
Dealing with Change: The Long-Term Challenge for the Electric Industry

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Since the 1880s, when Thomas Edison introduced the first modern electric generating station at Pearl Street in New York City, the electric industry has powered the technologically developing and growing United States through wars, peace, depression, expansion, and dramatic social and technological change. In our increasingly energized society, electricity is almost as vital a commodity to households and businesses as air and water. With the recent explosion of new technology, most notably personal digital appliances, and the continuing rise in our nation's population, the United States uses more electricity today than it ever has before—a demand for electric power that continues to grow. From 1978 to 2003, average household energy consumption in the United States increased by 21.5 percent. And, according to the U.S. Energy Information Administration (EIA), the government's official energy statistics resource, world electric energy consumption is expected to rise by another 57 percent from 2004 through 2030. The dramatic growth in worldwide electric consumption is significant to American utilities because it requires them to compete for fuel resources and other vital commodities (such as steel, aluminum, copper, concrete) as well as finished electric goods (such as transformers and similar devices) with utilities throughout the world, causing the price of such goods to increase considerably. That price increase translates into higher electric rates for American consumers.

Although electric prices are increasing now in many parts of the country, the price of electricity has still risen less over the past several years compared to most other products or services, and much less compared to other energy products such as oil and natural gas. According to a recent report, the price of electricity rose only 1.1 percent per year from 1985 to 2000, less than half of the average inflation rate of 2.4 percent annually. See *Why Are Electricity Prices Increasing? An Industry-Wide Perspective*, The Brattle Group for The Edison Foundation (June 2006).

But as demand for electricity grows, in both consumption and value, the landscape in which the power industry must operate to meet the increasing demand is changing considerably, creating substantial financial and operational challenges. For example, Congress is likely to enact global climate change legislation in some form in the near future. That would dramati-

cally affect electric utilities and their customers, who currently depend on carbon-emitting power plants to meet most of their electric generation needs. And although carbon legislation is certain to change the way utilities must plan for and fund new generation, no one knows today what that legislation will look like, what compliance will cost, what areas of the country will be most affected, or what the specific impacts will be on new generation expansion currently being planned.

Similarly, much discussion is occurring throughout the industry about the need to construct new nuclear power plants to meet the nation's future domestic electricity needs. As of today, however, no new nuclear power plant is under construction. Although several nuclear projects are at the licensing and permitting stage, it will be some time before we know whether a significant number of new plants will actually be built. The dilemma of, and litigation over, how to store spent nuclear fuel, coupled with the massive capital investments required to construct any new nuclear plant, complicates the matter.

The electric industry is also witnessing tremendous technological innovation and change. For example, electric meters are evolving from relatively simple devices that are read manually on a periodic basis to "advanced metering infrastructure," also known as "smart meters." Among other selling points, smart meters have the ability to communicate usage information from the customer's location to the utility remotely using cellular technology, and will give both customers and utilities the ability to monitor energy usage on a real-time or near real-time basis, without the need for manual meter reading. This will give utilities detailed data about customer usage patterns, which will be useful in designing electric rates that allow customers to benefit from shifting their energy usage away from "peak" hours—the time when the demand on a utility's system, and thus the price of electricity, is at its highest. Similarly emerging are other technologies supporting a "smart grid"—a modernization of the interconnected electric system in a manner that better supports investment in customer demand response technologies, consumer energy management systems, and distributed generation, among other things. Although this and other technological advancement is undoubtedly beneficial for both the industry and customers, it adds to the planning uncertainties that electric utilities face. We do not know today what technologies will be available for use in the future or at what costs.

One specific phenomenon that is intertwined with each of these issues is how the industry, policymakers, and other stake-

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holders can and should deal with the growth in needed infrastructure investments—growth caused by both consumer demand and increases in the costs that utilities must incur to meet that demand while maintaining electric reliability. It may seem contrarian to refer to the “challenge” of growth at a time when our economy is facing a recession. But addressing growing electricity demand, both today and over the long term, will impact how utilities plan their systems and how (or whether) needed electric infrastructure is constructed, which in turn affects the prices that consumers pay for electricity both today and in the future.

