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California In Context: Long-Term Scenarios Of Energy Efficiency And Renewable Energy

Author
Joint Global Change Research Institute, Pacific Northwest National Laboratory

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Arnold Schwarzenegger
Governor

CALIFORNIA IN CONTEXT: LONG-TERM SCENARIOS OF ENERGY EFFICIENCY AND RENEWABLE ENERGY

PIER PROJECT REPORT

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Prepared By:
S. J. Smith, G. P. Kyle, M. A. Wise, L. E. Clarke, E. M. Rauch,
S. H. Kim, J. A. Dirks, J. D. Dean, and D. B. Belzer
Joint Global Change Research Institute
Pacific Northwest National Laboratory
College Park, MD

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Prepared For:
Public Interest Energy Research (PIER) Program
California Energy Commission

Guido Franco
Project Manager

Beth Chambers
Contract Manager

Kelly Birkinshaw
Program Area Lead
Energy-Related Environmental Research

Laurie ten Hope
Office Manager
Energy Systems Research

Martha Krebs
Deputy Director
ENERGY RESEARCH & DEVELOPMENT DIVISION

B. B. Blevins
Executive Director

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California's electricity and natural gas ratepayers. The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

In 2003, the California Energy Commission's Public Interest Energy Research (PIER) Program established the **California Climate Change Center** to document climate change research relevant to the states. This Center is a virtual organization with core research activities at Scripps Institution of Oceanography and the University of California, Berkeley, complemented by efforts at other research institutions. Priority research areas defined in PIER's five-year Climate Change Research Plan are: monitoring, analysis, and modeling of climate; analysis of options to reduce greenhouse gas emissions; assessment of physical impacts and of adaptation strategies; and analysis of the economic consequences of both climate change impacts and the efforts designed to reduce emissions.

The California Climate Change Center Report Series details ongoing Center-sponsored research. As interim project results, the information contained in these reports may change; authors should be contacted for the most recent project results. By providing ready access to this timely research, the Center seeks to inform the public and expand dissemination of climate change information; thereby leveraging collaborative efforts and increasing the benefits of this research to California's citizens, environment, and economy.

California in Context: Long-Term Scenarios of Energy Efficiency and Renewable Energy is the final report for the Advanced Energy Technology Options for California Within the Context of National and Global Systems project (contract number 500-02-004, work authorization number MR-029) conducted by the Pacific Northwest National Laboratory.

For more information on the PIER Program, please visit the Energy Commission's website www.energy.ca.gov/pier/ or contract the Energy Commission at (916) 654-5164.

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Abstract

This project examined the long-term role of energy efficiency and renewable energy technologies in reducing energy use and meeting greenhouse gas emissions goals. This work presents an integrated, century-scale perspective that, for the first time, allows consistent long-term (100-year) scenarios that simultaneously include California building end-use and renewable energy detail, the rest of the United States, and 13 other world regions. The global and national context for climate mitigation under a variety of climate policy regimes are briefly presented, followed by an analysis of the potential value of end-use energy and renewable energy technologies. This analysis found that the deployment of a comprehensive suite of more energy efficient technologies has the potential to substantially lower climate mitigation costs. As an exploratory application of these modeling concepts at a state level, century-scale scenarios of building energy use in California are also presented, along with an analysis of long-term role of wind and solar power in California. The current divergence between California and the rest of the United States in terms of per-capita energy use is sustained. Residential building electricity demand in California, however, still increases by a factor of almost three, due to population growth. Solar and wind energy have the potential to supply a large portion of California's electricity needs, but further examination of the associated transmission and electric system stability requirements is needed.

Keywords: Climate change, emissions projections, emissions mitigation, California, United States, energy efficiency, solar power, wind power, renewable energy, integrated assessment

Executive Summary

Introduction

Reducing the effects from future climate change will ultimately require substantial changes in the way society supplies and uses energy. A primary goal of many climate policies is to stabilize atmospheric concentrations of greenhouse gases—particularly carbon dioxide, which is the greenhouse gas with the largest direct effect on the climate system. A wide range of new technologies and systems (including renewable energy sources such as wind and solar) will likely be needed to reduce emissions of greenhouse gases to the required levels. The time horizon for these changes stretches over the next 50–100 years and beyond. Accordingly, the time horizon for this project's analysis was 100 years.

Purpose

The aim of this project was to analyze the connections between end-use energy technologies, energy demand, renewable energy, and greenhouse gas emissions, to better guide climate change policy decisions.

Project Objectives

Focusing on the United States and California, this project explored two technology areas: energy efficiency and renewable energy (wind and solar energy). The research team conducted an integrated assessment that consisted of: (1) further developing and implementing detailed model components for building and industrial sectors in the United States, (2) developing a technology and resource-based representation of wind and solar energy, and (3) applying these analysis tools to California-specific residential and commercial buildings to develop long-term California-specific scenarios consistent with national and global scenarios for climate stabilization.

The analysis contains enough detail to be able to meaningfully represent the contributions of these technologies while still allowing a long-term regional and global perspective. By enabling the long-term analysis of specific end-use energy technologies, the elements that drive future demand growth can be better understood, and the effect of improved energy efficiency can be quantified over a long time horizon.

Project Outcomes

This research has demonstrated that there are substantial benefits to enhanced energy efficiency. Applying a comprehensive suite of more efficient end-use technologies across the United States economy reduced the cost of achieving a climate policy by 50 percent to 75 percent. The absolute value of improved efficiency increases substantially for stricter emissions targets because the cost of a climate policy increases strongly for lower carbon-dioxide concentration target levels.

Conclusions

The energy consumption reductions enabled by improved efficiency make it possible to reach long-term emissions targets at a lower economic cost. Even with substantially improved efficiency, however, total carbon dioxide emissions in the United States flatten but do not decline. Stabilization of greenhouse gas concentrations will still require an additional climate policy that either explicitly or implicitly puts a value on greenhouse gas emissions. The cost of a climate policy, however, can be substantially lower if more efficient end-use technologies are in place.

Wind is increasingly competitive and, based on generation costs and potential productive wind resources, wind power could supply up to a third of U.S. electric energy generation. To provide this level of wind generation, however, wind turbines would need to be located over large areas, requiring substantial construction of new electric transmission capacity. Because of this geographic dispersion the contribution of wind is dependent, among other things, on the ability to construct new electric transmission capacity.

This analysis also considered concentrating solar thermal power plants (CSP), such as solar trough technology. These CSP plants will be competitive in the future if costs decline as projected. They could provide a substantial portion of intermediate and peak power—power that is currently expensive and would otherwise produce additional greenhouse gas emissions.

The research team also applied the detailed analysis approach specifically to California, while still within the context of a global, long-term modeling framework. As an exploratory application of these modeling concepts at a state level, researchers generated century-scale scenarios of building energy use in California, as well as an analysis of the long-term role of wind and solar power in California. Researchers constructed scenarios for California building energy consumption over the twenty-first century that are consistent with national and global scenarios for climate stabilization. Even though per-capita building electricity use in California stays relatively constant, total electricity demand increases nearly three-fold over the century due to population growth. Further implementation of energy-efficient technologies could reduce this demand growth.

Climate policy affects the California building sector largely by decreasing the use of natural gas relative to what would be the case absent climate policy. With an economy-wide carbon price applied to the consumption of fossil fuels, it becomes economic to switch to electric end-use technologies, particularly for applications where heat-pump technologies are available. Natural gas use in the buildings sector eventually stabilizes under a carbon policy, instead of increasing as in the reference case.

It was found that wind and solar energy could potentially supply a very large portion of California electricity demand in the long-term. California has a large fraction of the total United States resource of direct sunlight as required for concentrating solar technologies. To realize a scenario with such a high fraction of wind and solar power large amounts of dispersed power, generation would have to be transmitted to load centers. The new additions or transmission system changes that would be necessary to facilitate high levels of renewable power supply could use further examination.

1.0 Introduction

Residents of affluent regions of the world generally take for granted the availability of food, well-lighted living spaces maintained at a comfortable temperature, and the ability to travel across town or across the country nearly at will. Those living in less affluent regions aspire to this status. The production and use of the energy needed to provide these services, however, generally contributes to local air pollution and increases atmospheric concentrations of greenhouse gases. The focus of this study is this fundamental connection between energy service demands, energy consumption, and climate change.

Climate change is a long-term problem that requires consideration of the global energy and climate system. Stabilization of greenhouse gas concentrations will require substantial changes to the energy system over the next 50–100 years. Given that the fossil fuels are the primary source of greenhouse gas emissions, most long-term work to date has focused on fossil energy supply and transformation. While these studies have supplied numerous insights into the nature of the problem, the tools developed in the past have generally offered limited insights into the potential role of energy efficiency and renewable energy.

The amount of energy used in the future is a central determinant of environmental impacts. Energy use will depend on the demand for energy services and the technologies used to supply those services. The aim of this project was to elucidate the connections between end-use energy technologies, energy demand, and greenhouse gas emissions, to better guide climate change policy decisions. To this end a long-used model of long-term energy and climate change has been enhanced to incorporate explicit end-use energy technologies. This allows the role of energy efficiency to be determined on a technology basis while consistently considering interactions with the regional and global energy system.

In addition to end-use energy, a second theme of this work was to examine the role of renewable energy. As with end-use energy, the long-term analysis of renewable energy has generally received less attention than fossil energy. The analytical techniques appropriate for fossil energy sources are not always appropriate for consideration of renewable energy. This study focused on wind and solar energy, which may play key roles as clean energy sources that have small net contributions to greenhouse gas emissions.

The structure of this report follows the overall study design. The analysis approach, which is known as *integrated assessment*, is introduced first. The overall modeling framework is then described. The analysis proceeds in three sections: energy efficiency, renewable energy, the application of those factors to California.

The largest portion of the project focused on energy efficiency. The first stages of the project were to further develop and implement detailed model components for building and industrial sectors in the United States. These model components are described, followed by an analysis of the value of energy efficiency in terms of lowering the cost of achieving climate stabilization.

The second portion of the project was the development of a technology and resource-based representation of wind and solar energy. These model components are described, followed by analysis results that focus on the primary factors that affect the potential role of renewable energy.

The final portion of the project was to apply this analysis approach specifically to California. California-specific residential building, commercial building, and renewable energy modules were developed and implemented within the overall framework. This allowed long-term scenarios for California to be developed that are consistent with national and global scenarios for climate stabilization.

2.0 Project Approach

2.1. Integrated Assessment

The practice of integrated assessment draws together knowledge and information across disciplines as well as across multiple spatial and temporal scales. When applied to climate change this practice often produces estimates of how much climate change is likely to occur in the future, quantification of climate change drivers (e.g., anthropogenic emissions, land-use changes), analysis of mitigation costs, identification of technologies and policies that can reduce costs, and analysis of climate impacts and the potential for adaptation. The most commonly used embodiment of integrated assessment practice is in the form of integrated assessment models, which are a class of decision support tools.

Integrated assessment is currently moving from illustrative analysis toward operational policy analysis, where the relative merits of different options need to be compared. The Global Energy Technology Strategy project at the Pacific Northwest National Laboratory (PNNL), for example, works to assess the role that technology can play in addressing climate change, noting that "A technology strategy that identifies a diversified portfolio of options and their likely timeframes for development and deployment is required."[1]

With such a broad set of goals, the tools used for integrated assessment vary widely in their complexity, intended uses, and range of topics covered. This report focuses on describing the integrated assessment modeling tools used at the Joint Global Change Research Institute (JGCRI). Results from these models have been used by U.S. government agencies, industrial clients, international assessment activities, and foundations, and they have been published in peer-reviewed journals.

The JGCRI's modeling tools integrate social, economic, and physical systems, to analyze in a comprehensive fashion the implications of potential future developments. The guiding philosophy behind integrated assessment modeling at JGCRI is to use relatively simple representations of relevant processes to model the complex behaviors that result from interactions among component systems. The need to be able to rapidly respond to decision makers means that JGCRI models must be able to calculate scenarios in minutes, not hours or days.

A common method of analysis using an integrated assessment model is the production and analysis of scenarios. One example, including contributions from JGCRI models, is the Intergovernmental Panel on Climate Change (IPCC) Special Report on Emission Scenarios (Nakicenovic and Swart 2000). For the present study, the research team used scenario analysis to allow the examination of the role of energy efficiency and renewable technologies within a changing energy-system and climate-policy context over the twenty-first century.

Numerous examples of integrated assessment applications can be found in the recent report by the Global Technology Strategy Project (GTSP; Edmonds et al. 2007).

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[1] See (www.pnl.gov/gtsp/index.stm).

2.2. O^bjECTS MiniCAM

The primary analysis tool used in this project is the Object-oriented Energy, Climate, and Technology Systems (O^bjECTS) framework, which uses a flexible, object-oriented modeling structure to implement an enhanced version of the partial-equilibrium model MiniCAM (Kim et al. 2006). The O^bjECTS MiniCAM is an integrated model of the economy, energy supply and demand technologies, agriculture, land-use, carbon-cycle, and climate. This new framework is intended to bridge the gap between "bottom-up" technology models and "top-down" macro-economic models. By allowing a greater level of detail where needed, while still allowing interaction between all model components, the O^bjECTS Framework allows a high degree of technological detail while retaining system-level feedbacks and interactions. By using object-oriented programming techniques (Kim et al. 2006), the model is structured to be data-driven, which means that new model configurations can be created by changing only input data, without changing the underlying model code.

The MiniCAM is a partial-equilibrium model structure that is designed to examine long-term, large-scale changes in global and regional energy system. The MiniCAM has a strong focus on energy supply technologies and has been recently expanded to include a comprehensive suite of end-use technologies. The MiniCAM was one of the models used to generate the IPCC SRES scenarios (Nakicenovic and Swart 2000). This model has been used in a number of national and international assessment and modeling activities such as the Energy Modeling Forum (EMF) (Edmonds, et al. 2004, Smith and Wigley 2006), the U.S. Climate Change Technology Program (CCTP; Clarke et al. 2006), and the U.S. Climate Change Science Program (CCSP; Clarke et al. 2007) and IPCC assessment reports.

The MiniCAM model is calibrated to 1990 and 2005 and operates in 15-year time steps to the year 2095. It takes inputs such as labor productivity growth, population, fossil and non-fossil fuel resources, energy technology characteristics, and productivity growth rates and generates outputs of energy supplies and demands by fuel (9 primary, 5 final fuels, agricultural supplies and demands, emissions of greenhouse gases (carbon dioxide, CO_2; methane, CH_4; nitrous oxide,N_2O), and emissions of other radiatively important compounds (sulfur dioxide, SO_2; nitrogen oxides, NO_X; carbon monoxide, CO; volatile organic compounds, VOC; organic carbon aerosols, OC; black carbon aerosols, BC). The model has its roots in Edmonds and Reilly (1985), and has been continuously updated (Edmonds et al. 1986; Kim et al. 2006). MiniCAM also incorporates MAGICC, a model of the carbon cycle, atmospheric processes, and global climate change (Raper et al. 1996; Wigley and Raper 1992).

The MiniCAM is one of the relatively few integrated assessment models that contains an explicit model of future land-uses, including agricultural crops, forestry, and bioenergy crop production (Sands and Leimbach 2003; Gillingham et al. 2007). This feature not only allows a direct representation of major greenhouse gas emissions sectors (e.g., livestock, rice production) but also enables future land-use changes to be directly simulated. This allows consideration of the link between the energy system and land-use through the potential production of commercial biomass, which can be derived either from waste streams (many of which stem from agricultural activities) or from crops grown explicitly for their energy content. Biomass crops must compete for market share with other crops, livestock, and forest products. As profitable agricultural opportunities increase, pressure to expand into increasingly less attractive land categories grows, as does pressure to convert unmanaged ecosystems to managed production.

Technology choice in the MiniCAM is determined using a logit choice formulation (Edwards 1992), which represents a least-cost paradigm (Clarke and Edmonds 1993). The market share of a technology is given by,

(1) $$S_{i,L} = sw_{i,L} P_{i,L}^{r_L} / \sum_{i}^{N} sw_{i,L} P_{i,L}^{r_L}$$

where, $S_{i,L}$ is market share of each technology, $sw_{i,L}$ is the share weight, $P_{i,L}$ is cost per unit output of each technology, r_L is a distribution parameter, and N is the number of vehicle technologies. The share weights capture current consumer preferences and geographic heterogeneities that are not explicitly modeled. Share weights are calibrated from data for current technologies or set as scenario parameters for future technologies that are not in widespread use at present.

During this project the O^bjECTS MiniCAM has been extended to incorporate specific classes of end-use technologies in the buildings and industrial sectors, as well as a resource and technology-based representation of wind and solar energy. These developments will be described in the next section.

A key advantage of working within an integrated framework such as the O^bjECTS MiniCAM is that the connection between different components of the energy system can be explicitly included. Regional and global energy supplies, demands, and, in particular, energy prices are endogenously determined. This is important largely because the feedbacks due to price changes are included in the analysis. Projections of future energy prices can also be of interest, even though these are much more uncertain. For example, the incorporation of more efficient end-use technologies will tend to reduce the demand for energy and, therefore, lower energy prices from what they would otherwise have been. This will tend to induce an increase in energy consumption. Although the magnitude of this effect is uncertain, its sign is not. These effects are automatically included when detailed technologies are included for analysis conducted within the O^bjECTS framework.

In summary, the O^bjECTS MiniCAM is used to provide analysis of the regional and global energy system over a century-long time horizon. The model produces projections of energy consumption and emissions of a full suite of greenhouse gas and pollutant emissions. As part of these projections the model results contain considerable technology detail, such as the fraction of electricity produced by various fossil fuel and renewable technologies and the contribution of different feedstocks such as crude oil, "unconventional" oil, biomass, and coal to refined liquid fuels. The model operates using fundamental economic principles, allowing estimates of the cost of meeting greenhouse gas emissions objectives. These capabilities will be used to produce the analysis that follows in Section 3.

3.0 Project Results

3.1. Climate Stabilization and the Energy System

The goal of the United Nations Framework Convention on Climate Change is the stabilization of atmospheric concentrations of greenhouse gases at a level that avoids dangerous anthropogenic interference with the climate system. Because of uncertainty in the response of climate to increasing greenhouse gases, the stabilization level that would achieve this goal is not known. While the required emissions levels are not known, the general characteristics of climate stabilization can be described.

Figure 3-1 shows a set of emissions pathways that lead to stabilization of atmospheric concentrations of CO_2 at levels ranging from 450 to 750 parts per million by volume (ppmv). Because some portion of any CO_2 emitted to the atmosphere will remain for centuries, concentration stabilization requires that emissions eventually continually decrease. The point at which emissions must begin to decrease is determined primarily by the stabilization level and the assumed details of the carbon cycle. Note that for stabilization of CO_2 at 450 ppmv, global CO_2 emissions must begin to decline within the next decade or two, which would require a dramatic departure from the present historical trend.

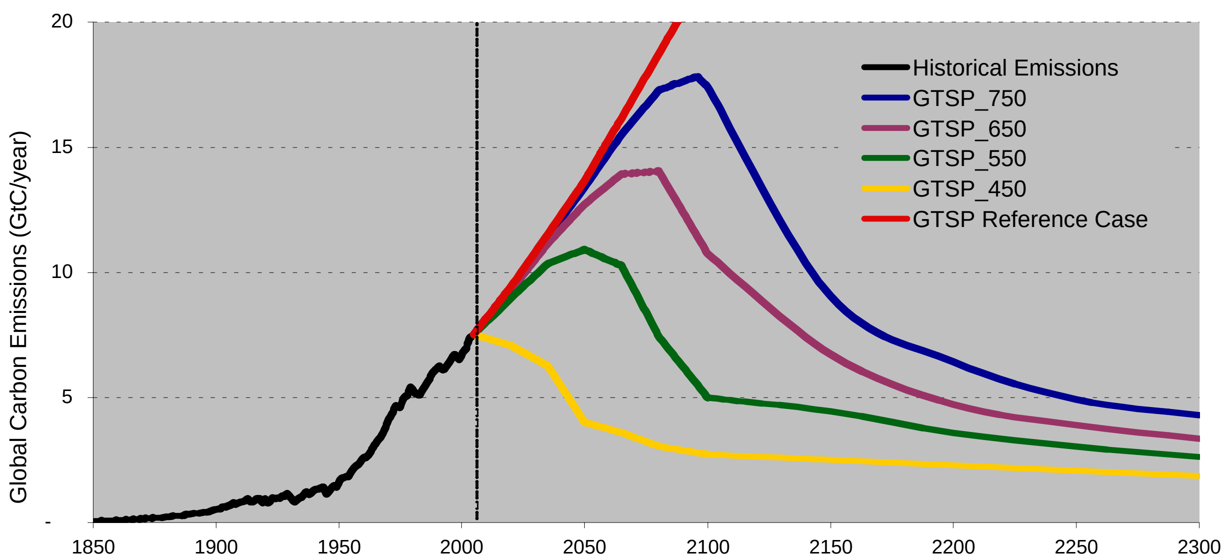


Figure 3-1. Emissions paths leading to stabilization of atmospheric carbon dioxide emissions. Emissions of carbon dioxide must eventually continuously fall in order to stabilize carbon dioxide emissions. The pathways represent stabilization levels ranging from 450 ppmv to 750 ppmv.

Source: GTSP

To achieve a global net decrease in CO_2 emissions, dramatic changes in the energy system will be required. The use of fossil fuels in technologies that freely vent CO_2 must decrease and the share of renewable energy increase. While there are multiple combinations of technologies that can achieve this goal (Clarke et al. 2006), the overall nature of the necessary changes is clear, as illustrated in Figure 3-2.

The general abundance and relative cost-effectiveness of fossil fuels means that the necessary changes will not occur at the magnitude necessary for stabilization of concentrations without placing an economic price on the emission of CO_2 to the atmosphere. As shown in Figure 3-3, a carbon price is necessary to motivate the transition to a less fossil-intensive economy. The carbon price must increase over time as deeper emission reductions become necessary. In the long-term the emissions path and associated carbon price transition to a pathway that balances emissions with global net carbon-cycle uptake. These idealized scenarios assume global participation in the carbon policy. The price necessary to achieve a given target will increase if participation in the carbon policy decreases.

The scale of these necessary changes means that there can be no one solution. Energy efficiency and renewable energy are potentially important components of a less carbon-intensive energy system. This examination turns next to an analysis of the value of enhanced deployment of more energy efficient end-use technologies in terms of meeting a climate stabilization goal.

This section provides only a brief introduction to climate stabilization and the role of energy technologies. For further details see the GTSP phase III final report (Edmonds et al. 2007), the CCSP scenarios report (Clarke et al. 2007), and the CCTP technology scenarios description (Clarke et al. 2006).

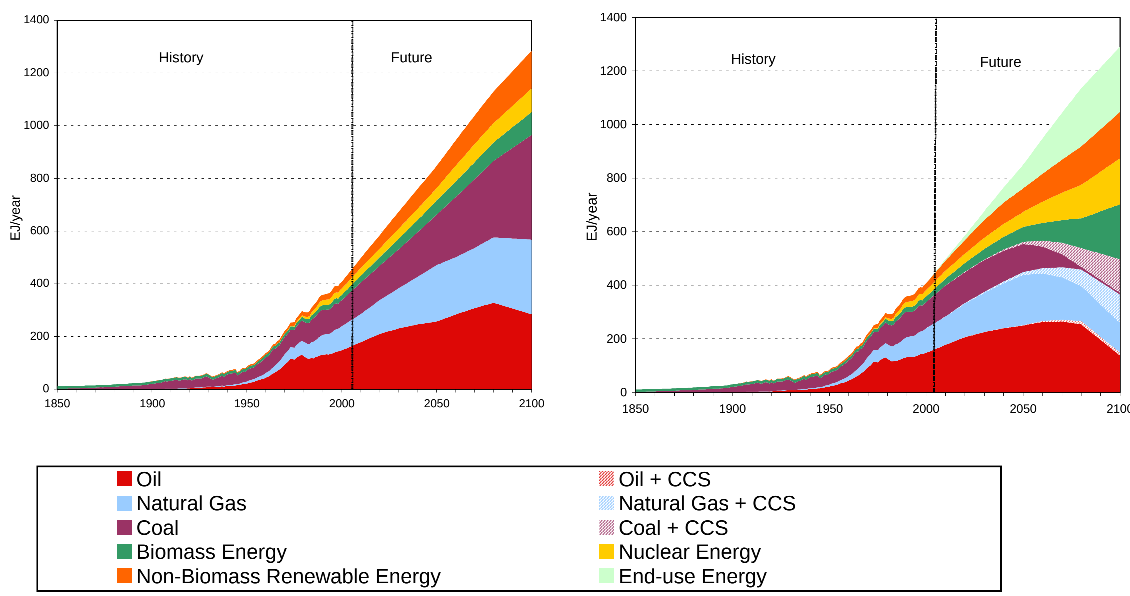


Figure 3-2. Global primary energy consumption for reference (right) and concentration stabilization (left) cases. Stabilization of carbon dioxide concentrations will require substantial changes in the energy system. The share of renewable energy sources will increase and the use of fossil fuels in ways that freely vent carbon to the atmosphere will need to decrease.

Source: Edmonds et al. (2007)

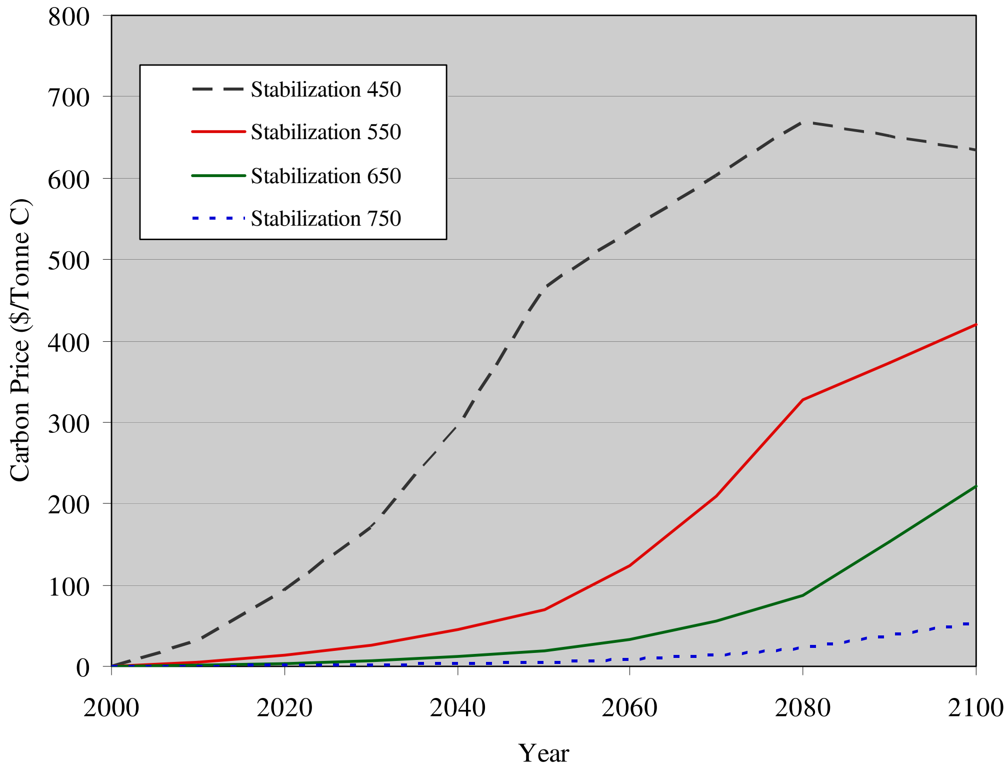


Figure 3-3. Carbon price paths for concentration stabilization. The carbon price initially increases at a level close to the long-term interest rate. The overall level of the price path depends on the concentration target and the assumed socioeconomic and technological developments over the next century. Note that the carbon price paths shown in this figure are presented for illustrative purposes, and differ somewhat from the carbon prices the scenarios presented later in this report.

Source: Edmonds et al. (2007)

3.2. Value of Energy Efficiency

3.2.1. Introduction

It is the provision of services such as housing, transportation, and material goods that results in the emission of greenhouse gases to the atmosphere. Reducing greenhouse gas emissions can be accomplished through three primary methods: reducing the level of services supplied, supplying services using less energy (demand-side efficiency), or supplying energy in forms that result in lower net emissions (supply-side).

Supply-side methods have generally received the most attention. In large part this is due to their convenience, both practically and politically. For example, if electricity were generated in a manner that did not result in net-carbon emissions to the atmosphere then carbon emissions would be substantially reduced and the change would be largely transparent to the majority of consumers, aside from a likely increase in the cost of electricity. A relatively small number of actors, that is, electric utilities, would need to be targeted by a policy to affect larger changes.

Reducing the level of services is the most difficult option. In economic terms, the demand for any service will decrease if the cost of providing that service increases. It is a general goal of most policies to balance costs and benefits so that undue costs are not borne by consumers.

