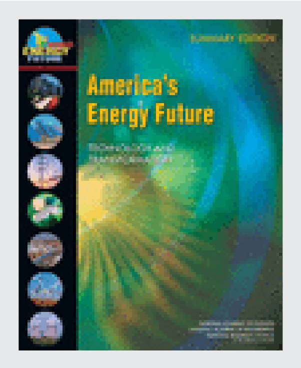

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America's Energy Future

TECHNOLOGY AND TRANSFORMATION

SUMMARY EDITION

Committee on America's Energy Future

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NATIONAL RESEARCH COUNCIL
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Foreword

Energy, which has always played a critical role in our country's national security, economic prosperity, and environmental quality, has over the last two years been pushed to the forefront of national attention as a result of several factors:

- World demand for energy has increased steadily, especially in developing nations. China, for example, saw an extended period (prior to the current worldwide economic recession) of double-digit annual increases in economic growth and energy consumption.
- About 56 percent of the U.S. demand for oil is now met by depending on imports supplied by foreign sources, up from 40 percent in 1990.
- The long-term reliability of traditional sources of energy, especially oil, remains uncertain in the face of political instability and limitations on resources.
- Concerns are mounting about global climate change—a result, in large measure, of the fossil-fuel combustion that currently provides most of the world's energy.
- The volatility of energy prices has been unprecedented, climbing in mid-2008 to record levels and then dropping precipitously—in only a matter of months—in late 2008.
- Today, investments in the energy infrastructure and its needed technologies are modest, many alternative energy sources are receiving insufficient attention, and the nation's energy supply and distribution systems are increasingly vulnerable to natural disasters and acts of terrorism.

All of these factors are affected to a great degree by the policies of government, both here and abroad, but even with the most enlightened policies the overall energy enterprise, like a massive ship, will be slow to change course. Its complex mix of scientific, technical, economic, social, and political elements means that the necessary transformational change in how we generate, supply, distribute, and use energy will be an immense undertaking, requiring decades to complete.

To stimulate and inform a constructive national dialogue about our energy future, the National Academy of Sciences and the National Academy of Engineering initiated a major study in 2007, "America's Energy Future: Technology Opportunities, Risks, and Tradeoffs." The America's Energy Future (AEF) project was initiated in anticipation of major legislative interest in energy policy in the U.S. Congress and, as the effort proceeded, it was endorsed by Senate Energy and Natural Resources Committee Chair Jeff Bingaman and former Ranking Member Pete Domenici.

The AEF project evaluates current contributions and the likely future impacts, including estimated costs, of existing and new energy technologies. It was planned to serve as a foundation for subsequent policy studies, at the Academies and elsewhere, that will focus on energy research and development priorities, strategic energy technology development, and policy analysis.

The AEF project has produced a series of five reports, plus this *Summary Edition*, designed to inform key decisions as the nation begins a comprehensive examination of energy policy issues this year. Numerous studies conducted by diverse organizations have benefited the project, but many of those studies disagree about the potential of specific technologies, particularly those involving alternative sources of energy such as biomass, renewable resources for generation of electric power, advanced processes for generation from coal, and nuclear power. A key objective of the AEF series of reports is thus to help resolve conflicting analyses and to facilitate the charting of a new direction in the nation's energy enterprise.

The AEF project, outlined in Appendix C, included a study committee and three panels that together have produced an extensive analysis of energy technology options for consideration in an ongoing national dialogue. A milestone in the project was the March 2008 "National Academies Summit on America's Energy Future" at which principals of related recent studies provided input to the AEF study committee and helped to inform the panels' deliberations. A report chronicling the event, *The National Academies Summit on America's Energy Future:*

Summary of a Meeting (Washington, D.C.: The National Academies Press), was published in October 2008.

The AEF project was generously supported by the W.M. Keck Foundation, Fred Kavli and the Kavli Foundation, Intel Corporation, Dow Chemical Company Foundation, General Motors Corporation, GE Energy, BP America, the U.S. Department of Energy, and our own Academies.

Ralph J. Cicerone, President
National Academy of Sciences
Chair, National Research Council

Charles M. Vest, President
National Academy of Engineering
Vice Chair, National Research Council

Preface

The security and sustainability of our nation's energy system have been perennial concerns since World War II. Indeed, all postwar U.S. presidents have focused some attention on energy-supply issues, especially our growing dependence on imported petroleum and the environmental impacts of fossil-fuel combustion—the latter including the direct effects of pollutant emissions on human health and, more recently, the impacts of greenhouse gases, particularly carbon dioxide (CO_2), on global warming.

The United States has made a great deal of progress in reducing traditional gaseous and particulate emissions (e.g., SO_x, NO_x) through regulatory controls and the technology improvements that have followed. But greenhouse gas emissions are only beginning to be addressed in any meaningful way. The United States also needs to lower its dependence on fragile supply chains for some energy sources, particularly petroleum at present and possibly natural gas in the future, and to avoid the impacts of this dependence on our nation's economy and national security.

As a result of these and other factors (described in Chapter 1), such as the nation's increasingly vulnerable transmission and distribution systems, there has been a steadily growing consensus[1] that our nation must fundamentally transform the ways in which it produces, distributes, and consumes useful energy. Given the size and complexity of the U.S. energy system and its reach into all aspects of

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[1]See, for example: *Lighting the Way: Toward a Sustainable Energy Future*, published by the InterAcademy Council in 2007 (www.interacademycouncil.net/?id=12161); *Ending the Energy Stalemate*, published by the National Commission on Energy Policy in 2007 (www.energycommission.org/ht/d/sp/i/492/pid/492); and *Facing the Hard Truths About Energy*, published by the National Petroleum Council in 2007 (www.npchardtruthsreport.org).

American life, this transformation will be an enormous undertaking; it will require fundamental changes, structural as well as behavioral, among producers and consumers alike. This report lays out the technical opportunities, the uncertainties, and some of the costs and benefits of initiating this transformation in earnest.

Given the massive installed base of long-lived energy production and distribution assets, together with a certain inertia—caused by uncertainties with respect to new technologies and regulations and by the generally slow pace of change in existing industrial practices, public policies, and consumer habits—the challenge that the nation faces not only is great but also will not be met overnight. *As a result, a meaningful and timely transformation to a more sustainable and secure energy system will likely entail a generation or more of sustained efforts by both the public and the private sectors.*

"Business as usual" approaches for obtaining and using energy will be inadequate for achieving the needed transformation. The efforts required will involve not only substantial new investments by the public and private sectors in research, development, demonstration, and deployment—in virtually all aspects of the energy infrastructure—but also new public policies and regulations on energy production, distribution, and use. Our energy system is, after all, much more than a set of technological arrangements; it is also a deep manifestation of society's economic, social, and political arrangements.

The America's Energy Future (AEF) Committee began this study at a moment of rapidly rising prices both in crude oil and in other raw materials that underpin the infrastructure that produces and delivers useful energy. As the study progressed, these prices reached a peak, began to fall steeply in the face of a global recession, and then began to rise again. Because it is virtually impossible to forecast future prices, this report makes no attempt to do so. Nevertheless, it is clear to the committee that market incentives for businesses and individuals to both invest in and deploy new energy technologies will depend most crucially, though not solely, on such prices. The technologies to be deployed must have adequate maturity, market appeal, and capability to meet the desired demands, and their development must be supported by appropriate public policies and regulations governing energy production, distribution, and use.[2]

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[2]Any substantial change in the demand for key inputs, whether of primary energy stocks or of the resources required to transport and transform them, will strain the existing infrastructure and limit the pace of change.

The committee carefully considered existing and emerging technologies alike, some of which are now fairly well understood in principle though not necessarily deployable at scale or competitive in the marketplace, and it assessed how the deployment of such technologies might enable the nation to achieve meaningful transformation of the energy system over the next few decades. The committee did not, however, consider the opportunities available through conservation efforts or other opportunities through changes in policy or other socioeconomic initiatives. One of the committee's conclusions is that there is no technological "silver bullet" at present that could transform the U.S. energy system through a substantial new source of clean and reasonably priced domestic energy. Instead, the transformation will require a balanced portfolio of existing (though perhaps modified) technologies, multiple new energy technologies, and new energy-efficiency and energy-use patterns. This will in turn require a sustained national will and commitment of resources to develop and deploy these assets where needed.

Throughout this study the committee also paid close attention to the practical problems of developing and deploying new technologies, even assuming that there is the requisite national commitment to do so. An example is the integration of sizable new supplies of electricity from intermittent sources (e.g., wind and solar power) into the nation's electrical transmission and distribution systems. These systems need to be upgraded and continuously improved to enhance their reliability and security, to meet the needs of 21st-century electricity production technologies, and to provide for patterns of use that are more efficient.

Although this report focuses on the U.S. energy system, decision makers will need to take a wider view. It is clear that the country's economic, national security, and environmental goals, especially with respect to energy, cannot be fully achieved without collective international action.[3] Our nation's prosperity depends on global prosperity, our national security is tied to international security, and the achievement of our environmental goals depends on environmental protection actions taken elsewhere. In short, full realization of goals of the United States for transforming its energy sector requires that we find effective mechanisms for working with other nations, many of which face similar challenges. Maintaining an awareness of international developments and cooperating with other countries on research and development, pilot projects, and commercial demonstrations will be key to our own success.

[3]Such collective action among nations is not easy to achieve, as it requires broad participation, consequential monitoring, and meaningful compliance by all.

It is beyond the scope of this committee's charge to opine on the priority, relative to other national issues, of initiating and sustaining a national effort to transform our energy sector. However, I personally believe that despite the uncertainties before us, it is a truly urgent matter to begin such a transformation and, moreover, that the technology and knowledge for doing so are at hand. Indeed, the urgency for action to meet the nation's needs in the economic, environmental, and national security arenas as they relate to energy production and use are unique in our history, and delayed action could dramatically increase the challenges we face. But a timely transformation of the energy system is unlikely to happen without finally adopting a strategic energy policy to guide developments over the next decades. *Long-term problems require long-term solutions, and only significant, deliberate, stable, integrated, consistent, and sustained actions will move us to a more secure and sustainable energy system.*

I also believe that we should not allow short-term fluctuations, either in the prices of energy supplies or in geopolitical affairs, to distract us from this critical long-term effort. Creating a more sustainable and secure energy system will require leadership, courage, risk-taking, and ample support, both public and private, but in my view such investments will generate a significant stream of long-term dividends.

Harold T. Shapiro, *Chair*
Committee on America's Energy Future

Acknowledgments

This study could not have been done so well and on such a rapid schedule without the inspired contributions of a large number of individuals and organizations. First and foremost, I thank the committee members and staff for their dedication and hard work. These individuals brought a remarkably diverse array of disciplines, skills, and viewpoints to the study. As a result, our deliberations were intellectually stimulating—sometimes vigorous, but always respectful—as we worked together to develop this consensus report.

The committee initially organized itself into seven subgroups to facilitate information-gathering and, ultimately, the development of Chapters 4–9, which appear in Part 2 of this report:

- Alternative liquid transportation fuels (chaired and staffed, respectively, by Mike Ramage and Evonne Tang)
- Crosscutting and integration issues (Jim Sweeney and Madeline Woodruff)
- Electricity transmission and distribution (Jim Markowsky; Alan Crane and Sarah Case)
- Energy efficiency (Lester Lave; Madeline Woodruff, Greg Eyring, and Tom Menzies)
- Fossil-fuel energy (Lynn Orr and Greg Eyring)
- Nuclear energy (Dick Meserve and Sarah Case)
- Renewable energy (Larry Papay and K. John Holmes, assisted by Mirzayan Science and Technology Policy Graduate Fellows Amy Hee Kim, Dorothy Miller, and Stephanie Wolahan).

I thank these chairs for their able leadership, and I thank the subgroup members, staff, and fellows for their good work. I also express my gratitude to study director Kevin Crowley, who worked tirelessly to keep the entire study moving forward and to help the committee develop and articulate its key findings, which appear in Part 1 of this report.

The subgroups held separate meetings to obtain presentations and to gather the information that now appears in the Part 2 chapters. On behalf of the entire committee, I thank the outside experts who participated in these meetings. They are too numerous to list in this short section but are identified in Appendix B.

I also gratefully acknowledge the consultants who assisted the committee and its three sister panels (see Appendix C) with some of the analyses that were used in this report:

- Anup Bandivadekar, International Council on Clean Transportation
- Peter Biermayer, Sam Borgeson, Rich Brown, Jon Koomey, Alan Meier, and Steve Selkowitz, Lawrence Berkeley National Laboratory
- Anjan Bose, Washington State University
- Steve Dunn, Southwest Energy Efficiency Project
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- Samuel Fleming, Claremont Canyon Consultants
- Mark Frankel, New Buildings Institute
- Jim Harding, Independent Consultant
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- Sheldon Kramer, Independent Consultant
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- Mike Messenger, Itron, Inc.
- Christopher Weber, Carnegie Mellon University.

Finally, I thank the many other National Academies staff who helped to make this study a success. Peter Blair and Jim Zucchetto, comanagers of the America's Energy Future Project, provided critical advice and guidance to the committee throughout the project. Mirzayan Science and Technology Policy Graduate Fellow Lawrence Lin and senior program associate Matt Bowen helped with the initial assembly of the massive literature that the committee used, and Matt Bowen also assisted with report review. Anderson Commonweal Intern Stephanie

Oparaugo assisted with research and administrative tasks for the nuclear energy chapter. LaNita Jones and Jonathan Yanger provided critical logistical support of the committee's work. Consultant Steve Marcus edited the report. Stephen Mautner supervised the report's publication by the National Academies Press, Estelle Miller provided design and layout, and Susan Maurizi and Livingston Sheats took responsibility for production editing. All figures in the report were rendered by Danial James Studios of Golden, Colorado.

It has been a great pleasure to work with such a talented and committed group of people. We learned a great deal from our presenters, consultants, and each other during the course of this study. It is my hope that our collective efforts have produced a report that will inform decision making and help engender wise policies and actions among our nation's political and business leaders.

Harold T. Shapiro

Acknowledgment of Reviewers

This report has been reviewed in draft form by individuals chosen for their diverse perspectives and technical expertise, in accordance with procedures approved by the National Research Council's Report Review Committee. The purpose of this independent review is to provide candid and critical comments that will assist the institution in making the published report as sound as possible and to ensure that the report meets institutional standards for objectivity, evidence, and responsiveness to the study charge. The review comments and draft manuscript remain confidential to protect the integrity of the deliberative process. We wish to thank the following individuals for their participation in the review of this report:

Rakesh Agrawal, Purdue University
Philip W. Anderson, Princeton University
R. Stephen Berry, University of Chicago
Thomas Cochran, Natural Resources Defense Council
Michael Corradini, University of Wisconsin, Madison
Paul DeCotis, State of New York, Office of the Governor
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John Wise, ExxonMobil (retired)
John Wootten, Peabody Energy
Kurt Yeager, Electric Power Research Institute.

Although the reviewers listed above have provided many constructive comments and suggestions, they were not asked to endorse the conclusions or recommendations, nor did they see the final draft of the report before its release. The review of this report was overseen by Elisabeth M. Drake, Massachusetts Institute of Technology, and Robert A. Frosch, Harvard University. Appointed by the National Research Council, they were responsible for making certain that an independent examination of this report was carried out in accordance with institutional procedures and that all review comments were carefully considered. Responsibility for the final content of this report rests entirely with the authoring committee and the institution.

Contents

APPENDIXES

Listed below are the chapters that constitute Part 2,
which is published in the complete edition of
America's Energy Future: Technology and Transformation.

PART 2

Executive Summary

This report of the Committee on America's Energy Future addresses a potential new portfolio of energy-supply and end-use technologies—their states of development, costs, implementation barriers, and impacts—both at present and projected over the next two to three decades. The report's aim is to inform policy makers about technology options for transforming energy production, distribution, and use to increase sustainability, support long-term economic prosperity, promote energy security, and reduce adverse environmental impacts. Among the wide variety of technologies under development that *might* become available in the future, this report focuses on those with the best prospects of fully maturing during the three time periods considered: 2008–2020, 2020–2035, and 2035–2050.

Eight key findings emerge.

First, with a sustained national commitment, the United States could obtain substantial energy efficiency improvements, new sources of energy, and reductions in greenhouse gas emissions through the accelerated deployment of existing and emerging energy-supply and end-use technologies. These options are described in more detail below and in Chapter 2. Mobilization of the public and private sectors, supported by sustained long-term policies and investments, will be required for the decades-long effort to develop, demonstrate, and deploy these technologies. Moreover, actions taken between now and 2020 to develop and demonstrate several key technologies will largely determine options for many decades to come. Therefore, it is imperative that the technology development and demonstration activities identified in this report be started soon, even though some will be expensive and not all will be successful: some may fail, prove uneconomic, or be overtaken by better technologies.

Second, the deployment of existing energy efficiency technologies is the nearest-term and lowest-cost option for moderating our nation's demand for energy, especially over the next decade. The potential energy savings available from the accelerated deployment of existing energy efficiency technologies in the buildings, transportation, and industrial sectors could more than offset the U.S. Energy Information Administration's (EIA's) projected increases in energy consumption through 2030. In fact, the full deployment of cost-effective energy efficiency technologies in buildings alone could eliminate the need to construct any new electricity-generating plants in the United States except to address regional supply imbalances, replace obsolete power generation assets, or substitute more environmentally benign electricity sources—assuming, of course, that these efficiency savings are not used to support increased use of electricity in other sectors. Accelerated deployment of these technologies in the buildings, transportation, and industrial sectors could reduce energy use by about 15 percent (15–17 quads, that is, quadrillions of British thermal units) in 2020, relative to the EIA's "business as usual" reference case projection, and by about 30 percent (32–35 quads) in 2030 (U.S. energy consumption in 2007 was about 100 quads). Even greater energy savings would be possible with more aggressive policies and incentives. Most of these energy efficiency technologies are cost-effective now and are likely to continue to be competitive with any future energy-supply options; moreover, additional energy efficiency technologies continue to emerge.

Third, the United States has many promising options for obtaining new supplies of electricity and changing its supply mix during the next two to three decades, especially if carbon capture and storage and evolutionary nuclear plants can be deployed at required scales. However, the deployment of these new supply technologies is very likely to result in higher consumer prices for electricity.

- Renewable-energy sources could provide about an additional 500 TWh (500 trillion kilowatt-hours) of electricity per year by 2020 and about an additional 1100 TWh per year by 2035 through new deployments in favorable resource locations (total U.S. electricity consumption at present is about 4000 TWh per year).

- Coal-fired plants with carbon capture and storage (CCS) could provide as much as 1200 TWh of electricity per year by 2035 through repowering and retrofits of existing plants and as much as 1800 TWh per year by 2035 through new plant construction. In combination, the entire existing coal power fleet could be replaced by CCS coal power by 2035.
- Nuclear plants could provide an additional 160 TWh of electricity per year by 2020, and up to 850 TWh by 2035, by modifying current plants to increase their power output and by constructing new plants.
- Natural gas generation of electricity could be expanded to meet a substantial portion of U.S. electricity demand by 2035. However, it is not clear whether adequate supplies of natural gas will be available at competitive prices to support substantially increased levels of electricity generation, and such expansion could expose the United States to greater import dependence and result in increased emissions of carbon dioxide (CO_2).

Fourth, expansion and modernization of the nation's electrical transmission and distribution systems (i.e., the power grid) are urgently needed. Expansion and modernization would enhance reliability and security, accommodate changes in load growth and electricity demand, and enable the deployment of new energy efficiency and supply technologies, especially intermittent wind and solar energy.

Fifth, petroleum will continue to be an indispensable transportation fuel during the time periods considered in this report. Maintaining current rates of domestic petroleum production (about 5.1 million barrels per day in 2007) will be challenging. There are limited options for replacing petroleum or reducing petroleum use before 2020, but there are more substantial longer-term options that could begin to make significant contributions in the 2030–2035 timeframe. Options for obtaining meaningful reductions in petroleum use in the transportation sector include the following:

- *Improving vehicle efficiency.* Technologies to improve vehicle efficiency are available for deployment now, and new technologies continue to emerge.
- *Developing technologies for the conversion of biomass and coal-to-liquid fuels.* By 2035, cellulosic ethanol and coal-and-biomass-

to-liquid fuels with CCS could replace about 15 percent of the fuel currently consumed in the transportation sector (1.7–2.5 million barrels per day of gasoline equivalent) with near-zero life-cycle CO_2 emissions. Coal-to-liquid fuels with CCS could replace about 15–20 percent of current fuel consumption in the transportation sector (2–3 million barrels per day; the lower estimate holds if coal is also used to produce coal-and-biomass-to-liquid fuels) and would have life-cycle CO_2 emissions similar to those of petroleum-based fuels. However, these levels of production would require the annual harvesting of 500 million dry tonnes (550 million dry tons) of biomass and an increase in coal extraction in the United States by 50 percent over current levels, resulting in a range of potential environmental impacts on land, water, air, and human health—including increased CO_2 emissions to the atmosphere from coal-to-liquid fuels unless process CO_2 from liquid-fuel production plants is captured and stored geologically. Commercial demonstrations of the conversion technologies integrated with CCS will have to be pursued aggressively and proven economically viable by 2015 if these technologies are to be commercially deployable before 2020. The development of advanced biomass-conversion technologies will require fundamental advances in bioengineering and biotechnology.

- *Electrifying the light-duty vehicle fleet through expanded deployment of plug-in hybrids, battery electric vehicles, and hydrogen fuel-cell vehicles.* Such a transition would require the development of advanced battery and fuel-cell technologies as well as modernization of the electrical grid to manage the increased demand for electricity.

Sixth, substantial reductions in greenhouse gas emissions from the electricity sector are achievable over the next two to three decades through a portfolio approach involving the widespread deployment of energy efficiency technologies; renewable energy; coal, natural gas, and biomass with carbon capture and storage; and nuclear technologies. Achieving substantial greenhouse gas reductions in the transportation sector over the next two to three decades will also require a portfolio approach involving the widespread deployment of energy efficiency technologies, alternative liquid fuels with low life-cycle CO_2 emissions, and light-duty vehicle electrification technologies.

To enable this portfolio approach in the electricity sector, the viability of two key technologies must be demonstrated during the next decade to allow for their widespread deployment starting around 2020:

- Demonstrate whether CCS technologies for sequestering carbon from the use of coal and natural gas to generate electricity are technically and commercially viable for application to both existing and new power plants. This will require the construction before 2020 of a suite (~15–20) of retrofit and new demonstration plants with CCS featuring a variety of feedstocks, generation technologies, carbon capture strategies, and geologic storage locations.
- Demonstrate whether evolutionary nuclear plants are commercially viable in the United States by constructing a suite of about five plants during the next decade.

A failure to demonstrate the viability of these technologies during the next decade would greatly restrict options to reduce the electricity sector's CO_2 emissions over succeeding decades. The urgency of getting started on these demonstrations to clarify future deployment options cannot be overstated.

Reducing greenhouse gas emissions from the liquid-fuel-based transportation sector in the 2020–2035 timeframe will also require a portfolio approach that includes cellulosic ethanol and coal-and-biomass-to-liquid fuels. Coal-and-biomass-to-liquid fuels can be produced in quantity starting around 2020 but will not have low carbon emissions unless geologic storage of CO_2 is demonstrated to be safe and commercially viable by 2015. Further reductions in greenhouse gas emissions could potentially be achieved in the transportation sector through electrification of the light-duty vehicle fleet, together with the production of electricity and hydrogen in ways that emit little or no CO_2, assuming the availability of suitable batteries or fuel cells. Although substantial reductions in emissions via these pathways are not likely until late in the 2020–2035 period and beyond, the widespread deployment of hydrogen fuel-cell vehicles during that time also holds some hope for more substantial long-term emission reductions in the transportation sector.

Seventh, to enable accelerated deployments of new energy technologies starting around 2020, and to ensure that innovative ideas continue to be explored, the

public and private sectors will need to perform extensive research, development, and demonstration over the next decade. Given the spectrum of uncertainties involved in the creation and deployment of new technologies, together with the differing technological needs and circumstances across the nation, a portfolio that supports a broad range of initiatives from basic research through demonstration will likely be more effective than targeted efforts to identify and select technology winners and losers. High-priority technology demonstration opportunities during the next decade include CCS, evolutionary nuclear power technologies, cellulosic ethanol, and advanced light-duty vehicles. Research and development opportunities during the next decade include advanced batteries and fuel cells, advanced large-scale storage for electrical load management, enhanced geothermal power, and advanced solar photovoltaic technologies.

Eighth, a number of current barriers are likely to delay or even prevent the accelerated deployment of the energy-supply and end-use technologies described in this report. Policy and regulatory actions, as well as other incentives, will be required to overcome these barriers. For technologies to be accepted in the market they must be clearly attractive—in terms of their performance, convenience, and cost—to investors, purchasers, and users. Regulations and standards that target performance characteristics can do a great deal to spur technological development and help improve market attractiveness.

Although the committee has done its best to identify those technologies likely to be available over the next two to three decades, many uncertainties remain on the scientific, technological, and policy frontiers and in energy markets. Consequently, the technology options identified in this report should be considered as important first-step technology assessments rather than as forecasts.

PART 1

1 Context and Challenges

This report assesses the status of energy-supply and end-use technologies[1] in the United States, both at present and over the next two to three decades. It is intended to inform the development of wise energy policies by our nation's decision makers and to provide the technical underpinnings for more detailed explorations of key energy-policy options in the second phase of the National Academies America's Energy Future (AEF) project. The complete study charge is presented in Box 1.1.

This first chapter, which establishes the context for the detailed energy-technology assessments that appear in Part 2 of this report, is divided into five sections. They describe the current U.S. energy system; some challenges that are likely to be encountered in transforming it; the role of technology in this transformation; the AEF Committee's strategy for addressing its study charge; and the report's organization.

[1]The AEF Committee uses the term "energy-supply and end-use technologies" in this report to connote the spectrum of technologies involved in the production, distribution, storage, and consumption of energy. These technologies include those that convert primary energy resources (e.g., fossil fuels, nuclear, solar, and wind) into useful forms (e.g., gasoline and electricity); technologies that transmit this energy to consumers (e.g., electrical transmission and distribution systems); technologies that store and utilize this energy (e.g., batteries, motors); and associated technologies, sometimes referred to as "demand-side" technologies, that control energy use (e.g., advanced electricity metering systems, or "smart meters").

BOX 1.1 Study Charge

This study will critically evaluate the current and projected state of development of energy-supply, storage, and end-use technologies. The study will not make policy recommendations, but it will analyze where appropriate the role of public policy in determining the demand and cost for energy and the configuration of the nation's energy systems. The committee will develop a "reference scenario" that reflects a projection of current economic, technology cost and performance, and policy parameters into the future. Within that scenario, the committee will evaluate energy technologies with respect to:

- Estimated times to readiness for deployment
- Current and projected costs (e.g., per unit of energy production or savings)
- Current and projected performance (e.g., efficiency, emissions per unit of output)
- Key technical, environmental, economic, policy, and social factors that would enhance or impede development and deployment
- Key environmental (including CO_2 mitigation), economic, energy security, social, and other life-cycle impacts arising from deployment
- Key research and development (R&D) challenges.

The committee may assess the sensitivity of these factors to possible variations in the key economic, technology cost and performance, and policy parameters that define the reference scenario.

The primary focus of the study will be on existing technologies and technologies likely to be available for deployment within the next decade. A secondary focus will be on technologies with longer times to deployment. The study will specifically provide estimates and findings on the following:

- For current technologies and technologies where initial deployment is judged to be within the next decade: estimates of costs, performance, and impacts
- For technologies where deployment is judged likely to be between 10 and 25 years: findings regarding key factors that enhance or impede adoption, implications for costs, and R&D challenges
- For technologies where deployment is judged likely to be greater than 25 years: findings regarding key factors that enhance or impede R&D challenges.

THE CURRENT U.S. ENERGY SYSTEM

The U.S. energy system currently comprises a vast and complex set of interlocking technologies for the production, distribution, and use of fuels and electricity (Boxes 1.2 and 1.3; Figure 1.1[2]). It evolved over the last century in response to a broad set of circumstances: rapidly growing demand for energy, advances in technology, diverse public policies and regulations, and the powerful market forces that have accompanied economic growth and globalization. As a result, the energy system's technologies and production assets are of many different vintages and often rely on aging and increasingly vulnerable infrastructures.

Five critical characteristics of this system stand out:

1. The United States relies on the burning of carbon-based fossil fuels for more than 85 percent of its energy needs (Figure 1.2).
2. The burning of fossil fuels has a number of deleterious environmental impacts, among the most serious of which is the emission of greenhouse gases,[3] primarily carbon dioxide (CO_2). At present, the United States emits about 6 billion tonnes (6 gigatonnes) of CO_2 per year into the atmosphere. Emissions have grown by almost 20 percent since 1990 but have recently leveled off somewhat (Figure 1.3). However, CO_2 emissions are projected to increase in the future under the Energy Information Administration's (EIA's) "business as usual" reference case (see Box 2.1 in Chapter 2).
3. Despite decades of declining energy intensity (i.e., energy consumption per dollar of gross domestic product; see Figure 1.4), the United States still has a higher per capita consumption of energy than either the European Union or Japan (Figure 1.5). And despite improvements in energy efficiency, U.S. energy consumption continues to rise, in part because of

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[2]Figures 1.1 through 1.12 are grouped under the section titled "America's Energy Past, Present, and Future: An Overview in Charts and Graphs," which starts on page 17.

[3]Greenhouse gases are so named because of their ability to absorb and emit infrared radiation. Water vapor and CO_2 are the most common greenhouse gases in Earth's atmosphere, but methane, nitrous oxides, and chlorofluorocarbons (CFCs) are also greenhouse gases. Recent studies (e.g., IPCC, 2007) indicate a high probability of a link between anthropogenic greenhouse gas emissions and observed effects on global warming, precipitation patterns, ocean acidification, and weather patterns. The National Academies recently initiated "America's Climate Choices," a suite of studies to inform and guide responses to climate change across the nation.

BOX 1.2 Primary Energy and Useful Energy

The energy that powers our civilization is obtained from a number of primary energy sources that exist in nature. These sources fall into two categories: flows of energy and stored energy. Examples of energy flows include sunlight, wind, and waves. Stored energy includes fossil energy (petroleum, natural gas, and coal), bioenergy (contained in biomass), and nuclear energy (stored in atomic nuclei in radioactive elements such as uranium) and the heat stored in Earth's upper crust. Primary energy sources can be converted into *useful* energy that, for example, powers a vehicle, lights a building, or supplies heat for an industrial process, although the conversion process inevitably involves energy losses (which can be quite considerable) and often entails substantial costs.

While the extent of these primary energy sources is usually large, there are a number of technological, economic, environmental, and labor constraints on converting them into useful energy. For example, many remaining domestic supplies of petroleum and natural gas are in difficult-to-access locations. Some are in environmentally sensitive areas. And renewable energy is unevenly distributed across the United States; in some cases, regions with abundant renewable potential are physically distant from demand centers. Such constraints are in fact critical in determining the actual mix of useful energy supplies that are available at particular times. Much of this report deals with the technology options for overcoming some of these constraints.

economic and population growth.[4] U.S. dependence on energy imports continues to rise as well (Figure 1.6). And steady increases in energy use are projected for the future (Figure 1.7) under EIA's business-as-usual reference case.[5]

4. The United States is almost completely dependent on petroleum for transportation—a situation that entails unique energy-security[6] chal-

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[4]In many cases, energy efficiency gains that could have further moderated per capita energy demand have instead been used to support new demands for energy, for example, through increased size and performance of light-duty vehicles.

[5]These are long-term projections that do not account for short-term demand variations. For example, global consumption of petroleum dropped in 2008 and is projected to drop in 2009 because of the current worldwide economic recession.

[6]The committee uses the term "energy security" to mean protection against disruptions to the energy supply chain that produces, distributes, and uses energy. Such disruptions can result from

BOX 1.3 ***Resources, Reserves, and Potential***

The terms "resource," "reserve," and "potential" are used throughout this report to describe the primary energy sources that exist in nature and may be tapped to produce useful energy. "Resource" refers to quantities of stored energy—i.e., solid, liquid, or gaseous fuels derivable from petroleum, natural gas, coal, uranium, geothermal, or biomass—that exist in nature and may be feasible to extract or recover, given favorable technology and economics. "Reserve" refers to that portion of the resource that can be economically extracted or recovered with current technology. "Potential" is used instead of resource to describe energy flows—such as from sunlight, wind, or the movement of water—that occur in nature and may be feasible to recover, given favorable technology and economics.

These primary energy sources are very large compared to U.S. energy demand. For example, the energy from sunlight reaching the land surface of the United States is thousands of times greater than the country's current annual consumption of energy; the energy from wind available in the United States is at least an order of magnitude larger; and the energy stored in geothermal, nuclear, and fossil reserves available to the United States is at least thousands of times larger. The challenge is to transform these vast resources into energy forms that are readily usable in a commercially and environmentally acceptable fashion.

lenges. The nation relies on coal, nuclear energy, renewable energy (primarily hydropower), and, more recently, natural gas for generating its electricity (Figures 1.8 and 1.9).

5. Many of the energy system's assets are aging: domestic oil and gas reserves are being depleted; currently operating nuclear plants were constructed largely in the 1970s and 1980s, and many coal plants are even older (Figure 1.10); and electrical transmission and distribution systems contain infrastructure and technologies from the 1950s. Renewing or replacing these assets will take decades and require investments totaling several trillion dollars.

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interruptions in energy imports, for example, or from damage to the energy infrastructure (either through intentional acts or overuse).

Fossil fuels have supported U.S. economic prosperity since the latter part of the 19th century. But their low market prices during most of this period encouraged high levels of energy consumption per capita and generally discouraged the development of alternative sources of energy, with two notable exceptions: hydroelectric and nuclear power, which currently account for about 7 percent and 19 percent, respectively, of U.S. electricity generation. Our nation's dependence on fossil fuels evolved not only because they were available at low market costs[7] but also because their physical and chemical properties are well suited to particular uses: petroleum for transportation; natural gas as an industrial feedstock, for residential and commercial space heating, and, more recently, as a fuel for electric-power generation; and coal for the generation of electricity and as a feedstock for some industrial processes (Figure 1.8). Indeed, most consumer-based, industrial, and governmental activities require, either directly or indirectly, the consumption of fossil fuels.

The current profile of U.S. energy use, summarized in Figures 1.1 and 1.2, shows that nearly 40 percent of the nation's economy is fueled by *petroleum*. More important, nearly all of our nation's transportation needs are being met by petroleum-based fuels, as shown in Figure 1.8, and prospects for alternatives are currently limited. Domestic production of petroleum in the United States peaked[8] in the 1970s and has been in decline for the past three decades. However, improvements in exploration and production technologies have helped to moderate these declines. About 56 percent of the petroleum consumed in the United States in 2008 was imported, in some cases from geopolitically turbulent or fragile regions.[9]

America's enormous appetite for oil, coupled with growth in demand from other countries, puts upward pressures on world prices, increases revenues to oil-exporting nations, and heightens the influence of those nations in world affairs.

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[7]These market costs often did not account for "externality" costs such as those stemming from the environmental and health impacts of producing, distributing, and consuming energy.

[8]There is a vigorous debate among experts about when we can expect world oil production to peak—and also about the importance of this issue for long-term energy supplies. Some judge that world production has already peaked or will do so in the near future; others argue that world oil production will continue to increase slowly for the foreseeable future or will have a sustained plateau. See, for example, Simmons (2005) and Wood et al. (2004).

[9]Each nation's access to or competition for energy is central to some of the major geopolitical tensions of our time. Using energy more efficiently and developing new domestic energy sources could help reduce U.S. dependence on imports from these unstable regions.

Historically, this influence has often been expressed in directions that are neither supportive of a well-functioning world oil market nor consistent with U.S. interests. Since U.S. consumption of oil is concentrated in key economic activities, such as transportation and home heating, this produces what many consider to be increasingly substantial economic and national security vulnerabilities. The current recession has reduced petroleum demand, and this condition may persist until the economic recovery gets under way. But if history is any guide, the resumption of worldwide economic growth will again raise the demand for petroleum and increase pressures on prices.

Almost a quarter of our nation's economy is fueled by *natural gas*, mostly for residential and commercial space heating and industrial uses, but increasingly for electric-power generation (see Figure 1.8). Indeed, over the past two decades, natural-gas-fired facilities have accounted for a significant fraction of new U.S. baseload power plants (Figure 1.10).[10] About 86 percent of the natural gas used in the United States at present is produced domestically, and much of the remainder comes from Canada. Prices for natural gas in the North American market have been lower than the price for liquefied natural gas[11] on the world market.

During the last 2 years, North American natural gas production from conventional resources has declined. But production from unconventional sources—such as coal beds, tight gas sands (rocks through which flow is very slow), and shale—has increased, largely in response to higher prices and new technology. Recent price declines, however, have reduced the incentive to develop new natural gas production, especially from unconventional sources. If domestic production growth could be continued and production sustained over long periods, North American sources could meet some portion of the potential growth in U.S. demand for natural gas. If, however, growth in domestic natural gas production is limited—by some combination of production declines from existing sources and of less-than-expected growth in new sources—the United States might have to import more natural gas, which would result in increased import dependence and exposure to world prices for liquefied natural gas.

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[10]Natural gas plants are used to provide both baseload and peaking power, but Figure 1.10 shows only baseload plants.

[11]Liquifying natural gas by cooling it to low temperatures (about –160°C) at close to atmospheric pressures makes it easier to transport and store.

Which of these futures occurs will depend as well on a set of interrelated factors including the following: demand growth, production technology, resource availability, and prices. There is some uncertainty, for example, regarding how easily domestic sources of natural gas production could be expanded and how quickly a global market for natural gas would emerge. If North American natural gas production cannot be expanded to meet demand, then dependence on natural gas imports could mirror that on petroleum.

Figure 1.8 also shows that the burning of fossil fuels—principally coal and secondarily natural gas—accounts for almost 75 percent of the electricity generated in the United States. Coal is abundant in this country and relatively inexpensive compared to other fossil fuels. The United States currently has about 20 years' worth of identified coal reserves in active mines. However, a much larger resource would be available for production if new mines were opened and if the rail infrastructure required to deliver coal—or sufficient long-distance transmission lines for delivery of electricity generated near the mine mouth—could be put in place. Costs of production are low enough that substantial quantities of coal can be produced at current coal prices. However, coal mining has significant environmental impacts, which will limit its suitability in some locations.

The use of fossil fuels to generate energy has a number of deleterious impacts on land resources, water supplies, and the well-being of citizens. Arguably, the most important unregulated environmental impact of fossil-fuel use is the emission of greenhouse gases, primarily CO_2, to the atmosphere. Petroleum use for transportation accounts for about one-third of total annual U.S. emissions of CO_2 (Figures 1.11 and 1.12), and fossil-fuel use for electricity generation accounts for more than another third (Figure 1.11). Coal use causes most of the emissions from electricity production. Natural gas produces about half as much CO_2 as coal per kilowatt-hour of electricity generated, but its emissions can be some 10–20 times higher per kilowatt-hour than those from nuclear or renewables (see Figure 2.15 in Chapter 2).

Although technologies for capturing and storing CO_2 have been demonstrated in nonelectrical applications, they have not yet been shown to be safely deployable at a sufficient scale for coal- and natural-gas-fired power plants. Even if the technology were to be proven for electrical applications, building the necessary infrastructure would require major investments over long periods of time, and substantial new regulations would have to be formulated to address safety, ownership, and liability issues. And, of course, there would be impacts on the price of electricity.

AMERICA'S ENERGY PAST, PRESENT, AND FUTURE
An Overview in Charts and Graphs

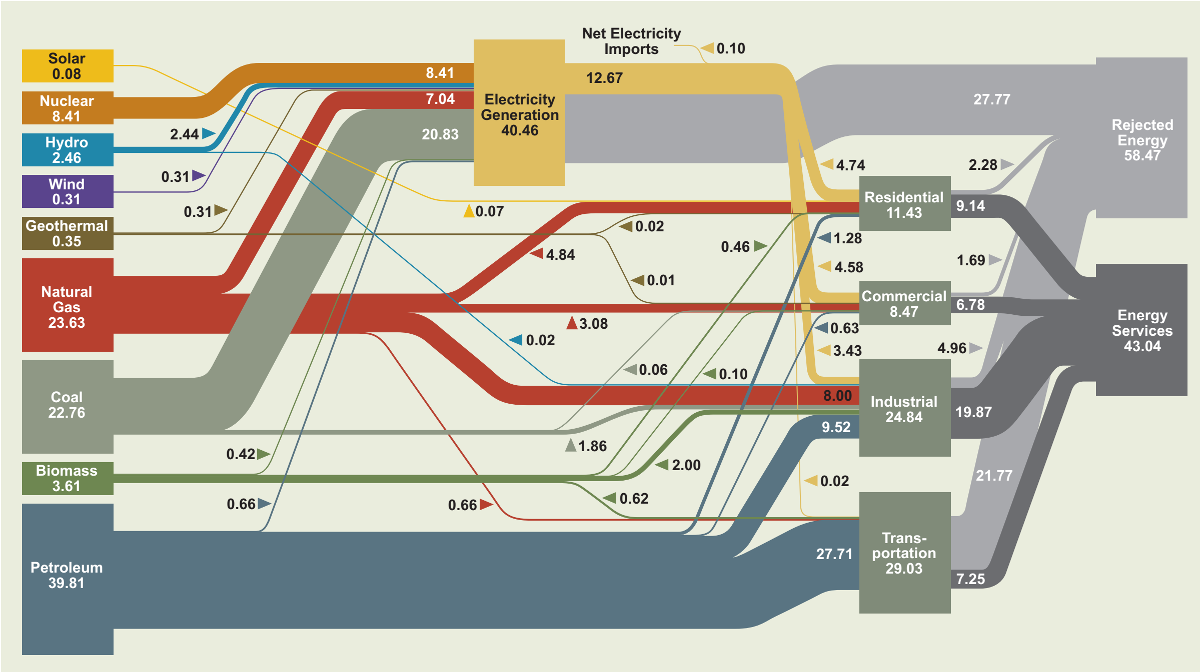

FIGURE 1.1 *Energy consumption in the United States in 2007 in quadrillions of British thermal units (quads). The figure illustrates the delivery of energy from primary fuel sources, which are shown in the boxes on the left side of the figure, to the residential, commercial, industrial, and transportation sectors, which are shown in the boxes at the center-right side of the figure. Energy is delivered to these sectors primarily in three forms: (1) electricity, which is produced principally from coal, natural gas, and nuclear power, and to a much lesser extent from renewable sources (hydro, solar, wind, and biomass); (2) liquid fuels, principally petroleum, with a small contribution from biomass-derived fuels (e.g., corn ethanol); and (3) natural gas for heating and as an industrial feedstock. Small quantities of coal and biomass are also used as industrial feedstocks. The width of the bars indicates the relative contributions of each energy source; the absolute contribution (in quads) is shown by the numerical labels next to each bar. The bar for electricity represents retail electricity sales only and does not include self-generated electricity. The boxes on the right side of the figure show that a total of about 101.5 quads of energy were consumed in the United States in 2007; about 43 quads were used to provide energy services, and more than 58 quads were "rejected" (i.e., not utilized to provide energy services) because of inefficiencies in energy production, distribution, and use.*
Sources: Lawrence Livermore National Laboratory and the Department of Energy, based on data from the Energy Information Administration, 2008a.