The changes now confronting electric utilities thus raise a number of issues, which are compounded by the financial and operational impacts of the industry’s growth in electric demand and costs. The challenge of adapting to these changes has wide-ranging impacts on the many policy decisions that electric utilities must make over the next decade. This article examines how recent changes have impacted each of the three segments of the modern electric system (generation, transmission, and distribution), how growth complicates the challenges caused by those changes, and how policymakers can adapt to ensure that reliable, affordable power continues to be supplied in the United States amidst our nation’s changing energy landscape.

Growth and Electricity

Electric utilities have experienced significant growth over the past ten years. In many areas, particularly in the desert Southwest and Sun Belt, the increasing demand for electricity is caused in large part by these regions’ unprecedented population growth. The U.S. Census Bureau estimates that Arizona’s population, for example, grew by more than 23 percent from the 2000 census through 2007, compared to a national growth rate of around 7 percent over that period. Arizona’s rapid growth rate is second only to that of Nevada, where the population has been growing at around 3.5 percent per year. In 2006 alone, Texas grew by more than 570,000 people, making it the fifth fastest-growing state that year in percentage terms. Despite a temporary slowdown from recent economic events, there is no evidence that—in these regions, at least—population growth will slow to any significant degree over the long term. To the contrary, while growth will slow in the near term, most if not all public forecasts expect that long-term growth at above the national average will continue.

Regions of high population growth obviously see high increases in electric demand. The rise in electricity consumption, however, is caused by more than just the rise in population. The amount of electricity consumed per capita is also increasing for several reasons. On average, fewer people now reside in each household compared to prior years, which means that, in areas of high population growth, the number of new households often grows faster than the population. New houses also tend to be larger than older ones, both in square footage and cubic footage, and customers thus consume more energy to heat or cool these larger homes. And, although new homes are increasingly more energy-efficient when compared to older homes, consumers are now using new appliances and electronic technology, such as plasma televisions, that require significantly more energy to

run. For example, a plasma television consumes over 40 percent more energy than does an LCD television. The proliferation of other emerging technologies such as personal digital appliances, which also consume high amounts of electricity, further increases our nation’s energy consumption. The result is that the demand growth that is now occurring in many parts of the United States will persist, both because of an increase in customers and because those customers tend to be more electricity-intensive than they have been in the past.

The country’s growing consumption of electricity can be mitigated to a degree by what the industry terms “demand response” and “demand side management” (or DSM), which are programs aimed at meeting demand by reducing the overall amount of energy consumed, such as by offering customer incentives for the use of energy-efficient light bulbs and appliances or technologies that automatically turn off customer air-conditioning units during periods when electricity demand peaks. If regulatory policy allows a utility to be adequately compensated for offering such programs (which, by their nature, reduce the amount of revenue that the utilities would receive in the absence of such programs), demand response and DSM can be cost-effective tools in a utility’s resource toolbox that benefit both customers and the utility. Under certain parameters, distributed generation—the industry term for electricity generating technology installed by a customer, such as rooftop solar panels, and connected to the electric grid at the distribution level—can also be useful in meeting the country’s growing demand. Even so, such programs alone are unlikely to address the massive rise in electric demand this country has seen over the past thirty years and will continue to see.

Rather, to meet this increasing demand, electric utilities must plan for and invest in new infrastructure in all aspects of the electric power system—generation (power plants), transmission (high voltage power lines), and local distribution (lower voltage lines and other facilities connecting customers to the power grid). There also are certain aspects of the electric power system that make planning for growth unique for electric utilities compared to that of other growth-intensive industries. First, electricity cannot be stored to any material degree, so a utility must be able to produce, transmit, and deliver the precise amount of power that is necessary to meet customer demand at all times, even when equipment is taken out of service or fails. Second, electric utilities do not have the option to simply cut back on production in tight times, like a manufacturing business might do, and let forces of supply and demand function. Neither can they unilaterally increase prices or engage in market segmentation to any significant extent as, for example, an airline might do. Electricity is an essential product in our society and most utilities have a legal obligation to meet all customer demands in their service territories. Finally, there are tremendously long lead times involved in planning, permitting, and constructing major electric facilities. If the industry does not begin to plan for and address future demand years before it occurs, the reliability of the electric system as a whole could be jeopardized.