Demand-side measures such as the deployment of more efficient end-use devices has the potential to decrease overall energy demand and, therefore, reduce greenhouse gas emissions. The difficulty with this approach, from both a practical and an analytic perspective, is that there is a very large set of end-use technologies deployed in a wide-rage of applications, ranging from personal automobiles to light fixtures. The potential value of improving end-use technologies, however, is quite large. Improving energy efficiency reduces the scale of any problems associated with energy use and production, making this a very attractive option for meeting energy and environmental goals in general. In addition, the deployment of more energy-efficient technologies can result in a net gain in welfare, as services are provided at a lower net cost. Note, however, any such analysis is complicated by qualitative differences in the service provided by different technologies.

Analysis using long-term models have generally not included detailed analysis of energy efficiency. Through this project the research team developed a sufficient level of detail to be able to analyze the contribution of end-use efficiency improvements over a century time frame. These model components are described in the next section. The following section describes the scenario assumptions for end-use technologies. The results of these assumptions in terms of future energy use scenarios are shown, concluding with an analysis of the value of end-use technologies in terms of reducing the cost of meeting climate stabilization goals.

The analysis focuses on the United States, where more detailed representations of end-use energy demands and renewable energy supplies have been implemented. The results are still in the context of a global energy model, but with enhanced detail for the United States. Global responses in terms of prices and the supply and demand of traded goods are retained.

3.2.2. End-Use Model Components

Buildings

Figure 3-4 shows the conceptual structure of the U.S. buildings-sector module. In the version presented here, two building subsectors are assumed for the United States: residential buildings and commercial buildings. For the analysis presented in this section, each sector represents building energy demand for the entire country. In essence, each sector is an aggregate representative building. Associated with each of these sectors is information such as floor space and building-shell thermal characteristics. Each of the two sectors demands a suite of building energy services. Since the model is calibrated to current energy consumption, the current distribution in building properties (that is, heterogeneity in building characteristics) is implicitly included in the model results. Changes in the distribution of building properties in the future, however, is not included in the present analysis; only changes in average properties are considered. As a first effort to consider regional details, an analysis focusing on California is presented in Section 3.7 below.

Both sectors demand heating, cooling, lighting, hot water, and an "other" category that captures all other demands, including potentially new future services not yet envisioned. In the residential sector the "other" category includes demands for information services such as those provided by computers and televisions and miscellaneous plug loads. In the commercial sector this category includes a wide range of services, including water treatment infrastructure. The residential sector also demands appliance services, which includes refrigeration, dish washers, and clothes washers and dryers. Similarly, office equipment, which consists primarily of computers, copiers, fax machines, and printers, is considered as a separate demand in the commercial sector.

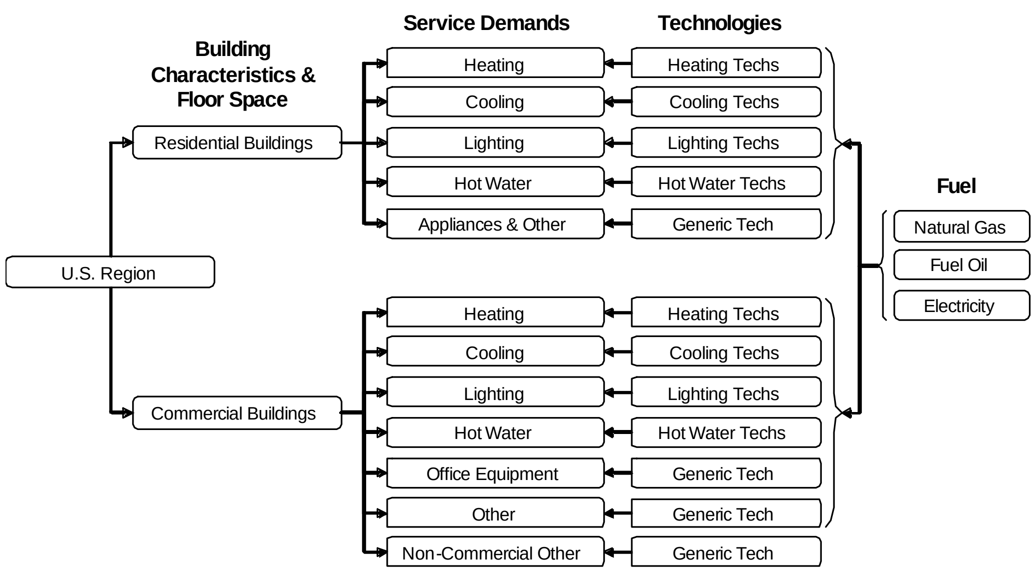


Figure 3-4. Conceptual structure of the U.S. building-sector module. The United States is split into two aggregate building sectors, residential and commercial buildings, each of which demands a range of services. These services are supplied by associated technologies that require fuel inputs. Note that residential appliances and residential "other" are separated in the current study, and the commercial other category is no longer separate.

Demands for these services in MiniCAM are expressed not in terms of input energy, such as electricity or natural gas, but in terms of the actual services provided, when feasible. For example, lighting demand can be expressed in lumens; heating and cooling demands are expressed in terms of the heat-transfer demands of the sector. Service demands for other categories are simply indexed. By specifying demand for services rather than input energy, MiniCAM is able to disentangle changes in the demand for services and the efficiency of the technologies that provide these services.

A number of technologies might provide any service. For example, lighting can be supplied by incandescent lamps, fluorescent lamps, or, in the future, solid-state lighting. Heating can be supplied by electric-resistance heating, electric heat pumps, natural gas furnaces, natural gas heat pumps, and fuel oil furnaces. For this analysis, three primary fuels are assumed to serve the buildings sector: electricity, natural gas, and fuel oil. Wood used in buildings is also included in the model.

Services are keyed to floorspace. As the amount of floorspace grows in the future, the level of services demanded increases as well. While it can be argued that some services might saturate as floorspace increases, there is little historical evidence of these effects to date (Rong, Clarke, and Smith 2007).

In particular it is useful to detail the equations that determine the demand for heating and cooling services. These are determined by:

(2)
$$d_H = \sigma_H \, u \, a \, HDD \, P_H^{-\beta_H} - G$$

(3)
$$d_C = \phi_C \left(\sigma_C \, u \, a \, CDD \, P_C^{-\beta_C} + G \right)$$

Where d_H and d_C are the demands for heating and cooling per square foot of floor space in terms of the thermal loads, the σ's are calibration coefficients, ϕ_C is a "saturation" parameter that captures the penetration of cooling technology over time, u is the thermal heat characteristics of the building, a is building shell area per square foot, *HDD* and *CDD* are heating degree days and cooling degree days, P_H and P_C are the service prices, the β's are price elasticities, and G represents the internal gains from other demands, such as lighting.

The effect of both increasing floorspace and the interaction with other building technologies through internal gains are accounted for in this representation. Internal gains decrease the demand for heating services and increase the demand for cooling services. Internal gains are calculated by assigning an internal gains coefficient to each end-use service. This coefficient represents the fraction of energy consumption that is dissipated within the building shell. It has been assumed that 10% of the energy goes to water heating, 90% to lighting, 80% to office equipment, and 50% to appliances and residential "other" contributes to internal gains. Only 5% of commercial "other" energy contributes to internal gains because most of the commercial "other" energy is exterior to the building shell. Also assigned is a fraction of the year active for heating and cooling, which represents the fraction of the year that the internal gain term will affect heating and cooling services. This fraction is determined by an analysis of heating and cooling degree-day trends in each region.

Demand for other services is calculated in a similar manner, although without the internal gains term. A full description of the model is given in (Rong, Clarke, and Smith 2007).

Industry

The U.S. industrial energy sector module in ObjECTS incorporates sufficient industry, process, end-use, and technological detail to examine the potential long-term impact of technology and process changes while maintaining compatibility with the rest of the integrated model. The level of aggregation and detail allows differentiation of the following components:

- Key industry groups that differ in terms of their long-term growth and consequent demand for energy services.

- Within each industry group, major energy end-uses and processes, with potential for process improvements where possible, as well as the potential for cogeneration of heat and power.
- Within each energy end-use, a set of explicit technology and fuel options that will compete, based on relative economics and engineering limits, to provide each of these energy services in each industry group.

The aggregation of industries in O^bj^ECTS is determined by common patterns of energy use in terms of fuel and end-uses. The aggregation of end-use categories across industries is based on data from the Manufacturing Energy Consumption Survey (MECS) data (MECS 1998).[2] Figure 3-5 shows the O^bj^ECTS U.S. industrial sector categories of industry groups and energy end-uses, with energy consumption data for 1998.

Although it is relatively small in terms of energy use, the cement industry is modeled separately because its non-combustion emissions of CO_2 justify special attention. An additional nonmetallic minerals category includes the production of lime and other processes that also produce non-combustion direct carbon emissions. Aluminum smelting is treated separately from other metals due to the large amount of electricity used in this sector.

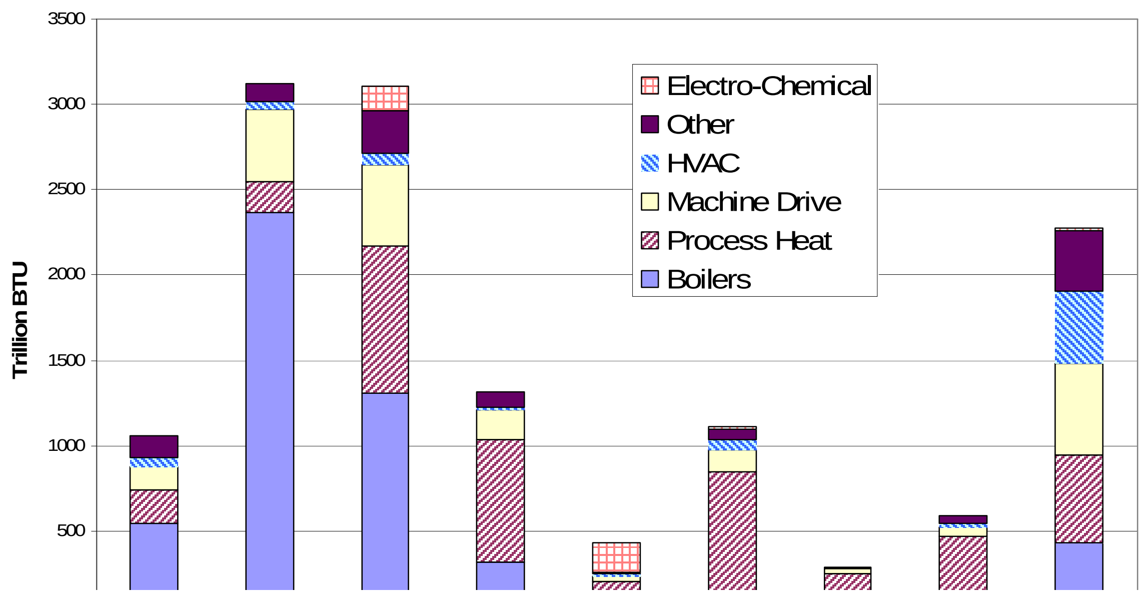


Figure 3-5. U.S. 1998 energy consumption, by O^bj^ECTS MiniCAM industry and energy end-use group

Source: MECS (1998)

[2] See www.eia.doe.gov/emeu/mecs/contents.html.

Non-manufacturing industry groups, which are not part of the MECS data, are also included, with the categories used by the Energy Information Administration (EIA) in the Annual Energy Outlook (EIA 2006). Specifically, Agriculture, Construction, and Mining industries are modeled.

Future demand growth in each of the industry groups is modeled econometrically based on historical relationships between income and population growth and demand for the products of each of these industries. Within each industry, the production process is modeled as a set of energy end services required to produce a unit of output. For example, to produce a unit of output from the Chemicals industry requires x units of steam, y units of process heat, and z units of "other." The input-output coefficients required to drive these production functions are determined by the MECS data, so that each column in Figure 3-5 represents a process for that industry. The impact of process improvements can be modeled by decreasing the proportion of specific end-uses as appropriate.

Finally, within each set of energy end-uses in a production process, multiple technology and fuel options compete to provide that end-use service based on their relative economics. A logit equation determines market shares based on the relative costs of producing an output, including capital and energy costs, assuming a distribution of costs (Clarke and Edmonds 1993).

This economic competition allows the examination of the impact of fuel price changes on technology choice. For example, coal, oil, natural gas, and renewable fuels can be used in operating boilers to generate steam. Under a carbon policy, the cost of using coal increases, and industries will switch to less carbon-intensive fuels such as natural gas or whatever renewable fuels are available to that industry. The carbon policy might also encourage increases in the use of cogeneration.

Figure 3-6 provides a simple schematic showing the competing technologies for providing steam in the chemicals industry. From this figure, a production process containing a set of energy end-uses is required to produce output in the Chemicals industry, and multiple fuel and technology options are available to provide each. This figure also shows how combined heat and power (CHP or cogeneration) technologies will compete with steam-only boilers to provide boilers (or steam) end-use service.

Transportation

The transportation sector is a large and growing source of greenhouse gas emissions and is responsible for nearly a quarter of total CO_2 emissions in the United States (EIA 2005). The transportation sector is modeled with two services—passenger and freight transport—with modal choices and vehicle technologies for each mode. The passenger transport modal categories are automobile, light truck, air, rail, ship, and motorcycle. The freight transport modal categories are truck, air, rail, and ship. Specific vehicle technologies using different fuels were included in each sub-sector or mode. See Figure 3-7 for the structure of the U.S. transportation sector as used in this study.

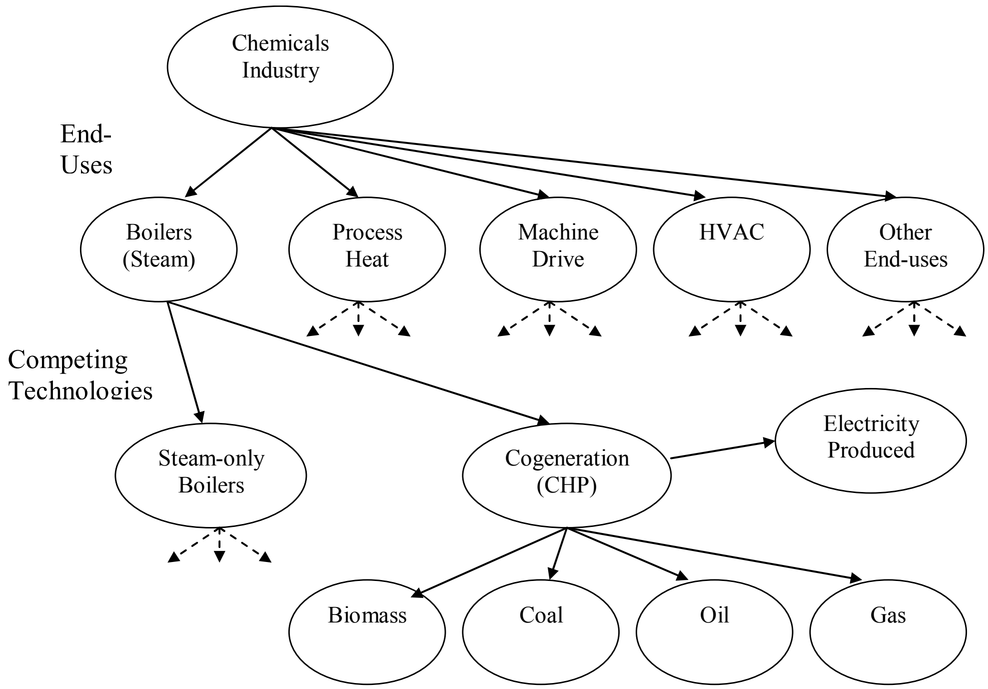


Figure 3-6. Simplified schematic of O$^{\text{bj}}$ECTS end-use and technology structure for the chemicals industry

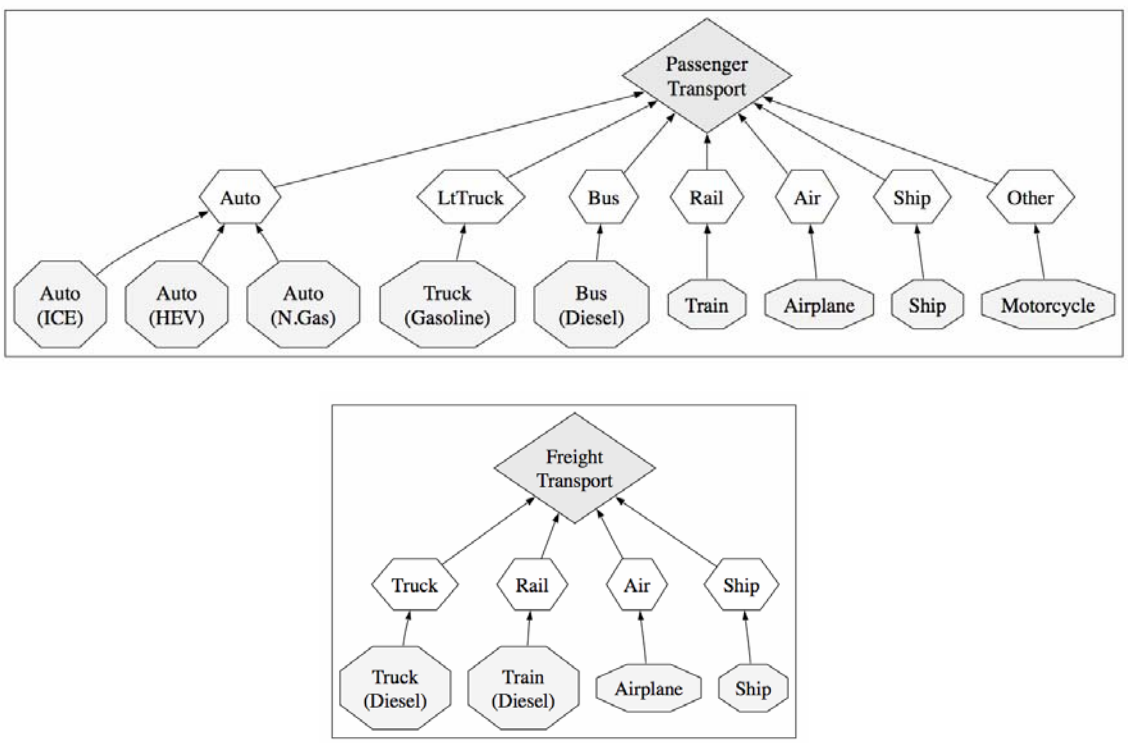


Figure 3-7. U.S. transportation structure. Transportation demand is split into freight and passenger service demands. A discrete set of technologies compete to supply these services.

The median cost of transport service by vehicle and mode is used to determine the vehicle and modal choices and the total demand for transport services. The median cost of passenger transport service not only includes the cost of vehicle operation and ownership but the passenger's time value associated with that particular vehicle use and modal choice (Edwards 1992). The time value is a function of the wage rate and average vehicle transit speed, which varies across modes. The cost of freight transport service also includes the cost of vehicle operation and ownership and the time value derived from modal speeds. The cost of vehicle operation includes fuel costs that include charges for environmental policies such as carbon taxes. The cost of passenger transport service by vehicle, *i*, and region, *L*, is given by

$$P_{i,L} = (P_{f,L} / Eff_{i,L} + P_{nf,i,L}) / LF_{i,L} + W_L / T_m \tag{4}$$

where, $P_{i,L}$ is cost of vehicle transport service, $P_{f,L}$ is fuel cost, $Eff_{i,L}$ is vehicle fuel economy, $P_{nf,i,L}$ is vehicle non-fuel cost, $LF_{i,L}$ is load factor, W_L is wage rate, and T_m is average vehicle transit speed. Vehicle non-fuel cost, $P_{nf,i,L}$, includes all costs of owning, operating, and maintaining the vehicle exclusive of fuel costs. Costs are in units of service, for example dollars per passenger-mile or vehicle-mile.

A full description and detailed results from the U.S. transportation model are given in Kim et al. (2006). A brief description of the transportation sector is given in this report for completeness, as this sector was used in the value of technology results shown below.

3.2.3. Scenario Descriptions

Scenario Assumptions

The definition of a scenario within this study's modeling framework has many aspects. There are assumptions for demographics, labor force productivity, technological development, technology availability, and environmental policies. The principal assumptions that affect the results of this study are the technology assumptions. Other assumptions are briefly described here as well.

Demographic assumptions affect total population levels in each region and the size of the available labor force. Labor force projections plus labor force productivity values combine to produce an estimate of gross domestic product (GDP) growth. For these scenarios, the demographic and labor force productivity assumptions for each region other than the United States are identical to those for the MiniCAM scenarios described in Clarke et al. (2007). The United States values for total population have been updated to the most recent long-term U.S. Census projection (U.S. Census Bureau 2000), adjusted to be consistent with the most recent mid-term projections (U.S. Census Bureau 2004). Labor productivity growth in the United States in the near-term was revised to reflect more recent historical data.

While the GDP and population trajectories used in this work were derived from the MiniCAM CCSP scenarios (Clarke et al. 2007), the other technology assumptions and calibration values differ from those used for the exploratory analysis presented here. Global carbon emission paths and other general scenario results also, therefore, are different. Future work may update this analysis to be consistent with the CCSP scenarios.

The combination of demographic and labor-force productivity assumptions for the United States result in a slowdown in the GDP growth rate after 2020 as the growth in the labor force decreases substantially. This is combined with a transition to an assumed long-term labor productivity growth rate of 1.5% per year. The result is a somewhat slower growth in service demands, which can be seen in many of the graphs as a slight discontinuity in 2020. Energy prices impact GDP through an aggregate long-term energy–price elasticity feedback, although this effect is small due to the relatively small fraction of energy as a component of total final service costs.

Demographic and socioeconomic assumptions are the proximate drivers in this model of demands for energy services. The demand for building floorspace, for example, is driven largely by growth in population and income, and then leading to a demand for energy services such as heating, cooling, and lighting. The growth in demand for residential building energy services is shown in Figure 3-8. The demand for the services provided by energy end-use technologies continues to increase throughout the century. The actual demand for energy will be determined by the efficiency of energy demand technologies.

Two features of building energy demand in particular are notable. First is the large increase in "other" energy demands. While the nature of these demands cannot be specified with any precision, historical experience suggests that many new uses for energy will be found over the course of time.

A second feature is that cooling demands increase substantially more than heating demands. This is largely because internal gains from other energy uses act to reduce heating demand while they increase cooling demand. An additional, but smaller, effect is that cooling technologies at the present time are not as fully deployed in the United States as heating technologies.

End-Use Technology Assumptions

The reference case scenario is intended to describe a future path for technology development and deployment with continued technological development, including the potential introduction of new technologies. New technology development, however, is assumed to take place at a moderate level representing a scenario where society has not focused extensive resources on developing and deploying either new or dramatically improved end-use technologies. Auto fuel economy, for example, is assumed to continue to improve but does not push technological limits.

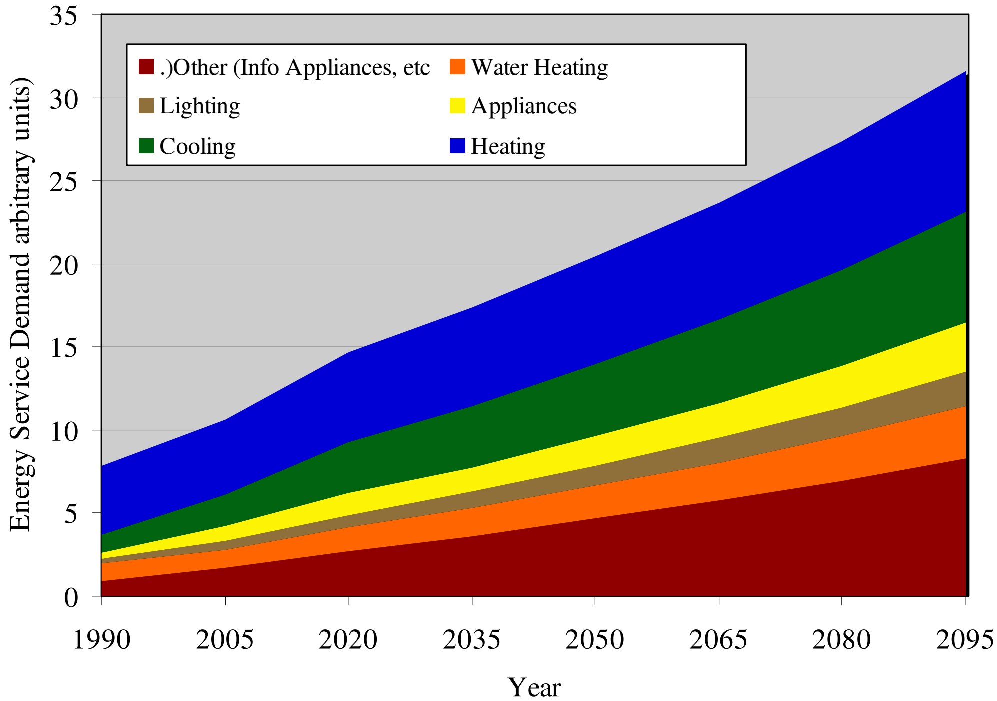


Figure 3-8. U.S. residential building energy service demand. This figure represents the demand for energy services, for example heating, cooling, and lighting. The demand for the services that are provided by end-use technologies continues to increase throughout the century.

In the advanced case, society is assumed to expend more resources, in terms of both technology development and deployment, including codes and standards to improve the efficiency of end-use technologies. In the advanced case, a broad suite of end-use technologies are assumed to be more efficient and more cost effective per unit output. Some additional technologies are also assumed to be available in the advanced technology case. In the reference case, it was assumed that these new technologies were not developed to an extent that they were practical for widespread use.

Table 3-1 shows the efficiency assumptions for the primary technologies used in the analysis, for both the reference and advanced cases. Estimated values for historical periods, where available, are shown as well. Where possible efficiency values are given as device efficiencies, such as miles per gallon (mpg) for vehicles or coefficients of performance (useful energy out/energy in) for heating and cooling equipment. Where device level efficiencies cannot be identified, efficiencies are indexed to relative performance in 2005. In all cases, efficiency figures represent aggregate stock efficiency.

In the reference case, light-duty auto efficiency improves by 20% by 2050 and by 30% by 2100. Note that for all vehicles, the net efficiency improvement represents the competition between power-train to wheel efficiency improvement and the trend toward increased vehicle features such as better acceleration and additional auxiliary services (such as heated seats, global positioning satellite devices, and passenger video players). Efficiencies for light-truck class vehicles, including sport-utility vehicles, improves at a slightly larger rate, reflecting in part a shift to market share to somewhat smaller vehicles and improved mileage standards. Hybrid vehicle efficiency is higher than internal combustion engine (ICE) vehicles but at relative values reflecting current technologies (see Table 3-1). For aircraft, efficiency figures include on-ground fuel-consumption improvements and changes in vehicle load factor (which have increased significantly in recent years), in addition to improvements in aircraft flight performance.

In the advanced case, efficiency for all classes of vehicles increases with efficiencies for hybrid vehicles increasing to a level about 50% higher than ICE vehicles. Note that many of the technologies envisioned to improve vehicle efficiency in one type of vehicle can be partially applied to other classes of vehicle as well.

Industrial end-use device efficiency is assumed to improve over time, however current efficiencies (of new stock at least) are already fairly high and have limited scope for improvement for the most common technologies such as boilers or electric motors. The largest scope for improvement is in process improvements where the procedures used for industrial production are reengineered to be more efficient. One example is the use of membranes for liquid processes. A modest level of process improvement is assumed in the reference case with a much higher level of process improvement in the advanced case.

Advances in building end-use technologies range from improvements in building shell efficiency to research developments that allow inexpensive solid-state lighting. Changes in building shell efficiency are particularly important. For exploration of building shell efficiency, a stock model of U.S. residential buildings was constructed, which allows the turnover in building stock to be taken into account. Consideration of building stock turnover is important, since buildings can be in service for many decades. Over 30% of current U.S. housing units, for example, are over 45 years old.

In the reference case, the overall thermal efficiency (including infiltration) of the average detached single-family house built in 2050 was assumed to be 40% more efficient than the average for houses built in 2005, with an 80% increase by 2095. Accounting for building stock evolution, this is equivalent to a 19% increase in the average by 2050 and 37% by 2095. The effect of long-lived building stock, therefore, reduces the effect of new improvements by around 50% in the reference case.

In the advanced case, it was assumed that the average new residential building is substantially improved as compared to the reference case, with building shells improved by a factor of two by 2050 and a factor of 3.4 by 2095. The 2050 value is only slightly higher than the average shell improvement found to be currently cost-effective using the BEOpt analysis software (NREL 2005). Due to the slow turnover of the building stock, the average stock efficiency change in 2050 is only 24% by 2050 and 53% by 2095.