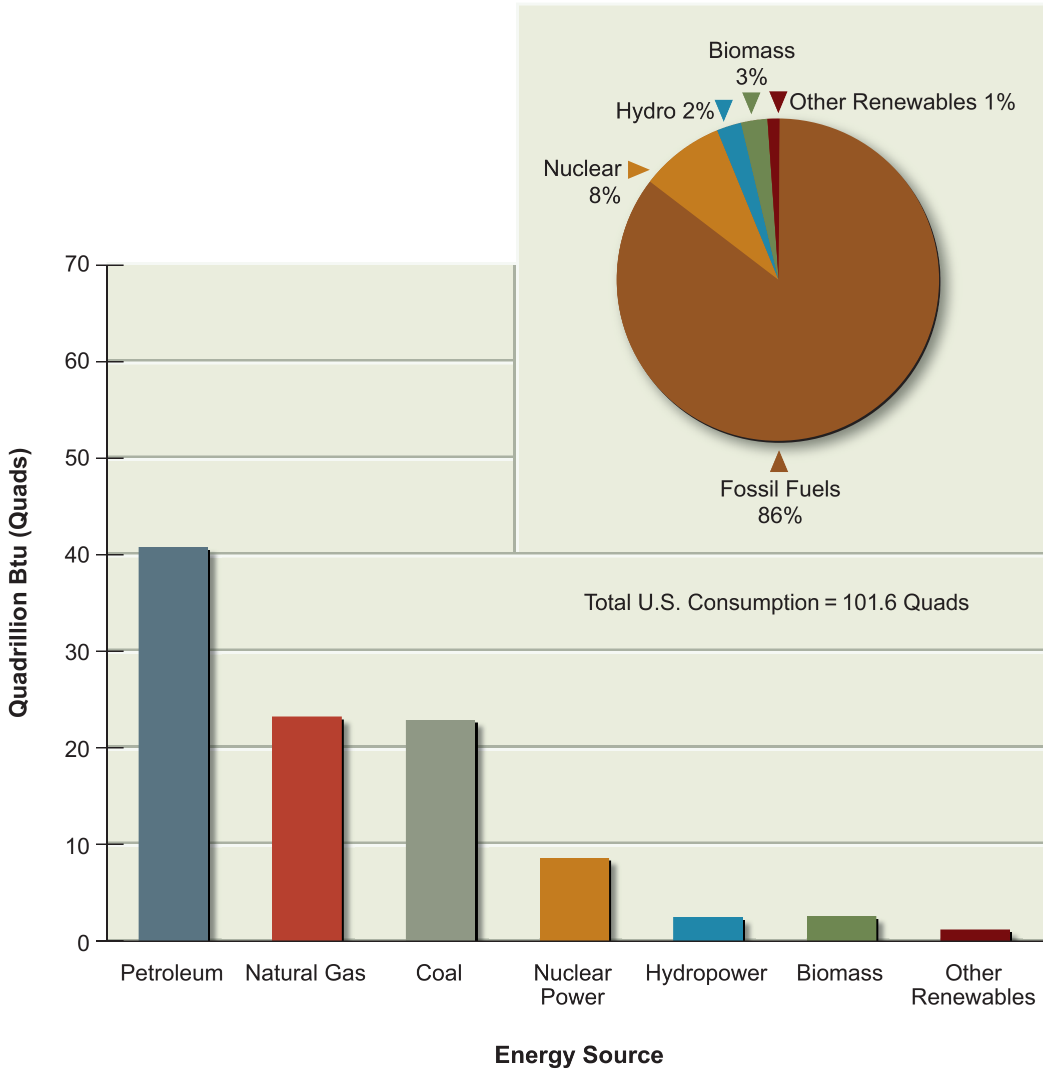

FIGURE 1.2 *Energy consumption in the United States in 2007 by fuel source, in quads (bars) and as percentages (pie chart).*
Source: Energy Information Administration, 2008b.

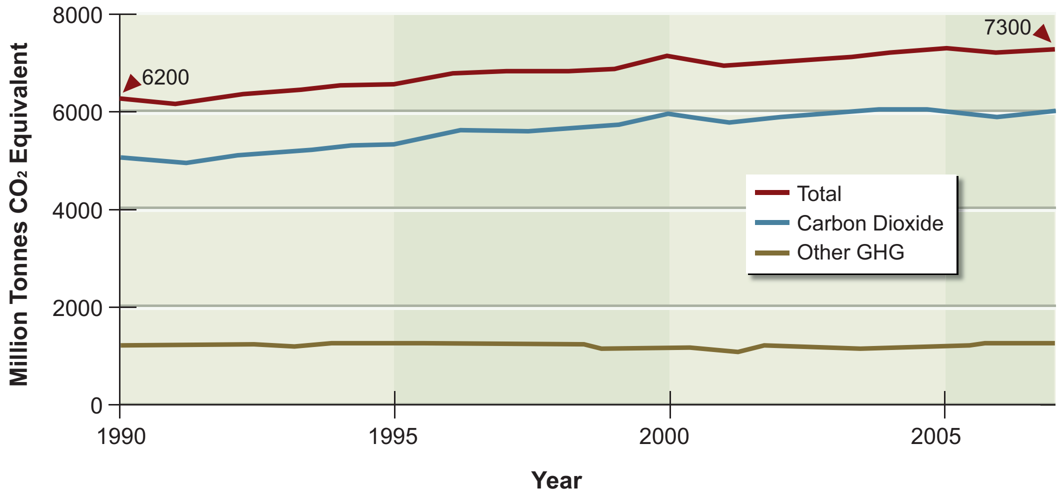

FIGURE 1.3 *Greenhouse gas emissions in the United States, 1990–2007, in millions of tonnes CO_2 equivalent. The "other" greenhouse gas (GHG) emissions shown on the diagram include methane and nitrous oxide, converted to CO_2-equivalent units. The 1990 and 2007 point estimates have been rounded to two significant figures.*
Source: Energy Information Administration, 2008b.

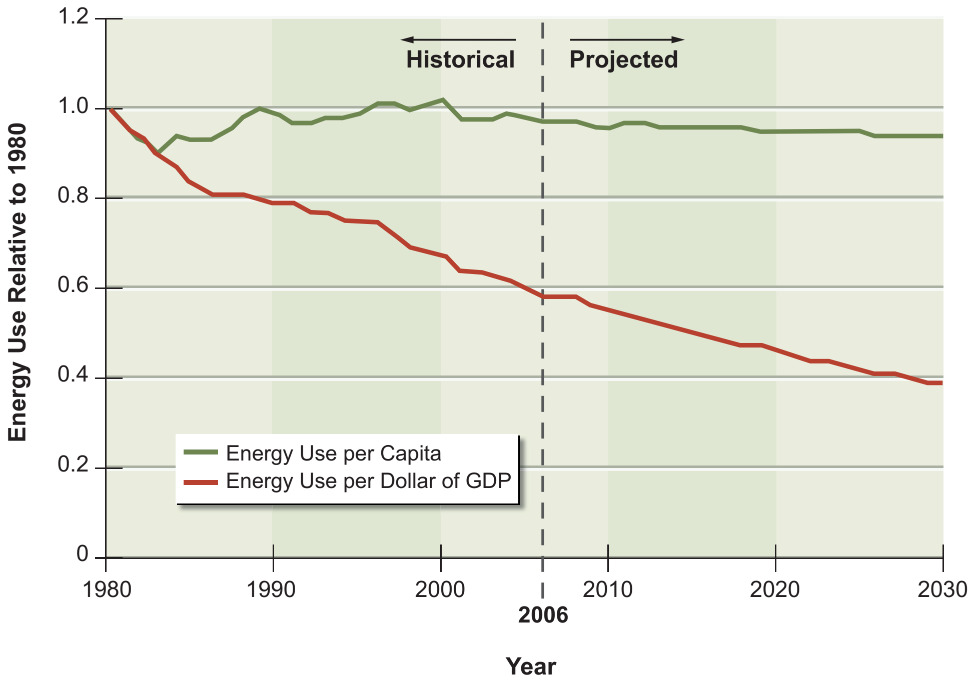

FIGURE 1.4 *Energy use in the United States per dollar of GDP and per capita, with 1980 energy use per dollar of GDP and per capita set to 1.0.*
Source: Energy Information Administration, 2008b.

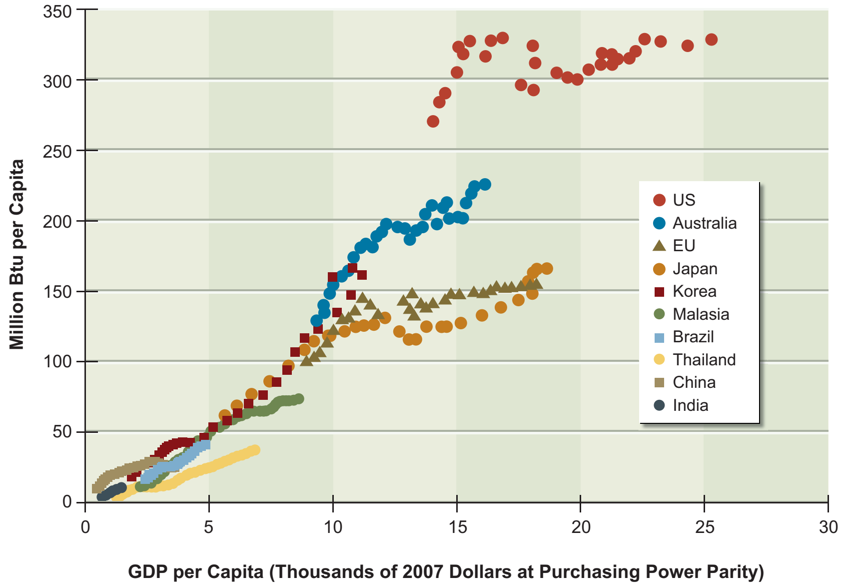

FIGURE 1.5 *Annual per capita energy use (in million Btu per capita) as a function of gross domestic product (GDP) at purchasing-power parity per capita. A progression over time for several representative countries is shown. GDP is a measure of economic activity. On average, higher per capita energy consumption is associated with increasing per capita GDP; however, in some cases, per capita GDP has increased while energy use has declined.*
Sources: Adapted from Shell International BV, Shell Energy Scenarios to 2050 *(2008), based on data from the International Monetary Fund and British Petroleum.*

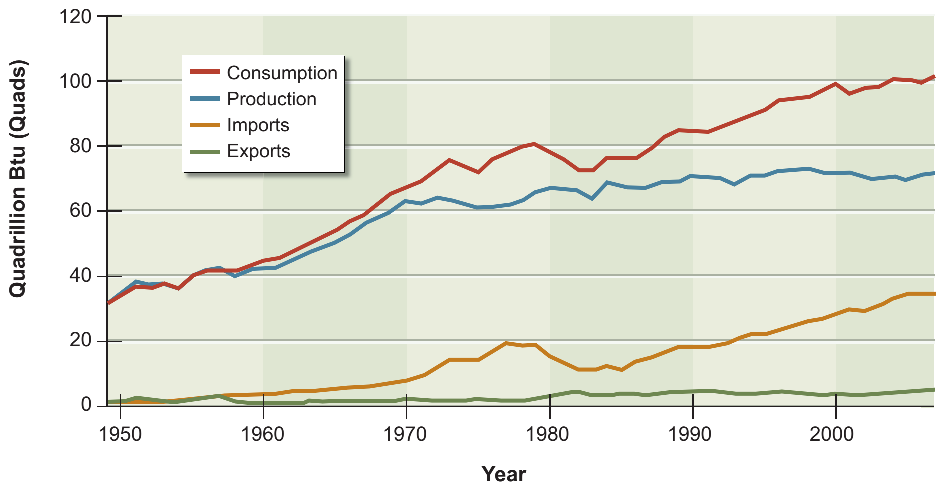

FIGURE 1.6 *Primary U.S. energy consumption, production, imports, and exports, 1949–2007, in quads.*
Source: Energy Information Administration, 2008b.

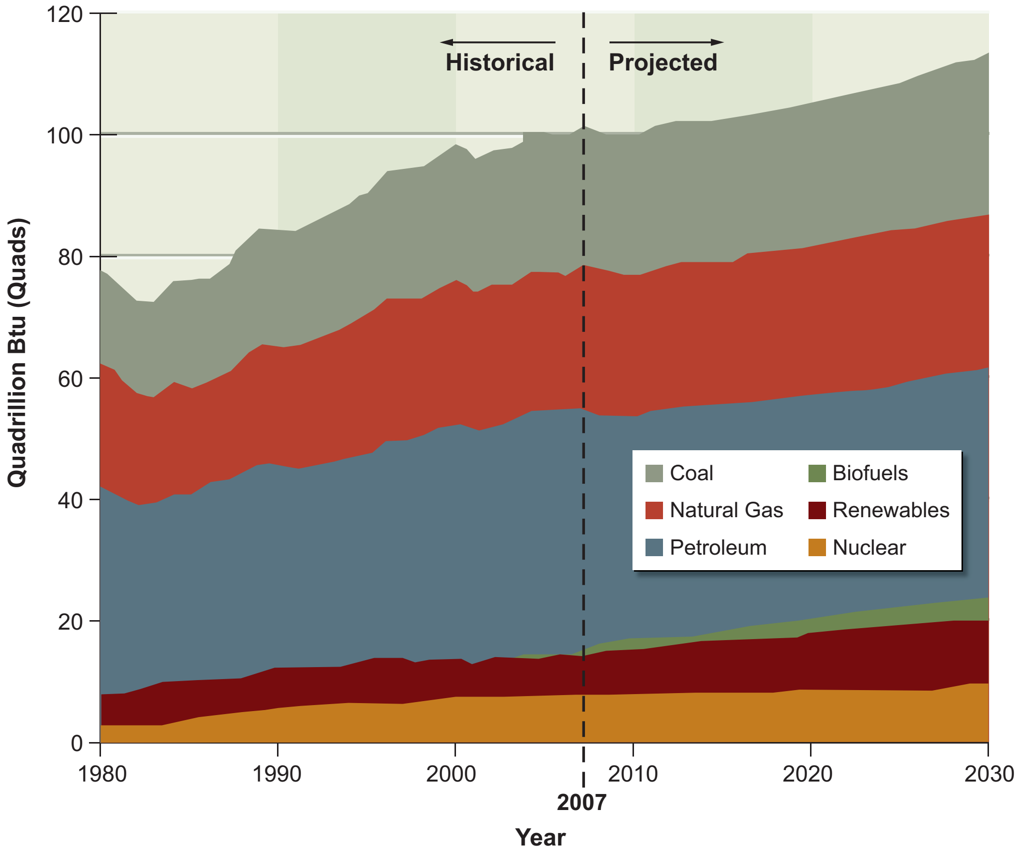

FIGURE 1.7 *Historical (1980–2007) and projected (2008–2030) energy consumption in the United States by primary energy source, in quads. The projected energy use from 2020 to 2030 reflects the U.S. Energy Information Administration's (EIA's) 2008 reference case; this reference case assumes that current policies that affect energy supply and consumption will remain unchanged and that economic growth rates and technology development and deployment trends will continue over the next 20 years. As explained in Box 2.1 in Chapter 2 and in Annex 3.A in Chapter 3, the AEF Committee uses the EIA reference case as the reference scenario for its study.*
Source: Energy Information Administration, 2008b.

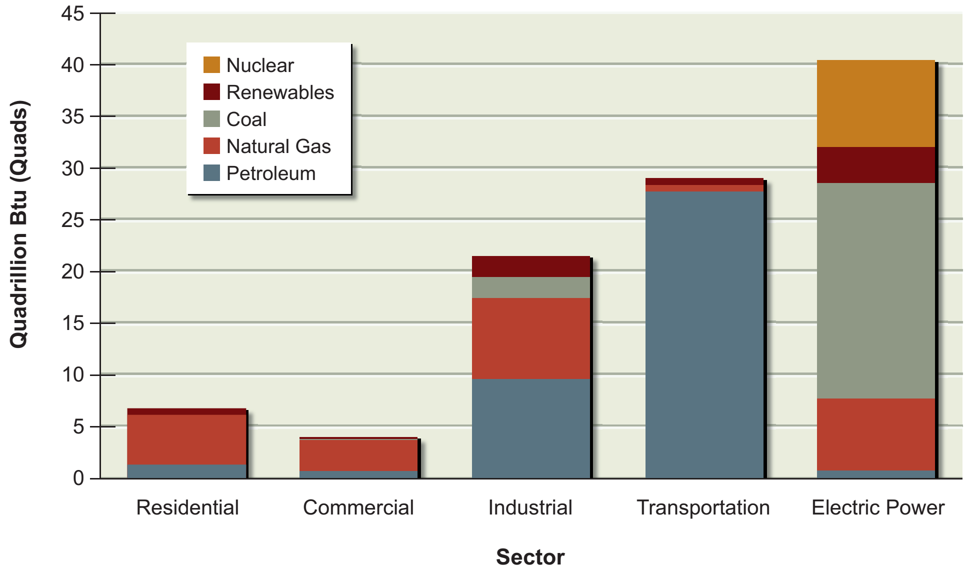

FIGURE 1.8 *Primary energy consumption by production sector and fuel type in the United States in 2007. Energy consumed by the electric power sector is used to produce electricity consumed by the end-use sectors shown in the figure.*
Source: Data from Energy Information Administration, 2008b.

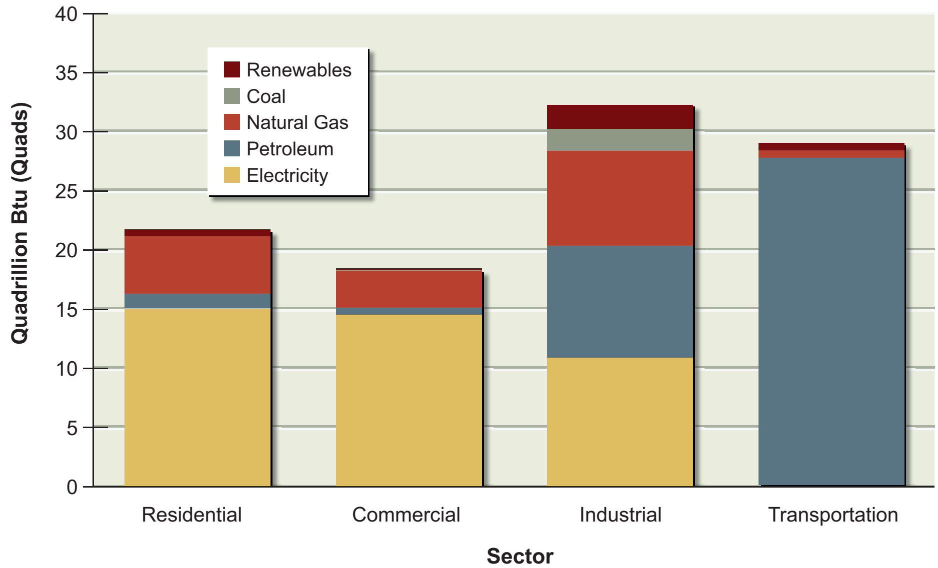

FIGURE 1.9 *Total energy consumption in the United States in 2007, shown by end-use sector and by fuel type. Also shown is each end-use sector's consumption of electricity. Electricity is a secondary energy source and is generated using fossil fuels and nuclear and renewable sources.*
Source: Data from Energy Information Administration, 2008b.

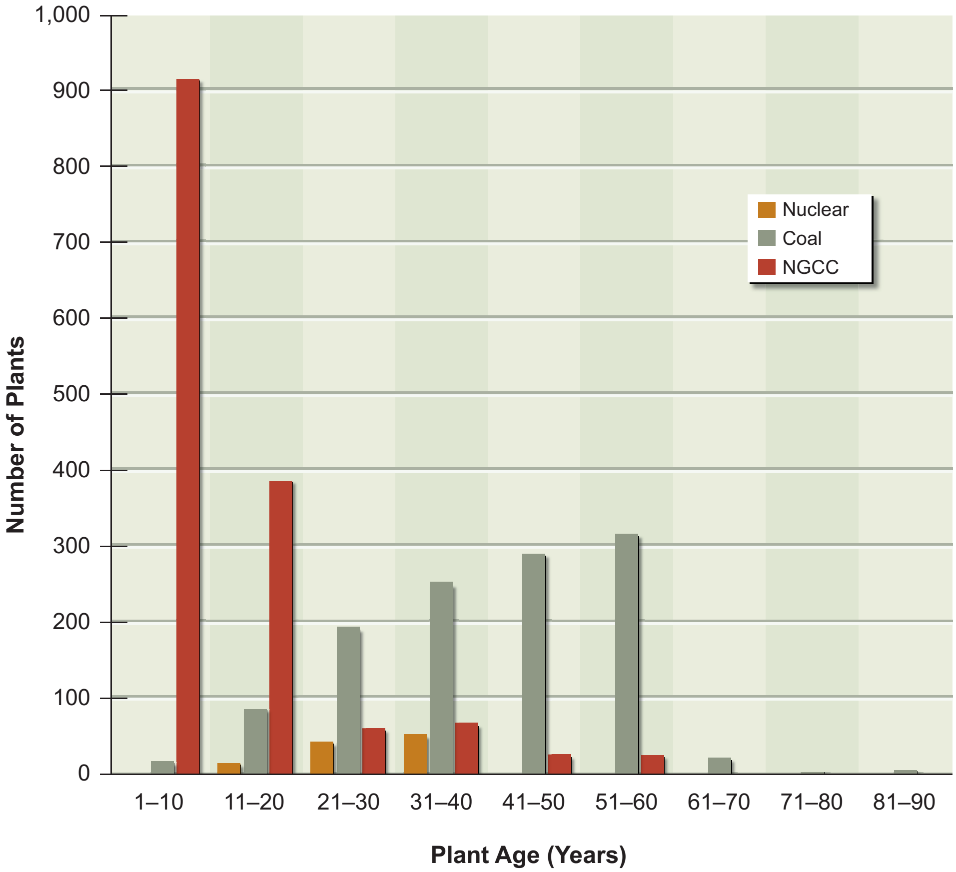

FIGURE 1.10 *Age of U.S. baseload power plants, in years. The age of U.S. nuclear plants, coal plants, and natural gas combined cycle (NGCC) plants is shown in 10-year intervals, as measured from their initial year of operation projected to 2007. Only plants that are used primarily for retail electricity production are shown. Natural gas single-cycle plants are not shown because they are intended for peaking rather than baseload generation. Many of these baseload plants have been upgraded since plant operations commenced. Source: Data from Energy Information Administration (www.eia.gov/cneaf/electricity/page/capacity/capacity.html).*

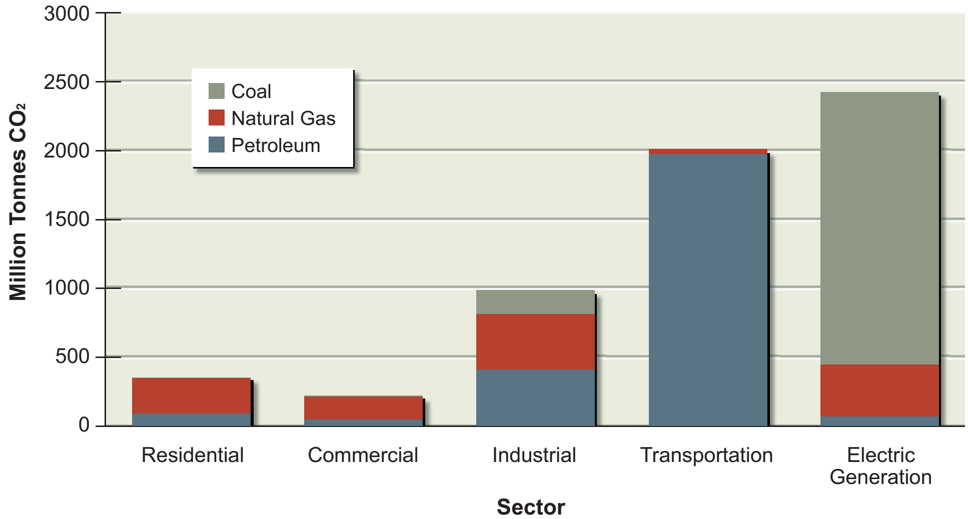

FIGURE 1.11 *Primary CO_2 emissions by production sector and fuel type in the United States in 2007 in millions of tonnes per year. Emissions from the electric power sector result from the production of electricity that is consumed by the end-use sectors shown in the figure.*
Source: Data from Energy Information Administration, 2008b.

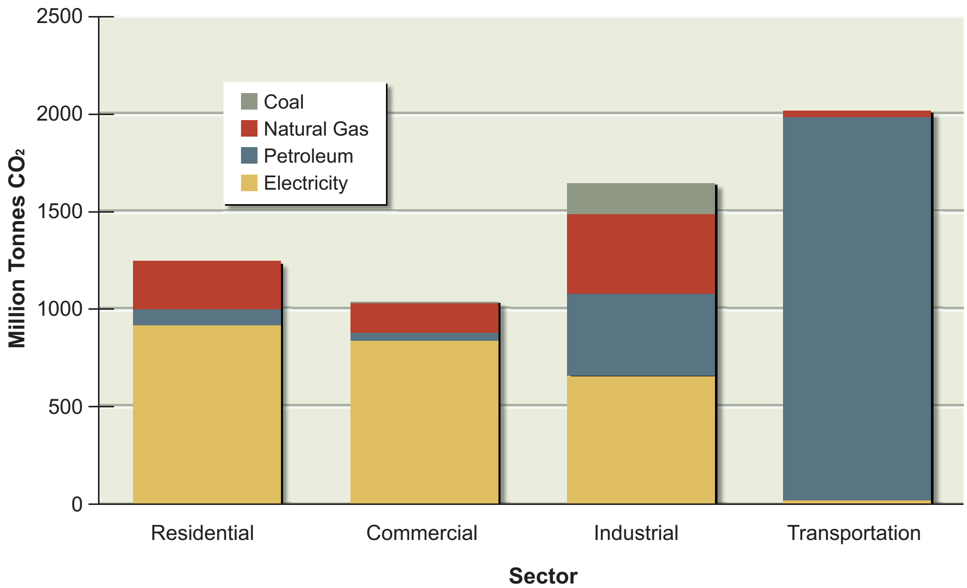

FIGURE 1.12 *Total CO_2 emissions in the United States in 2007 by end-use sector and primary energy source, in millions of tonnes per year. Also shown is each end-use sector's consumption of electricity. Electricity is a secondary energy source and is generated using fossil fuels and nuclear and renewable sources.*
Source: Data from Energy Information Administration, 2008b.

Nevertheless, new technologies that use energy more efficiently and that avoid, or capture and safely store, greenhouse gas emissions are essential components of a portfolio of alternatives for transforming energy production and use. *Indeed, failure to develop and implement such technologies will greatly limit the options available for reducing the nation's greenhouse gas emissions to the atmosphere.*

CHALLENGES TO TRANSFORMING ENERGY PRODUCTION AND USE

There is a growing recognition that our nation's current approaches for obtaining useful energy, being largely dependent on fossil fuels, are unsustainable over the long term and that we must therefore transform the manner in which energy is produced, distributed, and consumed. The need to transform the U.S. energy system is motivated by several factors.

- Heightened long-term competition for fossil fuels as a result of worldwide population and economic growth.
- Increasing U.S. reliance on world markets and their vulnerable supply chains for supplies of petroleum (and possibly, in the future, of natural gas).
- Mounting volatility in market prices for fossil fuels. For example, petroleum prices have ranged from about $32 to $147 per barrel over the past 2 years, which has helped to promote volatility in prices for coal and natural gas.
- Growing concerns about the impacts on the environment of burning fossil fuels—especially the impacts of CO_2 emissions to the atmosphere on global warming—and the time spans of such impacts.[12]

The challenge before us is to transform the U.S. energy system in a manner that increases its sustainability, supports long-term economic prosperity, promotes

[12]The committee refers in particular to uncertainties in the time-dependent relationships associated with anthropogenic CO_2 emissions and the resulting changes in atmospheric temperatures and sea levels. These uncertainties make it difficult to judge precisely how soon CO_2 emissions must be reduced to prevent major environmental impacts around the world. Many experts judge that there are, at most, just a few decades remaining in which to make these changes.

energy security, and reduces the adverse environmental impacts arising from energy production and use. Such a transformation could, for example, promote sustainability by using energy more efficiently and increasing the use of renewable-energy sources; support long-term economic prosperity by ensuring the availability of adequate supplies of energy; improve energy security by decreasing the nation's reliance on petroleum imports; and reduce adverse environmental impacts by reducing CO_2 emissions to the atmosphere.

Concerns about the sustainability, security, or environmental impacts arising from energy production and use have been reflected in the agendas of all U.S. presidents since Franklin D. Roosevelt. Such concerns were reflected, for example, in:

- Richard Nixon's "Project Independence" (1974)
- Gerald Ford's "Energy Independence Act" (1975)
- Jimmy Carter's "National Energy Plan" (1977)
- Ronald Reagan's "Energy Security" report (1987)
- George H.W. Bush's "National Energy Strategy" (1991)
- Bill Clinton's "Federal Energy R&D for the Challenges of the 21st Century" report (1997)
- George W. Bush's "Reliable, Affordable, and Environmentally Sound Energy for America's Future" report (2001).

Environmental policies and regulations—including, for example, those stemming from the Clean Air Act and the National Environmental Policy Act—have at times focused our nation's attention on energy efficiency and conservation and the use of renewable sources of energy, which has led to dramatic improvements in air quality. In fact, statutes such as the Clean Air Act demonstrate that thoughtful regulation can be a very useful tool for dealing with important externalities—those involved, for example, in the unconstrained emissions of pollutants (e.g., NO_x, SO_x) from the burning of fossil fuels.

These policies and regulations have focused in part on mitigating the environmental impacts of energy production and use, but they have been piecemeal efforts. The fact is that the United States has never implemented a truly comprehensive set of national policies for obtaining and using energy to meet national goals for sustainability, economic prosperity, security, and environmental quality. Instead, as noted previously, the U.S. energy system has developed in response to an array of uncoordinated market forces and shifting public policies.

Yet there has been a growing recognition over the past decade of the need for such comprehensive national policies. Congress made an unsuccessful attempt to pass major energy legislation in 2002, successfully passed such legislation in 2005 (Energy Policy Act of 2005) and in 2007 (Energy Independence and Security Act [EISA] of 2007), and was working on another major energy bill as the present report was being completed. Additionally, the Obama administration recently announced a new national fuel efficiency policy that will accelerate the implementation of EISA fuel economy standards for light-duty vehicles. During this same period there has been a sharp rise in investment activity focused on clean energy—from a few tens of millions of dollars in the late 1990s to hundreds of billions of dollars today.

It is the AEF Committee's judgment that comprehensive and sustained national policies for energy production and use will be needed to achieve a timely transformation to the more sustainable, secure, and environmentally benign energy system envisioned in this report. However, to help shape these policies will require sound and dispassionate technical analyses of the opportunities and challenges before us. Such analyses should address technology capabilities, costs, times to maturity and commercial deployment, and impacts on the environment, economy, and national security. The technical analysis in the present report aims to help support the development of such policies.

THE ROLE OF TECHNOLOGY

Transforming the U.S. energy system as described in the preceding section will require the continued improvement of existing technologies as well as the development and national-scale deployment of new technologies, including:

- Existing and new energy efficiency technologies.
- Existing and new energy-supply technologies—including wind, solar, geothermal, biofuels, and nuclear power.
- Carbon capture and storage (CCS) technologies on a large-enough scale to reduce CO_2 emissions from the burning of fossil fuels.
- Modern electrical transmission and distribution systems to accommodate 21st-century electricity supplies (especially from intermittent resources such as wind and solar), support future growth in electricity demand, and enable national-scale deployments of sophisticated demand-side technologies.

Many different pathways can potentially be pursued to these ends. But identifying pathways that are consistent with the nation's priorities and then taking the actions needed to achieve the desired transformations are among the most difficult challenges of our time.

The national-scale deployment of new technologies will have learning curves and will entail a variety of risks, and such deployments can have unforeseen economic and environmental impacts. Thus, in addition to evaluating the potential contributions of existing and emerging technologies, we also need to understand the nontechnological constraints on their rates of deployment and to decide on the roles of the public and private sectors and current and future generations for shouldering deployment costs and risks. In short, transformation of our nation's energy system will require a sustained national effort involving carefully focused technology research, development, and demonstration; realignments of public policies and regulations; substantial capital investments; and allied resources (materials, infrastructure, and people) in both the public and the private sectors.

Many energy-supply and end-use technologies are ready for significant deployment now, but others will not be available until they have been demonstrated at scale[13] or until important technological barriers have been overcome. Of course, once a technology is ready for deployment, a number of important economic, regulatory and policy, and resource factors will govern the actual pace, scale, and cost of deployment. Especially important in this regard are the prices for fossil fuels and other materials, the availability and costs of specialized resources and capital, and key public policies and regulations that address, for example, renewable-energy portfolio standards, building regulations, corporate average fuel economy (CAFE) standards, and carbon prices.[14] *Because of the uncertainties about how these factors will play out in the decades ahead, the technology-deployment options that are identified in this chapter and in Part 2 of this report should be considered as important first-step technology assessments rather than as forecasts as to which technologies will be implemented and how important each technology will be.*

The committee also recognizes that currently unpredictable developments in

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[13]The scale of a demonstration should be large enough to give an investor or company the confidence in the technology's economics, performance, and regulatory acceptability to build a commercial plant. The actual scale of demonstration required will vary across technologies.

[14]The term "carbon prices" denotes the costs that would be imposed through statute or regulation for emitting CO_2 and other greenhouse gases to the atmosphere.

technology could have dramatic impacts on future deployment options. There is little doubt that beyond the next few decades, new technologies—which employ, for example, advanced materials and innovative chemical processes not yet in view—could play transformative roles. Along these same lines, better understanding of how geoengineering[15] or the ecology of microbial systems affects climate could yield new insights on managing greenhouse gas emissions from energy production and use. In fact, unexpected breakthroughs might even enable fusion technology to contribute to the U.S. energy supply before 2050. Given the contingent nature of technology development, there will always be uncertainties in future technology pathways.

While the development and widespread deployment of both evolutionary and new technologies will play a central role in transforming the energy system, so too will new public policies and international collective actions that are equitable, efficient, and effective. Such collaborations will be needed not only because of the inherently global nature of the challenges but also because of the differing priorities and capacities of other countries. Market forces alone will not be sufficient to effect this transformation, as market externalities—including social costs not reflected in prices, regulatory constraints, the lack of information for knowledgeable market decision making, and other significant uncertainties—are likely to prevent energy markets from generating fully adequate price signals. Access to and competition for capital will be pertinent as well. And conflicts could arise when individual nations seek their own economic, political, or other national benefits—not necessarily consistent with shared international interests—in addressing issues such as global warming.

Because the energy system is so large, complex, and fully integrated into all aspects of American life, its successful transformation will take the full ingenuity and commitment of the public and private sectors. Moreover, the transformation must engage the routine attention of the public itself. In this sense, the present energy challenge is fundamentally different from historical efforts such as the Manhattan Project and the Apollo Project, which focused on specific technical objectives rather than on a very large and complex societal infrastructure. Those

[15]Geoengineering involves the use of technology to change the environment of Earth. For example, the emission of greenhouse gases into the atmosphere from human activity is now judged with very high confidence by climate scientists to cause global warming. Some scientists have proposed geoengineering as a way to reduce global warming—such as by changing the amount of sunlight that reaches the planet's lower atmosphere and surface or by removing greenhouse gases from the atmosphere.

projects were enormous technological and organizational triumphs, to be sure, but they were generally disconnected from the daily lives of the nation's citizens. Nevertheless, particular technological elements—such as CCS, advanced batteries for transportation, advanced geothermal energy for electricity production, and low-cost efficient lighting and solar panels—might very well benefit from focused development and demonstration programs even as the many nontechnological challenges are being addressed.

STRATEGY FOR ADDRESSING THE STUDY CHARGE

The focus of this study, consistent with its charge (Box 1.1), is on energy-supply and end-use technologies—in particular their deployment-readiness, performance, costs, barriers, and impacts. The AEF Committee also assessed the prospects of some other technologies that will be critical both in meeting the anticipated growth of energy demand and in enabling the deeper market penetration of the new energy-supply and end-use technologies themselves. These critical technologies range from CCS, which would support not only the continued use of fossil fuels for electricity generation but also any future production of liquid fuels, to advanced battery, fuel-cell, and hydrogen technologies.

The committee considered technology development and deployment over three time periods—2008–2020, 2020–2035, and 2035–2050—but focused mainly on the first two periods, not only because the more distant future is harder to analyze but also because it depends critically on what occurs (or does not occur) earlier. Notably, the committee found that what can be realized in the two later periods will be contingent on the accomplishments in the critical first period, which is immediately ahead of us. *Indeed, a major message of this report is that the nation can achieve the necessary and timely transformation of its energy system only if it embarks on an accelerated and sustained level of technology development, demonstration, and deployment along several parallel paths between now and 2020.* The cases for such urgent actions are strikingly similar in virtually all of the energy domains addressed in this report, whether they pertain to specific energy-supply technologies, end-use technologies, or electricity transmission and distribution.

In addressing its study charge, the committee avoided reinventing the wheel. Where appropriate, it took advantage of the existing energy literature, which is both extensive and information-rich, to inform its judgments. In some selected cases, the committee performed additional technical analyses to fill gaps in the literature or reconcile conflicting assessments. The approaches that the committee used are described in more detail in Part 2 of this report.

The committee also relied heavily on the reports of the three panels that were created as part of this Phase I study to undertake detailed examinations of energy efficiency technologies, alternative transportation fuels, and renewable-energy technologies. The three panel reports are, specifically:

- *Real Prospects for Energy Efficiency in the United States* (available at http://www.nap.edu/catalog.php?record_id=12621)
- *Liquid Transportation Fuels from Coal and Biomass: Technological Status, Costs, and Environmental Impacts* (available at http://www.nap.edu/catalog.php?record_id=12620)
- *Electricity from Renewable Resources: Status, Prospects, and Impediments* (available at http://www.nap.edu/catalog.php?record_id=12619).

The AEF Committee used these panel reports to inform its judgments about energy supply and cost for the particular technologies involved. Selected members of these panels, including their chairs and vice chairs, also served on the authoring committee for the present report.

The U.S. energy system is so large and complex that the committee was unable, in the time available, to assess the potential for transformation of its every relevant aspect. Note in particular that:

- The focus of the report is on energy-supply and end-use technologies that are most likely, in the judgment of the committee, to have meaningful impacts on the U.S. energy system during the three time periods considered in this study (encompassing the next 40 years or so). However, the committee did not assess the future role of technologies for the exploration, extraction, storage, and transportation of primary energy sources (e.g., fossil fuels), nor did it assess the role of some critial components of a modernized infrastructure—including tankers, roads, pipelines, and associated storage facilities—in delivering these resources from suppliers to consumers.
- The report does not explore in any depth the U.S. energy system at the regional level. Thus, the implications of the dramatic regional heterogeneity in the United States—for example, in energy resource endow-

ments, climates, and prices—on energy-supply and end-use technologies are not considered in any detail.

- The potential energy-supply contributions from the options assessed in this report have been estimated technology by technology. The committee did not, however, conduct an integrated assessment of how these technologies might compete in the marketplace and how that competition and other external factors could affect actual deployment rates and outcomes over time. For example, the successful deployment of energy efficiency technologies could reduce the demand for electricity and the need to deploy additional electricity-generation capacity, except perhaps to correct regional supply imbalances or replace aging assets with more efficient and environmentally benign facilities. Also, the utilization of biomass for liquid fuels production could reduce the supplies of biomass available for electricity generation. *Therefore the potential contributions of the energy-supply and end-use technologies identified in this report should not be viewed as predictions of any specific future mix of primary energy resources and conversion methods.*
- The committee has not made judgments about the relative desirability of the supply options described in this report or about their appropriate pace and scale of deployment. Such decisions are beyond the committee's charge and are the responsibility of policy makers, investors, consumers, and, indeed, all citizens.
- The committee and its panels developed the cost estimates presented in this report by using a range of methodologies (as described in Annex 3.A in Chapter 3 and in Part 2). It derived some of these estimates independently, with the assistance of consultants, whereas other estimates came from assessments documented in the literature. The cost estimates themselves were based on a number of underlying assumptions about commodity prices, construction costs, and fuel, regulatory, and operating costs, as well as on "conditional" assumptions[16] about the success of new-technology deployment. *As a consequence the cost estimates presented in this report should not be used to make* detailed *comparisons across technologies. However, because these estimates are presented as ranges that reflect the principal uncertainties in the underlying*

[16]Conditional assumptions posit that new technologies can be successfully deployed within a given time and at a given cost, even though the deployment is the first of its kind.

assumptions, the committee judges that they are sufficiently robust to be useful for rough *comparisons.*

- The report does not provide an evaluation of the full range of options for reducing energy use. Such reductions are generally understood to be obtainable in two ways: (1) deploying technologies to improve the efficiency of energy production and use and (2) conserving energy through behavioral or lifestyle changes (e.g., taking public transportation to work rather than driving).[17] The focus of this report is on the assessment of technologies that address the first factor—improving the efficiency of energy use. It addresses energy conservation only insofar as conservation is affected by the deployment of more energy-efficient technologies. To be sure, conservation is an important option for reducing energy use, but its detailed consideration is well beyond the technological scope of this study. A study on energy conservation would require, for example, an in-depth understanding of how social, economic, and policy factors affect energy consumption.
- The report does not provide forecasts of future prices of primary energy inputs (e.g., for petroleum and coal) or the effects of possible future policies and regulations concerning CO_2 emissions on such prices. Such prices, however, will influence the relative competitiveness of the energy-supply and end-use technologies discussed in this report, and they will affect technology choices and paces of development, especially in the private sector.

REPORT ORGANIZATION

This chapter has briefly discussed the current characteristics of the U.S. energy system, the challenges to improving the system's sustainability and security, the role of technology, and the committee's strategy for addressing its study charge (Box 1.1). The next two chapters complete Part 1 of this report by providing sum-

[17]Per capita energy use in a particular country can also be reduced by lowering energy intensity, for example, by importing energy-intensive goods from abroad rather than producing them domestically. However, this approach would not reduce overall energy use and could in some cases even result in increased energy use.

maries of the study's key findings (Chapter 2) and of the technology assessments (Chapter 3) of Part 2.

