solutions

The U.S. **Electric Power Sector** and **Climate Change Mitigation**

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Prepared for the Pew Center on Global Climate Change

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Foreword *Eileen Claussen, President, Pew Center on Global Climate Change*

The electricity sector in the United States enables almost every aspect of our economy—from agriculture, to manufacturing, to e-commerce. As witnessed during the California Energy Crisis and the 2003 blackout in the northeast and midwest, interruptions in the supply of electricity can be highly disruptive. It is hard to imagine a sector that is more important to our economy than electricity. But electricity also accounts for one third of our nation's greenhouse gas emissions. In order to effectively address the climate challenge, we must significantly reduce greenhouse gas emissions associated with electricity production and use. In this report, authors Granger Morgan, Jay Apt, and Lester Lave identify numerous opportunities to decarbonize the U.S. electricity sector over the next 50 years.

This Pew Center report is part of our effort to examine key sectors, technologies, and policy options to construct the "10-50 Solution" to climate change. The idea is that we need to tackle climate change over the next fifty years, one decade at a time. Looking at options available now and in the future, this report yields the following insights for reducing GHG emissions from the electricity sector.

- *There are likely multiple pathways to a low-carbon future for the electricity sector, and most involve some portfolio of technological solutions.* The continued use of coal with carbon capture and sequestration; increased efficiency in the generation, transmission and end use of electricity; renewable and nuclear power generation; and other technologies can all contribute to a lower-carbon electric sector. Yet, all of these technologies face challenges: Cost, reliability, safety, siting, insufficient public and private funds for investment, and market and public acceptance are just some of the issues that will need to be resolved.

- *A major effort is needed to develop and deploy commercially available low-carbon technologies for the electric sector over time.* The lower-carbon efficiency and generation technologies available and competitive in the market today are probably insufficient to decarbonize the electricity sector over the next few decades. Given the magnitude of the challenges the industry faces in coming decades, it is critical that the United States—both the public and private sectors—develops and maintains dramatically expanded R&D. Near-term and long-term R&D investments will help ensure that we have technologies to enable a low-carbon electricity sector.

- *It is critical that we start now to embark on the path to a lower-carbon electric sector.* A decarbonization of the electricity sector could be achieved in the next 50 years through increased efficiency and fuel-switching in the near term, and a gradual deployment of lower-carbon technologies over the next several decades. Over the long term, GHG reductions will be achieved at lower cost if climate considerations are incorporated into the industry's investment decisions today. Voluntary efforts to reduce GHG emissions will not be enough, especially given the current uncertainty in the industry. A clear timetable for regulation of GHG emissions is essential—a timetable that begins in the near future.

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Executive Summary

Measured by environmental impact and economic importance, the electricity industry is one of the most important sectors of the American economy. The generation of electricity is responsible for 38 percent of all U.S. carbon dioxide (CO_2) emissions and one third of all U.S. greenhouse gas (GHG) emissions. This sector is the largest single source of these emissions. It is also the largest source of sulfur dioxide (SO_2), oxides of nitrogen (NO_X), small particles, and other air pollutants.

At the same time, electricity is critical to the U.S. economy. Recent annual national expenditures on electricity totaled $250 billion—making the electricity sector's share of overall GDP larger than that of the automobile manufacturing industry and roughly equal in magnitude to that of the telecommunications industry. Expenditures alone, however, understate the importance of electricity to the U.S. economy. Nearly every aspect of productive activity and daily life in a modern economy depends on electricity for which there is, in many cases, no close substitute. As the most desirable form of energy for many uses, electricity use has grown faster than GDP. The Internet and computers would not operate without very reliable, high-quality electricity. Electricity also plays a major role in delivering modern comforts and easing household tasks, from running heating and cooling systems to washing clothes and dishes. It plays an even more important role in the commercial, manufacturing, and agricultural sectors, where it provides lighting and powers a variety of machines. In short, it is hard to imagine a modern economy functioning without large amounts of reliable, high-quality electricity.

The economic and environmental importance of the electric power industry is, moreover, likely to grow in coming decades. Electricity demand has increased steadily over the last three decades and is projected to continue rising in the future, despite ongoing improvements in end-use efficiency. The industry, meanwhile, has undergone dramatic structural changes over the last 10 years, moving from a system of monopolies subject to state price regulation to a mixed system that now includes some elements of market competition in many states. After declining for 75 years, electricity prices have risen since 1970, making expenditures for carbon control a difficult proposition in the absence of mandatory GHG policy. The uncertain state of electricity market restructuring efforts around the country, particularly since the California crisis of 2001-2002, has increased perceptions of investor risk and sharply raised the cost of borrowing for capital investments by investor-owned utilities.

In this context, reconciling growing demand for affordable and reliable electricity supplies with the need for substantial reductions in GHG and criteria pollutant emissions presents a significant challenge for policy-makers and for the electricity industry itself. Indeed, even if worldwide growth in demand for electric power ceased today, the industry's current level of emissions is not sustainable.

Stabilizing atmospheric carbon dioxide concentrations at twice the level of pre-industrial times is likely to require emissions reductions of 65-85 percent below current levels by 2100. Clearly, reductions of this magnitude can be achieved only by taking action globally and across all sectors of the economy.[1] But the electricity sector will undoubtedly need to assume a major share of the burden—in the United States and worldwide—given its centralized structure and contribution to overall emissions.

This report explores the electric power industry's options for reducing its GHG emissions over the next half century. Those options include new technologies that are still being developed—such as coal gasification with carbon capture and sequestration—as well as strategies that rely on existing technologies at different stages of commercial and technical readiness (such as nuclear and renewable generation), lower-carbon fuels (like natural gas), and efficiency improvements (both at the point of electricity production and end use). Many of these options, in addition to reducing CO_2 emissions, also reduce conventional air pollutants.

Although a power generating plant has a lifetime of 30-50 years, low-carbon technologies could claim a substantial fraction of the generation mix by mid-century—in time to help stabilize atmospheric GHG concentrations within the next century or two. Some of these technologies, such as coal-based integrated gasification and combined cycle (IGCC) generation, still need to overcome basic cost, reliability, and market-acceptance hurdles; others, such as carbon capture and sequestration, have yet to be demonstrated on a large scale. Still others, such as wind, nuclear, or even (given recent fuel price increases) natural gas combined cycle power, are relatively well developed but face constraints in terms of siting, public acceptability, cost, or other factors.

Nevertheless, the analysis presented in this report suggests that substantial GHG reductions could be achieved by the power sector—without major impacts on the economy or on consumer lifestyles—through the gradual deployment of lower-carbon options over the next several decades. At the same time, more immediate emissions reductions can be achieved through lowering demand by increasing the efficiency with which electricity is used; substituting natural gas for coal; improving efficiency at existing plants including highly efficient combined heat and power systems at suitable sites; expanding deployment of renewable generation technologies, including biomass co-firing of coal plants; and through the use of carbon offsets such as forestry projects and methane capture and collection. These immediate measures can reasonably be expected to reduce electricity growth and expand low-carbon electricity production in the United States from its 28 percent share in 2003, while also reducing emissions from higher-carbon generators.

While initial steps to limit electricity sector CO_2 emissions will have only a modest impact on total U.S. emissions, steady and deliberate efforts to promote long-term technological change in this sector eventually could produce significant climate benefits, given the industry's share of current emissions. The dollar cost of achieving GHG reductions will depend to a significant extent on which of several possible technology pathways emerge as both feasible and cost-effective in the decades ahead. Increasing the efficiency with which electricity is used is important to any energy future. In one scenario, the successful commercialization of carbon capture and sequestration technology would allow for continued use of fossil fuels in combination with somewhat increased reliance on similarly priced wind resources. In another scenario, a new generation of nuclear technology proves acceptable and plays an expanded role in meeting future electricity needs. Future emissions reductions might need to be achieved chiefly through increased reliance on relatively more expensive natural gas and renewable energy. Some forms of renewable energy can certainly play a role, but just how large a role depends on a range of uncertain issues in terms of cost, technical performance, and power system architecture. A major scale-up of renewable energy would likely require a greatly enhanced transmission network and expensive energy storage technologies to compensate for the remoteness and intermittency of much of the wind and solar resource base. These issues will be resolved only through further research and expanded field experience.

In all cases, however, long-term reductions will be achieved at lower cost if climate considerations are incorporated into the industry's investment decisions sooner rather than later. Building another round of conventional pulverized coal plants that comply with new pollution control requirements for SO_2, NO_X, particulate matter, mercury, and other toxic emissions, but that later need to be scrapped, or retrofitted with costly and inefficient CO_2 scrubbers, would likely be the most costly path.

To ensure that climate considerations figure in the industry's planning decisions and to provide effective market incentives for investment in low-carbon technologies, a clear timetable for the regulation of GHG emissions is essential. Many industry experts and utility executives see such regulations as inevitable over the next 10-20 years, but cannot—without some certainty about future regulation—justify added expenditures for low-carbon technologies today, either to their shareholders or to state regulators concerned about the local economic impacts of higher-priced power. Voluntary efforts to reduce CO_2 emissions simply will not be sufficient in an increasingly cost-competitive and risk-averse market. If, however, GHG emission limits are implemented in concert with other pollution control requirements, long-term air quality and climate objectives will be achieved more quickly and at lower total cost than under a piecemeal approach.

Four major policy recommendations emerge from the findings in this report concerning prospects for a long-term transition to a low-carbon electricity power sector:

- *Establish a firm regulatory timetable for reducing CO_2 emissions from the electricity industry that parallels the timetable for reducing discharges of conventional pollutants.* To assure that emissions targets are met at minimum cost, they should be set well in advance and should be implemented using market-based mechanisms such as a cap-and-trade system or a carbon tax. Avoiding high costs later requires accounting for CO_2 in current investment decisions and technology choices.

• *Address the most serious institutional and regulatory barriers to the development of low-carbon and carbon-free energy technologies by implementing policies aimed at:* (1) developing an adaptive regulatory framework for managing geologic carbon sequestration, in order to provide an alternative (coal gasification with carbon capture) to building new conventional coal plants; (2) determining if it is feasible to mitigate the safety, proliferation, and waste-management concerns that currently inhibit the expansion of nuclear power; (3) facilitating the adoption of cost-effective low- or no-carbon renewable technologies such as wind and biomass and promoting distributed resources and micro-grids—that is, clusters of small, modular generators interconnected through a low-voltage distribution system that can function either in concert with, or independent of, the larger grid; and (4) creating financial arrangements that decrease the risk penalty assigned by investors to new capital in the restructured era that have tended to discourage major electricity industry investments and that present further hurdles to the deployment of new technologies.

• *Promote greater end-use efficiency through policies that encourage power companies to invest in cost-effective, demand-side energy savings.* Impose stricter federal efficiency standards for appliances and buildings (as detailed in the Pew Center report, *Towards a Climate Friendly Built Environment*) and promote the deployment of efficient combined heat and power systems. California has succeeded in slowing per capita electricity demand growth significantly through a variety of efficiency initiatives; these and other programs should be examined to estimate their potential to reduce demand more broadly and to identify "best practices" that can be documented and implemented elsewhere.

• *Create a federal requirement that all parties in the electricity industry invest at least one percent of their value added in R&D in order to explore how promising new technologies can solve the difficult reliability, efficiency, security, environmental, cost, and other problems facing the industry.* Firms should have the choice to make the investments themselves or contribute to a fund managed by the U.S. Department of Energy. In parallel with this industry mandate, the Department of Energy needs to develop a more effective program of needs-based research into power generation and storage, electricity transmission and distribution, conservation, demand management, and other electric power technologies and systems.

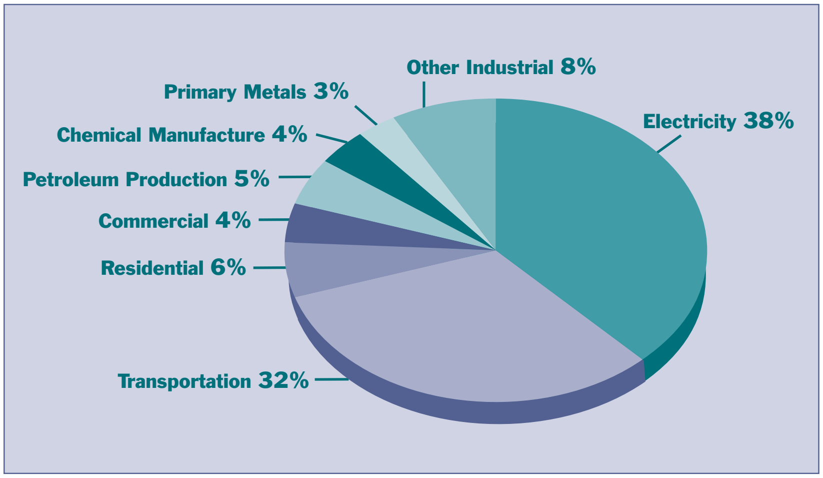
I. Introduction

The United States is the source of one quarter of the world's greenhouse gas (GHG) emissions. Adjusted for global warming potential, carbon dioxide (CO_2) emissions—mostly generated by fossil fuel combustion—account for more than 80 percent of the overall U.S. contribution.[2] The largest share of CO_2 emissions, in turn, comes from the electric power sector which accounts for 38 percent of the nation's overall CO_2 emissions (Figure 1). Changes in the electric power industry over the next several decades will therefore have major implications for efforts to mitigate climate risks—and vice versa. The future of the industry also matters enormously to the overall economy, given the extent to which households and businesses have come to rely on access to a ready supply of electricity.

This report explores options for reducing the electric power sector's GHG emissions over the next half century. Section I provides a basic introduction to the industry and reviews its evolution to date. Recent years have seen great changes in the structure and management of the electric power sector, as state and federal policy-makers have moved to restructure the industry in an attempt to introduce competition. Section II describes some of the problems that have arisen as a result of the partial restructuring of the industry. These problems complicate the policy options available for limiting CO_2 emissions and for promoting more efficient use of electricity. Section III addresses the important technological developments which, along

Figure 1

Sources of **U.S. CO_2 Emissions** in 2002



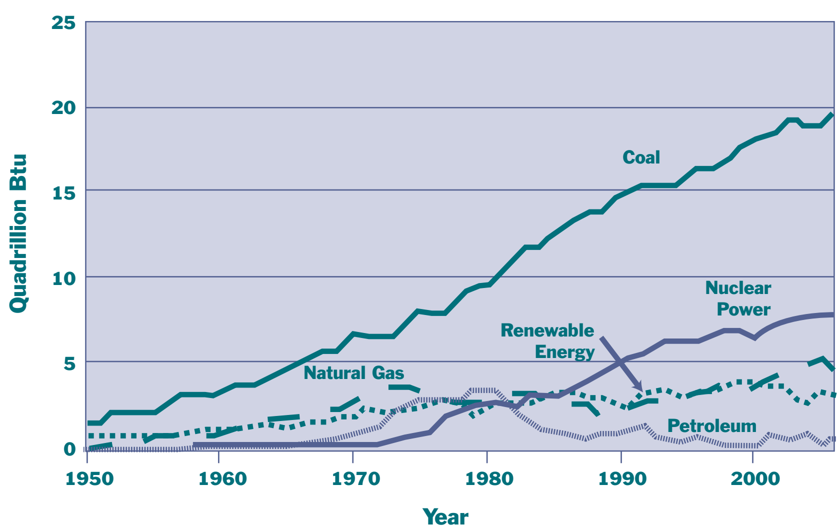
Sources: U.S. Energy Information Administration and U.S. Environmental Protection Agency.

with rapid institutional and regulatory change, are likely to play a major role in shaping the future of the industry. Such developments in the past have caused significant shifts in the nation's electricity supply mix within a matter of years or, in some cases, decades. Examples include the introduction of nuclear power in the early 1970s and a pronounced switch away from oil as a power plant fuel later that same decade. In the 1990's, low capital costs for natural gas plants caused a boom in the construction of combustion turbines. More recently, high natural gas prices have prompted renewed interest in an expansion of coal-based capacity—coal currently supplies more than 50 percent of the electricity generated in the United States and remains the nation's most abundant and least expensive domestic fossil fuel resource.

Given the complex dynamics involved, predicting how the electric power industry is likely to evolve over the coming decades is a task fraught with difficulties. Section IV discusses what we can and cannot hope to know in projecting the future and considers some strategies for narrowing attendant uncertainties, before proceeding to an exploration of several possible technology trajectories for the industry over both nearer- and longer-term time scales—that is, over the next decade and the next half century, respectively. Building on these insights, Sections V and VI conclude with a set of policy recommendations and a summary.

Figure 2

Energy Sources of Electricity Generation in the United States, 1949-2003



Hydroelectric generation (7.15% of net generation) is classified as renewable energy in the Annual Energy Review, along with wood (0.96%), biomass/landfill gas/waste (0.59%), geothermal (0.34%), wind (0.28%), and solar (0.01%). Coal provides 51.2% of electric generation, nuclear 19.85%, natural and other gas 16.63%, and diesel and other petroleum 3.07%.

Source: Energy Information Administration 2003 Annual Energy Review, Figure 2.1a.

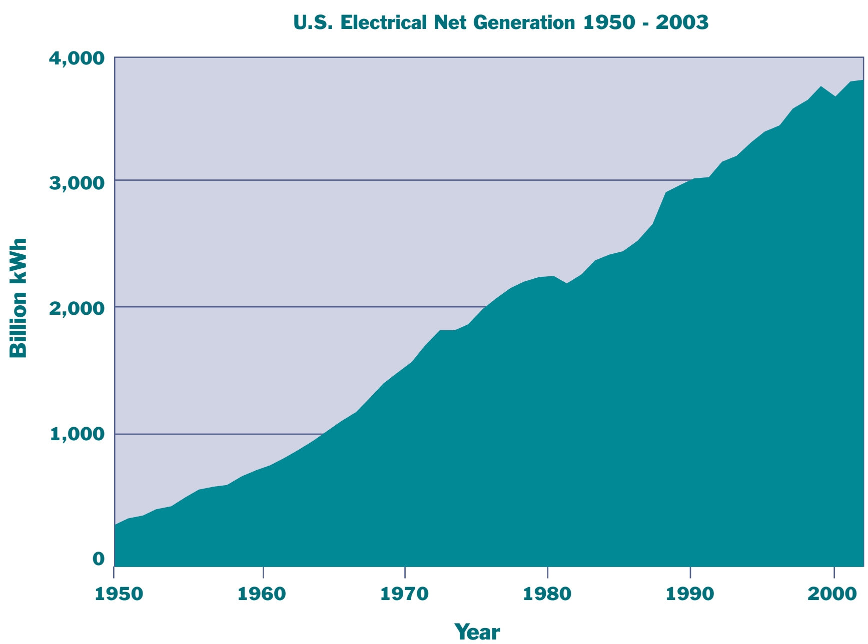
A. A Brief Description of the Electricity Industry Today

Demand for electricity continues to grow (Figure 3). Over two-thirds of the electric power generated in the United States is produced by burning fossil fuels: principally coal (51.2 percent), natural gas (16.6 percent), and oil (3.1 percent).[3] With CO_2 emissions of 2.2 billion metric tons or gigatons (Gt) per year,[4] the electricity sector as a whole accounts for the single largest share—38 percent—of total U.S. carbon emissions. Globally, about 30 percent of all the CO_2 produced by fossil fuel combustion and industrial activity comes from electric power plants.[5] The electricity industry is also a source of small amounts of other greenhouse gases.

The electric power industry is important not only in environmental terms—it also represents an important sector of the U.S. economy, with annual sales totaling $250 billion. As a share of U.S. GDP, electric sector revenues are larger than those of the motor vehicle manufacturing industry and similar in magnitude to those of the telecommunications industry (Figure 4). Sales data alone, however, understate the real importance of electricity to the U.S. economy. Electric energy is indispensable for meeting most basic lighting and communication needs and for a host of other services and amenities that are part of everyday life in a modern society. Because it has no close substitutes in many applications, consumers would likely be willing to pay far more for certain uses of

Figure 3

History of Generation by the U.S. Electricity Industry



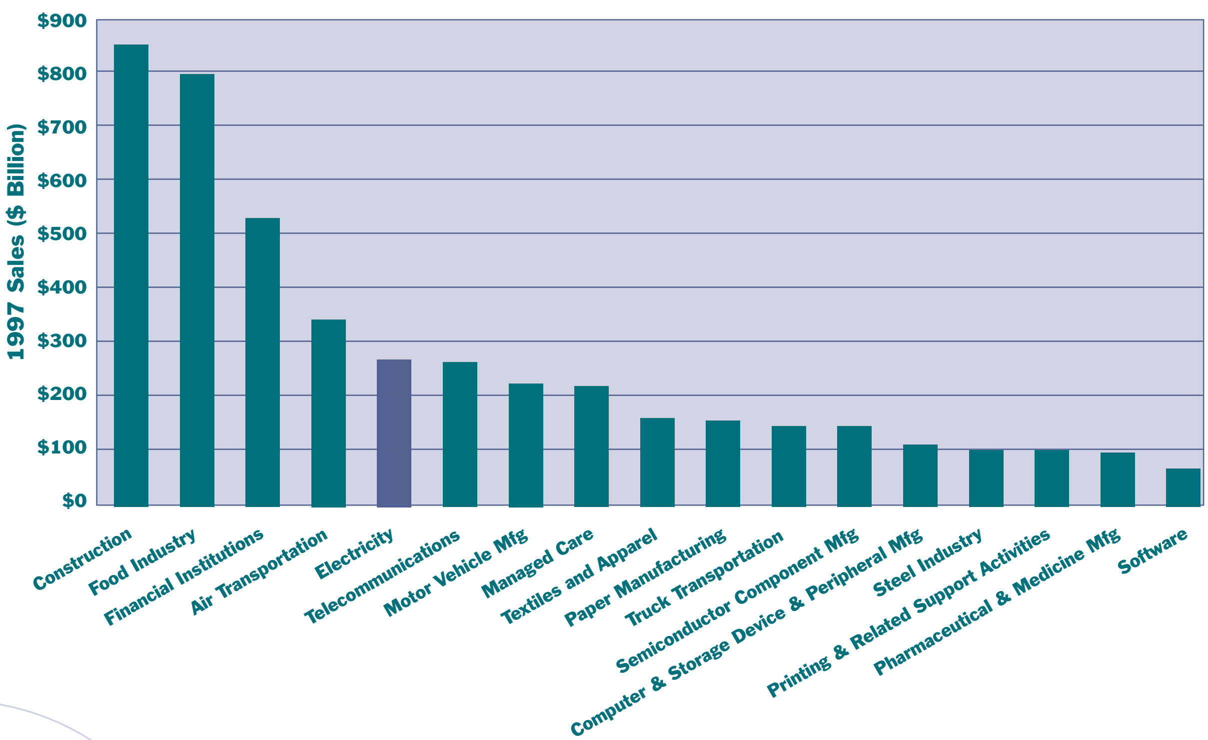
Source: Energy Information Administration.

electricity than the typical per kilowatt-hour (kWh)[6] cost of grid-supplied power. To operate portable electronic devices, for example, consumers routinely pay $1.85 for a D-cell alkaline battery that can produce 0.017 kWh, yielding an equivalent price of $108/kWh.[7]

Moreover, sales figures understate the extent to which other key economic sectors depend on reliable access to electrical energy. A study of infrastructure dependencies in the context of California's rolling blackouts in 2001 found that loss of electrical power caused significant direct disruptions in natural gas production, pipeline transport, and water supply. These disruptions in turn caused further disturbances in the manufacture of petroleum products such as specialty gasoline, heavy oil, and jet fuel; in crop irrigation; and in many other sectors. Clearly, disruptions in electricity supply impose large private and social costs (some of the social services that depend upon the availability of electric power are listed

Figure 4

Comparison of Sales in the U.S. Electricity Industry with Sales in 16 Other Large Industrial Sectors



Source: United States Census Bureau. 1997. http://www.census.gov/epcd/www/econ97.html in Table 1). Economic losses from the massive blackout that struck the midwestern and northeastern United States and parts of Canada in August, 2003 have been estimated at between $4 and $6 billion.[8] Based on data from the North American Electric Reliability Council (NERC), the amount of electrical energy that went undelivered because of the blackout totaled some 920,000 MWh. This implies that the economic cost of the blackout came to approximately $5 per foregone kWh, a figure that is roughly 50 times greater than the average retail cost of a kWh in the United States.

In short, if the U.S. economy were to lose electric power, its output would fall by much more than the $250 billion American households and businesses spend on electricity each year. As a result, policy measures designed to reduce the industry's CO_2 emissions must also be sensitive to the broader economic impacts of electricity price increases and of possible reductions in system reliability.

In terms of physical infrastructure, the U.S. electric power system today consists of large central-station generation plants that feed power through substations into a network of high-voltage transmission lines.[9] These lines connect to lower-voltage transmission lines through additional substations. Once power reaches its destination on the transmission

Table 1

Some of the Critical Social Services that Depend on the Availability of Electric Power

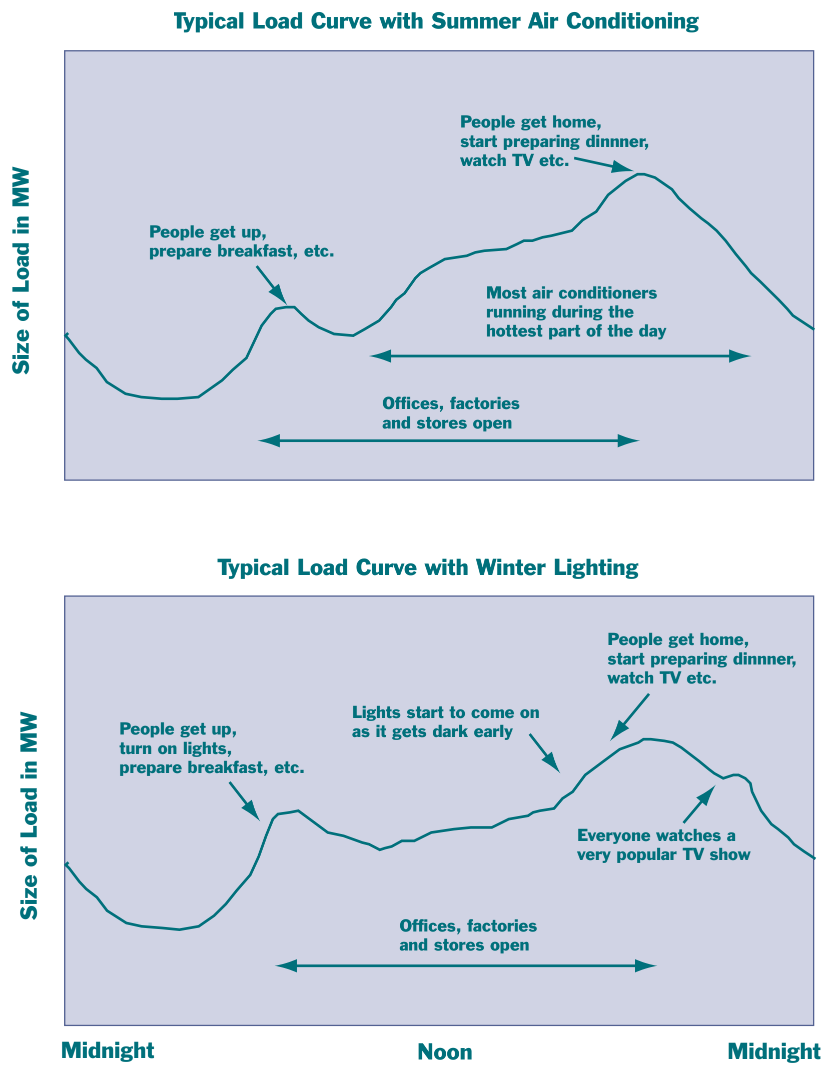
Emergency Services	Domestic lighting	Wire-line telephone
911, emergency operations centers, and other dispatch	Lighting in commercial establishments	Cable systems
Police services	Security lighting	Wireless telephone
Fire protection services	Street lighting	Wired data services
EMS		Wireless data services
	Food	Computer services on customer's premises
Medical Services	Cash registers	Computer services off customer's premises
Transport ambulance services	Lighting	
Life-critical in-hospital care (life support systems, operating rooms, etc.)	Refrigeration	**Non-emergency Government Services**
Non-critical in-hospital care (refrigeration, heating and cooling, sanitation, etc.	Restock operations	Government information and service offices
Clinics and refrigerated pharmacies		Prisons
Nursing homes and other non-hospital care	**Financial**	
	Cash machines	**Transportation and Mobility**
Non-electric Public Utilities	Banking services	Building elevators
Water	Credit card systems	Traffic signals
Sewer		Tunnels
Natural gas	**Fuel Infrastructure**	Light rail systems and subways
	Pump operations	Conventional rail systems including railroad crossings
Lighting	Pipeline systems	Air traffic control
Building evacuation and stairwell lighting	Local fuel storage capacity	Airport operations including landing and related lighting
	Transport and distribution capacity and operations (including river locks)	River lock and dam operations
	Whole sale and retail operations	Drawbridge operations
	Communication and Cyber Services	
	Radio transmission and reception	
	Television transmission and reception	

grid, transformers are used to step down the voltage for regional distribution, and then again for final delivery to customers.[10]

Electricity demand or "load" varies substantially by time of day, by day of the week or year, and depending on weather conditions. Patterns of demand also vary for different types of customers (i.e., residential, commercial and industrial) (Figure 5). A typical power system experiences high demand in the late afternoon and early evening and low demand after midnight. Large coal and nuclear plants that can operate efficiently and at low cost, but are not easily turned off and on, are called "baseload plants" and run nearly all the time. "Intermediate load" plants can turn on more rapidly but are typically more expensive to operate and run only a portion of the time. "Peaking plants" are the most costly to operate and usually run for only a few hours at a time—during periods when the demand is highest. In terms of capital cost, baseload plants are generally the most expensive to build (whereas peaking plants are least expensive), but their usual pat-

Figure 5

Typical Electrical **Load Curves**



Notes: The size of the load on an electrical system varies with the time of day, day of week, and season of the year. It also depends on the mixture and behavior of residential, commercial and industrial loads.

tern of operation means that average costs per kWh generated are usually lowest for baseload plants and highest for peaking plants. Daily demand patterns typically dictate that baseload, intermediate, and peaking units account for about one-third each of the overall generating capacity of most power systems (Figure 6).