As a result, long before growth occurs, the electric system must be upgraded and expanded in order to meet new demand. More electricity will need to be produced, eventually requiring

upgrades and additions to existing generating units and access to additional fuel sources, such as natural gas pipelines. New transmission and distribution infrastructure will also need to be constructed to ensure reliable delivery of that electricity from its source to all customers within a given utility's service area. Such new construction is causing capital construction costs for electric utilities to increase substantially. Compounding the problem is the fact that the cost of the materials and supplies necessary for these construction projects is substantially higher today than it has been in recent memory. For example, the price of copper—a vital commodity in utility construction projects—has increased by more than 250 percent since 2000. The price of steel has also soared by more than 140 percent since the turn of the last century. And because much of the hardware made for the electric system is either manufactured overseas or includes foreign components, the declining value of the U.S. dollar in the global economy is increasing utility construction costs as well. These increases translate into massive capital spending requirements facing utilities and their customers.

In addition, new environmental laws—both state and federal—require utilities to spend millions of dollars to ensure that their facilities are environmentally compliant. The Edison Electric Institute, the leading trade association for investor-owned utilities, reports that from 2002 to 2005, the electric utility industry as a whole spent at least \$21 billion to comply with federal environmental laws—a figure that does not include the impact of increasing state and local environmental measures. The capital investment electric utilities must make today and in the near term to meet both growing demand and new legal and regulatory requirements is straining the industry. Utilities struggle with how to fund these necessary expenditures at the same time that they are forced to grapple with the many other uncertainties currently facing the industry.

Regulatory Policy Implications

The evolving and growing energy landscape affects all segments of the electric system. For example, changes in the generation field that have occurred over the past decade highlight some of the challenges facing electric utilities on issues such as resource planning and the construction of new generation facilities—challenges that can only be resolved if regulatory policy recognizes such changes and evolves with the industry to improve a utility's certainty that its expenditures will be deemed prudent and its costs will be recovered accordingly before the decision to incur that expense is made.

Twenty years ago, the model that virtually all electric utilities followed in planning generation was relatively straightforward. Most power plants were owned by vertically integrated electric utilities; that is, a utility that owns and operates generation resources and “bundles” that component with its transmission and delivery services, as opposed to a utility that purchases generation from a third party in wholesale energy markets. A vertically integrated utility planned and built generation facilities as needed to meet that specific utility's anticipated retail demand. In some cases, power plants were jointly owned by several utilities, but for the most part there were few

nonutility power producers operating large-scale plants and selling generation to utilities in wholesale markets.

Today, while some states continue to allow vertically integrated utilities, others require “unbundled” generation, which means that a single utility in those states can no longer provide generation with the other components of electric service. Also, many “merchant” power plants are now owned by companies other than the utility that ultimately transmits and delivers energy to its customers. The Federal Energy Regulatory Commission (FERC), which has jurisdiction over wholesale power sales and transmission in interstate commerce, has implemented an “open access” policy for transmission. Under open access, transmission owners must make their transmission systems available to third parties on a nondiscriminatory basis. The open access policy thus anticipates that the country's growing transmission system is one that will carry a wide array of users—including multiple utilities, merchant generators, and power marketers—selling power across and through shared systems, and essentially changing what had been an interconnected series of private roads into an interstate highway system. This federal policy has contributed to promoting the construction of merchant power plants, regardless of whether a particular state has unbundled generation or follows a vertical integration model. In some regions, there are multistate organized markets that have developed or are developing formal markets to sell power plant capacity to utilities.