Part 2 contains six chapters (Chapters 4–9), which document the committee's detailed assessments of energy-supply and end-use technologies. The topics addressed in these chapters are, specifically,

- *Energy efficiency* in transportation, industry, and residential and commercial buildings (Chapter 4)
- Production and use of *alternative transportation fuels*, in particular biofuels as well as fuels derived from converting coal, or mixtures of coal and biomass, into liquids (Chapter 5)
- Production of *renewable energy* such as wind, solar, and geothermal energy, as well as hydropower and biopower (Chapter 6)
- Domestic *fossil-fuel energy*, particularly as coupled with technologies that would capture and safely store CO_2 (Chapter 7)
- Production of electricity from *nuclear energy* (Chapter 8)
- *Electricity transmission and distribution* systems that reliably accommodate intermittent energy supplies such as solar and wind and sophisticated demand-side energy efficiency technologies (Chapter 9).

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2 Key Findings

This chapter presents eight key findings from the AEF Committee's detailed analysis of existing and new energy-supply and end-use technologies presented in Part 2 of this report. These findings identify options for the *accelerated* deployment of these technologies during the next two to three decades, and they also identify needs for supporting research, development, and demonstration. Pursuing such options would, in the committee's judgment, hasten the transformation of the U.S. energy system, as described in Chapter 1.

By "accelerated," the committee means deployment of technologies at a rate that would exceed the "reference scenario" deployment pace (Box 2.1) but at a less dramatic rate than an all-out or "crash" effort, which could require disruptive economic and lifestyle changes that would be challenging to initiate and sustain. By contrast, accelerated technology deployments could likely be achieved without substantial disruption, although some changes in the behavior of businesses and consumers would be needed. Moreover, many of these changes could involve new costs and higher prices for end users.

The accelerated-deployment options identified in this chapter are based on the committee's judgments regarding two important factors: (1) the readiness of evolutionary and new technologies for commercial-scale deployment and (2) the pace at which such technologies could be deployed without the disruptions associated with a crash effort. In estimating these factors, the committee considered the maturity of a given technology together with the availability of the necessary raw materials, human resources, and manufacturing and installation capacity needed to support its production, deployment, and maintenance. In some cases, estimates of the evolution of manufacturing and installation capacity were based on the documented rates of deployments of specific technologies from the past.

BOX 2.1 **Reference Scenarios**

The statement of task for this study (Box 1.1) called for the development of a reference scenario "that reflects a projection of current economic, technology cost and performance, and policy parameters into the future." The AEF Committee decided to meet this requirement by adopting the Energy Information Administration's (EIA's) reference case for U.S. energy supply and consumption, which is the most commonly cited scenario for the U.S. energy system. It provides estimates of past, current, and future energy supply and consumption parameters by assuming that current energy policies remain unchanged and then extrapolating economic growth rates and technology-development trends into the future. In other words, the EIA reference case represents a business-as-usual and policy-neutral projection.

The EIA updates this reference case annually and presents it in the agency's Annual Energy Outlook reports. In this study, the committee uses the 2008 update (EIA, 2008), which reflects U.S. energy supply and consumption through 2007 and future projections through 2030, as its primary reference scenario. However, in limited cases the 2009 update (EIA, 2009a) was used, and explicitly noted in this report, when it was considered to be more indicative of current conditions.

The EIA's Annual Energy Outlook reports can be accessed at www.eia.doe.gov/oiaf/aeo/. Selected energy supply and consumption estimates from the 2008 update are shown in the three tables that follow.

TABLE 2.1.1 Reference Scenario Estimates of Electricity Consumption and Supply

	2007	2020	2030
Electricity Consumption (terawatt-hours)			
Residential	1400	1500	1700
Commercial	1300	1700	1900
Industry	1000	1100	1000
Transportation	6	8	9
Electricity Supply (terawatt-hours)			
Coal	2000	2300	2800
Petroleum	48	52	56
Natural gas	680	610	500
Nuclear power	800	870	920
Renewables			
Conventional hydropower	260	300	300
Onshore wind	38	100	120
Offshore wind	0	0	0
Solar photovoltaic	0.08	0.52	1.0
Concentrating solar power	0.92	2.0	2.2
Geothermal	16	24	31
Biopower	12	78	83

Note: Estimates have been rounded.
Source: EIA, 2008.

TABLE 2.1.2 Reference Scenario Estimates of Natural Gas Consumption and Supply

	2007	2020	2030
Natural Gas Consumption (trillion cubic feet)			
Residential	4.7	5.2	5.2
Commercial	3.0	3.4	3.7
Industrial	6.6	6.9	6.9
Electric power	6.8	5.9	5.0
Transportation	0.02	0.07	0.09
Natural Gas Supply (trillion cubic feet)			
Domestic production	19	20	19
Net imports	3.8	3.6	3.2

Note: Estimates have been rounded.
Source: EIA, 2008.

TABLE 2.1.3 Reference Scenario Estimates of Liquid Fuels Consumption and Supply

	2007	2020	2030
Liquid Fuels Consumption (million barrels per day)			
Residential and commercial	1.1	1.1	1.1
Industrial	5.1	4.8	4.7
Transportation	14	16	17
Electric power	0.25	0.26	0.28
Liquid Fuels Supply (million barrels per day)			
Petroleum			
Domestic production	5.1	6.2	5.6
Net imports	10	9.8	11
Natural gas plant liquids	1.8	1.7	1.6
Net product imports	2.1	1.4	1.3
Ethanol	0.44	1.4	2
Biodiesel	0.03	0.07	0.08
Biomass-to-liquids	0	0.14	0.29
Coal-to-liquids	0	0.15	0.24
Biomass-and-coal-to-liquids	Not considered		

Note: Estimates have been rounded.
Source: EIA, 2008.

FINDING 1: TECHNOLOGY DEPLOYMENT OPTIONS

With a sustained national commitment, the United States could obtain substantial energy efficiency improvements, new sources of energy, and reductions in greenhouse gas emissions through the accelerated deployment of existing and emerging energy-supply and end-use technologies, as described in some detail in Findings 2–5 in this chapter. Many energy efficiency and energy-supply technologies are ready for deployment now. But some emerging technologies will first require demonstration, either to prepare them for widespread commercial deployment starting about 2020 or to assess their readiness for deployment.

The U.S. energy system encompasses a large and complex installed base of energy-supply and end-use technologies. Transforming this system to increase sustainability, promote economic prosperity, improve security, and reduce environmental impacts as envisioned in Chapter 1 will require sustained national efforts to change the ways in which energy is produced, distributed, and used. The good news from the AEF Committee's assessment is that there are many practical options for obtaining energy savings, new supplies of energy, and reductions in greenhouse gas emissions through widespread and sustained deployments of existing and emerging energy-supply and end-use technologies. The most important of these options are described in Findings 2–5.

The United States cannot continue to muddle along on its current course if it hopes to transform its energy system. Indeed, both the public and the private sectors will have to be mobilized to achieve the necessary deployments in the decades ahead. Moreover, there is no "silver bullet" technology that can be deployed to overcome U.S. energy challenges. Contributions will be needed from the full array of currently available and emerging technologies:

- Numerous energy-supply and end-use technologies—energy efficiency, certain renewable-energy sources, and transmission and distribution (T&D) technologies—which can be deployed now and at relatively rapid rates with the appropriate mix of incentives.[1]

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[1]Such incentives might include carbon taxes, cap and trade systems for CO_2 emissions, and tax credits for investments in energy efficiency or renewable-energy sources. In addition, regulations that require increased energy efficiency in the buildings, transportation, and industrial

- Evolutionary nuclear energy technologies, already being deployed in some other countries, which are ready for deployment in the United States. However, their commercial viability in the United States will first need to be demonstrated.
- Some emerging technologies, such as carbon capture and storage (CCS), for which sustained programs of development and commercial-scale demonstration will be needed during the next decade to ready the most promising among them for widespread deployment starting around 2020.

Expanding the deployment of coal with CCS, renewable energy, and evolutionary nuclear energy technologies may require continuing strong financial and regulatory pushes and new policy initiatives.[2] But many of the technologies identified in this report will require decades-long lead times for development, demonstration, and deployment. *Therefore it is imperative that these activities be started immediately even though some will be expensive and not all will be successful: some may fail, prove uneconomic, or be overtaken by better technologies.* Some failures are an inevitable part of learning and development processes. Long-term success requires that we stay the course and not be distracted by the inevitable short-term disappointments. To help ensure that the potential benefits outweigh the risks, investments in new technology demonstrations must be carefully chosen so as to produce results that usefully inform the deployment decision-making process.

Although it is beyond the committee's charge to recommend policy actions, it notes that the effective transformation of the energy system will require long-term investment in new energy technologies, policies that encourage such investment, and acceptance of the inevitable disappointments that will punctuate our long-term success.

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sectors could play a key role both in moderating the demand for energy and stimulating related R&D.

[2]In addition to the incentives listed in Footnote 1, other possible actions include expanding renewable-energy portfolio standards to promote the deployment of renewable energy and providing federal loan guarantees to promote construction of a handful of evolutionary nuclear plants. Some of these actions are already under way.

FINDING 2: ENERGY SAVINGS FROM IMPROVED EFFICIENCY

The deployment of existing energy efficiency technologies is the nearest-term and lowest-cost option for moderating our nation's demand for energy, especially over the next decade. The committee judges that the potential energy savings available from the accelerated deployment of existing energy-efficiency technologies in the buildings, transportation, and industrial sectors could more than offset the Energy Information Administration's projected increases in U.S. energy consumption through 2030.

The deployment of energy efficiency technologies[3]—especially of mature technologies in the buildings, transportation, and industrial sectors—is the nearest-term and lowest-cost option for extending domestic supplies of energy. Many energy efficiency savings can be obtained almost immediately by deploying currently available technologies. In contrast, providing new energy supplies typically takes many years. Moreover, energy efficiency has broader societal benefits beyond saving energy. Society is giving more attention to the environment and other externalities as exemplified, for example, by concerns about the impacts of carbon dioxide (CO_2) emissions on global climate change. Laws and regulations, from the Endangered Species Act to the Clean Air Interstate Rule, inevitably slow the development of new energy supplies. In contrast, efficiency involves few emissions, endangers no species, and does not destroy scenic vistas.

To achieve such benefits, however, the efficiency savings must translate into actual reductions in energy consumption. This has been a particular issue in the transportation sector, where efficiency improvements that could have been used to raise vehicle fuel economy were instead offset by higher vehicle power and increased size.

Efficiency savings are realized at the site of energy use—that is, at the residence, store, office, factory, or transportation vehicle. The efficiency supply curves shown later in this chapter demonstrate that many energy efficiency investments cost less than delivered electricity, natural gas, and liquid fuels; in some cases, those costs are substantially less. In the electricity sector, many efficiency investments even cost less than transmission and distribution costs, which are typically

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[3]As noted in Chapter 1, the committee draws a sharp distinction between energy efficiency and energy conservation. Conservation can be an important strategy for reducing energy use, but it generally does not involve technology deployment and is therefore not addressed in this report.

4–6¢/kWh for a residential customer and about half that for large commercial and industrial customers. Chapter 4 also shows that many energy efficiency projects with a rate of return of 10 percent or more could be undertaken by industry. Although most companies do not consider this rate of return attractive, it is nevertheless an attractive investment for society.

The greatest capability for energy efficiency savings is in the buildings sector, which accounted for about 70 percent of electricity consumption in the United States in 2007 (2700 TWh out of approximately 4000 TWh in total). Improvements in the energy efficiency of residential and commercial buildings—through the accelerated deployment of efficient technologies for space heating and cooling, water heating, lighting,[4] computing, and other uses—could save about 840 TWh per year by 2020 (Figure 2.1), which exceeds the EIA's projected increase in electricity demand of about 500 TWh for residential and commercial buildings by the year 2020 (EIA, 2008) (see Table 2.1.1 in Box 2.1). Further continuous improvements in building efficiency could save about 1300 TWh of electricity per year by 2030 (Figure 2.1), which also exceeds the EIA-projected reference scenario increase in electricity demand of about 900 TWh per year. In addition, improvements in building efficiency could save 2.4 quads of natural gas annually by 2020 and 3 quads of natural gas annually by 2030 (Figure 2.2).

There are many examples of cost-effective efficiency investments that could be made in the buildings sector to save energy. For example, an approximate 80 percent increase in energy efficiency—translating to nearly a 12 percent decrease in overall electricity use in buildings—could be realized immediately by replacing incandescent lamps with compact fluorescent lamps or light-emitting diodes. Energy savings between 10 and 80 percent could be realized by replacing older models of such appliances as air conditioners, refrigerators, freezers, furnaces, and hot water heaters with the most efficient models. Such replacements would not occur as quickly as replacing lamps because it is usually cost-effective to replace appliances only when they near the end of their service lives. The same is true for motor vehicles. Buildings last decades, so the energy savings benefits of new buildings will take decades to realize. However, there are cost-effective retrofits that could be installed immediately.

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[4]On June 26, 2009, the Obama administration issued a final rule to increase the energy efficiency of general service fluorescent lamps and incandescent reflector lamps. The changes will take effect in 2012.

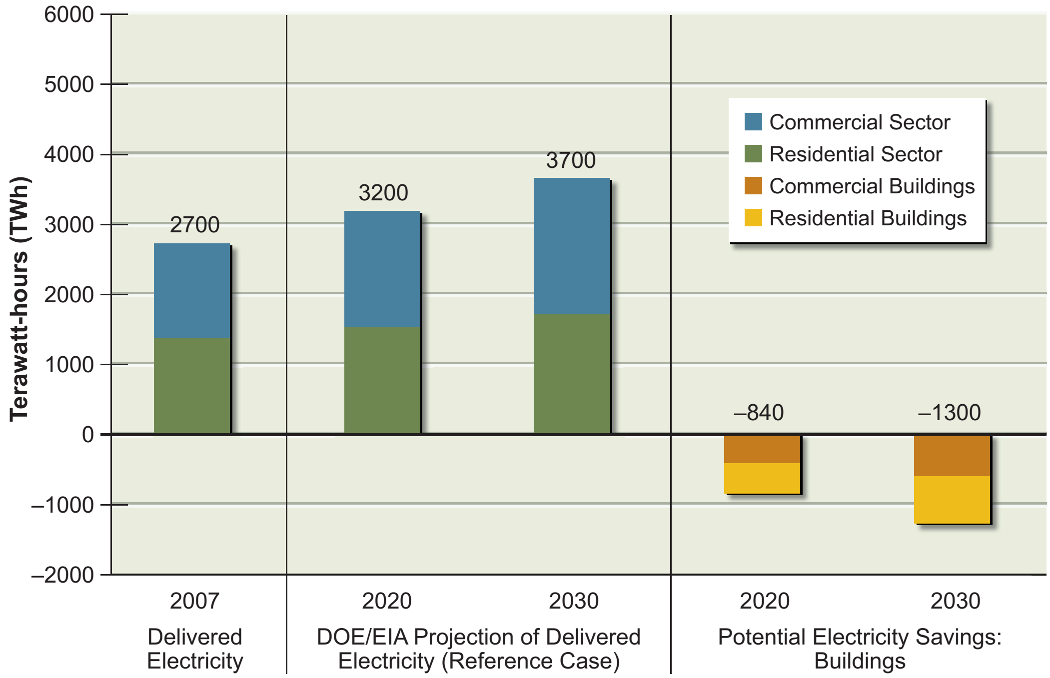

FIGURE 2.1 *Estimates of potential energy savings in commercial and residential buildings in 2020 and 2030 (relative to 2007) compared to projected delivered electricity. The commercial and residential sectors are shown separately. Current (2007) U.S. delivered electricity in the commercial and residential sectors, which is used primarily in buildings, is shown on the left, along with projections for 2020 and 2030. To estimate savings, an accelerated deployment of technologies as described in Part 2 of this report is assumed. Combining the projected growth with the potential savings results in lower electricity consumption in buildings in 2020 and 2030 than exists today. The industrial and transportation sectors are not shown. Delivered energy is defined as the energy content of the electricity and primary fuels brought to the point of use. All values have been rounded to two significant figures.*
Sources: Data from Energy Information Administration (2008) and Chapter 4 in Part 2 of this report.

In fact, the *full* deployment of cost-effective[5] energy efficiency technologies in buildings alone could eliminate the need to build any new electricity-generating plants in the United States—except to address regional supply imbalances, replace obsolete power-generation assets, or substitute more environmentally benign electricity sources—assuming, of course, that these efficiency savings would not be used to support greater electricity use in other sectors.

[5]See the section titled "Energy Efficiency" in Chapter 3 for a definition of "cost-effective."

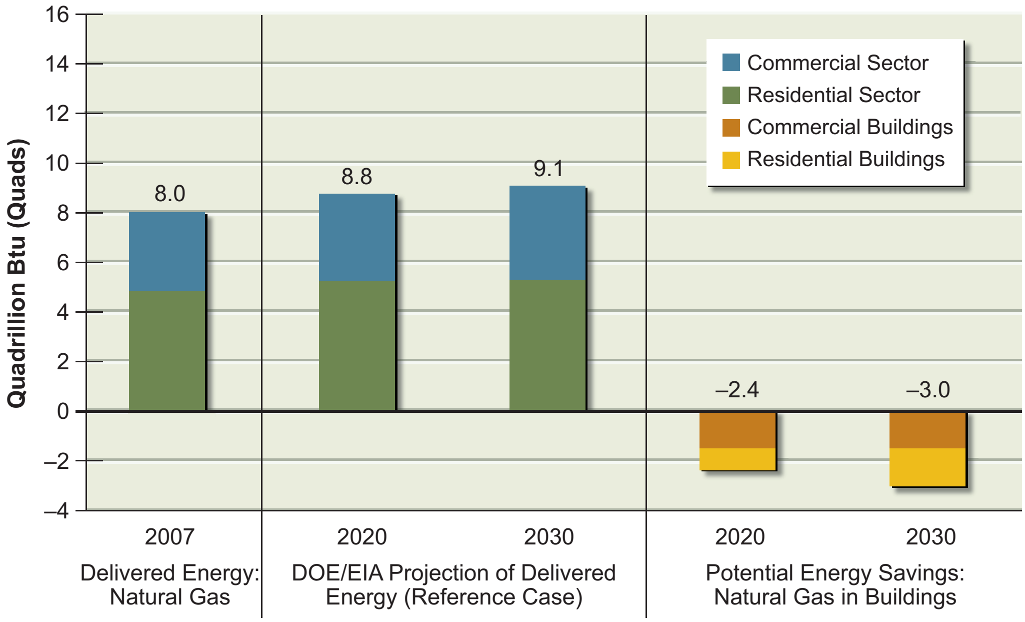

FIGURE 2.2 *Estimates of potential natural gas savings in commercial and residential buildings in 2020 and 2030 (relative to 2007) compared to delivered energy from natural gas. The commercial and residential sectors are shown separately. Current (2007) U.S. delivered energy from natural gas in the commercial and residential sectors, which is used primarily in buildings, is shown on the left, along with projections for 2020 and 2030. To estimate savings, an accelerated deployment of technologies as described in Part 2 of this report is assumed. Combining the projected growth with the potential savings results in lower natural gas consumption in buildings in 2020 and 2030 than exists today. The industrial and transportation sectors are not shown. Delivered energy is defined as the energy content of the electricity and primary fuels brought to the point of use. All values have been rounded to two significant figures.*
Sources: Data from Energy Information Administration (2008) and Chapter 4 in Part 2 of this report.

Opportunities for achieving substantial energy savings exist in the industrial and transportation sectors as well. For example, deployment of energy efficiency technologies in industry could reduce energy use in manufacturing by 4.9–7.7 quads per year (14–22 percent) in 2020[6] relative to the EIA reference case projection (Figure 2.3). Most of these savings would occur in the pulp and paper, iron

[6]These identified savings would provide industry with an internal rate of return on its efficiency investments of at least 10 percent or exceed the company's cost of capital by a risk premium. See Chapter 4 for additional discussion.

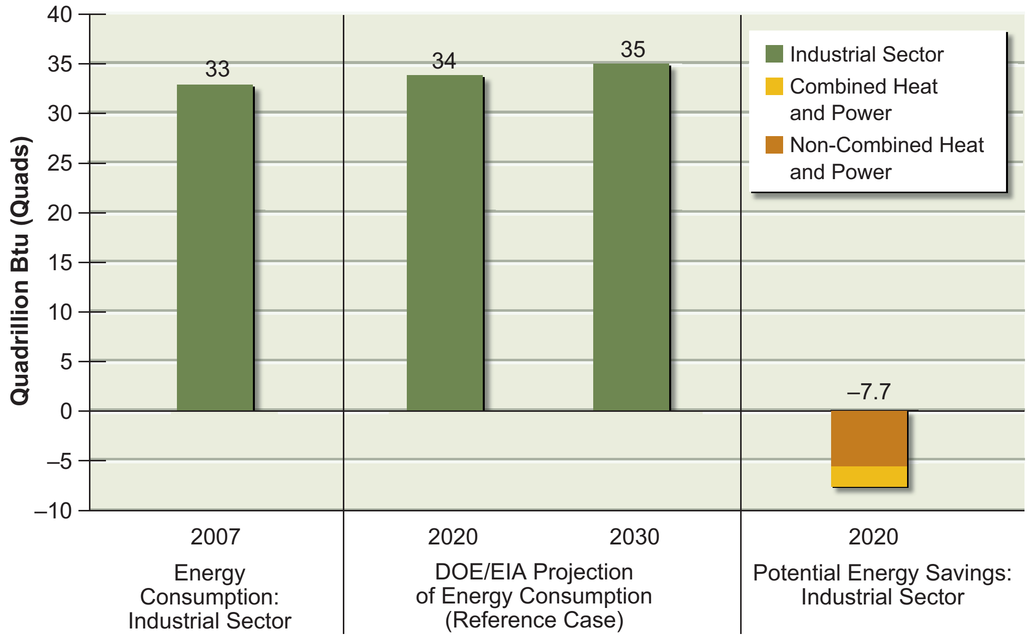

FIGURE 2.3 *Estimates of potential energy savings in the industrial sector in 2020 (relative to 2007) compared to total delivered energy in the industrial sector. Current (2007) U.S. delivered energy in the industrial sector is shown on the left, along with projections for 2020 and 2030. To estimate savings, an accelerated deployment of technologies as described in Part 2 of this report is assumed. Combining the projected growth with the potential savings results in lower energy consumption in the industrial sector in 2020 (7.7 quads) than exists today. A more conservative scenario described in Chapter 4 could result in energy savings of 4.9 quads. The committee did not estimate savings for 2030. Delivered energy is defined as the energy content of the electricity and primary fuels brought to the point of use. All values have been rounded to two significant digits. Sources: Data from Energy Information Administration (2008) and Part 2 of this report.*

and steel, and cement industries. The increased use of combined heat and power in industry is estimated to contribute a large fraction of these potential savings—up to 2 quads per year in 2020.

In the transportation sector, energy savings can be achieved by increasing the efficiencies with which liquid fuels (especially petroleum) are used and by shifting the energy source for part of the light-duty vehicle (LDV) fleet from petroleum to electric power. Of course, the environmental impacts of such a fuel shift are dependent on how electricity (or hydrogen, if fuel-cell vehicles are produced) is generated. Moreover, electrification of LDVs will increase the overall demand for electricity. Shifting this electricity demand to off-peak times (e.g., at night), through the use of demand-side technologies such as smart metering, may reduce the need for new power-plant construction and improve the utilization of current baseload power plants.

Improvements in the efficiency of today's spark-ignition and diesel engine LDVs, combined with increased use of hybrid and other advanced vehicle technologies, could reduce these vehicles' fuel consumption beyond 2020 to below that projected by the EIA (EIA, 2008). The EIA projection, which incorporates the increased fuel-economy standards mandated by the Energy Independence and Security Act (EISA) of 2007, equates to a 30 percent reduction in average fuel consumption (and a 40 percent increase in average fuel efficiency) in new LDVs in 2020 over today's consumption.[7] Exceeding this EIA projection is possible, but only if vehicle manufacturers focus on increasing vehicle fuel economy as opposed to their historic emphasis on increasing vehicle power and size. Figure 2.4 shows projections (described in Chapter 4) that illustrate how improvements in LDV fuel efficiency beyond that projected by the "no-change" reference scenario could further reduce total fuel consumption. These efficiency improvements, which include plug-in hybrid vehicles but not (fully) battery-electric vehicles or hydrogen fuel-cell vehicles, could reduce gasoline consumption by about 1.4 million barrels per day in 2020 and 5.6 million barrels per day in 2035. Of course, these fuel-efficient vehicles will have to be acceptable to consumers. Improvements are also possible in fuel consumption for freight shipping, but projected growth in airline travel is likely to offset improvements in aviation technologies.

Many energy efficiency technologies save money and energy. The cost of conserved energy (CCE) is a useful way to compare the cost of an energy efficiency technology to the cost of electricity and natural gas.[8] The range of

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[7]The EIA (2008) reference case incorporates the EISA corporate average fuel economy (CAFE) standard of 35 miles per gallon (mpg) by 2020. The EIA reference case projects that the fuel economy of new vehicles will reach 36.6 mpg in 2030. As is noted in Chapter 1, the Obama administration recently announced a new national fuel efficiency policy that requires an average fuel economy standard of 35.5 mpg for new light-duty vehicles in 2016.

[8]CCE is defined as the levelized annual cost of an energy efficiency measure—that is, the cost of a new technology, or the incremental cost for a more efficient technology compared with a less efficient one—divided by the annual energy savings in kilowatt-hours or British thermal units over the lifetime of the measure. (The levelized annual costs do not include the costs for public policies and programs aimed at stimulating adoption of energy efficiency measures.) The CCE is expressed here in cents per kilowatt-hour (¢/kWh) for electricity efficiency measures and dollars per million British thermal units ($/million Btu) for natural gas efficiency measures. The CCEs presented in this report were computed using a real discount rate of 7 percent.

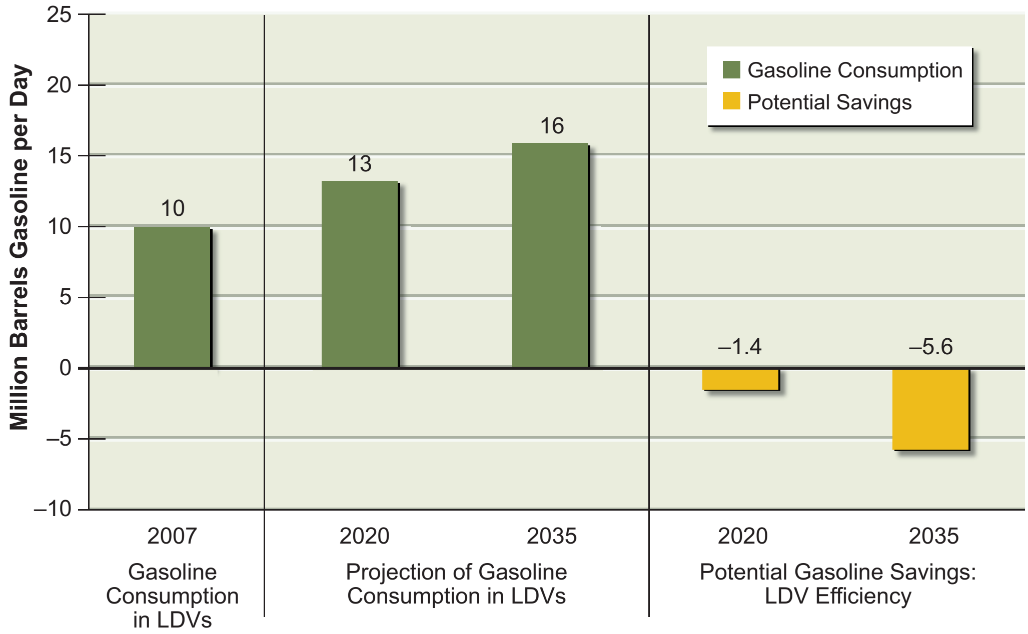

FIGURE 2.4 *Estimates of potential for gasoline consumption reduction in the U.S. light-duty vehicle (LDV) fleet in 2020 and 2035 (relative to 2007). Current (2007) U.S. gasoline consumption in LDVs is shown on the left. This consumption estimate, which was developed by the committee, includes gasoline-equivalent diesel fuel consumption in LDVs as well as fuel consumption in LDVs between 8,500 and 10,000 lb weight (the new Environmental Protection Agency upper limit on light trucks). Projected gasoline consumption in LDVs in 2020 and 2035 is shown by the middle set of bars. The projected consumption shown is an illustrative, no-change baseline scenario, where any efficiency improvements in powertrain and vehicle are offset by increases in vehicle performance, size, and weight. This baseline is described in more detail in Chapter 4 in Part 2 of this report. To estimate savings, an accelerated deployment of technologies as described in Part 2 of this report is assumed. Specifically, fuel efficiency improvements result from an optimistic illustrative scenario in which the corporate average fuel economy (CAFE) standards of the Energy Independence and Security Act of 2007 are met in 2020. This scenario assumes that fuel economy for new LDVs continues to improve until it reaches, in 2035, double today's value. Combining the projected growth in vehicle fleet size with the potential efficiency savings results in only slightly higher gasoline consumption in vehicles in 2020 and 2035 than exists today. A more conservative illustrative scenario, which results in savings of 1.0 and 4.3 million barrels of gasoline per day in 2020 and 2035, respectively, is also shown in Part 2 of this report. Beyond 2020, a 1 percent compounded annual growth in new vehicle sales and annual mileage per vehicle, combined, is assumed. Gasoline consumption can be further reduced if vehicle use (vehicle miles traveled) is reduced. All values have been rounded to two significant figures.*
Source: Data from Chapter 4 in Part 2 of this report.

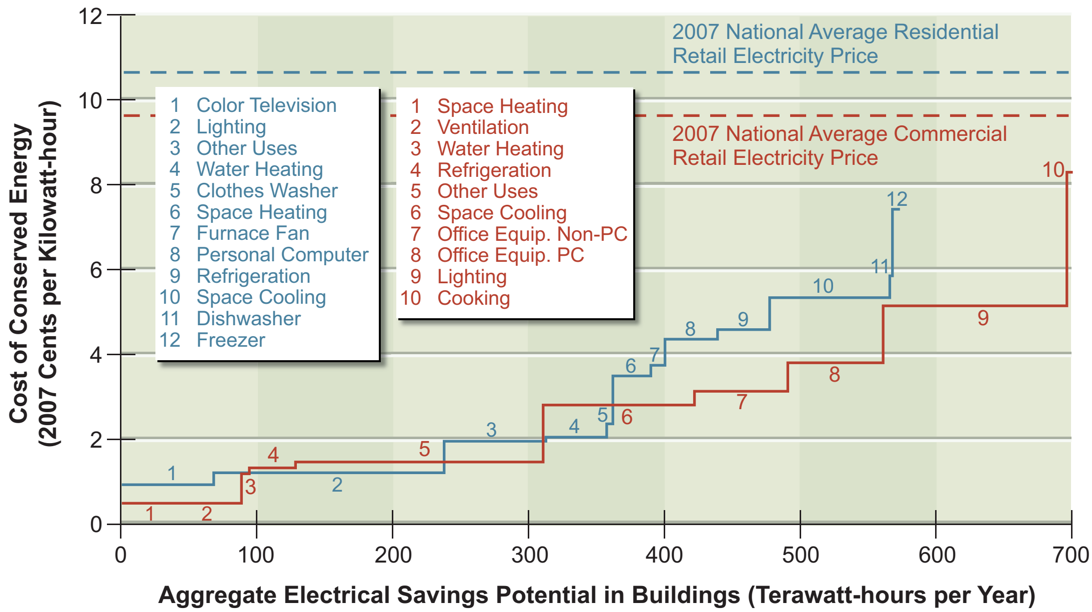

FIGURE 2.5 *Estimates of the cost of conserved energy (CCE) and energy savings potential for electricity efficiency technologies in buildings in 2030. The CCEs for potential energy efficiency measures (numbered) are shown versus the ranges of potential energy savings for these measures. The total savings potential is 567 TWh per year in the residential sector and 705 TWh per year in the commercial sector. Commercial buildings (red solid line) and residential buildings (blue solid line) are shown separately. For comparison, the national average 2007 retail price of electricity in the United States is shown for the commercial sector (red dashed line) and the residential sector (blue dashed line). For many of the technologies considered, on average the investments have positive payback without additional incentives. CCEs include the costs for add-ons such as insulation. For replacement measures, the CCE accounts for the incremental cost—for example, between purchasing a new but standard boiler and purchasing a new high-efficiency one. CCEs do not reflect the cost of programs to drive efficiency. All costs are shown in 2007 dollars. Sources: Data from Brown et al. (2008) and Chapter 4 in Part 2 of this report.*

CCE for electricity savings from commercial and residential buildings is shown in Figure 2.5. The range of CCE for electricity savings from commercial buildings is 0.5–8.4¢/kWh, with a weighted average of 2.7¢/kWh. However, nearly all of the efficiency savings are achievable at a CCE of 5¢/kWh or less. The range of CCE for electricity savings from residential buildings is 0.9–7.4¢/kWh, with a weighted average of 2.7¢/kWh. More than 80 percent of the potential savings are achievable at a CCE of 5¢/kWh or less. For comparison purposes, the average retail price of electricity in the residential and commercial sectors in 2007 was about

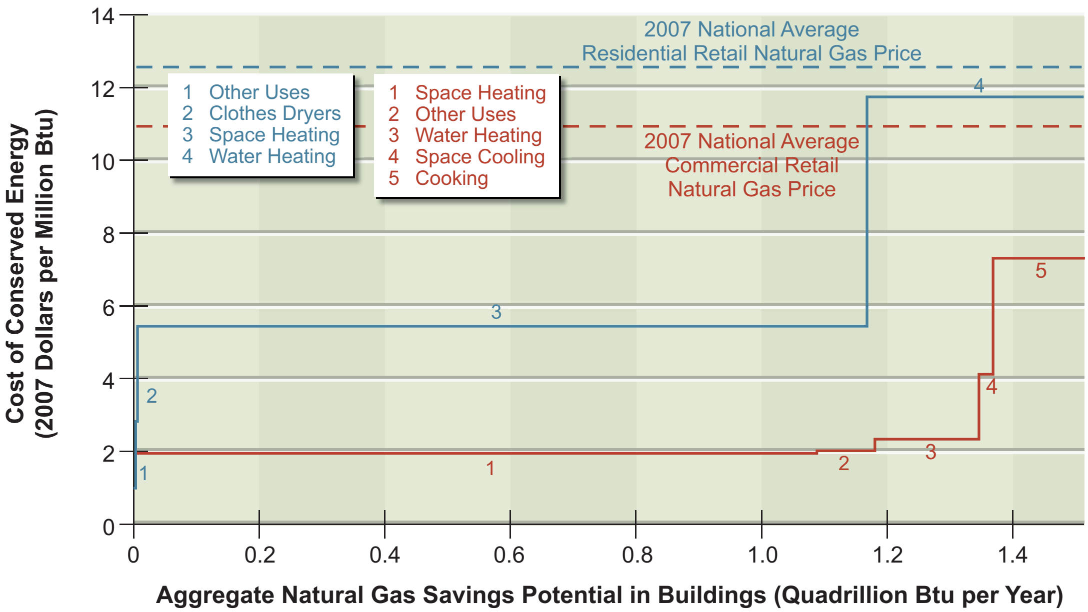

FIGURE 2.6 *Estimates of the cost of conserved energy (CCE) and energy savings potential for natural gas efficiency technologies in buildings in 2030. The CCEs for potential energy efficiency measures (numbered) are shown versus the ranges of potential energy savings for these measures. The total savings potential is 1.5 quads per year in the residential sector and 1.5 quads per year in the commercial sector. Commercial buildings (red solid line) and residential buildings (blue solid line) are shown separately. For comparison, the national average 2007 retail price of natural gas in the United States is shown for the commercial sector (red dashed line) and the residential sector (blue dashed line). For many of the technologies considered, on average the investments have positive payback without additional incentives. CCEs include the costs for add-ons such as insulation. For replacement measures, the CCE accounts for the incremental cost—for example, between purchasing a new but standard boiler and purchasing a new high-efficiency one. CCEs do not reflect the cost of programs to drive efficiency. All costs are shown in 2007 dollars.*
Sources: Data from Brown et al. (2008) and Chapter 4 in Part 2 of this report.

10¢/kWh.[9] In other words, it is substantially cheaper for a customer to save electricity rather than purchase electricity, even if these savings require up-front costs.

The range of CCE for natural gas savings from commercial and residential buildings is shown in Figure 2.6. The range of CCE from commercial buildings is $1.9–7.4/million Btu, with a weighted average of $2.5/million Btu. Nearly 80 per-

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[9]The figures were 10.65¢/kWh for residential and 9.65¢/kWh for commercial; see http://www.eia.doe.gov/cneaf/electricity/epa/epat7p4.html.

cent of the potential savings are achievable at a CCE of $2/million Btu. The range of CCE for natural gas savings from residential buildings is $1.1–11.8/million Btu, with a weighted average of $6.9/million Btu or less. Nearly 80 percent of the potential savings are achievable at a CCE of $5/million Btu or less. For comparison purposes, the retail price of natural gas in 2007 was about $12.7/million Btu in the residential sector and $11/million Btu in the commercial sector. Again, it is substantially cheaper for a customer to save natural gas rather than purchase natural gas, even if these savings require up-front costs.

The energy efficiency savings identified in this report are highly cost-effective with short payback periods. *Substantially greater energy efficiency savings could likely be obtained with a more aggressive mix of policies, regulations, and incentives to encourage an even wider deployment of energy efficiency technologies*. However, it should be noted that businesses and consumers have historically been resistant to making even modest up-front investments in such technologies (Box 2.2). New approaches may be required to break these patterns.

FINDING 3: OPTIONS FOR INCREASING ELECTRICITY SUPPLIES AND CHANGING THE SUPPLY MIX

The United States has many promising options for obtaining new supplies of electricity and changing its supply mix during the next two to three decades, especially if carbon capture and storage and evolutionary nuclear energy technologies can be deployed at required scales. However, the deployment of these new supply technologies is very likely to result in higher consumer prices for electricity.

The U.S. supply of electricity in 2007, about 4000 TWh,[10] was obtained from the following sources (EIA, 2009b):[11]

- 2000 TWh from coal-fired power plants
- 810 TWh from nuclear power plants

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[10]This estimate is for electricity supplied to the grid. The electricity delivered to the consumer is slightly lower because of losses in the transmission and distribution system. In 2007, these losses were estimated to be about 9 percent based on sales of electricity.

[11]These numbers have been rounded from the EIA estimates.

BOX 2.2 Energy Efficiency and the Behavioral Gap

A key finding of the present report is that there are substantial opportunities to reduce energy use through the widespread deployment of energy efficiency technologies in the buildings, transportation, and industrial sectors. The costs of deploying many of these technologies are much less than the costs to purchase energy; in fact, in these cases deployment saves money as well as energy. In spite of such advantages, many consumers are reluctant to make the necessary investments to deploy these technologies. Why the apparent dichotomy persists is the subject of ongoing research, which has already identified several reasons.

One reason for the behavioral gap between economically optimal technology choices and actual choices is the low salience of energy efficiency for consumers. That is, consumers in this case do not reflect the neoclassical economic model of the optimizing consumer. Although real-world consumers may recognize that purchasing an energy-efficient technology would be economically beneficial, the net benefits are usually so small relative to family budgets that individuals do not take the time to gather and analyze the requisite information.

Another reason for the gap has to do with the difficulty of changing consumers' purchasing and use habits. Preferences learned from parents, neighbors, and friends may change only very slowly, if at all. Also, most consumers do not calculate life-cycle costs when making purchases; instead, they focus primarily on first-purchase costs. Producers who understand this bias may be reluctant to design and market energy-efficient products unless forced to do so by governmental regulation.

Part of the behavioral gap is also based on economic-incentive issues—e.g., landlords of residential rental units are not motivated to pay for technologies that are more efficient when their tenants pay the utility bills. There are also historical path dependencies. For example, many existing building codes were developed when energy costs were not seen as important; these codes were optimized for safety, not for minimum life-cycle costs. Consumers also pay attention to product characteristics that tend to be ignored by analysts. They resisted buying early-generation compact fluorescent lamps, for instance, because they did not like the color of the light produced.

Continuing research is needed to more fully understand these and other reasons for the behavioral gap and to devise appropriate strategies for closing it.

- 690 TWh from natural-gas-fired power plants
- 320 TWh from renewable-energy sources, mostly hydropower (250 TWh), wind (34 TWh), geothermal (15 TWh), and biopower (8.7 TWh)
- 180 TWh from combined-heat-and-power plants, fed primarily by natural gas and coal
- 57 TWh from oil-fired power plants.

Through the deployment of new technologies and the repowering of current assets, the United States has many promising options both for increasing its electricity supply and for changing its electricity-supply mix. These estimates of new electricity supplies using different energy sources and technologies were derived independently and should not be added to obtain a total new supply estimate. As noted in Chapter 1, the AEF Committee has not conducted an integrated assessment of how these energy-supply technologies would compete in the marketplace or of how that competition and other external factors would affect deployment success.

Renewable-energy sources (Figure 2.7) could provide about an additional 500 TWh of electricity per year by 2020 and about an additional 1100 TWh per year by 2035 through new deployments in favorable locations. These levels exceed the amounts of new electricity supplies that are likely to be available from new nuclear-power generation or new coal-power generation with CCS in 2020 or from new nuclear power generation in 2035. However, expansion of transmission capabilities would be required to transport new electricity supplies from renewable resources to demand centers and regional energy markets. Backup supplies of electricity, or the capability to store energy during times when electricity production exceeds demand, would be needed when renewable sources were unavailable. Given current cost structures for renewable energy (discussed later in this chapter), policies such as renewable portfolio standards and tax credits would likely need to be continued, and possibly expanded, to obtain these new supplies.

