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Renewable Electricity Futures Study

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End-use Electricity Demand

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Renewable Electricity Futures Study

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Renewable Electricity Futures Study

Volume 3: End-Use Electricity Demand

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Perspective

The Renewable Electricity Futures Study (RE Futures) provides an analysis of the grid integration opportunities, challenges, and implications of high levels of renewable electricity generation for the U.S. electric system. The study is not a market or policy assessment. Rather, RE Futures examines renewable energy resources and many technical issues related to the operability of the U.S. electricity grid, and provides initial answers to important questions about the integration of high penetrations of renewable electricity technologies from a national perspective. RE Futures results indicate that a future U.S. electricity system that is largely powered by renewable sources is possible and that further work is warranted to investigate this clean generation pathway. The central conclusion of the analysis is that renewable electricity generation from technologies that are commercially available today, in combination with a more flexible electric system, is more than adequate to supply 80% of total U.S. electricity generation in 2050 while meeting electricity demand on an hourly basis in every region of the United States.

The renewable technologies explored in this study are components of a diverse set of clean energy solutions that also includes nuclear, efficient natural gas, clean coal, and energy efficiency. Understanding all of these technology pathways and their potential contributions to the future U.S. electric power system can inform the development of integrated portfolio scenarios. RE Futures focuses on the extent to which U.S. electricity needs can be supplied by renewable energy sources, including biomass, geothermal, hydropower, solar, and wind.

The study explores grid integration issues using models with unprecedented geographic and time resolution for the contiguous United States. The analysis (1) assesses a variety of scenarios with prescribed levels of renewable electricity generation in 2050, from 30% to 90%, with a focus on 80% (with nearly 50% from variable wind and solar photovoltaic generation); (2) identifies the characteristics of a U.S. electricity system that would be needed to accommodate such levels; and (3) describes some of the associated challenges and implications of realizing such a future. In addition to the central conclusion noted above, RE Futures finds that increased electric system flexibility, needed to enable electricity supply-demand balance with high levels of renewable generation, can come from a portfolio of supply- and demand-side options, including flexible conventional generation, grid storage, new transmission, more responsive loads, and changes in power system operations. The analysis also finds that the abundance and diversity of U.S. renewable energy resources can support multiple combinations of renewable technologies that result in deep reductions in electric sector greenhouse gas emissions and water use. The study finds that the incremental cost associated with high renewable generation is comparable to published cost estimates of other clean energy scenarios. Of the sensitivities examined, improvement in the cost and performance of renewable technologies is the most impactful lever for reducing this incremental cost. Assumptions reflecting the extent of this improvement are based on incremental or evolutionary improvements to currently commercial technologies and do not reflect U.S. Department of Energy activities to further lower renewable technology costs so that they achieve parity with conventional technologies.

RE Futures is an initial analysis of scenarios for high levels of renewable electricity in the United States; additional research is needed to comprehensively investigate other facets of high renewable or other clean energy futures in the U.S. power system. First, this study focuses on renewable-specific technology pathways and does not explore the full portfolio of clean technologies that could contribute to future electricity supply. Second, the analysis does not attempt a full reliability analysis of the power system that includes addressing sub-hourly, transient, and distribution system requirements. Third, although RE Futures describes the system characteristics needed to accommodate high levels of renewable generation, it does not address the institutional, market, and regulatory changes that may be needed to facilitate such a transformation. Fourth, a full cost-benefit analysis was not conducted to comprehensively evaluate the relative impacts of renewable and non-renewable electricity generation options.

Lastly, as a long-term analysis, uncertainties associated with assumptions and data, along with limitations of the modeling capabilities, contribute to significant uncertainty in the implications reported. Most of the scenario assessment was conducted in 2010 with assumptions concerning technology cost and performance and fossil energy prices generally based on data available in 2009 and early 2010. Significant changes in electricity and related markets have already occurred since the analysis was conducted, and the implications of these changes may not have been fully reflected in the study assumptions and results. For example, both the rapid development of domestic unconventional natural gas resources that has contributed to historically low natural gas prices, and the significant price declines for some renewable technologies (e.g., photovoltaics) since 2010, were not reflected in the study assumptions.

Nonetheless, as the most comprehensive analysis of U.S. high-penetration renewable electricity conducted to date, this study can inform broader discussion of the evolution of the electric system and electricity markets toward clean systems.

The RE Futures team was made up of experts in the fields of renewable technologies, grid integration, and end-use demand. The team included leadership from a core team with members from the National Renewable Energy Laboratory (NREL) and the Massachusetts Institute of Technology (MIT), and subject matter experts from U.S. Department of Energy (DOE) national laboratories, including NREL, Idaho National Laboratory (INL), Lawrence Berkeley National Laboratory (LBNL), Oak Ridge National Laboratory (ORNL), Pacific Northwest National Laboratory (PNNL), and Sandia National Laboratories (SNL), as well as Black & Veatch and other utility, industry, university, public sector, and non-profit participants. Over the course of the project, an executive steering committee provided input from multiple perspectives to support study balance and objectivity.

RE Futures is documented in four volumes of a single report: Volume 1 describes the analysis approach and models, along with the key results and insights; Volume 2 describes the renewable generation and storage technologies included in the study; This volume—Volume 3—presents end-use demand and energy efficiency assumptions; and Volume 4 discusses operational and institutional challenges of integrating high levels of renewable energy into the electric grid.

List of Acronyms and Abbreviations

°C	degrees Celsius
AEO	*Annual Energy Outlook*
BA	balancing area
BAU	business-as-usual
Btu	British thermal unit
CO_2	carbon dioxide
DOE	U.S. Department of Energy
EERE	U.S. DOE Office of Energy Efficiency and Renewable Energy
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FHA	Federal Highway Administration
ft^2	square foot/feet
GW	gigawatt(s)
HVAC	heating, ventilation, and air conditioning
IEA	International Energy Agency
kW	kilowatt(s)
kWh	kilowatt-hour(s)
LDC	load duration curve
MW	megawatt(s)
NAS	National Academy of Sciences
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
PEV	plug-in electric vehicle
PHEV	plug-in hybrid electric vehicle
ReEDS	Regional Energy Deployment System
RE Futures	Renewable Electricity Futures Study
TES	thermal energy storage
TWh	terawatt-hour(s)
W/ft^2	Watts per square foot
yr	year

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Introduction

The Renewable Electricity Futures Study (RE Futures) is an initial investigation of the extent to which renewable energy supply can meet the electricity demands of the contiguous United States1 over the next several decades. This study includes geographic and electric system operation resolution that is unprecedented for long-term studies of the U.S. electric sector.

The RE Futures study is documented in four volumes: Volume 1 describes the analysis approach and models along with the key results and insights from the analysis; Volume 2 documents in detail the renewable generation and storage technologies included in the study; Volume 4 documents the operational and institutional challenges of integrating high levels of renewable energy into the electric grid; this Volume—Volume 3—details the end-use electricity demand and efficiency assumptions.

The projection of electricity demand is an important consideration in determining the extent to which a predominantly renewable electricity future is feasible. Any scenario regarding future electricity use must consider many factors, including technological, sociological, demographic, political, and economic changes (e.g., the introduction of new energy-using devices; gains in energy efficiency and process improvements; changes in energy prices, income, and user behavior; population growth; and the potential for carbon mitigation).

In projecting electricity use, the primary historical drivers for electricity demand (population growth and economic growth) are taken into account along with other emerging trends, including the green building and supply chain[1] movements, carbon mitigation, policies and legislation dealing with codes and standards, research and development in energy efficiency, and foreign competition for manufacturing. For the RE Futures, two demand projections were developed to represent probable higher and lower electricity trajectories—hereafter referred to as the High-Demand Baseline and the Low-Demand Baseline. The two electricity demand trajectories used in RE Futures rely on the same assumptions for population and economic growth, so the differences stem from the assumptions regarding other trends.