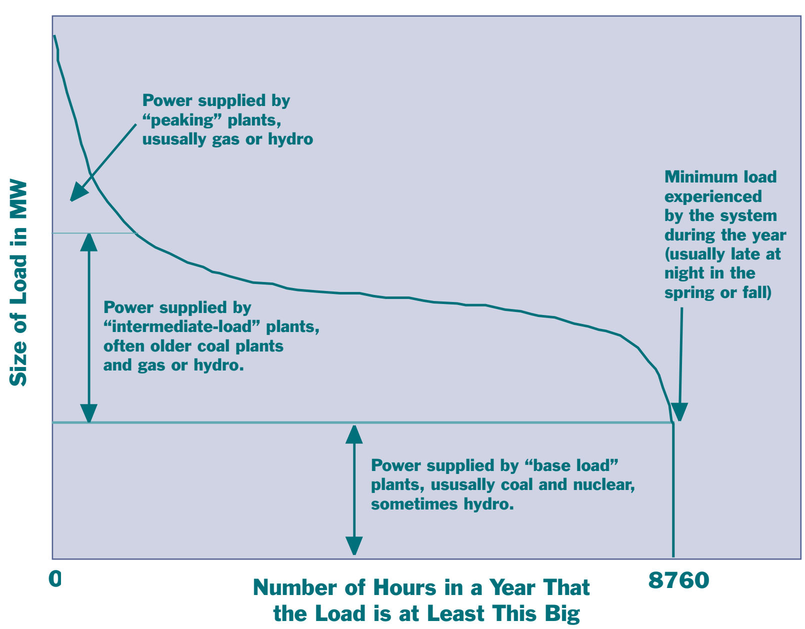
Most large electricity customers operate under a two-part rate system: they are billed both for each kWh they use (an "energy" charge), and for the peak kW demand they impose on the system during any hour of each billing period (a "demand" charge). Demand charges for large customers can be quite high during peak periods,[11] when the cost of supplying each marginal kWh rises sharply. By contrast, most residential customers pay a flat rate per kWh, independent of when they use the electricity. The latter rate structure provides no economic incentive to conserve during peak demand periods when power is relatively expensive, or to shift consumption to "off-peak" periods. Lower, off-peak rates have been offered for some years in a few parts of the country, but there is now considerable interest in significantly expanding the numbers of customers exposed to time-dependent rates so as to promote more efficient use of the electric system.

Based on test applications in a few locations, the California Energy Commission has estimated that the full implementation of time-of-use pricing throughout California would result in peak load reductions of 3-12 percent.[12] From a cost and system reliability standpoint, this result would clearly be beneficial. From the perspective of climate policy, however, the effects of time-dependent rates may be more ambiguous. On the one hand, correct price signals can induce more efficient use of electricity (especially during peak periods) and thereby lower demand and emissions.

Figure 6

Hypothetical Example of a Power System

"Load Duration Curve"



On the other hand, time-dependent rates can also have the effect of shifting consumption from peak periods to off-peak periods, without any gains in efficiency. In that case, a shift in generation from mostly natural gas-fired peaking plants to mostly coal-fired baseload plants could actually result in increased emissions (a typical baseload coal plant may emit 60 percent more CO_2 per kWh than a natural gas peaking unit).[13]

In sum, the electric power industry is critical to the U.S. economy and involves a large, long-lived, capital-intensive infrastructure. In the past decade, the industry has undergone dramatic structural changes. The next section provides a brief historical review of the industry's evolution to date.

B. Four Eras in the Evolution of the U.S. Electric Power Industry[14]

Era 1: Initial Competition (1892-1910)

The industry emerged in an era characterized by intense competition between Thomas Edison, his commercial rivals, and municipal cooperatives. Edison's direct current (DC) power required generation stations to be located within a mile of the end-use customer. A decade later, Edison merged his company with another company that had expertise in George Westinghouse's alternating current (AC) technology to form General Electric. AC power was both more efficient for powering motors than DC and could be transported long distances, allowing large central generation stations to supply many customers. This model of large generators at remote locations has endured.

Then, as now, two-thirds of the cost of electricity consisted of capital expenses for equipment. The industry's enormous capital needs and intense competitiveness made investors wary and led to the rapid consolidation of monopolies in Chicago, New York and Detroit. The public was not well served by this consolidation—in 1908, New York's Public Service Commission wrote: "That competition cannot be depended upon to protect the consumer from high prices and poor service has been fully demonstrated."[15] Municipal co-operatives constituted one early response to the market power of monopolies—by 1907, they supplied about one-third of the nation's electricity.

Era 2: The Regulated Utility Consensus (1910-1970)

By 1910, a consensus had emerged that vertically integrated electricity companies should be granted monopoly status within defined geographical areas in exchange for state regulatory oversight. This obliged them to serve consumers at prices set by state regulators, but gave them essentially guaranteed rates of return to attract capital. Power companies supported state regulation as a barrier to the entry of potential competitors and because it was preferable to a patchwork of local regulation. Most states allowed utilities to earn a defined return on their capital investments. This rate-of-return regulation provided certainty for investors, but also encouraged large investments when smaller ones would have sufficed. So long as regulators allowed rates of return to exceed the cost of borrowing money, utility shareholders stood to profit from each additional dollar of capital investment. This utility consensus defined the industry's second era.

After the 1929 stock market crash, revelations of market power abuse and corruption of state public utility commissioners set the stage for the federal government to enter the electric power business. The Columbia Basin Project's Grand Coulee Dam was approved in 1935 and the Bonneville Power Authority was created in 1937. By 1941, the Tennessee Valley Authority (TVA) was the nation's largest generator of electric power.

The creation of these large public power authorities coincided with a period of rapid electrification, particularly of the nation's rural areas. When TVA was founded, 90 percent of city dwellers had access to electricity as compared to only 10 percent of rural residents. Between the efforts of the Rural Electrification Administration (created in 1935) and private companies, the fraction of rural residents with electricity service increased to 25 percent by 1939.

Technology improvements and economies of scale caused electricity prices to fall until 1970, to the general satisfaction of both industrial and residential customers. In 2002 dollars, the average retail price of electricity fell from about $5.15 per kWh in 1892 to about 9.7 cents per kWh in 1970. Demand grew steadily as the country electrified and as air conditioning became increasingly commonplace.

Era 3: Discontent and Naïve Restructuring (1970-2001)

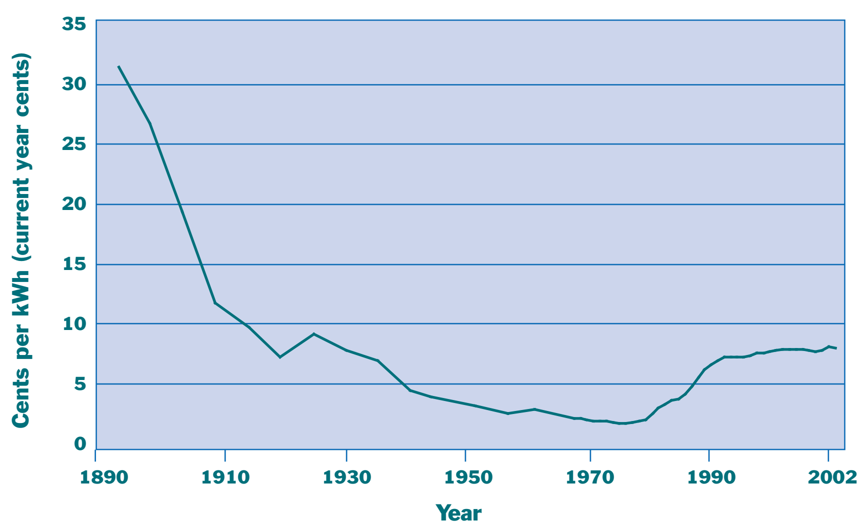
Beginning in the 1970s, prices for electric power began to rise sharply, increasing by 320 percent in nominal terms between 1970 and 1985, or 28 percent in inflation-adjusted terms (Figure 7). During this time, electricity demand—which had been growing exponentially during the period from 1949 through 1973 (at a compounded rate of 7.75 percent per year)—also began to moderate. Demand continued to grow after 1973, but in a linear fashion with annual increases averaging approximately 70 billion kWh per year.[16]

Earlier expectations of continued exponential demand growth, meanwhile, had caused utilities to propose—and regulators to approve—massive new investments in large coal and nuclear plants in the late 1960s and early 1970s. Many of these plants were later plagued by cost overruns and reliability problems and, with demand growth moderating, the industry's impetus toward large capital investments began to reverse by the late 1970s. By the 1980s, rising prices had begun to generate intense political pressure to reduce electric rates. Following on the deregulation of the airline industry in 1978 and of the trucking industry in 1980, restructuring of the electric power industry was seen as one means of fostering competition and lowering prices. Thus, a series of efforts at restructuring shaped the industry's third era.

Unfortunately, there are important differences between the electric power industry and other sectors of the economy that have been

Figure 7

Residential Price of Electricity in the United States, 1892-2002



Notes: In current year cents per kilowatt-hour. Adjusting for inflation, the 1892 cost of a kWh in 2002 dollars was $5.15.

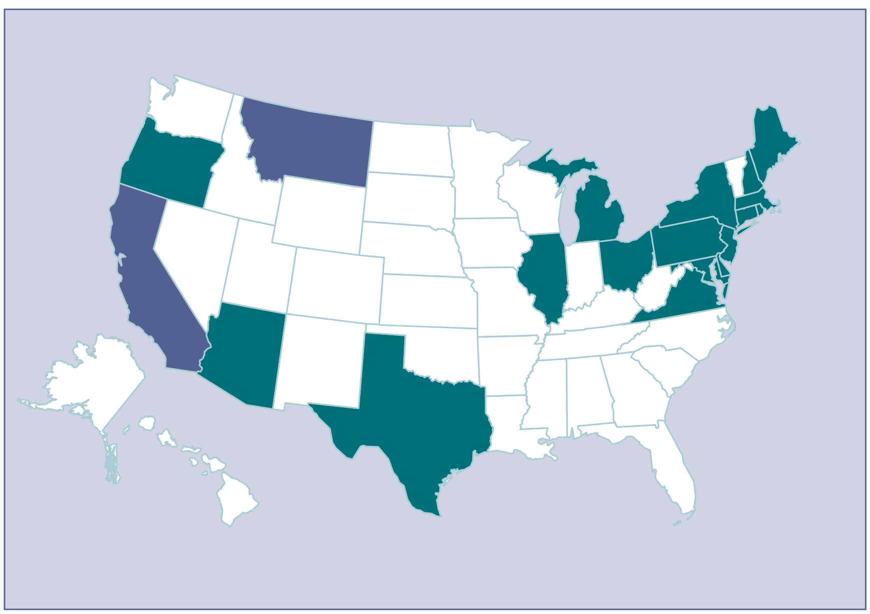
Source: Hirsh, Richard F. *Power Loss.* (2001). MIT Press, Cambridge. Figures 2.1 and 3.3 from Hirsh (2001) inspired this figure, which has been compiled from the data sources Hirsh cites and updated with data from U.S. Department of Energy, Energy Information Administration, Electric Power Annual Table ES, available at http://www.eia.doe.gov/cneaf/electricity/epa/epates.html.

successfully deregulated. Because electricity cannot be stored at a reasonable cost, suppliers and consumers cannot maintain stockpiles or inventories to even out supply and demand fluctuations and to hedge against price shocks. In addition, the capital investments required are more substantial than in nearly any other industry—the cost and useful life of a new power plant, for example, are many times that of a new airplane or truck. As a result, the ability to secure investment capital at low interest rates is particularly crucial to the electric power industry. As a result of restructuring, stock in utility companies turned from a secure investment into a volatile one, effectively increasing the industry's cost of capital. Meanwhile, policy-makers have struggled to find a balance between treating electricity as a public good which must always be available on demand at predictable and reasonable prices and reaping the benefits of free-market competition. Consequently, most restructuring efforts to date have been characterized by only limited competition, flawed market design, problematic transition rules, and unintended consequences. The result is that utilities around the country are subject to a patchwork of different regulatory regimes (Figure 8), with states that have restructured accounting for roughly 40 percent of all the electricity sold in the United States. This unsettled situation appears likely to persist for many years.

In reviewing the price effects of restructuring, it is useful to focus on industrial rates, since residential rates generally continue to be regulated even where competition has been introduced at the wholesale level. Based on the experience of the transportation sector, most policy-makers expected that deregulation would produce

Figure 8

Status of State Electric Restructuring



Notes: States with active restructuring are shown in green, those that have halted restructuring are shown in purple. Today, 40% of electricity in the United States is sold by firms in deregulated states.

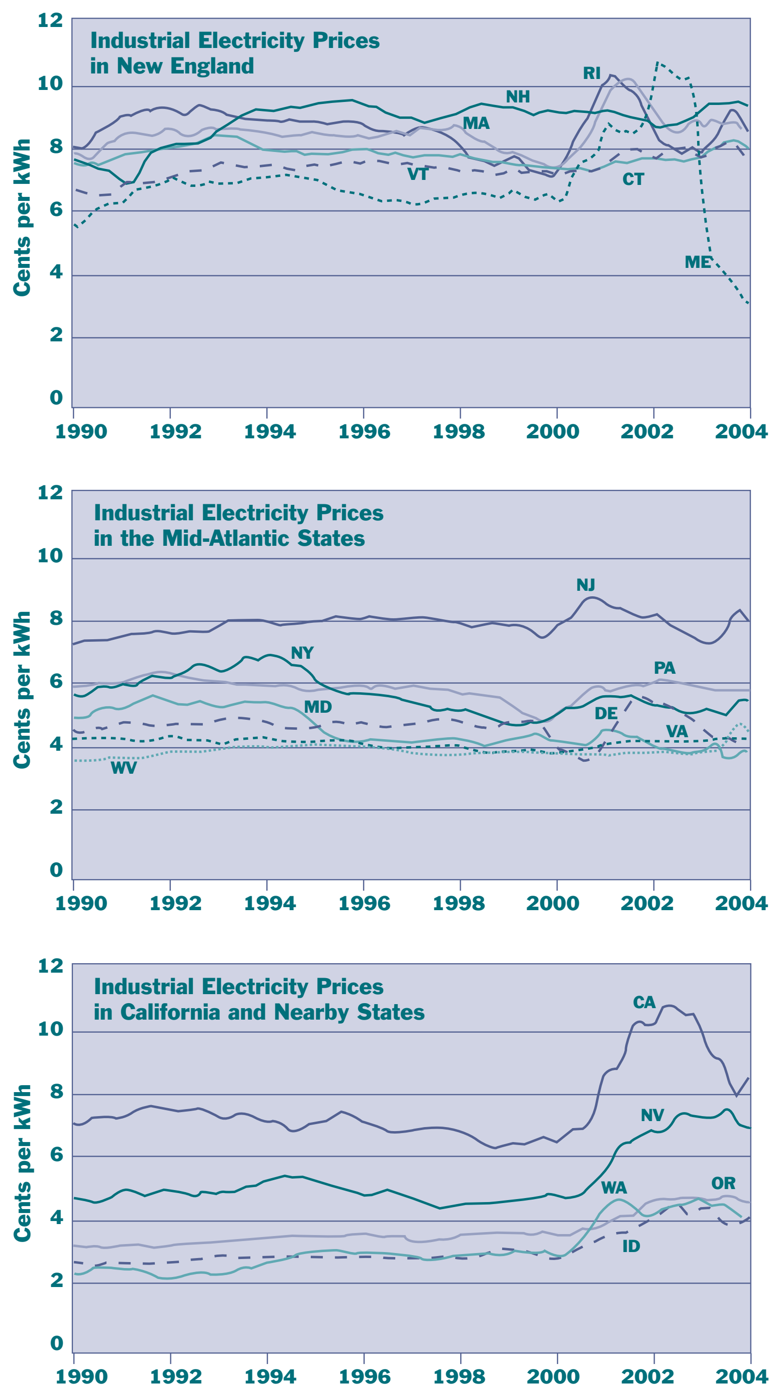
Source: Energy Information Administration, http://www.eia.doe.gov/cneaf/electricity/page/restructure.html.

lower rates for large industrial customers. This has turned out to be the case, however, in only one of the nineteen states that introduced competition (Figure 9). In that state (Maine), lower rates resulted from the completion of two long-scheduled natural gas pipelines from Canada, not from deregulation. In some other states, prices rose after restructuring. In Montana, for example, industrial rates rose from 3 to 7 ¢/kWh, and residential rates rose from 6 to 14 ¢/kWh. Prices also spiked in California during that state's energy crisis of 2001 and 2002, costing ratepayers tens of billions of dollars and driving electricity prices up in adjacent states as well (Figure 9).

In sum, price stability has become a key priority for the industry and its regulators. Past price shocks, in the 1970s and more recently in California and other states, have sensitized all stakeholders to the consequences of excessive volatility in electricity markets. In this context it is highly unlikely that utilities will make sub-

Figure 9

Industrial Electricity Prices in New England, the Mid-Atlantic States, and the West Coast for 1990-2003



Notes: In New England, only Vermont is regulated. Rhode Island and Massachusetts generate much of their electricity from natural gas, whose price at the Henry Hub rose from $2.25/MMBtu in 1999 to $4.35 in 2000 before declining to $3 in 2002. Of the five western states shown, California and Oregon were the only restructured states.

Source: Apt, J. (2005) "Competition has not Lowered U.S. Industrial Electricity Prices." *The Electricity Journal* 18 (2). 52-61 stantial investments in new and likely more expensive low-carbon generation options absent a mandatory and consistent policy for regulating GHG emissions.

Era 4: The New Challenge (2001 and Beyond)

Failed experiments in market design have cost customers and investors tens of billions of dollars and have prompted widespread skepticism about the wisdom of restructuring efforts to date. Many markets for electricity will never be competitive without an enormous expansion of generating capacity and of transmission infrastructure that would impose new costs far in excess of any savings achievable through competition.

Restructuring has also made it more difficult for the industry to raise capital and to invest in social goods—like improving environmental performance or enhancing system reliability—for which, in a deregulated setting, it has no clear ability to recover costs. In addition to the price issues discussed above, increased market uncertainty has raised financial risk for lenders to this capital-intensive industry. Even where traditional regulatory regimes are still in place, uncertainty about the future means that financial markets today routinely impose risk premiums on the industry that are higher than the 11-12 percent rate-of-return allowed by most state public utility commissions. These increased borrowing costs create further barriers to investment in pollution control and in lower-carbon technologies, especially where those technologies are viewed as more risky and/or more expensive than conventional technologies.

In addition to large direct expenditures on pollution controls, the electricity industry during the regulated era invested considerable sums in promoting end-use efficiency through demand-side management programs. The introduction of competition in many cases left utilities without incentives for continuing to make such investments and without mechanisms for recovering associated costs. Some states attempted to compensate by establishing public benefits funds to maintain efficiency and other "social goods" programs, or through other means. California, for example, directly appropriated $500 million to sponsor conservation programs in Fiscal Year 2001,[17] while Montana and Idaho are actively considering how to address the issue of removing disincentives for utility investment in energy efficiency. In other states, however, public benefits funds have recently been used to cover general budget shortfalls, reducing spending on end-use efficiency programs.

Box 1

Electricity Restructuring Around the World

In many nations, electricity has traditionally been supplied by government agencies or by government-owned companies. In such cases, it becomes relatively easy for government to use the electricity sector to solve political problems, from providing service to communities and individuals that are costly to serve, to increasing employment and subsidizing farmers or coal miners. The result is often high-cost electricity with substantial subsidies for some customers and workers.

The impetus for electricity reform generally starts from a recognition that the current system is either unreliable or too expensive—that is, a perception that the system is broken and needs to be fixed usually motivates the reform effort, rather than some abstract appeal to market forces (although some international development organizations are motivated by the latter). Deregulation in many countries has taken the form of privatizing government agencies or selling government-owned companies to investors. Governments themselves generally find it difficult to eliminate cross-subsidies and excess workers, or to run their electricity operations more efficiently. The prospect of generating a substantial one-time influx of revenue from selling state-owned assets has created a further temptation for some governments to privatize the electricity sector.

Many nations have introduced competition in the electric power sector with the objective of increasing efficiency and lowering costs. The first step in this process generally involves "unbundling" the industry by separating its generation, transmission, and distribution functions. The power generation side of the industry lends itself most readily to competition. By contrast, because of the infrastructure needs involved, there is disagreement about whether transmission can become truly competitive and general agreement that distribution services constitute a natural monopoly.

Restructuring efforts began in the 1980s with Chile, England and Wales, and Norway leading the way. All of these countries discovered that it was difficult to create a competitive electricity market that would lower prices and increase reliability. England has changed its electricity structure three times since it began restructuring. Despite these mixed results, many other nations throughout South America followed suit with their own restructuring initiatives. In the United States, California and Pennsylvania restructured their markets in 1998 with quite different results. In California, a flawed market design led to anti-competitive behavior beginning in 2000 and soon precipitated a severe crisis and extremely high prices. The experience in Pennsylvania has been more positive, in large part because state regulators and PJM (the system operator for that region[18]) have been much more assertive in monitoring for market power abuses and intervening to address price volatility.

In the 1990s, a wave of electricity restructuring initiatives swept over the Caribbean nations, Europe, and parts of the Middle East, Africa, and Asia. As of 2001, Bacon and Besant-Jones[19] counted 15 nations as having substantially liberalized their electricity structure and another 55 nations where liberalization was planned or underway.

Bjornsson, Crow, and Huntington[20] have attempted to extract lessons from the experience of developed nations in order to suggest a better design for Japan's deregulated market. They focus on California, Pennsylvania/PJM, England and Wales, Germany, Victoria/Australia, the Scandinavian Nord Pool, and France. England (under Margaret Thatcher) came closest to fully deregulating the electric power sector—primarily for ideological reasons, although the government also raised considerable revenues from the sale of national electric system assets. Germany and France are struggling to comply with a European Union directive concerning deregulation that was promoted by the UK and the Netherlands. The French government, meanwhile, has been reluctant to give up its monopoly of Electricité de France. Bjornsson et al. point out that there is no common model of deregulation being pursued by these countries. Thus, there are vast differences in the amount of regulatory oversight that remains in different places, with New Zealand and California having little or no effective market monitoring and PJM having a great deal.

At this point, it is fair to say that no model of electricity restructuring has emerged as clearly superior. In each case, unanticipated problems have emerged that have necessitated further regulatory changes, with the result that deregulation—or, as some prefer to call it, re-regulation—remains a work in progress, not only in the United States, but around the world. Nevertheless, many continue to believe that some form of competitive market structure should provide benefits greater than those of the traditional regulatory system.

C. GHG and Conventional Air Pollutant Emissions from the Electricity Industry

As noted above, electricity generation is a major source of GHG and conventional air pollutant emissions. Table 2 reports emissions estimates for coal-fired electric power from a number of field and model studies. Table 3 reports similar results for natural gas-fired plants. Data from the U.S. Environmental Protection Agency (EPA)[21] indicate that

Table 2

Comparison of Emissions From Coal-fired Electric Power Plants Based on a Number of Different Studies (in metric tons per GWh)

	ORNL-RFF		NREL			Argonne		Pacca and Horvath*	IECM†			
Emissions	Southeast Ref Site*	Southwest Ref Site*	Average*	NSPS*	LEBS*	Base Case**	Hydrogen Co-Product Case***		Super-Critical PC*	Super-Critical PC w/CCS	IGCC**	IGCC w/ CCS***
CO_2	1000	1100	1000	940	740	850	110	820	810	110	820	97
SO_X	1.6	0.8	6.7	2.5	0.72							
NO_X	2.7	2.1	3.4	2.4	0.54							
Particulate Matter (PM)	1.5	1.5	9.1	10	0.11							
CO	0.25	0.25	0.21	0.25	0.19							
HC	0.09	0.12	0.21	0.20	0.19							

* Pulverized Coal Plants ** Coal Gasification Plants (IGCC) *** IGCC with Carbon Capture and Sequestration
† IECM calculates generation phase only

Notes:

ORNL-RFF = Oak Ridge National Laboratory and Resources For the Future (Estimating Externalities of Coal Fuel Cycles. Report Number 3 on the External Costs and Benefits of Fuel Cycles. A Study by the U.S. Department of Energy and the Comission of the European Communities. September, 1994. McGraw Hill, Inc. USA.). This study examined generation plants in both the Southeast and Southwest.

NREL = The National Renewable Energy Laboratory (Spath, P.L., M.K. Mann, D.R. Kerr. 1999. "Life Cycle Assessment of Coal-fired Power Production," NREL/TP-570-25113, National Renewable Energy Laboratory, Golden, CO). This study examined three types of pulverized coal plants. It compared: (1) An average coal fired power plant in use today, (2) a power plant that has been built to satisfy the NSPS regulations and (3) a power plant that has installed Low Emission Boilers System (LEBS). The LEBS power plant increases the efficiency of the power plant to 42% (from the 32% of the average plant), decreasing the CO_2 emissions from 1,000 to 740 ton/GWh.