Coal-fired plants with CCS (Figure 2.8) could provide as much as 1200 TWh from repowering and retrofit of existing plants and as much as 1800 TWh from new plants. In combination, the entire existing coal power fleet (which currently delivers about 2000 TWh of electricity per year) could be replaced by CCS coal power by 2035. However, successful commercial-scale demonstrations of CCS technologies would be required during the coming decade to realize this potential. (A brief discussion of CCS demonstration needs and constraints is provided under Finding 6; additional information is

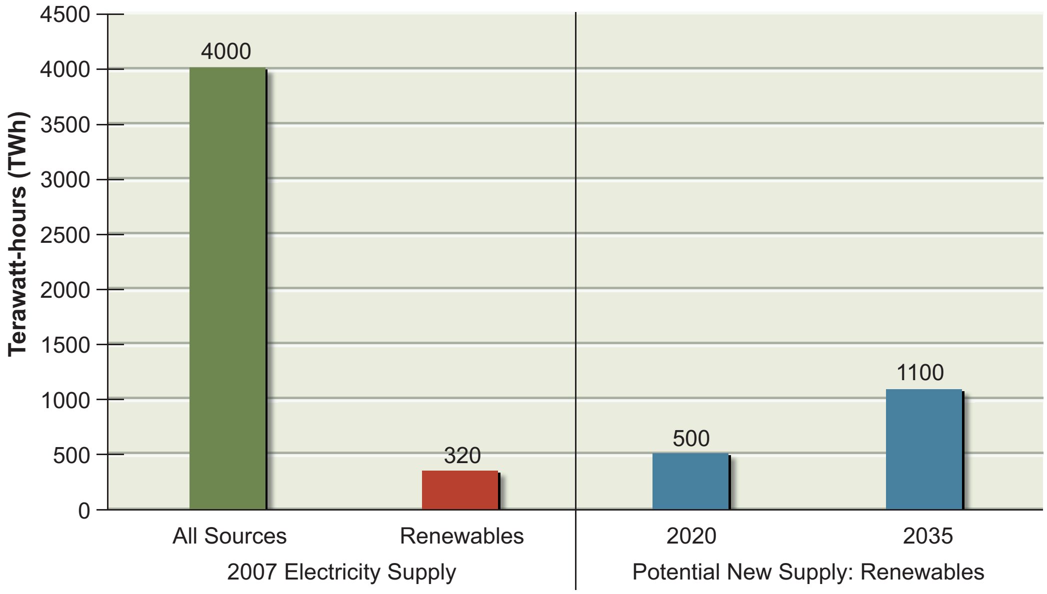


FIGURE 2.7 *Estimates of potential new electricity supply from renewable sources in 2020 and 2035 (relative to 2007) compared to current supply from all sources. The total electricity supplied to the U.S. grid in 2007 is shown on the left (in green). The supply generated by renewable sources (including conventional hydropower) is shown in red. Potential new supply shown is in addition to the currently operating supply. To estimate future supply, an accelerated deployment of technologies as described in Part 2 of this report is assumed. Potential new electricity supply does not account for future electricity demand or competition among supply sources. All values have been rounded to two significant figures.*
Sources: Data from Energy Information Administration (2008) and Part 2 of this report.

available in Chapter 7 in Part 2 of this report.) In addition, it will be necessary to assess the full implications, including the environmental externalities, of any very large expansion in coal production and use. Given the projected costs of CCS, the widespread deployment of CCS technologies will likely require new governmental policies that provide a regulatory or CO_2 price push. These deployments would reduce the environmental impacts of electricity generation and thereby provide indirect economic benefits to consumers, though such benefits are difficult to quantify.

Nuclear plants (Figure 2.9) could provide an additional 160 TWh of electricity per year by 2020 and about 850 TWh by 2035 through the modification of current plants to increase power output (referred to as "uprating")

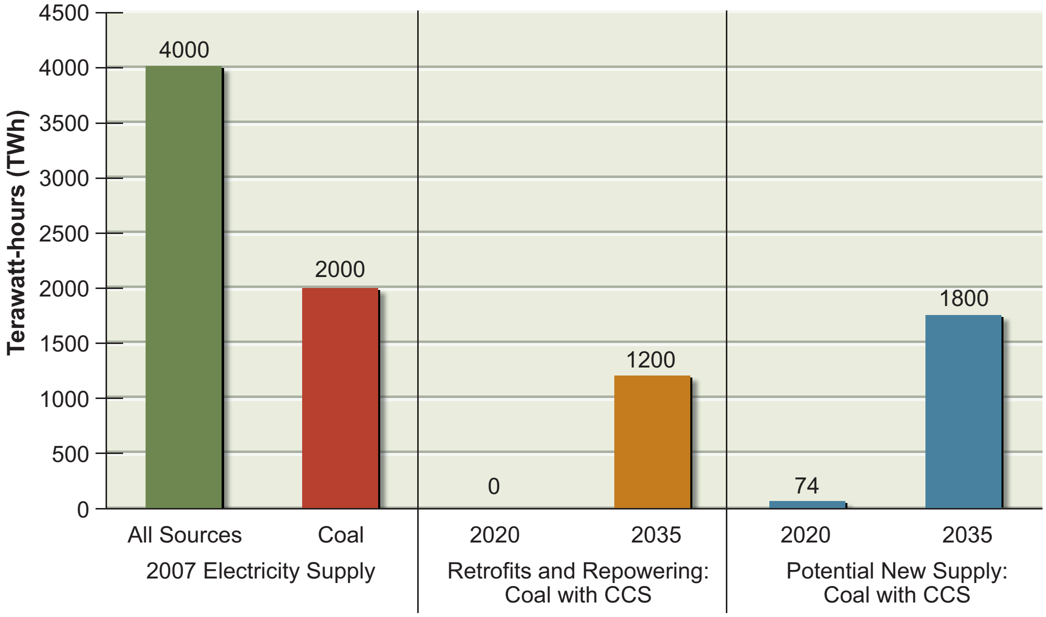


FIGURE 2.8 *Estimates of potential electricity supply, in 2020 and 2035 (relative to 2007) compared to supply from all sources, from new coal-fired plants with carbon capture and storage (CCS) and from plants retrofitted or repowered to add CCS. The total electricity supplied to the U.S. grid in 2007 is shown on the left (in green). The supply generated by coal is shown in red. To estimate future supply, an accelerated deployment of technologies as described in Part 2 of this report is assumed. The potential supply from new coal plants built with CCS is shown in blue; the potential supply from retrofitting and repowering currently operating plants to add CCS is shown in orange. Potential new supply with CCS and potential retrofits with CCS compete for the same CO_2 storage sites and other enabling elements. The simultaneous realization of both estimates of potential 2035 deployment is not anticipated because of this competition. Over the next decade CCS technologies will need to be successfully demonstrated to achieve the potential supply shown from coal plants with CCS in 2035. A strong policy push will also be required to realize the 2020 supply estimate. The AEF Committee assumed an average capacity factor of 85 percent for coal plants with CCS. Potential new electricity supply does not account for future electricity demand, fuel availability or prices, or competition among supply sources. All values have been rounded to two significant figures.*
Sources: Data from Energy Information Administration (2008) and Chapter 7 in Part 2 of this report.

and through new-plant construction. These amounts would be in addition to the 800 TWh produced by currently operating plants and do not account for possible plant retirements, which are shown by the negative 2035 supply estimate in Figure 2.9. The original (40-year) operating licenses of current plants are now beginning to expire. For the majority of these plants, license extensions

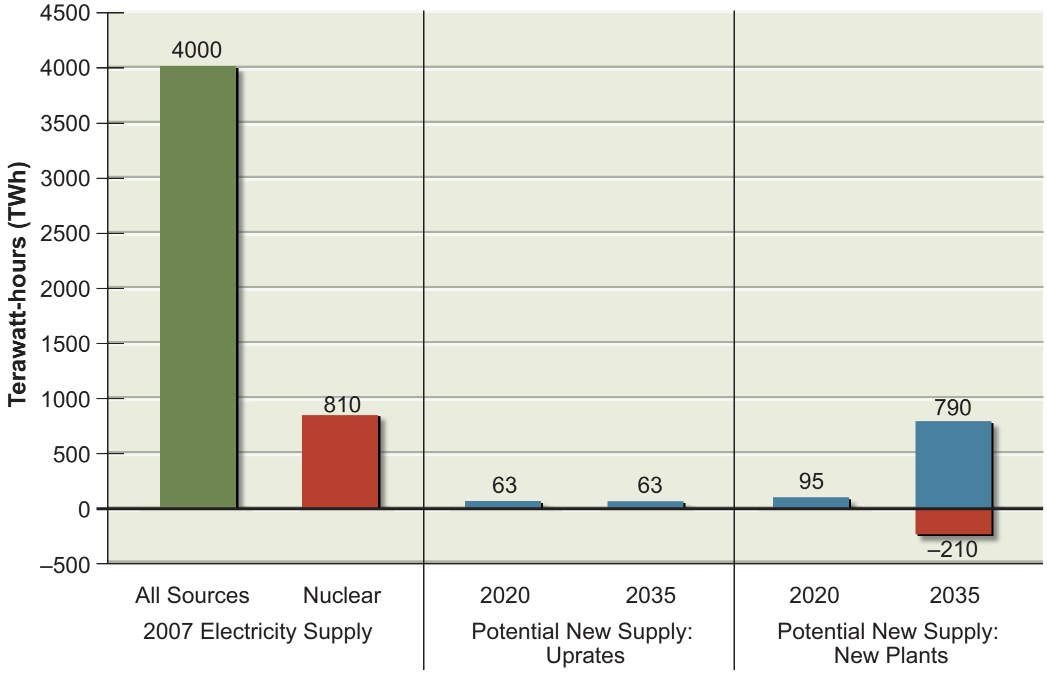


FIGURE 2.9 *Estimates of potential new electricity supply from nuclear power in 2020 and 2035 (relative to 2007) compared to supply from all sources. The total electricity supplied to the U.S. grid in 2007 is shown on the left (in green). The supply generated by nuclear power is shown in red. Over the next decade, the first few nuclear plants will need to be constructed and operated successfully to achieve the potential supply shown from nuclear power in 2035. To estimate supply, an accelerated deployment of technologies as described in Part 2 of this report is assumed. Current plants are assumed to be retired at the end of 60 years of operation, resulting in a reduced electricity supply from nuclear power in 2035 (shown by the negative valued red bar). However, operating license extensions to 80 years are currently under consideration, and it is possible that many of these plants may not be retired by 2035. The AEF Committee assumed an average capacity factor of 90 percent for nuclear plants. Potential new electricity supply does not account for future electricity demand, fuel availability or prices, or competition among supply sources. All values have been rounded to two significant figures.*
Sources: Data from Energy Information Administration (2008) and Part 2 of this report.

for an additional 20 years (to allow for a total of 60 years of operation) have been approved or are being processed. This will allow more electricity to be generated over the operating life of each of these plants. The negative 2035 supply estimate shown in Figure 2.9 illustrates potential supply losses resulting from the retirement of plants when these 60-year licenses expire; however, it is possible that some plants will receive license extensions for up to an additional 20 years (to allow for a total of 80 years of operation), decreasing these potential supply losses. A discussion of nuclear-plant demonstration needs and constraints is included under Finding 6; additional information is provided in Chapter 8 in Part 2 of this report. Existing federal loan guarantees (described in Chapter 8) will probably be essential for constructing at least some of the first few new nuclear plants in the United States.

Natural gas generation of electricity could be expanded to meet a substantial portion of U.S. electricity demand—if there were no concerns about the behavior of world natural gas markets and prices and about further increasing CO_2 emissions and U.S. import dependence. In fact, lower capital cost and shorter construction times favor natural gas over coal or nuclear power plants for new electric-power generation (see Figure 1.10). But it is not clear whether natural gas supplies at competitive prices would be adequate to support substantially increased levels of electricity generation. The role of natural gas will likely depend on the demand for electricity, the magnitude of growth in domestic natural gas production, the demand for natural gas for other uses (e.g., as an industrial feedstock or for space heating), and controls on CO_2 emissions. If growth in new domestic natural gas production were sufficient to offset declines in production from existing fields and could be sustained for extended periods, domestic resources could be used to support expanded electricity production. If domestic supplies could not be increased, liquefied natural gas imports would be needed, thereby exposing the U.S. market to increased import dependence and to international prices. Increased import dependence has important energy-security implications, as discussed in Chapter 1.

Although the potential picture with these new supplies is promising, they will likely result in higher electricity prices.[12] Estimates of the levelized cost of electricity (LCOE; Box 2.3) for new baseload and intermittent electricity generation in 2020 are shown in Figure 2.10. Descriptions of the methods and assumptions that were used to estimate these LCOEs are provided in Annex 3.A in Chapter 3 and in the Part 2 chapters. It is important to recognize that estimating future costs is notoriously difficult. The estimates are strongly dependent on the judgments of the experts who make them and are based on a necessarily lim-

[12]The deployment of new generating capacity, whether from an existing or a new technology, generally results in an increase in the cost of electricity. This is because the embedded costs (i.e., the “book values”) of existing generating assets are typically at least an order of magnitude less than those of the new generating assets (whether for replacement or supplementation).

BOX 2.3 ***Levelized Cost of Electricity***

The levelized cost of electricity (LCOE) is defined as the average cost of generating a unit of electricity over the generating facility's service life. The LCOE is computed by dividing the present value of the estimated full life-cycle costs of the generating facility by its estimated lifetime electricity production. The result is usually expressed in terms of cents per kilowatt-hour.

The full life-cycle costs of the generating facility include:

- Capital costs for construction
- Financing costs
- Operations and maintenance costs
- Fuel costs
- Decommissioning costs.

Facility lifetime is typically taken to be between 20 and 40 years, depending on the generating technology.

The LCOE is less than the cost of electricity to the consumer (i.e., less than the retail price) because it does not include the costs of transmission and distribution or the electricity generator's profit. These additional costs can typically add several cents per kilowatt-hour to the wholesale cost of electricity.

ited understanding about how future events might unfold. Consequently, such estimates usually have large uncertainties. Given these uncertainties and the particular methodologies used to estimate LCOEs in this report, differences in LCOEs of 2¢/kWh or less are probably not significant.[13]

Figure 2.10 shows both that there is a range of LCOE values for each technology and that the ranges for many different technologies are overlapping. For comparison purposes, consider that the EIA-estimated average wholesale price of electricity[14] in 2007 was about 6¢/kWh and is forecast to

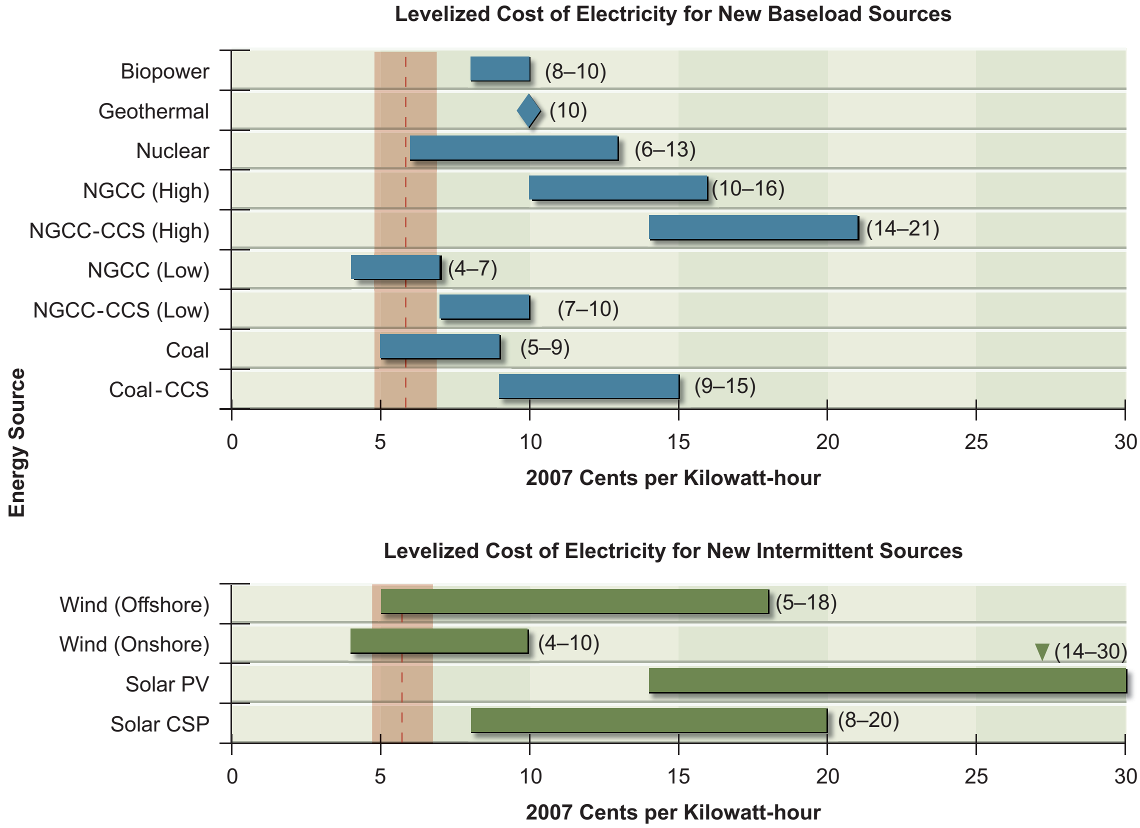
[13]It was difficult to obtain consensus within the committee about how to estimate LCOEs for different technologies on exactly comparable bases given the large number of assumptions that had to be made about costs, performance, and expected lifetimes for each technology. Consequently, the estimates shown in Figure 2.10 should be considered approximations.

[14]The wholesale price of electricity represents the price of electricity supplied at the busbar. It does not include the prices for transmission and distribution. As noted previously, the average retail price for electricity in 2007 was about 10¢/kWh.

remain at that level through 2030 under the agency's reference case projection (EIA, 2008). The LCOEs for most new electricity sources in 2020 shown in Figure 2.10 are higher than the EIA-projected wholesale cost. The clear exceptions are coal without CCS, some biopower for baseload generation, and onshore wind for intermittent generation. The cost for electricity from natural gas strongly depends on gas prices as shown in Figure 2.10. However, biopower can provide limited new supplies of electricity, and wind power can have large electrical-transmission and distribution costs because power generation sources are spatially distributed. Additionally, generation of electricity using natural gas and coal without CCS might not be environmentally acceptable, and the price for electricity from natural gas could increase substantially, of course, if there were large price increases for this fuel.

The LCOEs shown in Figure 2.10 represent what the AEF Committee judges to be reasonable cost ranges based on available information. Actual LCOEs could be different from those shown in the figure, however, for reasons such as unanticipated future changes in fuel prices, higher- or lower-than-expected costs for deploying and operating new technologies, costs arising from deployments at particular locations, and other regional cost differences. Obviously, the LCOEs for some technologies would be affected more than others by these factors; natural gas combined cycle (NGCC) plants, for example, utilize natural gas as a fuel, and recent prices for this fuel have been volatile. On the other hand, fuel costs for nuclear plants are only a small part of electricity generation costs. Wind, solar, hydro, and geothermal power have no fuel charges and their deployment costs are well established, especially for onshore wind and solar. Still, the potential outputs of solar arrays and wind turbines can vary greatly because of local conditions, so these technologies will have site-dependent cost impacts.

The overlapping LCOE estimates shown in Figure 2.10 make it difficult to pick winners and losers, suggesting the need to proceed on parallel tracks for demonstrating and deploying technologies. The results for electricity from natural gas strengthen this conclusion: given the low and high prices of natural gas in recent years, the LCOE for NGCC can be one of the lowest-cost—or one of the highest-cost—sources of electricity, as shown in Figure 2.10. Given the variability of fuel prices over the decades-long lives of these plants, it is impossible to be confident that a particular technology will have the lowest cost or even a reasonably low cost. Although the committee, along with most observers, concluded that over the 30-year life of an NGCC plant the price of



natural gas would be likely to rise, the year-to-year variations could also be large because of changes in the balance between demand and supply.

Figure 2.10 indicates that the LCOE range for nuclear plants is comparable with those for coal with CCS and certain renewable-energy sources, such as offshore wind and concentrating solar power. The bottom of the LCOE range for nuclear is for plants built with federal loan guarantees. At present, such guarantees are available only for the first few plants. The bottom of the LCOE range for wind, corresponding to class 7 wind sites, extends below the range for nuclear. However, nuclear and fossil-fuel electricity generation provide baseload power, whereas most renewable sources provide intermittent power, which reduces their value in the electricity system. The costs of integrating intermittent renewables such as wind and solar into the grid are generally low if they provide less than about 20 percent of total electricity generation (see Chapter 6), except when expensive transmission capacity must be added to bring power to demand centers.

FIGURE 2.10 *Estimates of the LCOE at the busbar for new baseload and intermittent generating sources in 2020. The horizontal bars represent the AEF Committee's judgments regarding plausible ranges of costs, given the uncertainties in fixed costs for each technology. Baseload electric power includes generating options with capacity factors above 75 percent; intermittent electric power includes generating options with capacity factors between about 25 and 40 percent. The vertical shaded bar shows the approximate range of average U.S. wholesale electricity prices across NERC regions in 2007; the dashed vertical line shows the average value in 2007, which was 5.7¢/kWh. Coal prices are assumed to be $1.71/GJ. Natural gas prices are shown for two cases: $6/GJ (low price case) and $16/GJ (high price case). The lower LCOE for nuclear power (6–8¢/kWh) includes federal loan guarantees. When installed at the point of energy use, such as on a residential rooftop, PV competes with the retail cost of electricity rather than with wholesale electricity prices. The cost estimates for different generating technologies were derived independently, with transmission and distribution costs not included explicitly in the estimates. These transmission and distribution costs are likely to be significant, however, for example, when installations are located far from load centers. Intermittent technology costs do not account for plants that must be kept available to assure adequate power supplies when the intermittent source is unavailable. All costs are in 2007 dollars. Estimated costs should be considered approximations.*
Note: CCS = carbon capture and storage; CSP = concentrating solar power; LCOE = levelized cost of electricity; NERC = North American Electric Reliability Corporation; NGCC = natural gas combined cycle; PV = photovoltaics.
Sources: Data from Energy Information Administration (www.eia.doe.gov/cneaf/electricity/wholesale/wholesalet2.xls) and Part 2 of this report.

Figure 2.10 also shows that solar photovoltaic (PV) technologies are a higher-cost option for generating electricity than most other renewables. However, when installed at the point of energy use, such as on a residential rooftop, PV competes with the retail cost of electricity and are therefore more cost competitive for a purchasing customer. Additional R&D work on this technology, particularly to find new materials and manufacturing methods to lower these costs, will be necessary if it is to be more cost competitive and, as a result, more widely deployed.

Although the LCOE is generally informative for assessing technology costs, many other factors will also influence technologies' competitiveness in the marketplace. Some of these factors have already been mentioned: fuel prices over the life of the generating asset, environmental regulations, costs of competing technologies, and, for technologies that are not yet commercial, uncertainties in construction and operation costs.

The deployment of new electricity-supply technologies will have a range of impacts beyond higher costs. They could include, for example, increased water consumption, especially for large baseload generating plants (see Chapters 7 and 8); health effects from pollutant emissions; and the siting and construction of facilities that are sometimes viewed as undesirable. Such facilities include electricity transmission lines, CO_2 pipelines, coal and uranium mines as well as coal and nuclear power plants, and waste-disposal facilities for mine tailings, fly ash, and used nuclear fuel. Even renewable-energy facilities such as wind plants could be difficult to site because of potentially degraded vistas and other environmental impacts. These kinds of deployment challenges should not be underestimated.

FINDING 4: MODERNIZING THE NATION'S POWER GRID

Expansion and modernization of the nation's electrical transmission and distribution systems (i.e., the power grid) are urgently needed to enhance reliability and security, accommodate changes in load growth and electricity demand, and enable the deployment of new energy efficiency and supply technologies, especially to accommodate future increases in intermittent wind and solar energy.

The nation's electrical transmission and distribution systems require expansion and modernization for several reasons:

- Increasing congestion threatens reliability and prevents the efficient transmission of electricity to areas where it is needed.
- Transmission systems are subject to cascading failures—resulting, for example, from human error, natural disasters, and terrorist attacks—that can lead to widespread and lengthy outages.
- Current systems have limited ability to accommodate new sources of electricity supply, especially intermittent sources, and sophisticated demand-side technologies such as advanced electricity metering technologies, sometimes referred to as "smart meters."

Modernization of these systems would have a number of economic, national security, and social benefits, among them:

- Reduced need for new transmission lines because systems could be operated more efficiently.
- Improved reliability and more rapid recovery from system disturbances.
- Ability to accommodate an expanded generation base, especially from intermittent wind and solar energy and from generation sources that are located at a distance from load-demand centers, which would help meet projected growth in future demand and deliver power to areas where it is needed.
- Ability to provide real-time electricity price information that could motivate consumers to use electricity more efficiently, thereby moderating future growth in electricity demand.

Some near-term expansion and modernization options include the deployment of modern power electronics and sensors, advanced control technologies, higher-capacity conductors, dispatchable energy storage, and other "smart" technologies.[15] Over the long term, new power storage and load-management strategies must be developed to accommodate the intermittent nature of solar and wind power.

The technologies needed to modernize and, where necessary, expand the transmission and distribution system are largely available now. Installing these technologies concurrently—that is, expanding and modernizing these systems simultaneously—would offer substantial cost savings. The committee estimates (see Chapter 9) that it would cost (in 2007 dollars) $175 billion for expansion and $50 billion for modernization of the transmission system when they are done concurrently, compared to $175 billion for expansion and $105 billion for modernization when done separately—a cost savings of $55 billion with simultaneous expansion and modernization. The committee also estimates that it would cost $470 billion for expansion and $170 billion for modernization of the distribution system when they are done concurrently, compared to $470 billion for expansion and $365 billion for modernization when done separately—a cost savings of $195 billion.

[15]That is, technologies that allow the transmission and distribution systems to rapidly and automatically adjust to changing conditions without the need for human intervention.

FINDING 5: CONTINUED DEPENDENCE ON PETROLEUM

Petroleum will continue to be an indispensable transportation fuel during the time periods considered in this report, but maintaining current rates of domestic petroleum production will be challenging. There are limited options for replacing petroleum or reducing petroleum use before 2020, but there are more substantial longer-term options that could begin to make contributions in the 2030–2035 timeframe. The options include increasing vehicle efficiency, replacing imported petroleum with other liquid fuels produced from biomass and coal that have CO_2 emissions similar to or less than that of petroleum-based fuels, and electrifying the light-duty vehicle fleet.

The United States consumed about 21 million barrels of liquid fuels[16] per day in 2007. Domestic consumption of liquid fuels is projected to increase to about 22 million barrels per day in 2020 and about 23 million in 2030 (EIA, 2008). In 2007, about 14 million barrels of liquid fuels per day were used in the transportation sector, of which about 9 million barrels were consumed by LDVs.

The best near-term option for reducing dependence on imported petroleum is through greater vehicle efficiency. The EISA requires a 40 percent increase in fuel economy for new LDVs by 2020. This could eventually result in a savings of about 1.4 billion barrels of gasoline per year (60 billion gallons of gasoline per year or about 164 million gallons of gasoline per day) when these fuel economy standards are fully realized in the on-the-road fleet. As noted previously, the Obama administration recently announced a new policy that requires an average fuel economy standard of 35.5 miles per gallon for new LDVs in 2016. As explained in Chapter 4, further efficiency gains are projected after 2020.

Reducing dependence on imported petroleum by substituting domestically produced liquid fuels would seem to be a good strategy, but the near-term options are limited. Just maintaining current rates of domestic petroleum production (about 5.1 million barrels per day in 2007) over the next two to three decades will be challenging. Petroleum production in current fields is declining, and it will be difficult to increase domestic production even with favorable developments in technology, prices, and access to new resources. Nevertheless, continued devel-

[16]Including 15.2 million barrels of crude oil, 2.1 million barrels of import products such as gasoline and jet fuel, and 3.5 million barrels of other liquid fuels such as natural gas liquids, ethanol, and biodiesel.

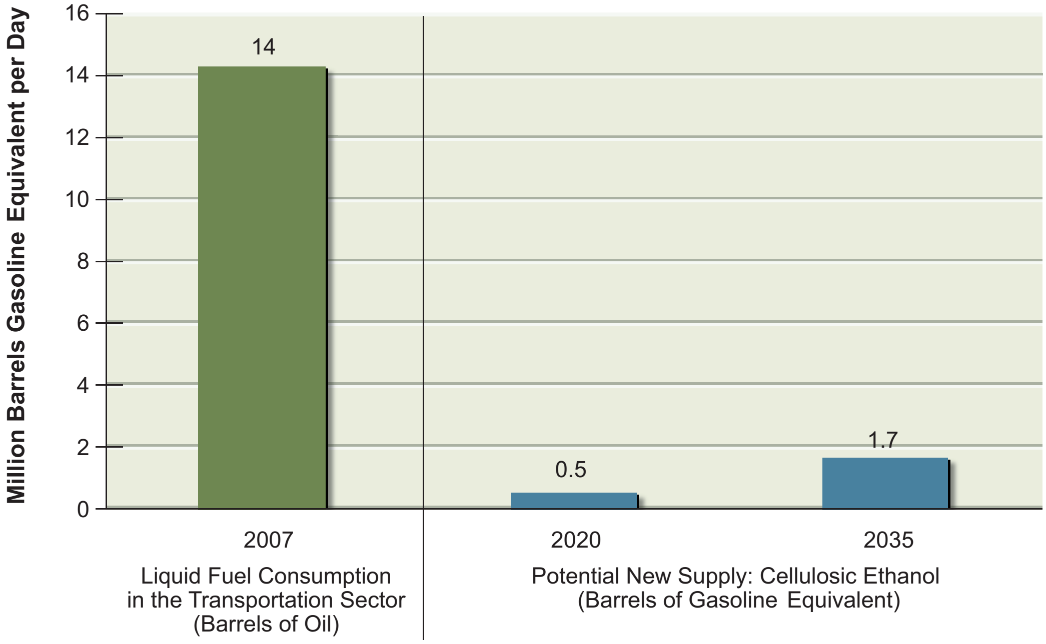


FIGURE 2.11 *Estimates of the potential cellulosic ethanol supply in 2020 and 2035 (relative to 2007) compared to total liquid fuel consumption. The current (2007) U.S. liquid fuel consumption, in barrels of oil, for transportation is shown on the left (in green). To estimate supply, an accelerated deployment of technologies (as described in Part 2 of this report) and the availability of 500 million dry tonnes per year of cellulosic biomass for fuel production are assumed after 2020. Potential liquid fuel supplies are estimated individually for each technology, and estimates do not account for future fuel demand, competition for biomass, or competition among supply sources. Potential supplies are expressed in barrels of gasoline equivalent. One barrel of oil produces about 0.85 barrels of gasoline equivalent of gasoline and diesel. All values have been rounded to two significant figures.*
Sources: Data from Energy Information Administration (2008) and Chapter 5 in Part 2 of this report.

opment of domestic resources will be essential to help prevent increases in U.S. import dependence.

Substituting other domestically produced liquid fuels could further reduce petroleum imports. Ethanol is already being made from corn grain in commercial quantities in the United States, but corn ethanol is likely to serve only as a transition fuel to more sustainable biofuels production, given the social and environmental concerns about using corn for fuel. The most promising substitutes before 2020 are cellulosic ethanol (Figure 2.11) and fuels produced from coal (coal-to-liquid fuels; Figure 2.12) and mixtures of coal and biomass (biomass-and-coal-to-

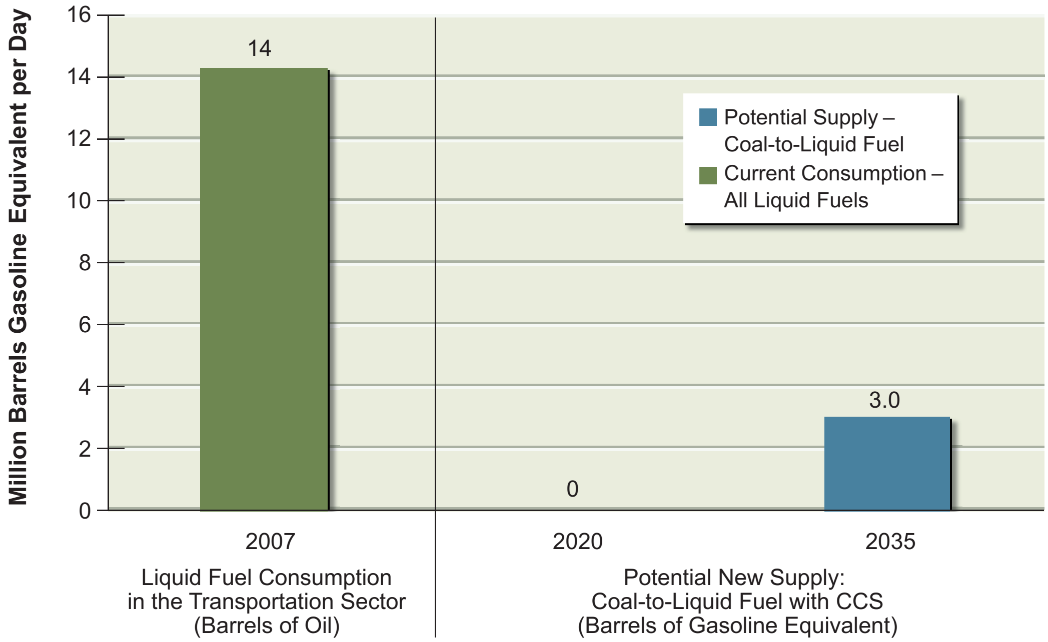


FIGURE 2.12 *Estimates of the potential liquid fuel supply from conversion of coal to liquid fuels in 2020 and 2035 (relative to 2007) compared to total liquid fuel consumption. The current (2007) U.S. liquid fuel consumption, in barrels of oil, for transportation is shown on the left (in green). To estimate supply, an accelerated deployment of technologies as described in Part 2 of this report is assumed for coal-to-liquid fuel (CTL) with carbon capture and storage (CCS). It is assumed that CTL without CCS would not be deployed. There is uncertainty associated with the technical potential for CCS. CCS technologies will need to be successfully demonstrated over the next decade if they are to be used for liquid fuel production in 2035. The volume of liquid fuel estimated to be available in 2020 and 2035 depends primarily on the rate of plant deployment. Potential liquid fuel supplies are estimated individually for each technology, and estimates do not account for future fuel demand or competition among supply sources. Potential supplies are expressed in barrels of gasoline equivalent. One barrel of oil produces about 0.85 barrels of gasoline equivalent of gasoline and diesel. All values have been rounded to two significant figures.*
Sources: Data from Energy Information Administration (2008) and Chapter 5 in Part 2 of this report.

liquid fuels; Figure 2.13). Cellulosic ethanol is in the early stages of demonstration, but coal-to-liquid fuels are being commercially produced today (but without geologic storage of CO_2) outside the United States. Coal-to-liquid fuels technologies could be deployed domestically, but these technologies would have to be integrated with CCS to produce fuels with CO_2 emissions similar to or less than those from petroleum-based fuels.

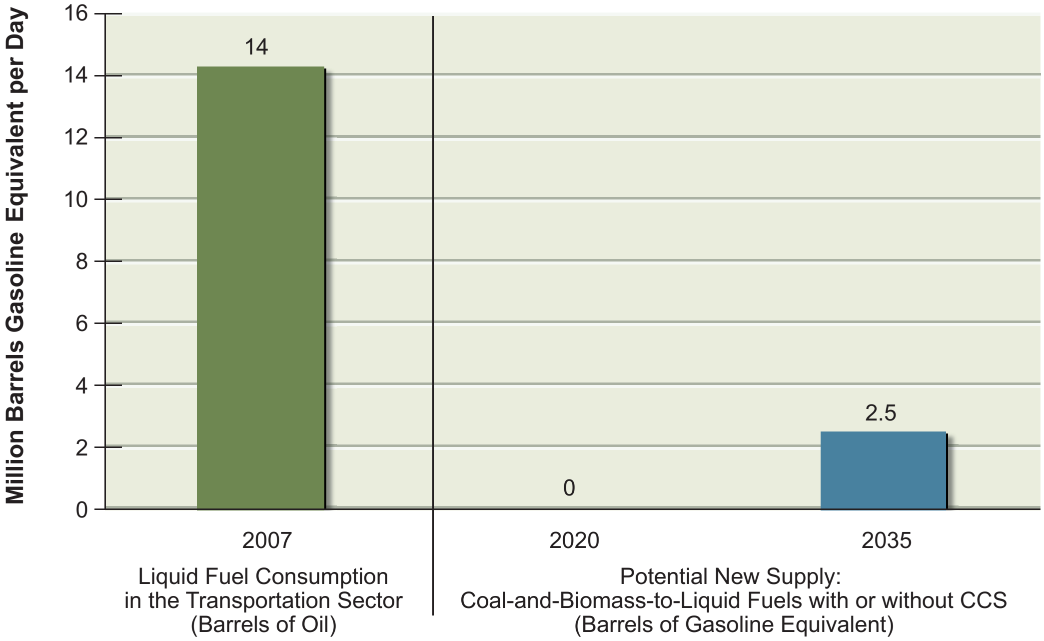


FIGURE 2.13 *Estimates of the potential liquid fuel supply from conversion of coal and biomass to liquid fuels in 2020 and 2035 (relative to 2007) compared to total liquid fuel consumption. The current (2007) U.S. liquid fuel consumption, in barrels of oil, for transportation is shown on the left (in green). To estimate supply, an accelerated deployment of technologies as described in Part 2 of this report is assumed. A mix of 60 percent coal and 40 percent biomass (on an energy basis) is assumed as well. The volume of liquid fuels estimated to be available in 2020 and 2035 depends primarily on the rate of plant deployment and also assumes availability of 500 million dry tonnes per year of cellulosic biomass for fuel production after 2020. The supply of cellulosic ethanol estimated in Figure 2.11 cannot be achieved simultaneously with this coal-and-biomass-to-liquid fuel (CBTL) supply, as the same biomass is used in each case. There is uncertainty associated with the technical potential for carbon capture and storage (CCS). CCS technologies will need to be successfully demonstrated over the next decade if they are to be used for liquid fuel production in 2035. Potential liquid fuel supplies are estimated individually for each technology, and estimates do not account for future fuel demand, competition for biomass, or competition among supply sources. Potential supplies are expressed in barrels of gasoline equivalent. One barrel of oil produces about 0.85 barrels of gasoline equivalent of gasoline and diesel. All values have been rounded to two significant figures.*
Sources: Data from Energy Information Administration (2008) and Chapter 5 in Part 2 of this report.

Beyond 2020, more advanced biofuels—with higher energy content and greater compatibility with the existing transportation-fuel infrastructure—might become available. However, additional research, development, and demonstration will be required to ready these technologies for widespread commercial deployment.

By 2035, cellulosic ethanol and coal-and-biomass-to-liquid fuels *with CCS* could replace 1.7–2.5 million barrels per day of gasoline equivalent—about 12–18 percent of the current liquid fuel consumption in the transportation sector—with near-zero life-cycle CO_2 emissions. Coal-to-liquid fuels *with CCS* could replace 2–3 million barrels per day of gasoline equivalent (the 2 million barrels per day estimate assumes that some coal is diverted to produce coal-and-biomass-to-liquid fuels)—about 14–21 percent of current liquid fuels consumption in the transportation sector—and would have life-cycle CO_2 emissions similar to those of petroleum-based fuels (Figures 2.11–2.13). However, commercial demonstration of these technologies would have to be started immediately and pursued aggressively to achieve that level of production by 2035. In addition, the annual harvesting of up to 500 million dry tonnes (550 million dry tons) of biomass and an increase in U.S. coal extraction by 50 percent over current levels would be required to provide the necessary feedstock supply for this level of liquid fuel production.

These expanded levels of liquid fuel production could have a range of environmental impacts on land, water, air, and human health. Moreover, the production of liquid fuel from coal would increase CO_2 emissions to the atmosphere unless conversion plants were equipped with CCS. Although CO_2 from the off-gas streams of conversion plants could be readily captured using commercially available technologies, engineered geologic storage of captured CO_2 has not yet been demonstrated at the needed scales. Additional discussion of CCS technologies is provided under Finding 6.

Coal-to-liquid fuel production, with or without CCS, is the least expensive option for producing alternative liquid fuels (less than or equal to $70 per barrel; see Figure 2.14), although such production raises important health and environmental issues, as noted above. Deploying cellulosic ethanol would be economically competitive only with petroleum prices above about $115 per barrel.

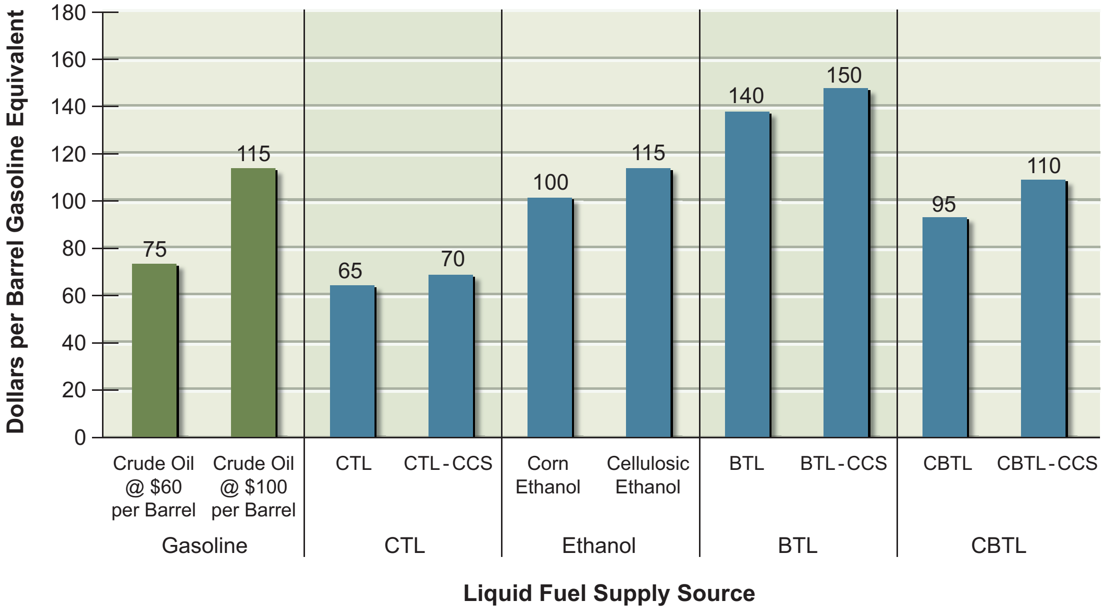


FIGURE 2.14 *Estimated gasoline-equivalent costs of alternative liquid fuels. For comparison, the costs of gasoline at crude oil prices of $60 per barrel and $100 per barrel are shown on the left. Estimated costs assume that a zero price is assigned to CO_2 emissions. Liquid fuels would be produced using biochemical conversion to produce ethanol from Miscanthus or using thermochemical conversion via Fischer-Tropsch or methanol-to-gasoline. All costs are in 2007 dollars and are rounded to the nearest $5.*
Note: BTL = biomass-to-liquid fuel; CBTL = coal-and-biomass-to-liquid fuel; CCS = carbon capture and storage; CTL = coal-to-liquid fuel.
Source: Data from Chapter 5 in Part 2 of this report.