Table 3-1. Residential and commercial building end-use efficiency assumptions

Transportation Technologies	Historical 1990	2005	Reference 2050	2095	Advanced 2050	2095
Vehicle mpg						
Hybrid Auto	na	30	35	39	58	75
ICE Auto	20	23	27	30	39	50
Hybrid Truck (light-duty)	na	23	30	33	39	50
ICE Truck (light-duty)	16	18	24	26	27	33
Freight truck	6.1	5.9	7.0	7.8	10	12
Passenger mpg						
Diesel bus	99	96	100	105	100	105
Hybrid bus	na	122	127	133	127	133
Diesel rail	72	75	78	82	78	82
Air	35	54	75	88	97	113
Freight ton mpg						
Truck	36	35	41	46	58	72
Rail	306	380	398	416	398	416
Air	3.7	5.8	6.9	7.4	7.8	8.4
Ship	542	608	636	665	636	665

Industrial Sector	Historical 2005	Reference 2050	2095	Advanced 2050	2095
Process improvements (relative)	1.00	1.05	1.09	1.14	1.31
Boilers (efficiency)					
Electricity	0.80	0.84	0.88	0.84	0.88
Oil	0.85	0.89	0.93	0.89	0.93
Gas	0.83	0.87	0.91	0.87	0.91
Coal	0.88	0.92	0.96	0.92	0.96
Biomass	0.73	0.76	0.79	0.76	0.79
Machine Drive (Efficiency)					
Electricity	0.93	0.95	0.97	0.95	0.97
Process Heat (relative)	0.85	0.87	0.89	0.87	0.89
HVAC (relative)	0.83	0.85	0.87	0.85	0.87
All other end uses (relative)	0.88	0.90	0.92	0.90	0.92

Table 3-1 (continued)

Residential Equipment	Historical 1990	Historical 2005	Reference 2050	Reference 2095	Advanced 2050	Advanced 2095
Shell efficiency (indexed to 2005)	1.03	1.00	0.81	0.63	0.76	0.47
Heating: energy out/energy in						
Gas furnace	0.70	0.82	0.88	0.91	0.88	0.91
Gas heat pump	na	1.30	na	na	1.67	1.90
Electric furnace	0.98	0.98	0.99	0.99	0.99	0.99
Electric heatpump	1.61	2.14	2.49	2.58	2.82	3.02
Fuel oil furnace	0.76	0.82	0.85	0.87	0.85	0.87
Wood furnace	0.52	0.58	0.66	0.68	0.66	0.68
Cooling: energy out/energy in						
Air Conditioning	2.16	2.81	3.76	3.90	4.18	4.47
Water heating: energy out/energy in						
Gas water heater	0.52	0.56	0.80	0.91	0.80	0.91
Gas hp water heater	na	na	na	na	1.53	1.91
Electric resistance water heater	0.84	0.88	0.95	0.96	0.95	0.96
Electric heatpump water heater	na	na	na	na	2.39	2.51
Fuel oil water heater	0.51	0.55	0.56	0.58	0.56	0.58
Lighting: lumens per watt						
Incandescent lighting	15	15	17	18	17	18
Fluorescent lighting	65	75	100	107	100	107
Solid-state lighting	na	na	122	127	152	186
Appliances and other: indexed to 2005						
Gas appliances	0.96	1.00	1.66	1.72	1.66	1.72
Electric appliances	0.70	1.00	1.42	1.47	1.58	1.80
Gas other	0.99	1.00	1.12	1.25	1.12	1.25
Electric other	1.04	1.00	0.98	1.01	1.42	1.47
Fuel oil other	0.99	1.00	1.05	1.09	1.05	1.09

Commercial Equipment	Historical 1990	Historical 2005	Reference 2050	Reference 2095	Advanced 2050	Advanced 2095
Shell efficiency (indexed to 2005)	1.13	1.00	0.88	0.67	0.85	0.55
Heating: energy out/energy in						
Gas furnace/boiler	0.69	0.76	0.85	0.89	0.85	0.89
Gas heat pump	na	1.30	na	na	1.67	1.90
Electric furnace/boiler	0.98	0.98	0.99	0.99	0.99	0.99
Electric heatpump	2.67	3.10	3.69	3.83	3.95	4.10
Fuel oil furnace/boiler	0.73	0.77	0.81	0.84	0.81	0.84
Cooling: energy out/energy in						
Air Conditioning	2.44	2.80	3.72	3.87	4.29	4.87
Water heating: energy out/energy in						
Gas water heater	0.72	0.82	0.93	0.93	0.93	0.93
Gas hp water heater	na	na	na	na	1.53	1.91
Electric resistance water heater	0.96	0.97	0.98	0.98	0.98	0.98
Electric heatpump water heater	1.39	1.93	na	na	2.39	2.51
Fuel oil water heater	0.74	0.76	0.80	0.82	0.80	0.82
Lighting: lumens per watt						
Incandescent lighting	15	15	17	18	17	18
Fluorescent lighting	65	75	100	107	100	107
Solid-state lighting	na	na	122	127	152	186
Office equipment and other: indexed to 2005						
Office equipment	0.96	1.00	1.09	1.13	1.42	1.47
Gas other	0.96	1.00	1.09	1.13	1.33	1.51
Electric other	0.96	1.00	1.09	1.13	1.33	1.51
Fuel oil other	0.96	1.00	1.09	1.13	1.09	1.13

na indicates that this technology was not available in that time period and/or scenario

The largest improvements in end-use technologies are heat-pump-based technologies and solid-state lighting. The performance of residential electric heat-pump heating and cooling technologies increases by 20% and 40%, respectively, in the reference case by 2095, and by 40 and 60% in the advanced case. Solid-state lighting efficiency increases from around 130 lumens per Watt in the reference case to 186 lumens per Watt in the advanced case. Costs for solid-state lighting also are assumed to decrease more than for other advanced technologies due to research advances in the advanced case (see Appendix A).

The "other" category of building electric loads is the fastest-growing building end-use energy category. Energy use for this category is not well defined, and the historical trends are not well constrained. Since efficiency for specific devices within this category were not identified, the assumed efficiency changes were indexed to a year 2005 value. In the advanced case the efficiency of all other electric loads was assumed to increase by 46% by 2095 relative to the reference case.

Further details on the assumptions for end-use technology assumptions are given in Appendix A.

"No Tech Change" Case Assumptions

For illustrative purposes a "no tech change" case was also examined. For this case, no improvements for end-use technologies are allowed for the rest of the century. The efficiencies and costs of current end-technologies are held constant at their 2005 levels. No new technologies are allowed. The technology mix is not held constant, however. The normal technology selection process used in the model (Section 2.2) is allowed to operate.

Scenario Results

Figure 3-9 shows a summary of scenario results for the United States in the form of total CO_2 emissions. Total emissions for reference and advanced case energy efficiency are shown. For comparison, U.S. emissions under the CCSP 550 ppm stabilization climate policy scenario is shown, as well as emissions from the "no technical change" case scenario, where no energy efficiency improvements are assumed to take place.

Assumptions for end-use energy efficiency have a substantial impact on carbon emissions in the United States. In the reference case, scenario emissions increase by a factor of 2.5 over the twenty-first century. The adoption of more advanced end-use energy technologies lowers carbon emissions, with emissions growth damped to a factor of 1.5 over the century. The growth in carbon emissions over the next 50 years slows considerably in the advanced end-use efficiency scenario. Emission eventually increase, however, as increased service demands begin to outpace efficiency improvements. In the very near-term, over the next 10–15 years, emissions continue on their upward trajectory, with efficiency changes beginning to flatten emissions growth in the advanced case after 2020.

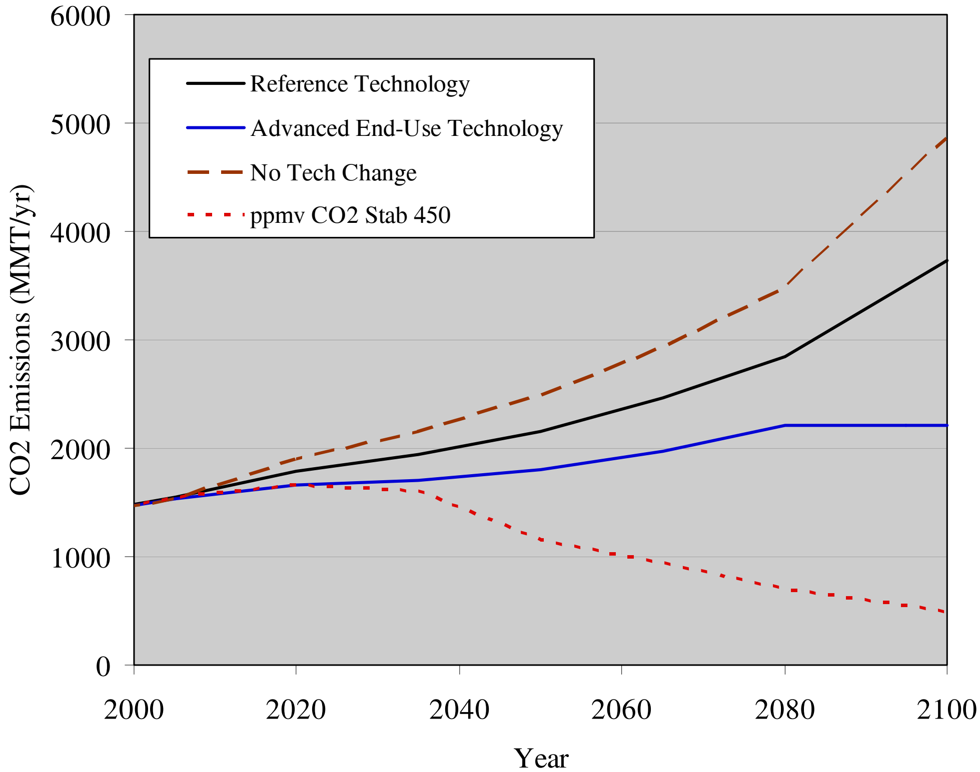


Figure 3-9. U.S. carbon emissions with reference, advanced, and "no tech change" scenarios. Carbon emissions for the United States are reduced significantly by the energy efficiency improvements assumed for the reference case. Only end-use efficiency assumptions were changed in these three scenarios. Energy supply assumptions are not changed across scenarios.

Some of the key details of the scenario results will now be examined. Steadily increasing demand for services (Figure 3-8) leads to energy consumption increases in the reference case, as shown in Figure 3-10. Energy consumption increases less rapidly than the demand for services, due to energy efficiency improvements. Energy consumption from transportation and buildings, both residential and commercial, comprises an increasing share of future energy demands. This is due to the research team's assumption that the long-term historical trend of increasing demand for floorspace and transportation services with income continues over the next century.

The "no technical change" scenario illustrates that, in the absence of any end-use energy efficiency improvements, emissions would increase much more than in the reference case. Carbon dioxide emissions are 30% higher by the end of the century without the reference case energy efficiency improvements.

While the case with no end-use technology improvements is not a realistic future scenario, it does demonstrate the impact of reference case technology improvements. Note that the no technological change assumption was only applied to energy-end use technologies. Energy supply technologies such as electric generation plants were still assumed to improve over the century in this result. If no technological change were applied to energy supply technologies, the impact of no improvement in end-use efficiency would be magnified as even more primary energy would be required to produce electricity or other end-use fuels.

In the building sector, end-use energy demands become increasingly supplied by electricity. This is a combination of two trends. First, the demand for information technology services powered by electricity such as computers, music players, and televisions is increasing rapidly. In addition this study assumes the continued development of heat-pump technology that allows some portion of heating services to be cost-effectively supplied by electricity instead of primary fossil fuels. The industrial sector also experiences electrification, although to a somewhat lesser extent, as some services (such as process heat) are supplied most cost-effectively by primary use of fossil fuels or biomass. Note that solar process heat might be a future option in some regions, but this was not included in this study.

The deployment of more advanced end-use technologies results in lower energy use overall, as shown in Figure 3-11. Electricity consumption decreases 25%, natural gas 29%, and liquid fuels used in the transportation sector 33%.

The reduction in the use of natural gas consumption is due to both improved efficiency and an enhanced switch to electricity. Many advanced technologies, particularly heat pump technologies, are based on electricity and advances in these technologies increase the number of situations where electricity-based technologies are more economically attractive than gas technologies.

Residential "other" electricity consumption increases to 25% of residential electricity consumption by mid-century, with this fraction roughly constant thereafter.

3.2.4. Climate Policy and The Value of Energy Efficiency Technologies

The effect of a climate policy on end-use energy is now examined. To construct the climate policy cases, the global model, including the detailed U.S. energy demand sectors, is constrained to follow the global emissions paths shown in Figure 3-1. To isolate the effect of advanced end-use technologies on the United States, both the reference and advanced end-use technology cases are constrained to follow the same emissions pathway for the United States.

The United States emissions path was determined by first running a scenario where global carbon emissions are constrained to follow one of the paths shown in Figure 3-1 using reference case technology assumptions for all end-uses. The resulting emissions paths for the United States and for the rest of the world are determined from this run. To determine the impact of advanced energy efficiency technologies, the United States is held to the same emissions path, but with more advanced energy end-use technologies deployed. Simultaneously, the rest of the world is also held to the emissions path for those regions under the reference case technology run.

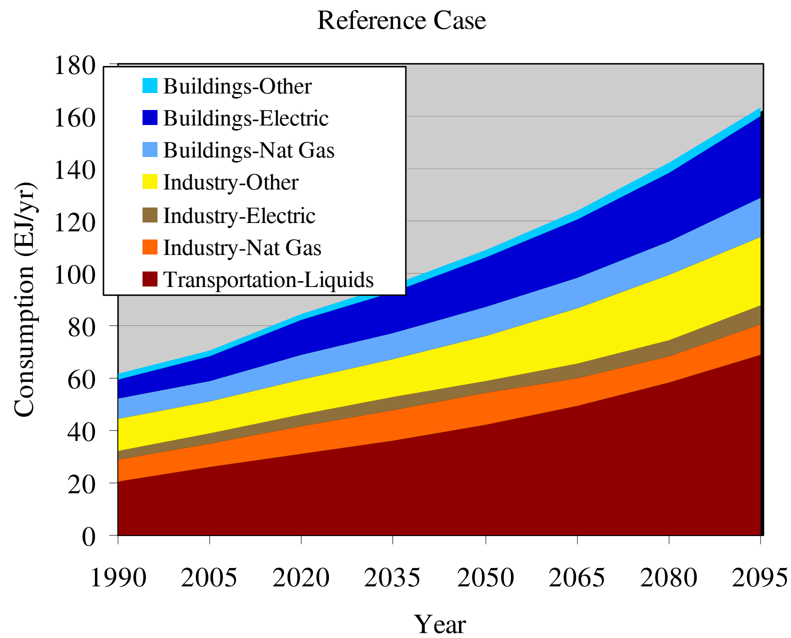


Figure 3-10. U.S. end-use energy consumption for reference case end-use technologies. End-use energy consumption increases substantially under the reference case. Energy consumption increases slower than service demand due to increasing efficiency.

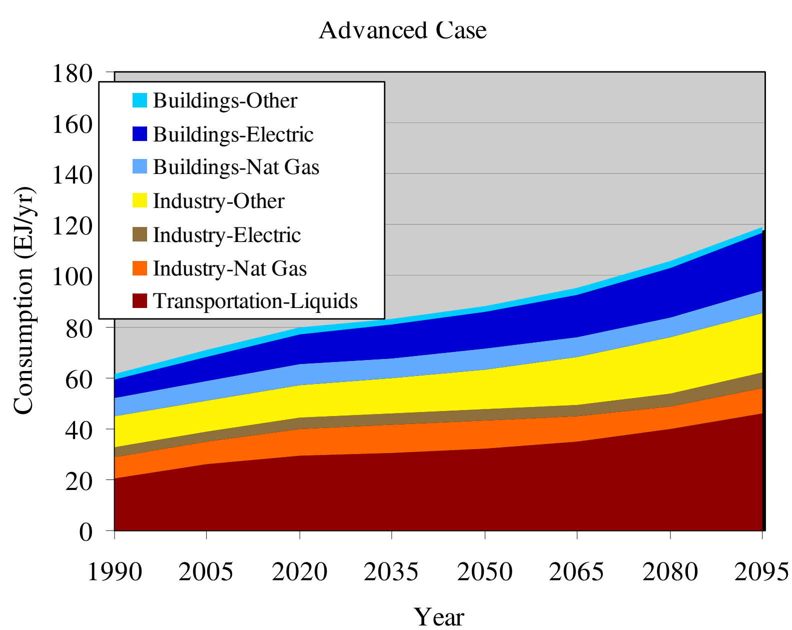


Figure 3-11. U.S. end-use energy consumption for advanced case end-use technologies. End-use energy consumption increases at a much slower rate with the deployment of advanced end-use technologies.

This structure isolates the impact of advanced technologies on climate policy costs in the United States. This isolation was necessary because advanced end-use technology representations are not available for other world regions. The global context for CO_2 concentration stabilization is, thus, included in that the global emissions pathway must still achieve concentration stabilization. While there could be differential effects of efficiency in different world regions, these could not be considered in the current analysis.

Increases in energy prices under a carbon policy do induce some reduction in energy services. Consumption of goods such as building floorspace and transportation services changes very little due to a climate policy. Total floorspace varies by 1% or less in these scenarios. This is because energy prices are a relatively small component of energy service costs.

Consumption of building end-use services such as lighting and heating vary a bit more, because energy costs are a larger portion of these services. A long-term price elasticity of -0.4 for building end-use services was assumed for this analysis. With this elasticity, there are noticeable changes in services due to price effects. This is illustrated in Figure 3-12, which shows lighting service for the reference and advanced cases, as well as the corresponding 450 climate stabilization cases. In the advanced case, the cost of lighting service decreases due to the assumption that cost-effective solid-state lighting devices are developed. The lower cost of these devices, both in terms of capital cost per unit output and lower operating costs, leads to an expansion of their use. While energy use is still lower in the advanced scenario due to this development, energy consumption for lighting is not as low as it would have been if lighting services were assumed to be constant.

The effect of a carbon policy that stabilizes emissions at 450 ppm is to reduce lighting services relative to the no climate policy case. For the assumptions considered here, the effect of the carbon policy is smaller than the effect of the assumed changes in lighting technology between reference and advanced scenarios.

Overall, under the 550 stabilization case, the effect of a carbon policy on the end-use sector is relatively small. Some fuel shifts are seen, but much of the climate response occurs upstream, as electricity production shifts to low or no-carbon technologies and some liquid transportation fuels are replaced by liquids derived from biomass. At the higher carbon prices seen in the 450 scenario, a substantial shift is seen away from natural gas consumption in end uses. Natural gas consumption declines after 2035 in the 450 case, in both reference and advanced end-use efficiency scenarios.

The lower final energy consumption enabled by advanced energy efficiency technologies (Figure 3-11) enables a climate policy target to be achieved at a lower cost. This is because the difference between the reference and policy cases is smaller with enhanced energy end-use efficiency, as shown in Figure 3-9. In the advanced efficiency case, emissions without a climate policy fall at or below the reference case 450 stabilization target path in the initial years, meaning that, in this case, the reduction policy can be delayed, lowering net costs.

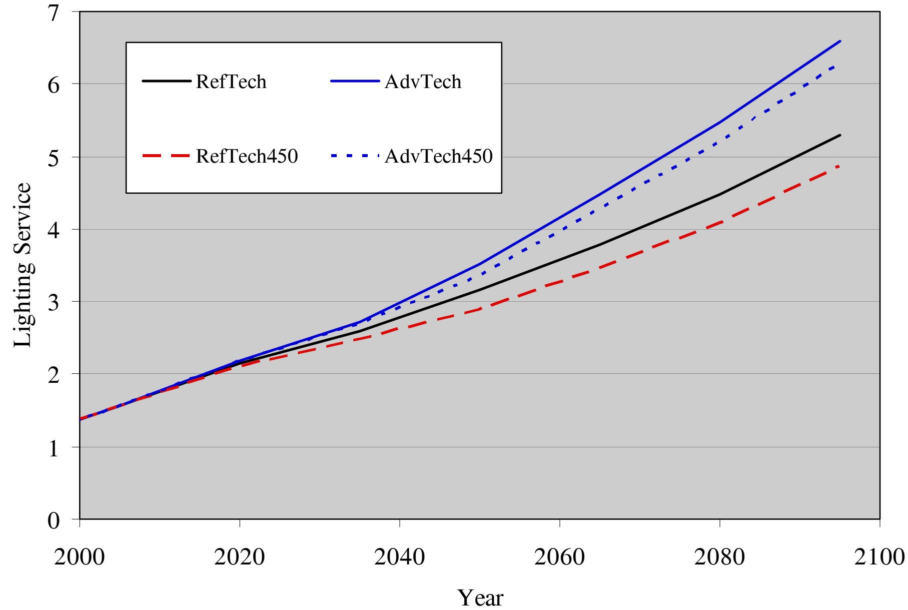


Figure 3-12. U.S. lighting service (arbitrary units). Lighting service (lumens) increases as the number and size of buildings increase over the century. Changes in the price of lighting services, however, noticeably affects the amount of lighting service used by consumers.

The value of energy efficiency was measured by computing the total discounted cost of emissions mitigation for a fixed United States carbon emissions path for the reference case, and again for the advanced energy-efficiency case. As shown in Figure 3-13 costs for the enhanced energy efficiency case are substantially lower with enhanced energy efficiency. The total discounted cost of the policy is decreased by 75% in the 550 stabilization case and 55% for the 450 stabilization case.

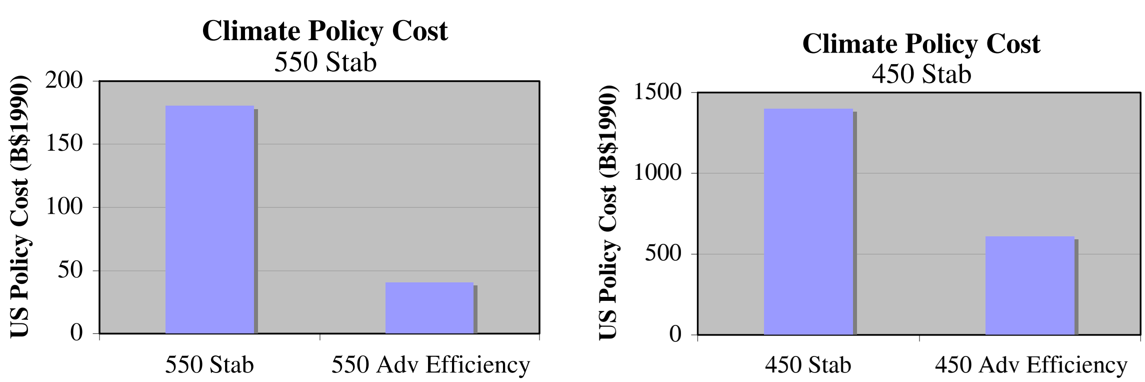


Figure 3-13. Total U.S. climate policy costs for 450 and 550 stabilization scenarios. Climate policy cost is calculated as the sum of total emission permit prices (carbon price time emissions mitigation amount) discounted over time at 5%.

The relative value of efficiency in fractional terms is slightly smaller for the more stringent target because more of the emissions reductions need to occur in the near-term, before efficiency improvements have had a chance to penetrate. The absolute value of efficiency reductions, as measured as the difference in cost, is much higher for the 450 stabilization target, however: 400 versus 70 billion dollars for the two cases. This difference is because the lower stabilization target is substantially more expensive. Undiscounted costs range from 0.5%–2% of GDP by the end of the century.

Note that the value of technology analysis presented here was constructed by not allowing any interaction between mitigation in the United States and the rest of the world. The same U.S. emissions target was applied in both reference and advanced technology scenarios. This construction was necessary due to the different level of end-use energy detail in the United States, which allowed an advanced efficiency scenario to be constructed for the United States but not for other regions. Interaction between regions would be expected under policy frameworks that allow permit trading. Actual costs incurred by a region would depend on details such as the policy structure and initial permit allocations. Differences in energy efficiency potential in different regions would play a role as well. The general point illustrated here, however, would still hold. That is, that the deployment of more efficient end-use technologies would substantially lower the cost of climate policies.

3.3. Wind and Solar Energy

3.3.1. Introduction

Wind and solar technologies are characterized by large resources, no direct emissions of pollutant or greenhouse gases, and the capability to produce sustainable energy indefinitely. Consequently, these technologies have enormous potential for meeting a significant portion of the world’s future energy demands with little impact on climate. However, large-scale deployment of wind and solar technologies raises unique research and systems analysis issues.

The first issue involves limits on availability. In contrast to other sources of electric power, wind and solar are intermittent resources in that their availability, while predictable, cannot be completely controlled. In addition, wind and solar power generators must be located where the physical resources exist, often requiring an investment in transmission capacity to deliver power to populated load areas.

Moreover, current wind and solar technologies require large up-front capital investment, although they offer low recurring costs. The present and future potential of these technologies will be determined in part by the extent to which technological developments can lower their capital cost. Finally, wind and solar generators are typically much smaller than fossil and nuclear plants, requiring multiple units over a wide area to build up to a large scale. This dispersion results in challenges for land use and environmental aesthetics. The extent of eventual deployment of these technologies will depend on land-use decisions and social acceptability.

To model the potential impact of wind and solar technologies, the research team has implemented a resource- and technology-based representation. For wind and solar, a set of resources, denominated in square kilometers available and distribution of distance to the electric transmission grid, was developed based on relevant characteristics such as direct and total irradiance, annual cloudy days, and wind speed and height. Wind and solar technologies are represented by their capital and operating costs and efficiencies of converting resource energy to electricity.

3.3.2. Renewable Energy Model Components

Wind Resources and Technology

To examine multiple scenarios and incorporate many possible future changes in technology, a model for wind energy generation and transmission costs in the U.S. was developed, drawing from geographically explicit datasets. This model incorporates high-resolution spatial datasets for U.S. wind resources combined with land-use exclusions, extant electricity infrastructure, and population. Scenarios can then be run with varied assumptions, such as exclusions, transmission costs, or reserve margins.

The data used in this model are based on wind resource data developed by the National Renewable Energy Laboratory (NREL) and partners for the contiguous United States (NREL 2006b). In summary, total land area in the NREL estimates was divided into 358 wind resource regions, and within each region, the number of square kilometers having each of seven wind speed classes was estimated. Speed classes are defined by the average annual wind speed in a given small region, and for these calculations researchers assumed the average wind speed of each class to be the midpoint of the range for each wind class.

Wind turbine density, defined as the capacity of wind turbines per unit of land area, was specified as 5 megawatts per square kilometer (MW/km^2), in accord with NREL (2006b). In general, wind turbines are spaced on the basis of multiples of turbine blade diameter, which makes turbine density roughly independent of turbine characteristics, since turbine rating tends to scale as the square of blade diameter. If turbines are spaced too close together, then the wake from upwind turbines will lower the energy production of turbines downwind. For instance, the U.S. Department of Energy (DOE)/Electric Power Research Institute (EPRI) (1997) assumed that class 4 wind sites with rectangular turbine arrays would result in a loss of 4% of farm energy in 2010, whereas no array losses were assumed for class 6 wind sites.

Exclusions to the wind resource are defined as geographic areas that may not be suitable for wind power production due to social factors, physical constraints, or prior land designation incompatible with wind power development. For instance, turbines should not be located immediately adjacent to homes for safety reasons, aesthetic impacts, and noise.

In general, the physical exclusion criteria have been chosen to be similar to those used in calculations used in the NREL WinDS model. Inland bodies of water are excluded, due to the social valuation of waterfront property and water-based recreation, and due to the logistical difficulty of their development for wind power. Slopes greater than 20% are similarly excluded for logistical challenges.

All public park lands and nature preserves are excluded, with the exception of Department of Defense (DoD)and Forest Service lands. A 50% exclusion was applied to all DoD lands, and likewise to Forest Service lands not specifically designated as wilderness, study, conservation, or roadless areas. This allows for the possibility that future wind power development may take place on some of these lands.

In the initial calculation, researchers excluded areas with population densities greater than 321 people/km^2, assumed to be urban or threshold urban areas. For areas with population densities less than this, maximum turbine density is assumed to be a negative linear function of the population density. At densities less than 50 people/km^2, no population-induced constraint to turbine density is applied.

Figure 3-14 shows a calculation of the resulting distribution of available land area, by wind speed class, for classes 3 to 7. As shown, available land area for wind power development decreases with increasing speed class. Because the higher speed classes have the highest capacity factor (power generation), there is a trade-off between site quality and availability (and thus power transmission costs).

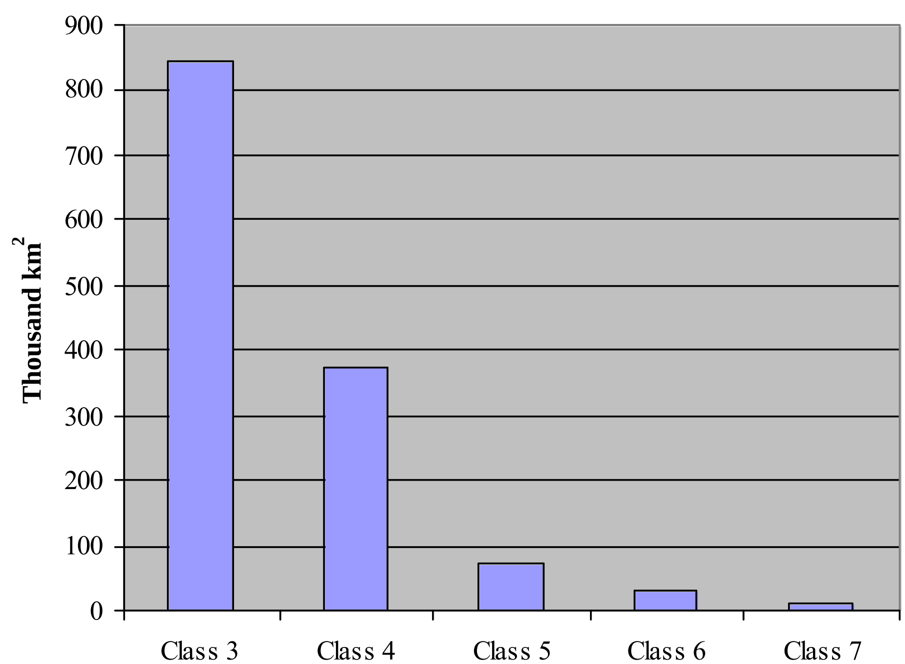


Figure 3-14. U.S. Wind resource area by wind power class. Wind resource area is inversely proportional to wind speed. Class 7 represents the best wind resource, with the highest speed winds.