Argonne = The Argonne National Laboratory (Doctor, R., J.C. Molburg, N.F. Brockmeier, L. Manfredo, V. Gorokhov, M. Ramezon, G.J. Stiegel, Argonne National Laboratory. Life-cycle Analysis of a Shell Gasification-based Multi-product System with CO_2 Recovery. Proceedings from the First National Conference on Carbon Sequestration. May 15-17, 2001. Washington, D.C.) examined a gasification plant with and without the production of hydrogen. It considered coal gasification in a combined cycle plant. The high efficiency of the plant decreased CO_2 emissions to 850 ton/GWh. A second case separated 90% of the CO_2 and sequestered it, putting the hydrogen into a fuel cell. The resulting CO_2 emissions were 110 ton/GWh.

Pacca and Horvath (Pacca, S., and A. Horvath, 2002, "Greenhouse Gas Emissions from Building and Operating Electric Power Plants in the Upper Colorado River Basin." Environmental Science and Technology 36(14) 3194-3200.) looked at the global warming impact. The Pacca and Horvath study found average CO_2 emissions of 820 but stressed that the global warming effect of a power plant varies from year to year over a plants life.

The IECM at Carnegie Mellon (Rubin, E.S., A.B. Rao and C. Chen. Comparative Assessments of Fossil Fuel Power Plants With CO_2 Capture and Storage (Proceedings of 7th International Conference on Greenhouse Gas Control Technologies, Cheltanham, England: IEA GHG, 2004 September 5-9). study looked at both sub critical pulverized coal as well as IGCC technology with and without carbon capture and sequestration. The IECM analysis considers only the generation phase but the results are comparable to the other studies.

emissions from the electric power industry account for 38 percent of the nation's total CO_2 emissions, 22 percent of total NO_X emissions, 8 percent of total primary $PM_{2.5}$ emissions,[22] and 69 percent of total SO_2 emissions. U.S. power plants also emit approximately 70 metric tons of lead and just over 45 metric tons of mercury each year.[23]

Despite these figures, considerable progress has been made in increasing the efficiency of electricity generation and reducing environmental impacts. Emission regulations to date have reduced SO_2 and NO_X emissions from U.S. power plants by 30 percent since 1991. Similar progress has not, however, been achieved with respect to GHG emissions. In fact, the industry's CO_2 emissions have increased by 25 percent over the last two decades (Figure 10).

Because coal is an abundant and relatively inexpensive domestic energy resource, it is likely to remain a major fuel for electricity production in the United States for some decades to come. In recent years, there has been an effort to integrate environmental regulations for the most important types of power plant pollutant emissions. So-called "3-P" legislation introduced at the state and federal levels attempts to establish simultaneous limits for power plant emissions of SO_2, NO_X, and mercury (an example is the Bush Administration's Clear Skies proposal), while "4-P" proposals add CO_2 limits as well (an example of the latter is a bill introduced in the 108th Congress by Senators Carper and Jeffords).[24] The argument for a 4-P approach is that it will be far more cost-effective in the long run if industry plans for reducing both GHG emissions

Table 3

Comparison of a Number of Different Studies of

Emissions From Natural Gas-fired Electric Power

Natural Gas: Comparison of Emissions

	ORNL-RFF	NREL	Pacca and Horvath	IECM†	IECM w/CCS†
Capacity (MW)	500	505	1000	520	520
Emissions (metric tons/GWh)					
CO_2	580	440	450	370	44
SO_2	neg.	0.32			
NO_X	0.45	0.57			
Particulate Matter	0.019	0.13			

† IECM calculates generation phase only Notes: For explanation, see notes for Table 2.

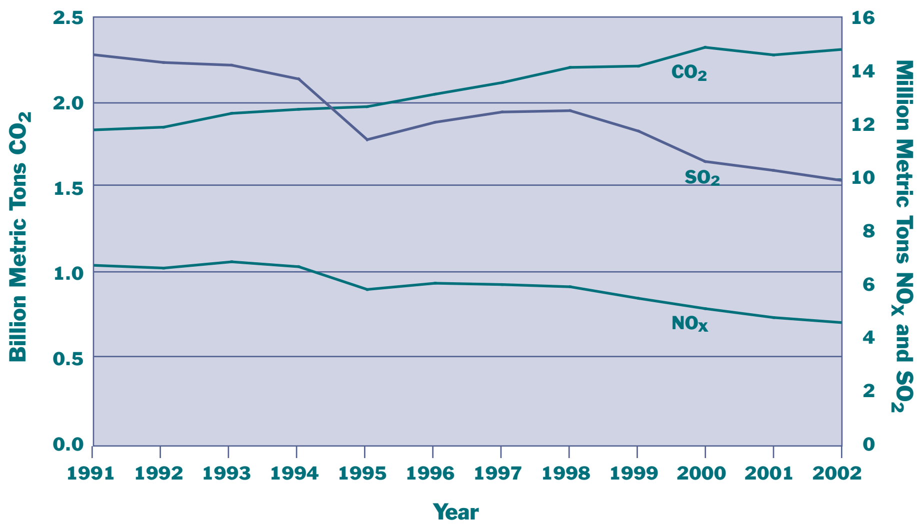
and conventional air pollutants at the same time, rather than implementing piecemeal fixes for SO_2, NO_X, and mercury and adding CO_2 controls later on.

Nearly all of the new generating capacity added in the United States during the 1990s was natural gas-fired. Natural gas combined cycle generators had lower emissions and were cheaper and faster to build than conventional coal plants (at that time, the cost of building a combined cycle natural gas plant was less than half that of building a new pulverized coal plant that could meet similar emissions standards). As a result, in 2003, the U.S. Department of Energy (DOE) predicted that by 2025, 29 percent of the nation's electricity would be generated from natural gas, up from 16 percent today.[25] In the last few years, however, natural gas prices have tripled, idling many of the new plants built in the 1990s. Unless prices fall, a carbon policy is enacted, or the cost of coal plants increase, the market share of natural gas is not likely to increase nearly as much as previously expected. Meanwhile, recent trends in natural gas markets have served as a reminder that, despite its many environmental advantages, natural gas remains a finite resource—one that is, moreover, significantly constrained in terms of domestic supply relative to coal.[26]

Figure 10

Emissions from Energy Consumption

for Electricity Generation



Source: Energy Information Administration Electric Power Annual 2002, Table 5.1.

Historically, hydroelectric power was often considered the most environmentally benign source of electricity. In recent years, however, awareness has grown of the adverse environmental impacts associated with flooding large areas and disrupting aquatic ecosystems and fish migration. As a result, a substantial further expansion of hydroelectric generating capacity beyond its present 7 percent share of total generation in the United States is unlikely. Other renewable energy sources such as geothermal, wind and biomass fuel are beginning to enter the U.S. electric power system; together they make up 0.6 percent of total generation. Their environmental implications are discussed as part of a broader discussion of new technology in Section III.

Early environmental legislation adopted in the United States in the 1970s typically relied on a command-and-control approach to reduce pollutant emissions. U.S. EPA and state environmental agencies established emission limits for new and existing sources that individual facilities were required to meet. Plants that failed to comply were subject to fines or other enforcement actions. While this approach was successful in lowering emissions, it proved to be slow, costly, and highly contentious. For example, implementation of the New Source Review program remains fraught with controversy even today, more than three decades after the Clear Air Act was enacted.[27]

Market-based approaches to limiting pollutant emissions have, by contrast, achieved their goals more quickly and cheaply, and have spawned less litigation than traditional command and control regulations.[28] An early and successful example of this approach was the federal Acid Rain program introduced as part of the 1990 Clean Air Act Amendments. This program established a national cap on power sector SO_2 emissions, but allowed emitters to trade allowances under the cap. On average, each coal-burning utility was given allowances to emit half the SO_2 that it emitted during the baseline period. Utilities that could reduce their emissions by more than half could sell unneeded allowances to those utilities that found it more expensive to achieve reductions. Because utilities were also allowed to "bank" allowances for any reductions they achieved ahead of schedule, the program resulted in substantial early emissions reductions. At the same time, eventual compliance costs turned out to be as much as two-thirds lower than had been anticipated. Similar tradable-allowance schemes have worked well for reducing power sector NO_X emissions in the eastern United States and in other areas[29] and have been proposed for reducing mercury emissions (although equity issues arising from local effects complicate the issue for mercury).

Based on the success of the Acid Rain program, the Clinton Administration insisted during the international negotiations of the Kyoto Protocol that emissions trading be part of the framework for abating global GHG emissions. Although some are skeptical that the complexity of an economy-wide trading system will be manageable, market-based approaches are generally thought to offer quicker and cheaper solutions than command-and-control regulation. As a result, most current U.S. climate proposals—such as the Climate Stewardship Act proposed by Senators McCain and Lieberman—continue to feature market mechanisms.[31] Moreover, the existing U.S. trading system for SO_2 is often held up as a model for an eventual international CO_2 trading system. Farrell and Morgan,[32] however, argue that a better analog is the NO_X trading regime that now exists in the eastern United States. The SO_2 trading regime was imposed nationally and from the top down by the federal government. In contrast the NO_X trading regime emerged from the bottom up as a result of cooperation by a number of quasi-independent entities (the participating eastern states) that all adopted compatible state-by-state regulations.[32]

While there has not yet been any federal regulation of GHG emissions, a number of states and regions have begun to take bottom-up[33] actions to limit CO_2 emissions from electricity generation.[34] New Hampshire and Massachusetts, for example, are requiring reductions in CO_2 emissions from existing power plants. At a regional level, nearly all the states in the northeastern United States have begun working together to establish a regional cap and trading system for power plant CO_2 emissions.[35] In addition, the attorneys general of Connecticut, California, Iowa, New Jersey, New York, Rhode Island, Vermont and Wisconsin, and the corporation counsel of the City of New York have filed suit against five electric generating companies, seeking to force them to reduce their CO_2 emissions. These five companies account for about a quarter of total U.S. power sector CO_2 emissions and about 10 percent of the nation's overall CO_2 emissions. Finally, 18 states and the District of Columbia have enacted renewable portfolio standards. These standards typically require that electricity providers include a minimum percentage of renewably generated electricity in their supply portfolios and, while often motivated by concerns other than climate (e.g., fuel diversity, energy security, air quality, local economic development, etc.), they nevertheless provide a mechanism for promoting the deployment of low-carbon generation technologies.[36]

State and regional efforts to address the climate issue have not been limited to the electric power sector. The Conference of New England Governors and Eastern Canadian Premiers has adopted a voluntary agreement to reduce overall GHG emissions from the New England states and eastern Canadian provinces. Similarly, the West Coast Governors' Global Warming Initiative[37] has begun considering actions that could be taken in concert by Washington, Oregon, and California to reduce emissions. In addition, California will be the first state to regulate GHG emissions from motor vehicles, pending the outcome of a legal challenge. California has also launched a research program on the impacts of climate change, especially as they relate to snow-pack in the mountains and to the state's water supply.

Section Summary

Electricity is critical to the U.S. economy. More than two-thirds (71 percent) of today's electric power supply is generated using coal, natural gas, and oil. The resulting CO_2 emissions account for 38 percent of total annual U.S. CO_2 emissions. After a 75-year decline, electricity prices in the United States began to rise in 1970. High prices and price stability continue to be major concerns for the industry and its regulators today, after a decade of restructuring efforts that have often cost consumers and produced flawed market designs. One result has been an increase in investor risk that has sharply raised the cost of borrowing for capital investments by investor-owned utilities. In this context, power companies are unlikely to make investments to reduce emissions absent a mandatory carbon control policy.

II. Problems in Managing the Restructured Industry

A. Conflicting Private and Social Goals

While cost and reliability have always been the electric power industry's primary concerns, utility managers and their regulators have historically also focused on wider social objectives. Examples include:

- supporting regional development;
- providing rural electrification;
- supplying electricity to meet the basic needs of the very poor;
- deriving co-benefits such as navigation, recreation, and fishing from hydro-electric dams;
- preserving and improving environmental quality; and
- promoting energy conservation and renewable sources of energy.

Under traditional rate-of-return regulation, regulators and legislators found it was relatively easy to address these issues through a variety of mandates. For example, regulators could require utilities to undertake programs to improve end-use efficiency and arrange for them to recover associated costs. While there has been some controversy over the cost-effectiveness of such programs and over how much they achieved in terms of energy savings (see discussion in Section III), there is little question that they slowed electricity demand growth.

Nevertheless, per capita electricity demand has trended steadily upward in recent decades. Residential consumption, for example, averaged 2.9 megawatt-hours (MWh) per person in 1977 and 4.4 MWh per person in 2002, a 52 percent increase. On a per capita basis, overall electricity consumption (i.e., including residential, commercial, and industrial) grew by 35 percent over the same timeframe. Because the nation's population also grew by 31 percent during this period, overall consumption increased substantially. (Given population growth, per capita consumption would have had to decline rather than increase to keep overall consumption at 1977 levels.) Notably, California's per capita electricity consumption grew by just 5 percent—markedly less than the national average—over the last quarter century, showing that it was possible to slow demand growth[38] and suggesting that the adoption of best practices for energy efficiency could significantly offset increasing CO_2 emissions from electricity generation.

As has already been noted, several states established public benefits funds when they restructured as a mechanism to continue funding energy efficiency, low-income, and other social goods programs once competition had been introduced and local utilities were no longer subject to rate-of-return price regulation. At present, such funds exist in 14 of the 19 deregulated states; their annual expenditures totaled $900 million in 2004.[39] In recent years, however, cash-strapped states have sometimes diverted these funds for other purposes. In sum, having only recently undertaken restructuring, many states are still experimenting with mechanisms to continue promoting end-use energy efficiency.[40] Based on the California experience, it seems likely that per capita demand growth can be slowed significantly, though perhaps not to the extent required to fully offset population growth. Nonetheless, a continued emphasis on end-use efficiency is likely to be important in helping to achieve climate policy goals for the electricity sector.

Another possible mechanism for reducing power sector CO_2 emissions is, of course, direct regulation. As discussed in previous sections, states and the federal government have used command-and-control style and, more recently, market-based regulatory approaches to limit power sector emissions of conventional air pollutants such as SO_2, NO_X and particulate matter. Such programs have sometimes spawned controversy and litigation (examples include recent debates about the New Source Review program and about pending regulations to limit mercury emissions), but overall they have succeeded in substantially reducing overall power sector emissions of several key pollutants, even as the industry's output grew to keep pace with steadily rising demand. While there has been no federal regulation of CO_2 emissions to date, a number of states, as noted above, have begun to enact or consider laws limiting CO_2 emissions from existing and/or new power plants.

The central issue for climate change mitigation policies—whether these policies are being implemented in traditionally regulated or restructured states—is cost. To the extent that restructuring has increased risk premiums for the industry as a whole, companies that operate in a restructured environment will find it more difficult to finance investments in lower-carbon technologies. According to Standard & Poor's, for example, the median bond rating of investor-owned utilities fell from A to BBB (3 grades) since deregulation. This change in bond rating has a direct effect on the interest rates utilities need to pay to finance new capital investments. (In contrast, the median ratings for bonds issued by municipal and co-operative power generators that are not subject to competition have remained unchanged at A.) The financing problem may be compounded if a utility's investment in technologies that financial markets view as risky or unproven leads to a further downgrading of bond ratings. Meanwhile, even where traditional rate-of-return regulation still allows utilities to earn a guaranteed profit from new capital investments, many public utility commissions are increasingly sensitive to price and local competitiveness concerns and may be reluctant to ask consumers to bear the higher costs and increased technology risks associated with some low-carbon options.

B. Capital Investment in the Face of Uncertainty

For the reasons described above, it will likely be difficult for the electric power industry to finance new low-carbon technology—especially in the absence of a mandatory climate policy—given the current investment climate. Absent a mandatory policy, other strategies may be needed to overcome present hurdles to such investments. One alternative is for the state or federal government to provide direct subsidies or incentives for low-carbon alternatives. Examples of this approach include the subsidies for new nuclear power plants contained in a comprehensive energy bill passed by the U.S. House of Representatives in 2003 and the federal production tax credit that was recently extended for qualifying renewable generators. William Rosenberg and others at Harvard University's Kennedy School of Government have proposed yet another approach to overcome financing hurdles for new technologies that involves a joint commitment by private investors, the federal government, and state utility regulators.[41] Under this so-called "3-party covenant" approach, the federal government would guarantee the loan for constructing a new, low-carbon generating facility (thereby lowering interest rates), state regulators would allow the utility to begin to recover its investment during construction, and the utility would use its best effort to build and operate a low-cost, reliable generation plant. Novel risk-sharing arrangements such as this could be crucial to ensure that capital is available for the early deployment of new low-carbon technologies such as coal IGCC.

Uncertainty about future regulations governing both conventional air pollutants and GHG emissions complicates the already difficult problem of financing large new capital investments in the electric power sector. Given the long-lived nature of much of the industry's infrastructure, uncertainty can also lead to sub-optimal decisions that ultimately impose unnecessary costs on firms and on society. Future changes in environmental regulations can affect fuel costs and may require different generation and control technologies. To the extent that such changes affect the cost of generating electricity from fossil fuels, they will also affect the future value of fossil fuel-fired power plants. Thus, uncertainty about the extent and timing of potential future regulations can confound decision-making with regard to the expansion or replacement of existing generating capacity and the installation of add-on control technologies to reduce air emissions. "Locking in" an emissions-control technology or strategy could be expensive if it subsequently proves to be inadequate to meet future regulations—or conversely, a given control technology or strategy could prove much more expensive than future regulations require. At the same time, plant owners and operators must keep up with electricity demand and cannot always wait to make investment decisions until all legislative, regulatory, and judicial uncertainties are resolved. In this context, reducing or eliminating uncertainty about the legislative and regulatory changes that are likely to affect the industry in the future could provide significant economic savings and reduce the likelihood of costly mistakes as the industry makes important capital investment decisions in the years to come.

Modeling can be helpful in exploring the implications of different kinds of uncertainty for investment planning by the electric power industry. One important source of uncertainty, as indicated by the foregoing discussion, is the impact of future environmental regulations to limit air emissions from coal-fired plants.[42] Such analyses that have identified a range of plausible regulatory scenarios, assigned different probabilities to those scenarios, and assessed impacts on plant emissions, allowance prices, and fuel costs have found that significant savings are likely to result if regulatory ambiguity and uncertainty are resolved quickly.

Another important source of uncertainty for the industry is the difficulty of predicting future effects from climate change itself. Yohe et al.,[43] have modeled uncertainty about the impacts of rising GHG concentrations as inputs to a financial hedging strategy. They find that doing nothing until 2035 imposes large costs if the magnitude of climate effects later necessitates the rapid imposition of substantial mitigation measures. By contrast, long-term costs are lower if relatively modest mitigation efforts are launched earlier and then ramp up gradually.

Both types of analysis, however, indicate clearly that overall control costs are lower when policies are defined clearly, enunciated early, and implemented consistently. This is also the basic conclusion of models developed by the economists Kydland and Prescott, who won the Nobel Prize in 2004 for their work on the time consistency of economic policy.[44]

Section Summary

To minimize long-term abatement costs it is important that a mandatory policy be introduced sooner rather than later–for two reasons. First, resolving regulatory uncertainty will help companies plan and optimize their investment decisions. Second, early action will allow time for modest initial steps with a gradual phase-in of more stringent requirements. This approach is far less likely to produce significant economic dislocations than waiting until it becomes necessary to implement more drastic reductions in a shorter timeframe.

State and federal initiative will continue to be critical in promoting conservation and end-use energy efficiency improvements as one strategy for reducing power sector GHG emissions. This is likely to be especially true in states that have deregulated and where utilities not only lack incentives for pursuing demand-side efficiency opportunities, but may be unable to recover the costs of doing so. The current regulatory and market environment has also made it more difficult for the industry to finance large new capital investments, particularly where these investments involve technologies that are more expensive than the conventional alternatives and/or are viewed as unproven or risky. In this context, government incentives and innovative mechanisms for sharing risk—such as the 3-party covenant concept—may be essential in overcoming financing hurdles to early investments in new, low-carbon technologies. In the long run, however, incentives alone are not likely to be adequate substitutes for a mandatory policy.

III. Factors Likely to Shape the Evolution and Carbon Intensity of the Industry

While climate change and its impacts are important, many other factors are likely to shape the future evolution and carbon intensity of the electricity industry. Table 4 lists some of these factors. This section discusses three drivers that are likely to be especially critical in determining how the electricity sector responds to future climate policy: energy conservation, new technology, and research investments.

A. Improved End-Use Efficiency and Load Control

Two factors account for the fact that overall electricity consumption in the United States tends to grow from year to year. The first is population growth; the second is per capita electricity demand, which tends to increase with rising income. Just to offset the 0.8 percent increase in U.S. population from 2002 to 2003, per capita electricity consumption would have had to decline by an equal share. Instead, per capita use increased by 2.1 percent. This increase occurred despite the substantial improvements in end-use efficiency that have occurred in many areas of the economy since the energy crisis of the early 1970s. For example, energy efficiency standards for refrigerators have reduced the average annual energy consumption of U.S. refrigerators by 74 percent over the past two decades.[45]

Reductions in electricity demand, and corresponding reductions in electric sector GHG emissions, can result from:

- technological changes (e.g., conversion to new, high-efficiency lighting technologies);[46]
- changes in overall system design (e.g., building designs that reduce heating or cooling requirements); and
- changes in pricing and technology that allow consumers to take advantage of price differences (e.g. time-of-day meters and computer controllers which automatically control loads in accordance with customer specifications).

Table 4

Some of the Many Factors Which Could Affect the Future Evolution and Carbon Intensity of the Electricity Industry

Economic and Financial Developments

- The state of the economy (boom, bust, levels of debt, levels of unemployment, etc.).
- The way in which financial markets view the industry (i.e., the availability and cost of capital).
- Large changes in the relative cost of fuels, especially natural gas, or in supply reliability (e.g., due to international developments).
- Large changes in the relative cost of new technologies for generation, transmission and end use.

Societal Developments

- Public awareness of the value of electricity.
- Level of concern about "energy independence."
- Level of interest and concern about efficiency and conservation.
- Level of interest and concern about renewables.
- Level of concern about global warming and the costs and benefits of mitigating technologies.
- Production of high quality graduates from universities and trade schools to fill the openings produced by an aging electricity industry workforce.

Legal and Regulatory Developments

- New federal regulations that affect the structure or operation of the industry resulting from actions by FERC or by new federal law such as an energy bill. Issues might include reliability and rules for the structure and operation of markets.
- New state regulations, and state laws, which either advance or retreat from restructuring. An example of the latter is provided by recent changes in California.
- New state or federal regulations, and laws, which facilitate the development of distributed generation, micro-grids and combined heat and power systems.
- National resolution of spent nuclear fuel storage and/or development of a secure international system to manage proliferation risks.
- New federal and state rules on conventional air pollutants such as fine particles and heavy metals.
- New state or federal renewable portfolio standards
- New state or federal regulations governing the emissions of greenhouse gasses.
- New regulations governing the underground injection of carbon dioxide.
- New state or federal rules mandating minimum levels of research investment by participants in the industry (e.g., a Federal "minimum research investment" mandate for all industry players—in house or through DOE).

New Market Entrants

- Oil companies become major players in the industry because of growth in coal gasification and CCS.
- Government becomes a bigger direct player in power production and distribution because of public frustrations with botched restructuring.
- Firms offering distributed co-generation and micro-grid services in an unregulated environment become significant players because of changes in regulations governing interconnection, exclusive service territories, building codes, zoning, etc. and demand for efficiency.
- Energy service companies become larger players, because of new policies that promote greater end use efficiency, or rising costs, which prompt greater customer interest.

Impacts from Climate Change

- Changes in the availability water for power plant cooling.
- Changes in electricity load due to increased air conditioning.
- Increased variability in heating and air conditioning loads.
- Increased frequency of extreme events which lead to larger design loads for transmission systems.
- Impacts of physical plant and fuel delivery from sea-level rise.
- Changes in air quality which impact emissions standards.

Research and Technology

- Changes in the level of government investment in research.
- Changes in the level of private-sector investment in research.
- Changes in the cost and performance of new technologies (IGCC w/CCS, solar photovoltaics, central station fuel cells, high efficiency lighting, high efficiency electric motors, etc.).
- Changes in the energy intensity of the U.S. economy.
- New developments in nano-technology; biotechnology; and communication and information technology.
- Changes in the level and geopolitical make-up of energy-related R&D.

Accidents and Terrorism

- The frequency and extent of large cascading power system failures brought about by either accidental or intentional (e.g., terrorist) causes.
- Political reaction to terrorist activities, not related to the power system, which result in a greater concern with infrastructure vulnerabilities.
- The occurrence of a large accidental or intentional (e.g., terrorist) event involving nuclear power or spent fuel storage facilities.
- Greatly expanded concerns about the management of spent nuclear fuel brought on by heightened concerns about nuclear proliferation.

Catastrophic Developments

- Finally, while no one likes to acknowledge the possibility, major regional catastrophes, such as: a very large earthquake or a Crater Lake size volcanic explosion (e.g., Mount Rainier), or global catastrophes such as a nuclear war, a highly communicable pandemic, or unexpectedly rapid and severe climate change, could profoundly affect all human activities, including the future of the electricity industry.

Efficiency gains achievable through improved technology and system design are described in the Pew Center report *Towards a Climate Friendly Built Environment*.[47] In general, these options clearly reduce total energy use and thus emissions. A review of the literature on the demand effects of peak pricing[48] indicates that if the price of off-peak electricity is fixed, a 10 percent increase in peak price causes a 1.5-3 percent reduction in peak usage, with most of the displaced consumption shifting to off-peak times. Time-of-day rates and load-shifting to off-peak times clearly improve the economic efficiency of the electricity system, but these measures—to the extent they displace load from natural gas-fired peaking plants to coal-fired baseload plants—may not reduce, and might even increase, CO_2 emissions.[49]

In the 1990s, many public utility commissions in the United States adopted significant incentives for utilities to implement demand-side management (DSM) programs. Loughran and Kulick[50] note that "Between 1989 and 1999, U.S. electric utilities spent $14.7 billion on demand-side management (DSM) programs aimed at encouraging their customers to make investments in energy efficiency." Loughran and Kulick studied 324 utilities, finding that DSM expenditures typically reduced electricity consumption by 0.3-0.4 percent at a cost of 14-22 ¢/kWh. When they considered only the 119 utilities with consistent DSM expenditures over the course of several years, they found demand reductions ranging from 0.6-1.2 percent at a cost of 6-12 ¢/kWh. The savings to utilities (avoided costs) of not serving these loads ranged from nothing for a refrigerator running after midnight in April, to 50 ¢/kWh for a refrigerator running at 6 pm in August. In areas facing generation and transmission constraints, demand reductions that avoided the need for system expansions were worth more than they cost; for an area with surplus generation and transmission capacity, demand reductions were worth less than they cost. Given increasing demand for electricity in most regions and given the difficulty and expense of building new generation and transmission capacity, demand reductions in areas such as California are likely to be worth more than 12 ¢/kWh overall. In areas with excess generating capacity, the savings would be worth much less. Finally, DSM programs can lead to attitude changes that further reduce electricity consumption and demand growth.