Additional reductions in petroleum imports would be possible by increasing the electrification of the vehicle fleet. The widespread deployment of electric and/or hydrogen fuel cell vehicles between 2035 and 2050 could lead to further and possibly substantial long-term reductions in liquid fuel consumption in the transportation sector. The National Research Council (2008), for example, estimated the potential reduction in petroleum use in 2050 from the deployment of hydrogen fuel-cell LDVs under a best-case scenario to be about 70 percent below the projected petroleum consumption of a fleet of comparable gasoline-fueled vehicles. The LDV fleet turns over every one to two decades, so the introduction of higher-efficiency vehicles would have relatively low impacts on petroleum use and CO_2 emissions from the transportation sector until sometime after the 2020–2030 period.

FINDING 6: REDUCING GREENHOUSE GAS EMISSIONS

Substantial reductions in greenhouse gas emissions from the electricity sector are achievable over the next two to three decades. They can best be realized through a portfolio approach involving the widespread deployment of multiple technologies: energy efficiency; renewable energy; coal, natural gas, and biomass with carbon capture and storage; and nuclear. However, to enable this portfolio approach, the viability of the following two technologies must be demonstrated during the next decade to make them ready for widespread commercial deployment starting around 2020: (1) the technical and commercial viability of CCS for sequestering CO_2 from electricity production and (2) the commercial viability of evolutionary nuclear plants in the United States. Achieving substantial greenhouse gas reductions in the transportation sector over the next two to three decades will also require a portfolio approach involving the widespread deployment of energy efficiency technologies, alternative liquid fuels with low life-cycle CO_2 emissions, and light-duty-vehicle electrification technologies.

As noted in Chapter 1, the United States emits some 6 billion tonnes (6 gigatonnes) of CO_2 into the atmosphere each year (see Figure 1.3); about 5.6 gigatonnes are attributable to the energy system. The potential for reducing greenhouse gas emissions from this system before 2020 is limited, but the potential for reducing emissions after 2020 is significant, especially in the electricity sector, if certain technologies can be successfully deployed at commercial scales.

Electricity is produced in stationary facilities, which in principle makes it easier to effectively monitor and control their greenhouse gas emissions. The options for reducing the electricity sector's emissions are apparent from an inspection of Figure 2.15, which provides estimates of life-cycle CO_2-equivalent[17] (denoted CO_2-eq) emissions per kilowatt-hour of electricity produced. Coal and natural gas plants are by far the largest emitters of greenhouse gases from electricity generation. In fact, their CO_2-eq emissions are far higher than those of any of the other technologies represented. As shown in Figure 1.8, coal and natural gas plants collectively supplied about 70 percent of electricity demand in 2007.

Achieving substantial reductions in CO_2 emissions from the U.S. electricity

[17] CO_2 equivalent expresses the global warming potential of a greenhouse gas in terms of CO_2 quantities.

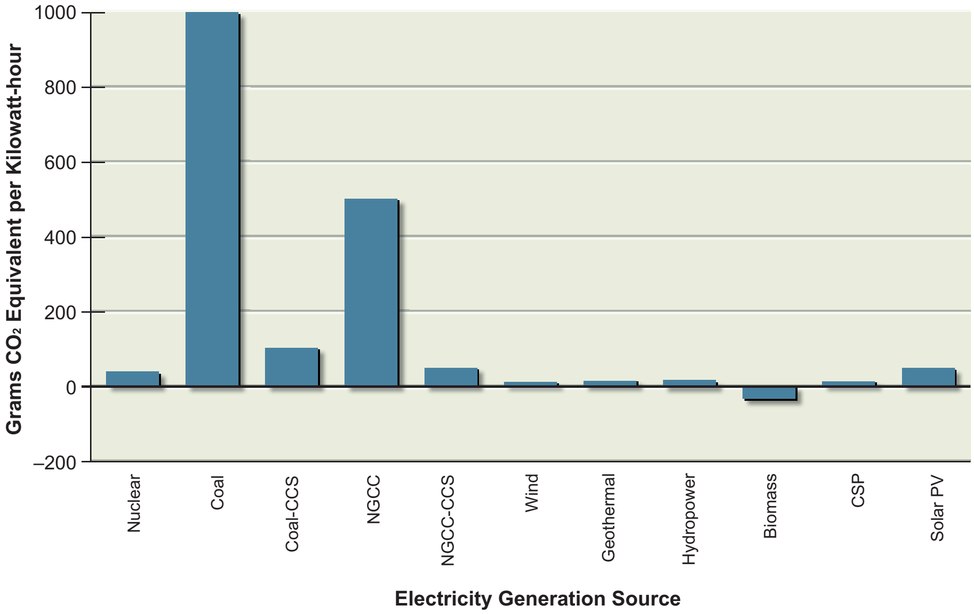


FIGURE 2.15 *Estimated greenhouse gas emissions from electricity generation. Estimates are in units of grams of CO_2-equivalent (CO_2-eq) emissions per kilowatt-hour of electricity produced. Estimates for all technologies (with the exception of coal, coal-CCS, NGCC, and NGCC-CCS) are life-cycle estimates, which include CO_2-eq emissions due to plant construction, operation, and decommissioning, levelized across the expected output of electricity over the plant's lifetime. For coal, coal-CCS, NGCC, and NGCC-CCS, only emissions from the burning of the fossil fuels are accounted for. A 90 percent capture fraction is assumed for CCS technologies. Negative CO_2-eq emissions mean that on a net life-cycle basis, CO_2 is removed from the atmosphere. For example, the negative CO_2 emissions for biopower result from an estimate that the sequestration of biomass carbon in power-plant char and the buildup of carbon in soil and roots will exceed the emissions of carbon from biofuel production. The life-cycle CO_2 emission from biofuels includes a CO_2 credit from photosynthetic uptake by plants, but indirect greenhouse gas emissions, if any, as a result of land-use changes are not included.*
Note: CCS = carbon capture and storage; CSP = concentrating solar power; NGCC = natural gas combined cycle; PV = photovoltaics.
Sources: Data from Part 2 of this report and from NAS-NAE-NRC (2009a).

sector will be possible only if existing coal plants and natural gas plants are retrofitted or repowered with CCS technologies or are retired.[18] However, retrofitting these plants will require diversion of some of their energy input to capturing and

[18]Comparable actions at existing fossil-fuel plants in other countries will also be required to achieve substantial reductions in worldwide CO_2 emissions.

compressing CO_2. Limitations of existing boilers and turbines could mean that reductions of emissions to something like those of natural gas power plants without CCS, about half that of a typical coal plant, would be more likely to be implemented than the 90 percent reduction that is technically possible. *Achieving more substantial reductions in emissions will require more extensive retrofitting of existing coal plants; their replacement with new coal plants (which have higher greenhouse gas-capture efficiencies) or with some combination of renewable-energy and nuclear-energy sources; or reductions in energy use.*

Consequently, achieving substantial reductions in CO_2 emissions from the electricity sector is likely to require a portfolio approach involving the accelerated deployment of multiple technologies: energy efficiency; renewables; coal and natural gas with CCS; and nuclear. However, the following two kinds of demonstrations must be carried out during the next decade if we are to more fully understand the range of available options:

- *Assess the viability of CCS for sequestering CO_2 from coal- and natural-gas-fired electricity generation.* This will require the construction of a suite (~15–20) of retrofitted and new demonstration plants with CCS, featuring a variety of feedstocks (diverse coal types and natural gas); generation technologies (ultrasupercritical pulverized coal, oxyfuel, integrated gasification combined cycle, natural gas combined cycle); carbon capture strategies (pre- and post-combustion); and geologic storage locations (enhanced oil recovery sites, coal seams, deep saline formations). A few retrofits of existing natural gas plants and new gas plants with CCS should be included among the demonstrations to prepare for the possibility that optimistic forecasts of domestic natural gas availability and price prove correct. The commercial-scale demonstration of CCS would also enable the integration of this technology into plants that produce liquid fuels from coal and biomass.
- *Demonstrate the commercial viability of evolutionary nuclear plants in the United States by constructing a suite of about five plants in this country during the next decade.* Evolutionary plants are already in operation and are being built in some other countries, so there are no technological impediments to their construction in the United States. However, plant construction requires multi-billion-dollar investments—very large for the size of nuclear plant owner-operators in the United States. The long lead times (6–10 years) required for planning, licens-

ing, and constructing these plants adds additional uncertainty, which can be reflected in the risk premiums for investments in first plants. The successful construction of a suite of evolutionary plants on budget and on schedule in the United States would demonstrate the commercial viability of this technology and enable its wider deployment after about 2020. This is an important option for meeting the projected national need for non-CO_2-emitting electricity generation technologies.

The failure to successfully demonstrate the viability of these technologies during the next decade will greatly restrict options to reduce CO_2 emissions from the electricity sector. In particular, such a failure would remove the options of retrofitting and repowering existing coal and natural gas power plants with CCS, of replacing existing plants with new coal or natural gas plants with CCS units, and of deploying new nuclear plants. The failure to demonstrate the viability of these technologies could also prompt a major shift to natural gas for electricity generation; that is because gas plants can be built relatively quickly and inexpensively and their electricity prices could be more attractive than those of other low-carbon supply technologies such as renewables with energy storage. Unless optimistic forecasts of natural gas availability and price prove correct, however, such a shift could create the same kind of dependence on imports of LNG from outside North America that now exists for petroleum. Moreover, an electric power generation system dominated by natural gas plants without CCS would still emit significant quantities of CO_2 compared to renewable and nuclear technologies (Figure 2.15).

It will take decades to achieve deep reductions in CO_2 emissions from the electricity sector. Building large quantities of new generation of any technology requires learning, licensing, permitting, and public acceptance. *The urgency of getting started on these demonstrations to clarify future deployment options cannot be overstated.*

Reducing greenhouse gas emissions from the liquid-fuels-based transportation sector will also require a portfolio approach because these emissions occur in millions of mostly nonstationary sources. As shown in Figure 2.16, the deployments of some alternative liquid fuels—cellulosic ethanol, biomass-to-liquids with or without CCS, and biomass-and-coal-to-liquids with CCS—are estimated to have zero or negative CO_2-eq emissions: that is, their production and use do not contribute to atmospheric CO_2 and might even result in net removal of CO_2 from the atmosphere. The other liquid-fuel options shown in Figure 2.16 have CO_2-eq emissions that are roughly equal to, or exceed, CO_2-eq emissions from gasoline

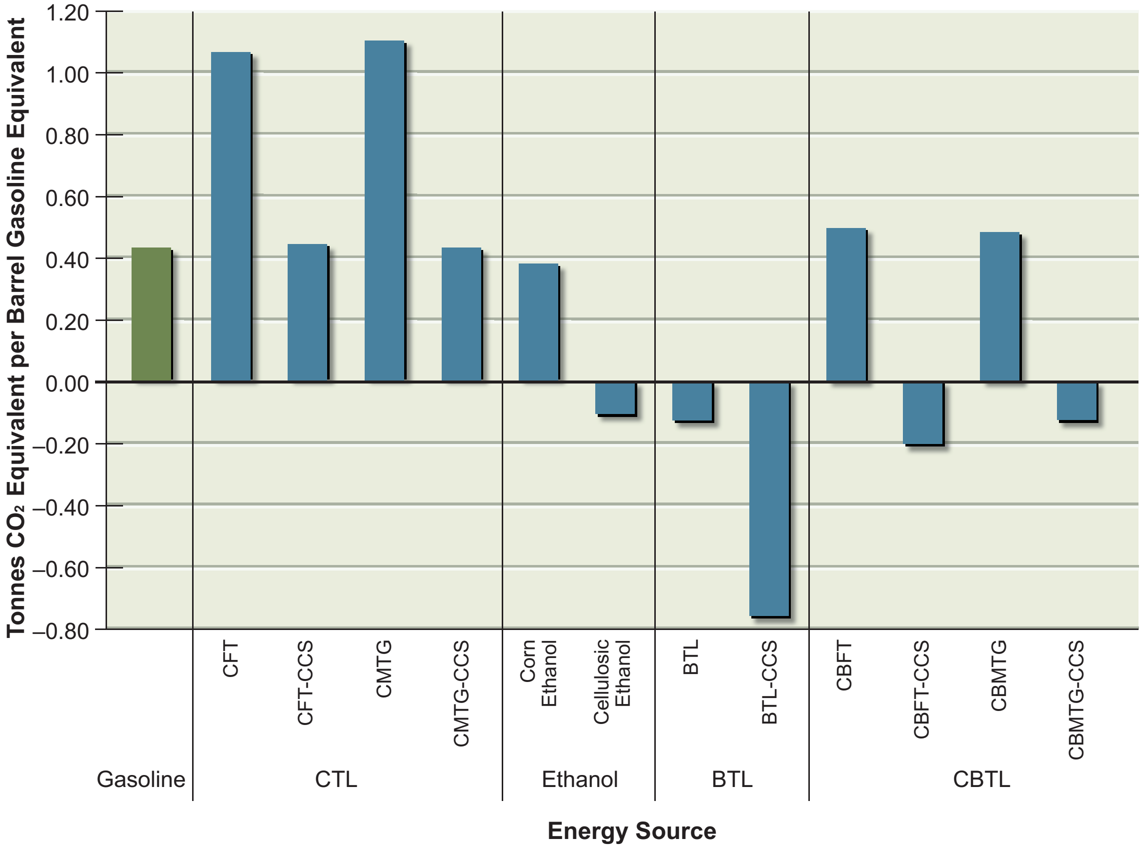


FIGURE 2.16 *Estimated net life-cycle CO_2-equivalent (CO_2-eq) emissions for production, transportation, and use of alternative liquid transportation fuels. Emissions are shown in units of tonnes of CO_2 equivalent per barrel of gasoline equivalent produced from biomass, coal, or a combination of coal and biomass. For comparison, the CO_2-eq emissions for gasoline are shown on the left. Negative CO_2-eq emissions mean that on a net life-cycle basis, CO_2 is removed from the atmosphere; for example, the negative CO_2 emissions for BTL and cellulosic ethanol result from an estimate that the sequestration of biomass carbon in power-plant char or the buildup of carbon in soil and roots will exceed the emissions of carbon in biofuel production. Growing perennial crops for cellulosic fuels provides CO_2 benefits because these crops store carbon in the root biomass and the associated rhizosphere, thereby increasing soil carbon sequestration. The precise value of CO_2-eq emissions from CBTL depends on the ratio of biomass to coal used. Indirect land-use effects on CO_2 emissions are not included.*

Note: BTL = biomass-to-liquid fuel; CBFT = coal-and-biomass-to-liquid fuel, Fischer Tropsch; CBMTG = coal-and-biomass-to-liquid fuel, methanol-to-gasoline; CBTL = coal-and-biomass-to-liquid fuel; CCS = carbon capture and storage; CFT = coal-to-liquid fuel, Fischer-Tropsch; CMTG = coal-to-liquid fuel, methanol-to-gasoline; CTL = coal-to-liquid fuel.

Sources: Data from Chapter 5 in Part 2 of this report and from NAS-NAE-NRC (2009b).

produced with petroleum. As noted under Finding 5, however, alternative liquid fuels can only substitute for a portion of petroleum use. Moreover, geologic storage of CO_2 from coal-to-liquid fuel and coal-and-biomass-to-liquid fuel production would have to be demonstrated to be safe and commercially viable by 2015 for these fuels to be produced in quantity starting around 2020.

Further reductions in greenhouse gas emissions from the transportation sector will have to be achieved through greater vehicle efficiency and, if greenhouse gas emissions from the electricity sector can be reduced, through electrification of the LDV fleet (as discussed under Finding 5). However, substantial reductions in emissions via these pathways are not likely to occur until late in the 2020–2035 period or beyond. As is the case for liquid fuel supply, the widespread deployment of electric or hydrogen fuel-cell vehicles between 2035 and 2050 holds some hope for more substantial long-term reductions in greenhouse gas emissions in the transportation sector, again depending on how the electricity and hydrogen are generated. As noted previously, the National Research Council (2008) estimated the potential reduction in petroleum use in 2050 from the deployment of hydrogen fuel-cell LDVs under the best-case scenario to be about 70 percent below the projected petroleum consumption of a fleet of comparable gasoline-fueled vehicles.

FINDING 7: TECHNOLOGY RESEARCH, DEVELOPMENT, AND DEMONSTRATION

To enable accelerated deployments of new energy technologies starting around 2020, and to ensure that innovative ideas continue to be explored, the public and private sectors will need to perform extensive research, development, and demonstration over the next decade. Given the spectrum of uncertainties involved in the creation and deployment of new technologies, together with the differing technological needs and circumstances across the nation, a portfolio that supports a broad range of initiatives from basic research through demonstration will likely be more effective than targeted efforts to identify and select technology winners and losers.

As discussed in some detail in Part 2 of this report, the next decade offers opportunities to gain knowledge and early operating experience that in turn could enable widespread deployments of new energy-supply technologies beginning around 2020. These technology-development opportunities include:

- The full range of energy efficiency technologies in the buildings, transportation, and industrial sectors.
- Coal and natural gas with CCS (see Finding 6 and Chapter 7 for details).
- Evolutionary nuclear power (see Finding 6 and Chapter 8).
- Integrated gasification combined cycle, ultrasupercritical pulverized coal, and oxyfuel plants to improve the efficiency and performance of coal-generated electricity, pursued in coordination with research, development, and demonstrations on advanced materials and CCS technologies (see Chapter 7).
- Thermochemical conversion of coal and coal-and-biomass mixtures to liquid fuels, integrated with CCS, at commercial scale. If decisions to proceed with such demonstrations are made soon, and if CCS is shown to be safe and viable by about 2015, these technologies could be commercially deployable within a decade under favorable economic conditions (see Chapter 5).
- Research and development on cellulosic-conversion methods, followed by demonstration of cellulosic ethanol production at commercial scale, to achieve proof of principle and prepare this technology for widespread deployment (see Chapter 5).
- Advanced LDVs, including plug-in hybrids and battery-electric and fuel-cell vehicles. Demonstrations of on-the-road vehicles are critical to getting real-world data on performance and service lives (see Chapter 4).

R&D will help to ensure the success of future new-technology deployments and especially to ensure that the technology pipeline remains full in the decades ahead. Significant investments in R&D over the next decade, by the public and the private sector alike, will be required for bringing some of the technologies described in this report to the point that they are cost-effective and ready for widespread deployment. The needed areas of R&D include:

- Advanced biosciences—genomics, molecular biology, and genetics—to develop biotechnologies for converting biomass to lipid, higher-alcohol, and hydrocarbon fuels that can be integrated directly into existing transportation infrastructures.
- Advanced technologies for producing alternative liquid fuels from renewable resources—such as fuel production from CO_2 feedstocks

(e.g., algae biofuels). Such fuels are needed to expand options for reducing petroleum use.

- Advanced technologies for the production of biomass that provides sustainable yields, minimizes competition with food and feed crops, and offers substantial greenhouse-gas-reduction benefits.
- Advanced PV materials and manufacturing methods to improve efficiencies and to lower costs. The deployed efficiency of current PV materials is greater than 10 percent, which is much higher than the field efficiency of plants for biomass. Although biomass is a compact form of chemical energy storage, its production requires a great deal of land and energy and it has to be harvested and processed to make electricity or liquid fuels, whereas the electricity from PV cells can be used directly.
- Advanced batteries and fuel cells for LDVs.
- Advanced large-scale storage for wind energy and electrical-load management.
- Enhanced geothermal power.
- Advanced technologies for extracting petroleum from shale and for harvesting natural gas from hydrates.
- Alternative fuel cycles that would allow for greater utilization of the energy content of nuclear fuel and the minimization of very-long-lived radioactive waste from nuclear power generation.
- Further exploration of geoengineering options.

R&D in other scientific fields that are not addressed in this report will likely provide important support for the development and deployment of new energy-supply and end-use technologies. For example, researchers' efforts to better understand the interactions between patterns of energy use and climate systems—including, for example, the ecology of microbial systems—could support the development of more effective means to capture, store, and recycle CO_2 from energy production. Additionally, social science research on how households and businesses make decisions could lead to more effective measures to encourage energy efficiency.

Finally, attractive technology options will likely emerge from innovation pathways that are essentially unforeseen today—some examples are cited in Part 2 of this report—underscoring the need for a continuing focus on and investments in basic research. Some breakthrough technologies are probably not even on the present horizon; in fact, they may not become apparent until the final time period considered in this report (2035–2050) or later. However, it is very likely that some of the potential breakthrough technologies that are indeed visible on today's horizon—for example, superconducting materials, second- and third-generation PV technologies, and advanced batteries—may begin to develop and have an important influence on technology trends during the first two time periods (2008–2020 and 2020–2035) considered in this study. Achieving such breakthroughs will require sustained federal support for basic scientific research, both in the physical and in the biological sciences, and private-sector "venture-backed" support for early-stage energy R&D.

The Department of Energy (DOE) has been the primary catalyst for basic energy research in the United States, primarily through its Office of Science. There are substantial opportunities in the years ahead for this office to increase the support of such activities and to ensure their coordination by partnering with the DOE's energy offices and with other basic-research agencies such as the National Science Foundation.

FINDING 8: BARRIERS TO ACCELERATED TECHNOLOGY DEPLOYMENT

A number of current barriers are likely to delay or even prevent the accelerated deployment of the energy-supply and end-use technologies described in this report. Policy and regulatory actions, as well as other incentives, will be required to overcome these barriers.

The assessments provided in the forgoing sections reflect the AEF Committee's judgments about the potential contribution of new energy technologies *if* the accelerated-deployment options identified in this report are actively pursued. However, a number of potential barriers could influence these options and, in turn, affect the actual scale and pace of the implementation of the technologies. Some of the barriers are purely market driven: technologies must be clearly attractive to potential investors, purchasers, and users. They must also provide improvements, relative to existing technologies, in terms of performance, convenience, and cost attributes; of course, they must also meet relevant performance standards and regulations.

In the course of this study, the AEF Committee identified several policy and regulatory barriers to the deployment of the energy-supply and end-use technologies that were examined. Some of these barriers have already been identified in this chapter, and additional ones are described in Part 2. But because the following barriers crosscut many of the technologies examined in this report, the committee considers them to be impediments to future deployment success:

- *Lack of private-sector investments for technology deployment*, ranging from relatively low-cost energy efficiency devices to capital-intensive facilities, because of uncertainties about a technology's return on investment, its viability and cost-effectiveness, the future costs of fuels, and other raw-material and construction costs. The mobilization of trillions of dollars of new capital between now and 2050 will be needed to transform our nation's energy system, but such capital may be difficult to obtain from the private sector if the noted uncertainties are not attenuated. The current economic downturn further complicates matters: the limited availability of resources, especially capital, and the reduction in energy demand may be additional barriers to new-technology deployment.
- *The low turnover rate of the energy system's capital-intensive infrastructure,* which makes rapid change difficult. Failure to take advantage of windows of opportunity to deploy new technologies as infrastructure turns over could lock in older technologies for decades, and this difficulty is compounded by the long lead times for deploying new technologies, especially capital-intensive technologies. Thus, there is a premium on modifying or retrofitting existing infrastructure and on pushing new technologies to be ready for deployment when assets reach the end of their service lives. There are some technology "lock-ins," however, that might not allow for future modification or improvements. Examples include new coal plants that cannot be easily retrofitted with CCS[19] and new buildings that are not designed to use energy efficiently over their lifetimes.
- *Resource and supply barriers to technology deployment.* They range, for example, from the limited availability of industrial capacity and skilled personnel for deploying the technologies to the availability of the biomass needed to expand the domestic production of liquid fuels.

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[19]This problem is not restricted to the United States alone. It will be an especially critical issue in countries, such as China, that are building new coal plants at very high rates.

Some of these barriers can be overcome with the right market and regulatory signals.

- *Uncertainties arising from the nature and timing of public policies and regulations related to carbon controls.* There is no authoritative guidance on best available technologies for CCS that could be used to guide deployment. Such guidance might be similar to New Source Performance Standards developed under the Clean Air Act for criteria pollutants. The initial rates of deployment of reduced-carbon technologies (energy efficiency, renewable-energy sources, nuclear energy, and coal with CCS) can be accelerated by such guidelines, by a better alignment of incentives, and by some selected direct public investments.
- *Coupling the commercial deployment of energy-supply technologies with key supporting technologies.* Examples include CCS both for electric-power generation and the production of transportation fuels; adequate dispatchable energy supplies or storage[20] for advanced and expanded transmission and distribution systems; and advanced batteries for plug-in hybrid and battery-electric vehicles. Successful demonstration of the key supporting technologies will clearly be required, but so too will a better alignment of incentives and the resolution of a number of economic, legal, and policy questions.
- *The regional ownership and regulation of the transmission and distribution systems* in the United States make it difficult to implement nationwide modernizations. Although there are exceptions in some regions, the current regulatory system is not designed to adopt available and future innovations in the national transmission system because of fractured jurisdictions at the local, regional, and national levels, as well as an institutional culture that emphasizes quantity of service over reliability, quality, efficiency, and security. Additionally, the methods for assessing returns on private investment in the transmission system are unclear because, owing to the dispersed nature of electricity transmission, reliability and societal benefits extend beyond a single region.
- *The lack of energy efficiency standards for many products* means that in many cases individual consumers must take the initiative to acquire

[20]Dispatchable energy storage is a set of technologies for storing or producing electricity that can be deployed quickly (dispatched) into the grid when other power sources become unavailable. These technologies are described in Chapter 9.

information about the costs and benefits of available energy efficiency technologies. Most consumers are unwilling or ill equipped to do so (see Box 2.2).

Overcoming these barriers will require a judicious mix of policies, regulations, and market incentives. A full analysis of the barriers, as well as of the means to overcome them, is beyond the scope of this AEF Phase I study. The National Academies will address many of these issues, however, in the project's Phase II.

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3 Key Results from Technology Assessments

This chapter summarizes the detailed assessments presented in Part 2 of this report, organized by subject and chapter as follows:

- Energy efficiency (Chapter 4)
- Alternative transportation fuels (Chapter 5)
- Renewable energy (Chapter 6)
- Fossil-fuel energy (Chapter 7)
- Nuclear energy (Chapter 8)
- Electricity transmission and distribution (Chapter 9).

The chapter annex, Annex 3.A, describes the key methods and assumptions that were used to develop the energy supply, savings, and cost estimates in this report. Additional detailed supporting information can be found in Part 2 of this report and in the following National Academies reports derived from this America's Energy Future (AEF) Phase I study:

- *Real Prospects for Energy Efficiency in the United States* (NAS-NAE-NRC, 2009c; available at http://www.nap.edu/catalog.php?record_id=12621)
- *Liquid Transportation Fuels from Coal and Biomass: Technological Status, Costs, and Environmental Impacts* (NAS-NAE-NRC, 2009b; available at http://www.nap.edu/catalog.php?record_id=12620)
- *Electricity from Renewable Resources: Status, Prospects, and Impediments* (NAS-NAE-NRC, 2009a; available at http://www.nap.edu/catalog.php?record_id=12619).

ENERGY EFFICIENCY

The potential for increasing energy efficiency—that is, for reducing energy use while delivering the same energy services—in the United States is enormous. Technology exists today, or is expected to be developed over the normal course of business between now and 2030, that could save about 30 percent of the energy used annually in the buildings, transportation, and industrial sectors. These savings could easily repay, with substantial dividends, the investments involved. In particular, if energy prices were high enough to motivate investment in energy efficiency or if public policies had the same effect, energy use could be lower by 15–17 quads (about 15 percent) in 2020 and by 32–35 quads (about 30 percent) in 2030 than the reference case projection of the U.S. Department of Energy's Energy Information Administration (EIA). The opportunities for achieving these savings reside in hundreds of technologies, many of them already commercially available and others just about to enter the market.

This section summarizes the capability of energy efficiency technologies to reduce energy use or moderate its growth. Technologies that pay for themselves (in reduced energy costs) after criteria have been applied to reflect experience with consumer and corporate decision making are considered cost-effective. For the buildings sector, supply curves were developed that reflect implementation of efficiency technologies in a logical order, starting with lowest-cost technological options. Using discounted cash flow[1] and accounting for the lifetimes of technologies and infrastructures involved, the reported efficiency investments in buildings generally pay for themselves in 2–3 years. For the industrial and transportation sectors, the AEF Committee relied on results from the report by the America's Energy Future Panel on Energy Efficiency Technologies (NAS-NAE-NRC, 2009c).[2] For industry, the panel reported industry-wide potential for energy savings reflecting improvements that would offer an internal rate-of-return on the efficiency investment of at least 10 percent. For transportation (which addresses fewer technologies and thus includes more in-depth assessments of each), the panel focused on how the performance and costs of vehicle technologies might evolve relative to one another (and the capability of these technologies to reduce fleet fuel consumption).

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[1]The discounted cash flow approach describes a method of valuing a project, company, or asset such that all future cash flows are estimated and discounted to give their present values.

[2]Further details on these estimates can also be found in Chapter 4 in Part 2 of this report.

The panel examined the available energy efficiency literature and performed additional analyses. For each sector, comparisons were made to a "baseline" or "business as usual" case to estimate the potential for energy savings. These are described in Annex 3.A.

Buildings Sector

About 40 percent of the primary energy used in the United States, and fully 73 percent of the electricity, is used in residential and commercial buildings. Diverse studies for assessing this sector's energy-savings potential, although they take many different approaches, are remarkably consistent and have been confirmed by the supply curves developed for this report. The consensus is that savings of 25–30 percent relative to current EIA (2008) reference case projections could be achieved over the next 20–25 years. These savings, which would come principally from technologies that are more efficient for space heating and cooling, water heating, and lighting, could hold energy use in buildings about constant even as population and other drivers of energy use grow. Moreover, the savings could be achieved at a cost per energy unit that would be lower than current average retail prices for electricity and gas.[3] For the entire buildings sector, the supply curves in Chapter 2 of this report (Figures 2.5 and 2.6) as well as in the panel report (NAS-NAE-NRC, 2009c) show that a *cumulative* investment of $440 billion[4] in existing technology between 2010 and 2030 could produce an *annual* savings of $170 billion in reduced energy costs.

Advanced technologies just emerging or under development promise even greater gains in energy efficiency. They include solid-state lighting (light-emitting diodes); advanced cooling systems that combine measures to reduce cooling requirements with emerging technologies for low-energy cooling, such as evaporative cooling, solar-thermal cooling, and thermally activated desiccants; control sys-

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[3]The average residential electricity price in the United States in 2007 was 10.65¢/kWh (in the commercial sector, the average price was 9.65¢/kWh). The average residential price for natural gas in the United States in 2007 was $12.70/million Btu (in the commercial sector, the average price was $11/million Btu).

[4]The investments include both the full add-on costs of new equipment and measures (such as attic insulation) and the incremental costs of purchasing an efficient technology (e.g., a high-efficiency boiler) compared with purchasing conventional-counterpart technology (e.g., a standard boiler). These investments would be made instance-by-instance by the individuals and public or private entities involved. The costs of policies and programs that would support, motivate, or require these improvements are not included.

tems for reducing energy use in home electronics; "superwindows" with very low U-values;[5] dynamic window technologies that adjust cooling and electric lighting when daylight is available; and very-low-energy houses and commercial buildings that combine fully integrated design with on-site renewable-energy generation.

Transportation Sector

The transportation sector, which is almost solely dependent on petroleum, produces about one-third of the U.S. greenhouse gas emissions[6] arising from energy use. The sector is dominated by use of the nation's highways, for both freight and passengers.

Current technologies offer many potential improvements in fuel economy, and they become increasingly competitive and attractive as fuel prices rise. Reductions in fleet fuel consumption over the next 10–20 years will likely come primarily from improving today's spark-ignition (SI), diesel, and hybrid vehicles that are fueled with petroleum, biofuels, and other nonpetroleum hydrocarbon fuels.

Over the subsequent decade, plug-in hybrid vehicles (PHEVs) that use electricity plus any of the fuels just mentioned may be deployed in sufficient volume to have a significant effect on petroleum consumption. Longer term, after 2030, major sales of hydrogen fuel-cell vehicles (HFCVs) and battery-electric vehicles (BEVs) are possible.

- *Light-duty vehicles*. Power-train improvements for LDVs offer the greatest potential for increased energy efficiency over the next two decades. Technologies that improve the efficiency of SI engines could reduce average new-vehicle fuel consumption by 10–15 percent by 2020 and a further 15–20 percent by 2030. Turbocharged diesel engines, which are some 10–15 percent more efficient than equal-performance SI engines, could steadily replace nonturbocharged engines in the SI fleet. Improvements in transmission efficiency and reductions in rolling resistance, aerodynamic drag, and vehicle size, power, and weight can all increase vehicle fuel efficiency.

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[5]U-values represent how well a material allows heat to pass through it. The lower the U-value, the greater a product's ability to insulate.

[6]In this report, the cited quantities of greenhouse gases emitted are expressed in terms of CO_2-equivalent (CO_2-eq) emissions.

Currently, corporate average fuel economy (CAFE) standards for new LDVs are targeted to reach 35 miles per gallon by 2020, which would equate to a 40 percent improvement in average new-vehicle fuel efficiency (and a 30 percent reduction in average fuel consumption).[7] Achieving this goal, and further improving fuel efficiency after 2020, will require that the historic emphasis on ever-increasing vehicle power and size be reversed in favor of fuel economy.

Gasoline hybrid-electric vehicles (HEVs) currently offer vehicle fuel-consumption savings of as much as 30 percent over SI engines. Thus it is likely that meeting the new CAFE standards by 2020 will require a large fraction of new vehicles to be HEVs or smaller, less powerful vehicles. PHEVs and BEVs could begin to make a large impact beyond 2020; however, the success of these technologies is crucially dependent on the development of batteries with much higher performance capabilities than today's batteries, and with lower costs. Research and development on battery technology continues to be a high priority.

If they could be equipped with batteries that powered the vehicle for 40–60 miles, gasoline PHEVs could reduce gasoline/diesel consumption by 75 percent. While HEVs mainly improve performance or fuel economy, PHEVs actually get most of their energy from the electric grid.

Improvements in battery and fuel-cell technologies are expected to pave the way for possible large-scale deployments of BEVs and HFCVs in the 2020–2035 period. Because BEVs and HFCVs could reduce and ultimately eliminate the need for petroleum in transportation, they could also reduce and possibly even eliminate LDV tailpipe greenhouse gas emissions.

- *Freight transportation*. Future technologies for heavy-duty trucks include continuously variable transmissions and hybrid-electric systems to modulate auxiliaries (such as air-conditioning and power steering) and reduce idling. Significant reductions in aerodynamic drag are also possible. Reductions in fuel consumption of 10–20 percent in heavy- and medium-duty vehicles appear feasible over the next decade or so.

[7] As noted in Chapters 1 and 2, the Obama administration recently announced new policies that will accelerate the implementation of these fuel economy standards.

Rail is about 10 times more energy-efficient than trucking, so shifting freight from trucks to rail can offer considerable energy savings.

- *Air transportation*. The latest generation of airliners offers a 15–20 percent improvement in fuel efficiency.[8] The newer airplanes, however, are likely to do little more than offset the additional fuel consumption caused by projected growth in air travel over the next several decades.
- *Long-term system-level improvements*. Examples of system-level innovations that could substantially improve efficiency include the utilization of intelligent transportation systems to manage traffic flow; better land-use management; and greater application of information technology in place of commuting and long-distance business travel.

Industrial Sector

Estimates from independent studies using different approaches agree that the potential for cost-effective reduction in energy use by industry range from 14 to 22 percent—about 4.9 to 7.7 quads—by 2020, compared with current EIA reference case projections. Most of the gains will occur in energy-intensive industries, notably chemicals and petroleum, pulp and paper, iron and steel, and cement.[9] Growth in the energy-efficient option of combined heat and power production is also likely to be significant. Beyond 2020, new technologies such as novel heat and power sources, new products and processes, and advances in recycling could bring about even greater gains in energy efficiency. Important progress might also come from adapting new technology (such as fuel cells for combined heat and power generation) and adopting alternative methods of operation (e.g., "on-demand" manufacturing).

- *Chemicals and petroleum*. Technologies for improving energy efficiency include high-temperature reactors, corrosion-resistant metal- and ceramic-lined reactors, and sophisticated process controls. Cost-effective improvements in efficiency of 10–20 percent in petroleum refining by 2020 are possible.

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[8]Increases in passenger airliner efficiency will also benefit air freight transport.

[9]Further details on the potential improvements in these industries can be found in Chapter 4 in Part 2 of this report and in the report of the America's Energy Future Panel on Energy Efficiency Technologies (NAS-NAE-NRC, 2009c).

- *Pulp and paper.* The industry could use more waste heat for drying, advanced water-removal and filtration technologies, high-efficiency pulping processes, and modernized lime kilns. Estimates of cost-effective gains in energy efficiency by 2020 range from 16 to 26 percent.
- *Iron and steel.* Promising advances in technology that could be available by 2020 involve electric-arc furnace (EAF) melting, blast-furnace slag-heat recovery, integration of refining functions, and heat capture from EAF waste gas. The American Iron and Steel Institute recently announced a goal of using 40 percent less energy for iron and steel production by 2025 compared with 2003.
- *Cement.* Major energy savings would require significant upgrades to an advanced dry-kiln process. Efficiency could also be enhanced with advanced control systems, combustion improvements, indirect firing, and optimization of certain components. A combination of these changes could yield a reduction in energy use of about 10 percent. In addition, changing the chemistry of cement to decrease the need for calcination could result in reduced energy use of another 10–20 percent. Advanced technologies for yielding further improvements are under development. Overall savings of 20 percent are possible by 2020.

A set of crosscutting technologies exists that could improve energy efficiency in a wide range of industrial applications. This includes the expansion of combined heat and power systems; separation processes based on membranes and other porous materials; advanced materials that resist corrosion, degradation, and deformation at high temperatures; controls and automation; steam- and process-heating technologies that improve quality and reduce waste; high-efficiency fabrication processes that improve yields and reduce waste; remanufacturing of products for resale; and sensor systems that reduce waste by improving control.

Barriers to Deployment and Drivers of Efficiency

Numerous barriers impede deployment of energy efficiency technologies in each of the sectors previously discussed. In the buildings sector, regulatory policies do not usually reward utility investments in energy efficiency; building owners in rental markets and builders are not responsible for paying energy costs and thus lack incentives to make investments that reduce energy use; information about the energy costs of specific appliances and equipment is often not readily available; and access to capital for such investments is limited. Drivers for greater efficiency—that is, for overcoming these barriers—could include rising energy costs, growing environmental awareness, improved and publicized building codes and appliance efficiency standards, and state and local utility programs.

In the transportation sector, barriers that limit energy efficiency include the lack of clear signals about future oil prices (expectations for future prices strongly affect technology and investment decisions) and the lack of sufficient production capability to manufacture energy-efficient vehicles across vehicle platforms.

The barriers to deployment in the industrial sector include the technical risks of adopting a new industrial technology; high investment costs for industrial energy efficiency improvements; intra-firm competition for capital, which may favor improvements in products and processes over energy efficiency; the lack of specialized knowledge about energy efficiency technologies; and unfavorable provisions of the tax code.

These barriers are formidable, and sustained public and private support will be needed to overcome them. Particular attention must be paid to infrastructure, industrial equipment, and other long-lived assets in order to ensure that energy efficiency technologies and systems are put into place when these assets are constructed or renewed.

Meanwhile, there are several drivers for greater efficiency. They include expected increases in energy prices and concern about availability of fuels and electricity; more stringent air-quality standards, which raise the prices of pollution allowances; demand charges and demand-response incentives; collateral benefits such as higher product quality and productivity; and corporate sustainability initiatives.

In general, substantial energy savings in all sectors will be realized only if efficient technologies and practices achieve wide use. Experience demonstrates that these barriers can be overcome with the aid of well-designed policies. Many policy initiatives have been effective, including efficiency standards (vehicle and appliance) combined with U.S. Department of Energy R&D on efficient equipment; promotion of combined heat and power, largely through the Public Utilities Regulatory and Policy Act of 1978; the ENERGY STAR® product-labeling program; building-energy codes; and utility- and state-sponsored end-use efficiency programs. These initiatives have already resulted in a nearly 13-quad-per-year reduction in primary energy use.

ALTERNATIVE TRANSPORTATION FUELS

The U.S. transportation sector consumed about 14 million barrels of oil per day in 2007, 9 million of which was used in light-duty vehicles. Total U.S. liquid fuels consumption in 2007 was about 21 million barrels per day, about 12 million of which was imported. The nation could reduce its dependence on imported oil by producing alternative liquid transportation fuels from domestically available resources to replace gasoline and diesel, and thereby increase energy security and reduce greenhouse gas emissions.

Two abundant domestic resources with such potential are biomass and coal. The United States has at least 20 years' worth of coal reserves in active mines and probably sufficient resources to meet the nation's needs for well over 100 years at current rates of consumption. Biomass can be produced continuously over the long term if sustainably managed, but the amount that can be produced at any given time is limited by the natural resources required to support biomass production. However, a robust set of conversion technologies needs to be developed or demonstrated and brought to commercial readiness to enable those resources to be converted to suitable liquid transportation fuels.

Biomass Supply

Biomass for fuels must be produced sustainably to avoid excessive burdens on the ecosystems that support its growth. Because corn grain is often used for food, feed, and fiber production, and also because corn grain requires large amounts of fertilizer, the committee considers corn grain ethanol to be a transition fuel to cellulosic biofuels or other biomass-based liquid hydrocarbon fuels (for example, biobutanol and algal biodiesel). About 365 million dry tonnes (400 million dry tons) per year of cellulosic biomass—dedicated energy crops, agricultural and forestry residues, and municipal solid wastes—could potentially be produced on a sustainable basis using today's technology and agricultural practices, and with minimal impact on U.S. food, feed, and fiber production or the environment. By 2020, that amount could reach 500 million dry tonnes (550 million dry tons) annually. A key assumption behind these estimates is that dedicated fuel crops would be grown on idle agricultural land in the Conservation Reserve Program. The size of the facilities for converting biomass to fuel will likely be limited by the supply of biomass available from the surrounding regions.

Producers will likely need incentives to grow biofeedstocks that not only do not compete with other crop production but also avoid land-use practices that cause significant net greenhouse gas emissions. Appropriate incentives can encourage lignocellulosic biomass production in particular. To ensure a sustainable biomass supply overall, a systematic assessment of the resource base—which addresses environmental, public, and private concerns simultaneously—is needed.

Conversion Technologies

Two conversion processes can be used to produce liquid fuels from biomass: biochemical conversion and thermochemical conversion.

Biochemical Conversion

Biochemical conversion of starch from grains to ethanol has already been deployed commercially. Grain-based ethanol was important for stimulating public awareness and initiating the industrial infrastructure, but cellulosic ethanol and other advanced cellulosic biofuels have much greater potential to reduce U.S. oil use and CO_2 emissions and have minimal impact on the food supply.