The emerging trends noted above that lead to increased efficiency motivate the Low-Demand Baseline. Based on these, a scenario was developed in which there is an approximately 30% reduction in overall electricity intensity[2] within the buildings sector, a 50% reduction in industrial electricity intensity, and electrification of approximately 40% of the light-duty vehicle stock by 2050.

The High-Demand Baseline is a business-as-usual scenario that assumes trends for the residential, commercial, and industrial sectors as forecast to 2030 by the Energy Information Administration (EIA) in its *Annual Energy Outlook* (AEO) (EIA 2009d). Because AEO 2009 contained only a forecast through 2030, RE Futures extended the AEO trends out to 2050. Under this scenario, the overall electricity intensity within the buildings sector remains relatively unchanged from 2010 to 2050, and the industrial sector electricity intensity declines by approximately 35% during the RE Futures period (2010–2050).

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[1] As public awareness of environmental issues grows, consumers and retailers are becoming more interested in the energy and environmental impacts of the entire manufacturing process, with some retailers (most notably WalMart) issuing green supply chain requirements.

[2] Definitions of electricity intensity are sector-dependent and are provided below.

Chapter 13. General Assumptions

Although there is a growing body of literature dedicated to factors affecting energy demand, including behavioral influences, climate change, and new technologies and materials, the explicit inclusion of the potential impacts arising from these influences is beyond the scope of RE Futures. RE Futures relied on readily available data and projections to the extent possible, and attempted to stay within reasonable bounds established by recent literature. RE Futures was further constrained by the modeling requirement for hourly load projections through the study period. This required the conversion of the estimated projections of electricity consumption into regional hourly load profiles. Although studies projecting potential energy consumption futures are plentiful, studies that tie those consumption futures to hourly loads are not readily available.

The basis for the scenarios presented was predominantly drawn from EIA's AEO for 2009 (industrial sector) and 2010 (buildings sector), which assumed that the major long-term drivers of energy demand—Gross Domestic Product and population—grow at 2.4%/yr and 0.9%/yr, respectively, over the period 2008–2035.[3]

The fuel prices assumed by the AEO were also taken into consideration in developing the scenarios because increasing natural gas prices might lead consumers to change out their natural gas heating equipment to equipment fueled by electricity, for example; however, given recent prospects to exploit shale gas deposits, the AEO forecast for natural gas prices was believed to be too high. As such, RE Futures did not assume more fuel switching from natural gas to electric devices for space and water heating than was already assumed in the AEO 2010 Reference Case (EIA 2010). Given the extreme difficulty of capturing carbon emissions arising from distributed use of fossil energy in the buildings sector, however, use of decarbonized electricity to provide space and water heating may be an important means for reducing carbon emissions in the future. Recent work for the European Union (European Climate Foundation 2010) projected greater electrification within the buildings sector; as a consequence, forecasted efficiency gains were offset by new electrical demands from transportation and space and water heating. While the total electrical demand for RE Futures would be represented by the High-Demand Baseline in such a case, the underlying load shapes would not capture the resulting hourly and seasonal changes.

Electricity prices also have an impact on the demand for electricity. However, because the demand profiles are provided as exogenous inputs to the models used in RE Futures, the potential impacts on demand due to changes in electricity prices caused by the various scenarios were not considered in developing the demand projections. The interactions that impact electricity prices between electricity supply and demand are complex and beyond the scope of RE Futures. The efficiency gains are assumed to be cost-effective using today's electricity prices and the current AEO forecasts for electricity prices.

Within the commercial sector, two additional trends underlie the AEO projections. First, the growth in disposable income increases the demand for services that depend on computers and other electronic equipment. Also, the growing share of the population over age 65 increases the

[3] Full descriptions of the AEO assumptions are detailed in EIA 2009a and EIA 2010.

demand for health care and assisted-living facilities and the demand for electricity to power medical and monitoring equipment at those facilities. Trends in the residential sector include population migration into the South and the West;[4] the conversion of older homes from room air conditioning to central air conditioning; and the growth in the use of “other” appliances, including large-screen televisions and computers. Within the industrial sector, the AEO projects that energy-intensive manufacturing industries will show slow growth due to increased foreign competition. Additionally, an increase in the use of biofuels in the transportation sector is expected to lead to an increase in the conversion of biomass to fuels such as ethanol, diesel, and jet fuel. This process creates heat, which can be used for industrial on-site generation.

[4] Note that changes in these trends, such as reduced migration due to water shortages, were not considered.

Chapter 14. Potential Impact of Carbon Mitigation Measures and Climate Change on Electricity Demand

There is currently much discussion about climate change, emissions, and carbon mitigation measures. Potential policies, legislation, and regulation can logically be expected to have an impact on the way in which energy is generated, delivered, and used, whether by specific controls or through pricing incentives or disincentives. The same drivers that might push the United States toward more renewable generation of electricity would also be expected to lead to increased energy efficiency—that is, a drive to use less energy to yield the same level of service. These drivers act in opposition to other trends, such as population growth and the development of new electricity-using devices. Climate change influences another aspect of the energy use picture because heating and cooling loads are highly dependent upon outside temperature.

Although a carbon mitigation policy was not explicitly assumed for RE Futures, implementation of a carbon mitigation policy would have an impact on electricity demand. Depending on how such a policy might be implemented, one potential outcome is higher prices for fossil energy, which could lead to fuel switching in end uses such as space and water heating. The Electric Power Research Institute (EPRI) (2009), the National Academy of Sciences (NAS et al. 2009), and the Union of Concerned Scientists (Cleetus et al. 2009) all use reference cases from recent editions of EIA's AEO. The extent to which fuel switching occurs in these projections is largely due to how EIA models fuel choice in its existing residential and commercial building models. In general, some amount of fuel switching (in the sense of the predicted fuel shares of space and water heating in new buildings) occurs as a function of projected fuel prices and the menu of available *energy efficiency* technologies for these end uses. With regard to the energy efficiency scenarios undertaken by these studies, none of them makes any explicit assumptions about any fuel switching that would alter the future evolution of electricity growth in buildings.[5] One of the results of a greater percentage of renewable generation is that the generation sector would reduce its use of natural gas in the longer term. Currently, electricity generation is responsible for approximately one-third of the U.S. demand for natural gas;[6] reduced demand could potentially lower natural gas prices, countering to some extent the price increases brought about by carbon policies.

Just as climate mitigation policies may impact electricity demand, climate change would also be expected to impact both energy supply and energy demand, and numerous studies have been conducted to determine the potential impacts of climate change on the U.S. (and world) energy picture (e.g., Scott and Huang 2007; Huang 2006; Mansur et al. 2005; Scott et al. 2005). Although these studies present varying estimates of the impact on energy demand within the United States,[7] they are in general agreement that overall heating consumption is expected to

[5] The NAS study is based in part on the Clean Energy Futures report (Interlaboratory Working Group 2000), an earlier study that assumed some fuel switching in the direction of increased gas use relative to electricity. The NAS study indicates that the estimates of this impact were eliminated in the more recent assessment of future electricity consumption.

[6] U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook 2010, Table A.2, http://www.eia.doe.gov/oiaf/aeo/pdf/appa.pdf (EIA 2010)

[7] These estimates depend on assumed change in temperature and year, as well as model differences, regions, and other study parameters.

decrease due to climate change (ranging from -3% to -35% by 2050), while overall cooling consumption could increase, ranging from 4% to 90% by 2050 (see Appendix G for comparisons). For RE Futures, climate change was not explicitly addressed because the overall impacts are subject to a number of assumptions, including temperature change and time frame, that are beyond the scope of RE Futures. Generally, if climate change and climate mitigation policies were to be taken into account, the demand profiles presented here would most likely be underestimating cooling and overestimating heating (although the lower heating demand may cause more switching into electricity, e.g. heat pumps that would offset some of the direct effects of higher temperatures).