In a recent report, the California Energy Commission's Demand Response Committee estimated that dynamic pricing (e.g., real-time market pricing or time-of-use pricing) could achieve a

> "short-term peak reduction…between 4.7 and 24 percent of California's estimated peak load by 2013. The residential and small commercial customer share of these estimated peak savings range from roughly 15 to 25 percent with the balance coming from medium to large commercial and industrial customers. The long-term peak reduction is estimated to be 3.4 to 15 percent of the projected 2013 peak load."[51]

During the 1990s, General Public Utilities, American Electric Power, and Gulf Power experimented with residential real-time pricing. In the GPU pilot program, residential summer peak use averaged 2 kW for the control group and 1.5 kW for the participating group. Peak load reductions for the participating group were even larger during "critical price" events.[52] Kempton presents a strong argument for dynamic pricing using residential water heating as an example, noting that: "consumer underestimates of hot-water cost, especially for electric resistance water heaters, suggest that we do not currently even enjoy the conservation effects that market forces would provide."[53] Florida Power & Light uses power line communication[54] to control loads from large appliances, such as air conditioning units, for 712,000 customers. FPL pays participating residential customers a monthly incentive of $3.50; in exchange the utility controls when equipment cycles on and off. FPL attributes 1 GW of peak demand reduction to this load control program alone.[55]

In the early days of electric industry restructuring in the 1990s, a number of energy service companies (ESCOs) offered to advise consumers on energy savings opportunities for a fee. Various ESCO business models continue to be tried, with mixed results. In one promising variant "curtailment service providers," or CSPs, aggregate consumers who are willing, in exchange for payment, to agree to curtail air conditioning or other loads at certain times of day or under certain market conditions.[56]

California achieved significant electricity demand reductions at a time when overall U.S. electricity demand was growing steadily, suggesting that the state's strategies for promoting efficiency should be pursued aggressively nationwide. However, stabilizing atmospheric CO_2 concentration at even twice pre-industrial levels will require emissions reductions of at least 65-85 percent from current levels.[57] Given continued population growth, reductions of this magnitude are unlikely to be achieved by energy conservation and efficiency measures alone.

B. Technologies That Could Change the Carbon Intensity of the Electric Power Industry

Table 5 identifies a number of technologies that may play a role in moving the electric power industry to a low- or no-carbon future. A brief review of the current status and potential of these technologies follows.

Generation Technologies

Coal technologies with carbon capture and sequestration (CCS)[58]

Basic approaches for capturing carbon emissions from fossil fuel electric power generators are illustrated in Figure 11. Post-combustion capture (upper diagram) may have a role as a transition technology, but carbon capture from the exhaust stream of a traditional pulverized coal plant is expensive and requires extra energy because the concentration of CO_2 in the exhaust stream is low. Rubin et al.[59] estimate that with today's technology (i.e., using an amine scrubber on the flue gas), a coal plant with a net output of 500 MW would have to consume 31 percent more coal just to run the CO_2 scrubber. The energy penalty associated with removing CO_2 in this manner is an order of magnitude larger than that associated with conventional pollution control systems such as flue gas desulfurization for reducing SO_2 emissions. As a result, Rubin et al. estimate that the cost of post-combustion carbon capture in a new pulverized coal plant would be about $50 per metric ton of CO_2.[60]

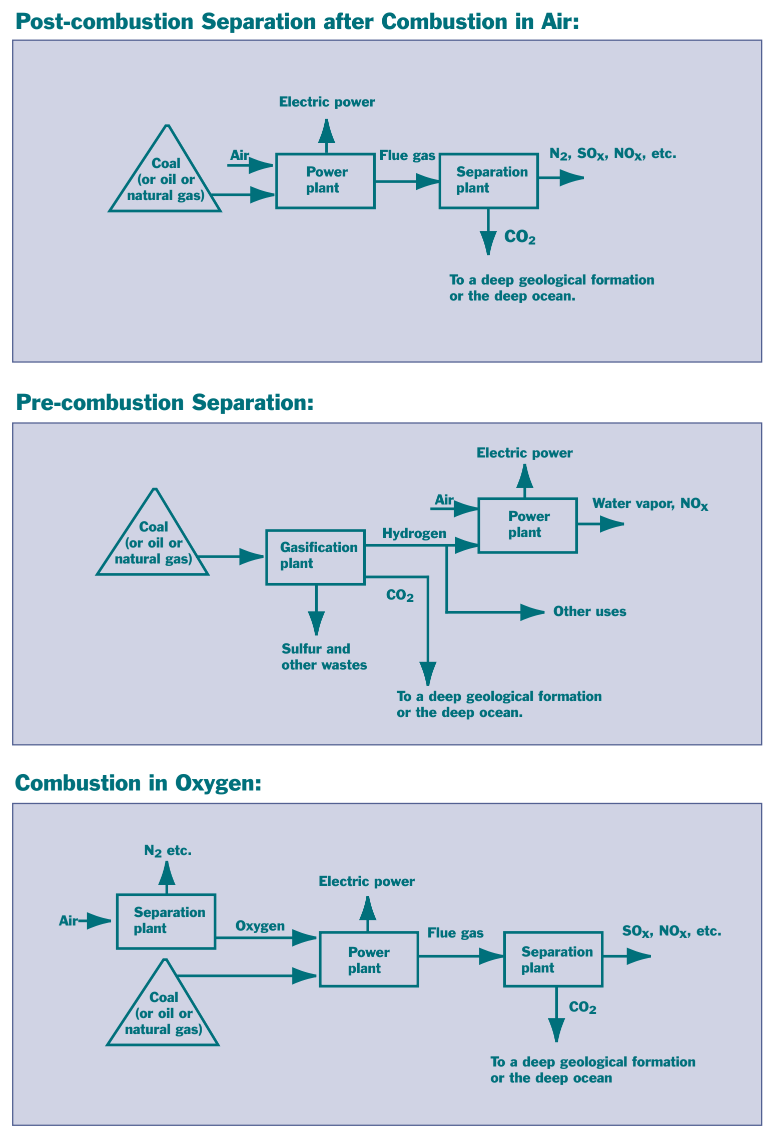
By contrast, carbon capture and sequestration is likely to be far more cost-effective in combination with advanced coal technologies such as integrated gasification combined cycle (IGCC) technology. IGCC allows for the pre-combustion separation of carbon, as illustrated in the center diagram in Figure 11. This approach has the advantage that it produces a concentrated stream of CO_2 and gaseous hydrogen that can be easily separated. The hydrogen then provides a clean, carbon-free fuel for combustion (alternatively, the hydrogen can be used for distributed generation applications or as a fuel for motor vehicles), while the CO_2 is sequestered by injecting it deep underground. Importantly, the gasification process also facilitates the separation and capture of conventional pollutants and impurities, such as sulfur and mercury. Gasification technology exists at commercial scale today (primarily in the chemicals industry), as does the technology for injecting CO_2 underground. At present, however, CO_2 injection systems are confined to enhanced oil and gas recovery operations. Rubin et al.[61] estimate that an IGCC plant could capture CO_2 at a cost of about $30 per metric ton of CO_2 and with an energy penalty of 16 percent, only half as large as that for an amine flue-gas scrubbing system. The extra coal used would produce more carbon and conventional pollution, but the IGCC system would allow for the effective capture of nearly all undesirable emissions. Compared to a pulverized coal plant with state-of-the-art pollution controls, net per kWh SO_2 emissions for a coal IGCC plant are estimated to be 5 percent higher and NO_X emissions are estimated to be 2 percent higher with the technology available today. The emissions penalty may decrease as IGCC plants are developed further.

Estimated costs for capturing CO_2 emissions from a natural gas fired combined cycle (NGCC) plant are higher than those for a coal IGCC plant—about $59 per metric ton of CO_2—while the associated energy penalty is similar (about 17 percent).[62]

Thus, choice of generating technology has significant implications for the cost of carbon capture. The significant advantage of IGCC is that associated carbon capture costs are potentially much lower than for conventional coal and natural gas technologies. Subsequently transporting and storing the captured carbon in a geologic repository would, of course, add further costs that are largely independent of the type of generating technology involved. It appears from preliminary studies that the costs of transport and sequestration will be roughly 10 percent of total carbon capture costs for IGCC plants.[63]

Figure 11

Three Basic Carbon Capture and Sequestration Design Systems



Notes: IGCC (integrated gasification combined cycle) is shown as the center diagram.

Table 5

Summary of New Technologies Which Could Affect the Future Evolution, Including the Carbon Intensity, of the Electricity Industry.

Technology	Climate relevance	Nature of impact	Limitations	Cost today	Available in volume
Advanced coal conversion (IGCC) with carbon capture and sequestration (CCS).	~10% of the CO_2 emissions of regular coal plants.	Could reduce a very large portion of the CO_2 from electric power.	Market learning is needed to bring costs down. Efficacy and regulation of deep geological sequestration not resolved.	5-10¢/kWh	15 yr
Advanced power electronics and transmission technologies.	Modest reductions in CO_2 emissions.	Improved system efficiency and reliability.	Market learning is needed to bring costs down.	NA	5 yr
Biomass	A renewable fuel, thus only net CO_2 emissions are those from farming and collecting.	Could reduce a large portion of the CO_2 from electric power.	Land availability, aesthetics, and costs of farming and collection. Technical limits to percentage that can be co-fired in a coal plant.	3-5¢/kWh	10 yr
Energy efficient end-use devices and advanced load control.	Reduces electricity consumption.	Could reduce CO_2 from electric power generation.	Largely behavioral and institutional.	Often low or negative (i.e. quickly pays for itself or better)	now
High efficiency combined cycle gas turbines.	Lower CO_2 emissions.	Less than half the CO_2 of regular coal plants and much higher conversion efficiency.	Gas price and supply reliability. Still emits some CO_2 and conventional pollutants.	~5¢/kWh	now
Hydrogen used in fuel cells	Once H_2 fuel is available can make electricity with no direct CO_2 emissions.	Could reduce a large portion of the CO_2 from electric power.	Have to get the H_2 fuel from somewhere: IGCC the most likely source. Electrolysis of water is very expensive	20-30¢/kWh	40 yr
Internal combustion engines	Lower CO_2 emissions.	Use natural gas so lower emissions than average central station power. Use of waste heat (CHP) increases end-use efficiency.	Current regulations limit distributed generation and micro-grids in many locations.	~5¢/kWh	now

Note that "Available in volume" is how soon the authors believe that the technology *could* meet more than 5% of U.S. electricity production.

Technology	Climate relevance	Nature of impact	Limitations	Cost today	Available in volume
Micro-turbines	Lower CO_2 emissions.	Use natural gas, thus lower emissions than average central station power. Use of waste heat (CHP) increases end-use efficiency.	Current regulations limit distributed generation and micro-grids in many locations.	~7¢/kWh	15 yr
Nuclear	No direct CO_2 emissions.	Could reduce a very large portion of the CO_2 from electric power.	High cost, public perceptions, safety issues, spent fuel disposal, prolifera-tion risk.	7-10¢/kWh	now
Solar photovoltaic	No direct CO_2 emissions.	Could reduce a high percentage of the CO_2 from electric power when the sun shines.	Currently too expensive. Will require a basic technology break-through to become cost effective. High cost of storage.	20-30¢/kWh plus storage or back-up	25 yr
Wind	No direct CO_2 emi-tions.	Could reduce some fossel-fired power.	Difficult to operate a power system with substantial wind due to intermittency. High cost of storage. Issues of land availability and aesthetics.	~6¢/kWh at good sites plus storage or back-up	10 yr

Notes:

Hydroelectric dams produce electricity without emitting CO_2. However most of the hydro capacity of North America has now been exploited and environmental concerns will likely limit future development and may even lead to a reduction. Because water can be stored, hydro can help deal with the intermittency problems posed by wind and solar.

Because in the authors' view they have the potential to supply only a very modest portion of total electricity needs, technologies such as low-head hydro, geothermal, wave or tidal power, and ocean thermal power systems are not included in this table. Solar thermal power for electricity generation is not included because of high costs.

Motivated both by national security as well as energy concerns, the United States continues to make significant investments in the development of fusion power. In the very long run this may be an important source of carbon-dioxide-free electricity, but it is unlikely to be a significant player in the next 50 years. Similarly space-based energy systems are not listed because they are unlikely to be commercially viable within the next 50 years. If and when either fusion or space-power became viable they would have to overcome significant safety and environmental issues.

Based on actual experience at IGCC demonstration plants, regulatory filings, and available estimates from the research literature, Rosenberg et al.[64] conclude that the capital cost of an IGCC plant will be 16 percent above that of a pulverized coal plant. Rubin et al. estimate that capital costs for an IGCC plant will be 9 percent higher than those of a pulverized coal plant.

An efficient pulverized coal plant emits about 810 metric tons of CO_2 per GWh (more typical coal plants emit 1,000 metric tons per GWh), while a coal IGCC plant with CCS would emit only about 95 metric tons of CO_2 per GWh. With CCS, emissions for an NGCC unit would be even lower, at about 45 metric tons CO_2 per GWh.[65] Although carbon capture costs are much higher per ton for a gas unit than for a coal gasification unit, the cost of electricity for the two may be comparable due to the lower capital cost for constructing a gas-fired unit. On the other hand, supply adequacy and high prices are currently major concerns for the U.S. natural gas market. Since worldwide supplies of natural gas are large, these concerns could be ameliorated in the future if U.S. access to liquefied natural gas (LNG) imports expands substantially. In that case, natural gas could displace an increasing share of coal-fired generation over the next several decades and play a major role in reducing electric sector carbon emissions.

The chemical industry operates over 300 gasification units worldwide and several plants to demonstrate the applicability of this technology for power production are now operating or planned.[66] Significant development goals for coal IGCC technology include increasing the reliability of the units to achieve capacity factors comparable to those of existing pulverized coal units, further reducing SO_2 and NO_X emissions, and standardizing unit designs. With respect to carbon capture and sequestration, substantial research is needed to determine how long CO_2 injected into deep geological formations will remain underground, what kind of risk management strategies and regulatory systems will be needed to support sequestration as an emissions reduction option, and whether the technology can achieve public acceptance.[67] In sum, IGCC technology with CCS is a leading candidate for generating low-carbon electricity at reasonable cost in the future, but carefully monitored sequestration projects at scales larger than have been demonstrated to this point, together with careful attention to attendant legal and regulatory issues[68] and further public education concerning risks and benefits are needed if it is to fulfill its promise.

Nuclear power

Since nuclear power does not involve the combustion of fossil fuel, there are no emissions of CO_2 from nuclear power plants. As illustrated by the case of France, which uses nuclear energy to generate nearly 80 percent of its electricity, expanded reliance on nuclear technology could significantly reduce CO_2 emissions from the U.S. electric power sector. A range of obstacles stand in the way of such an expansion, however, including high costs and siting difficulties associated with constructing new plants and the need to deal with issues of radioactive waste, plant safety, and proliferation risks. The U.S. Nuclear Regulatory Commission recently approved a standardized design for a 1,100-MW reactor that is meant to lower costs and to be less vulnerable to accidents. Nevertheless, plant safety and the disposal of spent fuel remain serious concerns and are the subject of ongoing research and development efforts by the federal government and the nuclear industry.

A recent MIT study[69] explored the feasibility, costs, and potential problems associated with a global growth scenario that by mid-century would see the construction of 1,000 to 1,500 new 1,000-MW nuclear reactors, deployed worldwide. One of the most serious problems identified in the MIT study is preventing the proliferation of nuclear materials for use in weapons. This risk might be reduced dramatically by creating an international system to oversee and manage spent nuclear fuel.[70] Details of an international spent-fuel management system, such as how it would be administered, how it would be paid for, how many storage facilities would be required, as well as the key issue of how waste management rules or agreements would be enforced, would all have to be worked out through international negotiation. The key point would be to make mandatory participation in a well-monitored, common system of international control for spent fuel the norm for all nations that employ nuclear power for civil energy purposes. Implementing such a system may be a prerequisite for expanding the role of nuclear power for electricity generation.

Natural gas combined cycle (NGCC) turbines

Highly efficient NGCC turbines have been the technology of choice for most new electric power plants built in the United States over the past decade. The relatively low capital costs of constructing such plants led to a building boom in the 1990s that effectively doubled the use of natural gas for electricity production (natural gas in 2003 accounted for 17 percent of total U.S. electricity production).[71]

It also, however, resulted in demand growth that has recently helped drive up natural gas prices. Because NGCC technology is quite efficient and because natural gas has the lowest carbon content of all conventional fossil fuels, an NGCC plant typically emits only about half as much CO_2 per kWh of output as a modern coal plant. Thus, a further shift toward natural gas and away from coal as a fuel for electricity production could reduce power sector emissions substantially, and could play an important role in the early stages of carbon mitigation. Several factors would favor such a shift. First, gas turbine technology has become steadily more efficient. It also has low capital costs. Moreover, unlike many coal plants, gas turbines can be started and stopped quickly (ramping up or down in minutes rather than hours). Thus, NGCC plants are well-suited to meet intermediate and peaking loads and to provide back-up for intermittent power sources such as wind. Meanwhile, even more advanced gas technologies that achieve near-zero emissions of conventional pollutants are in the early demonstration plant stage.[72]

Despite these advantages, however, high prices and the prospect of future supply constraints have emerged as potent barriers to a further expansion of natural gas-fired generating capacity in the United States. In fact, the recent tripling of natural gas prices has all but stopped the trend toward constructing new NGCC plants. In the future, U.S. participation in a world market for LNG—which can be shipped overseas in large ocean-going tankers—may help to alleviate domestic supply constraints, but natural gas prices are not likely to return to historic levels and imports will have to increase to accommodate new demand.[73]

Biomass

Because all of the carbon in plant material was originally extracted from the atmosphere during photosynthesis, using biomass as a fuel produces no net carbon emissions provided feedstocks are managed on a sustainable basis. To the extent that fossil fuels are used in the cultivation or transport of biomass feedstocks (e.g., to make fertilizers and pesticides, or by harvest and transport equipment), use of this resource will still produce some "upstream" life-cycle carbon emissions in most cases. These emissions and other upstream environmental impacts vary substantially depending on the type of biomass feedstock used, where it is grown, and how efficiently it is converted for energy purposes.[74] Overall, however, GHG emissions for biomass-generated electricity are usually much lower per kWh than for coal.

At present, biomass is most commonly co-fired with coal in conventional steam boilers. This practice produces modest reductions in emissions of CO_2 and of most conventional air pollutants, which generally fall in proportion to the amount of biomass used. Co-firing with more than about 20 percent biomass is typically not practical in conventional plants, although new or retrofitted plants can be designed to burn all biomass. However, all-biomass plants operate at lower temperatures and therefore achieve lower efficiencies than co-fired plants. In any case, using biomass to displace a significant fraction of the nearly 900 million tons of coal that are used annually to generate electricity in the United States[75] is unlikely to be feasible without significantly increasing land and water requirements and without raising the cost of competing food and feed crops. Some of these impacts can be ameliorated by choosing feedstocks that can be grown on marginal lands with minimal water and energy inputs; by integrating the production of fuel with that of other food, feed, or fiber outputs; and by deploying advanced biomass conversion technologies (such as gasification) that may not only be cleaner and more efficient, but that could potentially be used to generate other useful co-products (such as, for example, liquid fuels suitable for use in the transportation sector). Robinson and co-authors calculate that co-firing with 10% biomass can achieve carbon mitigation at a cost of $8-$27 per metric ton of CO_2.[76] Co-firing can be implemented quickly, without large capital expenditures, and can play a role in the next decade. In sum, biomass use should be encouraged and efforts to develop promising feedstocks and conversion technologies should continue, but for a number of reasons—including multiple competing uses, land and water constraints, and relatively high production costs—biomass is unlikely to play a dominant role in reducing GHG emissions from the electricity sector towards the middle of the century.

Wind power

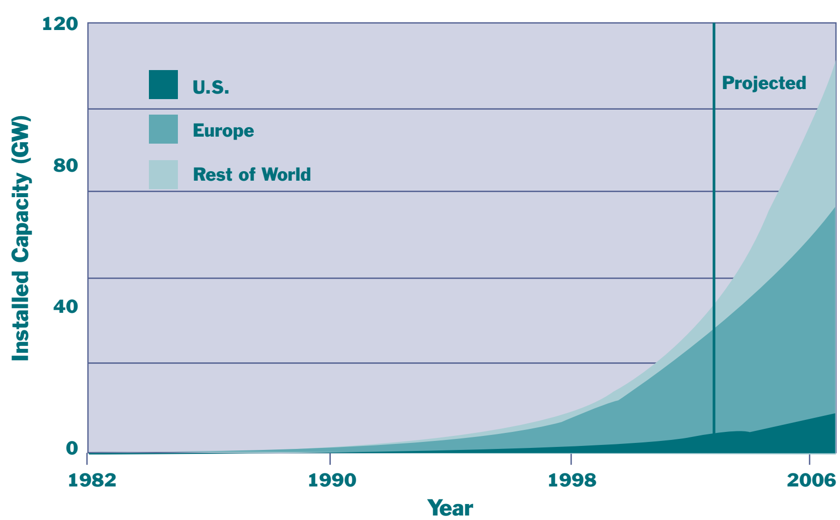
At present, wind power is the most competitive renewable electricity production option, with capital costs far lower than those for solar power and comparable to those of many fossil plants. (At $1,000/kW, the average capital cost of a wind installation compares to $450/kW for a combined-cycle natural gas plant, $1,150/kW for a new pulverized coal plant, $1,400/kW for a coal IGCC plant, and $7,000-$12,000/kW for solar PV.)[77] Like solar power, however, this resource is intermittent—i.e., the wind does not blow at constant speed, or all the time. As such, wind must be paired with expensive storage or back-up power from other sources that can vary their output quickly (such as gas or hydropower facilities) to meet demand. Linking sites in different locations can somewhat reduce, but does not eliminate, the need for back-up generation.[78] In Denmark, for example, 32 percent of overall wind capacity is paired with water power; 2.4 GW of wind capacity is supplemented with local fossil fuel generators; and another 1.6 GW of back-up capacity is provided by Norway and Sweden's ability to transfer electricity from their much larger hydropower systems.[79] The requirement that wind capacity be paired with a back-up power source exists for baseload, intermediate, and peaking applications, since supply must match demand exactly to avoid blackouts or system overloads. An additional concern that has emerged in a number of recent studies is the possibility that very large wind installations could extract a measurable fraction of the kinetic energy present in the lower atmosphere, causing potentially undesirable impacts on local weather and regional climate.[80] Whether such impacts would be large enough to be significant is an open question and further research is required.

Since the introduction of generous tax credits in California in the early 1980s created the first market for utility-scale wind power projects,[81] development of this technology has proceeded at a rapid pace (see Figure 12). Currently, there is just over 39 GW of wind capacity installed worldwide. Most of this growth has occurred in Europe, which added almost 29 GW over the last 20 years.[82] In the United States, wind currently accounts for 0.3 percent of total electricity generation.

At good wind sites, the average cost of power, when the wind is blowing, can range from 5-6 ¢/kWh without credits or subsidies (but also without back-up or storage costs). This is higher by 1-2 ¢/kWh than the cost of power from conventional fossil fuel technologies and is in line with the estimated costs of coal IGCC with carbon capture and

Figure 12

Historical Growth in **Wind Capacity**



Notes: Historical growth in wind capacity over the last two decades, as well as future projections based on analysis by BTM Consult (*World Market Update* 2003: International Wind Energy Development Status, BTM Consult APS [Ringkobing, Denmark]). Note the large growth in Europe over the last ten years.

sequestration. Rapid worldwide growth in wind capacity over recent years has been driven by environmentally motivated taxes, credits, and other regulatory incentives. Substantial further expansions of wind capacity will likely require new transmission infrastructure to access remote areas where some of the best wind resources are located, together with back-up generation or storage capacity to address the intermittent nature of the resource. Specifically, the need for cheap land, low population densities, and strong wind resources would likely dictate that the bulk of wind capacity be located in the remote, windy regions of the Great Plains and possibly off-shore, although recent proposals for off-shore facilities near Long Island and Cape Cod have met with intense local opposition. Managing wind's intermittency—either by finding some inexpensive means of storing electrical energy, by constructing back-up generating capacity, or by adding capacity to the wider transmission grid—also becomes a bigger issue as wind assumes a greater share of overall generation. The intermittency problem can be somewhat reduced (but not eliminated) by distributing wind farms across wider geographical areas (e.g., the Dakotas and Oklahoma), which reduces the correlation in wind patterns.[83]

Taking these factors into consideration, DeCarolis and Keith have estimated[84] that additional transmission and storage or back-up needs would add 1.5 ¢/kWh to the average cost of wind generation if wind power were to grow to the point of supplying a third of overall U.S. electricity demand. On top of wind's existing 1-2 ¢/kWh cost differential compared to conventional fossil technologies, this result suggests that continued incentive programs, renewable portfolio standards, or carbon constraints will be needed if wind is to achieve a substantial penetration of worldwide electricity markets.

Solar photovoltaic (PV) power

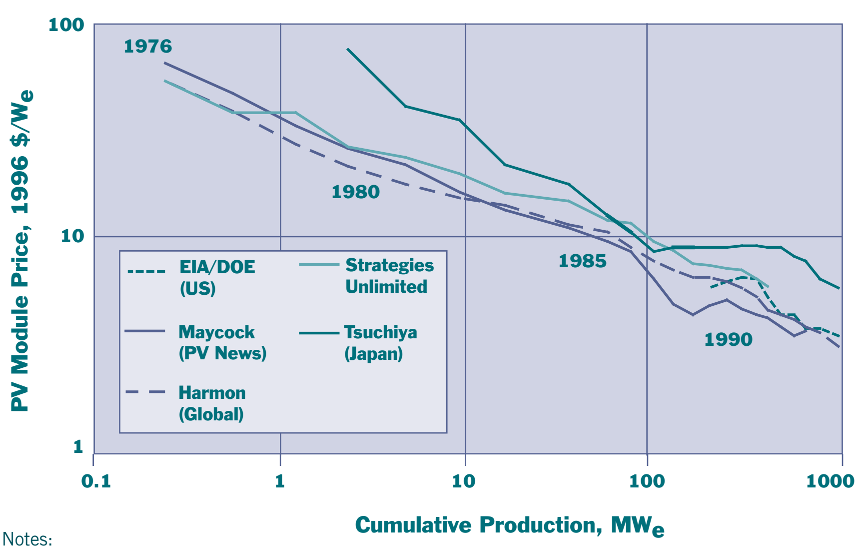
The amount of solar energy that reaches the United States each year is equivalent to roughly 3,900 times the nation's total electric power needs.[85] Thus, the solar energy theoretically available for human use so far exceeds society's energy needs that extracting a small portion of it would be unlikely to cause any significant perturbation in the earth's energy balance. Put another way, if solar cells achieved 10 percent conversion efficiency in transforming sunlight to electricity, they would need to cover only 0.3 percent of the nation's land area (excluding supporting infrastructure) to supply all U.S. electricity needs. (By contrast, farming now takes up approximately 27 percent of the land area of the United States.)

Unfortunately, the electronic materials presently available for converting sunlight into electricity are expensive and inefficient. Because the sun does not shine all the time, the cost for large-scale PV generation is further increased by the need for electricity storage or back-up generation capacity adequate to compensate for the PV power at times when it is unavailable. While PV costs have fallen (Figure 13), current costs still range between $7,000 and $12,000 per kW (including capital costs plus installation, but without electricity storage), significantly higher than typical costs for other generating technologies (e.g., a natural gas plant costs about $450/kW, while current costs for wind power are about $1000/kW). On the basis of a recent industry survey, Rogol, Doi and Wilkinson[86] report that prices for photocells (excluding the balance of system components) have recently risen slightly but will probably remain steady for the next couple of years, and can be expected to fall about 20 percent by 2010.