Processes for biochemical conversion of cellulosic biomass into ethanol are in the early stages of commercial development. But over the next decade, improvements in cellulosic ethanol technology are expected to come from evolutionary developments gained from commercial experience and economies of scale. Incremental improvements of biochemical conversion technologies can be expected to reduce nonfeedstock costs by about 25 percent by 2020 and about 40 percent by 2035. In terms of transport and distribution, however, an expanded infrastructure will be required because ethanol cannot be transported in pipelines used for petroleum transport.

Studies have to be conducted to identify the infrastructure that will be needed to accommodate increasing volumes of ethanol and to identify and address the challenges of distributing and integrating these volumes into the fuel system. Also, research on biochemical conversion technologies that convert biomass to fuels more compatible with the current distribution infrastructure could be developed over the next 10–15 years.

If all the necessary conversion and distribution infrastructure were in place, 500 million dry tonnes of biomass could be used to produce up to 30 billion gallons of gasoline-equivalent fuels per year (or 2 million barrels per day [bbl/d]). However, potential fuel supply does not translate to amount of actual supply. When the production of corn grain ethanol was commercialized, U.S. production capacity grew by 25 percent each year over a 6-year period. Assuming that the rate of building cellulosic ethanol plants would exceed that of building corn grain ethanol plants by 100 percent, up to 0.5 million bbl/d of gasoline-equivalent cellulosic ethanol (1 barrel of oil produces about 0.85 barrel of gasoline equivalent) could be added to the fuels portfolio by 2020. By 2035, up to 1.7 million bbl/d of gasoline equivalent could be produced in this manner, resulting in about a 20 percent reduction in oil used for LDVs at current consumption levels.

Thermochemical Conversion

Without geologic CO_2 storage, technologies for the indirect liquefaction of coal to transportation fuels could be commercially deployable today, but life-cycle greenhouse gas emissions would be more than twice the CO_2 emissions of petroleum-based fuels. Requiring geologic CO_2 storage with these processes would have a relatively small impact on engineering costs and efficiency. However, the viability of geologic CO_2 storage has yet to be adequately demonstrated on a large scale in the United States, and unanticipated costs could occur. Although enhanced oil recovery could present an opportunity for early demonstrations of carbon capture and storage (CCS), that storage would be small compared with the large amounts of CO_2 that would be captured if coal-to-liquid fuels production became widely deployed, potentially in the gigatonne-per-year range.

Liquid fuels produced from thermochemical plants that use only biomass feedstock are more costly than fuels produced from coal, but biomass-derived fuels can have life-cycle CO_2 emissions that are near zero without geologic CO_2 storage or highly *negative* emissions with geologic CO_2 storage. To make such fuels competitive, the economic incentive for reducing CO_2 emissions has to be sufficiently high.

When biomass and coal are co-fed in thermochemical conversion to produce liquid fuels, the process allows a larger scale of operation and lower capital costs per unit of capacity than would be possible with biomass alone. If 500 million dry tonnes of biomass were combined with coal (60 percent coal and 40 percent biomass on an energy basis), production of 60 billion gallons of gasoline-equivalent fuels per year (4 million bbl/d) would be technically feasible. That amount of fuel represents about 45 percent of the current volume (140 billion gal/yr or 9 million bbl/d) of liquid fuel used annually in the United States for LDVs. Moreover, when biomass and coal are co-fed, the overall life-cycle CO_2 emissions are reduced because the CO_2 emissions from coal are countered by the CO_2 uptake by biomass during its growth. Combined coal-and-biomass-to-liquid fuels without geologic

CO_2 storage have life-cycle CO_2 emissions similar to those of gasoline; with geologic CO_2 storage, these fuels have near-zero life-cycle CO_2 emissions.

A program to aggressively support first-mover commercial coal-to-liquid and coal-and-biomass-to-liquid fuel production plants with integrated geologic CO_2 storage would have to be undertaken immediately if the United States were to produce fuels with greenhouse gas emissions similar to or less than petroleum-based fuels to address energy security in the near term.

Whether thermochemical conversion involves coal alone or coal and biomass combined, the viability of CO_2 geologic storage is critical to its commercial implementation. This means that large-scale demonstrations of and the establishment of regulatory procedures for CO_2 geologic storage would have to be aggressively pursued in the next few years if thermochemical conversion plants integrated with CCS are to be ready for commercial deployment in 2020 or sooner. If such demonstrations are initiated immediately, and geologic CO_2 storage is proven viable and safe by 2015, the first commercial plants could be operational in 2020.

Because plants for the conversion of combined coal and biomass into liquids are much smaller than those that convert coal alone, and because they will probably have to be sited in regions that are close to coal and biomass supplies, build-out rates will be lower than for the cellulosic plants discussed above. The committee estimates that at a 20 percent growth rate until 2035, 2.5 million barrels per day of gasoline equivalent could be produced in combined coal and biomass plants. This would consume about 270 million dry tonnes (300 million dry tons) of biomass per year—thus tapping less than the total projected biomass availability—and about 225 million tonnes of coal.

Given the vast coal resource in the United States, the actual supply of such fuel will be limited by its market penetration rather than feedstock availability. At a build rate of two to three plants per year, in 20 years up to 3 million bbl/d of gasoline equivalent could be produced from about 525 million tonnes of coal each year. However, all costs and social and environmental impacts of the associated level of coal production—an increase of about 50 percent—would have to be considered. At a build out of three plants starting up per year, five to six plants would be under construction at any one time.

Costs, Barriers, and Deployment

The committee estimated the costs of cellulosic ethanol, coal-to-liquid fuels with or without geologic CO_2 storage, and coal-and-biomass-to-liquid fuels with or

TABLE 3.1 Estimated Costs of Different Fuel Products With and Without a CO_2-Equivalent (CO_2-eq) Price of $50 per Tonne

Fuel Product	Cost Without CO_2-eq Price ($/bbl gasoline equivalent)	Cost With a CO_2-eq Price of $50 per Tonne ($/bbl gasoline equivalent)
Gasoline at crude price of $60/bbl	75	95
Gasoline at crude price of $100/bbl	115	135
Cellulosic ethanol	115	110
Biomass-to-liquids without CCS	140	130
Biomass-to-liquids with CCS	150	115
Coal-to-liquids without CCS	65	120
Coal-to-liquids with CCS	70	90
Coal-and-biomass-to-liquids without CCS	95	120
Coal-and-biomass-to-liquids with CCS	110	100

Note: The numbers in this table are rounded to the nearest $5. Estimated costs of fuel products for coal-to-liquids conversion represent the mean costs of products from Fischer-Tropsch and methanol-to-gasoline conversion processes.

without geologic CO_2 storage using a consistent set of assumptions (shown in Table 3.A.1 at the end of this chapter). Although those estimates do not represent predictions of future prices, they allow comparisons of fuel costs relative to each other. As shown in Table 3.1, coal-to-liquid fuels with CCS can be produced at a cost of $70/bbl of gasoline equivalent and thus are competitive with $75/bbl gasoline. In contrast, the costs of fuels produced from biomass without geologic CO_2 storage are $115/bbl of gasoline equivalent for cellulosic ethanol produced by biochemical conversion and $140/bbl for biomass-to-liquid fuels produced by thermochemical conversion. The costs of cellulosic ethanol, and coal-and-biomass-to-liquid fuels with CCS, become more attractive if a CO_2 price of $50 per tonne is included.

Attaining supplies of 1.7 million bbl/d of biofuels, 2.5 bbl/d of coal-and-biomass-to-liquid fuels, or 3 million bbl/d of coal-to-liquid fuels will require the permitting and construction of tens to hundreds of conversion plants, together with the associated fuel transportation and delivery infrastructure. Given the magnitude of U.S. liquid-fuel consumption (14 million barrels of crude oil per day in the transportation sector in 2007) and the scale of current petroleum imports (about 56 percent of the petroleum used in the United States in 2008 was imported), a business-as-usual approach for deploying these technologies would be insufficient to address the need to develop alternative liquid transportation fuels, particularly because the development and demonstration of technology, the construction of plants, and the implementation of infrastructure require 10–20 years per cycle. In addition, investments in alternative fuels have to be protected against crude oil price fluctuations.

Because geologic CO_2 storage is key to producing liquid fuels from coal with life-cycle greenhouse gas emissions comparable to those of gasoline, commercial demonstrations of coal-to-liquid and coal-and-biomass-to-liquid fuel technologies integrated with geologic CO_2 storage would have to proceed immediately if the goal is to deploy commercial plants by 2020. Moreover, detailed scenarios for market-penetration rates of biofuels and coal-to-liquid fuels would have to be developed to clarify the hurdles preventing full feedstock utilization and to establish the enduring policies required to overcome them. Further, current government and industry programs would have to be evaluated to determine whether emerging biomass- and coal-conversion technologies could further reduce U.S. oil consumption and CO_2 emissions over the next decade.

Other Transportation Fuels

Technologies for producing transportation fuels from natural gas—such as gas-to-liquid diesel, dimethyl ether, and methanol—have been deployed or will be ready for deployment by 2020. But only if large supplies of natural gas were available at acceptable costs—for example, from natural gas hydrates—would the United States be likely to use natural gas as the feedstock for transportation fuel production.

Hydrogen has considerable potential, as discussed in *Transitions to Alternative Transportation Technologies—A Focus on Hydrogen* (NRC, 2008) and *The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs* (NRC, 2004). Hydrogen fuel-cell vehicles could yield large and sustained reductions in U.S. oil consumption and greenhouse gas emissions, but it will take several decades to realize these potential long-term benefits.

RENEWABLE ENERGY

The level of electricity generation from renewable resources has risen significantly over the past 20 years. Nonhydroelectric renewable sources, however, still provide a very small proportion of the U.S. total (about 2.5 percent of all electricity generated). In the 2008 reference-case estimates of the Energy Information Administration (EIA, 2008), the contribution of nonhydroelectric renewables was projected to be about 7 percent of total electricity generation by 2030. But the AEF Committee found that with a sustained effort and accelerated deployment, nonhydroelectric renewables could collectively provide 10 percent of the nation's electricity generation by 2020 and 20 percent or more by 2035. With current hydropower included, more than 25 percent of electricity generation could come from renewables by 2035.

Generation Capacity and Resource Base

Renewables currently represent a small fraction of total electricity generation. According to the EIA, conventional hydroelectric power is the largest source of renewable electricity in the United States, generating about 6 percent (almost 250,000 GWh out of a total 4 million GWh) of electricity produced by the electric power sector in 2007.[10]

The largest growth rates in renewable resources for electricity generation are currently in wind power and solar power. Though wind power in 2007 represented less than 1 percent of total electricity generation, wind electricity grew at a 15.5 percent compounded annual growth rate over the 1990–2007 time period and at a 25.6 percent rate between 1997 and 2007.

In 2007, wind power supplied over 34,000 GWh, almost 8,000 GWh more than in the year before. An additional 8,400 MW of capacity was added in 2008, representing an additional yearly generation of 25,000 GWh (assuming a 35 percent capacity factor). Total wind power capacity at the end of 2008 was approximately 25,000 MW. However, the overall economic downturn at that time caused financing for new wind power projects and orders for turbine components to slow, and layoffs in the wind turbine-manufacturing sector began. Thus, 2009 recently looked to be considerably smaller in terms of new capacity than 2008. However, recent data reveal that 2.8 GW of new wind power generation capacity was installed in the first quarter of 2009. Over the long term, the impacts of state renewable portfolio standards and the federal production tax credit will continue to spur installation of wind power capacity.

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[10]The electric power sector includes electricity utilities, independent power producers, and large commercial and industrial generators of electricity.

Central-utility electricity generation from concentrating solar power (CSP) and photovoltaics (PV) combined to supply 600 GWh in 2007, 0.01 percent of the total electricity generation for the United States. This level has been approximately constant since 1990. However, it does not account for the increase in residential and other small-PV installations, the sector that has displayed the largest growth rate for solar electricity. Solar PV in the United States has grown at a compounded annual growth rate of more than 40 percent from 2000 to 2005, with an installed generation capacity of almost 480 MW that, assuming a 15 percent capacity factor, produces approximately 630 GWh.

The United States has sufficient renewable-energy resources to significantly expand the amount of electricity generated from them. Solar in particular, followed by wind, offers the greatest potential among the domestic renewable resources. Solar energy derived from sunlight reaching Earth's surface could produce many times the current and projected future electricity consumption. And the total estimated electrical energy derivable from the continental U.S. wind resource in Class 3 and higher wind-speed areas is 11 million GWh per year—far greater than the estimated 2007 electricity generation of about 4 million GWh. But these numbers, which represent the total resource base, exceed what can be developed at an acceptable cost. Moreover, the resource bases for wind and solar energy are not evenly distributed, spatially as well as temporally, and they are more diffuse compared to fossil and nuclear energy sources. Finally, though the size of the resource base is impressive, there are many technological, economic, and deployment-related constraints on using sources of renewable energy on a large scale.

Technologies

Several renewable-energy technologies are available for deployment or are under active development.

- *Wind.* Turbine technology has advanced substantially in recent years. Future development will be evolutionary and will focus on improved efficiency and lower production costs. Major objectives are to increase the capacity factors and improve integration into the electric grid.
- *Solar photovoltaics.* The two major types of PV are silicon flat plates and thin films on various substrates. The former are more mature, with primary development objectives being higher efficiency and lower production costs. Thin films have the potential for substantial cost advan-

tages and can use a wider array of materials, but they are less well developed.

- *Concentrating solar power.* The three main options are parabolic troughs, power towers, and dish-Stirling engine systems. The first two are now the lowest-cost utility-scale solar electricity technology for regions of high solar flux. Design improvements and advances in high-temperature and optical materials are the major paths to cost reduction.
- *Geothermal.* Conventional geothermal, which relies on hydrothermal sources within 3 km of the surface to drive a heat engine, is a fairly mature technology, but it has a rather limited resource base. A study of the western United States found that 13 GW of electrical power capacity exists in identified geothermal resources in this region. Greatly expanding that base will require enhanced geothermal systems to mine heat down to a depth of 10 km. Such systems, however, face many technical challenges and are not now in operation.
- *Hydropower.* Conventional hydropower is the least expensive source of electricity. The technology is well developed, and objectives are to increase efficiency and reduce impacts on associated water bodies, as efforts to expand are likely to be limited by environmental concerns. Hydrokinetic technologies produce electricity using currents, tides, and ocean waves; many designs and demonstration plants exist, but there are no commercial deployments.
- *Biopower.* There are three main sources: wood/plant waste, municipal solid waste/landfill gas, and other (e.g., agriculture waste, used tires). A variety of technologies may be used to produce electricity, including current technologies based on the steam-Rankine cycle and future applications involving gasification combined-cycle plants. The use of biomass for biopower competes with its use for alternative liquid fuels.

Deployment Potential

Between now and 2020, there are no technological constraints to accelerated deployment of the major renewable resources with existing technologies. However, there are other kinds of barriers. The main ones currently include the cost-competitiveness of existing technologies relative to most other sources of electricity (with no prices assigned to carbon emissions or other externalities); markets not sufficiently shaped so as to allow the existing technologies to reach full scale and thus realize economies of scale; the lack of sufficient transmission capacity to move distant resources to demand centers; and the absence of sustained policies. Also, continued research to reduce costs and increase efficiencies is needed.

A reasonable target is that 20 percent of all electricity be supplied by renewable resources—including hydropower—by 2020. This would mean that approximately 10 percent of electricity generation would be from nonhydropower renewables. Continued accelerated deployment and sustained policies could permit nonhydropower renewables to reach 20 percent of total U.S. electricity generation by 2035.

The most in-depth scenario for increased renewables penetration into the electricity sector is the Department of Energy's (DOE's) 20 percent wind-penetration scenario (DOE, 2008; see Chapter 6 in Part 2 of this report for details), which includes an assessment of wind resources and available technologies; manufacturing, materials, and labor requirements; environmental impacts and siting issues; transmission and system integration; and market requirements. The scenario requires that installations reach an annual rate of about 16,000 MW by 2018, almost double the current annual deployment in the United States but less than the current global deployment of 27,000 MW. The committee considered this projected installation rate together with the reliability of wind facilities, and it concluded that this level of wind power deployment would be achievable with accelerated deployment as defined in Chapter 2.

Another accelerated deployment scenario for reaching 20 percent nonhydropower renewables is reliance on multiple renewable sources. Obtaining 20 percent of electricity generation solely from wind power would be a challenge because the 20 percent refers to an annual average, whereas wind power is intermittent. Balancing wind with multiple renewable resources—including solar, which does not normally peak when wind does, and baseload power from geothermal and biomass—could mitigate the temporal variability in generation. Reaching the goal of 20 percent nonhydropower renewables by 2035 could be achieved by adding 9.5 GW per year of wind power and a total of 70 GW of solar PV and 13 GW each of geothermal and biomass. Using multiple renewable resources to reach this level would take advantage of the geographical variability in the resource base.

Relying on multiple renewable resources would not eliminate the need to expand transmission capacity or make other improvements in the electricity infrastructure to enable the integration of renewables, nor would it reduce the magnitude of costs. However, such an approach to reaching 20 percent nonhydropower renewables could offer other attributes, such as providing baseload generation and combining different intermittent renewables to reduce the temporal variability in generation. The installation rate for wind under this option is approximately the current rate of deployment, and the installation rates of the other renewables technologies are consistent with the accelerated-deployment definition.

Greatly expanding electricity generation from renewable sources will require changes in the present electric system because of the intermittency, spatial distribution, and scalability of renewable resources. Integrating an additional 20 percent of renewable electricity, whether it comes from wind, solar, or some combination of renewable sources, requires expansion of the transmission system (to enable the power to reach demand centers and regional electricity markets) as well as large increases over current levels in manufacturing, employment, and investment. Further, although electricity storage is not needed, integrating intermittent renewables up to the 20 percent level would also require improvements in the electricity distribution system and fast-responding backup electricity generation.

Integrating renewables at a much greater level so that they account, say, for more than 50 percent of U.S. electricity generation would require scientific advances and major changes in electricity production and use. It would also necessitate the deployment of electricity storage technologies to offset renewables' intermittency. More details on deployment are available in Chapter 6 in Part 2 of this report, and an extensive discussion is presented in the panel report *Electricity from Renewable Resources: Status, Prospects, and Impediments* (NAS-NAE-NRC, 2009a).

Cost

Given the experience with renewables over the past 20–30 years, it is clear that their economics have generally not been attractive compared to most competing sources of electricity. The most favorable technology out to 2020 is onshore wind; with a federal production tax credit for renewables, or with high natural gas prices, wind is competitive with electricity generation from natural gas. Solar PV presents a different economic picture. It is much more expensive than current sources of electricity generated by centralized generating facilities, but PV installed for residential and commercial consumers provides electricity directly to the consumer.

Thus, the economics for a so-called distributed renewable generation source (termed a "distributed" source because the electricity generation occurs on the distribution side of the electricity system) depends on costs being competitive with retail electricity prices. Many residential and commercial systems are unlikely to have high capacity factors, given that such systems would be installed on roofs that are not currently designed to maximize sun exposure. Additionally, the full electricity distribution system and centralized power sources are still required for periods when electricity generation from distributed sources is not available. However, if electricity prices continue to increase and more utilities adopt time-of-day pricing (which charges the highest rate during the middle of the day), solar PV could become more widely competitive.

Nearly all of the costs associated with renewable energy are in the manufacture and installation of the equipment; fuel costs during operation—except for biomass—are zero. Economies of scale occur primarily during equipment manufacturing for nonhydropower renewable technologies and much less so with respect to plant size. The plants, however, can be built quickly and incrementally compared to conventional coal and nuclear electricity plants, allowing utilities and developers to begin recouping costs much more quickly. Thus, technological innovations will play a major role in how costs for renewables evolve in the future.

One estimate of the costs of obtaining 20 percent of electricity from renewables is provided by the DOE 20 percent wind energy study (DOE, 2008) referred to earlier and discussed in greater detail in Chapter 6 of this report and in NAS-NAE-NRC (2009a). Though this is a single study on the costs, it was developed with contributions from a wide array of stakeholders in the electric utility industry, wind power developers, engineering consultants, and environmental organizations. The study, which was externally peer reviewed (as mandated by the U.S. Office of Management and Budget), considered the direct costs both of installing the generating capacity and of integrating this power into the electricity system. Overall, it projects that increases in wind power generation costs (capital, operation, and maintenance expenses) in net present value would be approximately $300 billion—covering the installation of approximately 300 GW of new wind power capacity, of which about 250 GW would be installed onshore and 50 GW installed offshore. The total number of wind turbines required is estimated to be about 100,000. Estimates of the transmission costs range widely, from the $23 billion estimated within the DOE (2008) study to American Electric Power's $60 billion estimate (AEP, 2007) to the recent estimate of $80 billion by the Eastern Wind Integration and Transmission Study/Joint Coordinated System Planning Study (JCSP, 2009) for integrating 20 percent in the eastern part of the United States.

Barriers to Deployment

The major barrier to greater deployment of renewable electricity sources has been their high costs. And recent capacity limitations—in personnel, materials, and manufacturing—have raised the costs of PV and wind power projects even higher. Moreover, the variability of renewable energy makes integration into the electric power system more difficult as deployment grows. Integrating renewables at levels approaching 20 percent of all electricity generation requires not only greater transmission capacity but also the increased installation of fast-responding generation to provide electricity when renewables are not available. Expansion of the transmission system, improving its flexibility through advanced control technologies, and co-siting with other renewable or conventional generation can help this integration. Expansion of the transmission system also gives providers of renewable electricity access to regional wholesale electricity markets, thus improving its marketability. However, at a high level of renewable technology deployment, land-use and other local impacts would become quite important. In the past, such impacts have provoked local opposition to the siting of renewable electricity-generating facilities and associated transmissions lines, and opposition is likely to occur in the future. This represents an additional potential barrier.

In order to facilitate investment in the face of high costs and, as a result, allow renewable electricity generation to meet its potential, consistent and long-term policies are essential. As is shown in Chapter 6, the on-and-off nature of the federal production tax credit has direct impacts, positive and negative, respectively, on the installation of new renewable-energy generation facilities. The 20-percent-by-2030 target can be reached, but substantial increases in manufacturing capacity, employment, investment, and installation will be needed.

Impacts

Renewable-energy sources have significantly smaller lifetime emissions of CO_2 and criteria pollutants per kilowatt-hour than does fossil energy, although renewables' emissions are about the same as those of nuclear power (see Figure 2.15). Renewable electricity technologies (except biopower, some geothermal, and high-temperature solar technologies) also use significantly less water than do nuclear and gas- or coal-fired electricity technologies. On the other hand, land-use requirements are substantially higher for renewables but could be mitigated to some degree by multiuse features that allow some of the land to be devoted, say, to agricultural activities. However, land-use and related issues associated with renewables deployment, such as noise and aesthetics, often fall to local jurisdictions for approvals, and the resulting procedures can be controversial.

FOSSIL-FUEL ENERGY

Fossil fuels—petroleum, natural gas, and coal—have been the dominant energy source in the United States for decades past and will continue to be a major source for decades to come. At present, they collectively supply about 85 percent of the nation's primary energy (see Figure 1.2).

Resource Base for Petroleum and Natural Gas

Worldwide, the amount of petroleum and natural gas that could ultimately be produced is very large, but most of this resource is located outside the United States. In 2008, the United States imported about 56 percent of the petroleum it consumed, a drop from the peak of 60 percent in 2006. This drop can be attributed mainly to the growth in production of a half million barrels per day from the deepwater Gulf of Mexico, illustrating that domestic production depends on the ability to develop discovered resources to make up for the decline from existing fields.

Maintaining domestic petroleum production at current levels over the long run will be very challenging, however. Production of petroleum from U.S. unconventional resources (primarily oil shales), which is not likely to occur in significant volumes before 2020, will be more expensive than that from conventional oil sources and may have more negative environmental impacts. In any case, because U.S. crude oil reserves and production are 2 percent and 8 percent, respectively, of world levels, the actions of other countries could have greater effects than those of the United States on world oil production. By contrast, because U.S. petroleum consumption is 24 percent of world consumption, changes in U.S. demand are a significant factor in determining world demand. Growing demand in other countries could, however, offset any downward price pressures resulting from reduced U.S. demand.

Natural gas is the cleanest of the fossil fuels and has the lowest greenhouse gas emissions per unit of energy (emitting about half of the CO_2 of coal when burned for electricity generation). While the U.S. natural gas resource base is only about 9 percent of the known world total, some 86 percent of the natural gas consumed in the United States is produced domestically, with much of the remainder coming from Canada. In recent years, natural gas production from conventional resources has continued to decline, but production from unconventional resources such as coal beds, tight gas sands (rocks through which flow is very slow), and particularly from natural gas shales has increased. Higher natural gas prices in 2007 and 2008 led to expanded drilling in tight gas sands and gas shales, which increased total U.S. gas production by about 9 percent in 2008 after a decade of its being roughly constant.

If the increase in domestic natural gas production continues and is sustained over long periods, some portion of potential growth in domestic demand for natural gas could be accommodated. If, on the other hand, growth in U.S. natural gas production is limited by a combination of production declines from existing resources and modest growth from new resources, the United States may have to import liquefied natural gas (LNG) at prices subject to international market fluctuations. Which of these futures occurs will depend on some combination of linked factors that include the magnitude of demand growth, production technology, resource availability, and price.

About 12 percent of U.S. petroleum resources and 20 percent of U.S. natural gas resources are believed to lie in areas that, for a variety of policy reasons, are currently off-limits. These estimates are highly uncertain, however, and the technologies for exploration and production (which might permit more of these activities elsewhere) have advanced considerably since the estimates were made. Further, estimates of production from the restricted areas are moderate—for petroleum, they are on the order of several hundred thousand barrels per day by the mid-2020s (compared to current domestic production of 5.1 million barrels per day). The contribution to gas production from these areas could be about 1.5 trillion cubic feet per year in the 2020–2030 period, compared to current domestic production of 19.3 trillion cubic feet per year.

The issue for policy makers is to balance the energy security and economic benefits of developing these currently off-limits resources against the potentially negative environmental impacts. Most observers believe that the effect of incremental U.S. oil production from restricted areas on world oil price would be small, but because natural gas markets are more regional, they might respond differently; increased natural gas production from restricted areas could potentially offset the need for LNG imports.

Resource Base for Coal

U.S. recoverable reserves of coal are well over 200 times the current annual production of 1 billion tonnes, and additional identified resources are much larger. Thus the coal resource base is unlikely to constrain coal use for many decades to come. Rather, environmental, economic, geographic, geologic, and legal issues will likely be the primary constraints. Of particular concern regarding the greenhouse gas problem is that burning coal to generate electricity produces about 1 tonne of CO_2 equivalent per megawatt-hour, about twice the amount produced by natural gas. If CCS technologies were successfully developed, it is possible that future coal consumption could remain at current levels or increase (as a result, for example, of demand from a new coal-to-liquid-fuels industry), even if policies were put in place to constrain greenhouse gas emissions. On the other hand, if practical CCS technologies fail to materialize, coal use would be severely curtailed in a carbon-constrained world.

Fossil Energy Use for Electric Power Generation

In 2006, about 52 percent of U.S. electricity was generated from coal and 16 percent from natural gas. Many of these plants could operate for 60 years or more, and there is great reluctance on the part of plant operators to shorten their period of operation, given that new plants would require large amounts of capital and new permitting. Yet significant mitigation of U.S. greenhouse gas emissions will require dramatic reductions in the emissions from these plants. Alternatives include (1) retiring the plant; (2) raising the generating efficiency, thereby reducing greenhouse gas emissions per unit of electricity produced; (3) retrofitting with CO_2 "post-combustion" capture capability; or (4) repowering/rebuilding at the site, resulting in an entirely new or mostly new unit.

The two principal technologies for future coal-burning power plants are pulverized coal (PC) and integrated gasification combined cycle (IGCC), though the possibility of coal combustion with pure oxygen (oxyfuel) instead of air would simplify subsequent CO_2 capture. This option is also being investigated and may be competitive in the future. PC units now produce nearly all of the coal-based electric power in the United States. PC plants with 40–44 percent efficiency[11]

[11]Potential PC efficiencies as high as 48 percent have been estimated in the literature. This would require steam pressures and temperatures of 5000 psi and 1400°F main steam, 1400°F reheat, whereas the most robust current ultrasupercritical plants operate at pressures of around

(ultrasupercritical plants) could be achieved in the 2020–2035 period, as compared with a typical efficiency of 34–38 percent for older subcritical and supercritical steam plants. Replacing a 37 percent efficient plant with a 42 percent efficient plant, for example, would reduce CO_2-eq emissions and fuel consumption per kilowatt-hour of output by about 12 percent. To reduce emissions more dramatically in PC plants, CCS would be required.

Retrofitting for 90 percent CO_2 capture at existing PC plants with technology available today would require capital expenditures approaching those of the original plant itself; and 20–40 percent of the plant's energy would be diverted for separation, compression, and transmission of the CO_2, thereby significantly reducing thermal efficiency and increasing the levelized cost of electricity. In addition, retrofits face the added problems of site constraints and steam-management limitations, rendering the feasibility of installing CO_2 capture retrofits in existing plants highly plant dependent. Also, the optimum percentage of CO_2 capture in a retrofitted coal plant could be lower than that of a new coal plant. In any case, further engineering analyses to establish the shape of these cost-versus-percent-capture curves would aid policy analysis considerably.

Electricity demand and CO_2 price will have a strong effect on the rate of introduction of new coal plants. If the CO_2 price is zero and electricity demand stays relatively flat (as a result of increasing end-use efficiency, for instance), hardly any of the existing PC plants will be retired or modified and very few new plants will be built.

New natural gas combined cycle (NGCC) plants compete with new coal plants. Favoring natural gas plants are their lower capital costs and shorter construction times, but of primary importance is the price of natural gas. For example, in the committee's calculations, at a price of $6 per million British thermal units (Btu), NGCC plants have the lowest levelized cost of electricity (LCOE) of any baseload generating option, while at $16/million Btu they have the highest LCOE (see Figure 2.10 in Chapter 2). (Over the course of this study, U.S. natural gas prices have risen above $13/million Btu and fallen to below $4/million Btu.) Future rules governing greenhouse gas emissions and the pace at which CCS technologies can be commercialized will also affect the coal-gas competition.

If domestic natural gas (e.g., from shale gas deposits) proves plentiful, and

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4640 psi and temperatures of 1112–1130°F. Thus, achieving this potential efficiency would require major R&D breakthroughs. In addition, operating plants often do not realize their full design efficiencies.

confidence grows that prices will remain in the range of \$7–9/million Btu or lower for decades, as some commentators think may happen,[12] then NGCC plants with CCS could compete economically with PC and IGCC plants with CCS. In such a world, the cheapest way to gain large CO_2 reductions would be to use NGCC with CCS to replace existing and future coal units over time.

Although a large shift in this direction would increase natural gas demand significantly and put upward pressure on prices, the committee still considers it wise to plan for a broad range of future natural gas prices and domestic availabilities. Consequently, the committee envisions some CCS projects involving NGCC technology being part of the recommended 10 GW of CCS demonstrations (see Chapter 7 in Part 2). The committee did not make a judgment about the mix of NGCC, PC, and IGCC plants with CCS that would be appropriate.

The committee compared the costs of new PC and IGCC plants, with and without CCS, built with components available today and with various prices for CO_2 emissions. (It also considered as feedstocks not only coal but also natural gas, biomass, and biomass and coal in combination.) If no price is put on CO_2 emissions, PC without CCS is the cheapest option. However, the extra cost to add CCS to IGCC is less than the extra cost to add CCS to PC, because in IGCC, CO_2 is captured at high pressure[13] after gasification but before power generation (pre-combustion capture). For bituminous coal—at a price of \$50 per tonne of CO_2 emitted—IGCC with CCS is the cheapest of the four options, although all have a higher cost than current plants. These cost estimates, and similar estimates for the capture of CO_2 from natural gas plants and low-rank coal plants, have significant uncertainties particularly in fuel costs, capital costs for first-of-a-kind plants, and the costs of CO_2 capture and storage technologies.

Based on historical experience, and assuming that all goes well in the development and operation of CCS demonstrations from pilot plants to commercial scale, 10 GW of demonstration fossil-fuel CCS plants could be operating by 2020 with a strong policy driver (e.g., a CO_2 emissions price of about \$100 per tonne or comparably strong regulation), but not a crash program. With similar assumptions, 5 GW per year could be added between 2020 and 2025, and a further 10–20 GW per year from 2025 to 2035, resulting in a total of 135 to 235 GW

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[12]CERA, "Rising to the Challenge: A Study of North American Gas Supply to 2018," www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=10179.

[13]However, additional compression is still needed before the CO_2 can be injected underground.

of fossil-fuel power with CCS in 2035. Whether any coal plants and natural gas plants without CCS would still be operating in 2035 would depend on the nature of greenhouse gas policies at that time.

Carbon Capture and Storage

CCS technologies have been demonstrated at commercial scale, but no large power plant today captures and stores its CO_2. The few large storage projects now under way are all coupled to CO_2 capture at nonpower facilities; for example, in one offshore operation in Norway, 50 million standard cubic feet per day of CO_2 (1 million tonnes per year) are separated from natural gas before the fuel is inserted into the European grid; the CO_2 is injected under the North Sea.

CO_2 storage could be implemented in oil and gas reservoirs, deep formations with salt water, and deep coal beds. Specific sites would have to be selected, engineered, and operated with careful attention to safety. In particular, the deep subsurface rock formations that hold the CO_2 must allow injection of large total quantities at sufficient rates and have geologic layers that prevent, over centuries to millennia, the upward migration of injected CO_2. Current surveys suggest that the available storage within 50 miles of most of the major U.S. sources of CO_2 would be more than sufficient to handle all emissions for many decades and that up to 20 percent of current emissions could be stored at estimated costs of $50 per tonne of CO_2 or less. However, given the large volumes of CO_2 involved, the storage challenges should not be underestimated. At typical densities in the subsurface, a single 1 GW coal-fired plant would need to inject about 300 million standard cubic feet of CO_2 per day, or a volume flow equivalent to about 160,000 barrels per day—comparable to the petroleum production from a large oil field.

Too little is known at present to determine which power-generation technologies and which storage options could best produce electricity after 2020 if carbon emissions were constrained. Reliable cost and performance data are needed, both for capture and storage, and they can be obtained only by construction and operation of full-scale demonstration facilities. Such demonstrations could assure vendors, investors, and other private-industry interests that power plants that incorporate advanced technologies, and the associated storage facilities, could be built and operated in accordance with commercial criteria. Because of the variety of coal types and the myriad of technology-conversion options for coal, natural gas, and biomass fuels, a diverse *portfolio* of demonstrations of CO_2 capture technology will actually be required. Similarly, to sort out storage options and gain experience with their costs, risks, environmental impacts, legal liabilities, and regulatory and management issues, it will be necessary to operate a number of large-scale storage projects in a variety of subsurface settings.

The investments in this portfolio of CCS demonstrations will certainly be large, but there is no benefit in waiting to make them. The committee judges that the period between now and 2020 could be sufficient for acquiring the needed information on CCS viability, provided that the deployment of CCS demonstration projects proceeds as rapidly as possible. If these investments are made now, 10 GW of CCS projects could be in place by 2020. If not, the ability to implement CCS will be delayed.

Fossil Energy Use for Transportation

About 95 percent of the energy for transportation comes from crude oil, of which about 56 percent is imported. The transportation sector also generates about one-third of U.S. greenhouse gas emissions, which are difficult to eliminate from moving vehicles. Coal-to-liquid and natural-gas-to-liquid technologies with CCS can produce liquid transportation fuels with no more greenhouse gas emissions than those of crude oil. Other technologies to replace petroleum in the transportation sector are described in the "Energy Efficiency" and "Alternative Transportation Fuels" sections of this chapter.

Impacts and Barriers to Deployment

The widespread use of fossil fuels in the United States creates a substantial array of environmental impacts, most of which (with the notable exception of greenhouse gas impacts) have been addressed in principle by a broad array of laws and regulations over the last few decades. The continual challenge regarding most of these policy instruments is to keep them up-to-date and enforced while increases occur in the consumption of conventional or unconventional fuels.

All of these environmental issues need to be fully considered in assessing the real costs of different energy options. Further, agencies, other stakeholders, and funders concerned with environmental impacts must enhance their readiness for new challenges that are likely to emerge in the future regarding systems that make use of fossil fuels. These new challenges include the capture and storage of CO_2; potentially increased use of coal for coal-to-liquid fuel or coal-to-natural-gas production; shale oil and tar sands development; LNG safety; and water use.

A regulatory structure must be developed during the 2010–2020 period to enable large-scale deployment of the CCS necessary for continued use of fossil fuels. Pertinent issues include CO_2 pipeline-transport safety and land use, stability and leakage from underground carbon storage, and public acceptance of such storage.

Increased use of coal will intensify concerns about environmental and safety aspects of extraction as well as about pollutant emissions arising from power generation. Oil shale and tar sands production will also result in extraction issues, along with those pertaining to water availability and CO_2 production. Expansion of LNG imports may raise concerns about the potential coastal-area impacts of LNG storage facilities and their vulnerability to terrorist attacks, and the impacts of pipeline-capacity enlargements in some regions may raise concern as well. In general, increased fossil-fuel use for electricity generation will add to power plants' already substantial requirements for fresh water. In addition, there will be greater impacts on water quality, aquatic life, and surrounding ecosystems. Finally, although technologies exist to achieve high levels of control for most of the conventional pollutants produced in coal-to-liquid or gas-to-liquid fuel plants, performance standards relating to CCS will need to be written during the 2010–2020 period.

NUCLEAR ENERGY

Energy companies in the United States are expressing increased interest in constructing new nuclear power plants. Reasons cited include the need for additional baseload generating capacity; growing concerns about greenhouse gas emissions from fossil-fuel plants; volatility in natural gas prices; and favorable experience with existing nuclear plants, including ongoing improvements in reliability and safety.[14] No major R&D is needed for an expansion of U.S. nuclear power through 2020 and, likely, through 2035.

Nonetheless, the high cost of construction of new nuclear plants is a major concern, and the experience with the handful of new plants that could be built before 2020 will be critical to assess the future viability of the nuclear option. If

[14]The $18.5 billion in loan guarantees for new nuclear plants arising from the Energy Policy Act of 2005 may also contribute to this interest.

these plants are not built on time and on budget, or if the electricity produced is not cost competitive, few additional new plants are likely to follow, at least for a while.

Technologies

The nuclear plants now in place in the United States were built with technology developed in the 1960s and 1970s. In the intervening decades, ways to make better use of existing plants have been developed, along with new technologies that improve safety and security, decrease costs, and reduce the amount of generated waste—especially high-level waste. These technological innovations, now available or under development, include the following:

- *Improvements to existing plants.* The trend of technical and operational improvements in nuclear technology that has developed over the past few decades is expected to continue. Incremental improvements to the 104 currently operating U.S. nuclear plants have enabled them to produce more power over their operating lifetimes. Modifying existing plants to increase power output, referred to as "uprates," is considerably less costly than adding new capacity, and additional power uprates are expected in the future. In fact, nearly as much new nuclear capacity could be added in this way before 2020 as could be produced during that period by building new plants. Additionally, most currently operating nuclear power plants have received or are expecting to receive 20-year operating-license extensions, which will allow them to operate for a total of 60 years; discussions have recently commenced about extending licenses an additional 20 years (for a total of 80 years). Also, the periods when plants are off line have been reduced and can be further reduced. Average plant capacity factors have grown from 66 percent in 1990 to 91.8 percent in 2007, primarily through shortened refueling outages and improved maintenance, thereby greatly improving the plants' economic performance.
- *Evolutionary nuclear plants.* New plants constructed before 2020 will be based on modifications of existing plant designs, using technologies that are largely ready for deployment now.
- *Alternative nuclear plants.* Alternative designs in two broad categories are being developed or improved: thermal neutron reactor designs (all

current U.S. reactors are thermal) and fast neutron reactor designs. Thermal neutron reactor designs include plants that operate at higher temperatures, thereby offering process heat (which could be used, for example, for producing hydrogen) in addition to electricity production. Fast neutron reactor designs include plants intended to destroy undesirable isotopes associated with much of the long-lived radioactive waste burden in used fuel, and, in some cases, to breed additional fuel. These plants could reduce the volume of and the heat emitted by long-lived nuclear waste that must go to a repository for disposal.[15] Much R&D will be needed before any of these alternative reactor types can be expected to make significant contributions to the U.S. energy supply.

- *Alternative fuel cycles*. The United States currently employs a once-through nuclear fuel cycle in which used fuel is disposed of after removal from the reactor. In contrast, alternative (closed) nuclear fuel cycles involve the reprocessing of used fuel to produce new fuel. In principle, these alternative fuel cycles could extend fuel supplies and reduce the amount of long-lived nuclear waste requiring disposal. The reprocessing technology in common use today, called plutonium and uranium extraction (PUREX), is associated with an increased risk of nuclear weapons proliferation, as well as an increased risk of theft or diversion of nuclear materials,[16] because it yields a separated stream of plutonium. A modified version of PUREX that keeps uranium with the plutonium could result in modestly reduced proliferation risks relative to PUREX and could be deployed after 2020. Other alternatives are being investigated, but they are unlikely to be ready for commercial deployment before 2035. R&D is still needed on fuel design, separation processes, fuel fabrication, and fuel qualification, as well as on the associated alternative reactors.

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[15]For about the first century, the major challenges for managing high-level waste are the heat and radioactivity emitted by short-lived fission products. If a closed fuel cycle is implemented, these fission products will likely need to be removed from the waste and dealt with separately to achieve a significant reduction in the number of repositories needed.

[16]The United States is a nuclear weapons state and the primary proliferation risk applies to the use of such technologies in countries that are not nuclear weapons states. There is also concern about the theft of weapons-usable materials from reprocessing, wherever it takes place. The risk of proliferation is a controversial subject, and there are differing points of view about how it should affect technology trajectories within the United States.

Deployment Potential

As many as five to nine new nuclear plants could be built in the United States by 2020; however, in light of the long lead times expected for construction, the first one is unlikely to be operating before 2015. These new plants will have evolutionary designs that are similar to existing power plants. Combining new power plants with increased capacity obtained by uprating currently operating plants, a 12–20 percent increase in U.S. nuclear capacity is possible by 2020.

After 2020, the potential magnitude of nuclear power's contribution to the U.S. energy supply is uncertain. The operating licenses of existing plants will begin to expire in 2028, and the plants will have to be shut down if license extensions (to 80-year total operating lifetimes) are not obtained; under these circumstances, about 24 percent of the current U.S. nuclear capacity would be retired by 2035. Because of the long construction times, many companies will need to decide soon whether to replace retiring plants with new nuclear plants. As noted previously, the major barrier to new construction is financial; thus, companies will need to know whether evolutionary plants can be built on budget and on schedule. One important purpose of providing federal loan guarantees is to acquire experience with a few early plants that will guide these decisions.[17] This experience will affect the U.S. electricity portfolio up to and after 2035.