Chapter 15. Resulting Scenarios

RE Futures selected two energy demand scenarios to represent reasonable bounds for the electricity generation requirements through 2050. These two scenarios represent a "higher" level of demand (the High-Demand Baseline) and a "lower" level of demand (the Low-Demand Baseline). Developing scenarios of energy use 40 years into the future is challenging, and the analysis is further complicated by the requirement for detailed hourly system load shapes by region, which are needed for the modeling effort.

The High-Demand Baseline represents a business-as-usual case that assumed that trends within the residential, commercial, industrial, and transportation sectors recently forecast by the EIA (EIA 2009d and EIA 2010) to 2030 continue through 2050.[8] This scenario assumed no radical changes in available technologies or consumer behavior, although current technologies will evolve in terms of cost and efficiency. No new regulations or laws not already enacted are included in an AEO Reference Case, and beyond its 2030 horizon, a simple extrapolation is made to 2050. The AEO Reference Case was chosen to represent a higher demand trajectory because it does not include planned equipment and appliance standards or proposed energy code changes, which are expected to lower demand.

The Low-Demand Baseline assumed a moderately high level of energy efficiency within the buildings and industrial sectors. The Low-Demand Baseline assumed that approximately 40% of the light-duty vehicle stock becomes electrified by 2050. In the buildings sector, the efficiency improvements necessary to achieve ultra-high-efficiency buildings are estimated,[9] while in the industrial sector, estimated responses to carbon restrictions, based on the Waxman-Markey cap and trade provisions, are applied.

The electricity demand forecasts for buildings, industry, and transportation represent sales trajectories. Transmission and distribution losses are not considered as part of these on-site electricity projections. The electricity sector is expected to deliver these energy quantities according to the timing and distribution specified by the corresponding load shapes used in the models.

Table 15-1 compares the two scenarios and their underlying assumptions, which are discussed more fully in the following sections.

[8] Both the 2009 AEO Reference Case (April Stimulus version) (EIA 2009d) and the 2010 AEO Reference Case (EIA 2010) were used. The opportunity to use the 2010 AEO for the buildings sectors became available later in the Renewable Electricity Futures Study period; compared to the 2009 AEO Reference Case, the 2010 AEO Reference Case shows a small reduction in both residential (1.5%) and commercial (3.2%) electricity use in 2030. For the commercial sector, the somewhat greater reduction appears to be related to the availability and adoption of more efficient lighting, refrigeration, and computer technologies.

[9] Ultra-efficient buildings are designed and operated to generate as much on-site power as the energy they consume.

Table 15-1. Comparison of Efficiency Assumptions in 2050: High-Demand Baseline versus Low-Demand Baseline

Sector	High-Demand Baseline	Low-Demand Baseline
Residential	2% decline in intensity over 2010 levels	30% decline in intensity over 2010 levels
Commercial	5% increase in intensity over 2010 levels	32% decline in intensity over 2010 levels
Industrial	35% decline in intensity over 2010 levels	50% decline in intensity over 2010 levels
Transportation	<3% plug-in hybrid electric vehicle (PHEV) penetration	40% of vehicle sales are plug-in electric vehicles (PEVs)

Figure 15-1 illustrates the resulting demand trajectory for the Low-Demand and High-Demand Baselines through 2050. For comparison, the EIA analysis (EIA 2009b)[10] of the American Clean Energy and Security Act of 2009 (the Waxman-Markey Climate Bill from 2009)[11] is included, using the 2025–2030 trend to extend the analysis to 2050.

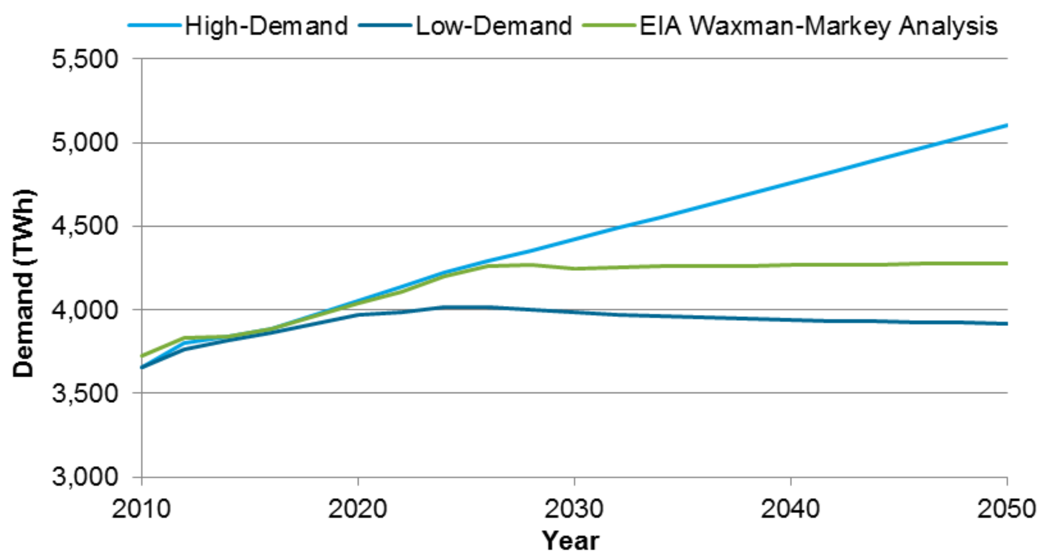

Figure 15-1. Total electricity demand, 2010–2050

[10] For its analysis, EIA ran a number of cases for the bill. The "EIA Waxman-Markey Analysis" line in this chart (Figure 15-1) presents the consumption resulting from its basic case (EIA 2009b).
[11] For the full text of the bill (H.R. 2454), see http://www.govtrack.us/congress/bill.xpd?bill=h111-2454.

Figure 15-2 illustrates the electricity consumption by sector for the High-Demand Baseline and the Low-Demand Baseline. For context, Figure 15-3 contains the historical energy use by sector.[12]

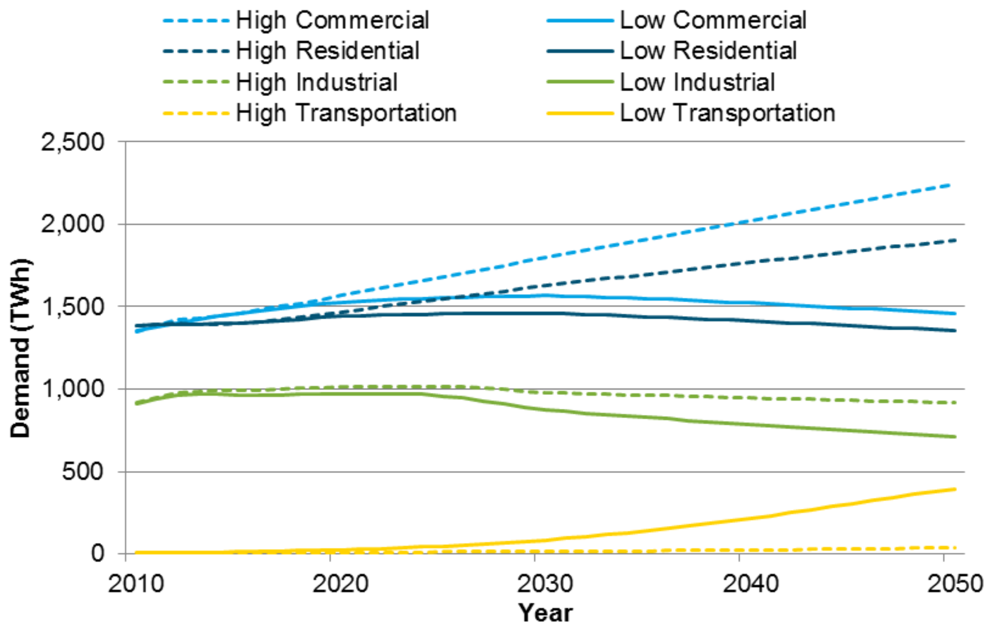

Figure 15-2. Total electricity demand, 2010–2050: High Demand (high) and Low Demand (low) by sector