Subsidies to solar power have been available for some time in hopes that higher PV production volumes would greatly reduce costs, but recent experience has not been encouraging. For example, substantial subsidies in Japan and Germany have led to PV cost reductions, but not of the magnitude that would make solar power competitive.[87] Moreover, further learning and improvements in the PV manufacturing process are unlikely to reduce the capital costs for large-scale solar installations (which are currently six times greater than the capital cost for a new conventional coal plant and 15 times greater than the capital cost for a new

Figure 13

Historical Experience With the Cost of Photovoltaic Modules for the Period 1976-1998



Notes:

Between the mid 1970s and late 1980s there were large investments by government and oil companies: BP $100 million; Amoco $350 million; Mobil $250 million

Modules typically comprise half of solar PV system costs. While the cost has fallen steadily as production volumes have increased, the kWh cost is still more than five times as expensive as conventional sources of power excluding the additional cost of back-up or storage. On the basis of a recent industry survey, Rogol, Doi and Wilkinson report that prices have recently risen slightly, will probably remain steady for the next couple of years, and will drop to about 80% of today's price by 2010.

Figure complied by Robert M. Margolis, Carnegie Mellon, 2002.

natural gas unit) to competitive levels. Fundamental breakthroughs in efficiency and manufacturing processes are required that necessitate further investments in basic research and development. Until costs fall dramatically, PV systems will not be economic except in selected off-grid niche markets.

Hydrogen

In contrast to the other technologies or resources listed in Table 5, hydrogen is an energy carrier not a primary source of energy. Because of its low density and chemical reactivity, hydrogen gas does not accumulate in significant quantities on earth such that it can be extracted, mined, or drilled like a fossil fuel. Rather, hydrogen—like electricity—must be made from some other source of energy such as coal, natural gas, nuclear, wind, or solar power. Hydrogen is present in great quantities in hydrocarbon fuels, such as oil and natural gas, and in water (H_2O)—but energy is required to separate the hydrogen from other constituent elements. At present, hydrogen production from natural gas accounts for about 2 percent of U.S. primary energy use. Most of this hydrogen is used as a feedstock in a variety of chemical processes. Examples include the manufacture of ammonia and the refining of reformulated gasoline.

Most hydrogen is produced today from natural gas (CH_4). Coal gasification provides another ready means of producing hydrogen (Figure 11, center diagram). Thus, if technologies for gasifying coal (and for capturing and sequestering associated CO_2 emissions) become common, hydrogen from coal could be widely used for the production of electricity in combustion turbines. The same IGCC plants could also supply hydrogen for other devices such as fuel cells, although the widespread use of hydrogen as a transportation fuel presents significant additional challenges.[88] In the longer run, electrolysis of water using energy supplied by wind, solar, or nuclear power could also become a major source of hydrogen. For the foreseeable future, however, the costs of these technologies are too high to make electrolysis using nuclear or renewable energy economically competitive with hydrogen made from fossil fuels.

As has already been noted, hydrogen and oxygen can be re-combined to produce electricity in fuel cells. While a few large-scale grid applications for fuel cell technology have been demonstrated, costs would have to decline dramatically for fuel cells to be competitive with other generation options outside of a few niche applications. For a commercially available phosphoric acid fuel cell, installed costs are $5,500/kW (versus about $450/kW for a new simple cycle gas plant). Long-term, projected costs for fuel cell technology are a subject of some dispute. On the pessimistic end, costs are projected to remain as high as $1,000-$1,500 per kW. Optimists, on the other hand, predict that within two decades fuel cell costs will decline to less than $50 per kW, particularly for automobile applications. Estimated maintenance costs for fuel cells are comparable to those for other distributed technologies, such as micro-turbines. These costs are expected to be relatively low based on the assumption that only the fuel supply and the reformer, not the fuel cell itself, will require maintenance during its service life.

Distributed Generation

Distributed generation is a generic term for small-scale electricity production technologies that can be located near the point of end-use. In situations where the electricity user also has thermal energy needs, a type of distributed generation technology known as combined heat and power (CHP or co-generation) can achieve high efficiencies by making use of the waste heat that central station generating plants must throw away. As a result, the overall energy efficiency of such systems may be on the order of 80 percent, compared to the 30-50 percent maximum efficiency of typical central station generating plants. Proximity to the end-user also means that distributed generation systems avoid transmission and distribution losses.[89] Coupled with well designed computer control systems, distributed generation technologies can also have significant reliability benefits, by reducing dependence on large central station units and by relieving congestion on transmission and distribution systems during peak demand hours.[90]

Two leading technologies for small-scale distributed generation are internal combustion engines (ICEs) and micro-turbines. ICEs derived from automotive and truck engines are widely used in Europe to generate electricity on customers' premises, often in combined heat and power configurations. In some parts of the Netherlands, ICEs that operate on natural gas are interconnected with the electric power system and amount to as much as 30 percent of installed capacity. The cost of generating electricity using ICEs ranges widely depending on technology, size, location, and other factors. At $300 to $900 per installed kW, capital costs for this technology compare favorably with those of other distributed technologies.

The overall efficiency gains available when ICEs are run as co-generation units (that is, to produce on-site heat and power) have the potential to reduce total CO_2 emissions when compared to centralized electricity generation plus additional fuel consumption to generate heat in on-site furnaces. In the United

States, however, most existing ICE units are diesel-powered and the technology has historically been characterized by high NO_X and particulate emissions. As a result, the use of ICE units, even for back-up purposes, has often met with opposition from environmental and public health advocates. In the future, the environmental performance of ICE technology could be improved substantially through the use of different fuels and engine types and with further improvement in emission control technologies. As shown in Table 6, such technologies can reduce emissions from both diesel and natural gas engines by a factor of ten.

Micro-turbines, another distributed generation technology, may soon be an attractive alternative to ICEs in small-scale, combined heat and power applications. These small (refrigerator size) devices can generate from 25 kW up to a few hundred kW of electricity at conversion efficiencies in the range of 20-30 percent (micro-turbines tend to be less efficient when operating below capacity). As with ICEs, however, overall system efficiency can be greatly improved—to as much as 80 percent—in combined heat and power applications. At these efficiencies, micro-turbine co-generation systems have the potential to reduce overall CO_2 emissions. Current capital costs for micro-turbines range from $700-$1,100/kW; adding the equipment needed for heat recovery increases capital costs by a further $75-$350/kW.

Table 6

Environmental Performance Characteristics

of Natural Gas and Diesel Internal Combustion Engines

	Natural Gas Exhaust gas, ppmv @15% O_2	**Diesel ICE** Exhaust gas, ppmv @15% O_2
Uncontrolled NOx	45-200	450-1,600
NOx with SCR	4-20	45-160
Uncontrolled CO	140-700	40-140
CO with Oxidation Catalyst	10-70	3-13

Notes: NO_X = oxides of nitrogen; CO = carbon monoxide.

Source: California Energy Commission, "California Distributed Energy Resource Guide." (http://www.energy.ca.gov/dbtgen/). 2004.

Another emerging technology that is closely related to distributed generation is the so-called "micro-grid." The term refers to a cluster of small-scale generators linked together by a low-voltage distribution system that can operate either in concert with, or independent of, the larger grid. Micro-grids can be used to serve medium to large commercial facilities such as office buildings, industrial parks, and even residential neighborhoods if regulatory constraints can be overcome. If used to connect low-carbon distributed generators they can deliver emissions reductions as well as significant system reliability benefits.

In sum, co-generation or combined heat and power and other distributed generation technologies can reduce electric sector GHG emissions by improving overall efficiency; in addition, these technologies also provide other important system benefits. Their contribution will, however, be limited by the number of industrial or commercial sites that lend themselves to combined heat and power applications. As such, distributed technologies are unlikely to replace central station power generation but will almost certainly have a role to play as part of the portfolio of strategies likely to be needed to cost-effectively reduce the carbon intensity of the electric power sector.

Grid Technologies

In addition to more efficient and/or lower-carbon generation technologies, technologies that allow for the improved operation of the power grid can reduce GHG emissions by enhancing overall system efficiency. Improved grid technologies—such as the advanced flow control systems or superconducting materials discussed below—can also play an important role in reducing the costs associated with wind and other renewable generation resources that may be concentrated in remote regions.

Power electronics, for example, are beginning to play an important role in the operation of the high-voltage transmission system and in the operation of some end-use devices. Today, power electronic devices can be used to convert AC to DC and vice-versa. Thus, it has become possible to develop high-capacity, long-distance DC transmission lines that have lower transmission losses, as well as lower cost, because they require only two rather than three wires. It is also possible to use DC "back-to-back" converters to provide isolation and control between two AC power systems. This allows much greater control of power flow between the two systems.

Controlling power flows in an AC system is difficult since current follows the laws of physics, not the laws of economics or the preferences of electricity dispatchers. Advanced power electronics systems called flexible AC transmission systems (FACTS)[91] can address this difficulty by allowing transmission operators to “dial in” the electrical properties they want a power line to have, and to send power where they want it to flow. The result can be greatly enhanced capacity on existing transmission lines, and a few percentage points of improvement in overall system efficiency through the reduction of line losses. The ultimate carrying capacity of many transmission lines is set by their “thermal limit”—the point at which lines get so hot that the wires stretch and sag, touching trees or the ground. Use of FACTS technology would allow more lines to be operated up to their thermal limits, as opposed to having their capacity constrained by electrical properties and by the need to maintain a stability margin.

Superconductors are special materials that, at very low temperatures, display little or no electrical resistance. As such, they can conduct electricity without the large resistive heating losses of more common materials such as copper or aluminum. Recent technology improvements and cost reductions are beginning to make superconductors economically viable in some niche applications. As the technology advances further, the market for superconducting transmission cables and large machines such as generators and motors is likely to grow. This would have important climate implications because superconducting devices could vastly reduce the electricity losses associated with existing transmission and distribution systems (these losses typically average about 10 percent).[92] Superconductors may also play a role in opening the door to cost-effective energy storage for intermittent resources like wind, but it is a bit early to compare costs with other storage options. At present, the energy penalties associated with cooling superconducting wires are large and would imply additional GHG emissions. The additional emissions associated with this cooling penalty have not yet been quantified.

Energy-efficient end-use devices and advanced load controls

It has long been known that significant reductions in electricity use are possible through the use of more efficient end-use appliances such as motors, refrigerators, heat pumps, and lights. The market, however, has often been slow to introduce more efficient technologies and architects, engineers, building designers, and energy managers—not to mention building codes—often fail to keep up with available options. Residential customers frequently fail to implement cost-effective efficiency improvements, either because they appear to demand a very high rate of return for efficiency investments or because equipment and appliance purchasing decisions are made by landlords and builders who have no incentive to minimize future operating costs. By contrast, commercial customers tend to be more responsive to energy saving opportunities, but significant potential for further efficiency improvements exists throughout this sector as well. In this context, some of the most effective approaches to promoting efficiency have involved federal appliance standards and labeling programs. Much more could be done if governments took the issue of improving end-use efficiency more seriously and if utilities had incentives to promote greater end-use efficiency as one means of addressing future system needs.

Control devices that allow the utility to turn off and on some customers' loads, such as water heaters and air conditioning units, can be very helpful in limiting peak electricity demand and improving system reliability. Because these devices largely shift the timing of demand rather than reducing demand, however, their impact on CO_2 emissions depends on the characteristics of peak versus baseload generating capacity in a given system. Other advanced computer-based systems can help consumers manage their electricity use more efficiently, thereby reducing overall (as well as peak) demand and associated CO_2 emissions. Finally, power electronics—which were mentioned previously in the context of grid improvements—are also playing an increasingly important role in improving the performance of end-use devices and appliances, such as dimmer switches for lights and speed controllers on appliances. From a climate perspective, probably the most important applications of power electronics are those that allow electric motors (the single most important end-use technology in terms of overall electricity consumption) to operate more efficiently, thus reducing electricity demand.

C. The Important but Neglected Role of Research[93]

Given the critical challenges that lie ahead for the electric power industry with respect to restructuring, reliability, security, and climate change, new technologies are urgently required. New technologies, however, do not just appear when needed. Rather, the process of creating new knowledge and of moving technologies from the laboratory to commercial viability is long and often difficult.[94] Where basic technical knowledge already exists, market forces can often produce commercial solutions as the need arises. Markets are notoriously bad, however, at investing in the basic research needed to develop future generations of advanced technology.

Researchers at the Pacific Northwest National Laboratory[95] have performed cross-national studies of energy R&D, looking at both corporate and public investment. They conclude that:

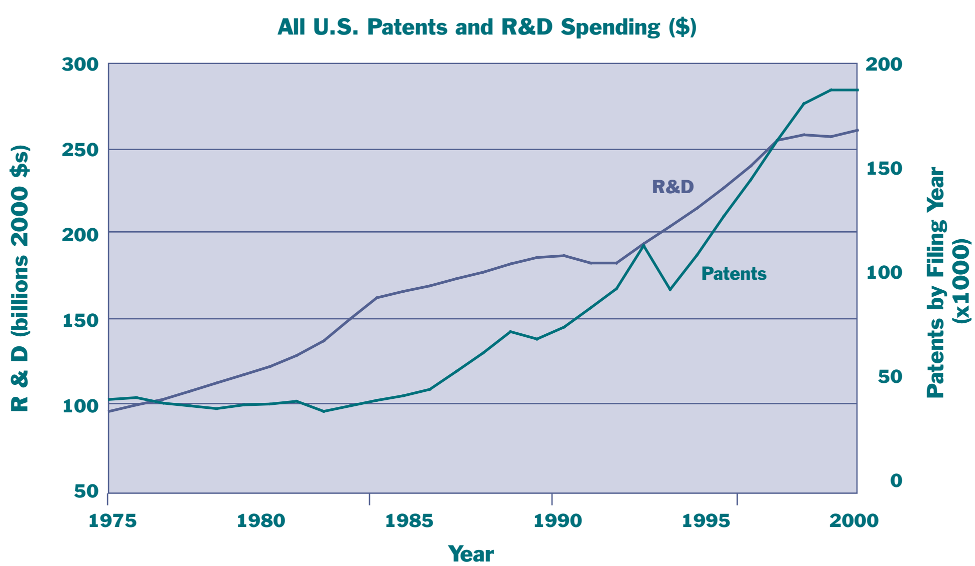
> "A small group of advanced industrialized countries has been responsible for about 95 percent of the world's energy R&D investments. The energy R&D enterprises of these countries embody, to a large extent, the capability for future technological changes in the world's energy systems. Recently each of these countries reduced its public and private sector investments in energy R&D—in some cases by more than 70 percent. Given fewer resources, firms and governments find themselves compelled increasingly to make difficult tradeoffs between technology areas and between long- and short-term research projects."[96]

In the United States, federal and state investments in energy R&D are not only low relative to the energy sector's economic, environmental, and national security importance, but are often directed at short-term or applied projects—and will likely remain so in the near future.[97] This is especially problematic as analysis shows that patenting activity, one commonly used measure of innovation, tends—sometimes with a lag of a few years—to track public R&D investments over time. Nemet and Kammen have plotted R&D investments by the U.S. government and patents issued for new technologies over the last 30 years, both generally (Figure 14) and for fossil fuel and renewable energy technologies specifically

Figure 14

Total **U.S. Government R&D Support and Patenting Activity**

From 1975 to 2003 (in 2000 dollars)

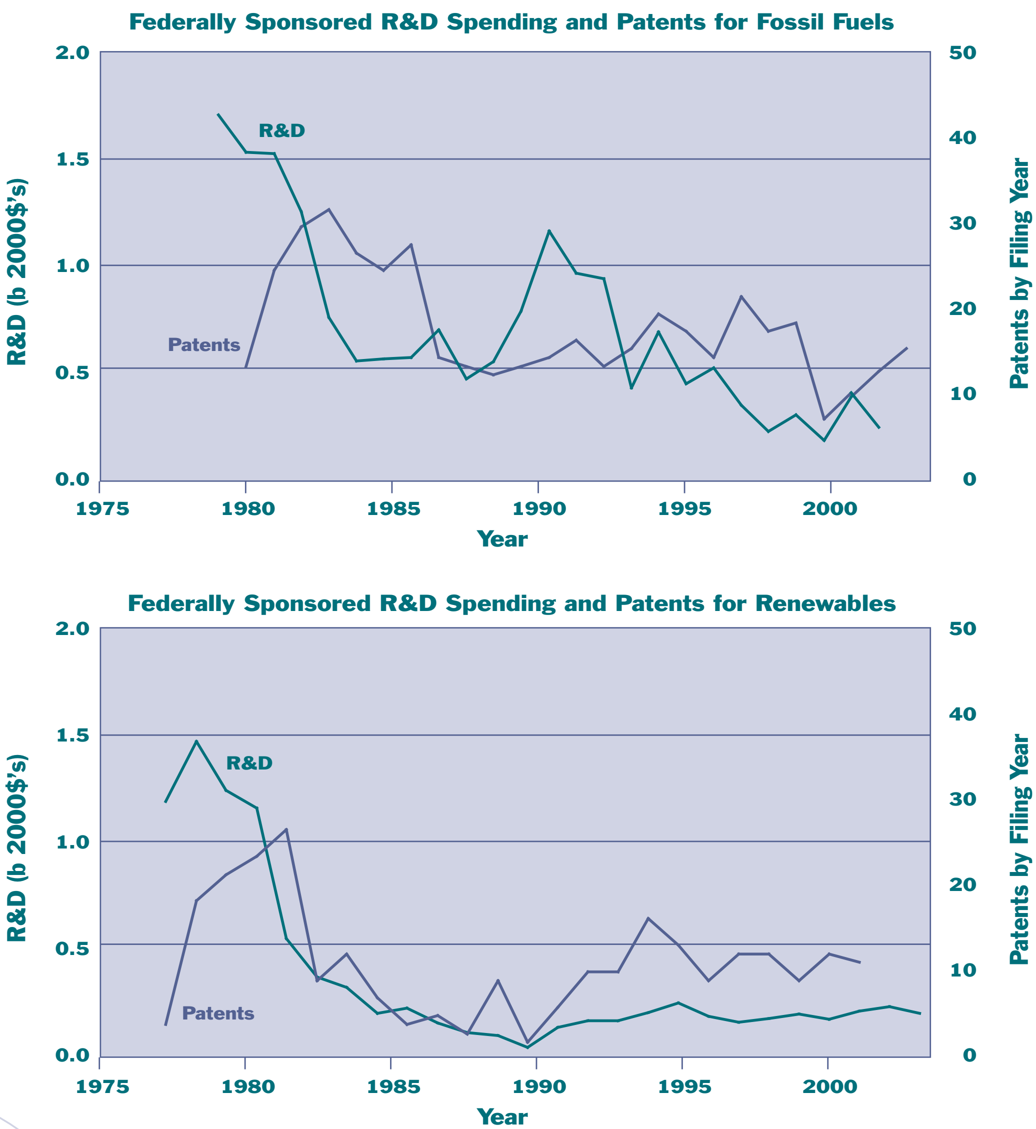


Source: Daniel M. Kammen and Gregory F. Nemet. Forthcoming. "The Effectiveness of Energy Research and Development," *Innovations*, 1(1).

(Figure 15).[98] The figures show that, with the exception of a small increase for fossil energy in the past few years, federal energy investments have been flat for a decade, while funding for both fossil and renewable technologies has declined significantly from the historic highs of the late 1970s. Figure 16 shows overall DOE support for energy research, development, and demonstration (RD&D).

Figure 15

R&D Support and Patenting Activity for Fossil Fuels and Renewables by the U.S. Government from 1975 to 2003 (in 2000 dollars)



Note that with the exception of a small increase for fossil energy in the past few years, both have been flat for a decade, and both have decreased significantly from their historical highs.

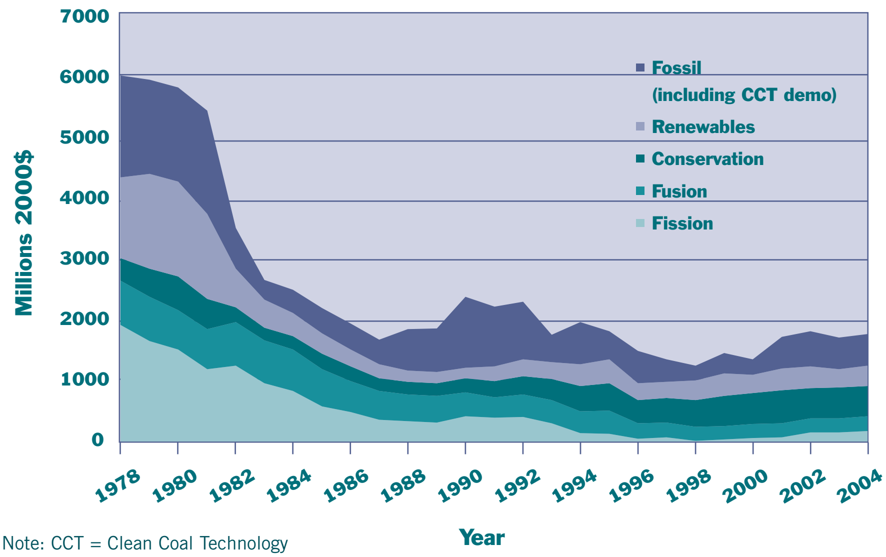
Source: Daniel M. Kammen and Gregory F. Nemet. Forthcoming. "The Effectiveness of Energy Research and Development," *Innovations*, 1(1).

Federal RD&D programs have often tended to focus on large demonstration projects rather than basic technology research. This is problematic when the technologies being promoted are relatively immature and when it is not yet known whether the commercial prospects for a given technology are sufficiently promising that it is likely to be able to play a significant role. Subsidized early deployment can be useful, once a technology has reached the point where dramatic cost reductions can be achieved through further learning and economies of scale. When, however, a basic technological breakthrough is needed before costs can begin to approach competitiveness—as in the case of currently available solar PV technology—increasing funding for early deployment yields relatively little benefit. As has already been noted, large PV subsidies in Japan and Germany (the German subsidy totals 58 ¢/kWh) have elicited more than 1,000 MW of installed PV capacity but have not driven PV prices down enough to make this technology economic compared to other alternatives. If costs for solar systems continue declining at the present rate, this technology will become competitive (in terms of capital costs) with current wind technology only after 40 years.[99] In cases like this, public funds should be directed to basic research that can produce the fundamental breakthroughs needed to make a technology potentially competitive in the future.[100] By contrast, sometimes the policies that promote the deployment of immature technologies can actually impede further public or private investment in the kind of research that would be more likely to produce needed breakthroughs.

Figure 16

U.S. DOE RD&D Expenditures

by Sector From 1978 to 2004 (in Millions of 2000 Dollars)



Note: CCT = Clean Coal Technology

Source: Gallagher, K.S., Sagar, A., Segal, D., de Sa, P., and J.P. Holdren, "DOE Budget Authority for Energy Research, Development, & Demonstration," John F. Kennedy School of Government, Harvard University, 2004.

In sum, current investments in basic energy-related technology research are far too modest. Moreover, "spillovers" from R&D investment in other sectors of the U.S. economy are unlikely to compensate for the shortfall. While spillover effects from basic research originally undertaken for national defense or other purposes have produced substantial benefits for some industries, spillover benefits to the electric power industry from other sectors have—with some notable exceptions—typically been more limited.[101] Absent policy intervention, public and private sector energy R&D investments are likely to continue to fall far short of what is needed to develop the technologies that would make the transition to an affordable, reliable, and largely carbon-free electricity system feasible over the next 50 years. A recent Pew Center report, *Induced Technological Change and Climate Policy*,[102] provides further discussion of the emissions reduction and other benefits that are likely to flow from technological innovation in response to future climate policies. Section V, below, discusses how such policies might begin to take shape.

Section Summary

To enhance and expand the options currently available for reducing electric sector GHG emissions requires substantial RD&D. Investments are needed to further explore carbon sequestration, to advance coal gasification beyond the demonstration phase, to continue reducing costs and improving the performance of wind technology, and to support the basic research needed to achieve fundamental breakthroughs in solar PV, energy storage, and transmission technologies.

A major unknown in anticipating how climate concerns might affect the future evolution of the electric power industry, given the difficulties that currently confront many carbon-free generating options, is whether coal IGCC with carbon capture and sequestration proves economically feasible and socially acceptable. Immediate, instrumented test programs at scale are required, as is development to increase the reliability and improve the environmental performance of IGCC technology. Available cost estimates suggest that if capturing and sequestering carbon proves technically feasible and acceptable to the public, a low-carbon future for electricity generation is likely to be achievable using coal IGCC and natural gas technologies at a cost ranging from 2 to 4 ¢ per kWh above today's electricity production costs. After advanced fossil technologies with carbon capture and sequestration, wind and perhaps nuclear power are likely to represent the next most competitive options for supplying substantial quantities of carbon-free energy. The remaining options are likely to be much more expensive. These include replacing coal with natural gas for the short term (and accepting the impacts of higher gas prices—not only for electricity generation but also for industrial, home heating, and other uses—that are likely to result from increased demand). Under any scenario, there is a major role for cost-effective investments in energy conservation and improved efficiency.

IV. Exploring Possible Futures for the Electric Power Industry

A. Extrapolations and their Limitations

What will the U.S. electricity industry look like 10 and 50 years from now?

Given the enormous capital investment that the current system of generation plants and transmission lines represents, the industry's physical infrastructure is likely to continue to look much the same as it does today. Nevertheless, signs of important change are likely to be visible even within a decade, and certainly by mid-century. Some of the factors that could induce such changes are listed in Table 4. Among the most important would be the implementation of a clear regulatory timetable for limiting CO_2 emissions.

The uncertainty inherent in making predictions on time scales of 50 years or more is best demonstrated by looking back and imagining the difficulty that people in 1900 would have had in making predictions about the world in 1950, or that people in 1950 would have had in making predictions for 2005. Figure 17 lists some of the key developments that have dramatically shaped the subsequent evolution of the energy system and the role of

Figure 17

Developments **Relevant for Predictions**

1900

1903 Wright brothers' first powered flight
1905 Einstein introduces special relativity
1907 first filling station; first vacuum tube
1922 balloon tires for autos
1925 first diesel electric locomotive
1935 Hoover Dam completed
1937 fluorescent lamp
1939 first turbo jet flight
1942 Fermi produces controlled chain reaction
1952 first jet airliner

1950

1953 Watson-Crick model of DNA, First 220 MW steam turbine
1970 first 747
1971 first processor on a chip (Intel 4004).
1975 ARPANET grows to 100 nodes
1981 IBM PC and DOS
1999 first U.S. high temperature superconducting power cable

2000

And two interesting predictions made during this period:

1943 ***I think there is a world market for maybe five computers.***
—T.J. Watson, President of IBM

1967 ***Packet switching wouldn't work.***
—BellLabs Engineers

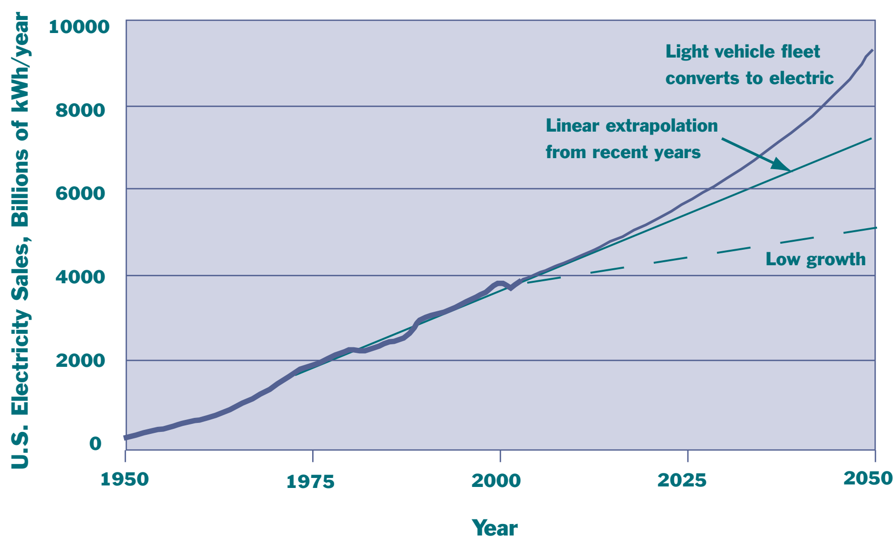
Note: This figure lists some of the developments over the past century that would have been relevant to making predictions about the energy industry and electricity's role in it, 50 years in the future. Most of these developments would have been difficult or impossible for people to anticipate several decades in advance.

electricity in today's modern, industrialized economy. Most of these developments would have been difficult or impossible to anticipate several decades in advance. For example, the development of balloon tires for automobiles in 1922 contributed to the demise of once-ubiquitous electric trolleys. The development of jet engines for aircraft in 1939 ultimately led to today's gas turbine generating plants. The invention of the first micro-processor chip in 1971 led to the computer and Internet revolution.