For integrated assessment modeling of wind energy, it is necessary to have an estimate of the potential power generation as a function of cost, appropriately averaged over time and space. To estimate the cost, there are two primary costs considered, shown in Equation (5), the generation cost and the grid connection cost.

(5) Wind cost (x,y) = Generation + Grid Connection Costs

Wind generation costs can be broken down into capital and operating costs of wind turbines, generally expressed as the cost per kilowatt (kW) of rated capacity.

The other component of wind energy cost is the additional cost of power transmission and grid connection, in excess of costs for other electric energy sources. Transmission and distribution costs that are generic to any electric power delivered to users are not considered in the wind component of electricity production in the model. The grid connection cost calculation includes the cost of the electric lines per unit of distance, and the distance required to connect to the grid from any point. To estimate the distance to the grid, GIS data for the U.S. electricity transmission and distribution network from the Platts PowerMap database (Platts 2001) was used. At high penetration levels grid reinforcement costs, or the cost to establish new transmission capacity to connect wind generation areas to load centers, may be needed. These costs were not considered in this calculation and will be discussed below.

Because of the intermittency of the wind resource, wind additions to electric generation require greater operating reserve than would generation from dispatchable energy sources such as fossil fuels, hydroelectricity, or nuclear power. Following the formulation used in the National Renewable Energy Laboratory WinDS model (NREL 2006a), this constraint is modeled by requiring:

(6) Additional Requirement = $\sqrt{ReserveRequirement^2 + \sigma^2 W^2}$ - Reserve Requirement

In equation (6), ReserveRequirement refers to the reserve requirement that would apply to new electric generation from dispatchable sources, which is needed in the event of generation and transmission failures. Wind generation and its variance are W and σ2, respectively. This equation specifies the amount of additional quick-start reserve capacity that would need to be provided as wind penetration increases. An intermittent energy resource such as wind adds variability into the system and, therefore, requires additional reserve capacity to maintain system stability. This equation assumes that wind variability is uncorrelated with demand variability.

Wind technology descriptions were drawn from the latest NREL projections (NREL 2007). This study's reference and advance cases correspond to the NREL reference and program cases, respectively. Capital costs for wind turbines are summarized in Table 3–2. Capital costs for wind turbines decrease significantly through to the end of the century, with larger decreases in the advanced technology case.

Table 3-2. Capital cost assumptions for wind turbines in units of $2004 per kW of rated output

	Class 4		Class 6	
Year	*Reference*	*Advanced*	*Reference*	*Advanced*
2005	1185	1185	1185	1185
2020	1167	1167	1167	1167
2035	1040	946	961	818
2050	1014	862	948	777
2065	998	839	935	747
2080	983	827	921	736
2095	968	814	907	725

Solar CSP

Concentrating solar thermal power (CSP) systems, such as solar trough and power tower systems, are a central station electric power technology that, in areas with sufficient direct solar irradiance, may provide electric power at a lower cost than central station photovoltaics (PV). The CSP thermal systems are also attractive in that they can provide predictable power through the use of relatively inexpensive integrated hybrid systems (usually gas-fired). Though not analyzed here, one potential future CSP technology development could be the incorporation of thermal storage, lowering the need for backup and allowing more dispatchability of the solar resource.

As with wind technologies, the total cost of electricity from CSP systems is the sum of the CSP generation cost and the cost to connect to the grid and transmit electricity to load centers. In contrast to wind resources, the solar resource areas are much larger. As a result, the distance of quality resources to the grid is much smaller, and grid connection and transmission costs are less of a factor. Calculation of the CSP generation cost is a function of capital costs, financing assumptions, and conversion efficiencies. However, the amount and cost of generation from hybrid backup operation must also be considered.

The total generation from the CSP system is the sum of the amount of generation from solar resources and the amount of generation required from backup. To compute these components, the solar availability must be compared to the electric demand profile and the other electric capacity available to meet demands in the intermediate and peak times of electric demand (i.e., during the middle of the day and the early evening). With near-zero variable costs, once built, CSP capacity will be used when the irradiance is sufficient. On cloudy or no-sun days, the CSP backup will have to operate to serve demand that cannot be met by other electric generating capacity. Conversely, if solar generation exceeds demand, then some of the solar output will be lost if there is no storage available.

At low to moderate penetration levels, gas-fired backup capacity is not necessary, except for use on cloudy days, if idle capacity elsewhere in the system is allowed to serve load.

Calculations detailing the amount of CSP generation and backup are given in Zhang and Smith (2007). As an illustration, Figure 3-15 shows the percentage of backup generation required as a function of CSP market penetration at three representative sites. Here, CSP market penetration is defined as the percentage of total intermediate and peak electricity supplied by CSP technology (including hybrid backup operation). From the figure, the amount of backup generation is rather small at market penetration levels below about 45%. This small amount corresponds to the backup generation needed on cloudy days. Beyond this point, backup generation increases steadily. However, depending on other policy and economic conditions, these higher backup requirements do not preclude higher penetration levels.

This calculation takes into account seasonal and time-of-day output profiles for a CSP plant in the locations shown. Note that this calculation assumes that the gas-fired hybrid backup capacity is only used when necessary to meet load demand and other intermediate and peak capacity is not available. For example, if there is need for additional capacity to meet load demands at a winter afternoon, then at modest penetration levels sufficient otherwise idle intermediate and peak capacity is available to meet this demand and the hybrid backup system is not used. This is because the use of hybrid backup is assumed to be subject to losses associated with operation of the CSP plant and has, therefore, a lower net electric conversion efficiency as compared to a stand-alone combustion turbine (and much less efficient than a combined-cycle turbine, if such units were available).

Note that, in current market conditions, some CSP plant operators choose to operate in hybrid mode in excess of the levels shown in Figure 3-15. This is because these plants were built as demonstration units, and once built are operated to maximize revenue. Under competitive market conditions, the relative cost of solar CSP output and gas-fired output would be different from conditions today, and the optimal long-term system operation profile would approach the conditions shown in Figure 3-15.

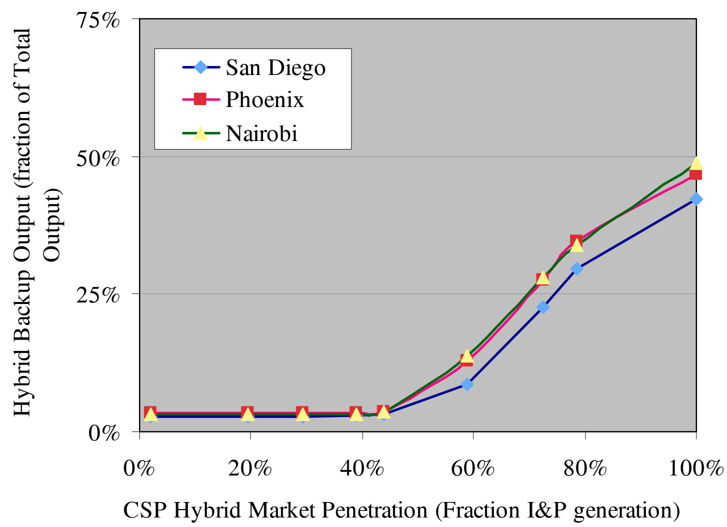


Figure 3-15. Backup requirement for CSP thermal solar plants as a function of market penetration

An analytic representation of the curve shown in Figure 3-15 is included in the model simulation to account for the need for hybrid backup operation. In addition, a similar representation for lost solar output as penetration increases is also included.

Initial CSP capital and operating costs, finance costs, and conversion efficiencies for this modeling effort were derived from Kearney and Price (2005). For the reference case results shown in the next section, capital and operating costs were assumed to decline by 0.5% per year while efficiencies increased from 14% to 18% by the end of the century. For the advanced case, costs declined 1% per year while efficiencies increase to 22%.

Solar resource data at a one-degree spatial resolution were obtained from the National Aeronautics and Space Administration (NASA) Surface meteorology and Solar Energy project.[3] Where the required type of solar resource data were not available from NASA, the closest available category was used and values were scaled by comparing with point estimates from NREL and scaling the NASA data to match the NREL estimate. This provides a reasonable solar resource estimate for the current analysis, which focused on direct solar irradiance in high resource areas in the southwestern United States.

3.3.3. Renewable Energy Contribution

To assess the potential contribution of wind and solar to the electric supply in the United States, the penetration of these technologies was modeled under both reference and advanced technology assumptions. These scenarios were run using the ObjECTS MiniCAM integrated assessment framework, analyzing the economics of these renewable technologies within a consistent context of improvements in other types of energy technologies.

Wind

The results of this study indicate that wind energy may become the largest renewable energy resource. Wind turbine technologies are proven and mature, and competitive or near-competitive in many areas. Wind energy is available year-round and around the clock, which allows it to displace baseload coal and gas power, and therefore reduce CO_2 emissions significantly. Figure 3-16 shows wind penetration in the U.S. electric power sector under reference and advanced technology assumptions.

Wind power under reference assumptions grows quickly, reaching over 20% of electric supply by 2050. Under advanced technology assumptions, growth would be even higher, exceeding 30% by 2050. Beyond 2050, growth slows under both sets of assumptions as the remaining available wind resources are more costly while competing technologies improve. In this study, as well as studies by others, the incremental costs of maintaining system reliability due to wind's intermittency do not become significant until higher penetration levels are reached. At a 20%–30% penetration in these scenarios, these costs increase, but they are not a prohibitive factor.

[3] See http://earth-www.larc.nasa.gov/solar/.

The deployment of wind grows rapidly from 2005 to 2050 under these assumptions. In these scenarios wind was assumed to complete on economic terms equally with other electric generation sources by 2050. The maximum rate at which wind capacity could be deployed in the intermediate years is not clear. There could be limits to the deployment of wind not explicitly considered here that might lower the actual growth in wind deployment. Conversely, deployment could grow at a faster rate than shown here.

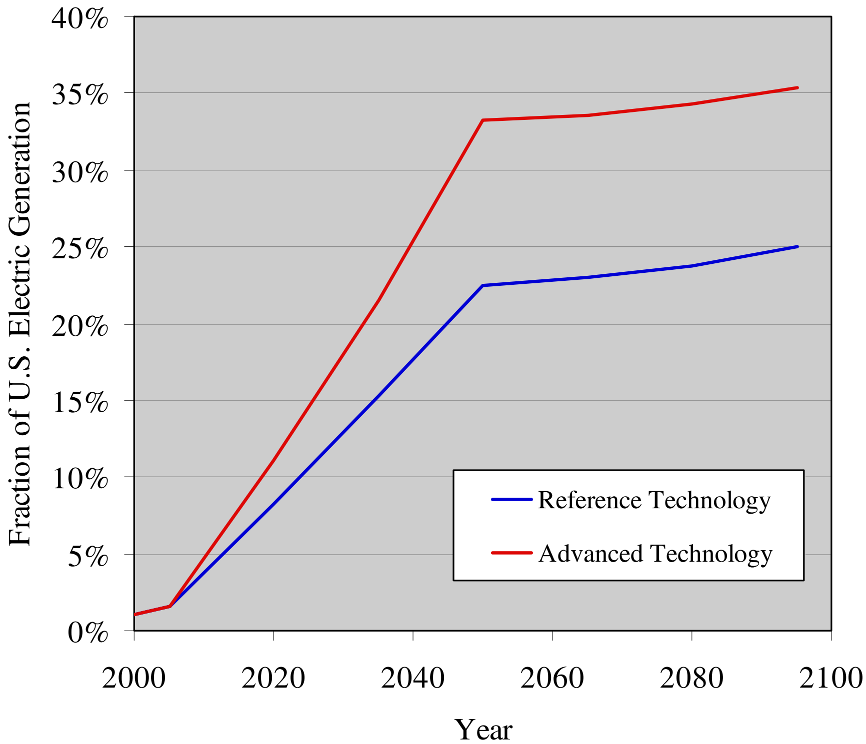


Figure 3-16. Wind as fraction of total U.S. electric power generation. When considered using only economic costs, wind generation could supply a large fraction of U.S. electricity generation. The fraction is defined in terms of energy generation, not capacity.

Note that several potentially important factors are not considered in the results shown here. First, only the cost of connecting wind generation sites to the existing transmission grid are included. At high penetration levels new lines would need to be built, or existing transmission grids reinforced, to transmit power to load centers. Neither this cost, nor any difficulties that might be encountered in building additional transmission capacity, was considered. The loss of wind generation during times when generation exceeds either load or local grid transmission capacity was also not considered. These factors would tend to reduce the penetration of wind.

Offshore wind resources were not considered. Offshore wind could potentially be connected to load centers by use of transmission lines along, or under, the ocean floor. While more expensive to build, such lines might not encounter the level of opposition that large terrestrial transmission line projects often encounter. Turbines sited in ocean areas, however, have encountered opposition in some regions. Turbines sited in deeper water more distant from the shore may be more acceptable, but at a the price of increased construction and transmission cost. Offshore wind generation has an additional advantage: ocean winds tend to peak in the daytime, rather than at night, which coincides better with demands. The inclusion of offshore wind resources would tend to increase the penetration of wind technologies.

Because quality wind resources are often available far from electric demand centers, the ability to transmit generation to load centers is a critical factor. To examine this, researchers conducted a sensitivity analysis of the impact of grid connection costs on wind penetration. Figure 3-17 shows the penetration of wind under four scenarios of transmission access. As a proxy for the ability to build new transmission capability, input values for transmission costs were varied from 5 to 50 times the estimated average line construction cost of $1500 per MW-km. The additional amounts stand in for difficulties encountered in obtaining approvals for building transmission lines due to a variety of factors. Transmission line costs vary substantially due to local circumstances. The base value used here is taken from EIA (2002), multiplied by a factor of 1.5 to account for sub-grid scale geographic heterogeneity.

Figure 3-17 shows that the ability to build additional transmission lines is important, and may be a limiting factor in the penetration of wind. At high penetrations, the grid will also need to be augmented to transmit power directly to load centers, and the ability to do so may also be critical to the widespread use of wind.

Solar CSP

Solar CSP power is, unlike wind, only available directly during the day. For that reason its total contribution may not be as large as that from wind power, however its contribution to providing clean and carbon-free energy may still be quite significant as technologies advance. Model scenarios including thermal CSP plants, shown in Figure 3-18, result in CSP penetration of approximately 10% by the end of the century under reference technology assumptions and 15% under advanced technology assumptions.

Because CSP operates only in the daytime, these high penetrations imply that a fraction of baseload capacity would need to operate at “turn-down” or reduced levels during the day to accommodate these high penetration levels. For example, see Denholm and Margolis (2006) for an analysis of PV technologies in this situation. The economics of this situation were not fully captured by the current model structure, however, so these results need to be viewed as preliminary.

At very high penetrations, the system may even build intermediate capacity that runs at night but not during the day, in contrast to standard practices today, but not unimaginable. And beyond these results, a cost-effective thermal storage could allow CSP to generate some power at night. This strategy could displace baseload generation and any associated CO_2 emissions.

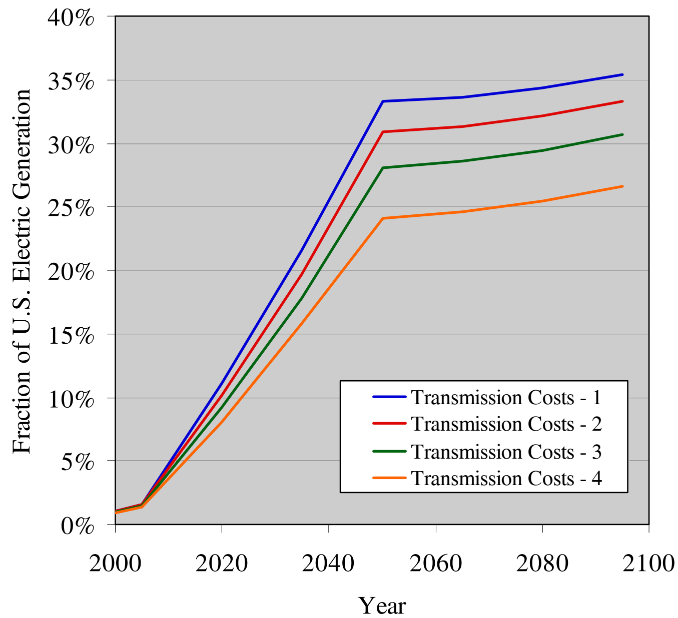


Figure 3-17. Wind penetration as a function of access to transmission capacity. The ability to connect wind resources to the transmission grid, and to load centers has a significant effect on wind penetration, particularly at high penetration levels.

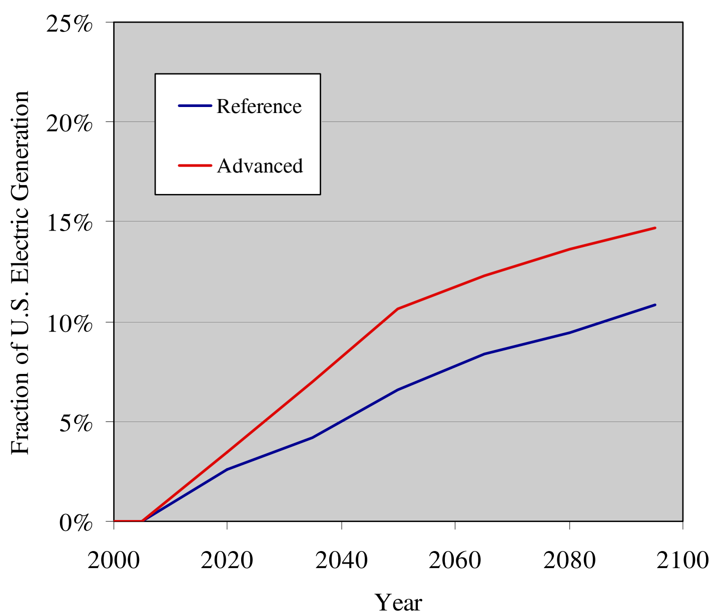


Figure 3-18. Thermal CSP penetration for reference and advanced case technologies

Solar PV

Solar photovoltaics (PV) will also become more cost competitive in the coming years. Unlike CSP, they can be distributed, and can be placed at load centers; even on rooftops. Distributed resources have some advantages in system reliability versus a central power station, but the main economic benefit for distributed PV may be in avoiding the construction of new transmission and distribution lines. These lines are often very expensive to construct, or more important, difficult to get approved.

However, since CSP is a thermal technology, it is possible to integrate thermal storage or backup fuel with heaters to generate electric power on cloudy days. This is not possible with PVs, so that other means of maintaining reliability are crucial when penetration of PVs becomes significant. It is often the case that solar irradiance is correlated with temperature, which helps alleviate reliability concerns.

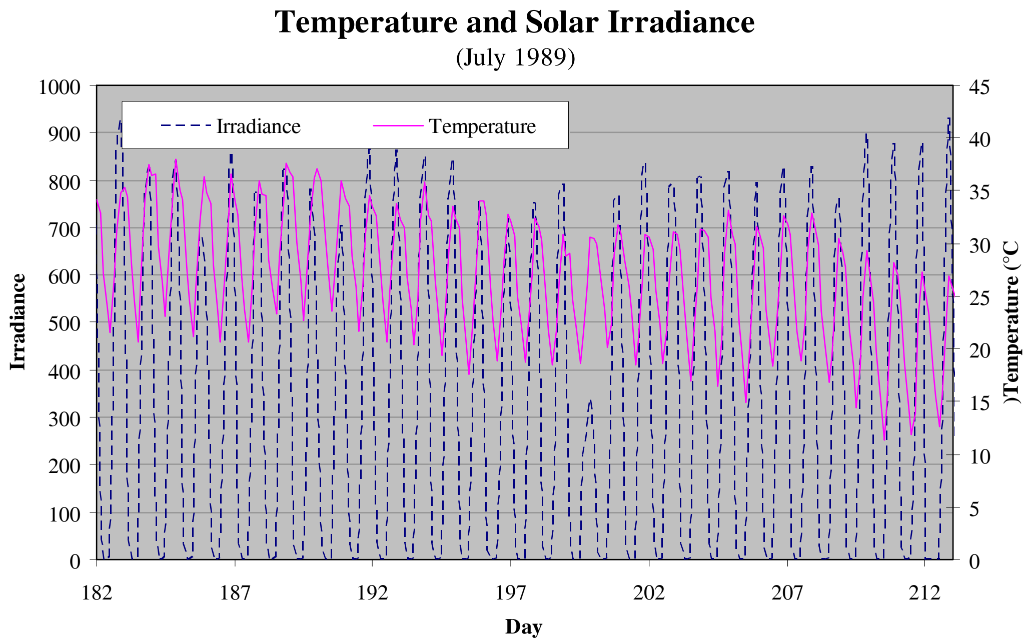
However, this correspondence cannot be guaranteed, as shown in Figure 3-19, which shows an example of irradiance and temperature, plotted every three hours for a location near Bakersfield California for July 1989 and August 1988. There is a significant correlation between temperature, and therefore cooling loads, and solar irradiance. There are, however, some days, and at times a series of days, where irradiance drops while temperature remains high. In July 1989 only one such day occurred. While this may be typical for this location, situations such as that illustrated for August 1988 also can occur where several cloudy, but otherwise hot, days occurred in sequence.

In cloudy, hot days, the system would have to have other capacity in place to provide electricity that is not available from the PVs. At low penetration levels, enough system reserve capacity may be available to handle this situation. At higher penetration levels, however, additional reserve capacity of some sort would be required to provide reliability in all weather conditions. The physical nature of the variation is important, as a drop in solar irradiance can be caused by large-scale weather patterns that would dramatically decrease solar output over large areas. So it is both the magnitude and the correlation of the variance that is important. Although this additional reserve requirement may not be prohibitive in terms of cost, it must be considered for the larger system as a whole, not just for individual installations.

3.4. California in Context

3.4.1. Introduction

While long-term climate policy must be nearly global in scope, mitigation actions will occur within a local context. The aim of this portion of the project is to put the California energy system into this context, focusing on building energy-use and renewable energy. California sub-modules were constructed for residential and commercial building energy demand and solar and wind electricity generation.



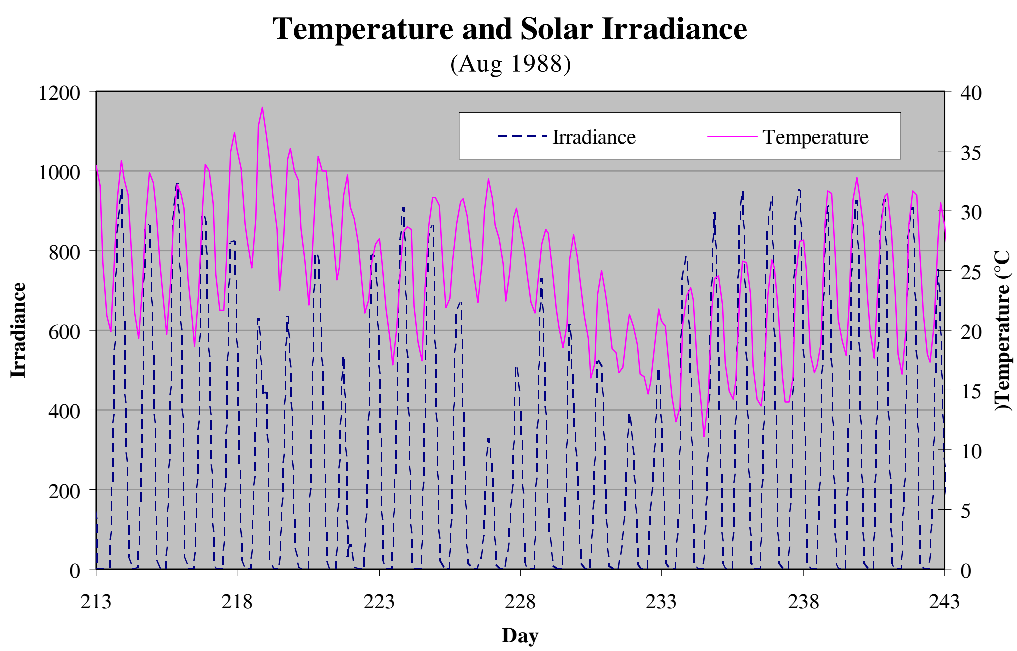


Figure 3-19. Correspondence between temperature and solar irradiance. Two different months are shown. In July 1989, there was only one cloudy day (about day 200) where temperatures remained high. In August 1988, however, there were a number of days where temperatures remained high, but solar irradiance was small. Data for Latitude: 35.5 N, Longitude 118.5 W. Solar irradiance value is the total insolation incident on a horizontal surface.

Source: NASA SEE (http://earth-www.larc.nasa.gov/solar/)

Note that a full California sub-model was not constructed for this analysis. However, the research team modeled the building demand sector (which is the primary determinant of the diurnal electric load curve) and wind and solar energy generation (which have important spatial heterogeneity). These components are embedded within the national and global modeling framework, allowing the examination of the long-term evolution of the California energy system over the twenty-first century.

3.4.2. California Building Scenarios

Floorspace Projections

Floorspace is an important determinant of building energy demands. The larger the conditioned floorspace, the more energy is required to heat and cool the space. Historical trends show that energy services such as appliances and lighting tend to grow as floorspace grows. Hence, the foundation of a California building energy consumption scenario is a meaningful California floorspace scenario.

As with the United States, the California buildings region is divided into two subsectors, California residential buildings and California commercial buildings. Two additional sectors were then developed to represent residential and commercial floorspace in the rest of the United States (ROUS). These scenarios were developed so that the sum of the California and ROUS residential and commercial scenarios is equal to the aggregate U.S. residential and commercial floorspace used in the full U.S. analysis.

On a per-capita basis, California and ROUS residential floorspace growth rates are taken to be identical in the scenarios, roughly consistent with historical trends. However, total California residential floorspace growth outpaces the ROUS through roughly 2040 because California population growth rates in these scenarios lead the ROUS over that same period. At the same time, Californians have historically used less floorspace per capita than the ROUS, and this trend continues in the scenarios here.

The historical trends in commercial floorspace indicate that California growth on a per-capita basis has been lower than for the United States in total, although total per-capita commercial floorspace has been higher in California than in the ROUS. (Note that there are a number of data collection and aggregation complexities in the commercial sector that tend to complicate the interpretation of differences between California and U.S. historical trends.) The floorspace scenarios here continue the trend of lower California commercial floorspace growth. By 2020, per-capita floorspace in California is lower than in the ROUS and continues to grow at a lower rate throughout the century. Again, however, higher California population growth up through 2040 tends to increase total California commercial floorspace growth relative to the ROUS.

Building Energy Projections

A detailed description of the building end-use technology assumptions used for California are given in the Appendix. The 1990 and 2005 data are calibrated to results from the California Energy Commission (Energy Commission) demand forecasting model. First period results from the model in 2020 were generally consistent with Energy Commission projections to 2016.

Energy efficiencies are generally assumed to be higher in California than for the rest of the United States. In some cases this difference is assumed to converge over time as federal efficiency standards take effect. In other cases California energy efficiency is assumed to remain ahead of the rest of the United States for the entire projection period. Note that only one California building scenario is presented here. This scenario is best compared to the U.S. reference case scenario discussed above. This point is discussed further below.

The combination of lower floorspace growth (Figure 3-20 and Figure 3-21) and continued energy efficiency improvements results in per-capita electricity demand that remains flat in California while increasing significantly in the rest of the United States (Figure 3-22). Total residential electricity consumption, however, still increases by a factor of 2.8 from 2005 to 2095, due to population increases. The corresponding increase for the rest of the United States is a factor of 3.3. Even with a continuation of the relatively constant per-capita electricity consumption, total electricity demand will increase substantially over the century. The relative increase in commercial demand is smaller in California as compared to the rest of the United States in these projections, but differences in data definitions make an exact comparison difficult.