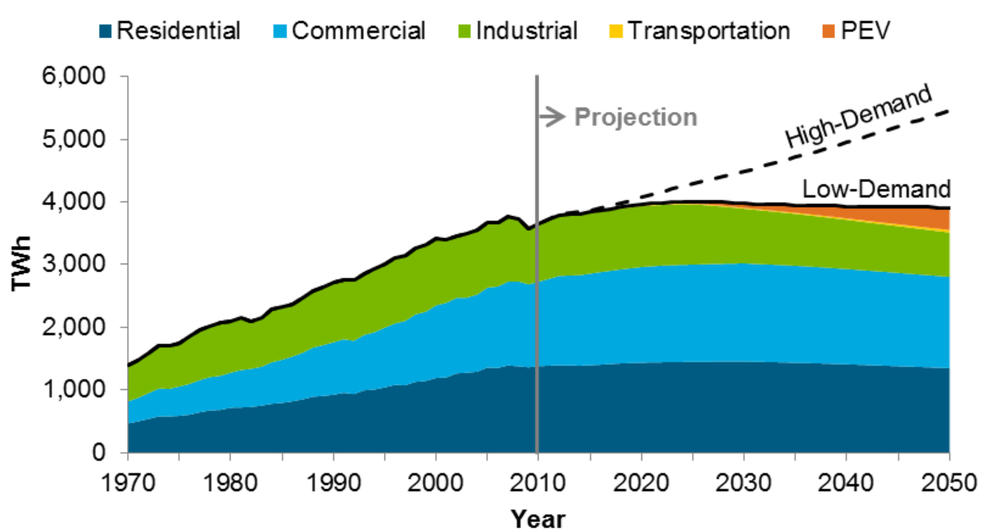

Figure 15-3. Historical and projected electricity demand assumptions in low-demand and high-demand scenarios

[12] The leveling of the industrial sector electricity demand is due in part to reduced production within the manufacturing sector. Appendix I contains a breakdown of the changes in the industrial sector due to energy efficiency versus declining production for the period 2010–2030.

Unlike the renewable technologies explored in RE Futures, the reductions in consumption have been generated without explicitly considering the investment needed to realize these gains. Terms such as *cost-effective* or *cost-competitive* are often used in discussing energy efficiency measures. These generally mean that the efficiency measures cost less or about the same as their less efficient counterparts once the various costs (e.g., energy, operation and maintenance, capital) over the lifetime of the measure are considered. Although these investment costs are not considered here, findings from other studies are presented to illustrate the approximate cost of efficiency gains to provide some perspective.

The National Academy of Sciences (NAS et al. 2009) reported conservation supply curves for energy efficiency in the buildings sector that were originally developed by Lawrence Berkeley National Laboratory (Brown et al. 2008). These supply curves indicated that energy savings of 30%–35% could be achieved over Brown et al.'s reported reference case at a cost less than the 2007 retail cost of energy. For electricity, the conserved cost of energy was found to range from less than 1 cent per kWh to about 8 cents per kWh, with an average conserved cost of energy of 2.7 cents per kWh. Brown et al. (2008) calculated that the cumulative capital investment[13] required between 2010 and 2030 to achieve their level of electricity savings[14] was approximately $299 billion.[15] Combined with average annual electricity bill savings of $128 billion in 2030, electricity efficiency measures, on average, had a payback of 2.3 years. Additionally, NAS et al. (2009) reported that energy savings of 14%–22% could be cost-effectively achieved by 2020 within the industrial sector. Within the National Academy of Sciences study, cost-effectiveness was defined as an internal rate of return of at least 10% or exceeding a company's cost of capital by that company's defined risk premium; however, no conserved cost of energy was specifically reported for the industrial sector.

In another study, McKinsey and Company (Granade et al. 2009) calculated the cost-effective energy efficiency potential in the residential, commercial, and industrial sectors.[16] Granade et al. (2009) calculated the present value of investment costs and annual energy savings for each sector, as well as a set of sub-sectors. Table 15-2 contains the simple paybacks calculated for selected categories.

[13] The cumulative capital investment is the reported capital investment as an incremental investment, including only costs above those incurred in the reference case. It includes the full "add-on" cost for new measures or equipment (such as additional insulation) as well as the incremental cost of the efficient technology compared with the cost of the conventional technology equivalent (e.g., the difference in price between a highly efficient heat pump and an electric air conditioner/furnace combination).

[14] For reference, Brown et al. (2008) estimated electricity savings within the buildings sector of about 1,270 TWh in 2030; the Low-Demand Baseline for the Renewable Electricity Futures Study estimated electricity savings in the buildings sector of approximately 410 TWh in 2030 and 1,350 TWh in 2050.

[15] All dollar amounts presented in this report are presented in 2009 dollars unless noted otherwise; all dollar amounts presented in this report are presented in U.S. dollars unless otherwise noted.

[16] McKinsey and Company (Granade et al. 2009) estimated the overall energy efficiency potential, defined as net present value positive. Total energy savings of 5.45 quadrillion Btu (buildings) and 3.65 quadrillion Btu (industrial) in 2020 were calculated, including 900 TWh of electricity savings (buildings) and 190 TWh of electricity savings (industrial).

Table 15-2. Simple Paybacks for Sectors and Selected Sub-Sectors[a]

Sector	Simple Payback (years)
Residential	5.6[17]
Existing Homes	9.5
New Homes	4.0
Commercial	3.4[18]
Existing Private	6.6
New Private	3.8
Government	5.2
Industrial	2.4
Energy Support Systems	2.0
Energy-Intensive Processes	2.7
Non-Energy-Intensive Processes	2.5

[a] Granade et al. 2009

Another cost estimate can be drawn from Lazard (2009), which reports a levelized cost of energy for energy efficiency measures to range from 0 cents/kWh to 5 cents/kWh, based on utility costs as reported in the joint U.S. Environmental Protection Agency and U.S. Department of Energy (DOE) *National Action Plan for Energy Efficiency Report* (DOE/ 2006).

[17] Includes investment and annual energy savings associated with electrical devices and small appliances, and lighting and major appliances (Granade et al. 2009)
[18] Includes investment and annual energy savings associated with community infrastructure and office and non-commercial devices (Granade et al. 2009)

Chapter 16. Building Sector Electricity Demand

The buildings sector dominates overall electricity consumption, representing almost 78% of the 2030 total in the AEO Reference Case.[19] Additionally, building electrical end uses are highly heterogeneous and changing over time.

16.1 Low-Demand Baseline

Within the buildings sector, trends that can be expected to influence future electricity use include the "green" building movement, more stringent building codes, more stringent appliance and equipment standards, and research by the DOE and others to develop ultra-efficient buildings. Ultra-efficient buildings are designed and operated to generate as much on-site power as the energy they consume.[20] Some of the approaches to achieving this ambitious goal include developing and applying very high-efficiency technologies, finding ways to reduce the cost of energy-efficient technologies that have already been developed, and implementing cost-effective technologies that are already available.