The introduction of competitive wholesale generation may well have yielded customer benefits. As a result of these changes, however, utilities no longer have a standard, centralized planning model to determine whether additional power plants should be built, when that construction should occur, or what fuel source should be used. In addition, some states have enacted rules that specify how utilities must perform resource planning or how utilities must procure or construct generation resources. As a result, the job of utility resource planning now requires a complex analysis of not just potential resource alternatives, but also how much supply should come from wholesale markets, what resources may be available as a result of merchant power plant construction, who should build the resources ultimately sought by the utility, what remedies or alternatives are available if anticipated resources are not timely constructed by market participants, and whether the resource option ultimately decided upon complies with rules set by and will prove acceptable to the governing regulatory body.

The complexity of this analysis has greatly impacted the utilities' generation planning process. For the last ten years, the majority of new power plants constructed in the United States have been natural gas-fired plants, which are relatively simple to permit and can be constructed in a comparatively short two- to five-year time frame. But utility planners strive to diversify whenever possible across multiple fuel sources and to hedge against volatile commodity prices, supply constraints, and other single-fuel risks. New nuclear, coal (whether conventional or clean), and some large renewable power plants could require ten years or longer to permit and construct, and involve significantly more investment than natural gas-fired generation. Whether such investments can be made without the centralized utility planning that occurred twenty years ago, or whether

they fit under some of the newer state planning and procurement frameworks, is largely untested. For example, it is unlikely that a typical merchant generating company could successfully pursue (at least alone) construction of a new nuclear or other long-lead-time plant when such a resource would likely yield zero return on a huge sum of invested capital for ten years or more—as long as it takes to get that nuclear plant on-line and generating energy for sale.

Another major uncertainty facing utility planners is how to evaluate resource alternatives given the likelihood of legislation, at either the state or federal level, on global climate change and uncertainty over what that legislation may look like. This is extremely important for high-growth states—a requirement to “roll back” carbon emissions to levels seen even five years ago is much harder to achieve in states where growth has been over 20 percent during that period. And potential legislation is likely to include a value or tax associated with carbon emissions, but the amount and nature of such monetization of emissions are today unknown. Thus, how should a planner today value the costs of carbon emissions to provide a meaningful comparison between a potential new coal plant, a nuclear plant, or renewable resource generation? In many cases, utilities are pursuing a portfolio approach to diversify the environmental risk associated with any single resource.

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Certainly, a carbon tax or imposition of a cap-and-trade regime for carbon emissions (a system that creates a financial incentive for emission reductions by assigning a sellable right to emit carbon) will have significant cost impacts for electric utilities and their customers. However, the uncertainty affecting overall planning will also result in new costs that will have to be addressed. First, pursuing new, major power plant projects to maintain diversity in fuel supply will, for most utilities, require regulatory policies to adapt in order to allow utilities timely recovery of costs incurred during the construction of the facilities, as described below. Second, there will be costs incurred in simply keeping options open pending resolution of key questions. For example, it may be prudent for a utility to invest money to begin a new nuclear project at the time that decision is made, but if spent fuel disposal costs increase

too much or if regulatory issues become unmanageable during the course of the project, it may be equally prudent for the utility to stop such a project. It will be critical for regulators to recognize that such costs associated with “abandoned plant,” at whatever stage of abandonment (from planning to actual construction), were nonetheless prudently incurred at the outset and should be recovered accordingly. Such a policy will help ensure that all potential resource alternatives are given appropriate consideration in a utility’s planning process.

Further, the historic standard of resource planning has been to promote the resource that costs the least—the “least cost” standard. In appreciation of the fact that some resources may be socially preferable, even if more expensive, the “least cost” standard is increasingly giving way to a more flexible, but less clear, standard that considers “externalities” other than cost. The California Public Utility Commission, for example, established a “least cost, best fit” standard for utility procurement plans, recognizing that some resources, like renewable generation, will not be the lowest-cost alternative but nonetheless have an important role in a utility’s resource portfolio.