Several predictions can, of course, be safely ventured about the electric power industry 50 years from now. Electricity will still be used in great quantities. If the historic growth shown in Figure 3 is extrapolated linearly, the result is an increase in annual U.S. electricity demand from approximately 4,000 billion kWh today to roughly 7,000 billion kWh/year by mid-century, or an increase of approximately 75 percent over current levels (Figure 18). In light of the discussion above, it is not possible to draw reliable conclusions from simple extrapolations of this type. Nevertheless, it is probably safe to assume that U.S. electricity demand in 2050 will total at least 5,000 billion kWh/yr, since it would take dramatic technical and structural changes to result in anything less. On the other hand, future developments could also cause future electricity demand to grow much faster than current expectations. One example would be if electricity emerges as a major source of energy for the motor vehicle fleet.[103] Future, "plug-in" hybrid electric vehicles could use batteries to store grid-supplied electricity for the vast majority of trips and rely on a liquid fuel such as cellulosic ethanol[104] for longer trips.[105] Under certain carbon policy and fuel price scenarios, such vehicles could come to dominate the motor vehicle fleet, particularly if technologies for cost-effectively generating large quantities of low- or no-carbon electricity become available. While it is currently far too expensive to be attractive, the emergence of hydrogen as an

Figure 18

Simple Extrapolation of Electricity Demand Growth Over the Past 50 Years for the Next 50 Years

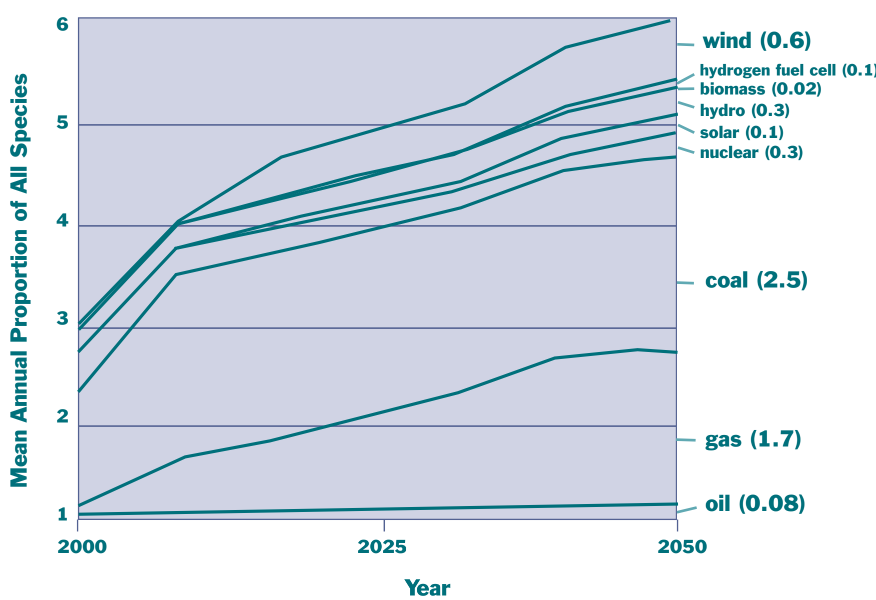


important vehicle fuel represents another possible development that could greatly increase demand for electricity—in this case, to produce hydrogen from water through electrolysis.[106] Because the efficiency of hydrogen fuel cells in vehicle applications would probably be comparable to that of battery systems, the implications for electricity demand are similar to those associated with increased market penetration of plug-in hybrid electric vehicles. Either scenario could lead to load growth of as much as 2,000 billion kWh/year by 2050 above the linear extrapolation depicted in Figure 18.[107] If, for some set of reasons that are not now foreseeable, future electricity demand were to exhibit the exponential growth seen between 1950 and 1970, overall U.S. demand by 2050 could even exceed 9,000 billion kWh/year.

From a climate perspective, a key question is what fuels will be used to generate electricity in the future. Figure 19 shows forecast results from a technical and economic modeling exercise conducted by researchers at Pacific Northwest National Laboratory using the Mini Climate Change Assessment Model (MiniCAM).[108] Clearly, the results of such a modeling exercise are critically dependent on input assumptions, particularly for projections beyond the first couple of decades. Moreover, predictions about what will happen in 50 years are almost certain to be inaccurate, especially when so many complex and different factors will affect outcomes over this timeframe. Nevertheless, modeling and other analyses can provide insights as to what the future might hold if current trends continue or, alternatively, if various policy interventions are introduced.

Figure 19

Projection of Fuel Mix for U.S. Electricity Generation (billions of kWh per year) Produced by the PNNL MiniCam Model Using Base Case Assumptions



Note: Values in brackets are estimates for the year 2050 in billions of kWh/year.

Source: Figure is redrawn from data supplied to the authors by Jae Edmonds of the Pacific Northwest National Laboratory.

Past efforts to model the likely evolution of the energy system several decades into the future often produce results that look like a spreading fan, with growing contributions from a range of different generation technologies (gas, coal, nuclear, and renewables). This perhaps explains, at least in part, why environmental advocates and policy-makers often assume that a broad portfolio of low-carbon technologies is likely to be needed to achieve and sustain substantial emissions reductions in the future. This assumption may prove to be correct. It is worth noting, however, that the historical evolution of the energy supply system in the United States has not been characterized by simultaneous and steady growth in the market share of multiple fuels and technologies.[109] Instead, one fuel-technology combination tends to dominate an era and then is replaced by another fuel-technology combination. In short, free markets do not necessarily assure a diversity of winners.

Public policies, such as regulations to limit carbon emissions, could have very significant impacts on the future of the electricity system. Even with relatively aggressive policies, however, the long-term evolution of the system can display strong path dependencies. As discussed below, for example, whether the energy system continues as a network of centralized power stations that distribute electricity over a super grid, or evolves toward a future that also incorporates many small, distributed, combined heat and power generators that use piped-in gaseous fuel, could well depend upon whether stringent carbon constraints precede or follow further natural gas price increases.

The potential for social and economic non-linearities that can cause successive, single technologies to assume dominant roles; the potential for seemingly unrelated developments to profoundly shape the basic structure of the energy system; and the likely path dependencies that will strongly influence the future evolution of the system are just three of many factors that make long-range energy forecasting notoriously inaccurate. When designed and constructed appropriately, however, models can be a powerful tool for identifying and exploring the factors that could give rise to a range of quite different futures, and for examining the robustness of alternative policy proposals across a range of possible scenarios—even if it is difficult or impossible to assess the probability that any particular scenario will come to pass. Thus it is important for political leaders and the public to understand the limitations of long-term predictions, while also recognizing the value of models for exploring different scenarios and informing policy decisions.

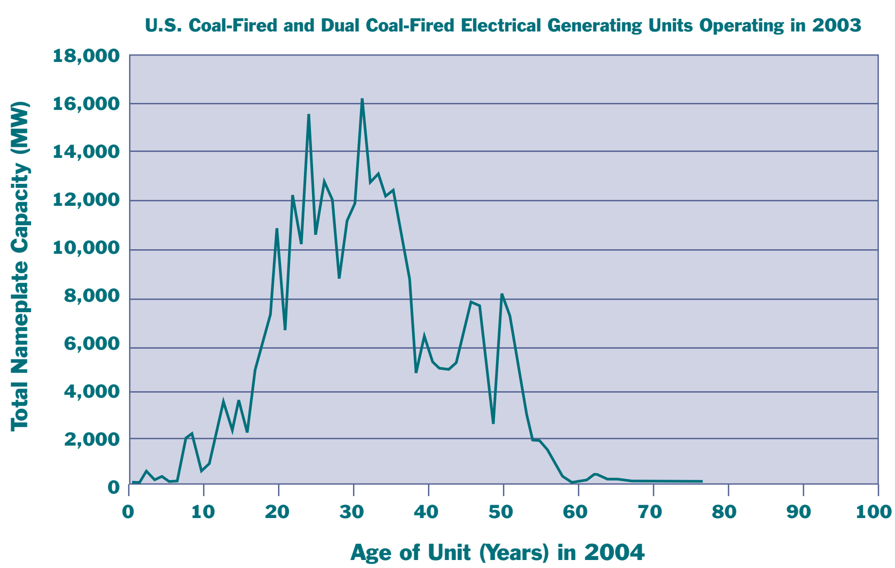
Technological uncertainty can be an argument for delaying policy responses in cases where a problem is not urgent. However, given the substantial inertia of the earth-climate system (in the sense that CO_2, once emitted, stays in the atmosphere for roughly a century) and the difficulty of transforming electric industry infrastructure over anything less than a multi-decade timeframe, uncertainty should not be used to justify inaction in the climate context—especially given the substantial downside risks to a wait-and-see approach.

B. The Next 10 Years

Because the electricity industry is built around costly long-lived capital investments, the physical infrastructure that generates and distributes most of the electricity in the United States will almost certainly be much the same in 10 years as the infrastructure that does this today. Public opposition to new transmission lines tends to freeze reliance on existing routes and corridors, which means that it is often easier to upgrade the capacity of existing transmission corridors than it is to locate a new line.[110] Baseload generation units are designed to last 30 years or more. Plant operators have succeeded in extending the useful life of many existing plants by simply replacing components. As shown in Figure 20, the current fleet of U.S. coal plants is now aging and many components (boilers, turbines) will have to be overhauled or replaced entirely in the next 10 to 20 years.

Figure 20

Aging U.S. Coal-fired Generating Plants



Note: This figure includes "dual-fired" plants which can burn coal or another fossil fuel.

Source: Energy Information Administration, "Existing Electric Generation Units in the United States, 2003", http://www.eia.doe.gov/cneaf/electricity/page/capacity/newunits2003.xls

While the structure of the electricity system cannot be expected to change dramatically in a decade's time, decisions made on this time scale can nevertheless be extremely important. New conventional coal plants built in the next decade, for example, would commit us to many decades of carbon emissions. Technology developments and policy changes introduced over the next 10 years can have profound long-term implications for the electric power system, for its emissions, and for its contribution to global climate change risks. For example, as has already been noted, several U.S. states have already begun to implement policies aimed at reducing carbon emissions.

The long-term nature of the climate challenge can be illustrated with a simple order-of-magnitude calculation. In the decade from 1993 to 2002, the United States added 150 GW of new generating capacity. In the two preceding decades—that is, from 1973 to 1982 and from 1983 to 1992—the industry added 207 and 262 GW of capacity, respectively.[111] Suppose that as much as 250 GW of new carbon-free generating capacity can be added over the next decade. Very approximately,[112] half of this new capacity would be needed just to meet projected demand growth over the next decade, leaving 125 GW of new capacity to replace existing coal-fired power plants.

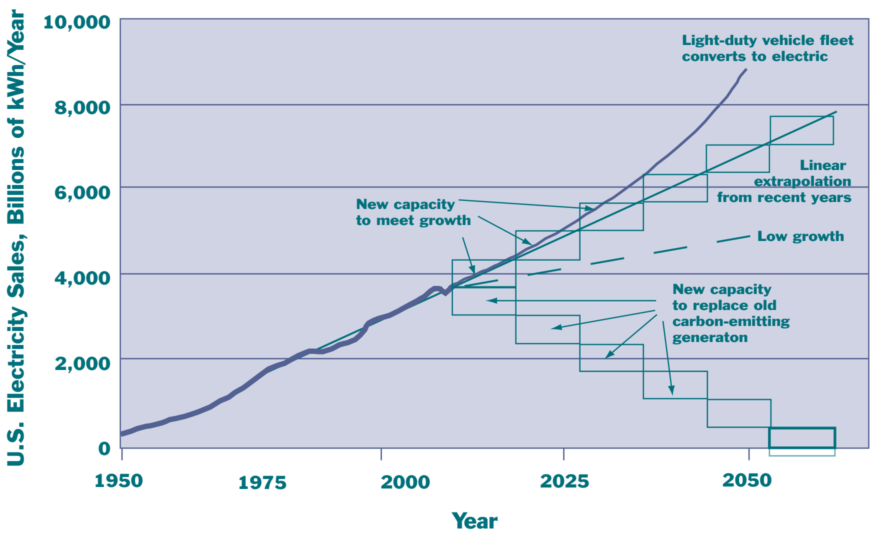
By the end of the decade, the 125 GW of new carbon-free capacity used to displace existing coal plants would be producing about 666 billion kWh per year, an amount equal to about 18 percent of current U.S. generation or about 35 percent of coal-based generation. Today's coal plants produce approximately 1,000 metric tons of CO_2 per GWh (Table 2). Thus the reduction in emissions would be 660 million metric tons of CO_2 per year, or roughly 11 percent of the 5.8 billion metric tons of CO_2 that are currently emitted on an annual basis by all U.S. sources.

Of course, most future generating options—even those that achieve substantially reduced emissions—are not likely to be wholly carbon-free. Suppose instead that 250 GW of new IGCC capacity with carbon capture and sequestration are added over the next decade. Assuming these plants emit about 100 metric tons of CO_2 per GWh (Table 2), the emissions reductions achieved under the same scenario would total roughly 590 million metric tons of CO_2 per year, or about 10 percent of current U.S. emissions. Finally, if the new capacity were all combined cycle natural gas, which emits about 500 metric tons of CO_2 per GWh (Table 3), associated CO_2 reductions would total about 330 million metric tons per year, or about 6 percent of current emissions.

Adding 250 GW of low-carbon capacity in a decade would be a substantial achievement, yet the impact on overall U.S. emissions would be relatively modest, at least initially. If, however, this rate of generation stock turnover were to continue—in other words, if 125 GW of old coal-based capacity were replaced every decade by low-carbon technology such as IGCC with carbon capture and sequestration capacity—CO_2 emissions from the electric power system would be nearly eliminated over the course of 50 years (this result is shown graphically in Figure 21). Associated costs could, of course, also be significant given that building new low-carbon capacity would almost certainly be more expensive than continuing to operate existing coal plants, which now account for more than half of U.S. electricity generation. As was noted in the previous section, available estimates suggest that implementing commercial-scale coal IGCC with carbon capture and sequestration would increase electricity costs by approximately 2 to 4 ¢/kWh (this increment represents about a third of current average retail electricity prices for residential customers). Because new technologies tend to become less expensive in the later stages of development and deployment, this range may represent an upper bound. On the other hand, costs have not always declined over time for other generating technologies (examples of technologies that have not exhibited a marked learning curve with associated cost reductions include large pulverized coal and nuclear units) and considerable uncertainties still surround the likely cost of carbon capture and sequestration.

Figure 21

Illustration of a **Gradual DeCarbonization in 50 years** of the Electric Sector



Notes: This figure is a graphical illustration of the order-of-magnitude argument that by adding 250 GW of new carbon-free capacity every decade, about half of which goes to new load growth, and half of which goes to replace old carbon emitting plants, the electricity system could be made entirely free of carbon emissions in just a few decades. However, because much of the existing fleet of generators is now aging, under business-as-usual, old plants near the end of their useful lifetimes, that can now be economically replaced, will be replaced with new long lived carbon-emitting plants. This would make the cost of conversion much higher in a few decades.

The very rough, order-of-magnitude calculations described above do not represent likely scenarios or projections for the U.S. electric power industry. Rather, they are merely intended to illustrate three more general points:

1. The first steps in managing CO_2 emissions from the electricity industry are likely to have only a modest impact on total U.S. emissions, at least initially.

2. Nevertheless, setting out to reduce emissions in a steady and deliberate way could eliminate most of the carbon emissions from electricity generation in just a few decades.

3. The dollar cost of reducing electric sector carbon emissions in this manner would not be trivial, but is likely to be far lower in the long run than building pulverized coal plants that comply with current standards for SO_2, NO_X, particulate, mercury, and other toxic emissions, and later retrofitting these plants for carbon control. If, as many experts and utility executives now believe, carbon limits will be implemented in the next 10 to 20 years, it is likely to be more prudent to build IGCC plants and plan to add carbon capture and sequestration later, than to make large new investments in long-lived pulverized coal plants that might need to be scrapped or retrofitted with costly, inefficient CO_2 scrubbers under a future carbon management regime.

C. The Next 50 Years

Earlier sections of this report have explored some of the factors that limit one's ability to make robust predictions about the future of the electricity industry decades from now. Nevertheless, it is possible to set some bounds on what the future might look like and to explore how different policies might affect those bounds.

Consider first the case of the 50-year linear extrapolation described in the foregoing section (center curve in Figure 18). If one assumes first, that emissions from all existing power plants could be reduced to the rates typical of state-of-the-art conventional coal and gas generating technologies and second, that future demand growth is met using the same mix of fuels that is now used to produce electricity in the United States, CO_2 emissions from the nation's power sector would be expected to increase 85 percent over current levels to about 4.2 gigatons (Gt) per year. In fact, however, it is more likely—at least absent further policy intervention—that no new large hydroelectric facilities or nuclear units will be built, in which case meeting all future demand growth with conventional coal and gas technologies would cause emissions to grow by 130 percent to 5.2 Gt/year. Even if all of the coal plants in the current generation mix were replaced by natural gas (an unlikely scenario, given current constraints on gas supply), overall CO_2 emissions would still be expected to increase by 5 percent over current levels, to approximately 2.4 Gt per year. If, on the other hand, the ratio of coal to natural gas did not change, but all existing coal plants were replaced by IGCC technology with carbon capture and sequestration, total emissions of CO_2 would decline by 60 percent to about 0.9 Gt per year. If, in addition, all carbon emissions from natural gas plants were also captured and sequestered, overall emissions would drop further, to 0.4 Gt per year or 80 percent below current levels. This is roughly the magnitude of the electric sector's share of the long-term emissions reduction that scientists estimate will be required to stabilize CO_2 concentrations in the atmosphere at twice pre-industrial levels.

Wind power is another potentially attractive option for reducing future carbon emissions from the electric power industry. Since the power output from wind generators varies with wind speed, however, and since there are only limited options for storing electricity once it has been generated, back-up capacity is likely to be needed if wind power assumes a significant share of the overall generation mix. Both natural gas and hydropower can be suitable for backing up wind generation. If all new capacity requirements were met with a combination of one-third wind and two-thirds new gas facilities, annual CO_2 emissions would increase by approximately 25 percent to 2.9 Gt. If, at the same time, all coal plants were also converted to IGCC with carbon capture and sequestration, annual emissions would decline by 50 percent to 1.1 Gt.

Finally, if existing fossil plants are unchanged and half of all new demand is met by new nuclear facilities, while the other half of new demand is met by a combination of new wind and gas generation, projected emissions increase by 10 percent to 2.5 Gt. Thus, over the long run, only those scenarios in which low-carbon options (including carbon capture and sequestration) not only supply new demand, but also replace existing fossil plants, produce emissions reductions of the magnitude required to stabilize atmospheric CO_2 at twice pre-industrial levels.

These results are summarized in Table 7. The table also displays the results obtained when similar assumptions concerning the future generating mix are combined with the high and low electricity demand growth projections shown in Figure 18. Since the high-growth scenario assumes that electricity will eventually be used, directly or indirectly (via hydrogen), to power the light-duty vehicle fleet, the results for this scenario show a 1.2 Gt offset due to reduced CO_2 emissions from vehicles.

The numbers in Table 7 span an enormous range, from more than a doubling of electric sector carbon emissions to a substantial reduction in emissions. This wide range illustrates the critical role of new technologies—and the importance of economic factors, policy drivers, and research investments that affect whether and how new technologies emerge—in determining the future evolution of the industry. It also underscores the difficulty of making meaningful predictions 50 years into the future.

Table 7

Estimated CO_2 Emissions for the Three Projections of Electricity Production Shown in Figure 18

	High Projection (9-million GWh/y)	High Projection w/1.2 Gt auto offset	Linear Extrapolation (7-million GWh/y)	Low Projection (5-million GWh/y)
Same mix as today	5.4 Gt or +135%	4.2 Gt or +85%	4.2 Gt or +85%	3.0 Gt or +30%
No new hydro or nuclear; new demand met by coal and gas in same mix as today	7.0 Gt or +205%	5.8 Gt or +155%	5.2 Gt or +130%	3.5 Gt or +55%
All coal converts to gas	3.0 Gt or +35%	1.8 Gt or –20%	2.4 Gt or +5%	1.7 Gt or –25%
All coal converts to IGCC w/ CCS	1.2 Gt or –50%	~ 0 or –100%	0.9 Gt or –60%	0.65 Gt or –70%
All coal converts to IGCC w/ CCS and all gas to CCS	0.5 Gt or –75%	~ 0 or –100%	0.4 Gt or –80%	0.3 Gt or –85%
All new demand met by wind and gas	3.4 Gt or +50%	2.2 Gt or – 30%	2.9 Gt or +25%	2.4 Gt or +5%
All new demand met by wind and gas, and existing coal converts to IGCC w/CCS	1.6 Gt or –30%	0.4 Gt or – 80%	1.1 Gt or –50%	0.6 Gt or –70%
All new demand met by wind and gas w/CCS, existing coal converts to IGCC w/CCS, gas to CCS	0.3 Gt or – 85%	~ 0 or –100%	0.3 Gt or – 85%	0.2 Gt or – 90%
All new demand met by wind / gas and nuclear	2.7 Gt or +20%	1.5 Gt or –35%	2.5 Gt or +10%	2.2 Gt or +0%

Note: Values are rounded to two significant figures and percentages are rounded to the nearest 5%.

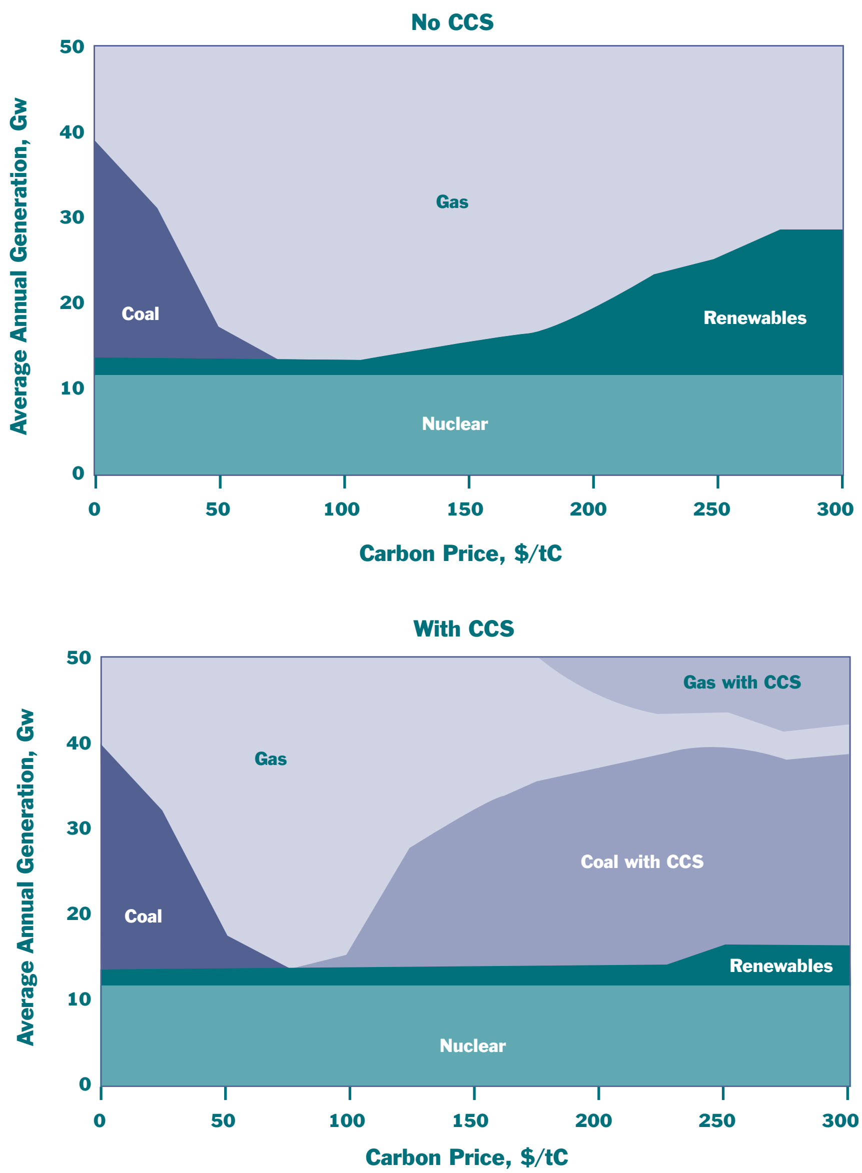
Because the electricity system consists of large long-lived plants servicing a variety of loads (base, intermediate, and peaking), any predictions about how low-carbon technologies are likely to diffuse into the system must account for the complexities of grid operation. Researchers at Carnegie Mellon University have developed a model that considers the age of capital assets and the need to dispatch plants economically to study how new facilities with carbon capture and sequestration might be integrated into real electricity systems. Results for the mid-Atlantic PJM system are shown in Figure 22.[113]

As noted at the outset of this chapter, it is also important to consider possible path dependencies and take into account possible interactions among the price of natural gas, the imposition of serious CO_2 emissions controls, the deployment of distributed generation and co-generation technologies, and the likely evolution of the electric power system in the future.

For example, if substantial further natural gas price increases occur before any serious carbon constraints are imposed, this would likely

Figure 22

Possible Mix of **Fuel Types in the PJM System** in 2025-2030



Note: Fuel mix as a function of carbon price, in dollars per ton of carbon, without (above) and with (below) the availability of carbon capture and sequestration.