Because the focus of RE Futures was on the generation of electricity, the lower-demand baseline was developed using a more generic, energy-intensity projection, rather than attempting to build a projection up from the various technologies and practices available within each of the end uses. Although a certain level of energy efficiency gains is possible through the normal adoption of new energy-efficient practices and technologies, the larger gains here implicitly require more active policy and behavioral change to come to fruition. The efficiency gains within the Low-Demand Baseline are assumed to be feasible by sustained efforts on the part of government, businesses, and households, and to be cost-effective without major increases in electricity prices as a driver. It is implicit to efficiency gains that the measures are properly installed, operated, and maintained as intended, and that the resulting savings are not used to increase the level of service (e.g., permanently adjusting the thermostat).[21]

Although a detailed analysis of policy changes remains to be examined, potential policy changes could include increased code adoption and enforcement; financial incentives such as tax credits, energy efficient mortgages, rebates, and coupons; broadening rating and labeling efforts; and encouragement of volume purchase programs. Behavioral changes could include users using technologies such as controls and sensors as they were intended, a greater focus on continuous building commissioning, and acting on available information on energy use. Other changes might include an increased focus on building commissioning so that buildings are built and commissioned as designed; more integration between the financial, construction, and associated industries to better enable the deployment of highly efficient buildings; and deployment of smart meters to provide users with a better understanding of their energy consumption.

[19] EIA AEO (EIA 2010) Table 2.

[20] Generally, ultra-efficient buildings are assumed to reduce their energy requirements by up to 70%, with the remainder of the building load met by local generation sources, such as photovoltaics. For RE Futures, only the efficiency improvements were considered as input to the end-use electricity demand.

[21] Granade et al. (2009) summarizes the possible impacts on savings in these instances to be in the range of 15% to 50%.

16.1.1 New Building Energy Intensity

The Low-Demand Baseline for RE Futures was based on the energy efficiency vision of DOE's ultra-efficient building programs. Consideration of what level of energy consumption intensity must be achieved to reach ultra-high efficiency motivates the overall approach to projecting future energy demands for the residential and commercial buildings. The electricity demand forecast for residential and commercial buildings under the Low-Demand Baseline assumes a larger number of buildings to be capable of ultra-high efficiency. Due to the inability to predict which technology and end-use consumption areas are most likely to show the greatest improvements, the Low-Demand Baseline focused only on the broadest measure of energy intensity: energy use per square foot (or per household) at the whole-building level. Accordingly, the basic assumption for new buildings is that the average energy intensity in 2050 will be 60% below that of new buildings being built today.[22] The factors underlying this reduction include increased energy code stringency, the continued development and implementation of federal energy efficiency standards for equipment and appliances, and research and development efforts directed at both the component and system (or whole-building) level. This reduction is also assumed to occur along an exponentially declining path. Thus, absolute reductions in energy intensity are assumed to be greater in the immediate future than several decades from now. Additional detail on the approach and assumptions can be found in Appendix H.

16.1.2 Existing Building Energy Intensity

Due to the cost to substantially change the building envelope and the heating and cooling system, the potential for large efficiency increases for existing buildings is much lower than that for new buildings. Moreover, the addition of electrical services in older buildings (e.g., air conditioning) tends to increase electricity consumption. However, both research and development improvements and federal energy efficiency standards for equipment and appliances will contribute to a reduction in electricity use. For the Low-Demand Baseline, intensity in existing residential buildings (e.g., pre-2010 homes still in the stock in 2050) was assumed to decline by 30% by 2050. For commercial buildings, the assumed decline by 2050 is somewhat greater at 40%. The larger decline for commercial buildings reflects an assumption that the amount of miscellaneous electrical uses in commercial buildings will be more amenable to reductions from policy and new technology than those in the residential sector. Additional detail on the approach and assumptions can be found in Appendix H.

16.1.3 Retrofits and Renovations

For a study with a long-term time horizon, one cannot assume that the intensity of buildings built today and in the near future will remain constant through 2050. Many ultra-high efficiency technologies introduced in the latter years (2030–2050) will be adopted, through retrofits and renovations, in buildings built over the next 20 years. As a means of accounting for that phenomenon, the Low-Demand Baseline assumed that buildings (both residential and commercial) built over the next 20 years (2010–2030) will be retrofitted (or renovated) with

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[22] Best practices guides and case studies that illustrate pathways to achieving 15%–40% whole-building energy savings for various residential climate zones are available via DOE's Building America website (http://www1.eere.energy.gov/buildings/building_america/climate_specific_publications.html). Design guides and strategies containing pathways to achieving 30%–50% whole-building energy savings for selected building types within the commercial sector are available through the U.S. Department of Energy's Commercial Building Initiative website (http://www1.eere.energy.gov/buildings/commercial_initiative/guides.html).

more efficient equipment in the subsequent 20 years (2030–2050). Operationally, this assumption is implemented as a 15% reduction in the electricity intensity for housing units and a 20% reduction in commercial buildings starting in 2031. In other words, residential and commercial buildings built between 2010 and 2030 are "revisited" in the analysis 20 years later (e.g., buildings built in 2011 are revisited in 2031; buildings built in 2012 are revisited in 2032, and so on, through 2050), with the intensity reduction applied in the out years to account for improvements in building and equipment practices.

16.2 High-Demand Baseline

The High-Demand Baseline for the residential and commercial sectors uses the AEO Reference Case (EIA 2010), as mentioned earlier. The AEO assumed that total electricity consumption grows by 0.9%/yr from 2007 to 2030. Commercial growth is approximately 1.4%/yr (with commercial electricity intensity in kilowatt-hours per square foot increasing by 0.1%/yr), and residential growth is approximately 0.8%/yr (with electricity use per household declining at an average annual rate of 0.2%/yr). Documentation of the assumptions is found in the AEO 2009 and AEO 2010 and supporting materials (EIA 2009a; EIA 2009d; EIA 2010).

16.3 Comparison of Projected Energy Intensities

To provide some context for the both the High-Demand and Low-Demand Baselines, the energy intensities have been compared to other studies. The comparison studies are from the Union of Concerned Scientists (Cleetus et al. 2009), University of California-Davis (McCarthy et al. 2008), EPRI (2009), EIA's analysis of Waxman-Markey (EIA 2009b), and NAS et al. (2009). To maintain the focus on potential energy efficiency improvement, the comparisons have been made in terms of energy intensities. Consistent with EIA's AEO, the intensity for the residential sector is in terms of electricity use per household; for the commercial sector, energy use per square foot of floor space is employed as the intensity measure. For comparison purposes, the intensities were converted to index numbers normalized to be 1.0 in 2010.

Figure 16-1 shows the projected intensities for the residential sector, and Figure 16-2 shows the scenarios from the same studies for the commercial sector. Within the residential sector, the High-Demand Baseline shows the least decline in intensity to the year 2030, while commercial sector electricity under this scenario is expected to increase through 2030. The light blue squares connected by the solid line in both figures depict the high-efficiency scenario (Low-Demand Baseline) developed for RE Futures. As shown in Figures 16-1 and 16-2, this scenario falls within the range of intensity forecasts drawn from other studies. Although not included in the figures, McKinsey and Company (Granade et al. 2009) conducted another recent study of cost-effective energy efficiency potential in the United States. When converted to an index basis, the implied intensity indexes (2020 relative to a 2010 base) for the residential and commercial sectors are 0.71 and 0.73, respectively. These values are substantially lower than those shown for 2020; however, due to the shorter time frame and greater emphasis on cost-effective potential compared to other studies, these values are not shown in either figure.