The uncertainty in the planning standard likely will affect the regulatory process by which utility prudence is reviewed. Historically, many utilities had to wait until a rate case—a proceeding before a utility’s regulators to determine the rates it can charge—to establish whether a decision to invest in a particular resource was prudent, and thus one for which the utility would be allowed cost recovery. But today, there may be no clear standard to assess planning prudence. So utilities may have to request approval of resource decisions prior to making the investment, rather than follow the more traditional approach of waiting until a rate case to assess such decisions. Growth compounds these issues, requiring policymakers to quickly resolve these uncertainties so that utilities can plan and provide for new load to meet the increasing demand with reasonable certainty that the costs they incur in doing so will be recovered.

Growth also compounds challenges created by recent changes in the transmission of electricity. Today’s transmission grid is a massive, complex interconnection of high-voltage transmission lines and equipment. The Western Interconnection, for example, one of three interconnections in the continental United States, spans from western Canada to Baja, Mexico, and from the Pacific Coast to the Great Plains. The interconnection operates on a single frequency as, essentially, one giant electrical machine. The nature of how the transmission system develops, however, is evolving.

Historically, transmission lines were sited and constructed to connect generation resources, which were often in remote locations, to loads such as cities or industrial areas. Interconnections among utility systems added reliability benefits in the event of transmission line or power plant outages, but until the last couple of decades or so, there was relatively little exchange of power (called “wheeling”) across many systems. As a result, the transmission system largely present today was planned and built for the relatively limited purpose of moving energy from a utility’s power plants to its load centers. The federal open access policy, discussed above, changed how the electric power grid operates and opened the country’s interconnected transmis-

sion lines to a vast array of users. In many parts of the country, particularly those that are more tightly networked, there are regional organizations that now operate multiple transmission systems as a single regional transmission organization (RTO). This expanded use of the transmission system is resulting in the need for additional transmission facilities, not just to meet traditional load growth but also to facilitate commercial transactions across and through interconnected transmission systems.

The transmission network must expand to accommodate the interconnection of these new resources as well as the increasing intensity of use by existing transmission customers. If it does not, congestion on the power grid will limit its use. But there are several key challenges to this expansion. Among these challenges is the question of who should pay for new transmission facilities. Typically, the company that requires new transmission, whether a merchant generator or a load serving utility, pays for the expansion, with some provision for socializing the cost of upgrades that benefit the network as a whole. In RTOs, complex price signals are intended to incentivize construction of resources and transmission where they can best relieve congestion on the system. However, these mechanisms often do not work effectively for new resources, like renewable generation, that cannot shoulder the costs of upgrades for relatively small increments of new generation. As a result, some utilities are seeking to construct “trunk” lines to areas rich in renewable generation capability and that will be paid for by the utility’s customers but will allow access to the grid by many small renewable generation developers.

In addition to the question of “who pays,” the process involved in determining where to construct and then actually constructing new transmission lines remains challenging. For utilities and system operators, the superficially “simple” task of even studying the many proposed projects—both transmission and generation interconnections—can be daunting. Congestion in the interconnection “queue,” where projects are studied and transmission upgrades and costs are identified, is a significant challenge. Regional planning practices required by the FERC, as well as new queuing practices being considered by transmission providers and RTOs, may help smooth some of these issues. But even then, new transmission lines must obtain siting approval and rights of way must be acquired. Obtaining approval from state regulatory authorities for new transmission lines can be difficult and time-consuming. Following passage of the Energy Policy Act of 2005, the federal government authorized federal backstop siting authority in areas of significant congestion. Such backstop siting authority, when sought, would remove siting authority from the states, tighten the procedural timeline applicable to siting projects, and enable the use of eminent domain for right-of-way acquisition. However, to date, backstop siting is untested and, if sought, could generate significant controversy. Further, the potential recourse to backstop siting does not alleviate the need for utilities to work closely with states and other affected jurisdictions to address local concerns to avoid the controversy associated with federal preemption. Compounding the procedural complexity in determining where to site a transmission line, in the western United States, at least, a considerable amount of the transmission network crosses Native American

reservations, which adds significant legal and policy challenges due to the sovereign nature of these areas.