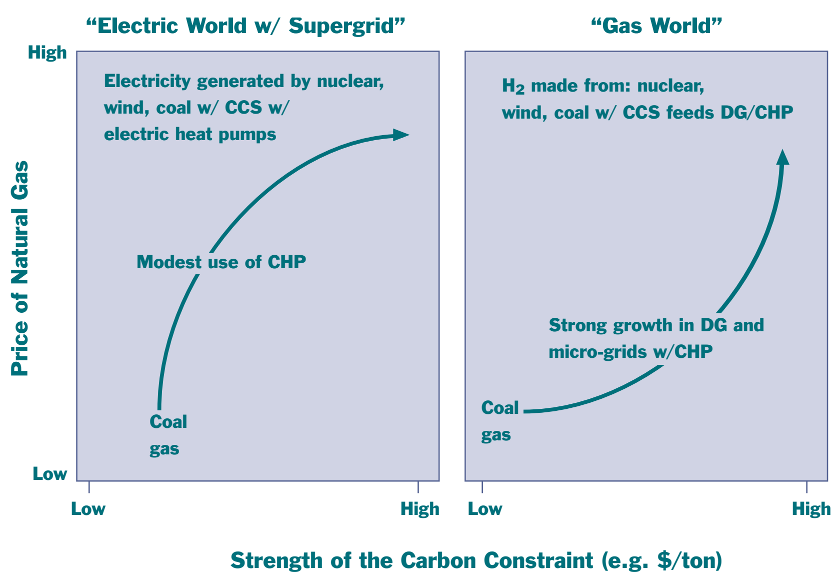
Source: Figure courtesy of Timothy Johnson. See also Johnson, T.L. and D.W. Keith. 2004. "Fossil Electricity and CO_2 Sequestration: How Natural Gas Prices, Initial Conditions and Retrofits Determine the Cost of Controlling CO_2 Emissions." *Energy Policy* 32: 367-382.

encourage still greater dependency on central station coal plants. High prices would limit the future growth of central station natural gas-fired generating capacity, but might encourage some use of combined heat and power systems that could use expensive gas more efficiently than relying on a combination of separate on-site heating systems and grid-supplied electricity.[114] Subsequent constraints on CO_2 emissions could then push the system toward heavy dependency on carbon capture and disposal, and perhaps also to a new generation of nuclear technologies—that is, toward greater dependence on large central-stations plants and an enhanced high-voltage transmission system. Since it would be difficult to capture carbon emissions from small distributed systems, electric heat pumps might replace many combined heat and power plants. This possible technology trajectory is illustrated in the left panel of Figure 23, with the resulting end-state identified as "electrical world with supergrid."[115]

Alternatively, if there are no further substantial natural gas price increases until well after serious carbon constraints are imposed, the nation's electricity system could evolve in quite different directions. If natural gas was not expensive (perhaps because of an unexpectedly successful exploration program encouraged by today's high prices, completion of an Alaska natural gas pipeline, or greatly expanded LNG import capacity), there could be rapid growth in the use of natural gas for electricity production in both central station and distributed configurations (including

Figure 23

Possible **Trajectories of the Electricity System**



The left-hand graph illustrates a world in which natural gas prices rise before substantial carbon constraints are imposed. The right-hand graph illustrates a world in which first substantial carbon constraints are imposed before the price of natural gas rises further. This formulation was developed with David Keith.

expanded deployment of micro-turbine and combined heat and power technologies along with associated growth in gas distribution infrastructure). If significant carbon constraints were then introduced, the large infrastructure commitment that had already been made to natural gas might provide incentives for the continued use of gaseous fuel in distributed settings. In that case, a trend could emerge toward making hydrogen at centralized facilities and distributing it to users via an upgraded pipeline system. This alternative technology path is illustrated in the right panel of Figure 23 with the resulting end-state labeled "gas world."

Section Summary

Affordable low-carbon electricity could be supplied by several possible generating technologies over the next 50 years. Options at present include coal IGCC with carbon capture and sequestration, wind, combined cycle natural gas with carbon capture and sequestration, and perhaps nuclear power. Given the limitations of available renewable resources—in the case of wind, for example, new back-up generation that can be ramped up quickly is needed to compensate for the intermittent nature of the resource, given that hydro-electric storage options are likely to be limited—substantial reductions in CO_2 emissions from the electric power sector will be very difficult to achieve without significant use of technologies for carbon capture and sequestration. By mid-century the fuel mix might include more or less natural gas, electricity generation might be centralized or distributed, and the nation's electric system as a whole could look quite different depending on whether fuel costs or carbon constraints dominate the economic calculus that governs investment decisions over the next decade or two.

V. Discussion and Policy Recommendations

The United States faces interrelated economic, environmental, regulatory, and social issues in connection with energy generally and electricity in particular. These include:

- emissions of greenhouse gases and their impacts on climate;
- inefficient use of energy, particularly electricity, by consumers;
- cost of fuels and new plants, and resulting impacts on the price of electricity;
- conventional air and water pollution (SO_2, NO_X, particulate matter, mercury, etc.);
- nuclear proliferation and nuclear waste;
- vulnerability to supply interruptions; and
- inefficient generation and distribution of energy.

For the most part, the country has addressed these issues as separate problems—an approach that often leads to contradictory policies and wasted resources. All of the above problems could be solved far more efficiently if they were solved together.

The generation of electricity in the United States accounts for one-third of the nation's overall GHG emissions. This contribution could be reduced substantially over the next 50 years without high costs to the economy or significant lifestyle changes, but only if a clear regulatory timetable is established so that investments are made in new plant and equipment that reduces, rather than increases, the electricity industry's CO_2 emissions. The natural evolution of the industry itself, and of the U.S. economy more generally, is likely to continue to produce a gradual decline in carbon intensity (as measured by carbon emitted per dollar of GDP),[116] but this decline is not likely to be enough to offset expected growth in electricity demand and resulting emissions increases, let alone to reduce overall emissions by the 65-85 percent required over the long term to stabilize atmospheric CO_2 concentrations at twice pre-industrial levels. Voluntary efforts to reduce GHG emissions are unlikely to reduce emissions significantly.

Based on available estimates of the likely cost of future low-carbon options (including carbon capture and sequestration), the authors estimate that the annual cost of eliminating most CO_2 emissions from the electricity system would range from 0.2-0.6 percent of U.S. GDP each year over the next several decades,[117] provided the transition to lower carbon technologies is achieved in a gradual and orderly manner. While the cost is significant, (about $20-$60 billion per year), it is certainly manageable. Despite dire predictions, the U.S. economy thrived while spending 1.5-2 percent of GDP to reduce pollution discharges in the 1980s and 1990s.[118] The Pew Center report, *U.S. Market Consequences of Global Climate Change*,[119] concludes that the costs avoided by mitigating climate change are likely to be more than enough to offset the costs of a dramatic reduction in CO_2 emissions, although these avoided costs would occur much later than the abatement costs.

Efficiency and conservation are strategies that can be implemented rapidly to reduce electricity sector emissions. Nationally, the industry has insufficient incentives to encourage end-use efficiency, but the California experience shows that states can implement programs that reduce electricity demand growth significantly (nationally, per capita electricity consumption grew by 35 percent from 1977 to 2002, while in California per capita consumption increased by only 5 percent over the same 25-year period). Even where efficiency and conservation efforts are successful in curbing per capita demand growth, however, population increases are likely to continue to boost overall electricity consumption.

On the generation side, most electricity (60 percent) is still produced under traditional state regulation. Since, under that system, fuel costs are generally passed on to customers immediately, utilities have little incentive to replace old inefficient plants with more efficient modern plants. In contrast, deregulated markets provide incentives to reduce costs generally and fuel costs in particular, but market uncertainty has made investment capital very expensive. In fact, given the difficulty of siting and financing new plants, existing coal plants—with their relatively low operating costs—may have become more valuable as a result of restructuring. Distributed generators have the potential to achieve high efficiencies—especially in combined heat and power applications where there is a use for the thermal energy that would otherwise be wasted in central-station power generation—and can also avoid the line losses (of as much as 10 percent) that occur as electricity travels through extended transmission and distribution networks. Thus, policies that remove current regulatory barriers to the deployment of distributed generators could boost system efficiency and achieve corresponding emissions reductions. While important, however, the benefits ultimately achievable through these technologies are likely to be limited by the availability of suitable sites for combined heat and power applications. Thus, it seems likely that other measures will be required to stabilize and then reduce electricity sector emissions to the extent required (roughly 65-85 percent) to achieve the long-term goal of stabilizing atmospheric GHG concentrations at twice pre-industrial levels.

Essentially all the new electricity generating capacity built in the United States in the past decade is designed to operate on natural gas and therefore has substantially lower GHG emissions, on average, than the older fleet of fossil-fuel generators. Compared to conventional steam-electric coal plants, combined cycle natural gas turbines emit only half as much CO_2 per kWh of electricity output. Much of this new capacity, however, has recently been idled by a three-fold increase in natural gas prices—itself a response to growing demand from the electricity sector in combination with emerging constraints on North American gas supplies—that has boosted the cost of natural gas-fired electricity by as much as 2.5 ¢/kWh. Using existing natural gas units to displace coal-based electricity generation would significantly lower emissions and could be one immediate result of a carbon policy. However, high natural gas prices are likely to continue to be a major issue for some time, particularly since the use of natural gas for electricity generation also drives up costs of home heating and production costs for gas-intensive industries (including fertilizer and chemical manufacturers). Increased reliance on imports of LNG from overseas producers may eventually help to stabilize natural gas prices, but would also create exposure to supply disruptions and price volatility in world markets. Finally, even if it were feasible from a price and supply standpoint to replace all coal-based generation with natural gas, the resulting emissions reductions—while substantial—would not be sufficient to achieve the long-term goal of atmospheric stabilization (as has already been noted, CO_2 emissions from modern gas plants are roughly 50 percent below those of conventional coal plants, whereas stabilization is likely to require emission reductions on the order of 65-85 percent, even as demand continues to increase). Meanwhile, the cost of capturing and sequestering CO_2 emissions from natural gas generators is likely to be higher than for the coal gasification option discussed below.

Wind power is roughly competitive with natural gas generation at current gas prices and can provide even larger CO_2 reductions. Since wind turbines at the best sites generate electricity only a third of the time, substantially expanded reliance on wind power would require roughly an equal amount of backup generation; in addition, since the best wind sites are distant from customers, substantial expansion of existing transmission capacity would be needed. Natural gas generators are a good pairing option for wind facilities, given their ability to increase or decrease electricity output quickly; thus, the two technologies in combination have the potential to produce significant emissions reductions. Siting has also emerged as a significant issue for many wind facilities, however, as have related concerns about aesthetic and ecosystem impacts. There are also open questions regarding weather and climate impacts of extracting energy from the wind which should be addressed quickly through further research.[120] Assuming that these concerns can be addressed successfully, that necessary transmission infrastructure can be added at low cost, and that natural gas prices fall or that electricity storage become inexpensive, wind power can play a substantial role in reducing future GHG emissions from the electricity sector.

Currently, hydroelectric power provides a low-carbon source for meeting roughly 7 percent of overall U.S. electricity needs. While there may be some opportunities for new, small, run-of-river hydro units, it is unlikely that large new hydro projects will be built. As a result, the percentage of demand supplied by this resource inevitably will decline over time as overall electricity production increases.

Nuclear power now accounts for a fifth of overall U.S. electricity generation and 72 percent of the country's non-carbon power supply. Unless they can be successfully addressed, however, significant concerns about capital cost, safety, waste transport and storage, and proliferation are likely to limit significant expansion of this power source in the United States. To ensure that nuclear power remains a viable option for reducing future electricity sector carbon emissions, further research, development, and demonstration to address these issues is warranted.

While domestic supplies of natural gas are limited, coal is abundant. Several demonstration units are operating and others are planned that gasify coal without burning it to produce a clean gaseous fuel that can be used to generate electricity in an efficient combined cycle-turbine (the same process can be used to produce feedstocks for chemicals as well as hydrogen or other synthetic liquid fuels for use in the transportation sector). If integrated coal gasification technology (or IGCC) is combined with carbon capture and sequestration, emissions of CO_2 can be reduced by 90 percent below those of a conventional pulverized coal unit, at costs similar to those of wind or natural gas (and below the cost of natural gas with CO_2 capture). Capital and operating costs for IGCC are projected to be 20 percent to 40 percent higher than costs for a pulverized coal plant over the next few decades. Since the higher cost and novelty of this technology are a concern for investors, public-private risk-sharing partnerships have been proposed to jump-start the deployment of coal IGCC systems in advance of a broader policy to limit CO_2 emissions. Meanwhile, the reliability of gasification technology in the context of power plant applications remains an issue and is receiving attention as part of the planning that is currently underway for a number of new demonstration units.

Another major open question that will likely affect the future of all fossil-fuel generating options, including IGCC, concerns the feasibility and acceptability of capturing and sequestering CO_2 in underground repositories. While some naturally occurring CO_2 has been trapped in geologic reservoirs for millions of years and while large-scale injections of CO_2 are currently performed for oil recovery, a significant research and development program is required to assess the practical aspects of carbon capture, transport, and sequestration at the level that would be required to offset a substantial portion of emissions from energy-related fossil-fuel consumption.

The electricity industry will need to achieve major technological advances if it is to meet the combined challenges of restructuring, modernizing infrastructure, and converting to generation options that produce far lower emissions of CO_2. Despite these challenges, R&D investments by the electricity industry—as a percentage of revenues—are among the lowest of any major industrial sector. Meanwhile, government investment in electricity-related R&D has also declined substantially from historic levels. At present, government research and policy efforts are less focused on near-term options for reducing CO_2 emissions than they are on much longer-term and more speculative technologies. For example, the DOE's Fiscal 2003 budget included $240 million for fusion power and its Fiscal 2005 budget request included $228 million for hydrogen research. By comparison, the Department's Fiscal 2003 budget included just $43 million for IGCC, $41 million for wind power, and $39 million for carbon capture and sequestration.[121]

To begin the technological transformation required to achieve a low-carbon electricity sector over the next 50 years the authors make the following policy recommendations:

A. Establish a firm regulatory timetable for reducing CO_2 emissions from the electricity industry that parallels the timetable for reducing discharges of conventional pollutants. To assure that emissions targets are met at minimum cost, they should be set well in advance and should be implemented using market-based mechanisms such as a cap-and-trade system or a carbon tax. Avoiding high costs later requires accounting for CO_2 in current investment decisions and technology choices.

The United States needs to make a clear commitment to controlling future carbon emissions today. A variety of alternative strategies is possible. A carbon tax that increases gradually in a pre-determined way would be an efficient strategy for steadily reducing future emissions, but may not be viable politically. The same declining emissions trajectory could be achieved through a cap-and-trade approach utilizing tradable emissions allowances in which the cap, or total number of allowances available, is gradually reduced over time. The key point in terms of minimizing future abatement costs is that a commitment to reducing carbon emissions must be made and publicized well in advance of achieving the long-term policy objective. While immediate costs need not be large, the commitment to implement an increasingly binding constraint in the future needs to be made now. As David Victor has recently noted,[122] such a commitment need not await a Kyoto-like international agreement. Firm regulatory commitments that remain stable on the time-scale of capital investment in major energy infrastructure would enable the electricity industry to select least-cost methods of meeting the policy goal.

Failure to implement a clear timetable for emissions control would put off the moment when serious change begins and would impose higher costs in the long run because: (1) waiting until a later time could lead to a situation where dramatic emissions reductions need to be implemented much more rapidly; (2) the United States would not benefit from the learning that can occur during a more gradual deployment of new technologies; and (3) significant capital investments that occur prior to an announced policy commitment might be stranded under a future carbon management regime (e.g., conventional coal plants that become uneconomic once a cost is attached to their carbon emissions would be scrapped before the end of their useful life).

Converting to generation systems that do not produce CO_2 is likely to produce significant co-benefits in terms of other air pollutants. The electricity industry faces ongoing challenges to reduce emissions of SO_2 and NO_X, and to nearly eliminate releases of other pollutants such as mercury. The industry has spent billions of dollars to develop and install add-on environmental controls for these pollutants such as scrubbers and catalysts. Unfortunately, however, many of these control technologies—by reducing the power output and hence the operating efficiency of most plants—actually increase CO_2 emissions. By contrast, emissions of conventional air pollutants for most of the low-carbon options discussed in Section III are much lower or non-existent. As a result, it would almost certainly be cheaper, quicker, and more effective to integrate control of all emissions as soon as possible rather than first spending billions of dollars to clean up SO_2, NO_X, and mercury emissions from conventional power plants and later spending additional billions of dollars to replace the same plants with generation options that don't emit CO_2.

B. Address the most serious institutional and regulatory barriers to the development of low-carbon and carbon-free energy technologies by implementing policies aimed at: (1) developing an adaptive regulatory framework for managing geologic carbon sequestration, in order to provide an alternative (coal gasification with carbon capture) to building new conventional coal plants; (2) determining if it is feasible to mitigate the safety, proliferation, and waste-management concerns that currently inhibit the expansion of nuclear power; (3) facilitating the adoption of cost-effective low- or no-carbon renewable technologies such as wind and biomass and promoting distributed resources and micro-grids; and (4) creating financial arrangements that decrease the risk penalty assigned by investors to new capital in the restructured era that have tended to discourage major investments by the electricity industry and that present further hurdles to the deployment of new technologies.

The nation's heavy dependence on coal for electricity generation means that deep cuts in CO_2 emissions from the electricity sector will be very difficult to achieve over the next 50 years without significant use of technologies for carbon capture and sequestration. As discussed in Section III, the technologies to do this are already in use at commercial scale in other industrial sectors. With continued research and experience, it should be possible to reduce costs and adapt the technologies involved to capturing and sequestering emissions from coal-fired electricity generators. The primary obstacles to widespread use of carbon capture and sequestration are likely to be non-technical. Thus, DOE and the EPA should begin to work together now to develop the scientific knowledge and risk assessment tools that will be needed to perform plausible risk analysis, characterize potential injection sites, implement adaptive performance-based regulations, and monitor and account for the fate of CO_2 injected in geologic formations in an ongoing way. At the moment, such efforts are only just getting started. If they do not receive high priority, a clumsy regulatory approach could seriously impede or even eliminate further development of this promising mitigation option. Equally important is the need for open and honest public communication about reducing the electricity industry's GHG emissions. Preliminary studies[123] suggest that the public does not understand the urgency of moving forward with low- or no-carbon generation technologies, nor is there widespread understanding of the difficulties that, if not overcome through technical and cost breakthroughs, are likely to limit the magnitude of emissions reductions achievable through increased reliance on renewable resources such as wind and solar power.

Nuclear power is a well-established source of carbon-free electricity that, as the French example demonstrates, is capable of supplying a large share of overall electricity needs. But if nuclear power is to be used to make planet-wide reductions in CO_2 emissions, the risk that nuclear materials could be diverted to weapons systems, together with other concerns related to safety and the management and disposal of spent fuel must be addressed. Without a resolution of these issues, proliferation risks and waste management liabilities associated with the existing nuclear fleet may be unacceptably large, and are likely to preclude any further expansion of nuclear capacity. However, a robust system for handling spent fuel, which includes international control and supervision, could enable nuclear generation to displace a larger share of fossil-fuel based generation and produce substantial emissions reductions.

The investments required to reduce the electricity industry's emissions of SO_2, NO_X, mercury, and CO_2 control are substantial and the cost of financing these investments has risen significantly under the uncertain business environment created by industry restructuring. In this context, innovative risk-sharing mechanisms like the 3-party covenant concept described previously may be more efficient than direct government subsidies in promoting the early deployment of new technologies. Such mechanisms and others may be necessary to reduce borrowing costs for large investments in low-carbon generation technologies to reasonable levels.

C. Promote greater end-use efficiency through policies that encourage power companies to invest in cost-effective demand-side energy savings. Impose stricter federal efficiency standards for appliances and buildings (as detailed in the Pew Center's 2005 report, *Towards a Climate Friendly Built Environment*) and promote the deployment of efficient combined heat and power systems. California has succeeded in slowing per capita electricity demand growth significantly through a variety of efficiency initiatives; these and other programs should be examined to estimate their potential to reduce demand more broadly and to identify "best practices" that can be documented and implemented elsewhere.

Greater efficiency in using electricity can reduce CO_2 emissions significantly. In the past, utility regulators in many states required power companies to implement efficiency programs. Analysts agree that these programs reduced demand, although they do not agree about how much.[124] In the regulated portions of the industry, such programs should be continued and strengthened. In restructured states, alternative approaches—such as California's state-funded programs—may be effective. Meanwhile, mandatory efficiency standards and labeling requirements for electrical appliances have proved to be among the most successful strategies for improving end-use efficiency.

As discussed above and in Section III, distributed generation, including micro-grids, hold the potential to provide a variety of advantages, including improved overall efficiency and—especially when fueled by natural gas—lower CO_2 emissions. Unlike large central station plants that lose roughly two-thirds of the energy content of their fuel inputs in the form of waste heat that must be dissipated using cooling towers, small distributed plants can deliver waste heat to meet on-site thermal loads, thereby reducing or eliminating the need for furnaces, boilers, and, in some cases, air conditioning.

D. Create a federal requirement that all parties in the electricity industry invest in R&D at least one percent of their value added in order to explore how promising new technologies can solve the difficult reliability, efficiency, security, environmental, cost, and other problems facing the industry. Firms should have the choice to make the investments themselves or contribute to a fund managed by the Department of Energy. In parallel with this industry mandate, the Department of Energy needs to develop a more effective program of needs-based research into power generation and storage, electricity transmission and distribution, conservation, demand management and other electric power technologies and systems.

The power industry currently invests a very low share of revenues in R&D. Averaged over all sectors, current U.S. expenditures for R&D amount to roughly 2.2 percent of GDP; the authors therefore recommend a target level for non-governmental spending on electricity-related R&D of at least 1 percent of total electricity sales.[125] Efforts to increase this investment voluntarily have been largely unsuccessful. In light of current challenges and opportunities, the lack of funding for energy-related R&D is short-sighted. Given the magnitude of the challenges the industry faces in coming decades, it is critical that the United

States develop and maintain a greatly expanded, long-term program for conducting basic research into various technology options and for developing and testing those technologies that are nearly ready for commercial adoption.

While the federal government's ability to fund and manage energy-related R&D is likely to be constrained by competing pressures for tax and spending reductions, the urgency of the climate problem, and other problems in energy supply and management justify a larger and more effective program of needs-based research into problems of electricity. Without a sustained and concerted research effort, it will be difficult to meet the nation's energy challenges, including the challenge of reducing carbon emissions. The nation must assess the status and needs of important technologies with respect to research, development, demonstration, and early deployment and focus federal funding accordingly. For example, solar photovoltaic technology requires long-term research breakthroughs to become cost-competitive, while coal gasification requires further development to become sufficiently reliable for power-generating applications. By contrast, carbon sequestration requires commercial-scale demonstration to verify its feasibility.

VI. Conclusions

The path to a low-carbon future for the electricity sector poses a range of challenges. As France has demonstrated, nuclear power is a known technology that could produce such a future, but nuclear power faces a number of major problems including high cost, low public acceptance, and risks of proliferation. Large-scale fuel switching to natural gas could lead to substantial reductions in CO_2 emissions, though not their complete elimination, but it would be expensive and probably adversely impact the nation's energy independence. Carbon capture and sequestration holds the promise that it could allow continued use of America's enormous coal reserves. While likely affordable and technically feasible, it has yet to be demonstrated on a large scale and faces open questions of cost and reliability. Some forms of renewable energy can certainly play a role, but just how large that role can be depends on a range of uncertain issues in terms of cost, technical performance, and power system architecture. These issues will be resolved only through further research and expanded field experience. Conservation and load management hold great potential, but to date regulators and political decision makers have not advanced these solutions with the vigor that is needed. Clearly there are multiple paths to success, most involving some portfolio of these solutions. Today our best option is to work hard to advance the most promising, in the hopes that several ultimately prove to be technically, economically, and politically feasible.

The electricity industry's investment decisions are unlikely to favor low-carbon options unless and until a clear regulatory timetable for limiting CO_2 emissions is established. Absent such a timetable, aging pulverized coal units will likely be retrofitted with add-on controls for SO_2, NO_X, and mercury and could continue operating for decades with no provision for CO_2 abatement. This could lead to a situation where more drastic CO_2 reductions must be achieved over a shorter timeframe in the future, potentially at far higher cost.

Environmental issues generally, and global warming concerns in particular, have focused attention on a number of major challenges to the current U.S. electricity system. Industry restructuring, underinvestment in transmission infrastructure and other system assets, under-utilization of currently available low-carbon electricity generation sources, reliability and security issues, and insufficient R&D funding interact to cloud the future of this vital sector of the U.S. economy. Under any future scenario, this complex set of issues must be addressed in a manner that accounts for the hybrid—half restructured and half traditionally-regulated—nature of the industry. The elements that matter most now are:

- An end to regulatory uncertainty regarding future CO_2 control. Establishing clear and consistent policy goals sooner rather than later and implementing these goals through mechanisms such as a cap-and-trade system with scheduled cap reductions will avoid very significant costs.

- Development efforts focusing on promising technologies that do not require fundamental breakthroughs, such as IGCC with carbon capture and sequestration for coal as well as natural gas.

- Adoption of best practices for promoting energy conservation and improved efficiency.

- A federal requirement that electricity industry companies spend at least one percent of their value added on research to develop critical enabling technologies and to address core questions that are likely to be crucial in determining which of several possible technology paths the industry should follow in the future. Examples include making carbon capture and sequestration feasible and determining whether cost-effective electricity storage options can be developed for intermittent resources like wind and solar.

Properly managed, it should be possible to accomplish the transition to a low-carbon electricity future at manageable cost and with little disruption to the U.S. economy. But the United States must initiate that transition now.

Endnotes

1. For more information on options for reducing greenhouse gases from other sectors of the U.S. economy, see other reports from the Pew Center Solutions Series: Greene, David L., and Andreas Schafer. 2003. *Reducing Greenhouse Gas Emissions from U.S. Transportation* and Brown, M.A., F. Southworth, and T. K. Stovall. 2005. *Towards a Climate Friendly Building Environment*. Pew Center on Global Climate Change, Arlington, VA.

2. Other major greenhouse gases include methane, nitrous oxide, and industrial gases like hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. Adjusted for global warming potential, the latter categories of GHGs accounted for 9 percent, 5 percent, and 2 percent, respectively, of the overall U.S. inventory in 2002. Carbon dioxide accounted for the remainder, or approximately 84 percent.

3. Energy Information Administration. *Annual Energy Review 2003*, Table 8.2a.

4. Energy Information Administration. *Annual Energy Review 2003*.

5. Davison, J., P. Freund, and A. Smith. 2001. *Putting Carbon back into the Ground*. International Energy Agency Greenhouse Gas R&D Program. See Table 1, p6. Available at http://www.ieagreen.org.uk/putcback.pdf.

6. A kilowatt-hour, or kWh, is a measure of *energy* used. It is equal to the amount of energy required to run a thousand watt load (e.g. ten 100 watt light bulbs or a typical two slot toaster) for one hour. *Power* is the rate of use, or production of energy. Power is measured in watts. A kilowatt, abbreviated 1kW, is 1000 watts. The capacity of power plants is typically reported in millions of watts, abbreviated as MW.

7. Based on the price of an Energizer D-cell battery as listed at http://www.batteries.com/sales/Energizer-2-Pack-D-cell-batteries.htm, and on data from http://data.energizer.com/PDFs/e95.pdf.

8. Hilsenrath, J.E. 2003 August 18. "The 2003 Blackout: Economy Won't Likely be Derailed; Cost Could Hit 6 Billion." *Wall Street Journal* (Eastern Edition): A6.

9. High voltages are more efficient for transmitting electricity over long distances. The amount of power (measured in watts) that travels though a line is the product of voltage (measured in volts) and current (measured in amps). However, just as running a current through the elements of a toaster causes some of the power to be converted to heat, so too, running current through a transmission line heats the line and results in some loss of energy. The amount of heating is proportional to the resistance of the line multiplied by the square of the amount of current that is flowing (Ohm's law). Thus, to minimize line losses, one wants to keep the current as low as possible. That means operating at high voltages. Many modern transmission lines operate at a voltage of 500,000 volts (500kV). A few operate at 765,000 volts (765kV).