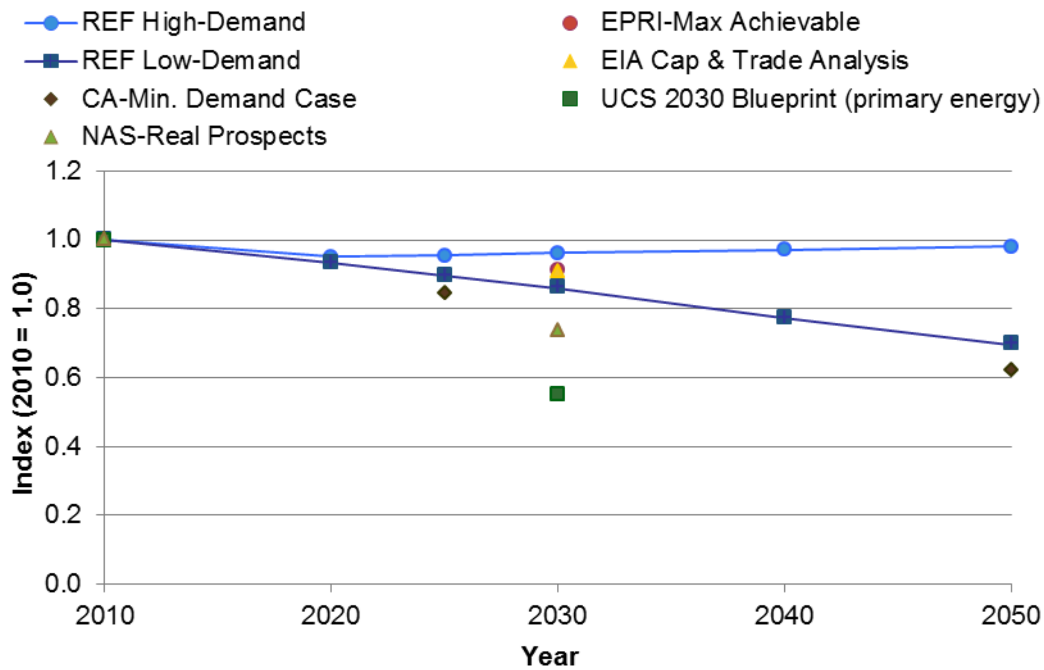

Figure 16-1. Residential electricity intensities from six studies, including RE Futures

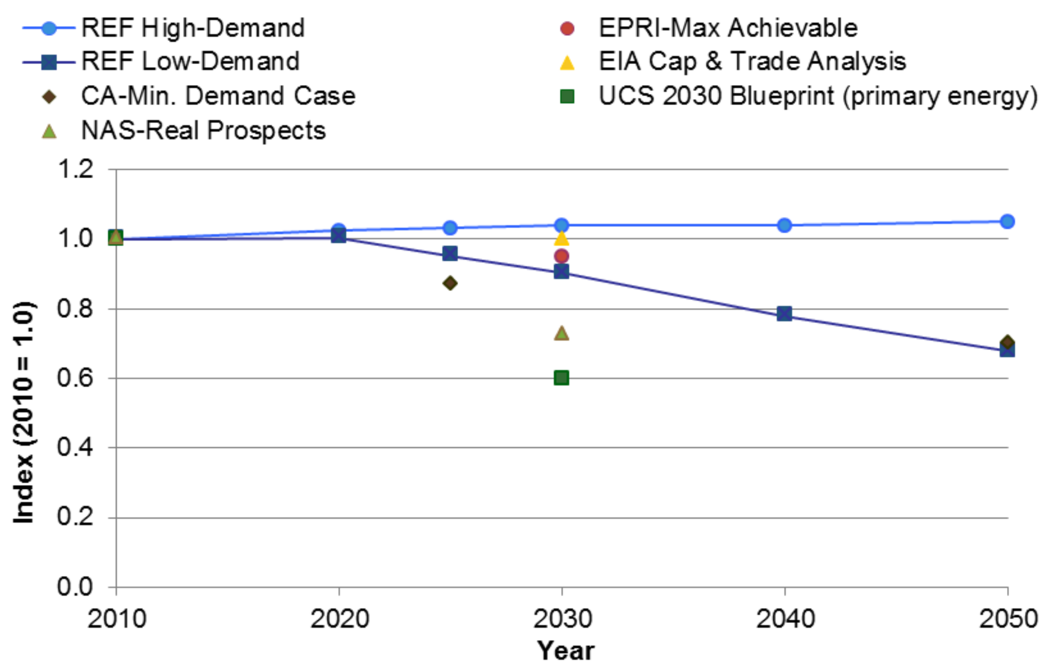

Figure 16-2. Commercial electricity intensities from six studies, including RE Futures

Sources: EIA 2009b, EPRI 2009, Cleetus et al. 2009, McCarthy et al. 2008, NAS et al. 2009

Appendix G provides additional detail regarding the comparisons of these studies.

Chapter 17. Industrial Demands and Energy Efficiency

The industrial sector accounts for approximately 27% of total electricity demand,[23] with more than 50% used to power electric motors (representing the single largest end use of electricity in the United States).[24] Within the industrial sector, the chemicals and primary metals industries consume the most electricity, representing approximately 35% of electrical consumption.[25] The sector's electricity use will be impacted by increases in the efficiency of motor drive systems and other processes, a slower growth rate of the more energy-intensive manufacturing industries, and a shift toward green supply chains. The sector is also affected by foreign competition.

In projecting industrial loads over the next 40 years, there are a number of unknowns. Industrial demands are more difficult to project due to the wider variation in the industrial sector makeup over time, as well as large differences in energy intensity across various industries. The extent of changes from the energy sector that would feed back in to the industrial sector based on different renewable energy scenarios further complicates the task of projecting loads and would ideally require iteration. Because RE Futures is a renewable energy study and not an industrial demand study, an approximation of the projected industrial demands was deemed sufficient.

A more detailed analysis of the consequences of some factors of the renewable energy scenarios, such as construction of renewable energy technologies and electric vehicle batteries, may result in increased load forecasts for some industrial sub-sectors, while other sectors, such as oil refining, may see countervailing changes. Possible changes in onshore versus outsourcing of manufacturing are also a large unknown and are beyond the scope of RE Futures. In addition, climate change, new processes for existing products, and new products altogether further magnify the uncertainty regarding future industrial loads.

17.1 Low-Demand Baseline

The Low-Demand Baseline industrial demand trajectory is derived in a quite different manner than that used for the buildings sector. It was based on the EIA's HR2454Cap National Energy Modeling System (NEMS) Case,[26] which, as its name suggests, includes a carbon cap and trade policy roughly equivalent to the provisions of the Waxman-Markey Climate Bill from 2009. Given that this case would evoke a significant efficiency boost (ranging from 6% to 69% in 2050, depending on the specific industrial sector), RE Futures believed its consumption level represents a reasonable energy efficiency scenario and adopted it as the Low-Demand Baseline.[27] Underlying the Low-Demand Baseline are EIA's assumptions that further standards for industrial energy efficiency will be established, an awards program for increasing efficiency in the thermal electricity generation process will be created, and the waste-to-heat energy incentives in the Energy Independence and Security Act of 2007 will be clarified. Overall, the changes in

[23] EIA AEO (EIA 2010), Table 2
[24] EIA 2006, Table 5.3
[25] EIA 2006, Table 3.1
[26] This is the Basic Case described in EIA 2009b.
[27] Although RE Futures does not explicitly assume the implementation of any carbon mitigation policy, the HR2454Cap case was used as the industrial sector input in the high-efficiency case because the resulting industrial loads (and load shapes) were consistent with the higher efficiency targets that characterize the Low-Demand Baseline.

the Low-Demand Baseline result in an approximately 23% decrease in electricity use compared to the High-Demand Baseline. Appendix I contains additional information about the derivation of the load curves and the implicit energy efficiency gains.

17.2 High-Demand Baseline

The High-Demand Baseline industrial demands provided to the models were based on the electricity sales to industry reported in the 2009 AEO Reference Case (EIA 2009d), with a simple extrapolation beyond 2030 through 2050. The AEO assumed that total electricity consumption grows by 0.9%/yr from 2007 to 2030, with growth in the industrial sector declining by 0.2%/yr (industrial electricity intensity in terms of consumption per real dollar of shipments declining by 1.3%/yr). Documentation of the assumptions can be found in the AEO 2009 and AEO 2010 and supporting materials (EIA 2009a; EIA 2009d; EIA 2010).