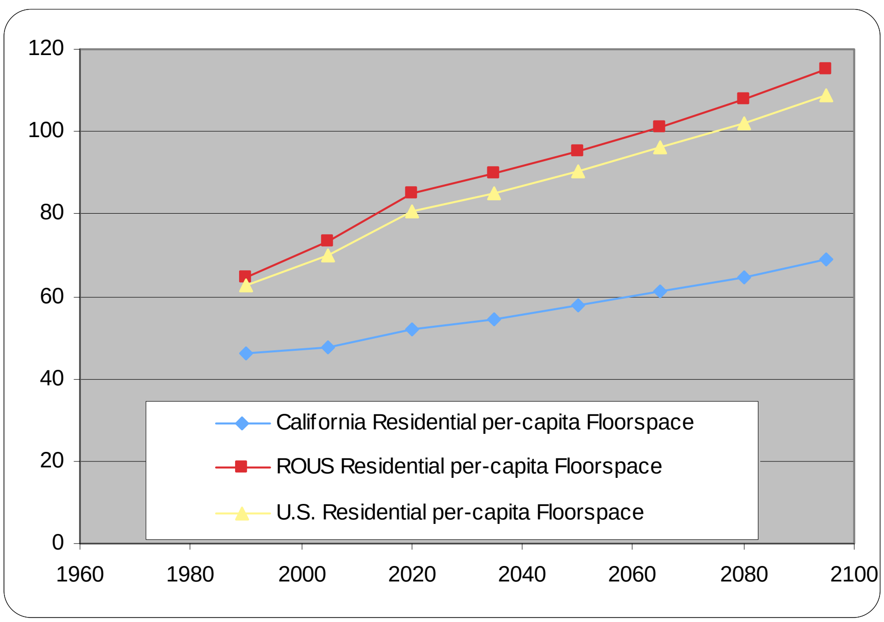


Figure 3-20. Per-capita residential floorspace in California and the United States. Historically, Californians have used less floorspace per capita than the rest of the U.S., and this trend continues the in these scenarios used here.

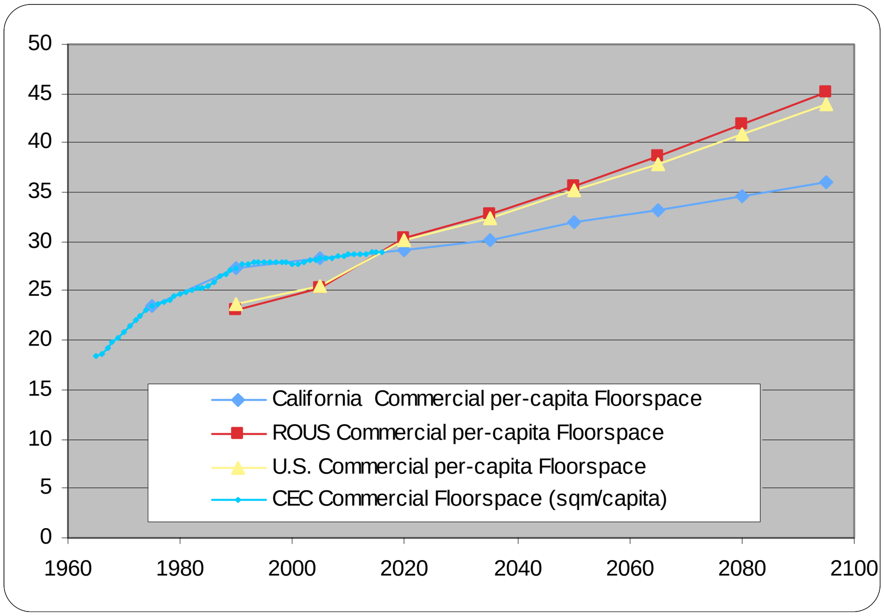
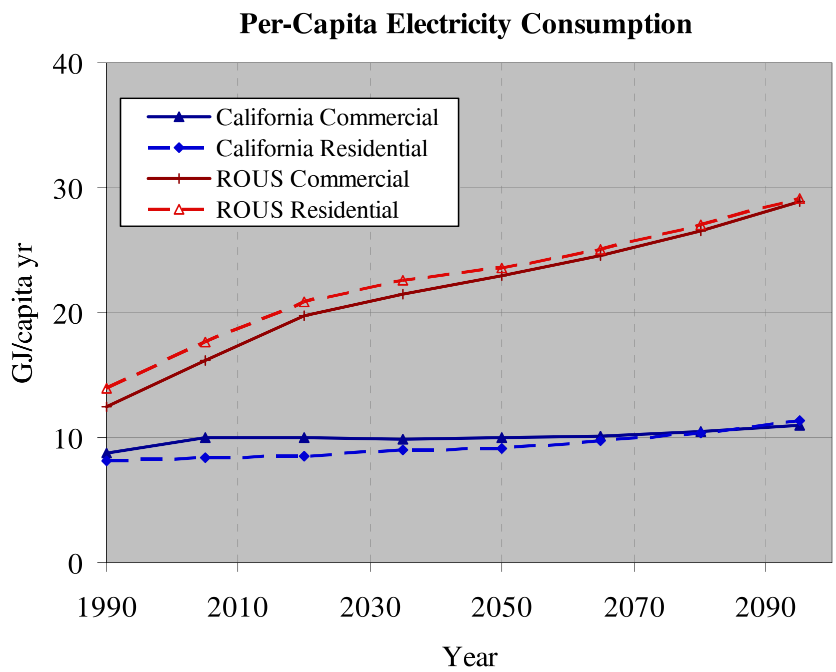


Figure 3-21. Per-capita commercial floorspace in California and the United States. Commercial floorspace appears to have been growing more slowly in California as compared to the rest of the United States, but comparisons between these sectors is problematic due to definitional differences and a lack of consistent historical data. Data are sources given in Appendix A.

The effect of energy efficiency improvements can also be seen in terms of energy use per unit residential floorspace. Electricity consumption per unit floorspace is about 25% lower in California as compared to the rest of the United States, and this difference increases with time as this value remains relatively flat in California, but increases steadily in the rest of the United States (Figure 3-22). As discussed below, these projections implicitly include current energy efficiency programs in California, but not large potential new programs that might be undertaken in the future.

Figure 3-23 shows the effect of building shell improvements on residential energy consumption in California. For this sensitivity study only building shell thermal efficiency was changed relative to the California reference case. Building shell improvements affect primarily heating demand, because of interactions between internal loads and improved shell efficiency. Improved building shell thermal efficiency increases thermal loads from outdoor temperature changes, but also better traps heat from internal loads. For residential cooling these two effects nearly cancel, for almost no net effect.



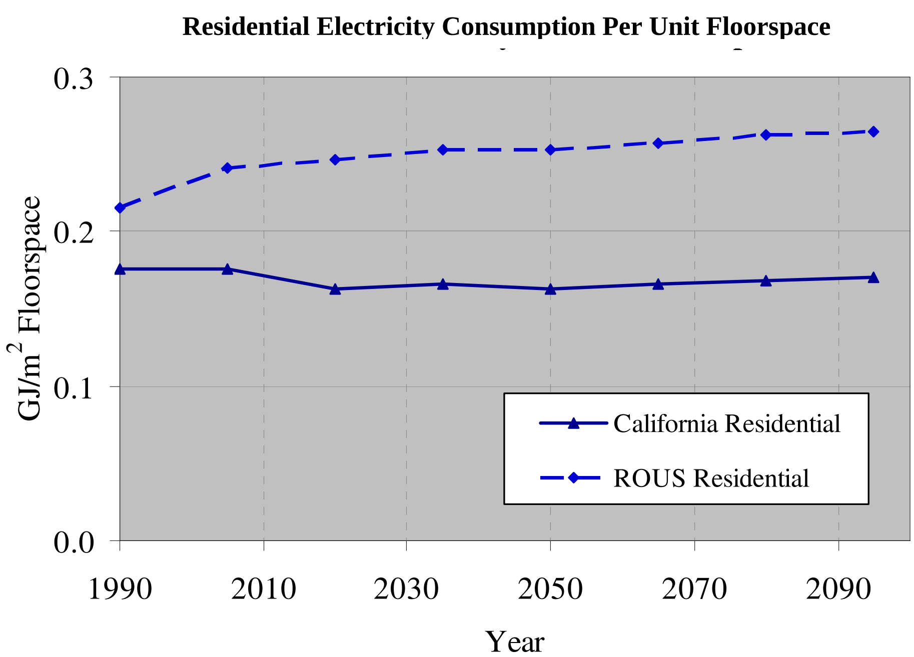


Figure 3-22. Per-capita (top) and per-unit floorspace (bottom) electricity consumption. Per-capita electricity consumption in California remains fairly constant (top). Residential per-capita consumption falls slightly in contrast to increasing in the rest of the United States (bottom).

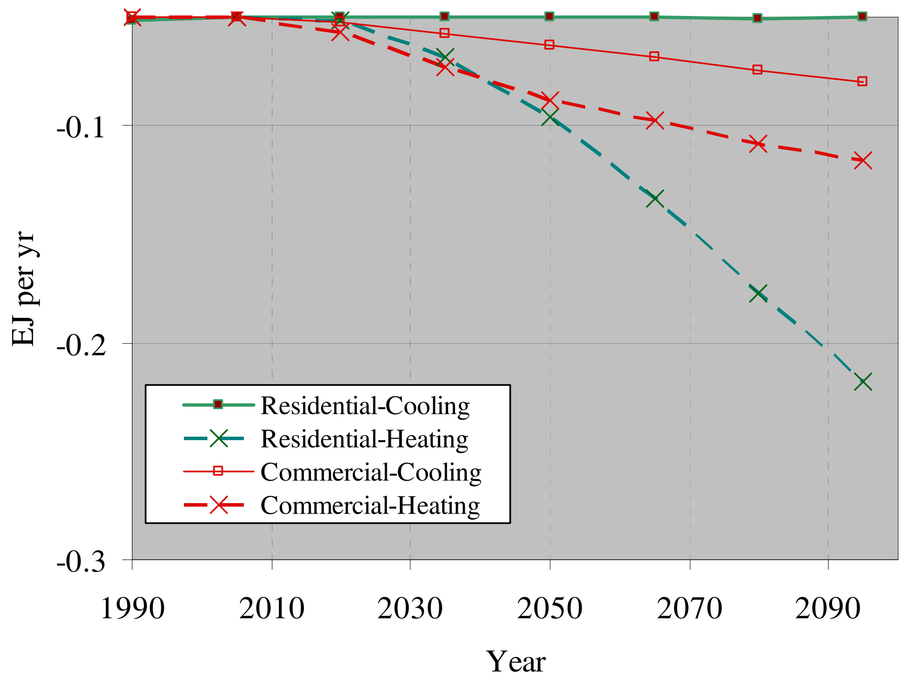


Figure 3-23. Effect of building shell improvements on California residential energy consumption. The figure shows the reduction in California cooling and heating energy use due to improved building shell thermal efficiency. Because of interaction with internal gains, building shell improvements impact heating demand much more than cooling demands.

For heating, the effect of an improved building shell on thermal losses adds to the effect of improved trapping of internal gains for a much larger net effect. Demand for residential heating energy decreases by 19% by the end of the century. The effect on commercial buildings is much smaller—only 8% by the end of the century. These effects illustrate the utility of incorporating a physically based building representation into the modeling framework.

Building Energy and Climate Policy

As discussed previously climate policy has the strongest effect upstream of the end-use sectors, altering the mix of electricity production technologies and the fuels used for the transportation sector. Some effects are seen in the buildings sector, however, as illustrated in Figure 3-24, which shows consumption of electricity and natural gas in the California building sector.

The net consumption of each fuel is the result of two effects: demand reductions and fuel switching. In the reference case, consumption of both natural gas and electricity increase over the century. Natural gas technologies currently have an efficiency advantage in end-use applications, because conversion losses are much lower as compared to electricity generation. This advantage is smaller in the future due to the combination of improved electric generation efficiencies and the improved efficiency of heat-pump-based heating and cooling technologies.

This trend changes in policy cases. Natural gas consumption flattens as a climate policy is implemented. With a carbon tax applied to natural gas consumption in building end-uses, electric heating technologies gain a cost advantage. Instead of increasing, natural gas consumption in buildings flattens. In the residential sector, for example, natural gas used for water and space heating applications in the 450 stabilization scenario is reduced to a third of the reference (no policy) case value.

3.4.3. Renewable Energy

The overall role of wind and solar resources in the United States and the impact of transmission and intermittency are qualitatively similar for California as for the United States taken as a whole. In this section the role of renewable energy in California is addressed by comparing results for California to results for the rest of the United States. For these results resources for California were derived from spatially explicit wind and solar resource data. California-specific generation for each class of resource and technology was identified. Note that the California electricity system was not modeled, as this was beyond the scope of the current project. California-specific generation was supplied to the aggregate United States electricity sector.

Figure 3-25 shows the ratio of California to total U.S. generation for wind and CSP solar power. There is a significant contrast for wind and CSP solar. California has around half of the high-quality solar resource in the United States, and this translates directly to a constant fraction of just over 50% of U.S. CSP generation over time, excluding transmission issues, to be discussed below.

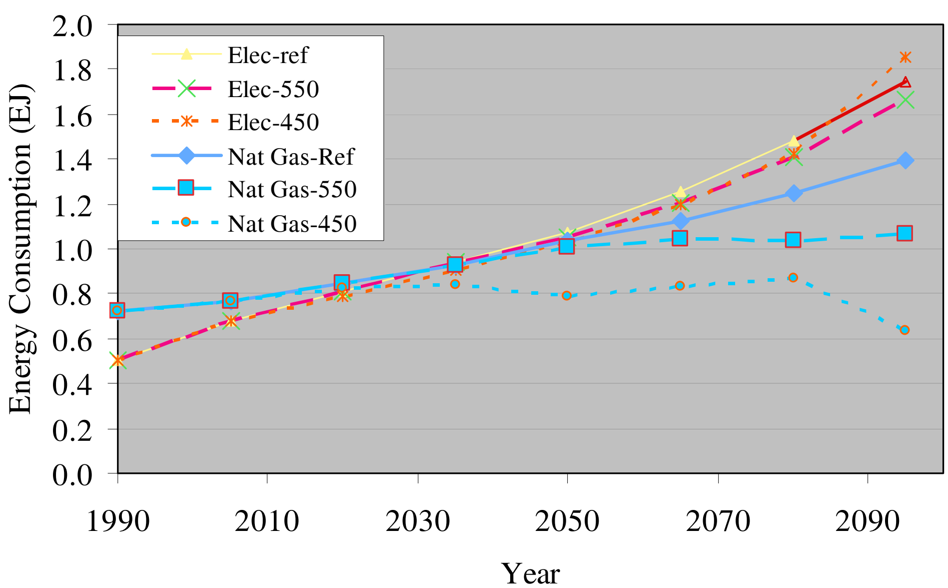


Figure 3-24. Climate policy and California building energy consumption. The imposition of an economy-wide carbon price reduces natural gas consumption in the building sector. Electricity consumption can increase for some end-uses and decrease in others, resulting in a small net effect.

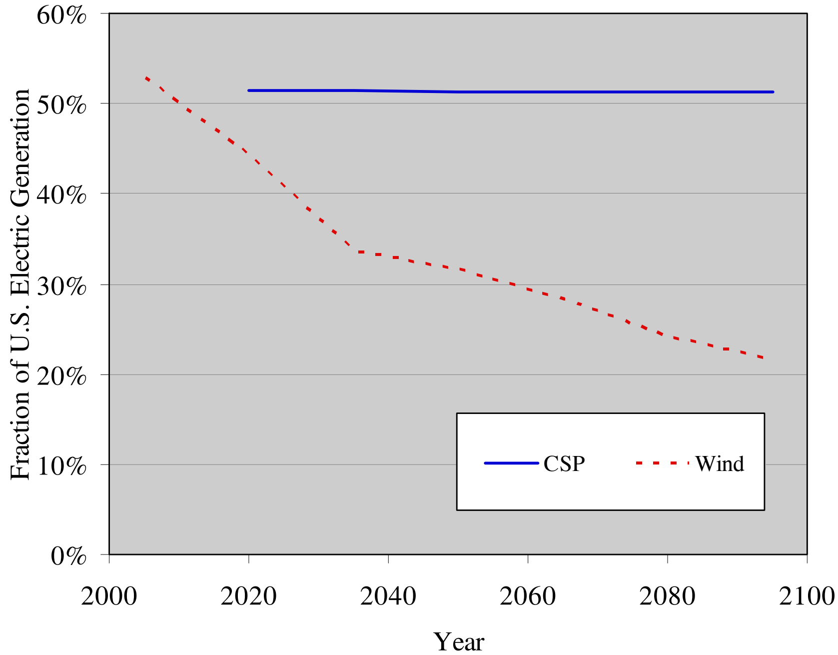


Figure 3-25. California fraction of wind and CSP electric generation. Spatially explicit resource estimates were used to derive separate U.S. and California resources and renewable energy production.

The situation is different for wind. California generation in the near term is around half of total U.S. generation. This reflects the fraction of high-quality wind resources close to the transmission grid. Note that this calculation was based on resource and distance to grid calculations and not calibrated to actually generation figures. The actual share of total United States wind generation from California in 2003 is 35%.

As wind generation increases overall, however, more wind is developed in intermediate and lower-quality wind resources, which are predominantly located in the Midwest. By the end of the century, California wind generation falls to about 20% of the total U.S. wind generation in the reference case.

These figures raise issues related to transmission capacity and regional concentration of resources. To investigate this issue, the research team considered the ratio of California wind and CSP generation to total California building electricity demand. While it would be useful to include other electricity demands, these are relatively small in comparison. Residential and service demands comprise 75% of California electricity consumption in 2000 (Murtishaw et al. 2005). Under the reference case scenario presented here, residential and commercial electricity demands would be expected to continue to dominate total demand in California in the future. This could change, however, in the case of a dramatic increase in electric demand from the transportation sector from technologies such as plug-in hybrid vehicles—a case not considered in this work.

Figure 3-26 shows the ratio of CSP and wind generation to building electricity demand in California. First consider wind. Wind generation in California exceeds building electricity demand well before 2050 in this scenario. Given that building demand peaks during the day, and land-based wind generation tends to peak at night, significant wind generation would be unused in the absence of storage.

The situation for CSP power is even more dramatic. CSP power plants without high levels of thermal storage operate only in intermediate and peak time periods. This is only a fraction of overall annual demand, even for the buildings sector. CSP generation, therefore, exceeds available demand in California by as early as 2020 in this scenario.

On the surface, the implication of these results is that California could become a net electricity exporter rather than an importer under a scenario with widespread deployment of renewables. In the case of wind power, however, deployment at this scale would, although to a lesser extent than in the rest of the United States, require significant transmission infrastructure (e.g., Figure 3-17). It would seem likely that, absent a large baseload demand in neighboring states, wind would be developed just to the extent necessary to supply California energy demands—which could utilize a sizable fraction of California's wind power potential.

The situation for CSP power is more problematic. The use of even a moderate fraction of the economically practical solar resource in California would exceed available demand. The states adjacent to California to the east also contain high-quality solar resources suitable for CSP thermal power generation, which would result in limited opportunities for power export to these regions. This is not the case for states to the north, however, where opportunity would exist to export electricity during intermediate and peak times, although this would likely only be feasible to a large degree if existing transmission capacity were upgraded.

3.4.4. Potential Extensions

This project enabled the development of consistent scenarios for both California and the rest of the United States. California tends to be a leader in terms of energy efficiency, which means that the impact of California energy efficiency improvements extend beyond California energy use. This is particularly important in terms of a climate policy, since more energy efficiency overall in the United Sates as a whole means a lower effective carbon price to meet any given greenhouse gas emissions target.

Note that the California building energy scenario presented here is best described as a continuation of current trends without the imposition of significant new policies. The reason for this is because, while results were calibrated to current California energy use, a detailed analysis of the efficiency of specific building end-use technologies is required to construct a meaningful set of advanced efficiency scenarios. In the present scenarios a nominal continued gap between California energy efficiency relative to the rest of the United States was assumed. An improved analysis would require a more detailed analysis and comparison between the current energy efficiency data for California and the United States as a whole; particularly analysis to identify differences in historical and current building end-use technologies in California and the rest of the United States. Historical trends in end-use technology adoption are particularly valuable to guide analysis and energy projection efforts.

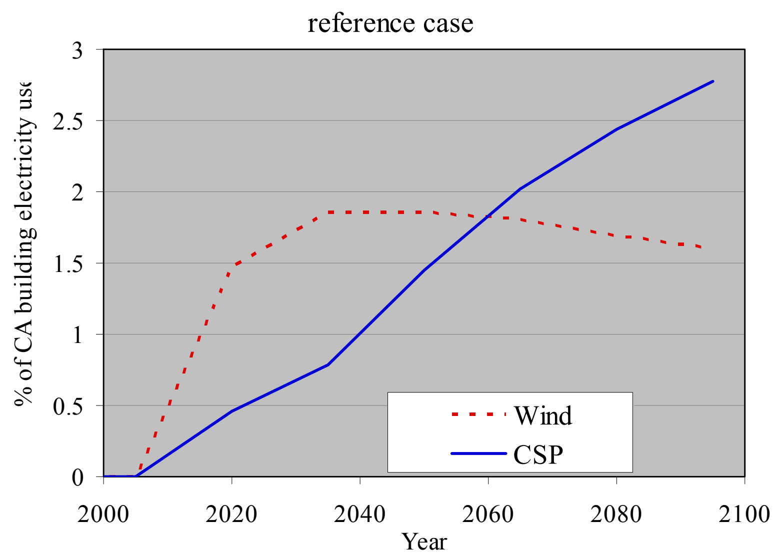


Figure 3-26. California of wind and CSP generation as a fraction of total California building electricity demand. Buildings are the dominant electricity consumer in California. Based simply on generation costs, CSP thermal generation in particular exceeds demand.

A useful extension of this work would then be to model the "gap" between California and the rest of the United States in terms of building energy efficiency. The effect of narrowing this "gap" for California and the United States as a whole could be then examined.

This work could also be compared to the California Energy Commission's Public Interest Energy Research (PIER) projects underway to construct energy-efficiency cost curves for California. The approach taken here for the United States could be applied to California in terms of developing reference and advanced efficiency scenarios. The total energy savings obtained by this more aggregate approach could be compared to the results obtained from other approaches. These long-term results might also be useful as boundary conditions for more detailed analyses.

A significant issue for renewable energy use is transmission. Most of the detailed work on electric transmission has, at most, a 10–15 decade time horizon. The path forward to a potential high renewable energy future, which appears to be very feasible for California in terms of generation cost at least, requires efforts to examine the changes to transmission infrastructure that would be needed.

4.0 Conclusions

This study has examined end-use energy efficiency and renewable energy—two sets of technologies that have received only limited attention in most previous century-scale modeling efforts. To examine end-use efficiency, new end-use energy demand representations were developed within a long-term energy-economic-land-use model. These developments allow the impact of specific classes of technologies to be examined in a more realistic manner.

While numerous technology-based studies of energy efficiency have been conducted, this project provides researchers and decision makers the ability to consider explicit energy end-use technologies over a 100-year time frame. Note that it was not the goal of this research to predict in detail the structure of the energy system over this time frame. Instead, the goal of this work was to understand the dynamics of the coupled energy supply, energy, demand, climate, and natural systems. By enabling the long-term analysis of specific end-use energy technologies, the elements that drive future demand growth can be better understood and the impact of improved energy efficiency can be quantified over a long time horizon within a modeling system with endogenous prices and price responses.

While enhanced energy efficiency lowers energy consumption, the reduction in energy service cost can result in an increase in end-use service consumption in some cases. This effect was seen for lighting, where more efficient and more cost-effective lighting in the advanced technology case results in an increased production of energy services, in this case lumen-hours of lighting service.

This research has shown that there are substantial benefits to enhanced energy efficiency. If a comprehensive suite of more efficient end-use technologies were deployed across the U.S. economy, the cost of achieving a climate policy could be reduced by 50%–75%. The absolute value of improved efficiency increases substantially for stricter emissions targets as the cost concentration stabilization increases strongly for lower concentration target levels.

The energy consumption decreases enabled by improved efficiency make it possible to reach long-term emissions targets at a lower economic cost. Note that, even with substantially improved efficiency, total U.S. carbon dioxide emissions flatten but do not decline in the absence of a climate policy. Stabilization of atmospheric CO_2 concentration still requires a policy that puts a price on greenhouse gas emissions, but improved efficiency substantially lowers the price necessary to achieve any given climate goal.

The advanced energy-efficiency scenarios considered in this work assumed the deployment of a wide range of more efficient technologies. There are a number of potential technologies that were not considered, such as plug-in hybrid vehicles and integrated building renewable energy technologies such as daylighting and solar heating technologies.

Another key element of a climate policy is renewable energy sources such as wind and solar. Wind and solar electric power generation have different roles within the electric system. Wind power is, to first order at least, available around the clock. The largest portion of carbon emissions from the electric system comes from baseload plants that also operate nearly around the clock. From this standpoint wind can potentially play a large role in reducing CO_2 emissions. Wind is increasingly competitive and, based on generation costs, wind power could supply up to a third of U.S. electric energy generation. To provide this level of wind generation, however, wind turbines would be located over large areas, requiring substantial construction of new electric transmission capacity. Because of this geographic dispersion the contribution of wind is dependent on the ability to construct transmissions lines.

For solar energy, this analysis focused on concentrating solar thermal plants (CSP) such as solar trough technology. CSP power is attractive because this technology can be easily equipped for hybrid operation where natural gas can be used to produce power when solar irradiance is insufficient to operate the plant. Even without the development of cost-effective thermal storage, CSP plants will be competitive in the future if costs decline as projected. The role of CSP within the electric system, however, is different from wind, as solar power is only available during the day (or potentially into the evening with integrated thermal storage). CSP plants, therefore, supply peak and intermediate power, which, while a smaller part of total generation, is more expensive to produce in general and also more expensive to mitigate in terms of carbon emissions.

The details of both efficiency and renewable energy technologies vary by region. As the final step in this project, the building and renewable energy analysis methodology developed here was applied to California. Data from Energy Commission forecasting model projections and historical reconstructions have been used to initialize residential and commercial building model components for California. A "rest of the United States" (ROUS) component is also constructed in order to allow a consistent comparison between California and the ROUS. The simulation results in a nearly flat per-capita building energy consumption continuing throughout the century for California, in contrast to an increasing per-capita consumption for the rest of the United States.

Climate policy affects the California building sector largely by decreasing the use of natural gas. With an economy-wide carbon price applied to the consumption of fossil fuels, it becomes economic to switch to electric end-use technologies, particularly for applications where heat-pump technologies are available. This switch occurs to some extent even without a carbon policy as both heat-pump and electric generation technologies become more efficient, but is accentuated under a carbon policy. Natural gas use in the buildings sector eventually stabilizes under a carbon policy, instead of increasing as in the reference case.

The effect of a carbon policy on electricity consumption is mixed and generally small. This is due to two counteracting effects. Substitution for natural gas tends to increase electricity consumption, while service demand reduction due to higher energy prices reduces electricity consumption. The net effect is small.

Finally, the regional importance of wind and solar CSP power were considered for California. Based on resource and grid connection cost, California initially has a very high share of total U.S. wind generation. This share declines over time as extensive wind resources elsewhere in the United States begin to be developed. While wind power supplied up to a third of total U.S. energy, a much higher fraction of California energy was supplied in these future scenarios. Without additional electric loads such as plug-in hybrids, a national consideration of wind energy may slightly overestimate the contribution of wind power from California.

The situation for CSP power illustrates a much larger bias if resource heterogeneity is not considered. California has roughly half of the potentially usable direct solar resource base of the United States. The amount of California CSP generation without consideration of regional limits very quickly exceeds the available building intermediate and peak demand under the scenarios considered. This means that the potential from CSP power is overestimated unless the regional concentration of this resource is considered.

Taken together, however, these results indicate that a large fraction of California electricity consumption could be supplied by wind and solar power in the long-term. Such a high penetration of renewable power raises questions of system reliability and transmission capability. Large amounts of dispersed power generation would have to be transmitted to load centers. The significant projected growth in overall energy demand, however, implies that significant new infrastructure would need to be constructed in any event. The type of new additions or transmission system changes that would be necessary to facilitate high levels of renewable power supply could use further examination.

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6.0 Acronyms

Acronym	Definition
CCSP	United States Climate Change Science Program
CCTP	United States Climate Change Technology Program
CDD	Cooling Degree Days
CHP	Combined Heat and Power (also known as cogeneration)
CSP	Concentrating Solar Power
DoD	Department of Defense
EIA	Energy Information Administration
EMF	Energy Modeling Forum
GDP	Gross Domestic Product (used as a measure of income change over time)
GJ	gigajoule (10^9 Joules)
GTSP	The Global Technology Strategy Project at PNNL/Battelle
HDD	Heating Degree Days
ICE	Internal Combustion Engine
IPCC	Intergovernmental Panel on Climate Change
JGCRI	Joint Global Change Research Institute
kW	kilowatt
MECS	Manufacturing Energy Consumption Survey
MiniCAM	The long-term, partial-equilibrium integrated assessment model used at PNNL
MW	megawatt
NASA	National Aeronautics and Space Administration
NREL	National Renewable Energy Laboratory
$O^{bj}ECTS$	Object-oriented Energy, Climate, and Technology Systems (framework)
PNNL	Pacific Northwest National Laboratory
ppmv	parts per million by volume (used as a measure of atmospheric concentrations)
PV	Photovoltaic (solar electric generation)
ROUS	Rest of United States (exclusive of California)
SRES	(IPCC) Special Report on Emissions Scenarios

Appendix A.