10. In homes the final voltage is 120 volts for most purposes, and 240 volts for certain appliances such as electric stoves and clothes dryers.

11. The peak load on an electric power system is the maximum kW demand. In many systems it occurs in the early evening. In hot weather when there is a heavy air conditioning load, peak load may occur in the early- to mid-afternoon.

12. California Energy Commission Report, Demand Response Committee. 2003. "Feasibility of Implementing Dynamic Pricing in California." 400-03-020F. Available at http://www.energy.ca.gov/reports/2003-10-31_400-03-020F.PDF.

13. Holland, S.P., and E. T. Mansur. 2004. *Is Real-Time Pricing Green?: The Environmental Impacts of Electricity Demand Variance*. Center for Study of Energy Markets, Working Paper 136.

14. For a more detailed discussion, see Hirsh, R.F., *Power Loss* (Cambridge, MA: MIT Press, 2001).

15. Maltbie, M.R. 1908. “Application of Long Acre Company,” *Electrical World* 52(1): 8-9.

16. Energy Information Administration. December, 2003. “Electric Power Annual: 2002.” DOE/EIA-0348(2002). Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, U.S. Department of Energy, Washington, DC.

17. “California’s Energy Efficiency Leadership.” Available at http://www.nrdc.org/air/energy/eecal/eecal.pdf.

18. PJM is a voluntary organization that initially acted as the systems operator for much of Pennsylvania, New Jersey, and Maryland. The geographical scope of PJM has expanded substantially in recent years.

19. R. W. Bacon & J. Besant-Jones, “Global Electric Power Reform, Privatization, and Liberalization of the Electric Power Industry in Developing Countries,” *Annual Review of Energy and Environment*, 2001, 26:331-59.

20. Hans Bjornsson, Robert Crow and Hillard Huntington, “International Comparisons of Electricity Restructuring: Considerations for Japan,” Center for Integrated Facility Engineering Technical Report # 150, Stanford University, February 2004.

21. U.S. EPA. 2001. “National Emission Inventory. Air Pollutant Emission Trends.” Current Emission Trends Summaries. See http://www.epa.gov/ttn/chief/trends/index.html and Environmental Protection Agency, eGRID, Emissions & Generaton Resource Integrated Database, www.epa.gov/cleanenergy/egrid/.

22. Note that this figure includes only direct or “primary” emissions of particulate matter (PM). The overall power plant contribution to particulate levels in the atmosphere is significantly higher, since emissions of SO_2 and NO_X play a key role in the formation of secondary aerosols that account for a large portion of total fine PM ($PM_{2.5}$) mass in many parts of the country.

23. U.S. EPA. 2001. “National Emission Inventory. Air Pollutant Emission Trends.” Current Emission Trends Summaries. See http://www.epa.gov/ttn/chief/trends/index.html.

24. Several multi-pollutant proposals for limiting power sector emissions were introduced in the 108th Congress. They include S.366, The Clean Power Act of 2003; S.485, The Clear Skies Act of 2003; and S. 843, The Clean Air Planning Act of 2003. S. 366 (The Clean Power Act) would have required reductions of CO_2 emissions to 1990 levels by 2009, as well as reductions of SO_2, NO_X, and mercury emissions, from electric power plants. S. 366 was introduced by Sen. James M. Jeffords (I-VT) with 19 cosponsors. Its companion House bill, H.R.2042, was introduced by Rep. Henry A. Waxman (D-CA) with 97 cosponsors and was titled The Clean Smokestacks Act of 2003. S.485 (The Clear Skies Act of 2003) would have required reductions of power plant emissions of SO_2, NO_X, and mercury, but not CO_2, and would have exempted new power plants from the current requirement that they disclose their CO_2 emissions. It was sponsored by Sen. James M. Inhofe (R-OK) with one cosponsor and was introduced at the request of the Administration. The companion House bill, H.R. 999, was sponsored by Rep. Joe Barton (R-TX) with one cosponsor. (A subsequent version of the Clear Skies Act was later introduced in the Senate as S.1844.) S.843 (The Clean Air Planning Act) would have required reductions of CO_2 (to 2005 levels by 2009 and to 2001 levels by 2013), as well as SO_2, NO_X, and mercury emissions reductions, from electric power plants. It was sponsored by Sen. Thomas R. Carper (D-DE) with three cosponsors The companion House bill, H.R.3093, was introduced by Rep. Charles F. Bass (R-NH), also with three cosponsors.

25. U.S. DOE. 2003. “Energy Information Administration, Assumptions to the Annual Energy Annual Energy Outlook 2003 with Projections to 2025.” U.S. Department of Energy, Electricity Generation.

26. The EIA estimates that minable reserves of coal in the United States total some 248 billion metric tons (http://www.eia.doe.gov/cneaf/coal/reserves/chapter1.html). U.S. coal use in 2001 totaled 1.02 billion metric tons. By contrast, the nation’s proven reserves of dry natural gas are estimated to total 187 trillion cubic feet (http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/current/pdf/ch4.pdf), while U.S. consumption in 2001 totaled approximately 22.5 trillion cubic feet (domestic production was 19.3 trillion cubic feet). Thus, domestic coal reserves would be sufficient to meet 243 years of demand at current rates of consumption, whereas domestic natural gas reserves would be sufficient to meet only eight years of demand at current rates of consumption.

27. For views from contrasting perspectives, see Jonathan Adler’s piece in *The National Review* at http://www.nationalreview.com/adler/adler200310010939.asp and the Natural Resources Defense Council piece at http://www.nrdc.org/air/pollution/pnsr.asp.

28. Ellerman, A.D., P. L. Joskow, and D. Harrison, Jr. 2003. *Emissions Trading in the U.S.: Experience, Lessons, and Considerations for Greenhouse Gases*. Pew Center on Global Climate Change, Arlington, VA. In phasing out the production of chlorofluorocarbon compounds (CFCs) in order to protect the stratospheric ozone layer, a tax was placed on each CFC in proportion to its ozone depletion potential. In contrast to command-and-control regulation, the tax achieved desired emissions reductions quickly and with little fuss. Still more popular have been tradable permit or allowance programs.

29. Farrell, A. March 2000. "The NO_X Budget: A Look at the First Year." *Electricity Journal*: 83-92.

30. The Lieberman-McCain bill, S.139, 108th Congress http://www.theorator.com/bills108/s139.html.

31. Farrell, A.E. and M.G. Morgan. 2003. "Multi-lateral Emission Trading: Heterogeneity in Domestic and International Common Pool Resource Management." In *The Commons In The New Millennium: Challenges and Adaptation*. N. Dolsak and E. Ostrom, eds. MIT Press, Cambridge, MA.

32. Note that while the Ozone Transport Commission in the East was set up by the federal Clean Air Act, it was done in response to a request from the states.

33. Morgan, M.G. 2000. "Climate Change: Managing Carbon from the Bottom Up." *Science*: 2285m; and Victor, D. 2004. *Climate Change; Debating America's Policy Options*. Council on Foreign Relations.

34. Hassol, S. J. and R. Udall. Spring 2003. "A Change of Climate." *Issues in Science and Technology*: 39-46. See also "In-Brief: Learning from State Action on Climate Change" and *Climate Change Activities in the United States: 2004 Update*. The Pew Center on Global Climate Change, Arlington, VA. Current updates are available at http://www.pewclimate.org/what_s_being_done/in_the_states/news.cfm.

35. One example is the Regional Greenhouse Gas Initiative, whose website at http://www.rggi.org/ has a number of documents of interest.

36. Six of these states have renewable energy credit trading programs. The DOE's Efficiency and Renewable Energy maintains a website with current information at http://www.eere.energy.gov/state_energy_program/projects_all_state.cfm.

37. http://www.ef.org/westcoastclimate/.

38. Bachrach, D., M. Ardema, and A. Leupp. 2003. *Energy Efficiency Leadership in California*. Natural Resources Defense Council, Figure 3.

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42. Patiño Echeverri, D., *The Cost of Regulatory Uncertainty in Air Emissions for a Coal-fired Power Plant*. Carnegie Mellon Electricity Industry Center. Working paper CEIC-03-03. Available at http://wpweb2k.gsia.cmu.edu/ceic/papers/ceic-03-03.htm.

43. Yohe, G., N. Andronova, and M. Schlesinger. 15 October 2004. "To Hedge or Not Against an Uncertain Climate Future?" *Science* 306: 416-417.

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45. S. Wiel and J. McMahon, *Energy-Efficiency Labels and Standards: A Guidebook for Appliances, Equipment, and Lighting* (CLASP. Feb. 2001), 16.

46. The Natural Resources Defense Council summarizes a number of such improvements and case studies on a portion of their website at http://www.nrdc.org/air/energy/appliance/applianceinx.asp. A detailed discussion can also be found in the publications of the Rocky Mountain Institute at http://www.rmi.org.

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48. California Energy Commission, Demand Response Committee. 2003. "Feasibility of Implementing Dynamic Pricing in California." Report Number 400-03-020F. Available at http://www.energy.ca.gov/reports/2003-10-31_400-03-020F.PDF.

49. Holland, S.P., and E. T. Mansur. 2004. *Is Real-Time Pricing Green?: The Environmental Impacts of Electricity Demand Variance*. Center for Study of Energy Markets, Working Paper 136.

50. Loughran, D. and J. Kulick. 2004. "Demand Side Management and Energy Efficiency in the United States." *The Energy Journal* 25 (1): 19-41.

51. California Energy Commission, Demand Response Committee. 2003., op. cit.

52. The inability to store electricity at reasonable cost and the fact that blackouts are likely to result if demand is significantly greater than supply means that wholesale electricity prices are volatile and are likely to be very high at times of peak demand or other critical price events. Braithwait, S.D. 2000. "Residential TOU Price Response in the Presence of Interactive Communications Equipment." In *Pricing in Competitive Electricity Markets*. A. Faruqui and K. Eakin, Kluwer, eds. Academic Publishers, Boston, MA. and Braithwait, S.D., and K. Eakin. 2002. "The Role of Demand Response in Electric Power Market Design." Edison Electric Institute. Available at http://www.eei.org/industry_issues/retail_services_and_delivery/wise_energy_use/demand_response/demandresponserole.pdf.

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57. Section 8.4.1. 2001. "Alternative Pathways for Stabilization Concentrations." In *Climate Change 2001: Mitigation Report of Working Group III of the Third IPCC Assessment*. Cambridge University Press.

58. Today many have begun to use the phrase carbon capture and "storage." However this is somewhat misleading because the word storage means "to supply or stock with something, as for future use…to accumulate or put away for future use…" Since there are no serious plans to take the CO_2 back out of the ground and use it in the future, the authors use the term sequestration throughout this report.

59. Rubin, E.S., A.B. Rao and C. Chen. *Comparative Assessments of Fossil Fuel Power Plants With CO_2 Capture and Storage* (Proceedings of 7th International Conference on Greenhouse Gas Control Technologies, Cheltanham, England: IEA GHG, 2004 September 5-9). Available at: http://uregina.ca/ghgt7/PDF/papers/pcc-/475.pdf.

60. In this report, costs are reported per metric ton of carbon dioxide (CO_2). In discussions of climate policy, emissions are also commonly expressed in terms that include just carbon. To convert a given quantity of carbon to an equivalent quantity of carbon dioxide, the former term is simply multiplied by 3.66.

61. Rubin, E.S., A.B. Rao and C. Chen, op. cit.

62. Calculated at a gas price of $4 per Gigajoule or GJ ($4.22 per million BTU), high heating value.

63. Bock B, Rhudy R, Herzog H, et al. *Economic Evaluation of CO_2 Storage and Sink Enhancement Options [Final Report to USDOE]*. Muscle Shoals, TN: TVA Public Power Institute; 2003. 500 p. and McCoy, S. (2005), "A Technical and Economic Assessment of Transport and Storage of CO_2 in Deep Saline Aquifers for Power Plant Greenhouse Gas Control" Carnegie Mellon Electricity Industry Center Working Paper CEIC-05-02. Available at: http://wpweb2k.gsia.cmu.edu/ceic/papers/ceic-05-02.htm.

64. Rosenberg, W., M. Walker, and D. Alpern, op. cit.

65. as reported by Rubin et al., op. cit.

66. For example, the existing demonstration plants include facilities at Wabash River, Indiana and Polk County, Florida as well as an operational 512 MW unit in Priolo, Italy. Another 285-MW unit is planned near Orlando, Florida for operation in 2010

67. In principle, the techniques and technologies involved in geologic sequestration are nothing new. The United States currently injects a mass of fluid underground (mostly waste water with some hazardous materials) that is larger than the mass of all the CO_2 produced by U.S. power plants add reference. See Wilson, E. J. and D. W. Keith (2003). "Regulating the Ultimate Sink: Managing the Risks of Geologic CO_2 Storage." *Environmental Science and Technology* 37(16): 3476-3483 and Palmgren, C., W. B. de Bruin, D. W. Keith and M. G. Morgan (2004). "Initial Public Perceptions of Deep Geological and Oceanic Disposal of Carbon Dioxide." *Environmental Science and Technology* 38: 6441-6450.

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78. DeCarolis, D. 2004. *The Economics and Environmental Impacts of Large-Scale Wind Power in a Carbon Constrained World*, Ph.D. thesis in the Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA.

79. *Eltra 2003 Annual Report*, p.24. Available at http://www.eltra.dk/composite-15581.htm. Scandinavian hydro power has 34 times the capacity of Danish wind.

80. Roy, S.B., S. Pacala, and R.L. Walko. 2004. “Can Large Wind Farms Affect Local Meteorology?” *Journal of Geophysical Research* 109(D19): 4763. Rooijmans, P. *Impact of a Large-scale Offshore Wind Farm on Meteorology: numerical simulations with a mesosclae circulation model*, M.S. thesis Utrecht University, Utrecht, The Netherlands. Keith, D.W., DeCarolis J.F., Denkenberger D.C., Lenschow, D.H., Malyshev, S.L., Pacala, S., and Rasch, P.J. 2004. “The Influence of Large-scale Wind-power on Global Climate.” *Proceedings of the National Academy of Sciences* 101(46) 16115-16120.

81. Today many people think of European countries as leaders in deploying wind power. However, California was the world’s first market for utility-scale wind. Denmark also had incentives in place during the 1980s, but the financial incentives provided by the Danish government encouraged development of wind turbines by individual farms or small cooperatives. By 1985, when California’s wind energy boom came to an end, roughly 1,000 MW of wind were installed in California, compared with only 100MW in Denmark. Danish manufacturers produced 12,500 turbines during the 1980s of which about 9,000 were exported, mostly to California. Germany and other European countries didn’t become heavily involved in wind development until the mid-1990s.

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85. Using an average insolation value of 4.5 kWh/m^2/day (insolation is the rate of solar radiation per unit of horizontal surface), a land area of 9.2x 10^{12} m^2, and 365 days in a year, 1.5 x 10^{16} kWh of solar energy fall on the United States each year. Total U.S. net electricity generation in 2002 was 3.84 x 10^{12} kWh, so the amount of solar energy reaching U.S. land is roughly 3,900 times the nation’s current electricity consumption.

86. Rogol, M., S. Doi, and A. Wilkinson. July 2004. Figure 26. In *Sun Screen: Investment opportunities in solar power*, (CLSA, New York , NY: Caylon Securities), 74.

87. *The Japan National Status Report on PV 2003* (May 2004), p. 6, (available at http://www.oja-services.nl/iea-pvps/nsr02/jpn.htm) states that installed prices for industrial-scale systems were 800,000 yen per kW in 2003 ($7800 /kW). Per NREL (see http://www.nrel.gov/ncpv/hotline/japan9-20.pdf), the Japan solar subsidy was in effect from late 1994 through March 2003. The subsidy was subsequently extended for another year, but at half the budget, with overall subsidies falling from 50% in 1994 to 5% in 2004. Costs for residential systems (the main target of the subsidy) decreased by an average of 6% during the subsidy period. Industrial system costs decreased at an average of 13% per year in Japan prior to the introduction of the subsidy, and 8% during the subsidy period (*ibid* Table 5a). Japan is now directing large-scale funding to companies and universities directly in order to reduce manufacturing costs, increase yield, and develop higher efficiency cells to meet a 2010 target of $2440/kW (see pp. 17-20 of the *European Commission Joint Research Center PV Status Report 2003*, available at http://streference.jrc.cec.eu.int/pdf/Status%20Report%202003.pdf). A comprehensive survey of solar module, inverter, and battery prices is conducted monthly by the solar energy research firm Solarbuzz Inc., and results are available at www.solarbuzz.com. They indicate that worldwide module prices have been decreasing at 4% per year from 2000-2004 (although prices have increased since mid-2004). A longer history has been compiled by the National Renewable Energy Laboratory (NREL), and is available at http://www.nrel.gov/ncpv/thin_film/docs/module_price_history_and_forecast.ppt, showing that large modules sold in quantity decreased at 4.8% per year from 1987-2000. Module prices represent approximately half of installed PV system costs, and the monthly surveys show very little price reduction in components such as inverters and grid connection hardware.

88. Keith, D.W. and A.E. Farrell. 2003. “Rethinking Hydrogen Cars,” *Science* 301:315-316.

89. When power flows through transmission and distribution lines, some of it is lost to electrical resistance. This loss is equal to the square of the current times the resistance. On average, power systems loose about 10% of the power they generate to line losses.

90. Zeriffi, H., H. Dowlatabadi, A. Farrell. In review. "Incorporating Stress in Electric Power Systems Reliability Models." *Proceedings of the IEEE*.

91. FACTS = flexible AC transmission systems. FACTS is a general term that covers a variety of specific systems such as transmission level static var compensators (SVCs), static reactive compensation (STATCOM), and unified power flow control (UPFC). For a popular treatments of this technology see Fairley, Peter. 2001. "A Smarter Power Grid," *Technology Review.* July/August, pp. 41-49.

92. Diagram 5, note g. 2003. *Annual Energy Review 2003*. Energy Information Administration, Washington, DC.

93. The discussion in this section draws on arguments developed in Morgan, M.G. and S. Talukdar, "Nurturing R&D in the New Electric Power Regime," *IEEE Spectrum*, 32-33, July 1996 and in Morgan, M.G. and S.F. Tierney, "Research Support for the Power Industry," *Issues in Science & Technology*, pp. 81-87, Fall 1998.

94. Alic, J.A, D.C. Mowery, and E.S. Rubin. 2002. *U.S. Technology and Innovation Policies*. Pew Center on Global Climate Change, Arlington, VA.

95. The "energy trends" web site operated by the Pacific Northwest National laboratory "examines trends in energy research, development, and investment around the world." See: http://energytrends.pnl.gov/crosscut.htm

96. J.J. Dooley. "Unintended Consequences: Energy R&D in a Deregulated Market." Pacific Northwest National Laboratory. Washington, D.C. PNNL-SA-28561. February 6, 1997.

97. Lubell, M.S.. 2004. "Chapter 9: The Department of Energy in the FY 2005 Budget." In *AAAS Report XXIX: Research & Development FY 2005*. AAAS, Washington, DC.

98. Daniel M. Kammen and Gregory F. Nemet. Forthcoming. "The Effectiveness of Energy Research and Development," Innovations, 1(1), and Margolis, R.M. and D.M.Kammen. 1999. "Underinvestment: The Energy Technology and R&D Policy Challenge," Science, 285: 690-693.

99. Using a 2004 installed cost for solar PV systems of $7000/kW and assuming that costs decline by 5% per year, while installed costs for wind total $900/kW. Wind costs have also been declining, however, so the break-even point may not be reached at 40 years. Note also that the comparison in terms of cost per kW is favorable to solar, since the average capacity factor of wind at good sites is 35%, while for solar it is no greater than 24% for the best location in the United States (NREL, see http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/).

100. For estimates of the demand for PV in the U.S. if system prices fall to $2000/kW, see Chaudhari, Maya, L. Frantzis, and T. E. Hoff, 2004. "PV Grid Connected Market Potential under a Cost Breakthrough Scenario," The Energy Foundation and Navigant Consulting, Inc. Available at: http://www.ef.org/documents/EF-Final-Final2.pdf

101. Morgan, M.G. and S.F. Tierney. 1998 Fall. "Research Support for the Power Industry." *Issues in Science & Technology* 81-87. There have been some spillovers. Civilian nuclear power benefited significantly from defense-motivated investments in nuclear weapons and ship propulsion. Combustion turbines are derived from aircraft jet engines, originally developed by the Department of Defense. The basic underpinnings for FACTS technology, fuel cells and photovoltaics also did not come from research supported by the power industry. These technologies are the outgrowth of developments in other sectors, including, in the latter two cases, the space program.

102. Goulder, L.H. 2004. *Induced Technological Change and Climate Policy*. Pew Center on Global Climate Change, Arlington, VA.

103. A breakthrough in electrochemistry that would allow a vehicle to achieve a 350 mile range with a 500 pound battery that cost $2,000 and lasted 15 years could lead to an all electric vehicle fleet. Even with current technology, plug-in hybrid electric vehicles with batteries sufficient for a 50-mile range could allow for the vast majority of vehicle miles to be powered by electricity rather than gasoline.

104. From high-yield plants such as switchgrass.

105. Maclean, H.L and L.B. Lave. 2003. "Life Cycle Assessment of Automobile/Fuel Options." *Environmental Science & Technology* 37(23): 5445-5452.

106. Separating one gram of hydrogen from water requires 119 kJ or 0.033 kWh. If the hydrogen is then burned in pure oxygen the same amount of energy is released. In any real system, however, one must de-rate these values by the system efficiency.

107. Currently the light duty vehicle fleet consumes $130x10^9$ gallons of gasoline per year. Assume that technical improvements offset growth in population and vehicle miles traveled so that this overall consumption level stays about the same. The energy content of a gallon of gasoline is 125,000 BTU or 36.6 kWh. Thus, the current vehicle fleet consumes the energy equivalent of $4.8x10^{12}$ kWh per year. Internal combustion engines in light vehicles are only about 20% efficient. Suppose that electric storage and drive could be made three times as efficient. Then about $1.6\ x10^{12}$ or 1,600 billion kWh/year would be needed to power the U.S. vehicle fleet. The authors round that to 2,000 billion kWh/yr.

108. For details see: http://sedac.ciesin.org/mva/minicam/MCHP.html.

109. The authors thank David Keith for contributing ideas on which parts of this discussion are based.

110. Vajjhala, S. P. "Expanding the Grid? Indicators of Transmission Demand and Siting Difficulty." Carnegie Mellon Electricity Industry Center Working Paper CEIC-03-06, available at http://wpweb2k.gsia.cmu.edu/ceic/papers/ceic-03-06.htm.

111. Based on EIA Existing Generation data.

112. For example, this calculation used a load factor of 0.6 throughout, whereas many of the plants being replaced probably have a lower load factor. For this order-of-magnitude exercise, such details are not critical.

113. Johnson, T.L. and D.W. Keith. 2004. "Fossil Electricity and CO_2 Sequestration: How Natural Gas Prices, Initial Conditions and Retrofits Determine the Cost of Controlling CO_2 Emissions." *Energy Policy* 32: 367-382.

114. While CHP is more efficient than central station generation in many cases, if natural gas is much more expensive per BTU than coal, CHP will offer little or no savings over central station coal generation.

115. The authors use the word "supergrid" to imply an even larger and more robust transmission infrastructure than the one that now exists—one that has incorporated advanced transmission technologies.

116. Wernick, I.K. and J.H. Ausubel. 1995. "National Material Metrics for Industrial Ecology." *Resources Policy* 21(3): 189-198.

117. This estimate is made as follows: generation costs are approximately 4.5 ¢/kWh, and 2 trillion kWh were generated in 2002, for a cost of $100 billion. Carbon free electricity can be generated from coal using carbon capture technology at an incremental cost over conventional coal of no more than 40% (Rubin et al., op. cit.) or from nuclear, depending upon assumptions, for an incremental cost over conventional coal of between 20 and 60% (Deutch and Moniz, co-chairs, op. cit.). Assuming the cost of carbon-free electricity production to be 1.4 times that of conventional coal, this means that the cost of electricity delivered to the end-use customer would increase by $40 billion. Current electricity sales in the United States are running about $250 billion per year so the amount spent on electricity would increase by 16%. U.S. GDP is approximately $10 trillion; $40 billion/$10 trillion = 0.004 or 0.4%. It is plausible that the range may be 0.2 to 0.6% for these coarse estimates.

118. U.S. EPA. October 1997. "Benefits and Costs of the Clean Air Act, 1970 to 1990." Available on line at http://www.epa.gov/oar/sect812/copy.html.

119. Jorgenson, D.W., R. Goettle, B.W. Hurd, J.B. Smith, and S.M. Mills. 2004. *U.S. Market Consequences of Global Climate Change*. Pew Center on Global Climate Change, Arlington, VA.

120. As mentioned above, the work by Keith et al. on wind power climate change and by Pacala et al. on wind power weather change is very recent. All three groups involved feel that additional research is needed.

121. http://www.cfo.doe.gov/budget/

122. "Speech Three: Making a Market." 2004. In *Climate Change: Debating America's Policy Options.* New York. Council on Foreign Relations, as well as Morgan, M.G. 2000. "Managing Carbon from the Bottom Up." *Science* 289:2285, September 29.

123. Palmgren, C.R., M.G. Morgan, W. Bruine de Bruin, and D.W. Keith. In press. "Initial Public Perceptions of Deep Geological and Oceanic Disposal of Carbon Dioxide." *Environmental Science and Technology*.

124. Loughran, D.S. and J. Kulick. 2004. "Demand Side Management and Energy Efficiency in the United States." *The Energy Journal,* 25(1): 19-43; and Parfomak, P.W. and L.B. Lave. 1996. "How Many Kilowatts Are in a Negawatt? Verifying ex-post estimates of utility conservation impacts at the regional level." *Energy Journal* 17:59-88, 1996.

125. The following is an example of how such a 1% charge for R&D might be allocated (the numbers, in millions of dollars, are intended simply to illustrate a plausible level of R&D investment). Development of IGCC and other advanced coal conversion systems (800); Research on ameliorating the environmental impacts of coal extraction (30); Methods to evaluate and monitor sites for deep geological storage (300); 3P emissions control technology (30); Basic technology research on photovoltaic materials (60); Other solar related research (30); Advanced wind technology (50); Studies of the potential weather/climate impacts of wind (5); Research on advanced nuclear power and spent fuel management options (500); Research on low cost LNG (80); Research on H_2 handling and storage (20); Basic technology research on fuel cells (40); Advanced electric vehicle propulsion systems (100); Research on portable micro-fuel cells (5); Basic technology research on wide band-gap semi-conductors, advanced power electronics and FACTS (80); Basic technology research on superconducting materials (30); Research on energy storage systems (70); Development and demonstration of advanced methods for grid surveillance and control (50); Development and demonstration of advanced energy efficient end use devices (50); Development and demonstration of advanced methods for real time load management (30); Development and demonstration of advanced distribution system controls (20); Development and demonstration of micro-grid control technologies (10); Development and demonstration of CHP DG technologies (20); Fusion (60); Other geophysical energy sources besides wind and solar (10); Other environmental issues (20); Total (2,500).

This report discusses options for reducing greenhouse gas emissions from the U.S. electricity sector. The Pew Center on Global Climate Change was established by the Pew Charitable Trusts to bring a new cooperative approach and critical scientific, economic, and technological expertise to the global climate change debate. We intend to inform this debate through wide-ranging analyses that will add new facts and perspectives in four areas: policy (domestic and international), economics, environment, and solutions.

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