Growth also presents unique regulatory issues that impact the distribution of electricity once it moves from the transmission system to local businesses and residences. In many states, as described previously, utilities have a legal duty to serve any customer within its service territory. Even in those localities where the market has been deregulated and competition has been introduced, certain utilities are deemed the “provider of last resort” within their service territories and must provide service to any customer not served by a competitor. These utilities do not have the option of refusing to serve a customer and must thus anticipate and plan for *all* new load growth irrespective of cost so that the utility may reliably and cost-efficiently serve both existing and future customers. When capital costs are high, those costs become increasingly difficult for utilities to absorb between rate cases, when the rates that the utilities are permitted to charge are reset.

Moreover, even if the utility files a rate case with the state regulatory commission in an effort to bring its revenue in line with its increasing costs, the “traditional” rate-setting model used by many regulatory jurisdictions may not produce rates that will allow it to do so. In general, a utility’s rates are set by a state regulatory commission to allow the utility to recover its operating costs and also provide it an opportunity to earn a reasonable return on and of its invested capital. In setting such rates, the state commission typically evaluates the costs of a utility, including the expense associated with the utility’s required return on its invested capital, during a period of time called a “test year.” Some regulatory jurisdictions use a historical test year method when setting utility rates. In other words, they set a utility’s electric prices based on the costs that the utility incurred during a single year in the past. But, for utilities with capital costs that are increasing faster than year-over-year revenues, rates that have been set using costs incurred during historical years will not compensate a utility for the rising costs that the utility will incur going forward. For this reason, utilities with longer periods of regulatory lag—the lag between when a cost is incurred and when it is authorized for recovery in rates—often suffer severe cash-flow pressure and eroding financial metrics. These factors, in turn, can detrimentally impact the utility’s credit ratings and its ability to finance the required capital expenditures on reasonable terms. Ultimately, higher financing costs will result in higher rates for customers because they increase the costs of the utility to provide service. As a result, addressing this issue is critical to both the utility and its customers.

Various regulatory mechanisms exist for policy makers to moderate the financial pressure that these utilities experience because of regulatory lag and increasing capital cost pressures. For example, rather than looking backward at historic costs, regulators can use a future test year, setting the utility’s rates using projections of the utility’s costs during a future year when the rates determined in a proceeding will be effective. Alternatively, formula rates can be used to automatically adjust the prices that the utility may charge based on various predetermined cost inputs. For federally regulated transmission service, the FERC is increasingly approving formula rates for transmission providers that adjust on an annual basis. The use of adjustment mechanisms to flow through changes in current costs, such as fuel and purchased power, can also alleviate such

financial pressures. While fuel adjustment clauses have been relatively common in many jurisdictions, adjustment clauses are now expanding to cover environmental charges, conservation program costs, and other variable costs that cannot be fixed in a rate case. Regulators can also take advantage of a specialized accounting concept permitted for regulated utilities—deferral accounting—which can allow a utility to record certain expenses incurred for items such as construction of infrastructure on its balance sheet, rather than expensing them as traditional accounting practices would otherwise require. The “regulatory asset” created by a deferral accounting order is then paid off by amortizing the amount recorded in subsequent rates, giving a future income stream to the utility that otherwise could not have been recovered.

Another tool that can help fund high capital spending requirements is to include in a utility’s rates the Construction Work in Progress costs (CWIP), which is the accounting classification for money spent on capital projects that have not yet been placed in service. Under traditional regulation, utilities generally cannot include in rates money spent during project construction, and thus earn a return on that investment, until the facilities are completed and actually placed in service. Allowing inclusion of CWIP in the “rate base” upon which a utility’s rates are established allows the utility to earn a cash return on those invested dollars earlier, thus alleviating some of the financial challenges utilities face during periods of high growth and capital spending and lowering the ultimate cost to customers. Also, CWIP can reduce a sudden increase in rates from a large capital project, such as a new nuclear plant, by spreading the increase over the construction of the project and reducing the final capital cost of the project that would be reflected in rates.