Energy Efficiency Assumptions for the United States and California

Appendix A: Energy Efficiency Assumptions for the United States and California

The purpose of this appendix is to identify and source assumptions pertaining to the present and future technologies in the U.S. and California buildings modules.

1.0 U.S. Buildings Module

The buildings scenarios addressed in this appendix are reference and advanced technology for the Value of Technology analysis, and California and rest-of-U.S., with the rest-of-U.S. assumptions similar though not equal to the reference scenarios in the Value of Technology analysis. Points of divergence between the rest-of-U.S. and the reference technology scenarios will be noted where they occur. Historical and future technology efficiencies and non-energy costs are addressed individually for each technology below, but a number of conditions apply to all technologies for both the residential and commercial sectors.

1.1. Equipment Efficiencies

In the model, technologies compete for market share of service provision primarily on the basis of efficiencies and non-fuel costs. Each technology in each period is assigned a stock efficiency, assumed to be the average efficiency across all units of the given technology in use in the given year. Efficiencies are expressed as service energy output divided by energy consumption, a unitless measure allowing calculation between fuel consumption and service supply or demand. For heating and cooling technologies, the measure is straightforward; for instance, a gas furnace with efficiency of 0.86 provides 860 British thermal units (Btu) of heating service for every 1000 Btu consumed. For lighting, where the service is in lumens, a conversion of 683 lumens per Watt is assumed, allowing lighting output to be expressed in terms of energy. For appliances, office equipment, and other energy services, an index efficiency of 1 is assigned to the equipment stock in 2005, and future efficiencies are calculated based on the base year.

Future efficiency improvements beyond current projections were generally assumed to take place according to one of five prescribed trajectories of annual rates of efficiency improvement, shown in Table A-1. The trajectories refer to different stages of maturity of technologies, and each technology was assigned to one trajectory based on its present rates of efficiency change and its opportunities for improvement. Some efficiencies were limited by physical or thermodynamic constraints, and these constraints will be noted where applied. All equipment efficiencies are shown in Table A-2.

Table A-1. Trajectories of annual efficiency improvement (% per year) used for the U.S. buildings module

Period	A (%)	B (%)	C (%)	D (%)	E (%)
1990–2005	0.60	0.80	1.00	1.00	0.00
2005–2020	0.50	0.60	0.80	1.00	1.00
2020–2035	0.25	0.50	0.60	0.80	1.00
2035–2050	0.10	0.25	0.50	0.60	0.80
2050–2065	0.10	0.10	0.25	0.50	0.60
2065–2080	0.05	0.10	0.10	0.25	0.50
2080–2095	0.05	0.05	0.10	0.10	0.25

For the California and rest-of-U.S. comparison, the rest-of-U.S. efficiencies were calculated using the U.S. efficiencies and the California efficiencies according to the energy consumption share of each region in 2005. That is,

$Eff_{roUS,t} = [Eff_{US,t}*Energy_{US,2005} – Eff_{CA,t}*Energy_{CA,2005}] / Energy_{roUS,2005}$ where:

Eff = efficiency in specified region in specified period

roUS = rest-of-U.S.

CA = California

Energy = energy consumption in specified region in specified period

t = time period

1.2. Equipment Non-Fuel Costs

Non-fuel costs are expressed in terms of dollars per service provided per year. The annual non-fuel cost consists of a capital cost (in $ per kW) levelized over an expected lifetime of the product, plus a maintenance cost (also in $ per kW), divided by the expected service output (in terms of energy) in a given year. The expected service output is equal to the capacity of the equipment (in kW) times a capacity factor, the expected amount of time during a year that the equipment will be in operation.

Non-fuel costs, shown in Table A-3, were calculated for all non-2005 years based on the assumption that increases in efficiency will tend to increase the capital cost of equipment, but technological improvement over time will tend to offset these cost increases. This concept is shown in Figure A-1. The rates of technological improvement assumed and the slopes of the cost-efficiency functions are addressed within each technology specification below. Operating and maintenance costs were assumed to remain constant regardless of technological change or changes in capital costs.

Capital costs were levelized based on expected equipment lifetime and a discount rate of 10%. These costs, in $ per year, were then converted to $ per gigajoule (GJ) of output, assuming a capacity factor (the portion of time during which equipment is operating), and finally adjusted for efficiency changes over time. This last step was necessary because, if capital and operating costs ($ per kW) remain constant, an efficiency increase will effectively increase output (equal to efficiency times fuel consumption) and therefore decrease the non-fuel cost ($ per GJ) used as the model input.

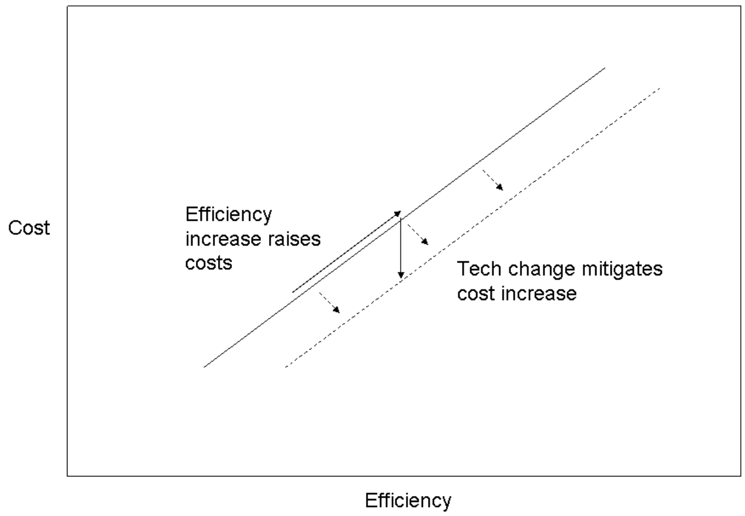

Figure A-1. Efficiency-cost trade-off, with conceptual schematic for technological improvement

Past and future non-fuel costs were calculated based on the following equation:

$Cost_t = Cost_{(t-1)} + m(Eff_t - Eff_{(t-1)})*(1-Tech_t)^{15}$, where:

Cost = Capital cost, in $1990 per kW of capacity

m = slope of cost-efficiency function (see Figure A-1)

Tech = rate of technological improvement

1.3. Energy Calibration

1.1.1. U.S. Energy Consumption

Energy consumption by each technology in 1990 and 2005 for the U.S. module was calculated based on the 1993 and 2005 base years from the 1996 and 2007 Annual Energy Outlook (AEO; EIA 1996 and EIA 2007c). All energy consumption values were scaled to the Annual Energy Review (EIA 2005; Tables 2.1b and 2.1c) totals for energy consumption by each of four major fuels (natural gas, electricity, fuel oil, and biomass) in the residential and commercial sectors in 1993 and 2005. Because the earliest base year for the 1996 AEO was 1993, in order to calibrate the energy uses to 1990, the 1993 energy uses were further scaled such that the aggregate energy consumption by each fuel was equal to the AER total for 1990. Because the AEO separates end-use demands by fuels, though not necessarily technologies, an additional step was required in some cases to determine the fuel consumption at the technology level. For example, both fluorescent and incandescent lighting use electricity, and as such are not separated in the AEO. Such cases required the use of additional data sources and are addressed individually below.

1.1.2. California Energy Consumption

Residential Sector

The Energy Commission provided model results by utility planning area for the years 1970 through 2017. The Energy Commission residential model structure uses unit energy consumption values to calculate end use consumption by technology (Abrishami et al. 2005).

$EUC_{e,t} = HOUSES_t * ASAT_{e,t} * UEC_{e,t}$ where:

EUC = end use consumption

HOUSES = households

ASAT = appliance saturation

UEC = average unit energy consumption for each end use

e = index of appliance end uses relevant to a particular fuel type

t = year index.

It was determined that the annual California residential consumption in the model totals did not exactly match the Energy Commission's reported historical and projected values. The differences in these values in the years compiled ranged from 2%–10% in electricity consumption and 8%–29% in natural gas consumption. The model results were used to calculate the California technology shares, and these shares were applied to the historical and projected energy consumption values reported in the *California Energy Demand 2006–2016 Staff Energy Demand Forecast (*Gorin and Marshall 2005*)*.

California does not consume statistically detectable quantities of fuel oil for residential heating (EIA 2007a). Biomass for heating was estimated using the Residential Energy Consumption Surveys (RECS; EIA 1993, 2001).

The 2016 projections for energy consumption were documented from this analysis and were used to compare with the MiniCAM model results up to 2020.

Commercial Sector

The commercial end-use consumption values were also derived from Energy Commission model data. The commercial end-use energy consumption was determined by the amount of floor space, the proportion of floor space receiving an end use energy service, and the type, efficiency and use of energy using equipment. The model computed energy use in forecast year "T" for a particular fuel, end use, and building type of vintage year "t", as (Abrishami et al. 2005):

$$Q_{T,t} = U75*U_{T,t}*UTIL_{T,t}*F_t*A_t*d_{(T-t)} \quad (1)$$

$Q_{T,t}$ =	Energy use for a particular building, fuel, end use and vintage (t) in the current forecast year T
U75 =	Fuel use per square foot in 1975
$U_{T,t}$ =	Current energy use intensities (EUI), relative to 1975, of equipment installed in year t in use in forecast year T
$Util_{T,t}$ =	Utilization rate of equipment installed in year t in use in forecast year T for a particular end use, fuel, building type and vintage
F_t =	Fuel share of equipment installed in year t
A_t =	Floor space of a particular building type added in year t
$d_{(T-t)}$ =	Fraction of floor space constructed in year t remaining in year T

Total commercial building energy use is the sum of $Q_{T,t}$ across all buildings, fuels, end uses, and vintages. U75 are often termed the base year energy use intensities (EUI) and are fixed parameters. $U_{T,t}$ is the average efficiency for each end use, fuel, building type, and vintage.

Equation (1) is subject to a limit on the range of utilization rates: these are embodied in constraints (1a) and (1b); DLO and DHI are limited to 0.80 and 1.20, respectively. These limits had very little impact on the forecast results, as they were rarely reached. Constraint (1c) prevents equipment efficiency from reaching unrealistically low values. These limits differ by end use and fuel type. The model assumes the average equipment efficiency of a particular vintage to be a function of price, the rate of replacement of old equipment and the efficiency levels set by various building and equipment standards.

Within the model average efficiency is determined for all equipment of a given end use. For example, space heating end use efficiency is determined for the composite heat source, distribution, and building shell elements. Thus, "equipment" is regarded as the composite factors governing consumption per square foot. They use new commercial building standards and 1979 efficiency standards to calculate the efficiency component associated to the equipment itself.

It was determined that the annual California commercial consumption in the model totals did not exactly match the Energy Commissions' reported historical and projected values. The differences in these values in the years compiled ranged from 0%–18% in electricity consumption and 0%–5% in natural gas consumption. The model results were used to calculate California commercial end-use shares, and these shares were applied to the historical and projected energy consumption values reported in the *California Energy Demand 2006–2016 Staff Energy Demand Forecast* (Gorin and Marshall 2005).

The California Demand Forecast was used for determining 2005 commercial consumption of electricity and natural gas. Because the model did not report 2005 commercial electric consumption, values were interpolated from the 2004 actual and 2006 projected electric consumption values. Fuel oil consumption estimates came from EIA, *Commercial Sector Energy Consumption Estimates, Selected Years, 1960-2003, California* (EIA 2007b).

The 2016 projections for energy consumption were documented from this analysis and were used to compare with the MiniCAM model results up to 2020.

2.0 Technology Specifications

2.1. U.S. and California Residential Building Sectors

Tables A-2 and A-3 show efficiency and non-fuel cost assumptions for all residential technologies during the next century. Each technology is addressed individually below. Some California technologies (noted individually) were assumed to have higher efficiencies than the rest-of-U.S. stock, but for most technologies, there was little data available from which California stock efficiency could be estimated or compared to the rest-of-U.S. For technologies where California was thought to be more efficient than the rest of the U.S., the California equipment efficiency was generally assumed to be 2.4% higher, an amount that was calculated in the fluorescent lighting market (see Section 2.1.5).

Despite having efficiencies that were typically higher than the rest of the U.S., non-fuel costs in California were assumed equal to the rest of the U.S. for all building equipment. This was designed to reflect rebates or other policies designed to offset the increased capital costs of more efficient equipment.

2.1.1. Building Shell Efficiency

Building shell thermal efficiencies depend on a wide range of specific technologies (e.g., walls, windows, foundation), which in this module were treated in aggregate fashion. A model of the U.S. buildings stock was built to examine how expected improvements in thermal characteristics of new buildings would influence the entire stock, which has a much slower turnover time than the specific technologies within the buildings. Historical data on the numbers of homes by type (single-family, multi-family, and mobile) were based on the 1990 Census of Population and Housing (Census 1990) and the base years from the 1996 and 2007 Annual Energy Outlook (EIA 1996, EIA 2007c; Table A-3). The different housing types were assumed to have different base year shell efficiencies, multi-family dwellings having the highest values, and mobile homes the lowest. Individual units in multi-family buildings capture gains from neighboring units, whereas mobile homes were assumed to be less well insulated than the other types of buildings.

Table A-2. Efficiency assumptions in the Residential Building Sector, with California, reference, and advanced assumptions shown for 1990, 2005, 2050, and 2095. California efficiencies shown only where they differ from U.S. reference case assumptions.

	Historical		Reference		Advanced	
	1990	**2005**	**2050**	**2095**	**2050**	**2095**
Shell efficiency	0.260	0.253	0.205	0.160	0.191	0.120
Heating: energy out/energy in						
Gas furnace	0.70	0.82	0.88	0.91	0.88	0.91
CA Gas furnace	0.70	0.82	0.89	0.91	na	na
Gas heat pump	na	1.30	na	na	1.67	1.90
Electric furnace	0.98	0.98	0.99	0.99	0.99	0.99
Electric heatpump	1.61	2.14	2.49	2.58	2.82	3.02
CA Electric heatpump	1.65	2.19	2.55	2.65	na	na
Fuel oil furnace	0.76	0.82	0.85	0.87	0.85	0.87
Wood furnace	0.52	0.58	0.66	0.68	0.66	0.68
Cooling: energy out/energy in						
AC	2.16	2.81	3.76	3.90	4.18	4.47
CA AC	2.22	2.88	3.85	3.99	na	na
Water heating: energy out/energy in						
Gas water heater	0.52	0.56	0.80	0.91	0.80	0.91
CA Gas water heater	0.57	0.60	0.88	0.92	na	na
Gas heatpump water heater	na	na	na	na	1.53	1.91
Electric resistance water heater	0.84	0.88	0.95	0.96	0.95	0.96
Electric heatpump water heater	na	na	na	na	2.39	2.51
Fuel oil water heater	0.51	0.55	0.56	0.58	0.56	0.58
Lighting: lumens per watt						
Incandescent lighting	15.00	15.00	17.04	17.55	17.04	17.55
Fluorescent lighting	64.50	75.00	99.64	106.59	99.64	106.59
CA Fluorescent lighting	64.50	76.80	100.50	106.60	na	na
Solid-state lighting	na	na	122.38	127.06	151.90	185.90
Appliances and other: indexed to 2005						
Gas appliances	0.96	1.00	1.66	1.72	1.66	1.72
Electric appliances	0.70	1.00	1.42	1.47	1.58	1.80
CA Electric appliances	0.72	1.02	1.45	1.51	na	na
Gas other	0.99	1.00	1.12	1.25	1.12	1.25
Electric other	1.04	1.00	0.98	1.01	1.42	1.47
Fuel oil other	0.99	1.00	1.05	1.09	1.05	1.09

Table A-3: Non-fuel cost assumptions in the U.S. residential module for the advanced and reference scenarios; California non-fuel costs are assumed equal to the U.S. reference scenarios. Costs are represented as 2004$ per GJ of output by equipment.

	Historical		Reference		Advanced	
	1990	**2005**	**2050**	**2095**	**2050**	**2095**
Aggregate building cost ($/m^2)	12.89	20.99	55.51	134.64	55.51	134.64
2004 $ per GJ of output						
Heating						
Gas furnace	2.18	3.62	3.90	3.80	3.90	3.80
Gas heat pump	na	19.33	na	na	23.13	23.45
Electric furnace	4.40	4.35	4.16	4.01	4.16	4.01
Electric heatpump	13.56	13.93	14.16	12.55	14.60	12.92
Fuel oil furnace	4.35	4.05	4.03	3.97	4.03	3.97
Wood furnace	8.54	7.65	6.44	5.98	6.44	5.98
Cooling						
AC	7.51	9.56	10.58	9.93	10.30	9.02
Water heating						
Gas water heater	5.10	6.05	7.91	7.16	7.91	7.16
Gas heatpump water heater	na	na	na	na	35.22	34.57
Electric resistance water heater	12.20	14.64	16.51	14.94	16.51	14.94
Electric heatpump water heater	na	na	na	na	21.66	20.86
Fuel oil water heater	6.62	6.51	6.17	5.84	6.17	5.84
Lighting[1]						
Incandescent lighting	300.93	300.93	264.97	257.15	264.97	257.15
Fluorescent lighting	198.33	170.57	128.39	120.02	128.39	120.02
Solid-state lighting	na	na	357.62	294.17	288.14	201.06
Appliances and other[2]						
Gas appliances	16.59	16.34	15.62	14.94	15.62	14.94
Electric appliances	31.83	31.36	29.98	28.66	29.98	28.66
Gas other	70.07	70.07	70.07	70.07	70.07	70.07
Electric other	134.46	134.46	134.46	134.46	134.46	134.46
Fuel oil other	70.07	70.07	70.07	70.07	70.07	70.07

1 Lumens converted to GJ of output assuming 683 lumens per Watt

2 Appliance and other output calculated as “energy in” times efficiency

The model parameters of expected and minimum structure lifetime were selected such that the model output of houses by construction year in 2005 roughly matched the 2005 U.S. Census (Census 2005; see Figure A-2). Past building shell efficiency was estimated based on the heating loads in 2001 per heated floorspace according to the construction year (EIA 2001). Heating loads were calculated as fuel input times stock efficiency of heating equipment (assumed equal for houses of all ages).

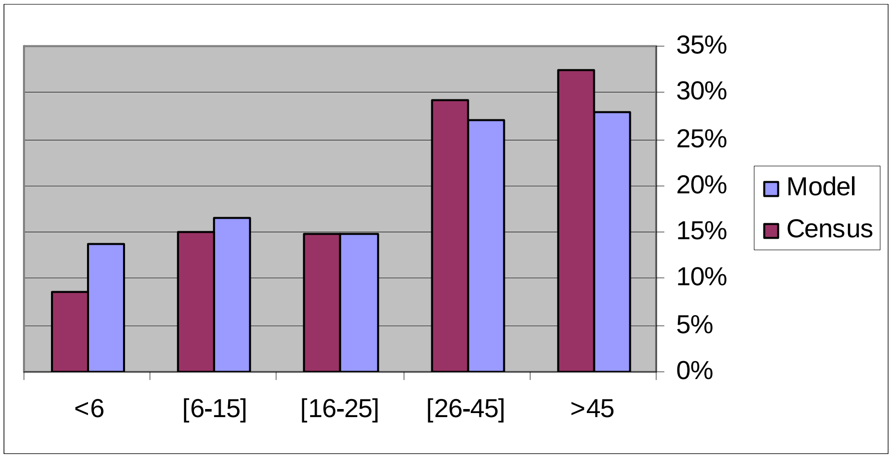

Figure A-2. House age distribution in 2005, in stock model as compared with census data

The different heating demands per floorspace by buildings of different ages were used to construct a past trend of building shell efficiencies. It was assumed that the calculated trend overestimated the actual improvement, as more houses have been built in warmer climates than in cold ones in the past few decades, effectively decreasing the heating loads while not necessarily improving the shell. This was confirmed in the observation that cooling service per unit of floorspace does not show a positive trend with building age.

Future trajectories in shell efficiencies were assumed as follows: in the reference case, single-family homes will be built 1.4 times more efficient in 2050 than in 2005, and by 2095 this factor will be 1.8. Shell efficiencies for multi-family and mobile homes will increase by 1.6 and 1.4 by 2095, respectively.

Advanced case assumptions were informed by BEopt 0.8, a computer program developed by the National Renewable Energy Laboratory (NREL) for economizing energy use reductions in new buildings (Christensen et al. 2005). Heating loads per square foot were calculated for several BEopt scenarios in five U.S. cities, to calculate a range of feasible potential improvement trajectories. In the advanced case, new single-family homes were assumed to have 2.0 times greater shell efficiency in 2050 than in 2005, and 3.4 times greater shell efficiency by 2095.

2.1.2. Heating

Gas Furnace

U.S. Efficiency: For the United States, the 2005 efficiency in Table 21 of the AEO 2007 (EIA 2007c) was used, and the 1990 value was back-calculated using an annual rate of improvement derived from the 2005 residential stock model from the National Energy Modeling Systems (NEMS). Efficiency in 2020 was assumed to be equal to the AEO projected value, and the 2035 estimate was calculated using the AEO annual rate of improvement between 2020 and 2030. In subsequent periods, efficiency improvement was assumed to follow Trajectory A, limited by an assumed maximum efficiency of 0.96.

California Efficiency: In 1990 and 2005, California is assumed to match the rest of the United States, having had no concerted efforts to boost gas furnace efficiency until recently. In the future, California is assumed to implement a condensing standard well before the rest of the United States, represented by California efficiency being one fifteen-year time-step ahead of the rest of the United States through 2030. This lead is assumed to diminish as U.S. standards are enacted and by 2065, efficiencies are equal in California and the United States.

Non-fuel costs: Present capital costs for residential gas furnaces were from the 2003 stock estimate in *Technology Forecast Updates* (NCI 2004a). The slope of the cost-efficiency function was determined using the estimates for high-efficiency and typical gas furnaces in 2010. An improvement rate of 0.25% per year was then applied to the costs prescribed by the assumed efficiency changes.

Gas Heat Pump

Because natural gas heat pumps currently have no market share (nor does the EIA project their entry by 2030; EIA 2007c), they were not included in the reference scenarios for the United States, or for California. They were included in the advanced U.S. scenario and in the rest-of-U.S. scenario, entering the market in 2020. Due to their limited applications (i.e., only in multi-family buildings) they were not assumed to compete on an equal level with gas furnaces.

Efficiency: 2005 and 2020 values came from AEO 2007 (EIA 2007c); 1990 was back-calculated assuming 2005–2020 improvement, and 2035 was calculated assuming extrapolation of 2020–2030 rate of improvement. Trajectory D was used in future periods.

Non-fuel costs: *Technology Forecast Updates* (NCI 2004a). The slope of cost-efficiency function was based on projected improvement between 2001 and 2025. The rate of technological improvement was 0.25% per year.

Electric Resistance Furnace

California Title 24 went into effect in 1977 and forbade the installation of electric resistance heating for either space or water unless it would be cost effective over the full life of the building. For this reason, California was assumed to have no electric resistance furnace stock, nor was the technology permitted to enter the market in the future.

Efficiency: Efficiency was assumed to be 0.98 in 2005, increasing to maximum of 0.99 by 2020.

Non-fuel costs: Capital costs of gas furnaces were used, multiplied by the cost quotient between gas and electric furnaces of similar capacity in Sezgen et al. (1995; Table 6.10). Operating costs were assumed equal to those of a gas furnace. No cost-efficiency slope was derived due to the limited availability of efficiency improvements; the technological improvement rate was set to 0.1% per year.

Energy calibration: Because electric resistance furnaces share the electricity-fueled space-heating market with electric heat pumps, the NEMS stock model was used to estimate the relative market share of each technology in 1990 and 2005. The following equation specifies the market share of electric resistance furnaces:

$$\text{Energy}_{elfurn,t} = \text{Energy}_{electric\ heating,t}*(\text{Stock}_{elfurn,t} / \text{Efficiency}_{elfurn,t}) / [(\text{Stock}_{elfurn,t} / \text{Efficiency}_{elfurn,t}) + (\text{Stock}_{heatpump,t} / \text{Efficiency}_{heatpump,t})]$$

where:

Stock = number of units of the specified technology in use at the specified time period
Efficiency = stock average efficiency of the specified technology at the specified period
Energy = energy consumption by the specified fuel or technology at the specified period

Electric Heat Pump

Efficiency: For the United States, the AEO 2007 (EIA 2007c) estimates were used in 2005 and 2020, and 1990 was back-calculated using the annual rates of improvement in the NEMS residential stock model. 2035 was estimated using the AEO rate of improvement between 2020 and 2030. In subsequent time periods, the improvement rate was set to the B Trajectory. In the advanced scenarios for the United States, the 2030 estimate from the AEO is reached in 2020, and Trajectory C is used for subsequent time periods.

California heat pump efficiencies were assumed to be 2.4% greater than the U.S. efficiencies in all time periods. This value was calculated from the fluorescent lighting stock, and is designed to reflect California rebate programs and higher code standards.

Non-fuel cost: The *Technology Forecast Updates* report (NCI 2004a) was used for capital and operating costs in 2005, and the 2010 projected costs of typical and high-efficiency heat pumps were used to calculate the slope of the cost-efficiency function. This was used to calculate the future cost, with an annual technological improvement rate of 0.5%.

Energy calibration: The energy consumption in the base years was determined as for electric resistance furnaces. In California, heat pumps were assumed to account for all electric space heating energy consumption.

Oil Furnace

No stock was assumed for California, as the residential consumption of fuel oil was not statistically different from zero. Oil furnaces were not allowed into the market in future time periods.

Efficiency: Efficiency in 1990 was back-calculated from 2005 using the NEMS stock model. The 2005 and 2020 data were from the AEO (EIA 2007c), and 2035 was calculated based on the projected 2020–2030 rate of improvement. Trajectory A was applied to subsequent time periods.

Non-fuel cost: *Technology Forecast Updates* (NCI 2004a) used for 2005; all other periods calculated based on projected or historical efficiency change, with slope of cost-efficiency function derived from 2010 typical/high efficiency furnaces in *Technology Forecast Updates.* A technological improvement rate of 0.25% per year was applied to the costs.

Wood Furnace

Efficiency: Wood furnaces were assumed to have efficiencies of 0.52 and 0.58 in 1990 and 2005, respectively, and to increase according to Trajectory A in the future.

Non-fuel cost: Capital costs were estimated based on an informal survey of available wood furnaces currently on the market. Costs were assumed to decrease over time at 0.1% per year, with no efficiency-induced cost increase assumed.

Energy calibration: It was assumed that all residential consumption of biomass was for heating.

2.1.3. Air Conditioning

Electric

Efficiency: For the United States, the 2007 AEO (EIA 2007c) was used for 2005 and 2020, and the 2020–2030 rate of improvement was extrapolated to 2035. Subsequent efficiency improvement took place according to Trajectory B. In the advanced scenarios, the 2030 estimate from the AEO was reached in 2020, and subsequent technological improvement took place according to Trajectory C.

California was assumed to have 2.4% higher efficiency than the U.S. average in all time periods, reflective of rebate programs and code standards.

Note: Theoretical efficiencies (Carnot) for air conditioning were estimated by the equation $T_{low}/(T_{high}-T_{low})$ yielding the following:

DX: T_{high} = 95°F T_{low} = 52°F → EER = 40.6 & COP = 11.9
Chiller: T_{high} = 80°F (water cooled) T_{low} = 45°F → EER = 49.2 & COP = 14.4

Non-fuel cost: *Technology Forecast Updates* (NCI 2004a) was used for 2005, and the 2010 typical and high-efficiency air conditioners were used to determine the cost of efficiency improvement. The rate of technological improvement was assumed to be 0.25% per year in the reference scenarios and 0.50% in the advanced scenarios.

Gas Absorption Chiller

Gas absorption chillers were not included in the U.S. market, but due to their market share in the Energy Commission models, gas chillers were included in the California module.

Efficiency: 1990 was decelerated by Trajectory A; 2005 and 2020 were taken from EIA's Technology Forecast Update (NCI 2004a). 2035–2095 were assigned to Trajectory A.

Non-fuel cost: 2005 value from *Technology Forecast Updates* (NCI 2004a); 2003–2025 projections used to estimate cost of efficiency. Technological improvement was assumed to be 0.25% per year.

2.1.4. Water Heating

Gas Water Heater

Efficiency: The 2005 value came from the 2007 AEO (EIA 2007c), and the 1990 estimate was back-calculated using the NEMS stock model. 2020 came from EIA (2007c), and 2035 was estimated by extrapolation of the 2020–2030 rate of improvement in EIA (2007c). Trajectory D was used for future efficiency improvement, indicative of a shift to tankless water heaters.

For California, the 1990 estimate was derived from 2005 California reported efficiency. The 2005 estimate was derived from California Residential Sector Energy Efficiency Potential Study (April 2003), pg. A-10. The 2020–2035 efficiencies were based on California adopting a standard for condensing water heaters in 2020, and by 2035 it is assumed that all water heaters in California will meet this standard (EF 0.86). The maximum possible efficiency, 0.92 (0.96 conversion efficiency and 0.04 standby loss; same as electric), is reached in 2095.

Non-fuel cost: *Technology Forecast Updates* (NCI 2004a) used for 2005 and the 2010 typical and high-efficiency water heaters were used to determine the cost of efficiency improvement. The rate of technological improvement was assumed to be 0.50% per year.

