricing, peak pricing, and full real-time pricing, and finds that higher peak period prices always lead to a reduction in peak demand. However, the reported price responses across these studies vary by an order of magnitude, and the factors that lead to the variability of responses have been subject to very limited analysis.

Before discussing what conclusions can be drawn from this evidence, a few warnings seem appropriate. First, there is wide variation in the design of the pilot/experimental studies and the variation in prices included in them. Just looking at the magnitude of the response without more information is not adequately informative. Second, essentially all of these studies include only "volunteers," which raises the possibility that those who choose to participate may be unusually sensitive to price variation. Third, many of these pilots include a very small number of participants, and in at least one study a large fraction of those who started in the pilot dropped out before it was completed. Fourth, few of the pilot programs use full real-time pricing. A few use "critical peak pricing" mechanisms, and this may yield results similar to what we would get with full real-time pricing. For example, PG&E's voluntary tariff for customers with smart meters starts with the regular tariff price, except during "Smart High Price Periods," which are communicated to the customer in advance by telephone, Internet posting, or text messaging, and the price rises to 60 cents per kilowatt hour between 2 p.m. and 7 p.m. for a maximum of 15 days per summer season. Fifth, several of the pilots apply only one price to the treatment group, which makes it impossible to trace out the relevant demand functions without making very strong assumptions about the shape of the demand curves. Using several treatment groups requires a larger pilot study than has often been the case (see Aigner, 1985, regarding the need for multiple treatment groups). Finally, few of these studies use data on consumer responses along with electricity supply and metering cost data to perform a proper cost–benefit analysis. Indeed, I have not yet seen a recent study as well designed, or with a welfare analysis as carefully performed, as the Los Angeles experiments managed and analyzed by RAND during the 1970s (Mitchell and Acton 1980).

Despite these concerns, the available evidence does suggest a number of conclusions: First, consumers do respond to higher peak prices by reducing peak demand. Second, dynamic pricing with very high prices during critical periods generally leads to much larger prices responses than traditional time-of-use pricing with predetermined time periods and prices, which typically use much smaller price differences. Third, wide variation in price responsiveness is observed across studies, suggesting wide underlying variation in the attributes of households and pilot study conditions. Fourth, most if not all of the price response to higher peak period prices is to reduce peak demand rather than to shift from peak to off-peak demand. For example, a common reaction is to use less lighting, air conditioning, and refrigeration when prices are high—with no offsetting increase in electricity used at other times. However, the diffusion of plug-in vehicles or other technologies where time-of-use is a more important choice variable could yield very different results.[6] Fifth, technologies and information that make it easier for consumers to respond to high price signals lead to larger responses to any given price increase, although many of the reported results do not contain adequate information to estimate demand functions or to perform proper cost–benefit analyses.

Faruqui and Wood (2011) present a well-conceived "template" for what items should be included in a comprehensive cost–benefit analysis and present simulations for four "prototype" utilities. The aggregate benefit/cost ratios vary from 1.4 to 1.9 for the four simulations. The simulations are not based on real utilities nor complete data, but the hypothetical numbers are not unreasonable and the results are suggestive. Of course, cost–benefit analysis of universal smart meter installation and real-time pricing may also find that while the benefit/cost ratio is greater than 1.0 in the aggregate, it may not be beneficial to some significant number of individual customers. Borenstein (2007b) takes the wide variation in customer utilization attributes seriously, although his focus is on larger commercial and industrial customers, not residential customers. But the heterogeneity of the effects of smart meters and real-time pricing on residential and small commercial customers is an important issue that still needs to be addressed.

Some states that have mandated the installation of smart meters for all customers have found the decision to be controversial (for newspaper accounts, see Smith, 2009; Turkel, 2011a, b; Fehrenbacher, 2010; Baker, 2010). Some consumers have reacted negatively to increases in up-front distribution costs to pay for the smart grid enhancements. First, some customers with "unfavorable" consumption patterns—weighted toward times when prices are high—may see higher bills, rather than the lower bills they are being promised, compared to their billing under flat rates (Borenstein 2007b). Second, some smart meters have been deployed too quickly and have not worked properly. Third, with all of the data that these meters can collect, privacy advocates have raised concerns about

[6] "Storage space heating" allows off-peak electricity to be used to heat up special bricks or slabs or water tanks, which are then used as a source of warmth during on-peak hours. When storage space heating was introduced in Europe during the 1960s, it was consciously designed to shift demand to off-peak periods. It did such a good job that the peak shifted from day to night in England and northern Germany and the regulated prices no longer reflected the patterns of demand and cost. Steiner (1957) and Kahn (1970) discuss this "shifting peak" case theoretically. More generally, we should be reminded that we should not take our eyes off of the long-run equilibrium which may look very different from the short-run equilibrium—especially after technological change.

what data will be made widely available and how it may be used and protected. Finally, some public utility commissions and some utilities have done a poor job educating their customers and have rolled out their smart meter installation program too quickly. There are lessons to be learned about deployment strategy from these experiences.

Conclusions

The existing electricity distribution system is very old in many areas, and investments to replace key components will have to accelerate just to maintain the reliability of the system. These replacement programs should be consistent with longer-term strategies for modernizing the distribution system. However, there is a lot of uncertainty about the size of costs and benefits, and these costs and benefits vary across distribution feeders as well as customers and regions. The rate and direction of future technological change on both sides of the meter is also uncertain. The transition to smart grid technology is going to take years, and there are sure to be notable bumps along the way.

Accordingly, it seems to me that a sensible deployment strategy is to combine a long-run plan for rolling out smart-grid investments with well-designed pilots and experiments. Using randomized trials of smart grid technology and pricing, with a robust set of treatments and the "rest of the distribution grid" as the control, would allow much more confidence in estimates of demand response, meter and grid costs, reliability and power quality benefits, and other key outcomes. For example, Faruqui's (2011b) report on the peak-period price responses for 109 pilot programs displays responses between 5 to 50 percent of peak demand. An order-of-magnitude difference in measured price responses is just not good enough to do convincing cost–benefit analyses, especially with the other issues noted above. In turn, the information that emerges from these studies could be used to make mid-course corrections in the deployment strategy. Given the large investments contemplated in smart meters and complementary investments, along with the diverse uncertainties that we now face, rushing to deploy a particular set of technologies as quickly as possible is in my view a mistake.

Despite these reservations, the country is on a path to creating smarter transmission and distribution grids. Exactly how far and how fast we go remains quite uncertain, especially as the federal subsidies enacted in 2009 for promoting the smart grid come to an end.

■ *The views expressed here are my own and do not reflect the views of the Alfred P. Sloan Foundation, MIT, Exelon Corporation, Transcanada Corporation, or any other organization with which I am affiliated. I am an outside director of Exelon Corporation and of Transcanada Corporation. My other affiliations are identified on my CV at ⟨http://econ-www.mit.edu/faculty/pjoskow/cv⟩.*

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