The scale of new nuclear deployment after 2020 will depend on the performance of plants built during the next decade. If the first handful of new plants (say, five) to be constructed in the United States meet cost, schedule, and performance targets, many more plants could be deployed after 2020. Construction of as many as three plants per year could take place up to 2025, and as many as five

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[17]The statute authorizes DOE to provide guarantees for loans covering up to 80 percent of the total project cost. When the government provides a guarantee for 100 percent of the debt instrument, the standard government loan-guarantee rules require that the government itself allocate and provide the capital for the investment (through the Department of the Treasury's Federal Financing Bank [FFB]), which is then repaid by the entity receiving the guarantee over the period of the loan. If an entity other than the FFB provides the loan, there is no federal money that changes hands at the outset. The program is intended to be revenue neutral to the government; that is, the company benefiting from the guarantee is required to pay a fee to cover the risk of failure to repay the loan, as well as the administrative costs. DOE is authorized to provide $18.5 billion in loan guarantees for nuclear power facilities, but it is not yet clear whether this allocation will be sufficient for the four to five plants the committee judges will be needed to demonstrate whether new nuclear plants can be built on schedule and on budget. DOE has found it difficult to implement the program, in part because of the challenge associated with estimating the appropriate fee.

plants per year could be constructed between 2026 and 2035. This could grow to 5–10 plants per year after 2035 if there is sufficient demand. However, if the first new plants do not meet their targets, few others are likely to follow, at least for a while.

Costs

The committee estimates that the LCOE at the busbar from new evolutionary nuclear plants could range from 8¢/kWh to 13¢/kWh (see Figure 2.10). Existing federal incentives—including loan guarantees such as those of the Energy Policy Act of 2005—could reduce the LCOE to about 6–8¢/kWh for plants that receive them. These levelized costs are higher than the current average cost of wholesale electricity, but they are likely to be comparable to future costs of electricity from other sources, particularly if fossil-fuel plants are required to store CO_2 or pay a carbon fee. The LCOEs for improvements to existing plants are from one-tenth to one-third those of new plants. The possible LCOEs from advanced plant designs and alternative fuel cycles are highly uncertain at this time. However, these costs are likely to be higher than the LCOEs from current designs using the once-through cycle, although cost advantages from reductions in long-lived high-level waste could offset some of these differences.

Barriers to Deployment

The potential barriers to the deployment of new nuclear plants are several:

- *Economics*. The high cost of new plants, with the resulting financial risk, is the most significant barrier to new deployment. Nuclear power plants have low operating costs per unit of electricity generation, but they incur high capital costs that present a financing challenge for generating companies, particularly given the long lead times for construction and the possibility of expensive delays.
- *Regulatory processes*. The U.S. Nuclear Regulatory Commission (USNRC) is implementing a revised licensing process that allows for reactor design certification, early site permits, and combined construction and operating licenses. Nevertheless, in light of the surge in recent applications, bottlenecks and delays could occur in the near term.
- *Public concerns*. Public opinion about nuclear power has improved in recent years, at least in part because of the safe and reliable perfor-

mance of existing plants, but it would likely become more negative if safety or security problems arose. The absence of a policy decision regarding the disposal of long-lived nuclear wastes, while not technically an impediment to the expansion of nuclear power, is still a public concern.[18] New reactor construction has been barred in 13 states as a result, although several of these states are reconsidering their bans.

- *Shortages of personnel and equipment.* These current shortages could limit construction during the next decade. The market should respond, however, and over time, the shortages should disappear.

Impacts

The impacts of an increased use of nuclear power include the following:

- *Diversity of supply.* Barring a crash program, renewable-energy sources and fossil fuels with CCS are unlikely to be able to provide all of the U.S. electricity demand projected for 2035, even with gains in energy efficiency. Future deployment of nuclear plants would help to ensure a diversity of sources for electric supply—at present, they provide a significant proportion (about 19 percent). Thus, they could serve as an insurance policy for the United States, which would be particularly needed if carbon constraints were applied.
- *Environmental quality.* A major factor in favor of expanding nuclear power is the potential for reduction in greenhouse gas emissions. Avoided CO_2 emissions could reach 150 million tonnes per year by 2020 and 2.4 billion tonnes per year by 2050 under the maximum nuclear power deployment rate discussed in this report.[19] However, an environmental challenge is presented by the disposal of the result-

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[18]The USNRC previously determined that the used fuel could be safely stored without significant environmental impacts for at least 30 years beyond the licensed life of operation of a reactor, at or away from the reactor site, and that there was reasonable assurance that a disposal site would be available by 2025 (10 CFR 51.23). The USNRC is now revisiting this determination and has proposed to find that used fuel can be stored safely and without significant environmental impacts until a disposal facility can reasonably be expected to be available (73 Fed. Reg. 59,547 [Oct. 9, 2008]).

[19]This calculation assumes that nuclear plants replace traditional baseload coal plants emitting 1000 tonnes of CO_2 equivalent per gigawatt-hour and that nuclear plants emit 24–55 tonnes of CO_2 equivalent per gigawatt-hour on a life-cycle basis.

ing radioactive waste, particularly used fuel. The one site previously envisioned for such disposal—Yucca Mountain, Nevada—would not be ready until after 2020, if at all. And the prospects for the Yucca Mountain repository are substantially diminished by the declared intent of the Obama administration not to pursue this disposal site. Nonetheless, the safe and secure on-site or interim storage of used fuel for many decades—until a location for a permanent disposal location is agreed upon—is technically and economically feasible.

- *Safety and security.* Accidents or terrorist attacks involving nuclear reactors or used fuel storage could result in the release of radioactive material. Measures have been taken in recent years to reduce the likelihood and consequences of such events for existing plants, and evolutionary and advanced designs have features that further enhance safety and security.
- *Adequacy of resources*. The estimated supply of uranium is sufficient to support a doubling of current world nuclear power capacity through the end of this century.

ELECTRICITY TRANSMISSION AND DISTRIBUTION

The U.S. electric power transmission and distribution (T&D) systems—the vital link between generating stations and customers—are in urgent need of expansion and upgrading. Growing loads and aging equipment are stressing the system and increasing the risk of widespread blackouts.

Adding transmission lines and replacing vintage equipment currently in operation would solve this problem. But with an investment only modestly greater, new technology could be incorporated that would have many additional advantages. Among the benefits of modern T&D systems are the following:

- *Superior economics*. By improving the reliability of power delivery, enabling the growth of wholesale power markets, optimizing assets (reducing the need for new generating stations and transmission lines), and providing price signals to customers.
- *Better security*. By improving resilience against major outages and speeding restoration after a system failure.

- *Environmental quality.* In particular by accommodating a large fraction of generation from renewable-energy sources.

Technologies

Technologies used to modernize the T&D systems must be implemented systematically and nationwide, particularly with respect to the transmission system, to achieve maximum benefit. R&D will be important for reducing costs and improving performance, but except in a few cases, breakthroughs are not needed. In fact, most of the technologies already exist and could be deployed now.

Included among these key modernizing technologies are the following:

- *Advanced equipment and components.* Power electronics and high-voltage AC and DC lines offer the potential for long-distance transmission and grid operation that are more efficient. Power electronics both for transmission (Flexible Alternating Current Transmission System—FACTS) and distribution (Custom Power) currently exist and have been deployed in limited applications. Corresponding higher-voltage long-distance lines and substations could be deployed by 2020. High-voltage DC systems can be more economical than AC under some conditions, especially when lines must be underground or underwater, and several DC lines are already in operation. Cost-effective electric storage would be valuable in smoothing power disruptions, preventing cascading blackouts, and accommodating intermittent renewable-energy sources. Some storage technologies (e.g., compressed air energy storage and perhaps advanced batteries) will be ready for deployment before 2020, but significant development is still needed.
- *Measurements, communications, and control.* Modern T&D systems will have the ability to gather, process, and convey data on the state of the system far more effectively than can be done at present. Sampling voltage, frequency, and other important factors many times per second will give operators a much clearer picture of changes in the system and enhance their ability to control it. Most of the necessary technologies are available and have been installed to a limited degree. The communications and control software needed to take full advantage of these technologies could use further development but should be ready by

2020. The costs of installation of the technologies and development of the required software will be significant, however, and the monitoring, sensing, and communications technologies for distribution systems differ from those for transmission systems. Nevertheless, full deployment of modern T&D systems could be achieved by 2030.

- *Improved decision support tools.* The data that a modern grid collects and analyzes can assist operators in deciding when action must be taken, but only if the data are presented in timely and useful forms. During disruptions, split-second decision making may be necessary to prevent cascading failures. Improved decision support tools (IDST) will provide grid visualization to help operators understand the problem and the options available to resolve it. In addition, IDST can strengthen longer-term planning by identifying potential vulnerabilities and solutions. These technologies could be developed by 2020 and continually improved afterward.
- *Integrating technologies.* The technologies discussed in this section can achieve their maximum benefit only through integrated deployment, which poses the primary challenge to creating modern T&D systems. Even though many of these technologies are available now, continued R&D will be important for improvements and cost reductions.

Costs

Modernization and the necessary expansion of T&D systems could be completed in the next 20 years. The total costs are estimated to be about $225 billion for the transmission system and $640 billion for the distribution system. Expansion alone without modernization would cost $175 billion and $470 billion, respectively. Such estimates are complicated by the expansive and interconnected nature of the system and the difficulty of determining development costs, particularly for software.

Barriers to Deployment

Significant barriers hinder the development of modern T&D systems. First, even though most of the necessary technologies are now available, many are expensive and present some performance risk. Second, in the short term it is more costly to develop modern T&D systems than to just expand current systems, and utilities tend to be risk averse; many consumers are more interested in low rates than in reliability of service. And third, legislative and regulatory changes are needed to provide utilities and customers with adequate incentives to invest in modernization. Shortages of trained personnel and equipment could also be a barrier to T&D systems modernization, especially over the near term.

A clear vision for the modern grid is tantamount to providing an environment where utilities, regulators, and the public can understand the benefits and accept the costs, especially as the ownership, management, and regulation of the T&D systems are highly fragmented and collaboration will thus be required. Moreover, investments will be needed in locations and jurisdictions that do not directly benefit—e.g., areas that must be crossed by transmission lines to link generation and load centers. Such a vision would also provide a road map for integrating modernization of the various parts of the enormously complicated transmission system. It might also help expedite the construction of new transmission lines that are now subject to long delays. Clear metrics that measure benefits and progress, as well as the costs of *not* following this path, should be part of the strategy. In contrast, distribution systems can be modernized on a regional level, and some elements, such as smart meters, are appearing already.

Impacts

Modern T&D systems will provide substantial economic benefits by correcting the inefficiency and congestion of the current system and by reducing the number and length of power disruptions. Some estimates are that benefits will exceed costs by four to one. In addition, expanded capacity and improved information flows will raise the efficiency of the electricity markets. Modern T&D systems will be less vulnerable to potential disruptions because of their greater controllability and higher penetration of distributed generation, but the overlay of computer-driven communications and control will make cybersecurity an integral part of modernization. Environmental benefits from modern T&D systems will result from the greater penetration of large-scale intermittent renewable sources and of distributed and self-generation sources; better accommodation of demand-response technologies and electric vehicles; and improved efficiency. Finally, modern systems will be safer because improved monitoring and decision making allow for quicker identification of hazardous conditions, and less maintenance will be required.

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ANNEX 3.A: METHODS AND ASSUMPTIONS

This annex provides a description of some of the key methods and assumptions that were used to develop the energy supply, savings, and cost estimates made in this report. More detailed explanations of these methods and assumptions can be found in Chapters 4–9 of Part 2.

Energy Supply and Cost Estimates

The methodologies and assumptions used to develop the energy supply and cost estimates in this report are shown in Table 3.A.1. Each row in the table is described in the bulleted list that follows:

- *Reference scenario*. The statement of task for this study (see Box 1.1) called for the development of a reference scenario "that reflects a projection of current economic, technology cost and performance, and policy parameters into the future." This reference scenario is the "base case" for comparison with the AEF Committee's energy savings and supply estimates resulting from the accelerated deployment of technology. The committee adopted the Energy Information Administration's reference case as the reference scenario for this study (see Box 2.1). The reference case for 2007 (EIA, 2008) was used for all but one of the energy supply assessments. The exception was renewable energy, which used the reference case for 2008 (EIA, 2009) because it contained estimates of capital costs for renewable energy technologies that the committee judged to be more realistic than the EIA (2008) estimates.
- *Source of cost estimates* and *models used to obtain estimates* describe the methodologies that were used by the AEF Committee to estimate energy supply costs—either the levelized cost of electricity (LCOE; see Box 2.3) or the costs of liquid fuels. Committee-derived model estimates (i.e., developed by the committee itself or for the committee by consultants) were used for the costs of fossil, nuclear, and alternative liquid fuel technologies. The fossil- and alternative-liquid fuel cost estimates were developed using a common set of models and assumptions (see Box 7.2 in Chapter 7). The nuclear energy cost estimates were developed using a different but comparable set of models and assumptions (see Box 8.4 in Chapter 8). The renewable energy cost estimates were

developed through a critical review of published studies that employed a range of models and assumptions; two examples are shown in the table. The AEF Committee used expert judgment in selecting the estimates from these studies that it considered to be reliable.

- *Cost estimate limitations* are key knowledge gaps and uncertainties that could affect the accuracy of the cost estimates. These limitations arise primarily from technology immaturity or a lack of experience with deploying technologies at commercial scales. One would expect these uncertainties to be reduced as technologies mature and deployment experience is gained.
- *Plant maturity.* The costs of initial deployments of a new technology, sometimes referred to as first plant costs, are generally higher than the costs of deployments of mature proven technologies, sometimes referred to as Nth plant costs. The cost estimates presented in this report reflect the AEF Committee's judgments about the state of technology maturity in 2020. The committee presents first plant cost estimates for immature technologies, Nth plant costs for mature technologies (e.g., pulverized coal plants), and intermediate plant costs for technologies that are still maturing (e.g., IGCC, liquid fuels production). In some cases, cost contingencies were added for immature technologies to bring them closer to Nth plant estimates.
- *Plant size* is the nameplate capacity of the energy supply plant assumed in the cost estimates. The AEF Committee selected plant sizes that it deemed to be typical of each technology class.
- *Plant life* is the time over which the energy supply plant is assumed to generate electricity or liquid fuels. The AEF Committee generally followed industry convention in selecting plant lives for each technology class. In some cases, the plant lives selected were less than the lives of current generating assets (e.g., pulverized coal plants).
- *Feedstock and fuel costs* are the costs for the feedstocks and fuels that are used to produce electricity and liquid fuels. The fuel costs used in this report were selected by the committee based on examinations of historical costs, recent costs, and cost trends. In some cases, ranges of costs were used in the estimates. There are no fuel costs for some renewable energy supplies (e.g., solar and wind).

- *CO_2 prices* represent potential future costs to operators for emitting CO_2 to the atmosphere from energy production. A base-case CO_2 price of $0 per tonne was assumed for all of the energy supply cost estimates presented in this report; prices of $50 and $100 per tonne were also considered in the fossil energy and alternative liquid fuels estimates in order to assess the sensitivity of energy supply costs to CO_2 prices for a future in which climate change is taken seriously.
- *Financing period* is the length of time that capital borrowed for constructing the energy supply plant would be financed. The financing periods used in this report reflect current industry practices, which vary across technology classes.
- *Debt/equity* indicates the ratio of borrowed capital to equity capital in financing the construction of the energy supply plant. The ratios used in this report reflect current industry practices, which vary across technology classes. In some cases ranges were used.
- *Before-tax discount rate* was used to convert future energy supply costs into present values. The ratios used in this report reflect standard industry practice.
- *Overnight costs* represent the present-value costs, paid as a lump sum, for building an energy supply plant. The overnight costs do not include any costs associated with the acquisition of capital, the acquisition of land on which the plant would be built, or site improvements such as new or upgraded transmission equipment. In some cases, overnight costs are given as ranges. For the fossil-fuel estimates, however, 10 percent of the capital costs were added to account for owners' costs.
- *Source of supply estimates* describe the methodologies that were used by the AEF Committee to estimate the supply of electricity and liquid fuels. Many factors can affect deployment rates of a technology beyond its readiness for deployment. Consequently, it was not possible to develop a single methodology for estimating deployment rates for all of the energy supply technologies considered in this report. The committee's estimates of deployment rates were instead based on expert judgment informed by historical rates of technology deployments or by current deployment trends. The supply estimates represent new electricity or liquid fuel supplies and do not account for possible future supply reductions arising from retirements of existing assets.

- *Build time* is the estimated time required to construct a new energy supply plant. This estimate represents actual construction time; it does not include the time required to acquire a site, to design the plant, and to obtain any needed licenses, permits, or other approvals. The build times used in this report reflect current industry practices, which vary across technology classes.
- *Capacity factor* is the ratio (expressed as a percent) of the energy output of a plant over its lifetime to the energy that could be produced by that plant if it was operated at its nameplate capacity. Some capacity factors are expressed as ranges. The capacity factors used in this report reflect current experience and projected future improvements, both of which vary across technology classes.
- *Near-term build-rate limitations* identifies important factors that could limit the rates of plant deployments between 2009 and 2020. These limitations arise from a lack of experience in deploying new technologies (e.g., CCS), bottlenecks in obtaining critical plant components (e.g., large forgings for nuclear plants), and reduced availabilities of other materials and personnel. Most of these bottlenecks are expected to be temporary and should not present major impediments to deployment after 2020.
- *Resource limitations* are factors that could restrict the supply of energy obtained from the deployment of existing and new technologies. These limitations relate mainly to the availability of feedstocks and fuels that are needed to operate the energy supply plants.

TABLE 3.A.1 Sources and Key Assumptions Used to Develop Cost and Energy Supply Estimates in This Report

	Fossil-Fuel Energy (Chapter 7)	Nuclear Energy (Chapter 8)	Renewable Energy (Chapter 6)
Reference scenario	EIA (2008)	EIA (2008)	EIA (2009)
COST ESTIMATES: SOURCES AND KEY ASSUMPTIONS			
Source of cost estimates	Committee-derived model estimates	Committee-derived model estimates	Critical assessment of the literature[a]
Models used to obtain estimates	NETL (2007) and Princeton Environmental Institute[b]	• Keystone (2007) model for LCOE[c] • Monte Carlo for sensitivity analysis	• NEMS model for EIA (2009) cost estimates • MERGE model for EPRI (2007) cost estimates • Other literature estimates are not model based
Cost estimate limitations	• IGCC, USPC, and CCS technologies are not yet mature and have not been deployed • Geologic storage of CO_2 has not been demonstrated on a commercial scale	Evolutionary nuclear technologies are mature but plants have not yet been deployed in the United States.	Solar technologies are undergoing rapid technological improvements that could bring down future costs.
Plant maturity	• Nth plant for pulverized coal • 3 percent premium on capital costs added for IGCC, PC-CCS, and IGCC-CCS to account for immaturity of technologies • 20 percent premium on CCS capital costs added for CCS 2020 estimates to account for immaturity of technologies	Nth plant	Nth plant
Plant size	500 MW (coal and gas)	1.35 GW, based on weighted average of current plant license applications	Variable

Alternative Transportation Fuels (Chapter 5)		
Cellulosic Ethanol	Coal to Liquid	Coal + Biomass to Liquid
EIA (2008)	EIA (2008)	EIA (2008)
Committee-derived model estimates	Committee-derived model estimates	Committee-derived model estimates
See NAS-NAE-NRC (2009), Appendix I	Princeton Environmental Institute[b]	Princeton Environmental Institute[b]
Cellulosic technologies are not yet mature and have not been deployed	Geologic storage of CO_2 has not been demonstrated on a commercial scale	Geologic storage of CO_2 has not been demonstrated on a commercial scale
• Intermediate plant • No capital cost contingency included in estimate for CCS	• Intermediate plant • No capital cost contingency included in estimate for CCS	• Intermediate plant • No capital cost contingency included in estimate for CCS
4,000 bbl/d	50,000 bbl/d	10,000 bbl/d

continued

TABLE 3.A.1 Continued

	Fossil-Fuel Energy (Chapter 7)	Nuclear Energy (Chapter 8)	Renewable Energy (Chapter 6)
Reference scenario	EIA (2008)	EIA (2008)	EIA (2009)
COST ESTIMATES: SOURCES AND KEY ASSUMPTIONS			
Plant life (yr)	20	40	Variable
Feedstock and fuel costs	Coal: \$1.71/GJ (\$46/tonne) Gas: \$6/GJ, \$16/GJ	Average: 1.25¢/kWh Range: 0.8–1.7¢/kWh	Biomass: \$15–35/MWh Others: \$0
CO_2 prices (\$/tonne)	0, 50, 100	0	0
Financing period (yr)	20	Average: 40 Range: 30–50	Variable
Debt/equity	55/45	• IPP: Average 60/40 Range: 50/50 to 70/30 • IOU: Average 50/50 Range: 45/55 to 55/45 • Also considered: 80/20 for IPP and IOU with federal loan guarantees	Variable
Before-tax discount rate (percent/yr)	7	• IOU: 6.9 • IPP: 7.7	Variable
Overnight costs (Millions of 2007\$/kW) (Millions of 2007\$/bbl)	• PC: 1625 • PC+CCS: 2961 • IGCC: 1865 • IGCC+CCS: 2466 • NGCC: 572 • NGCC+CCS: 1209 • –20%/+30% uncertainty	Average: 4500 Range: 3000–6000	• Biopower: 3390 • Traditional geothermal: 1585 • CSP: 2860–4130 • PV: 2547–5185 • Onshore wind: 916–1896 • Offshore wind: 2232–3552
ELECTRICITY OR LIQUID FUELS SUPPLY ESTIMATES: SOURCES AND KEY ASSUMPTIONS			
Source of supply estimates	Committee-generated, based on historical build rates of plants in the United States	Committee-generated, based on historical build rates of plants in the United States	Committee-generated, based on an examination of natural resource base and other factors[d]

Alternative Transportation Fuels (Chapter 5)		
Cellulosic Ethanol	Coal to Liquid	Coal + Biomass to Liquid
EIA (2008)	EIA (2008)	EIA (2008)
20	20	20
$111/tonne dry biomass	$46/tonne coal	$46/tonne coal $111/tonne dry biomass
0, 50	0, 50	0, 50
20	20	20
70/30	55/45	55/45
7	7	7
349	4000–5000 (with CCS) (0.08–0.09/bbl per day)	1340 (with CCS) (0.134/bbl per day)
Committee-generated, based partly on corn-ethanol plant build rates in the United States[e]	Committee-generated, based on historical build rates of plants in the United States	Committee-generated, based partly on corn-ethanol plant build rates in the United States[f]

continued

TABLE 3.A.1 Continued

	Fossil-Fuel Energy (Chapter 7)	Nuclear Energy (Chapter 8)	Renewable Energy (Chapter 6)
Reference scenario	EIA (2008)	EIA (2008)	EIA (2009)
ELECTRICITY OR LIQUID FUELS SUPPLY ESTIMATES: SOURCES AND KEY ASSUMPTIONS			
Build time (yr)[g]	3[b]	Average: 5.5 Range: 4–7	• 1–2 for solar and wind • Longer for biopower and hydrothermal
Capacity factor (percent)	85	Average: 90 Range: 75–95	• Biopower: 83–85 • Traditional geothermal: 90 • CSP: 31–65 • PV: 21–32 • Wind: 32.5–52
Near-term build-rate limitations	Learning curve for CCS slows build rate before 2025	Build rates slowed before 2020 by: • Time to acquire license and construct plants • Lack of domestic experience • Potential bottlenecks in obtaining plant components	Barriers to reach 20 percent renewables generation: • Availability of raw materials • Manufacturing capacity • Availability of personnel
Resource limitations	Historical resources limits considered	None	None for wind and solar; limited resource bases for biomass, traditional hydropower, hydro-kinetic, and traditional geothermal

Note: CCS = carbon capture and storage; CSP = concentrating solar power (i.e., solar thermal); IGCC = integrated gasification combined cycle; IOU = investor-owned utility; IPP = independent power producer; MERGE = Model for Evaluating Regional and Global Effects [of greenhouse gases]; NEMS = National Energy Modeling System; NGCC = natural gas combined cycle; PC = pulverized coal; PV = photovoltaics; USPC = ultrasupercritical pulverized coal.

[a]The following studies were used to “bookend” the renewable energy cost estimates: ASES (2007), EIA (2008, 2009), EPRI (2007), and NREL (2007).

[b]See Kreutz et al. (2008) and Larson et al. (2008).

[c]This model was run using committee-developed assumptions as described in Chapter 8 in Part 2 of this report.

Alternative Transportation Fuels (Chapter 5)		
Cellulosic Ethanol	Coal to Liquid	Coal + Biomass to Liquid
EIA (2008)	EIA (2008)	EIA (2008)
1	3	3
90	90	90
None	None	None
Biomass availability	Coal extraction rates	Biomass availability

[d]These additional factors included manufacturing and materials constraints, employment and capital requirements, and necessary deployment rates. The committee also considered current growth rates of renewables technologies and historical build rates of other types of plants.

[e]The committee assumed twice the capacity achieved for corn grain ethanol.

[f]The committee assumed a build-out rate slightly slower than that for corn grain ethanol because of issues involving accessing sites with about 1.0 million tonnes of biomass per year and a similar availability of coal.

[g]Estimates do not include the time required for permitting and other approvals.

[h]This estimate does not account for differences in complexity of different types of coal and natural gas plants.

Energy Savings and Cost Estimates

The methodologies and assumptions used to develop the energy savings and cost estimates are provided in Table 3.A.2. Each row in the table is described in the following bulleted list:

- *Reference scenarios*. The reference case for 2006 (EIA 2007) was used for the buildings and industrial sector estimates, but these were adjusted in some cases to reflect the 2007 reference case provided in EIA (2008). The transportation estimates were based on a committee-derived, no-change baseline.
- *Source of cost estimates* describes the methodologies that were used to estimate energy savings costs. As shown in the table, these estimates were derived from critical assessments of the literature.
- *Source of savings estimates* describes the methodologies that were used to estimate energy savings. As shown in the table, these estimates were derived from critical assessments of the literature and, for buildings and transportation, committee-derived analyses.
- *Key cost-effectiveness criteria* describes the criteria that were used to determine which energy savings were cost-effective. Different criteria were used in the buildings, transportation, and industrial sectors, as described in the table.
- *Technology lifetimes* are average useful lifetimes of the technologies used to obtain energy savings. These estimates are highly technology specific.
- *Before-tax discount rate* was used to convert future energy supply costs into present values. The ratios used in this report reflect standard industry practice.
- *Other considerations* describe other factors that were considered in developing the energy-savings cost and supply estimates.

TABLE 3.A.2 Sources and Key Assumptions Used to Develop Energy Savings and Cost Estimates

	Buildings Sector	Transportation Sector	Industry Sector[a]
Reference scenario	EIA (2007, 2008)	Developed by committee[b]	EIA (2007, 2008)
Source of cost estimates	Critical assessment of the literature	Critical assessment of the literature	Critical assessment of the literature
Source of savings estimates	Critical assessment of the literature on individual technologies and committee-derived conservation supply-curve analysis	• Critical assessment of the literature on specific technologies • For light-duty vehicles (LDVs), committee-derived illustrative scenario analysis of overall savings in fuel consumption	Critical assessment of the literature on industry-wide savings, industry-specific savings, and savings from specific crosscutting technologies
Key cost-effectiveness criteria	Levelized cost of energy savings is less than the average national electricity and natural gas prices	Recovery of discounted costs of energy savings over the life of the vehicle	Energy savings provide an internal rate of return on investment of at least 10 percent or exceed the company's cost of capital by a risk premium
Technology lifetimes	Technology specific	Average vehicle lifetime	Technology specific
Before-tax discount rate (percent/yr)	7	7	15
Other considerations	Assessment accounts for stock turnover in buildings and equipment	For LDVs, assessment considers how the distribution of specific vehicle types in the new-vehicle fleet affects the on-the-road fleet	Assessment of savings in specific industries used to confirm industry-wide estimates

[a]Manufacturing only.
[b]This is a "no-change" baseline in which, beyond 2020 (when Energy Independence and Security Act targets are met), any efficiency improvements are fully offset by increases in vehicle performance, size, and weight.

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APPENDIXES

A Committee and Staff Biographies

COMMITTEE

HAROLD T. SHAPIRO (*Chair*), a member of the Institute of Medicine, is president emeritus of Princeton University and a professor of economics and public affairs at the Woodrow Wilson School. He served as president of the University of Michigan from 1980 to 1988. Dr. Shapiro's expertise is in the intersection of public policy, science policy, and bioethics. Widely recognized for his astute judgment in policy situations, he has chaired the National Bioethics Advisory Committee under President Bill Clinton and served as vice chair of the President's Council of Advisors on Science and Technology under President George H.W. Bush. Other distinctions include his chairing of the Association of American Universities and service on the board of directors of the National Bureau of Economic Research, Inc., and the board of trustees of the Universities Research Association, Inc. He has also served on numerous National Research Council committees, including the Committee on the Organizational Structure of the National Institutes of Health. In 2006, the American Association for the Advancement of Science awarded Dr. Shapiro the William Carey Medal for Lifetime Achievement in Science Policy. In 2008, he was awarded the Clark Kerr Medal for lifetime achievement in higher education. He received a bachelor's degree from McGill University in 1956 and a Ph.D. in economics from Princeton in 1964.

MARK S. WRIGHTON (*Vice Chair*) is chancellor and professor of chemistry at Washington University in St. Louis. Prior to moving there in 1995, he had been a faculty member at the Massachusetts Institute of Technology since 1972. Dr. Wrighton was head of the Department of Chemistry at MIT from 1987 until

1990, when he was appointed provost. He was elected a fellow of the American Academy of Arts and Sciences in 1988 and of the American Association for the Advancement of Science in 1986. In 2001, he was elected to membership in the American Philosophical Society. From 2000 to 2006, Dr. Wrighton was a presidential appointee to the National Science Board (NSB), which serves as a science policy advisor to the president and Congress and is the primary advisory board of the National Science Foundation. While serving on the NSB, he chaired the Audit and Oversight Committee. Dr. Wrighton earned a B.S. from Florida State University in 1969 and a Ph.D. in chemistry from the California Institute of Technology in 1972.

JOHN F. AHEARNE, a member of the National Academy of Engineering, is Executive Director Emeritus of Sigma Xi, The Scientific Research Society; an adjunct scholar at Resources for the Future; and an adjunct professor of civil and environmental engineering at Duke University. His professional interests are reactor safety, energy issues, resource allocation, and public policy management. He has served as commissioner and chair of the U.S. Nuclear Regulatory Commission, system analyst for the White House Energy Office, deputy assistant secretary of energy, and principal deputy assistant secretary of defense. Dr. Ahearne currently is vice chair of the Department of Energy's Nuclear Energy Advisory Committee. He is a fellow of the American Physical Society, the Society for Risk Analysis, the American Association for the Advancement of Science, and the American Academy of Arts and Sciences; he is a member the American Nuclear Society; and he has been active in several National Research Council committees that examined issues in risk assessment. Dr. Ahearne received a Ph.D. in physics from Princeton University.

ALLEN J. BARD, a member of the National Academy of Sciences, is a professor of chemistry and biochemistry and holds the Norman Hackerman/Welch Regents Chair in Chemistry at the University of Texas at Austin. He has published widely and is the winner of numerous honors and awards, including the Priestley Medal and the Welch and Wolf Prizes. Dr. Bard was president of the International Union of Pure and Applied Chemists (IUPAC) and editor in chief of the *Journal of the American Chemical Society* from 1982 to 2001. He has served on the National Research Council's Energy Engineering Board (EEB), been chair of the Board on Chemical Sciences and Technology, chaired the EEB Committee on Potential Applications of Concentrated Solar Photons, and served as president of the U.S.

National Committee for IUPAC. His research interests include electro-organic chemistry, photoelectrochemistry, electrogenerated chemiluminescence, electroanalytical chemistry, and fuel cells. His policy interests include issues related to electrochemical and renewable-energy sources. Dr. Bard received a Ph.D. in chemistry from Harvard University.

JAN BEYEA, chief scientist of Consulting in the Public Interest, consults on nuclear physics and other energy/environmental topics for numerous local, national, and international organizations, including the National Audubon Society. He has served as chief scientist and vice president of the National Audubon Society and has held positions at Holy Cross College, Columbia University, and Princeton University's Center for Energy and Environmental Studies. Dr. Beyea has been a member of numerous advisory committees and panels, including the National Research Council's Board on Energy and Environmental Systems, Energy Engineering Board, Committee on Alternative Energy R&D Strategies, and Committee to Review DOE's Fine Particulates Research Plan. He has also served on the Secretary of Energy Advisory Board's Task Force on Economic Modeling, been a member of the policy committee of the Recycling Advisory Council, and advised various studies of the Office of Technology Assessment. Dr. Beyea has expertise in energy technologies and associated environmental and health concerns, and he has written numerous articles on energy and the environment. He received a B.A. from Amherst College and a Ph.D. in physics from Columbia University.

WILLIAM F. BRINKMAN is vice president of physical sciences research for Lucent Technologies, formerly AT&T Bell Laboratories; he held the same position at AT&T Bell Laboratories. He was vice president of the Sandia National Laboratories in 1984–1987, director of the Chemical Physics Research Laboratory in 1981–1984, head of the Infrared Physics and Electronics Research Department of Bell Laboratories in 1972–1974, and a resident fellow at Oxford University in 1965–1966. Dr. Brinkman received his B.S. (1960), M.S. (1962), and Ph.D. (1965) in physics from the University of Missouri at Columbia. He received an honorary D.H.L. from the same institution in 1987. He is a member of the National Academy of Sciences.

DOUGLAS M. CHAPIN, a member of the National Academy of Engineering (NAE), until recently was principal officer and director of MPR Associates, Inc., in Alexandria, Virginia. He has extensive experience in electrical, chemical, and nuclear engineering, with particular application to nuclear and conventional power plants. He has worked in areas such as instrumentation and control systems, nuclear fuels, fluid mechanics, heat transfer, pumps, advanced analysis methods, test-facility design, and electrical systems and components. Dr. Chapin has participated in projects such as the Japan/Germany/United States research program on loss-of-coolant accidents; served as project leader for the design, construction, and testing of the loss of fluid test facility; been a member of the Electric Power Research Institute's (EPRI's) Utility Review Committee on Advanced Reactor Designs; and worked with the Utility/EPRI Advanced Light Water Reactor Program that defines utility requirements for future nuclear power plants. He was chair of the National Research Council's Committee on Application of Digital Instrumentation and Control Technology to Nuclear Power Plant Operations and Safety. He is currently a member of the NRC's Committee on Review of DOE's Nuclear Energy R&D Program, chair of the NRC's Board on Energy and Environmental Systems, and a member of the NAE's Committee on Membership. He formerly served as a member of the NAE's Electric Power/Energy Systems Engineering Peer Committee. He is also a fellow of the American Nuclear Society. Dr. Chapin has a B.S. in electrical engineering from Duke University, an M.S. in applied science from George Washington University, and a Ph.D. in nuclear studies in chemical engineering from Princeton University.

STEVEN CHU,[1] a recipient of the Nobel Prize for Physics (1997), was appointed by President Obama as Secretary of Energy and sworn into office on January 21, 2009. Dr. Chu has devoted his recent scientific career to the search for new solutions to our energy challenges and to stopping global climate change—a mission he continues with even greater urgency as Secretary of Energy. He is charged with helping to implement President Obama's ambitious agenda to invest in alternative and renewable energy, end U.S. addiction to foreign oil, address the global climate crisis, and create millions of new jobs. Prior to his appointment, Dr. Chu was director of the U.S. Department of Energy's Lawrence Berkeley National Laboratory and a professor of physics and professor of molecular and cell biology at the University of California, Berkeley. He has successfully applied the techniques he developed in atomic physics to molecular biology and, motivated by his deep interest in climate change, has in recent years led the Lawrence Berkeley National Lab in pursuit of new alternative and renewable energies. Previously, he held posi-

[1]Dr. Chu resigned from the committee on January 21, 2009.

tions at Stanford University and AT&T Bell Laboratories. Dr. Chu's research in atomic physics, quantum electronics, polymers, and biophysics includes tests of fundamental theories in physics, the development of methods to laser-cool and trap atoms, atom interferometry, and the manipulation and study of polymers and biological systems at the single-molecule level. While at Stanford, he helped start Bio-X, a multidisciplinary initiative that brings together the physical and biological sciences with engineering and medicine. Dr. Chu is a member of the National Academy of Sciences, the American Philosophical Society, the Chinese Academy of Sciences, Academica Sinica, the Korean Academy of Sciences and Technology, and numerous other professional and civic organizations. He holds an A.B. in mathematics and a B.S. degree in physics from the University of Rochester, a Ph.D. in physics from the University of California, Berkeley, and honorary degrees from 10 universities.

CHRISTINE A. EHLIG-ECONOMIDES, a member of the National Academy of Engineering, is a professor in the Harold Vance Department of Petroleum Engineering at Texas A&M University and holder of the Albert B. Stevens Chair in Petroleum Engineering. Before returning to academia, she worked for Schlumberger for 20 years. Dr. Ehlig-Economides is a distinguished member of the Society of Petroleum Engineers (SPE) and has held a variety of leadership positions in the society. In 1982 she was named the Alaska SPE Engineer of the Year and received the SPE Distinguished Achievement Award for Petroleum Engineering Faculty. She received the SPE Formation Evaluation Award in 1995 and the society's Lester C. Uren Award in 1997, and was named distinguished lecturer in 1997. Dr. Ehlig-Economides is also a member of Sigma Xi, The Scientific Research Society. She received a bachelor's degree in math-science from Rice University, a master's degree in chemical engineering from the University of Kansas, and a Ph.D. in petroleum engineering from Stanford University.

ROBERT W. FRI is a visiting scholar and senior fellow emeritus at Resources for the Future (RFF), where he served as president from 1986 to 1995. From 1996 to 2001, he was director of the National Museum of Natural History at the Smithsonian Institution. Before joining RFF, Mr. Fri served in both the public and the private sectors, specializing in energy and environmental issues. In 1971 he became the first deputy administrator of the U.S. Environmental Protection Agency. In 1975, President Ford appointed him deputy administrator of the U.S. Energy Research and Development Administration. He served as acting administrator of both agencies for extended periods. From 1978 to 1986, Mr. Fri headed his own company, Energy Transition Corporation. He began his career with McKinsey & Company, where he was elected a principal. A senior advisor to private, public, and nonprofit organizations, Mr. Fri is currently a member of the National Petroleum Council and of the Advisory Council of the Electric Power Research Institute. He is also vice chair of the National Research Council's (NRC's) Board on Energy and Environmental Systems. He has chaired several NRC committees, most recently the Committee on Review of DOE's Nuclear Energy R&D Program. Mr. Fri is a member of Phi Beta Kappa and Sigma Xi, The Scientific Research Society. He received a B.A. in physics from Rice University and an M.B.A. (with distinction) from Harvard University.

CHARLES H. GOODMAN has had a long career in electric utility research and development at Southern Company, primarily in establishing and improving coal-to-energy processes and in addressing the public policy issues associated with coal utilization. His contributions span heat transfer, emission controls, environmental science, and advanced generation technologies. Prior to retirement in 2007 he was the senior vice president for generation policy, with responsibilities that included serving as chair of the board for the FutureGen Industrial Alliance. Earlier, he was senior vice president for research and environmental policy—Southern Company's chief environmental officer. In that capacity he directed environmental research and development, environmental policy, and compliance-strategy efforts for Southern Company as it initiated cleaner and more efficient ways to meet the energy needs of its customers. Dr. Goodman served for many years on the Electric Power Research Institute's Research Advisory Committee and was chair of its Environment Sector Council. He is a member of the National Research Council's Board on Energy and Environmental Systems, the Energy and Environment Directorate Review Committee at Pacific Northwest National Laboratory, and the R&D Advisory Council for the Babcock and Wilcox Company. He has chaired the Environmental Staff Committee of the Business Roundtable, and he was a member of the U.S. Environmental Protection Agency's Clean Air Act Advisory Committee. His responsibilities included oversight of the Power Systems Development Facility—the United States' premier clean-coal-technology research center—in cooperation with the U.S. Department of Energy (DOE). In addition, he led the development and execution of four DOE Clean Coal Technology projects that provided new emission-control options, which have now been applied to the industry's conventional power plants. He is a life fellow in the American Society of

Mechanical Engineers. Dr. Goodman received an undergraduate degree from the University of Texas at Arlington and a master's degree and Ph.D. in mechanical engineering from Tulane University.

JOHN B. HEYWOOD, a member of the National Academy of Engineering, is Sun Jae Professor of Mechanical Engineering and director of the Sloan Automotive Laboratory at the Massachusetts Institute of Technology (MIT). Dr. Heywood's research has focused on engine combustion, pollutant formation, the operating emissions characteristics and fuel requirements of automotive and aircraft engines, and on reducing transportation's petroleum consumption and greenhouse gas emissions. He has served on a number of National Research Council committees, including the Committee on Review of the Research Program of the Partnership for a New Generation of Vehicles, and has consulted for many companies in the automotive and petroleum industries and for governmental organizations. Among the many awards he has received for his research contributions, Dr. Heywood was honored by the American Society of Mechanical Engineers, the British Institution of Mechanical Engineers, and the Society of Automotive Engineers. He has a Ph.D. in mechanical engineering from MIT, an Sc.D. from Cambridge University, and honorary doctorates from Chalmers University of Technology (Sweden) and City University (UK). He is a fellow of the American Academy of Arts and Sciences.

LESTER B. LAVE, a member of the Institute of Medicine, is the Harry B. and James H. Higgins Professor of Economics, a university professor, director of the Green Design Initiative, and codirector of the Electricity Industry Center at Carnegie Mellon University. Dr. Lave's teaching and research interests include applied economics, political economy, quantitative risk assessment, safety standards, modeling the effects of global climate change, public policy concerning greenhouse gas emissions, and issues surrounding the electric transmission and distribution system. A recipient of the Distinguished Achievement Award of the Society for Risk Analysis, he is a member of the National Research Council's Committee on Prospective Benefits of DOE's Energy Efficiency and Fossil Energy R&D Program Phase 2; he is also chair of the NRC's Panel on Benefits of Sequestration R&D. Dr. Lave has a B.S. in economics from Reed College and a Ph.D. in economics from Harvard University.

JAMES J. MARKOWSKY, a member of the National Academy of Engineering, is retired executive vice president of American Electric Power (AEP) Service Corporation, where he led the power-generation group and was responsible for providing overall administrative, operational, and technical direction to the AEP System's fossil and hydropower generating facilities, including fuel procurement and transportation, coal mining, planning, licensing, environmental engineering, design, construction, maintenance, and integrated operation of the fossil and hydro generation fleet. Dr. Markowsky served as chair of the National Research Council's Committee to Review DOE's Vision 21 R&D Program, Phase 1, and he was chair of the Committee on R&D Opportunities for Advanced Fossil-Fueled Energy Complexes. He was also a member of the NRC's Board on Energy and Environmental Systems and of its Energy Engineering Board. Dr. Markowsky received a B.S. in mechanical engineering from the Pratt Institute, master's degrees from Cornell University and the Massachusetts Institute of Technology, and a Ph.D. in mechanical engineering from Cornell University.