Gas Heat Pump Water Heater

Gas heat pump water heaters were not included in the reference U.S. scenario for the Value of Technology analysis, nor in California. In the advanced U.S. scenario, they are allowed into the market starting in 2020.

Efficiency: Calculated according to the following equation:

$$Eff_{gasheatpumpwaterheater,t} = Eff_{gasheatpump,t} * Eff_{gaswaterheater,t} / Eff_{gasfurnace,t}$$

Non-fuel cost: The same cost-efficiency trade-off was used as for gas heat pumps; the technological improvement rate was set to 0.5% per year.

Electric Resistance Water Heater

Efficiency: AEO 2007 (EIA 2007c) was used for 2005 and 2020, 2035 was extrapolated from the 2020–2030 trend, and the 1990 data were back-calculated from the 2005 NEMS stock model. A limit of 0.96 was assumed and applied starting in 2050. California efficiencies were assumed equal to U.S. efficiencies.

Non-fuel cost: *Technology Forecast Updates*; cost-efficiency slope calculated from 2010 typical and high-efficiency projections, and technological improvement set to 0.50% per year.

Energy calibration: Assumed to account for entire electric water heating market, as electric heat pump water heaters are very rare (NCI 2004a).

Electric Heat Pump Water Heater

Electric heat pump water heaters were not part of the technology portfolio in the base years or in the U.S. reference scenarios. They were included in the advanced U.S., California, and rest-of-U.S. scenarios, but are slowly phased in starting in 2020. While significant R&D has been aimed at reducing the costs of the technology for popular use, a breakthrough would currently be required for the technology to become cost-competitive on the U.S. market (NCI 2004a).

Efficiency: Calculated according to the following equation:

$$Eff_{electricheatpumpwaterheater,t} = Eff_{electricheatpump,t} * Eff_{electricresistancewaterheater,t} / Eff_{electricresistancefurnace,t}$$

Non-fuel cost: The 2003 typical cost from *Technology Forecast Updates* (NCI 2004a) was used for 2005. The cost-efficiency slope was determined from 2010 typical and high-efficiency projections, and technological improvement was set to 0.25% per year.

Oil Water Heater

Oil water heaters were not included in the California model. Efficiencies and non-fuel costs for the U.S. model were assumed equal to gas water heaters.

2.1.5. Lighting

Lighting in 1990 and 2005 was split between two technologies: fluorescent and incandescent. Fluorescent includes high-intensity discharge (HID) lighting (rare in the residential sector) as well as compact fluorescent lighting (CFL). The total energy allocated to lighting in 2005 came from the AEO (2007) estimate for 2005. The AEO (EIA 1996) estimate for 1993 did not include outdoor lighting, which accounted for approximately 53% of residential lighting in 2000 (derived by comparing the year 2000 in EIA (2002) Table A-3, and EIA (2003) Table A-3). This proportion was assumed to apply in 1990 as well, and was used to estimate total energy to lighting for 1990.

Non-fuel costs were calculated according to the following equations:

Non-fuel cost = [Levelized lamp cost / (Lamp wattage * Efficiency (lumens/Watt) * Capacity factor * hours per year)] + [Levelized fixture cost / (Lamp wattage * Efficiency (lumens/Watt) * Capacity factor * hours per year)]

The capacity factor was assumed to be 0.40 for both types of lighting.

Incandescent

Efficiency: Efficiency was assumed to be 15 lumens per Watt in 2005, increasing according to Trajectory A.

Non-fuel cost: Based on $14.20 fixture price levelized over 12 years, and $1.00 lamp price levelized over 1500 hour lifetime.

Energy calibration: Assumed to follow equal proportions in 1990 and 2005, with incandescent taking 90% of electricity to lighting in the residential sector in both years (NCI 2002).

Fluorescent

Efficiency: Efficiency was assumed to be 60 lumens per Watt in 2005, increasing according to Trajectory C, approaching the upper limit of efficiency for commercially manufactured fluorescent lighting.

For California, the fluorescent lighting efficiency values were assumed to be equal to U.S. values in 1990, but in 2005 were calculated using efficiencies of 4-foot T-12s and greater than 4-foot T-8 bulbs (NCI 2002) and the California Installed Base values (Aspen 2005). This is detailed in the following equation:

$$Eff_{CA,2005} = \left(Eff_{T12-4\,ft} * 45\%_{CA2005\,InstalledBase} + Eff_{T8->4\,ft} * 55\%_{CA2005\,InstalledBase}\right)$$

A trajectory for future years was set such that the United States and California have the same efficiency in 2095.

Non-fuel cost: A fixture price of $60 was levelized over a 15-year lifetime (2004$), and $3.00 lamp price levelized over 18,000 hours of operation.

Energy calibration: Ten percent of the electricity in United States was consumed by lighting in 1990 and 2005 (NCI 2002). In California, it was assumed that the CFL market accounted for 4% more of the market share than in the rest of the United States (Sandahl et al. 2006), and as such, in 2005 the fluorescent market in California was increased by 4% (and incandescent was decreased by this amount).

Solid-state

Solid-state lighting is assumed to enter the market in 2020.

Efficiency: Starting at 100 lumens per Watt, solid-state lighting is assumed to improve according to Trajectory B in the reference U.S. case (and in California), and according to Trajectory E in the advanced case. In this case, it passes the Department of Energy target for solid-state lighting efficiency of 150 lumens per Watt in 2050 (D&R 2006), and by 2095 is still within the range of Navigant (NCI 2006) projections for 2027.

Non-fuel cost: PNNL estimates for capital costs of solid state lighting were used.

2.1.6. Appliances

Appliances consist of refrigerators, freezers, dishwashers, clothes washers, and clothes dryers. The only gas appliances considered are gas clothes dryers.

Electric Appliances

Efficiency: Efficiency was set to an index value (1) in 2005, and future and historical efficiencies were calculated relative to the index value. To determine an aggregate U.S. appliance efficiency rate of improvement between the time periods, rates of improvement were calculated for each of the five electric appliances, then weighted by the energy consumption of the appliance in 2005.The AEO 2007 (EIA 2007c) was used to estimate 2005 and 2020 stock efficiencies, and the 2020–2030 rate of improvement was extrapolated for the 2035 estimate. The 1990 data were back-calculated based on the NEMS stock model improvement from 1990 to 2005. After 2035, appliance efficiency is assumed to follow Trajectory B.

In California, appliances were assumed to be 2.4% more efficient than the rest of the United States in all time periods, reflecting standards and rebates for high efficiency equipment.

Non-fuel cost: Because non-fuel costs are represented as costs per unit of output, and 2005 was the index year for efficiency, in this year output of appliances was assumed equal to energy input. The NEMS residential module was used to estimate the total number of appliances in the stock in 2005. This was divided by the energy consumption by that type of appliance to determine the energy consumption per unit each year. Levelized capital costs were determined using a 10% interest rate and capital costs from the DEER database (2007). Costs per output were then determined for each appliance, and the aggregate cost for appliances as a group was weighted by energy consumption by appliance type in 2005. Future costs were assumed to decrease at 0.1% per year.

Energy calibration: Energy consumption for each of the five appliance types was aggregated from the AEO 2007 and 1993.

Gas Appliances

Efficiency: The AEO 2007 (EIA 2007c) was used for 2005; the NEMS stock model was used to back-calculate 1990 based on 2005 efficiency. The AEO 2007 (EIA 2007c) was used for 2020 value; 2020–2030 rate of improvement was extrapolated to 2035. After 2035, gas appliance efficiency follows Trajectory B.

Non-fuel cost: Levelized costs were calculated as for electric appliances. Energy consumption per unit was calculated accordingly:

Unit energy consumption = washer cycles/yr * fraction of washer cycles requiring dryer * water to be evaporated/cycle * kWh per pound of water

Future non-energy costs were assumed to decrease at 0.1% per year.

2.1.7. Other End Uses

Other energy consists of many sources, many of which do not have service outputs that can be measured in terms of energy. However, as with appliances, these were modeled with an index efficiency in 2005, and therefore in 2005 energy in is assumed equal to service out.

Electric Other

The residential other electric energy was broken into twelve end use categories by TIAX (2006), each of which were analyzed for current energy use, future efficiency changes, and future energy use. This report forms the basis for the efficiency and non-fuel cost assumptions in the California and U.S. modules.

Efficiency: As shown in Table A-4, each of 13 “other” end uses was analyzed for future improvement and used to calculate a weighted average efficiency improvement.

This rate of technological change was used for the time periods 1990 to 2005 and 2005 to 2020. For 2020 to 2035, the rate of technological change was set to 0, and for the next two time periods, the rates were 0.1% improvement per year, followed by all subsequent time periods having 0.05% per year. Little improvement is assumed in this category because technological improvement has tended to focus on consumer utility rather than energy use reduction.

In the advanced scenario for the U.S. Value of Technology Analysis, these other energy sources are assumed to be subjected to the same efficiency standards as appliances, and efficiencies increase at the same rate.

Table A-4. Energy consumption, unit energy consumption (UEC) change, and weighted efficiency improvement 2005–2025 in the residential "other" end uses. As shown, the average is actually projected to decrease in efficiency, driven mostly by TVs and set-top boxes.

	Energy consumption TWh/yr	UEC improvement (% / year) 2005–2025
Audio equipment	13	0.39
Ceiling fans	20	0
Coffee machines	4.7	-0.20
Microwave ovens	16	0
Portable electric spas	9.5	0.24
Cordless phones	4.16	0.57
Cell phones	0.78	0
Power tools	3.63	0.86
Vacuum cleaners	0.48	0.73
Security systems	1.8	2.06
Set-top boxes	30	-1.27
TVs	73	-0.81
VCRs	12	2.01
Total	189	**-0.24**

Source: TIAX (2006)

Non-fuel costs: Non-fuel costs were calculated as for appliances, with the levelized annual cost-per-unit of energy consumption (assumed equal to the service output in 2005) divided by the expected annual energy consumption of the equipment. This was computed for all thirteen identified other energy consumers and averaged according to the energy consumption of each. No future changes were assumed in the costs over time, as it was assumed that technological improvement would be focused on consumer utility rather than cost reduction.

Energy calibration: The following categories were added from the AEO energy breakouts (within electric): cooking, furnace fans, personal computers, color televisions, and other uses.

Gas and Fuel Oil Other

Due to a lack of data on residential gas and fuel oil other categories, efficiency improvements were set to 0.25% improvement per year, and costs are assumed constant. The energy calibration for fuel oil other includes the AEO category "other fuels," which are specified as kerosene, coal, and other minor fuels.

2.2. U.S. and California Commercial Building Sectors

Tables A-5 and A-6 show efficiency and non-fuel cost assumptions in the United States (reference and advanced) and California commercial buildings sectors.

Table A-5. Commercial sector equipment efficiency, in the U.S. reference and advanced scenarios. Where California efficiency assumptions differ from the U.S. assumptions, they are included in the table, denoted by a "CA" in front of the technology name.

	Historical		**Reference**		**Advanced**	
	1990	**2005**	**2050**	**2095**	**2050**	**2095**
Shell efficiency	0.250	0.220	0.194	0.148	0.188	0.121
Heating: energy out/energy in						
Gas furnace/boiler	0.69	0.76	0.85	0.89	0.85	0.89
CA Gas furnace/boiler	0.69	0.76	0.87	0.89	na	na
Gas heat pump	na	1.30	na	na	1.67	1.90
Electric furnace/boiler	0.98	0.98	0.99	0.99	0.99	0.99
Electric heatpump	2.67	3.10	3.69	3.83	3.95	4.10
CA Electric heatpump	2.73	3.17	3.78	3.93	na	na
Fuel oil furnace/boiler	0.73	0.77	0.81	0.84	0.81	0.84
Cooling: energy out/energy in						
AC	2.44	2.80	3.72	3.87	4.29	4.87
CA AC	2.50	2.86	3.81	3.96		
Water heating: energy out/energy in						
Gas water heater	0.72	0.82	0.93	0.93	0.93	0.93
Gas hp water heater	na	na	na	na	1.53	1.91
Electric resistance water heater	0.96	0.97	0.98	0.98	0.98	0.98
Electric heatpump water heater	1.39	1.93	na	na	2.39	2.51
Fuel oil water heater	0.74	0.76	0.80	0.82	0.80	0.82
Lighting: lumens per watt						
Incandescent lighting	15.00	15.00	17.04	17.55	17.04	17.55
Fluorescent lighting	64.50	75.00	99.64	106.59	99.64	106.59
CA Fluorescent lighting	64.50	76.80	100.50	106.60	na	na
Solid-state lighting	na	na	122.38	127.06	151.90	185.90
Office equipment and other: indexed to 2005						
Office equipment	0.96	1.00	1.09	1.13	1.42	1.47
Gas other	0.96	1.00	1.09	1.13	1.33	1.51
Electric other	0.96	1.00	1.09	1.13	1.33	1.51
Fuel oil other	0.96	1.00	1.09	1.13	1.09	1.13

Table A-6. Non-fuel costs in the commercial buildings sector for U.S. advanced and reference scenarios. For all technologies (regardless of efficiency differences), non-fuel costs in California are assumed equal to the reference U.S. costs.

	Historical		Reference		Advanced	
2004 $ per GJ of output	**1990**	**2005**	**2050**	**2095**	**2050**	**2095**
Aggregate building cost ($/m^2)	13.20	22.92	67.83	172.43	67.83	172.43
Heating						
Gas furnace/boiler	1.50	1.77	1.95	1.91	1.95	1.91
Gas heat pump	na	17.15	na	na	15.74	14.44
Electric furnace/boiler	2.56	2.53	2.40	2.30	2.40	2.30
Electric heatpump	11.50	14.54	16.30	15.36	13.55	11.38
Fuel oil furnace/boiler	1.75	1.72	1.58	1.50	1.58	1.50
Cooling						
AC	7.79	7.69	8.88	8.26	8.51	7.57
Water heating						
Gas water heater	2.45	2.33	2.09	1.95	2.09	1.95
Gas hp water heater	na	na	na	na	17.35	17.15
Electric resistance water heater	2.30	2.74	3.19	3.07	3.19	3.07
Electric heatpump water heater	na	na	na	na	5.93	5.72
Fuel oil water heater	2.38	2.33	2.23	2.14	2.23	2.14
Lighting						
Incandescent lighting	250.78	250.78	220.81	214.29	220.81	214.29
Fluorescent lighting	165.27	142.14	106.99	100.02	106.99	100.02
Solid-state lighting	na	na	298.02	245.14	240.12	167.55
Office equipment and other						
Office equipment	249.94	246.22	235.38	225.02	235.38	225.02
Gas other	80.67	80.67	80.67	80.67	80.67	80.67
Electric other	80.67	80.67	80.67	80.67	80.67	80.67
Fuel oil other	80.67	80.67	80.67	80.67	80.67	80.67

2.2.1. Building Shell Efficiency

Building shell improvement in the commercial sector was estimated based on the difference in insulation between stock and new buildings in Sezgen et al. (1995; Table 6.2). Buildings were analyzed according to twelve types, each with its own average R-values for walls, ceilings, and windows, and each with its own ratio of roof-to-wall area, and window-to-wall area. Within each building type, the wall, ceiling, and window R-values were averaged, weighted by surface area, and then the whole-building R-values of the twelve different types of buildings were averaged, weighted by floorspace of each building type. Census data was analyzed to obtain a median building age of commercial buildings in the United States, and this median age was assumed to be a stock turnover time, allowing estimation of a rate of improvement in the base years. This was used for 2005 to 2020, and in the reference U.S. and California scenarios, future changes in shell efficiency were assumed to increase on Trajectory B. Trajectory D was used in the advanced U.S. scenario.

2.2.2. Heating

Gas Furnace

U.S. Efficiency: For the United States, the 2005 efficiency in Table 22 of the AEO 2007 (EIA 2007c) was used, and the 1990 value was back-calculated using an annual rate of improvement derived from the 2005 residential stock model from NEMS. Efficiency in 2020 was assumed to be equal to the AEO projected value, and the 2035 estimate was calculated using the AEO annual rate of improvement between 2020 and 2030. In subsequent periods, efficiency improvement was assumed to follow Trajectory B.

California Efficiency: In 1990 and 2005, California is assumed to match the rest of the United States, having had no concerted efforts to boost gas furnace efficiency until recently. In the future, California is assumed to implement a condensing standard well before the rest of the United States, represented by California efficiency being one fifteen-year time-step ahead of the rest of the United States through 2030. This lead is assumed to diminish as U.S. standards are enacted, and by 2065 efficiencies are equal in California and the United States.

Non-fuel costs: Present capital costs for residential gas furnaces were from the 2003 stock estimate in *Technology Forecast Updates* (NCI 2004a). The slope of the cost-efficiency function was determined using the estimates for high-efficiency and typical gas furnaces in 2010. An improvement rate of 0.25% per year was then applied to the costs prescribed by the assumed efficiency changes.

Gas Heat Pump

Because natural gas heat pumps currently have no market share (nor does the EIA project their entry by 2035; EIA 2007c), they are not included in the reference scenarios for the United States, or for California. In the advanced U.S. scenario they enter the market in 2020.

Efficiency: 2005 and 2020 values came from AEO 2007 (EIA 2007c); 1990 was back-calculated assuming 2005–2020 improvement, and 2035 calculated assuming extrapolation of 2020–2030 rate of improvement. Trajectory D was used in future periods.

Non-fuel costs: *Technology Forecast Updates* (NCI 2004a) was used. The slope of the cost-efficiency function was based on projected improvement between 2001 and 2025, and the rate of technological improvement was set to 0.25% per year.

Electric Boilers

These have no market share in California at present and were also excluded from the California market in future time periods.

U.S. Efficiency: Assumed to be 0.98 in base years, and to reach a maximum of 0.99 in 2020.

Non-fuel cost: Based on *Technology Forecast Updates* (NCI 2004a) 2003 stock average, decreasing at 0.1% per year with no efficiency-induced cost changes through 2095.

Energy calibration: Because electric boilers share the electricity-fueled space heating market with electric heat pumps, a NEMS commercial equipment module was used to estimate the relative market share of each technology, based on the number of units in use. The following equation specifies the market share of electric boilers:

$$Energy_{elboiler,t} = Energy_{electric\ heating,t}*(Stock_{elboiler,t} / Efficiency_{elboiler,t}) /$$

$$[(Stock_{elboiler,t} / Efficiency_{elboiler,t}) + (Stock_{heatpump,t} / Efficiency_{heatpump,t})]$$ where:

Stock = number of units of the specified technology in use at the specified time period

Efficiency = stock average efficiency of the specified technology at the specified period

Energy = energy consumption by the specified fuel or technology at the specified period

Electric Heat Pump

Efficiency: For the United States, the stock estimate for 2003 from *Technology Forecast Updates* (NCI 2004a) was used for 2005, and the 2020 typical heat pump was assumed for 2020. In the reference scenarios, Trajectory B was used for the future time periods. In the advanced scenarios, the high-efficiency heat pumps from *Technology Forecast Updates* become the stock in 2035, and future technological changes take place according to Trajectory B.

California efficiencies were assumed to be greater than the U.S. efficiencies by 2.4% in all time periods, representative of rebate programs and code standards.

Non-fuel cost: In the reference scenarios, the slope of the cost-efficiency function was calculated based on the average of the heating and cooling components of the heat pumps, for the 2010 typical and high-efficiency models in *Technology Forecast Updates*. The technological improvement was set to 0.25% per year. In the advanced scenarios, the same calculation was performed, using the data from the high tech case of *Technology Forecast Updates* (NCI 2004b), and the technological improvement was set to 0.50% per year.

Energy calibration: In the United States, the energy consumption was computed using the same equation as electric boilers, with the number of heat pumps in use in 2005 coming from the NEMS commercial equipment module.

Oil Furnace

Efficiency: The 1990 data were back-calculated from 2005 using the NEMS stock model. The 2005 and 2020 data were from the AEO 2007 Table 22 (EIA 2007c), and the 2035 estimate was calculated based on the projected 2020–2030 rate of improvement. Trajectory A was applied to subsequent time periods.

Non-fuel cost: *Technology Forecast Updates* (NCI 2004a) was used for 2005; all other periods were calculated based on projected or historical efficiency change, with slope of cost-efficiency function derived from 2010 typical/high-efficiency furnaces in the Navigant report. A technological improvement rate of 0.10% per year was applied to the costs.

2.2.3. Air Conditioning

Electric

Efficiency: For the United States, Table 22 of the 2007 AEO (EIA 2007c) was used for 2005 and 2020, with the 1990 estimate back-calculated from 2005 using the residential NEMS module, and the 2020–2030 rate of improvement extrapolated to 2035. Subsequent efficiency improvement took place according to Trajectory B. In the advanced scenarios, the 2030 estimate from the AEO was reached in 2020, and subsequent technological improvement took place according to Trajectory C.

California was assumed to have 2.4% higher efficiency than the U.S. average in all time periods, reflective of rebate programs and code standards.

Non-fuel cost: *Technology Forecast Updates* (NCI 2004a) was used for 2005, and in the reference scenarios, the 2010 typical and high-efficiency air conditioners were used to determine the cost of efficiency improvement. The rate of technological improvement was assumed to be 0.25% per year. In the advanced scenarios, the high tech case of *Technology Forecast Updates* (NCI 2004b) was used to calculate the cost of efficiency improvement, and a yearly technological change rate of 0.50% was applied.

2.2.4. Water Heating

Gas Water Heater

Efficiency: For the U.S. module, the 2005 estimate from Table 22 of the 2007 AEO was adjusted to account for standby losses (E. Boedecker, EIA, pers. comm.), and rates of future technological change matched the rates of the same table. The 1990 values were calculated from the 2003–2010 projected rate of change, and 2035 was calculated based on the 2020–2030 rate. The assumed technical limit of 0.93 is reached in 2050, after which no further improvements take place.

Unlike in the residential sector, no efficiency change is assumed for California commercial gas water heaters, as the efficiencies in these scenarios are already quite high.

Non-fuel cost: *Technology Forecast Updates* (NCI 2004a) was used for 2005, and the 2010 typical and high-efficiency water heaters were used to determine the cost of efficiency improvement. The rate of technological improvement was assumed to be 0.25% per year.

Gas Heat Pump Water Heater

Gas heat pump water heaters are not assumed to enter the market in the reference scenarios or in the California scenarios.

Efficiency: Efficiencies were set equal to gas heat pump water heaters in the Residential Sector.

Non-fuel cost: Costs were set equal to gas heat pump water heaters in the Residential Sector.

Electric Resistance Water Heater

Efficiency: Table 22 of AEO 2007 (EIA 2007c) was used for 2005 and 2020; 2035 was extrapolated from 2020–2030 trend, and 1990 was back-calculated from 2005 NEMS stock model. A maximum of 0.98 was assumed and reached in 2035. California efficiencies were assumed equal to U.S. efficiencies.

Non-fuel cost: *Technology Forecast Updates* 2003 stock efficiency was used for 2005. The cost-efficiency slope was calculated from 2010 typical and high-efficiency projections, and technological improvement was set to 0.10% per year.

Energy calibration: Electric resistance water heaters were assumed to account for entire electric water heating market, as electric heat pump water heaters are not common (NCI 2004a).

Electric Heat Pump Water Heater

Electric heat pump water heaters were not part of the technology portfolio in the base years or in the U.S. reference scenarios. They were included in the U.S. advanced scenarios, California, and the rest-of-U.S., but are slowly phased in starting in 2020. Although significant R&D since 1990 has been directed at reducing the costs of the technology for popular use, a breakthrough would currently be required for the technology to become cost-competitive in the United States (NCI 2004a).

Efficiency: This was set equal to electric heat pump water heaters in the Residential Sector.

Non-fuel cost: This was calculated according to the following equation:

$Cost_{electricheatpumpwaterheater,commercial,t} = Cost_{electricresistancewaterheater,commercial,t} * Cost_{electricheatpumpwaterheater,residential,t} / Cost_{electricresistancewaterheater,residential,t}$ where:

Cost = Capital cost of specified equipment in specified sector at specified period

Oil Water Heater

Efficiency: Table 22 of AEO 2007 (EIA 2007c) was used for 2005 and 2020; 2035 was extrapolated from 2020–2030 trend, and 1990 was back-calculated from 2005 NEMS stock model. Trajectory A was used for 2035 to 2095 efficiency improvement.

Non-fuel cost: Set equal to Residential Sector oil water heater; a 0.10% per year rate of technological improvement was applied.

2.2.5. Lighting

Lighting efficiency assumptions were identical to those of the Residential Sector, and the non-fuel costs were reduced by 20% relative to the Residential non-fuel costs, to reflect that commercial lighting purchases are typically made at wholesale rates.

Energy calibration: Fluorescent (and HID) accounted for 68% of the energy used for lighting in 1990 and 2005, and the other 32% was incandescent lighting (NCI 2002). This same proportion was applied to California.

2.2.6. Office Equipment

Office equipment consists primarily of computers, copiers, printers, and fax machines.

Efficiency: Efficiencies of office equipment were addressed in aggregate. Office equipment efficiency was indexed to 2005, and in the reference and California scenarios was set to the improvement rates of the commercial other end uses through 2020 (see Section 2.2.7). In future time periods, office equipment efficiency was assumed to increase according to Trajectory A, reflecting that while efficiency improvements are possible in office equipment, energy savings are not currently taking place as research and development tends to focus instead on consumer utility. In the advanced cases, office equipment is assumed to be subjected to similar standards as residential appliances in the reference scenarios, increasing at the same rates.

Non-fuel cost: Non-fuel costs were computed individually for each office equipment technology, and weighted by the total energy consumption of each. Computers were addressed explicitly in the AEO 2007 (EIA 2007c), Table 22, while the other three pieces of equipment were assumed to equally share the non-computer office equipment energy. Non-fuel costs were calculated accordingly:

Non-fuel $cost_{2005}$ ($/energy output) = Levelized capital cost / UEC

2.2.7. Other End Uses

As with the Residential other end uses, the Commercial Sector other end uses consist of many disparate sources, and the module is based on the eleven addressed by TIAX (2006).

Note: approximately 90% of the commercial other end uses take place exterior to the building, and as such do not contribute to internal gains. For this reason, the internal gain factor of commercial other energy is assumed to be only 5%.

Electric Other

Efficiency: As shown in Table A-7, the future efficiency for all other end uses was calculated as the weighted average of the eleven identified in the TIAX report.

Table A-7. Energy consumption, Unit energy consumption (UEC) change, and weighted average efficiency improvement 2005–2025 for commercial electric “other” end uses

Commercial “Other” End Use	Energy consumption TWh/yr	UEC improvement (% / year) 2005–2025
Distribution transformers	53.8	1.06
Water distribution	44.0	0.15
Water treatment	26.0	-0.16
Elevators	4.9	0.71
X-Ray	8.9	-2.69
Non-road electric vehicles	5.8	0
Coffee makers	3.2	0.09
Water purification	1.2	0
Computed tomography	2.2	0
Escalators	0.9	0
Magnetic resonance imaging	2.9	-2.06
Total	137.4	**0.24**

Beyond 2020, the rate of improvement in the reference scenarios and in the California model were set to Trajectory A. In the advanced scenarios, the improvement rates were slowly phased in, analogous to the improvement rates in the shell efficiencies, reflecting a slower turnover of stock.

Non-fuel costs: Non-fuel commercial other costs could not be computed as residential other costs were, as costs for the commercial other equipment were not available. As such, the commercial other costs have been set to 60% of the residential costs per unit of output (fuel consumption in 2005), reflective of the wholesale/retail discrepancy between residential and commercial purchases. As in residential, no decrease in costs are assumed for the upcoming century.

Energy calibration: The following AEO categories were added for electric other: ventilation, cooking, refrigeration, and other uses.

Gas and Fuel Oil Other

Efficiency: Efficiencies were set equal to the electric other in the reference scenarios, and in the advanced scenarios, efficiencies were also assumed to improve by 50% over the next century, though phased in more slowly than other technological improvements due to the slow turnover time of stock.

Non-fuel cost: Costs were set equal to electric other.

Energy calibration: As in the Residential Sector, fuel oil other consists of distillate fuel, in addition to the "other fuels" category in the AEO that refers to fuels such as LPG, kerosene, and coal.

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Appendix B.

Energy Efficiency Assumptions for the United States Transportation and Industrial Sectors

Appendix B: Energy Efficiency Assumptions for the United States Transportation and Industrial Sectors

The purpose of this appendix is to identify and source assumptions pertaining to the present and future technologies in the U.S. transportation and industrial modules.

1.0 U.S. Transportation Module

The scenarios addressed in this appendix are the reference and advanced technology suites for the Value of Technology analysis. The only input parameters that differed between the reference and advanced scenarios were the fuel intensities and non-energy costs. The input parameters are covered in detail below, and include the load factors (average number or passengers or tons of freight per vehicle), non-fuel costs, intensities, and energy consumption or service output in 1990 and 2005. In the scenarios presented, load factors for all transportation technologies were assumed to remain constant to their 2005 values in the next century; changes in service intensities are therefore mediated entirely through vehicle efficiency.