Because the 2009 NEMS version projects energy use only through 2030, the demands for both the High-Demand Baseline and Low-Demand Baseline scenarios were extrapolated to 2050 using the 2020–2030 growth rate (Figure 17-1). Additional calculations explained in Appendix I describe the method used to find the results for each North American Electric Reliability Council region and convert them to hourly profiles.

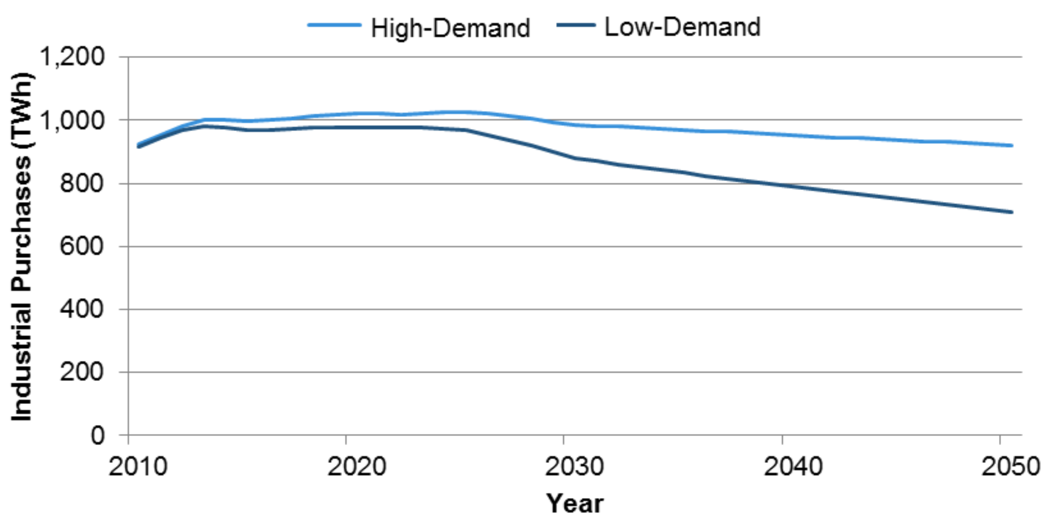

Figure 17-1. Industrial electricity purchases under the High-Demand Baseline and Low-Demand Baseline

17.3 Comparison of Projected Energy Intensities

As was done for residential and commercial buildings (Section 16.3), a comparison of scenarios for the industrial sector was developed and is shown in Figure 17-2.[28] For the industrial sector, the electricity intensity is computed as the electricity consumption per dollar (in real terms) of shipments. For comparison purposes, the intensities were converted to index numbers normalized to be 1.0 in 2010.

Both the High-Demand Baseline and Low-Demand Baseline are taken from EIA model simulations. The High-Demand Baseline was based on the 2009 AEO Reference Case (EIA 2009d). The Low-Demand Baseline was based on the analysis of the Waxman-Markey Climate Bill from 2009 performed by EIA (EIA 2009b), whose results here have been extrapolated to 2050. Figure 17-2 indicates that the Low-Demand Baseline in this instance is reasonably close to the projections made by both EPRI (2009) and UC–Davis (McCarthy et al. 2008). The Union of Concerned Scientists scenario (Cleetus et al. 2009) is again considerably lower; under its policy and research and development scenario, industrial electricity intensity falls to less than half of its current value by 2030. Although the results are not included in the figures, McKinsey and Company (Granade et al. 2009) conducted another recent study of efficiency potential in the United States. When converted to an index basis, the implied intensity index (2020 relative to a 2010 base) for the industrial sector is 0.68 in 2020. Because of the shorter time frame and greater emphasis on cost-effective potential compared to other studies, this value is not shown in Figure 17-2.

[28] The base year for index numbers was moved back to 2008 for the industrial sector to avoid the distortion in the intensities for 2009 and 2010 caused by the economic recession and reflected in the 2009 AEO.

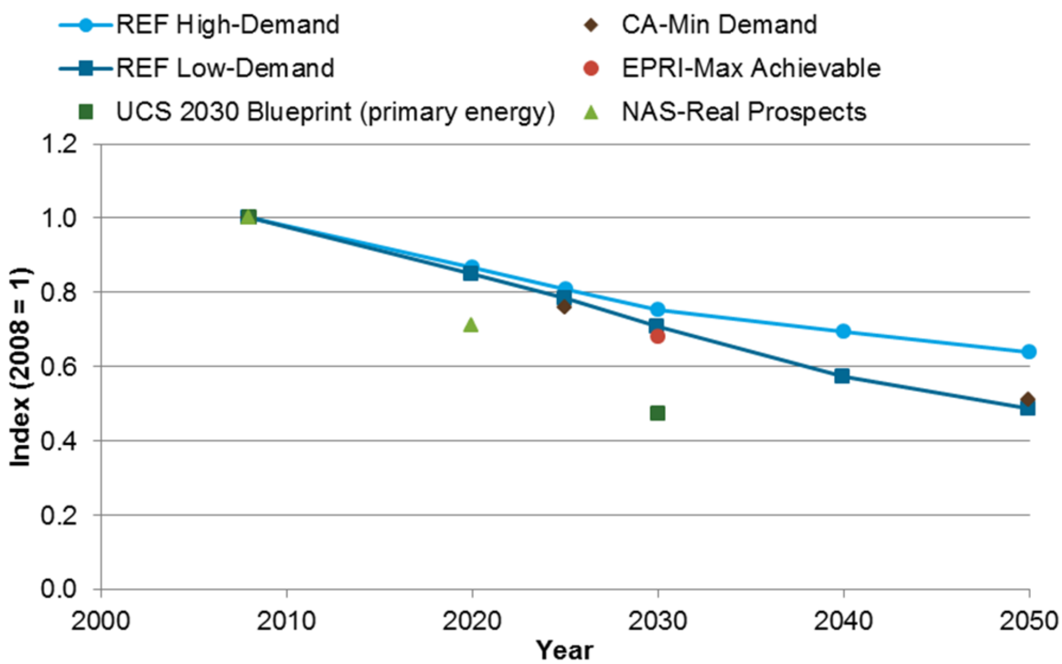

Figure 17-2. Industrial electricity intensities from five studies, including RE Futures

Sources: EIA 2009b, EPRI 2009, Cleetus et al. 2009, McCarthy et al. 2008, NAS et al. 2009

Appendix G provides additional detail regarding the comparison studies.

17.4 Combined Cooling, Heating, and Power within the Industrial Sector

The industrial sector can generate some of its own power needs, either through dedicated electricity plants or through combined cooling, heating, and power plants. Some of this power generated may also be sold to the electric sector for sale to other sectors. Total industrial electricity demand is the sum of purchased electricity and electricity generated less electricity sold to the grid. For RE Futures, the amount of cooling, heating, and power embedded within the High-Demand Baseline and the Low-Demand Baseline was determined, as discussed in Appendix J. No additional modifications were made to either increase or decrease the amount of cooling, heating, and power within the industrial sector.