Although these and other regulatory tools exist, the challenge is explaining to stakeholders and customers why it is important to employ such methods and, in some cases, depart from the status quo, particularly in an environment when electric rates are generally increasing. In high-growth areas, another challenge is addressing who should pay for growth—all customers or only those new customers who are moving onto the utility’s system. For utilities in high-growth areas, the cost increases associated with expanding electric distribution facilities is creating as much cost pressure as a new generation or transmission plant.

Under traditional regulatory policy, utilities recover the costs associated with planning and constructing new distribution infrastructure through the base rates that all customers pay for electric service, after the facilities are already constructed and placed in service. In a low-growth or declining-unit-cost environment, regulators generally are not concerned with asking all customers to pay in base rates the cost of delivering energy to future customers. After all, every existing customer was a new customer at one time. But when growth is high and distribution-related construction costs are extreme, thus causing unit costs to increase faster than revenues, there is a significant tension between planning for future facilities and recovering the cost of those facilities through base rates. By their nature, distribution facilities—substations, transformers, and distribution lines—are generally constructed to connect new customers to the utility’s existing electric system. If the cost of such facilities

is recovered through the base rates that all customers pay, as traditional regulatory policy had required, current customers may understandably perceive that they are being asked to subsidize the cost of growth, which in some cases can be quite significant.

One potential solution to mitigate some growth-related costs is through the design of an impact fee, similar to the fees that municipalities charge new developments to fund the cost of infrastructure. Such a fee can shift at least some of the cost of growth away from base rates to those customers causing the increased costs—an outcome that is consistent with a general rate-setting practice of associating rates with cost causation. An impact fee is different from the traditional fee charged by a utility when connecting new customers, which is often called a “line extension” or “facilities” charge. These charges are usually designed to recover only a portion of the incremental costs incurred by the utility to connect new customers based on specific facilities needed by the customer. Also, line extension proceeds are often not treated as income to the utility, but as customer-contributed capital. A properly designed impact fee can offset growth-related costs that are not collected through a utility’s line extension policy, and thus reduce overall rates needed by the utility by allocating some of the revenue needs caused by growth to new customers, rather than socializing these costs in the utility’s general rates.

While potentially beneficial for some systems, the impact fee mechanism is not foolproof. The funding source is a volatile one, and depends in large part on the nature of the housing market and new construction, which currently are in distress throughout the country. Such a mechanism also does not compensate the utility for growth-related costs already incurred prior to the implementation of such a fee. Nevertheless, the consideration of such a funding mechanism, or other nontraditional regulatory policies, could go a long way towards preserving the financial condition of a rapidly growing utility.

While the evolving energy landscape presents the electric industry with a number of challenges, those challenges are not insurmountable. Policymakers and regulators must understand the nature of the challenges facing electric utilities in the industry’s changing environment—one that is particularly challenging for utilities in areas of high customer and demand growth—and adapt accordingly. While the result may be higher electric prices in the short term, the long-term customer benefits of regulatory policies that would allow utilities to maintain financial health and focus on necessary infrastructure improvements and expansion are tangible. Regulatory policies that provide utilities with the certainty they need to address the many challenges they now face, as well as rate treatment that will allow them to face these challenges without risking their financial integrity, can, for example, enhance the reliability of the nation’s electric system, promote investment in “clean” energy resources such as solar and nuclear power, and lower a utility’s operating costs in the long term. Such cost savings would ultimately be reflected in a relatively lower price of electricity in the long run. Regulators should focus on these long-term benefits to ensure that utilities can address the many challenges confronting them in this changing environment, so that the electric industry can continue its century-long tradition of powering our increasingly energized nation. 🌍