RICHARD A. MESERVE, a member of the National Academy of Engineering, is president of the Carnegie Institution for Science. He previously was chair of the U.S. Nuclear Regulatory Commission (USNRC; the federal agency with responsibility for ensuring public health and safety in the operation of nuclear power plants and usage of nuclear materials). He served as chair during the terms of Presidents Bill Clinton and George W. Bush and led the USNRC in responding to the terrorism threat after the 9/11 attacks. Before joining the USNRC, Dr. Meserve was a partner in the Washington, D.C., law firm of Covington & Burling, and he now serves as Senior of Counsel to the firm. Early in his career, he served as legal counsel to the president's science advisor and was law clerk to Justice Harry A. Blackmun of the U.S. Supreme Court and to Judge Benjamin Kaplan of the Massachusetts Supreme Judicial Court. Dr. Meserve has served on numerous legal and scientific committees over the years, including many established by the National Academy of Sciences and the National Academy of Engineering; currently he serves as chair of the Academies' Nuclear and Radiation Studies Board. He is chair of the International Nuclear Safety Group, which is chartered by the International Atomic Energy Agency, and serves as a member of the Harvard Board of Overseers. Among other affiliations, he is a member of the American Philosophical Society and a fellow of the American Academy of Arts and Sciences, the American Association for the Advancement of Science (AAAS), the American Physical Society, and Phi Beta Kappa. Dr. Meserve serves on the boards of directors of the

PG&E Corporation, Luminant Holding Co. LLC, the Universities Research Association, Inc., and the Council of the American Academy of Arts and Sciences. He has a bachelor's degree from Tufts University, a law degree from Harvard University, and a Ph.D. in applied physics from Stanford University.

WARREN F. MILLER, JR., a member of the National Academy of Engineering, is associate director of the Nuclear Security Science and Policy Institute at Texas A&M University. He has expertise in nuclear reactor analysis and theory, reactor design, radioactive waste management, transmutation of materials, and management of R&D programs. From 1974 to 2001 he held a number of positions at Los Alamos National Laboratory, including group leader for reactor and transport theory, deputy associate director for nuclear programs, associate laboratory director for energy programs, and deputy laboratory director for science and technology. Dr. Miller has held positions at the University of New Mexico, the University of Michigan, Howard University, the University of California, Berkeley, and Northwestern University. He is a fellow of the American Nuclear Society and a State of New Mexico Eminent Scholar (1989); he was honored as 2004 distinguished engineer by the National Society of Black Engineers. He has served on a variety of advisory groups and committees, including as vice chair of the National Research Council's Division of Earth and Life Sciences and as a member of the NRC's Committee on Long-Term Environmental Quality Research and Development. Dr. Miller was a member of the NRC's Nuclear and Radiation Studies Board and the NRC Committee on Review of DOE's Nuclear Energy R&D Program. He served on the U.S. Department of Energy's Nuclear Energy Research Advisory Committee from 1997 to 2006. He has a B.S. in engineering sciences from the United States Military Academy at West Point and M.S. and Ph.D. degrees in engineering sciences from Northwestern University.

FRANKLIN M. (**"LYNN"**) **ORR, JR.**, a member of the National Academy of Engineering, became director of the Precourt Institute for Energy at Stanford University upon its establishment in 2009. He served as director of Stanford's Global Climate and Energy Project from 2002 to 2008, was the Chester Naramore Dean of the university's School of Earth Sciences from 1994 to 2002, and has been a member of the faculty since 1985. Dr. Orr's research activities involve the flow of complex fluid mixtures in the porous rocks of Earth's crust; the design of gas-injection processes for enhanced oil recovery; and CO_2 storage in subsurface formations. He is a member of the board of directors of the Monterey Bay Aquarium

Research Institute and was a board member of the David and Lucile Packard Foundation from 1999 to 2008; he now chairs the foundation's Science Advisory Committee. Dr. Orr received a B.S. in chemical engineering from Stanford University and a Ph.D. in chemical engineering from the University of Minnesota.

LAWRENCE T. PAPAY, a member of the National Academy of Engineering, is currently a consultant with a variety of clients in electric power and other energy areas. His expertise and knowledge span a wide variety of electric system technologies, including production, transmission and distribution, utility management and systems, and end-use. He has served as senior vice president for the integrated solutions sector of Science Applications International Corporation and as senior vice president and general manager of Bechtel Technology and Consulting. Dr. Papay also held several positions at Southern California Edison, including senior vice president, vice president, general superintendent, and director of research and development, with responsibilities for bulk power generation, system planning, nuclear power, environmental operations, and development of the organization and plans for the company's R&D efforts. Among his other professional affiliations, past and present, are the Electric Power Research Institute's Research Advisory Committee; the Atomic Industrial Forum; the U.S. Department of Energy's Energy Research Advisory Board, Lab Operations Board, and Environmental Management Advisory Board; the Department of Homeland Security's Science and Technology Advisory Board; numerous National Academies' boards and committees, including the National Academy of Engineering's Board of Councillors; and the Renewable Energy Institute. Dr. Papay received a B.S. in physics from Fordham University and S.M. and Sc.D. degrees in nuclear engineering from the Massachusetts Institute of Technology.

ARISTIDES A.N. PATRINOS is president of Synthetic Genomics, Inc. (SGI), a privately held company founded in 2005 that is devoted to applying genomic-driven commercial solutions to global energy and environmental challenges. Prior to joining SGI, he was instrumental in advancing the scientific and policy framework underpinning key governmental energy and environmental initiatives while serving as director of the Office of Biological and Environmental Research in the Department of Energy's (DOE) Office of Science. Dr. Patrinos oversaw the department's research activities in human and microbial genome research, structural biology, nuclear medicine, and climate change. Previously Dr. Patrinos worked at several DOE National Laboratories and the University of Rochester. The recipient of numerous awards and honorary degrees, including three presidential-rank awards for meritorious and distinguished service and two Secretary of Energy gold medals, Dr. Patrinos is a fellow of the American Association for the Advancement of Science and the American Meteorological Society, and is a member of the American Society of Mechanical Engineers, the American Geophysical Union, and the Greek Technical Society. Dr. Patrinos received a diploma in mechanical and electrical engineering from the National Technical University of Athens and a Ph.D. in mechanical and astronautical sciences from Northwestern University.

MICHAEL P. RAMAGE, a member of the National Academy of Engineering, is a retired executive vice president of ExxonMobil Research and Engineering Company. Previously he was executive vice president, chief technology officer, and director of Mobil Oil Corporation. Dr. Ramage held a number of positions at Mobil, including research associate, manager of process research and development, general manager of exploration and producing research and technical services, vice president of engineering, and president of Mobil Technology Company. He has broad experience in many aspects of the petroleum and chemical industries. Dr. Ramage has served on a number of university visiting committees, was a director of the American Institute of Chemical Engineers, and now is a member of Secretary of Energy Chu's Hydrogen Technical Advisory Council. He is a member of several professional organizations and serves on the Energy Advisory Board of Purdue University. Dr. Ramage was a member of the National Academies' Government-University-Industry Research Roundtable. He chaired the National Research Council (NRC) committees responsible for the reports *The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs* and *Resource Requirements for a Hydrogen Economy*. He is currently chairing the NRC Panel on Alternative Liquid Transportation Fuels. Dr. Ramage has B.S., M.S., Ph.D., and H.D.R. degrees in chemical engineering from Purdue University.

MAXINE L. SAVITZ, vice president of the National Academy of Engineering, is a director of the Washington Advisory Group. A former deputy assistant secretary for conservation at the U.S. Department of Energy (DOE), she received the department's Outstanding Service Medal in 1981. Prior to her DOE service, she was a program manager for research applied to national needs at the National Science Foundation. Following her government service, Dr. Savitz held executive positions in the private sector—including president of the Lighting Research Institute, assistant to the vice president for engineering at the Garrett Corporation, and general manager of AlliedSignal Ceramic Components. She recently retired from the position of general manager for technology partnerships at Honeywell. Dr. Savitz serves on advisory bodies for Sandia National Laboratories and Pacific Northwest National Laboratory. She serves on the board of directors of the Draper Laboratory and the American Council for an Energy Efficient Economy. She was recently appointed to the President's Council of Advisors for Science and Technology. Dr. Savitz received a B.A. in chemistry from Bryn Mawr College and a Ph.D. in organic chemistry from the Massachusetts Institute of Technology.

ROBERT H. SOCOLOW is a professor of mechanical and aerospace engineering at Princeton University, where he has been a faculty member since 1971. He was previously an assistant professor of physics at Yale University. Dr. Socolow currently codirects Princeton's Carbon Mitigation Initiative, a multidisciplinary investigation of fossil fuels in a future carbon-constrained world. From 1979 to 1997, he directed Princeton's Center for Energy and Environmental Studies and contributed significantly to progress in energy efficiency technologies, policy, and applications. Dr. Socolow has served on many National Research Council boards and committees, including the Committee on R&D Opportunities for Advanced Fossil-Fueled Energy Complexes, the Committee on Review of DOE's Vision 21 R&D Program, and the Board on Energy and Environmental Systems. He is a fellow of the American Physical Society and the American Association for the Advancement of Science. Dr. Socolow has B.A., M.A., and Ph.D. degrees in physics from Harvard University.

JAMES L. SWEENEY, Stanford University, is director of Stanford University's Precourt Energy Efficiency Center, professor of management science and engineering, senior fellow of the Stanford Institute for Economic Policy Research, and senior fellow of the Hoover Institution. His professional activities focus on economic policy and analysis, particularly regarding energy, natural resources, and the environment. Dr. Sweeney served as chair of the Stanford Department of Engineering-Economic Systems, chair of the Department of Engineering-Economic Systems and Operations Research, director of the Energy Modeling Forum, chair of the Institute for Energy Studies, and director of the Center for Economic Policy Research. He was a founding member of the International Association for Energy Economics, served as director of the Office of Energy Systems Modeling and Forecasting of the U.S. Federal Energy Administration, has been a member of numerous committees of the National Research Council, and is a lifetime National Associate of the National Academies. Dr. Sweeney is a senior fellow of the U.S. Association for Energy Economics and a council member and senior fellow of the California Council on Science and Technology; he is also a member of the External Advisory Council of the National Renewable Energy Laboratory and a member of Governor Arnold Schwarzenegger's Council of Economic Advisors. He holds a B.S. in electrical engineering from the Massachusetts Institute of Technology and a Ph.D. in engineering-economic systems from Stanford University.

G. DAVID TILMAN, a member of the National Academy of Sciences, is Regents' Professor and McKnight Presidential Chair in Ecology at the University of Minnesota. His research explores how to meet human needs for energy, food, and ecosystem services sustainably. He is a member of the American Academy of Arts and Sciences, a J.S. Guggenheim Fellow, and a recipient of the Ecological Society of America's Cooper Award, the ESA's MacArthur Award, the Botanical Society of America's Centennial Award, and the Princeton Environmental Prize. He has written two books, edited three others, and published more than 200 scientific papers, including more than 30 in *Science*, *Nature*, and the *Proceedings of the National Academy of Sciences*. For the past 18 years, the Institute for Scientific Information has ranked him as the world's most-cited environmental scientist. In 2008, the emperor of Japan presented him with the International Prize for Biology.

C. MICHAEL WALTON, a member of the National Academy of Engineering, is a professor of civil engineering and holds the Ernest H. Cockrell Centennial Chair in Engineering at the University of Texas at Austin. In addition, he holds a joint academic appointment in the Lyndon B. Johnson School of Public Affairs. He is a past chair and member of the Transportation Research Board (TRB) Executive Committee. As the National Research Council chair of the TRB Division he serves as an ex-officio member of the Governing Board of the NRC. He is a past chair of the board of the American Road and Transportation Builders Association, past member of the Board of Governors of the Transportation and Development Institute of the American Society of Civil Engineers, and a founding member and past chair of the board of the Intelligent Transportation Society (ITS) of America. Dr. Walton has published widely and received numerous honors and awards for his research in the areas of ITS, freight transport, and transportation engineering, planning, policy, and economics. Dr. Walton has a B.S. from the Virginia Military Institute and M.S. and Ph.D. degrees from North Carolina State University, all in civil engineering.

STAFF

KEVIN D. CROWLEY (*Study Director*) is senior board director of the Nuclear and Radiation Studies Board, which advises the National Academies on the design and conduct of studies on radiation health effects, radioactive-waste management and environmental cleanup, and nuclear security and terrorism. The board also provides scientific support to the Radiation Effects Research Foundation in Hiroshima, Japan, a joint U.S.-Japanese scientific organization that investigates the health effects arising from exposures to ionizing radiation among World War II atomic-bombing survivors. Dr. Crowley's professional interests and activities focus on the safety, security, and technical efficacy of nuclear and radiation-based technologies. He has directed or codirected some 20 National Research Council (NRC) studies, including *Safety and Security of Commercial Spent Nuclear Fuel Storage* (2005); *Going the Distance: The Safe Transport of Spent Nuclear Fuel and High-Level Radioactive Waste in the United States* (2006); and *Medical Isotope Production without Highly Enriched Uranium* (2009). Before joining the NRC staff, Dr. Crowley held teaching/research positions at Miami University of Ohio, the University of Oklahoma, and the U.S. Geological Survey. He received his Ph.D. in geology from Princeton University.

PETER D. BLAIR is executive director of the Division on Engineering and Physical Sciences of the National Academies and is responsible for overall management of the America's Energy Future portfolio of studies. At the time of his appointment in January 2001 he was executive director of Sigma Xi, The Scientific Research Society. From 1983 to 1996, he served in several capacities at the Congressional Office of Technology Assessment, concluding as assistant director of the agency and director of the Division of Industry, Commerce and International Security. Dr. Blair has served on the faculties of the University of Pennsylvania (1976–1996) and the University of North Carolina at Chapel Hill (1997–2001). He was cofounder in 1978 and principal of Technecon Research, Inc., an engineering-economic consulting and power generation projects firm in Philadelphia, Pennsylvania, acquired by the Reading Energy Corporation in 1985. Dr. Blair holds a B.S. in engineering from Swarthmore College (1973), an M.S.E. in systems engineering (1974) and M.S. (1975) and Ph.D. (1976) degrees in energy management and policy from the University of Pennsylvania. He is the author or coauthor of three books and more than 100 technical articles in the areas of energy and environmental policy, electric power systems, operations research, regional science, and economic systems.

SARAH C. CASE joined the National Research Council in December 2007 and is currently a program officer in the Nuclear and Radiation Studies Board. In that capacity she has worked primarily with the study committee on America's Energy Future, facilitating the committee's work on nuclear energy and the electric transmission and distribution systems. Before arriving at the NRC, Dr. Case conducted research in condensed-matter physics, studying the collective behavior of ordinary materials such as fluids and granular material at the point of transition between states. Her research focused primarily on the physics of fluid topological transitions (such as droplet coalescence and drop snap-off). She has also conducted research in experimental high-energy particle physics, primarily in "beyond the Standard Model" particle searches and in neutrino physics. She was an NRC Christine Mirzayan Science and Technology Policy Fellow in the fall of 2007. Dr. Case received an A.B. in physics from Columbia University and M.S. and Ph.D. degrees in physics from the University of Chicago.

ALAN T. CRANE is a senior program officer at the National Research Council. He has directed projects that analyzed fuel-cell vehicle development, electric power systems, alternatives to the Indian Point nuclear power station, and fuel-economy standards for cars and light trucks. He has also contributed to other projects on energy R&D and on countering terrorism against energy systems and urban infrastructure. Prior to his current position, Mr. Crane was an independent consultant on energy, environmental, and technology issues for government and private-sector clients. He was also a senior associate at the Congressional Office of Technology Assessment, where he directed projects on energy policy and international technology transfer. During sabbaticals from OTA he served as director of energy and environmental studies at the European Institute of Technology, visiting researcher at the Oak Ridge National Laboratory, and visiting professor at Dartmouth College. His earlier work included engineering and managerial positions in the nuclear power industry. Mr. Crane has a B.S. from Haverford College and an M.S.M.E. from New York University.

GREG EYRING received a B.S. in chemistry from Stanford University in 1976 and a Ph.D. in chemistry from the University of California, Berkeley, in 1981. After doing 3 years of postdoctoral research at Stanford University, he joined the congressional Office of Technology Assessment (OTA), where he directed several studies related to advanced materials and environmental aspects of the use of materials. After the demise of OTA in 1995, Dr. Eyring worked as an independent consultant before joining the National Research Council in 2006. His work at the NRC has included studies on chemical weapons, explosives, and military- and intelligence-related technologies.

K. JOHN HOLMES has served as a study director at the National Research Council for the past 10 years. In this position he has been responsible for directing committee studies on contentious environmental and energy issues, particularly those related to motor vehicles, energy, air quality, and the quantitative analysis of policy impacts. Dr. Holmes is currently a senior staff officer at the Board on Energy and Environmental Systems, where he is responsible for the NRC Committee on Fuel Economy Technologies for Light Duty Vehicles. Dr. Holmes received his B.S. from Indiana University, an M.S.E. from the University of Washington, and a Ph.D. from the Johns Hopkins University. His doctoral dissertation focused on integrated assessment modeling of climate change and other environmental system impacts.

THOMAS R. MENZIES is a senior program officer in the Transportation Research Board's (TRB) policy studies unit. In this capacity, he manages studies on transportation-related programs and policies called for by the U.S. Congress and sponsored by the U.S. Department of Transportation, U.S. Department of Homeland Security, National Aeronautics and Space Administration, and other federal agencies. Since joining TRB in 1987 he has staffed more than two dozen projects examining the economic, safety, security, environmental, and energy performance of the aviation, rail, maritime, transit, trucking, and automotive sectors. Reports from relevant studies of energy performance include *Tires and Passenger Vehicle Fuel Economy*, *Toward a Sustainable Future: Addressing the Long-term Effects of Motor Vehicle Transportation on Climate and Ecology*, and an ongoing assessment of policy options for reducing energy use and greenhouse gas emissions from transportation. He has published numerous articles in technical journals and has made presentations on study results, and he serves on the editorial board of *TRNews*. He earned a bachelor's degree in economics from Colby College and an M.A. in public policy and public finance from the University of Maryland.

EVONNE P.Y. TANG is a senior program officer at the National Research Council. She has served as study director for multiple projects, on subjects ranging from science policy to research and development, since she joined the National Academies in 2002. Dr. Tang's areas of expertise include ecology, genomics, and biofuels. Among her recently completed projects are the studies *Liquid Transportation Fuels from Coal and Biomass* (2009), *Achievements of the National Plant Genome Initiative and New Horizons in Plant Biology* (2008), *Protecting Building Occupants and Operations from Biological and Chemical Airborne Threats* (2007), and *Status of Pollinators in North America* (2007). Dr. Tang received a B.Sc. from the University of Ottawa, an M.Sc. from McGill University, and a Ph.D. from Laval University, Canada. Her doctoral dissertation focused on the ecophysiology of cyanobacteria and the use of cyanobacteria in tertiary wastewater-treatment systems. After completion of her doctorate, she received postdoctoral fellowships from the Smithsonian Institution, the National Research Council Canada, and the Quebec Ministry of Education.

MADELINE G. WOODRUFF, a senior program officer at the National Research Council's Board on Energy and Environmental Systems, is responsible for the AEF Panel on Energy Efficiency Technologies. Prior to joining the NRC she spent 8 years as a senior analyst and project manager at the International Energy Agency in Paris, France, focusing on evaluation of energy technology R&D policy and programs, both domestic and international, and assessment of the potential for energy technology to contribute to reducing greenhouse gas emissions. Earlier, Ms. Woodruff was a senior analyst at the Pacific Northwest National Laboratory, where she managed or contributed to projects on nuclear energy regulatory policy, storage of plutonium recovered from retired nuclear weapons, regulation of mixed radioactive and chemical wastes, industrial energy efficiency, and energy technology R&D. Ms. Woodruff received an M.S. in nuclear engineering and an M.S. in technology and policy from the Massachusetts Institute of Technology, where she was a National Academy of Sciences Graduate Fellow.

JAMES J. ZUCCHETTO is director of the Board on Energy and Environmental Systems, National Research Council. Since joining the NRC in 1985, Dr. Zucchetto has been involved in a variety of multidisciplinary studies related to energy technologies, engineering, the environment, research and development programs, and public policy. In his work at the NRC, he has contributed to numerous studies and reports with an important influence on federal programs and policies, including on technologies for improving the fuel economy of light-duty and heavy-duty vehicles and for producing liquid fuels from a variety of fossil and nonfossil resources; hydrogen production; fuel-cell vehicles; and electricity generation, transmission and distribution, as well as related policy analyses and issues. Prior to joining the NRC, he was on the faculty of Arts and Sciences, Department of Regional Science, University of Pennsylvania; a guest researcher at the Institute of Marine Ecology and Zoologiska Institutionen, University of Stockholm; an associate in engineering, Department of Environmental Engineering Sciences, University of Florida; and a member of the technical staff, Bell Telephone Laboratories. He serves on the editorial advisory board of the International Journal of Ecological Modelling and Systems Ecology and is a former member of the editorial advisory board of Ecological Economics. In addition to work and research on energy technologies and associated environmental, economic, and policy implications since the early 1970s, he has also worked in the area of systems ecology and ecological modeling. He has published approximately 50 articles in refereed journals, books, and conference proceedings, two monographs, and one book. He has a Ph.D. in environmental engineering sciences from the University of Florida, an M.S.M.E. from New York University, and a B.S.M.E. from the Polytechnic Institute of Brooklyn (Polytechnic University).

Editorial Consultant

STEVEN J. MARCUS, an independent editor specializing in science, technology, and health policy, edited the America's Energy Future report. Prior to establishing his own practice in 2001, he was editor in chief of MIT's *Technology Review,* editor in chief of the National Academies' *Issues in Science and Technology*, executive editor of *High Technology*, science/medicine editor of the *Minneapolis Star Tribune,* and technology reporter for the *New York Times*. Prior to becoming a journalist, Dr. Marcus worked as a systems engineer for the MITRE Corporation and as an environmental engineering consultant. Under a Fulbright Lecturer grant, he taught courses on environmental issues at the University of Paris. He holds a bachelor's degree in electrical engineering from the City College of New York and a Ph.D. in environmental sciences and engineering from Harvard University.

B Meeting Participants

The following individuals provided information for this study through their participation in subgroup meetings of the America's Energy Future Committee and in the Summit on America's Energy Future (see Appendix C).

ALTERNATIVE TRANSPORTATION FUELS SUBGROUP MEETINGS

Rich Bain, National Renewable Energy Laboratory (NREL)
Bruce Dale, Michigan State University
Otto Doering, Purdue University
Jonathan Foley, University of Wisconsin, Madison
Amory Lovins, Rocky Mountain Institute
Maggie Mann, NREL
James Newcomb, Rocky Mountain Institute
Robert Perlack, Oak Ridge National Laboratory
Sam Tabak, Exxon Mobil
Samuel Tam, Headwaters
Theodore Wegner, U.S. Department of Agriculture Forest Service
Robert Williams, Princeton University

ELECTRICITY TRANSMISSION AND DISTRIBUTION SUBGROUP MEETINGS

David Andrejcak, Federal Energy Regulatory Commission (FERC)
George Bjelovuk, American Electric Power
Paul Centolella, Ohio Public Utility Commissioner
Joe Eto, Lawrence Berkeley National Laboratory (LBNL)
Gerald FitzPatrick, National Institute of Standards and Technology
Craig Glazer, PJM Interconnection
Chris Gomperts, Siemens
Patricia Hoffman, U.S. Department of Energy (DOE)
Lawrence Jones, Areva Transmission and Distribution
Stephen Lee, Electric Power Research Institute (EPRI)
Ron Litzinger, Southern California Edison
Richard Lordan, EPRI
John McDonald, General Electric (GE)
Ken Nemeth, Southern States Energy Board
Dave Nevius, North American Electrical Reliability Council
Dave Owens, Edison Electric Institute
Steve Pullins, Horizon Energy Group
Edmund O. Schweitzer III, Schweitzer Engineering Laboratories, Inc.
Le Tang, ABB, Inc.

ENERGY EFFICIENCY SUBGROUP MEETINGS

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John Heywood, Massachusetts Institute of Technology (MIT)
Kathleen Hogan, U.S. Environmental Protection Agency
Revis W. James, EPRI
Douglas Kaempf, DOE
Mark Levine, LBNL
Fred Moore, The Dow Chemical Company
Steve Nadel, American Council for an Energy Efficient Economy
Jaana Remes, McKinsey Global Institute
David Rodgers, DOE
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Steven Smith, Pacific Northwest National Laboratory (PNNL)

FOSSIL ENERGY SUBGROUP MEETINGS

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Jim Dooley, PNNL
Julio Friedmann, Lawrence Livermore National Laboratory
James Katzer, ExxonMobil Research and Engineering Company (retired)
Granger Morgan, Carnegie Mellon University
John Novak, EPRI
Scott Tinker, University of Texas, Austin

NUCLEAR ENERGY SUBGROUP MEETINGS

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Ralph Bennett, Idaho National Laboratory (INL)
Tom Cochran, National Resources Defense Council
Philip Finck, INL
Jim Harding, Consultant
Adrian Heymer, Nuclear Energy Institute (NEI)
Valentin Ivanov, State Duma Energy Committee, Russia
Revis James, EPRI
Elizabeth King, NEI
Paul Lisowski, DOE
Arjun Makhijani, Institute for Energy and Environmental Research
Michael Mariotte, Nuclear Information and Resource Service
Ernest J. Moniz, MIT
Richard Myers, NEI
John Parsons, MIT
Per Peterson, University of California, Berkeley
Dennis Spurgeon, DOE
Gordon Thompson, Institute for Resource and Security Studies

RENEWABLE ENERGY SUBGROUP MEETINGS

Dan Arvizu, NREL
Alan Beamon, Energy Information Administration (EIA)

Jacques Beaudry-Losique, DOE
Peter Bierden, GE
J. Michael Canty, DOE
Steve Chalk, DOE
Craig Cornelius, DOE
Mike Grable, ERCOT
Imre Gyuk, DOE
Pat Hoffman, DOE
Christopher King, U.S. House of Representatives Science and Technology Committee Staff
Martha Krebs, California Energy Commission
Ben Kroposki, NREL
Steve Lindenberg, DOE
Ann Miles, FERC
JoAnn Milliken, DOE
Christopher Namovicz, EIA
Pedro Pizarro, Southern California Edison
Dan Rastler, EPRI
Adam Rosenberg, U.S. House of Representatives Science and Technology Committee Staff
J. Charles Smith, The Utility Wind Integration Group
Steven Smith, PNNL
Jeff Tester, MIT
Ryan Wiser, LBNL

SUMMIT ON AMERICA'S ENERGY FUTURE

Jeff Bingaman, U.S. Senate
Samuel W. Bodman, DOE
Jon Creyts, McKinsey and Company
Ged Davis, World Economic Forum
Jose Goldemberg, International Institute for Applied Systems Analysis
John P. Holdren, Harvard University
Reuben Jeffery III, U.S. Department of State
Amory Lovins, Rocky Mountain Institute
Robert Marlay, DOE

Ernest J. Moniz, MIT
Rod Nelson, National Petroleum Council
Raymond L. Orbach, DOE
Paul R. Portney, University of Arizona
Dan W. Reicher, Google.org
James R. Schlesinger, MITRE Corporation and Lehman Brothers
Steven R. Specker, EPRI
Charles M. Vest, National Academy of Engineering

C America's Energy Future Project

In 2007, the National Academies initiated the America's Energy Future (AEF) project (Figure C.1) to facilitate a productive national policy debate about the nation's energy future. The Phase I study, headed by the Committee on America's Energy Future and supported by the three separately constituted panels whose members are listed in this appendix, will serve as the foundation for a Phase II portfolio of subsequent studies at the Academies and elsewhere, to be focused on strategic, tactical, and policy issues, such as energy research and development priorities, strategic energy technology development, policy analysis, and many related subjects.

PANEL ON ENERGY EFFICIENCY TECHNOLOGIES

LESTER B. LAVE, Carnegie Mellon University, *Chair*
MAXINE L. SAVITZ, Honeywell, Inc. (retired), *Vice Chair*
R. STEPHEN BERRY, University of Chicago
MARILYN A. BROWN, Georgia Institute of Technology
LINDA R. COHEN, University of California, Irvine
MAGNUS G. CRAFORD, LumiLeds Lighting
PAUL A. DECOTIS, Long Island Power Authority
JAMES DEGRAFFENREIDT, JR., WGL Holdings, Inc.
HOWARD GELLER, Southwest Energy Efficiency Project
DAVID B. GOLDSTEIN, Natural Resources Defense Council
ALEXANDER MACLACHLAN, E.I. du Pont de Nemours & Company (retired)

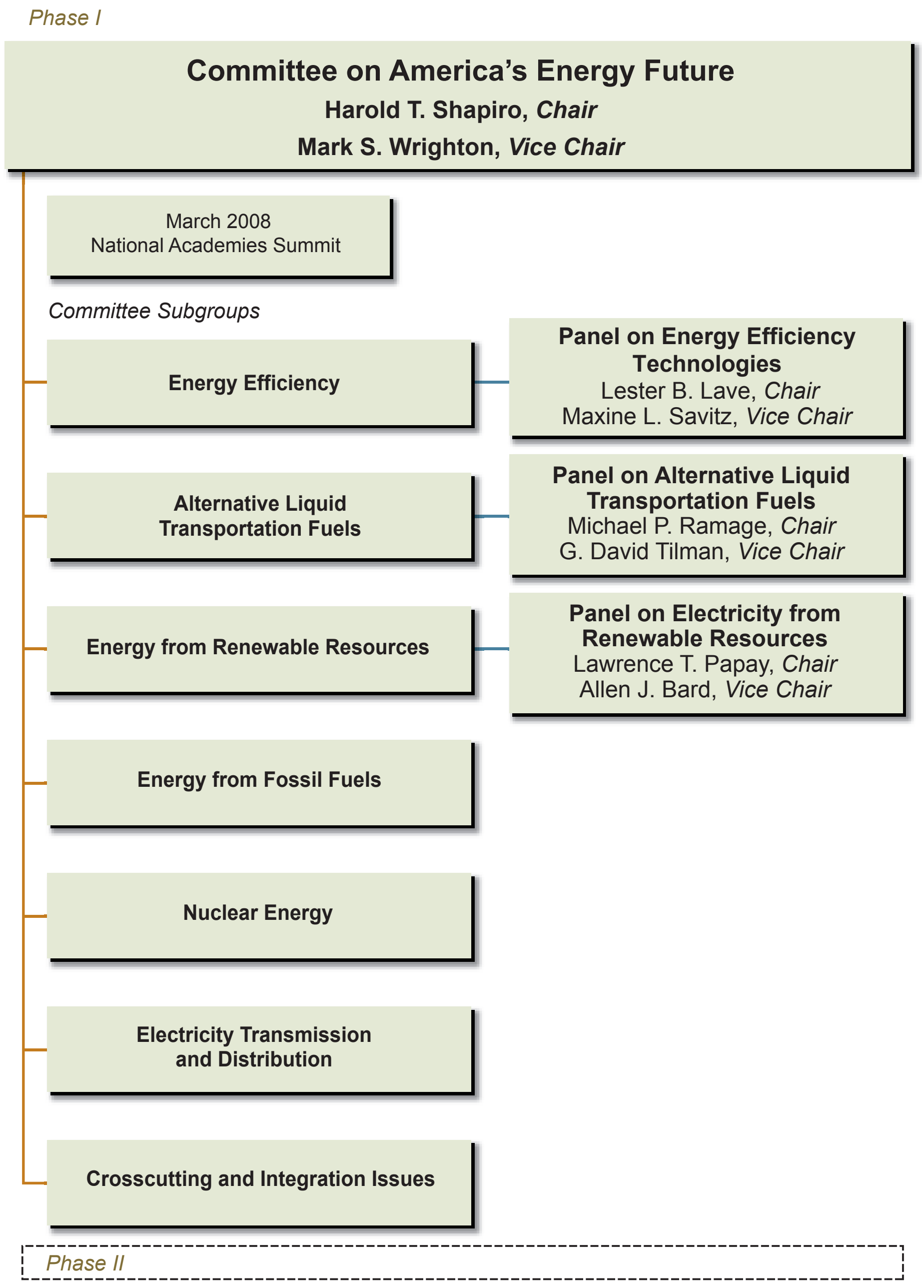

FIGURE C.1 *America's Energy Future Project.*

WILLIAM F. POWERS, Ford Motor Company (retired)
ARTHUR H. ROSENFELD, California Energy Commission
DANIEL SPERLING, University of California, Davis

PANEL ON ALTERNATIVE LIQUID TRANSPORTATION FUELS

MICHAEL P. RAMAGE, ExxonMobil Research and Engineering Company (retired), *Chair*
G. DAVID TILMAN, University of Minnesota, St. Paul, *Vice Chair*
DAVID GRAY, Noblis, Inc.
ROBERT D. HALL, Amoco Corporation (retired)
EDWARD A. HILER, Texas A&M University (retired)
W.S. WINSTON HO, Ohio State University
DOUGLAS R. KARLEN, U.S. Department of Agriculture, Agricultural Research Service
JAMES R. KATZER, ExxonMobil Research and Engineering Company (retired)
MICHAEL R. LADISCH, Purdue University and Mascoma Corporation
JOHN A. MIRANOWSKI, Iowa State University
MICHAEL OPPENHEIMER, Princeton University
RONALD F. PROBSTEIN, Massachusetts Institute of Technology
HAROLD H. SCHOBERT, Pennsylvania State University
CHRISTOPHER R. SOMERVILLE, Energy Biosciences Institute
GREGORY STEPHANOPOULOS, Massachusetts Institute of Technology
JAMES L. SWEENEY, Stanford University

PANEL ON ELECTRICITY FROM RENEWABLE RESOURCES

LAWRENCE T. PAPAY, Science Applications International Corporation (retired), *Chair*
ALLEN J. BARD, University of Texas, Austin, *Vice Chair*
RAKESH AGRAWAL, Purdue University
WILLIAM L. CHAMEIDES, Duke University
JANE H. DAVIDSON, University of Minnesota, Minneapolis
J. MICHAEL DAVIS, Pacific Northwest National Laboratory
KELLY R. FLETCHER, General Electric

CHARLES F. GAY, Applied Materials, Inc.
CHARLES H. GOODMAN, Southern Company (retired)
SOSSINA M. HAILE, California Institute of Technology
NATHAN S. LEWIS, California Institute of Technology
KAREN L. PALMER, Resources for the Future, Inc.
JEFFREY M. PETERSON, New York State Energy Research and Development Authority
KARL R. RABAGO, Austin Energy
CARL J. WEINBERG, Pacific Gas and Electric Company (retired)
KURT E. YEAGER, Galvin Electricity Initiative

D Principal Units and Conversion Factors

This report uses a variety of units to describe the supply and consumption of energy. Although these units are in common usage throughout the energy industry, they are generally not well understood by nonexperts. This appendix describes the principal supply and consumption units and provides some useful conversion factors. The Department of Energy–Energy Information Administration's website (see www.eia.doe.gov/basics/conversion_basics.html) provides additional information about energy units and conversion factors, including easy-to-use energy conversion calculators.

ELECTRICITY

- **Electrical generating capacity** is expressed in units of *kilowatts* (kW), *megawatts* (MW = 10^3 kW), and *gigawatts* (GW = 10^6 kW). It is defined as the maximum electrical output that can be supplied by a generating facility operating at ambient conditions. Coal power plants typically have generation capacities of about 500 MW; nuclear plants about 1000 MW (1 GW); intermittent sources (e.g., natural gas peaking plants and wind plants) about one to a few megawatts; and residential roof-top installations of solar photovoltaics about a few kilowatts.
- **Electricity** supply and consumption are expressed in units of *kilowatt-hours* (kWh), *megawatt-hours* (MWh = 10^3 kWh), *gigawatt-hours* (GWh = 10^6 kWh), and *terawatt-hours* (TWh = 10^9 kWh). One kilowatt-hour is equal to the energy of 1000 watts (the typical amount of elec-

tricity that is consumed by a handheld hair dryer) supplied or consumed over a period of 1 hour. Annual total delivered electricity in the United States is about 4,000 TWh, and the average annual electricity consumption per U.S. household is about 11,000 kWh.

FOSSIL FUELS AND OTHER LIQUID FUELS

- **Coal** supply and consumption are usually expressed in units of *metric tons* (tonnes); 1 metric ton is equal to about 2205 pounds. A typical coal-fired power plant consumes about 2 million tonnes of coal per year, and annual coal consumption in the United States is about 1 billion tonnes per year. Coal prices are expressed in units of *dollars per gigajoule* ($/GJ). A tonne of coal contains about 23.5 GJ of energy.
- **Petroleum and gasoline** supply and consumption are expressed in units of *barrels* (bbl); a barrel contains 42 U.S. gallons or 159 liters. Units of barrels of gasoline equivalent (bbl gasoline eq) represent the energy content of **other liquid fuels** (e.g., ethanol) in terms of the energy content of a barrel of motor gasoline. The United States consumes about 9 million barrels of motor gasoline per day and over 7 billion barrels of liquid fuels (crude oil, finished products, and other liquid fuels) per year.
- **Natural gas** supply and consumption are expressed in units of *trillion cubic feet* (Tcf). The United States consumes about 23 Tcf of natural gas each year.
- **Biomass** supply for liquid fuels production is expressed in units of dry tonnes; 1 dry tonne is equal to about 2205 pounds. The dry ton equivalent is 2000 pounds.

ENERGY CONVERSION FACTORS

- **Total energy** supply and consumption are expressed in *British thermal units* (Btu) and *quads* (quadrillion Btu = 10^{15} Btu). A Btu is defined as the amount of energy (in the form of heat) needed to raise the temperature of 1 pound of water by 1 degree Fahrenheit. The energy content of electricity and natural gas, liquid, and coal fuels can be quantified in terms of Btu using the following approximate factors:

1 kilowatt-hour electricity = 3,412 Btu
1 barrel crude oil = 5,800,000 Btu
1 barrel gasoline = 5,200,000 Btu
1 barrel fuel ethanol = 3,500,000 Btu
1 cubic foot of natural gas = 1,028 Btu
1 tonne coal = 22,230,000 Btu

The United States consumes about 100 quads (100×10^{15} Btu) of energy per year (see Figure 1.2 in Chapter 1).

GREENHOUSE GASES

- **Carbon dioxide (CO_2)** emissions from energy production and use are expressed in tonnes. The term *tonnes of CO_2 equivalent* (CO_2 eq) indicates the global warming potential of other greenhouse gases (e.g., methane) in terms of CO_2 quantities. The United States emits about 7 billion tonnes of CO_2 eq per year, about 6 billion of which is CO_2 arising primarily from energy production and use (see Figure 1.3 in Chapter 1). Average CO_2 emissions in the United States are about 20 tonnes per person.

E Select Acronyms and Abbreviations

3D	three-dimensional
AAAS	American Association for the Advancement of Science
AC	alternating current
AEF	America's Energy Future
AEO	Annual Energy Outlook
AEP	American Electric Power Corporation
ASES	American Solar Energy Society
bbl	barrel
bbl/d	barrel(s) per day
BEV	battery-electric vehicle
BTL	biomass-to-liquid
Btu	British thermal unit
C	Celsius
CAFE	corporate average fuel economy
CBTL	coal-and-biomass-to-liquid
CBFT	coal-and-biomass-to-liquid fuel, Fischer-Tropsch
CBMTG	coal-and-biomass-to-liquid fuel, methanol-to-gasoline
CCE	cost of conserved energy
CCS	carbon capture and storage
Cf	californium
CFC	chlorofluorocarbons
CFR	Code of Federal Regulations

CFT	coal-to-liquid fuel, Fischer-Tropsch
CH_4	methane
CMTG	coal-to-liquid fuel, methanol-to-gasoline
CO_2	carbon dioxide
CO_2 eq	carbon dioxide equivalent
COL	construction and operating license
CSP	concentrating solar power
CTL	coal-to-liquid fuel
DC	direct current
DI&C	digital instrumentation and control
DNA	deoxyribonucleic acid
DOE	U.S. Department of Energy
DSM	demand-side management
EAF	electric-arc furnace
EEB	Energy Engineering Board
EGR	enhanced gas recovery
EIA	Energy Information Administration
EISA	Energy Independence and Security Act
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
EU	European Union
F	Fahrenheit
FACTS	Flexible Alternating Current Transmission System
FFB	Federal Financing Bank
GDP	gross domestic product
GE	General Electric
GHG	greenhouse gas
GJ	gigajoule
Gt	gigatonne
GW	gigawatt
GWh	gigawatt-hour
H_2	hydrogen

H_2O	water
H_2S	hydrogen sulfide
HEV	hybrid-electric vehicle
HFCV	hydrogen fuel-cell vehicle
IDST	improved decision-support technology
IGCC	integrated gasification combined cycle
INL	Idaho National Laboratory
IOU	investor-owned utility
IPCC	Intergovernmental Panel on Climate Change
IPP	independent power producer
ISL	in situ leach
ITS	Intelligent Transportation Society
IUPAC	International Union of Pure and Applied Chemists
J	joule
JCSP	Joint Coordinated System Plan
km	kilometer
kW	kilowatt
kWh	kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelized cost of electricity
LDV	light-duty vehicle
LLC	limited liability corporation
LNG	liquefied natural gas
MIT	Massachusetts Institute of Technology
MW	megawatt
MWh	megawatt-hour
NAS	National Academy of Sciences
NaS	sodium-sulfur
NAE	National Academy of Engineering
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory

NGCC	natural gas combined cycle
NRC	National Research Council
NREL	National Renewable Energy Laboratory
NSB	National Science Board
PC	pulverized coal
PHEV	plug-in hybrid vehicle
PNNL	Pacific Northwest National Laboratory
PUC	public utility commission
PUREX	plutonium and uranium extraction
PV	photovoltaic
quads	quadrillion Btu
R&D	research and development
RFF	Resources for the Future
SGI	Synthetic Genomics, Inc.
Shell	Shell Frontier Oil and Gas, Inc.
SI	spark-ignition
SPE	Society of Petroleum Engineers
SPP	Southwest Power Pool
t	tonne
Tcf	trillion cubic feet
T&D	transmission and distribution
TRB	Transportation Research Board
TWh	terawatt-hour
USNRC	U.S. Nuclear Regulatory Commission
USPC	ultrasupercritical pulverized coal
U-value	heat-transfer coefficient
V	carbon dioxide vented
W	watt
Wh	watt-hour

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