1.1. Passenger Sector

The passenger sector consists of seven transportation modes in the reference scenarios, and eight in the advanced; they are shown in Table B-1 along with the average speeds by each mode of transportation. Speeds are used to determine the time value of transportation.

Table B-1. Average speeds assumed for passenger modes of transportation

Passenger mode	Speed (mph)
Auto	30
Truck	30
Bus	25
Rail	35
Air	120
High Speed Rail	120
Ship	5
Motorcycle	35

Table B-2 shows the specific technologies within each mode, along with the assumptions of service fuel intensity in the reference and advanced scenarios. Note that while it appears that electric-powered technologies have the lowest service intensities, the data in the table do not account for the primary energy used to generate electricity.

Table B-2. Historical, reference, and advanced assumptions for fuel intensity of transportation technologies

	Historical		Reference		Advanced	
	1990	**2005**	**2050**	**2095**	**2050**	**2095**
Hybrid Auto	na	2491	2105	1881	1261	977
ICE Auto	3560	3222	2723	2433	1900	1471
Hybrid Truck	na	2918	2251	2011	1721	1332
ICE Truck	4469	3698	2852	2548	2500	2040
Diesel bus	1304	1341	1282	1226	1282	1226
Hybrid bus		1058	1012	967	1012	967
CNG bus	1799	1850	1769	1691	1769	1691
Trolleybus	440	453	433	414	433	414
Diesel rail	1798	1719	1644	1571	1644	1571
Electric rail	1035	1052	1005	961	1005	961
High speed rail	na	na	na	na	660	631
Air	3624	2357	1698	1461	1316	1133

ICE=internal combustion engine; CNG=compressed natural gas

1.1.1. Auto and Light Truck

Table B-3 shows vehicle miles per gallon (mpg) and non-fuel costs for light-duty vehicles.

Table B-3. Light-duty vehicle miles per gallon and non-fuel costs in the advanced and reference scenarios

	Historical		Reference		Advanced	
Vehicle mpg	1990	2005	2050	2095	2050	2095
Hybrid Auto	na	29.5	34.9	39.1	58.3	75.3
ICE Auto	20.3	22.8	27.0	30.2	38.7	50.0
Hybrid Truck	na	23.0	29.8	33.4	39.0	50.4
ICE Truck	16.1	18.1	23.5	26.3	26.8	32.9
Vehicle non-fuel cost (2005 $/mi)						
Hybrid Auto	na	0.70	0.70	0.70	0.58	0.58
ICE Auto	0.48	0.58	0.58	0.58	0.58	0.58
Hybrid Truck	na	0.77	0.77	0.77	0.64	0.64
ICE Truck	0.54	0.64	0.64	0.64	0.64	0.64

Internal Combustion Engine (ICE) Vehicle

Load factor: Davis and Diegel (2006) Table A17 was used for 1990; Auto = 1.6 and Truck = 1.6. For 2003, Davis and Diegel (2006) Table 2.10 was used; Auto = 1.57 and Truck = 1.72.

Non-fuel cost: Non-fuel costs for both 1990 and 2005 came from Davis and Diegel (2006) Table 10.11. The 2003 estimate was assumed for 2005 (see Table B-3).

Vehicle fuel intensity: Davis and Diegel (2006) Table 2.11 was used for both 1990 and 2005. The 2005 estimate was calculated by linear extrapolation from 1990–2003 trend.

Energy consumption: Davis and Diegel (2006) Table 2.6 was used for 1990; AEO (EIA 2007) Table 35 was used for 2005.

Future improvement in vehicle fuel intensity: This was assumed equal to AEO (EIA 2007) Table 7 rate of improvement from 2005 to 2020, with 2020–2030 rate of improvement extrapolated to 2035. Subsequent time periods: 0.25% improvement per year (see Table B-3).

Hybrid Electric Vehicle (HEV)

Load factor: HEV load factor was assumed equal to ICE vehicle.

Non-fuel cost: Hybrids were assumed 21% more expensive than ICE (calculated from Lipman and Delucchi 2006). In the reference scenarios, this cost premium was assumed to remain constant in future time periods.

Vehicle fuel intensity: Intensity was calculated to be 1.28 times less than ICE intensity, based on fuel economy comparisons between HEV and ICE versions of seven similar makes of cars currently on market (see Table B-3).

Energy consumption: The HEV share in mileage was assumed proportional to the share in registrations; the energy consumption share was calculated based on intensity multiplied by registrations.

Future intensity improvement: This was assumed to be 0.58% per year from 2005 to 2020 (same as ICE in EIA 2007), declining to 0.25% per year starting in 2035 in reference scenarios. In advanced scenarios, it was assumed to be 2% per year in 2005–2020, declining over time, such that HEV stock averages reach 75 mpg for auto and 50 mpg for light trucks by 2095.

Future cost decrease in advanced case: HEVs were assumed to decrease in cost to match ICE cars in 2050 (see Table B-3).

1.1.2. Bus

While four different drivetrain technologies were included separately in the scenarios, all were assumed to have the same load factors, and the vehicle fuel intensity of each technology was assumed to decrease at 0.1% per year from 2005 to 2095.

Load factor: In 1990, this was assumed to be 17.1 persons per vehicle, from Davis and Strang (1993). For 2005, 16.6 persons per vehicle was used, from 1997 value in Davis (2000) Table 2.11.

Diesel

Non-fuel cost: Non-fuel cost was calculated according to the following equation:

Non-fuel cost = (Revenue per revenue passenger mile) * (load factor) – (intensity) * (fuel cost).

The revenue per revenue passenger mile came from BTS (2005), Table 7.5A, 7.6A, with fuel cost from Table 14.4A. In 2005, the non-fuel cost (2005$) was $0.12 per passenger mile.

Vehicle fuel intensity: This was calculated as energy use (1990: Table 2.6 in Davis 1995) divided by total vehicle miles (1990: Table 3.2 in Davis 1995), with transit buses, inter-city buses, and school buses calculated separately, weighted by energy consumption. Vehicle fuel intensities for inter-city buses and school buses could only be calculated for 1990 and 1991; intensities for each bus type were assumed to remain constant through 2005. See Table B-1 for calculated service intensity.

Energy consumption: For 1990, Davis and Diegel (1995) Table 2.6 was used; total bus energy consumption was assumed equal to the sum of transit, intercity, and school buses. Electric and CNG transit bus energy use was subtracted (see below). For 2005, AEO 2007 (EIA 2007) was used.

Total vehicle miles: Transit buses in 1990 and 2003 came from Davis and Diegel (2006) Table 5.12. Intercity and school buses in 1990 came from Davis (1995) Table 3.27. Intercity and school bus vehicle miles in 2000 used for 2005; Davis (1995) Table 5.13.

Electric and CNG

Non-fuel cost: CNG was assumed to be 20% more expensive than diesel; electric was assumed to be 13% more expensive (based on National Transit Database operating costs per passenger mile). Non-fuel costs per passenger mile in 2005 (2005$) were $0.13 (electric) and $0.14 (CNG).

Vehicle fuel intensity: Conversion factors were calculated for electric-diesel and CNG-diesel; electric was based on efficiency minus line losses, and CNG was based on NREL 2006. See Table B-1 for service intensity.

Energy consumption: The 1990 values were calculated from Davis and Diegel (2006), Table A3, using 3324 British thermal units per kilowatt-hour (Btu/kWh) for electric buses. The 2003 electric and CNG shares of bus fuel use were assumed to remain equal in 2005.

Hybrid

Non-fuel cost: Hybrid buses were assumed to be 21% more expensive than diesel; this was the same cost premium as was used for light truck and auto. Non-fuel cost per passenger mile in 2005 (2005$) was $0.14.

Vehicle fuel intensity: Hybrid buses were assumed 27% more efficient than diesel buses, similar to HEV to ICE vehicle fuel intensity ratio for light duty vehicles (auto and truck). See Table B-1 for service intensity.

Energy consumption: No calibration data was entered.

1.1.3. Rail

Diesel and Electric

Load factor: This was calculated from Davis and Diegel (2006) data on total service output and vehicle miles traveled (Tables 9.13–9.15; sum of Amtrak, commuter, and transit rail).

Non-fuel cost: This was calculated as the average of commuter, heavy, and light rail revenue per passenger mile times load factor, minus fuel costs times vehicle intensity. Data sources included BTS (2005) Table 7.5a/7.6a for revenue per passenger mile; and Table 14.4a (BTS 2005) for fuel costs. Non-fuel costs per passenger mile in 2005 (2005$) were $0.15 (electric) and $0.12 (CNG).

Energy consumption: For 1990, Davis and Diegel (2006) tables A.13 to A.15 were used, with electricity consumption recalculated without primary energy conversion. Fuel mixes for transit rail, intercity rail, and commuter rail came from Tables A.14, A.15, and A.13, respectively. Shares of diesel versus electric from 2003 were assumed for 2005; the 2005 energy consumption estimate was from AEO 2007 (EIA 2007).

Vehicle fuel intensities: See Table B-1 for service intensity. Diesel intensity was calculated as weighted average of Amtrak (which is about 90% diesel; Davis and Diegel (2006), Table A.15) intensity and commuter rail intensity (Table A.13), weighted by the number of miles traveled by each (Tables 9.13 and 9.14). Commuter rail number of miles were multiplied by the percent that were fueled by diesel.

Commuter rail intensity was multiplied by a conversion factor, estimated by the efficiency difference between transit rail and Amtrak.

Diesel conversion factor = $(\text{intensity}_{\text{Amtrak}} + \text{intensity}_{\text{transit}}) / (2 * \text{intensity}_{\text{transit}})$

Electric intensity was calculated as weighted average of transit rail (which is 100% electric; Table A.14) and commuter rail (Table A.13), weighted by the number of miles traveled by each (Tables 9.14 and 9.15). Commuter rail number of miles (Table 9.14) were multiplied by the percentage that were fueled by electricity.

Commuter rail intensity was multiplied by a conversion factor, estimated by the efficiency difference between transit rail and Amtrak.

Electric conversion factor = $(\text{intensity}_{\text{transit}} + \text{intensity}_{\text{Amtrak}}) / (2 * \text{intensity}_{\text{Amtrak}})$

Future intensity improvement: This was assumed to be 0.1% per year for both diesel and electric.

High-speed Rail

This mode of transportation was only available in the advanced scenarios, and there was no service in 1990 or 2005.

Vehicle fuel intensity and load factor: These were calculated from CCAP & CNT (2006), a report on five existing systems worldwide. The average across the four electric-fueled systems (France, Germany, and two systems in Japan) was used. See Table B-1 for service intensity.

Non-fuel costs: This was calculated based on Levinson et al. (1999). Non-fuel cost per passenger mile in 2005 (2005$) was $0.25.

Future intensity improvement: 0.1% per year.

Air

Vehicle miles and energy consumption were split between passenger and freight according to the respective proportion of ton-miles serviced in a given year, assuming a passenger weight of 200 lbs per person (BTS 1995).

Passenger and freight ton-miles, and vehicle miles: 1990 came from Davis and Diegel (2006), Table 9.2. 2005 came from BTS (2007a), multiplied by calibration factor to match Davis and Diegel (2006) vehicle miles in years 1996 to 2003.

Load factor: This was calculated based on revenue passenger miles traveled (BTS 2007a), divided by number of passenger vehicle miles traveled (the total vehicle miles minus the freight share; BTS 2007a).

Non-fuel cost: Revenue per revenue passenger came from BTS (2007b), Table 3.16, and fuel costs came from BTS (2007c**)**. The 2002 estimate of revenue per passenger was assumed for 2005. Non-fuel cost per passenger mile in 2005 (2005$) was $0.08.

Energy consumption: This was calculated from airline fuel use (BTS 2007c), corrected for the fraction allotted to passenger transportation.

Vehicle fuel intensity: This was calculated as energy consumption times the load factor, divided by the service output. See Table B-1 for service intensity.

Future change in fuel intensity: In reference scenarios, improvement rates were set to match the AEO 2007 (EIA 2007) through 2035, declining to 0.5% per year through 2065 and 0.25% per year thereafter. In advanced scenarios, improvements in airline fuel use take place rapidly, reaching the AEO projection for 2030 by 2020. Improvements in both aircraft design and whole-system management continue for the next two time periods, until whole-system airline fuel use approaches present-day fuel intensities of individual aircraft.

Future cost changes: In advanced scenarios, costs decrease roughly to match the projections of Lee et al. (2001).

Recreational Boat

Load factor: This was assumed to be four persons per vehicle.

Intensity: This was assumed equal to three times that of a freight truck in 1990.

Energy use: Energy use came from Davis and Diegel (2006), Table 9.8.

Future intensity improvement: This was assumed to be 0.1% per year.

Motorcycle

Fuel intensity, load factor, service output, and energy consumption: 1990 data from Davis and Strang (1993), and for 2005, the 2003 estimates from Davis and Diegel (2006) were used. In both years, passenger miles and load factor came from Table 2.10, and energy consumption came from Table 2.6, Vehicle fuel intensity was calculated as the product of load factor and fuel consumption divided by the number of passenger miles.

Future intensity improvement: 0.1% per year.

1.2. Freight Sector

The freight sector consists of four modes of transportation in the reference scenarios, and five in the advanced; the structure of the module is similar to the passenger sector, with ton-miles (rather than passenger miles) as the service output. There is no time value of transportation considered in the freight sector.

All freight revenue per revenue ton-miles, used to calculate non-fuel costs, are found in the BTS (2007d) Table 3.17. Freight service intensities and non-fuel costs are presented in Table B-4.

Truck

Load factor: Load factor was calculated from service (ton-miles, BTS 2005, Table 1-9b) divided by vehicle miles (Davis and Diegel (2006), Tables 5.1–5.2).

Fuel intensity: This came from Davis and Diegel (2006), Table 2.14.

Non-fuel cost: This was calculated from average freight revenue per ton-mile (BTS 2007d), multiplied by load factor, minus fuel costs from BTS (2005, Table 14.4a**)** times fuel intensity.

Energy consumption: This came from Davis and Diegel (2006) Table 2.6.

Table B-4. Service intensities, in Btu per ton-mile, and non-fuel costs, in 2005$ per revenue ton-mile. Ship freight costs include overseas waterborne commerce.

	Historical		Reference		Advanced	
Btu per ton mile	**1990**	**2005**	**2050**	**2095**	**2050**	**2095**
Truck	3601	3717	3146	2811	2225	1776
Diesel rail	420	338	324	309	324	309
Electric rail	142	114	109	104	109	109
Air	34440	21944	18630	17283	16415	15228
Ship	237	212	202	193	202	193
2005 $ per ton mile						
Truck	0.15	0.16	0.16	0.16	0.16	0.16
Diesel rail	0.017	0.014	0.014	0.014	0.014	0.014
Electric rail	na	na	na	na	0.02	0.02
Air	0.30	0.27	0.21	0.21	0.21	0.21
Ship	0.004	0.004	0.004	0.004	0.004	0.004

Diesel Rail

Load factor: Load factor was calculated as service output (in ton-miles) divided by vehicle miles (per car; Davis and Diegel (2006), Table 9.10).

Energy consumption: This came from Davis and Diegel (2006) Table 9.10.

Fuel intensity: Fuel intensity was calculated as energy use divided by vehicle miles (per car).

Non-fuel cost: Non-fuel costs were calculated from average freight revenue per ton-mile (BTS 2007d), multiplied by load factor, minus fuel costs from BTS (2005, Table 14.4a**)** times vehicle fuel intensity.

Future intensity improvement: This was assumed equal to 0.1% per year (EIA 2007).

Electric Rail

Electric rail was only included in the advanced scenarios, and even then it was not allowed to compete evenly with diesel, due to the barriers to electrification of the U.S. rail system.

Fuel intensity: Fuel intensity was assumed equal to diesel intensity times freight electric conversion factor, halfway between 1 and the passenger vehicle electric conversion factor.

Non-fuel cost: This was assumed equal to diesel.

Future technological change: This was assumed to be 0.1% per year (EIA 2007) through 2095.

Air

Load factor: This was calculated from freight ton miles divided by vehicle miles allocated to freight (share of freight ton-miles divided by the sum of freight and passenger ton miles; BTS 2007a).

Energy consumption: This was calculated as total fuel to aviation multiplied by freight-to-total service proportion. BTS (2007c).

Vehicle fuel intensity: This was calculated as energy consumption times load factor divided by service output.

Non-fuel cost: This was calculated from average freight revenue per ton-mile (BTS 2007d), multiplied by load factor, minus fuel costs from BTS (2007c) times vehicle fuel intensity.

Service output: This came from BTS (2007a) air carrier traffic statistics (freight ton miles by year).

Future intensity improvement: Future vehicle intensity was assumed to improve at half of the rate of passenger air.

Ship

International and domestic shipping were modeled as one mode of transport, even though the intensities, outputs, load factors, and energy consumption of each was calculated separately and then a weighted average was taken.

Energy consumption by foreign and domestic shipping: This came from Davis and Diegel (2006), Table 9.4.

Domestic shipping service intensity: This came from Davis and Diegel (2006), Table 9.5.

Domestic shipping load factor: This was assumed to be 900 tons, equivalent to a 1500-ton barge at 60% capacity.

International shipping service intensity: This was assumed equal to worldwide shipping intensity, calculated as total marine bunker fuel (IEA 2004a and IEA 2004b) divided by total number of ton-miles shipped (UNCTAD 2006).

International shipping load factor: This was calculated based on a breakdown of the U.S. Fleet in 1994 and 2004 (UKDFT 2005), known cargo capacities of each ship type (Fearnleys 2001), and an assumption of 60% average loading.

Vehicle fuel intensity: This was calculated as load factor times service intensity.

Future technological change in fuel intensity: This was assumed to be 0.1% per year (EIA 2007).

Non-fuel cost: Non-fuel cost was calculated from average freight revenue per ton-mile for domestic shipping (BTS 2007d), multiplied by load factor (international and domestic), minus the cost of diesel fuel (BTS 2005, Table 14.4a).

2.0 U.S. Industrial Module

Data collected by the Energy Information Administration (EIA) formed the basis for determining the categories of industry groups and end-uses for the manufacturing sector. For agriculture, mining, and construction—the non-manufacturing industries—data on end-use energy by fuel came from the Annual Energy Outlook (AEO; EIA 2005), and for manufacturing industries, the Manufacturing Energy Consumption Survey (MECS) was used. At the time of this writing, the 1998 MECS (EIA 1999) is thought to be a more reliable and internally consistent source of data than the 2002 MECS (EIA 2003). Table B-5 shows the total fuel consumption by the most prominent energy end-uses, by fuel, across all industries represented in the 1998 MECS.

As shown in Table B-5, of the total energy used by the U.S. manufacturing sector, about 26% is electricity, 58% is natural gas, 10% is coal (excluding coal coke and breeze), and the remainder is from liquid fuels. Electricity provides most of the services for machine drive, electrochemical, and heating, ventilating and air conditioning (HVAC) services. Process heat tends to be generated by natural gas, as a clean-burning fuel is required for this service. In contrast, steam can be generated using a number of fuels, and while natural gas is the most common fuel used, the fuel mix for steam production differs by industry. For instance, the pulp, paper, and wood industry group uses mostly biomass, and the petroleum industry uses more oil for this purpose than any other industry.

Table B-5. Total fuel consumption by end-use for all MECS industries, 1990, trillion Btu

	Electricity	Liquid Fuels	Natural Gas	Coal[1]	Total
Boiler Fuel	29	308	2538	770	3645
Process Heating	363	185	3187	331	4066
Process Cooling and Refrigeration	209	2	22		233
Machine Drive	1881	25	99	7	2012
Electrochemical Processes	354				354
Other Process Use	13	5	52		70
Facility HVAC	289	14	403	4	710
Facility Lighting	227				
Other Facility Support	53	7	40		100
On-site Transportation	5	59	5		69
Conventional Electricity Generation		6	210	27	243
Other Nonprocess Use	4	1			5
End Use Not Reported	71	12	72	3	158
Total Fuel Consumption	**3498**	**625**	**6644**	**1143**	**11910**

[1] Excluding coke and breeze

2.1. Modeling Demand Growth

In addition to the composition of energy demands within industry groups, scale of activity is also important for modeling scenarios of the U.S. industrial sector. Econometric relationships were developed to analyze the historical relationships between U.S. energy consumption, gross domestic product (GDP), and population.

The demand function was modeled within each industry group according to one of two forms. For some industries, energy demand is best modeled as a function of national GDP. For other industries, energy services have begun to saturate, and for these industries, demand was modeled as proportional to population, with a secondary dependence on per-capita income. For instance, it is reasonable to assume that individuals (on average) in the U.S. population would not consume substantially more food as incomes increase. Thus, using population as the primary demand driver may be more accurate than income.

The elasticity of energy consumption with respect to income is defined as follows:

$\acute{\eta} = \delta \ln (\text{energy}) / \delta \ln (\text{income})$

With two alternative demand functions, two regressions were performed on each industry group:

1) GDP-based: ln (energy of the industry) was regressed on ln (realGDP)

2) Per-capita-based: ln (per-capita energy of the industry) was regressed on ln (per-capita realGDP)

The regressions were performed on historical data from 1977 to 2004 for several industry groups, and from 1985 to 2004 for groups in which primary demand sharply decreased in response to the oil shocks of the 1970s. Energy demand was found to be proportional to population in the food processing and pulp, paper, and wood industry groups, while for all others the GDP-based regression was used to generate income elasticities. These elasticities are shown in Table B-6.

Table B-6. Income elasticities used for industrial sector

Industry Group	Driver	Regression Period	Income Elasticity
Food Processing	Population and PerCapita Income	1977–2004	0
Pulp Paper and Wood	Population and PerCapita Income	1977–2004	0.05
Chemicals	Total Regional Income (GDP)	1985–2004	0.55
Petroleum	Total Regional Income (GDP)	1985–2004	0.65
Aluminum	Total Regional Income (GDP)	1985–2004	0.15
Total Primary Metals	Total Regional Income (GDP)	1985–2004	0.15
Cement	Total Regional Income (GDP)	1977–2004	0.15
Other NonMetallic Mineral	Total Regional Income (GDP)	1985–2004	0.15
Other Manufacturing	Total Regional Income (GDP)	1977–2004	0.1
Agriculture	Total Regional Income (GDP)	NA	0.1
Mining	Total Regional Income (GDP)	NA	0.1
Construction	Total Regional Income (GDP)	NA	0.1

As shown, the fastest growth is taking place in chemicals and petroleum, whereas all others have elasticities between 0.1 and 0.2. The data for non-manufacturing industries during this time was a residual and was not collected directly. Because the time series does not appear to be reliable, the elasticities of these industries have been set to 0.1, matching the elasticity of other manufacturing.

2.2. Modeling Consumption of Energy Feedstocks

Approximately 27% of the energy used in the industrial sector is in the form of energy feedstocks (that is, non-fuel uses of energy sources). Distinguishing feedstocks from fuel consumed as energy is critical because much of the total fossil fuel consumed as feedstocks can be assumed to be non-emitting. Instead, some portion of these feedstocks are used in a way that sequesters the carbon content for a significant time. Natural gas, liquefied petroleum gas, asphalt, and coking coal are some examples of fossil fuels that are consumed for non-energy uses. Possible applications include solvents, lubricants, waxes, or as raw materials in the manufacture of plastics, chemicals, rubber, and synthetic fibers. Emissions may arise from non-energy uses during manufacturing process, or during the product's lifetime (e.g., solvent use). It is estimated that about 65% of the total carbon content of fuel used in feedstocks is sequestered, a proportion that has remained relatively constant since 1990 (EPA 2005). This proportion was used in the model, and is assumed to remain constant in the future.

Given the large fraction of industrial energy consumption that is actually used as feedstocks, this category has been added as an end-use demand for petroleum, chemicals, and primary metals. These three industry groups together account for greater than 99% of the total industrial consumption of feedstocks. Table B-6 shows the feedstock use of combustible energy in each of these three groups in 1998, and Table B-7 shows the percentage of each industry's feedstock use accounted for by each fuel.

Table B-7. Consumption of feedstocks, in exajoules (EJ) for three major industries that use feedstocks and the remainder

Industry group	Fuel (EJ)	% of U.S. industrial total
Petroleum and Coal Products	3,748	51
Chemicals	2,772	38
Primary Metals	758	10
Other Industry	62	1
Total	**7,340**	**100**

Table B-8. Percentage of each industry group's total consumption of feedstocks, by fuel

	Oil	Natural Gas	Coal	Other
Petroleum and Coal Products	0	0	0.3	99.5
Chemicals	65.1	26.2	0.8	8
Primary Metals	0	5.8	86.8	7.1
Other	3.6	7.1	1.8	64.3
All Industry	**24.7**	**10.7**	**9.5**	**55.1**

2.3. Modeling Technological Improvement

The specific technologies that produce the basic industrial energy services such as heat and machine drive are already highly efficient. For instance, the average heat-to-steam efficiency of gas boilers already exceeds 80%, and electric motor efficiencies exceed 90%. Consequently, although increasing the efficiency of the technologies used to provide specific end-use requirements may offset emissions to some degree, by itself it is relatively limited as a means of making major reductions in CO_2 emissions in many industrial sector end-uses.

The modeling approach for energy end-uses, and technology/fuel options in the industrial sector were covered in Section 3.2.2.2 of the main report. What follows is a summary of assumptions of technological efficiencies and process changes, and data sources used in formulating the assumptions to the technologies in the model.

Table B-9 shows efficiency assumptions for the end uses. As shown, the efficiencies of boilers and machine drive differ by fuel, based on data compiled by the Council of Industrial Boiler Owners (2003). Efficiencies of electric motors were taken from NEMS (DOE 2005), and the efficiencies of all other end uses are not assumed to differ by fuel. Given the already high efficiencies in these end-uses a nominal efficiency improvement of 0.1% per year was applied to all end use technologies. For this reason, the future efficiency assumptions for these specific technologies are equal between the reference and advanced scenarios presented.

2.4. Modeling Process Improvements

Future reductions in industrial energy intensity are more likely to come from redesigns and fundamental changes in the processes used to manufacture industrial products than from more efficient equipment technologies. The potential for process change is more industry-specific than the generic industry services, and such changes are difficult to forecast. The enabling technologies for such advances may not even arise out of traditional energy research, but rather, for instance, from advances in information technology or materials science.

Table B-9. Efficiencies of technologies used to provide industrial services, 2005–2095. A yearly improvement rate of 0.1% was assumed for all end uses except for machine drive, which was set to 0.05% per year.

		2005	2050	2095
Boilers				
	Electricity	0.80	0.84	0.88
	Oil	0.85	0.89	0.93
	Coal	0.88	0.92	0.96
	Natural Gas	0.83	0.87	0.91
	Biomass	0.73	0.76	0.79
Machine Drive				
	Electricity	0.93	0.95	0.97
	Oil	0.85	0.87	0.89
	Coal	0.88	0.90	0.92
	Natural Gas	0.83	0.85	0.87
	Biomass	0.73	0.74	0.76
Process heat		1.00	1.05	1.09
HVAC[1]		1.00	1.05	1.09
Electrochemical[1]		1.00	1.05	1.09
Other[1]		1.00	1.05	1.09
Feedstocks[1]		1.00	1.05	1.09

[1] Indicates an index efficiency assumed in 2005

For the model, generic assumptions for process improvements have been applied equally to all industries. Assumptions differ between the advanced and reference scenarios. Improvement rates were informed by a study on presently available energy-saving process changes and the amount of energy that would be saved by adoption of each of five potential processes by 2025 (Worrell et al. 2004). Processes in the study included membrane technology, gasification of low-grade feedstocks, and net shape/strip casting.

In the study, it was demonstrated that the energy savings potential of reasonable rates of adoption of the advanced processes in the relevant industries could reduce sector-wide energy consumption by 8% by 2025 (relative to NEMS projection of industrial energy consumption). This figure would have been 24% with 100% technological penetration, highlighting that a wide range of assumptions for sector-wide process improvements over the next century could be considered feasible.

In the reference technology scenario, process efficiencies are assumed to improve at 0.1% per year, resulting in the fuel intensity of each industry's "process" about 10% more efficient than present-day values by 2095. In the advanced scenarios, an annual improvement rate of 0.3% was used, resulting in a 30% improvement by 2095.

2.5. Modeling Cogeneration (CHP)

Cogeneration of electricity along with steam and heat (also called combined heat and power, CHP) increases the net energy efficiency of the system. Combined heat and power typically requires only about three quarters of the total primary energy that separate heat and power systems ordinarily require. Cogeneration is best suited to large facilities with a steady demand for steam and heat; because the electricity produced can be sold back to the grid, electricity demand is not necessary for cogeneration to be economical. Its use would likely increase in an emissions-constrained economy.

Efficiency data for cogeneration technologies were adapted from The Institute for Thermal Turbomachinery and Machine Dynamics (2002) for steam, gas turbine, and gas combined cycle technologies. In the model, the investment in cogeneration is based on relative economics as compared with stand-alone boiler and process heat systems. The cogeneration system would have a higher capital cost and use more fuel than a stand-alone boiler or burner, but it would be compensated for the electricity it would produce and decrease the amount of electricity that would have to be produced elsewhere in the system. The calibrated amount of cogenerated electricity in the model base years (1990 and 2005) was based on EIA (1999).

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