Chapter 18. Transportation Demands

Although electricity use in the transportation sector is currently negligible (less than 0.2%),[29] plug-in electric vehicles (PEVs) offer the opportunity for the transportation sector to significantly reduce petroleum consumption through electrification. Light-duty vehicles currently use more than 60% of the energy consumed in transportation, making them the primary focus of an electrification effort.[30] Medium- and heavy-duty vehicles are the next largest segment (approximately 20%) and, while some portion of these could likely be electrified, it is quite difficult to compete with diesel powertrains in these applications. The likely load shape of medium- to heavy-duty vehicles is also less certain, making the development and incorporation of their associated load shapes into the models difficult. Therefore, RE Futures concentrated the transportation electrification effort in the light-duty vehicle market. Additionally, hybrid PEVs may have moderately sized energy storage systems and combustion engines that operate over a limited range under battery power while retaining the range capability of conventional combustion-engine vehicles. Other PEVs may be entirely battery dependent and provide complete petroleum displacement for specific vehicle sectors—several manufacturers are slated to introduce these types of vehicles to the market over the next several years. Based on past technology markets, maturity would likely occur within several decades from introduction.

The introduction of PEVs also creates new flexible loads that can be integrated into utility operations with a high penetration of renewables to achieve a long-term strategy of creating a more sustainable transportation system.[31] RE Futures developed energy system load characteristic forecasts on a regional basis during the study period. The work builds upon past travel survey data analyses, regional population forecasts, and charge management scenarios.

18.1 Low-Demand Baseline

Results were generated for 3,109 counties and were consolidated into 134 balancing areas (BAs) for use in regional generation planning analysis tools. PEV aggregate load profiles from previous work were combined with vehicle population data to generate hourly loads on a regional basis. A transition from consumer-controlled charging toward utility-controlled charging was assumed such that by 2050, approximately 45% of the transportation electricity demands could be optimally managed from the utility perspective. No other literature has addressed the potential flexibility in energy delivery to electric vehicles in connection with a regional power delivery study. This electrified transportation analysis resulted in an estimate for both the flexible load and fixed load shapes on a regional basis.

As input to RE Futures, hourly PEV load and energy demand profiles for the fleet of PEVs by region over time were developed. The approach was as follows:

1. Use population growth forecasts and historical vehicle ownership trends to estimate vehicle population by region

[29] EIA AEO (EIA 2010), Table 2
[30] *Transportation Energy Data Book*, Table 2.6 (DOE EERE 2011)
[31] See, for example, Tuffner & Kintner-Meyer 2011a and Tuffner & Kintner-Meyer 2011b

2. Use a market evolution model to estimate the fraction of vehicles that will be PEVs throughout the study period
3. Develop a vehicle fleet energy demand profile based on those from past studies that transitions from market introduction with no utility control to one in which the utility is able to manage a portion of the vehicle load.

Simplifying assumptions, detailed in Appendix K, were made to constrain the study scope.

A PEV market growth and saturation model was used with the motor vehicle estimates to determine the number of PEVs likely to be in use on a county level over the period discussed in RE Futures. The market model represents a slow ramp toward consistent market growth and a final tapering of growth to saturation. PEV sales saturates at a 50% market share after about 50 years (equivalent to approximately 40% of the total stock by 2050). A comparison of the sales rate and vehicle stock is shown in Figure 18-1. The rates in this scenario are consistent with results recently developed by Lin and Greene (2010).

Additional calculations to convert the demand to hourly profiles are explained in Appendix K. This appendix also discusses the development and application of three charging profiles:

- A No Utility Control profile in which the consumer is allowed to plug in and charge as soon as the vehicle ends the last trip for the day
- An Opportunity profile in which the charging infrastructure is prevalent and the consumer will choose to plug in any time the vehicle is parked
- A Valley Fill/Managed profile that allows utilities to choose the charging time for vehicles

The energy demands of the Valley Fill/Managed scenario are assumed to grow to become a flexible load that can be managed by the utility to improve renewable generation asset utilization. By 2050, 45% of the total vehicle energy demand of 350 TWh was under managed control while the remaining 55% was a fixed load to be planned for and met by utility assets. The hourly load profile of the fixed transportation energy demand also shifted over the time period from No Utility Control toward Opportunity Charging.

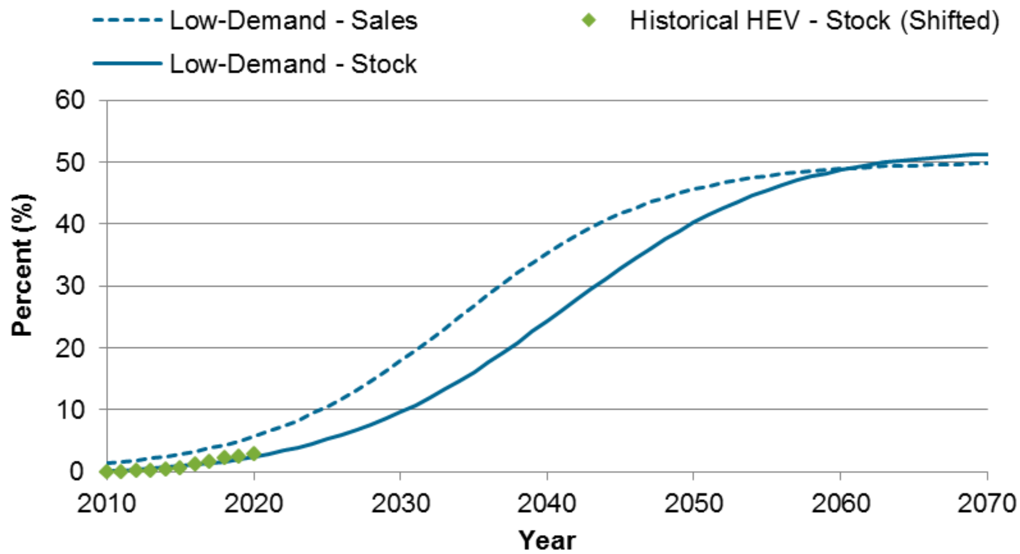

Figure 18-1. Technology market penetration scenarios

18.2 High-Demand Baseline

For the High-Demand Baseline, the 2009 AEO Reference Case (EIA 2009d) was used to represent the transportation sector. Within the 2009 AEO Reference Case, PHEVs with a 10- to 40-mile all-electric range represented less than 3% of vehicle sales by 2030 (EIA 2009d), and overall electricity use by the transportation sector remains less than 1% by 2030.

18.3 Comparison to Other Studies

Many analyses have been conducted and papers published that include PEV market projections. EPRI and the Natural Resources Defense Council collaborated on a foundational study highlighting the nationwide greenhouse gas and pollutant emissions impacts of PEVs on the U.S. electrical grid on a regional basis (EPRI 2007). The fleet makeup assumed approximately 40% PEVs by 2030 and 60% by 2050. An aggregate hourly load profile was assumed in which 74% of the energy was delivered during the off-peak period and 26% during the daytime. Both the Pacific Northwest National Laboratory and the Oak Ridge National Laboratory have assessed regional PEV penetrations and future load characteristics. The Pacific Northwest National Laboratory study (Scott et al. 2007) considered the situation in which all electric vehicle loads could be managed and fit into the low points of the daily utility load curve. The Oak Ridge National Laboratory study (Hadley and Tsvetkova 2008) considered a variety of charge levels and loading scenarios to understand the regional capacity and emissions impacts of the various scenarios.

Chapter 19. Hourly Electricity Demand for 2050

The potential for renewable electricity production to meet a large portion of future electricity demand depends not only on the magnitude of that demand but also on its variability regionally, seasonally, and diurnally; therefore, RE Futures focuses on load shapes. A central challenge for RE Futures was to convert the energy forecasts to the 13 regional hourly system load shapes required for the models.[32] Within the EIA's NEMS residential and commercial buildings modules, energy consumption by end use is forecast individually and regionally (EIA 2009c). These annual energy estimates are then attached to corresponding dimensionless load shapes and the results summed up to deliver hourly regional electricity system loads.

Because the High-Demand Baseline is a direct extension of a NEMS run, in this case, the load shapes for all sectors can be derived directly from NEMS (see Figure 19-1). This exercise is described further in Appendix H.

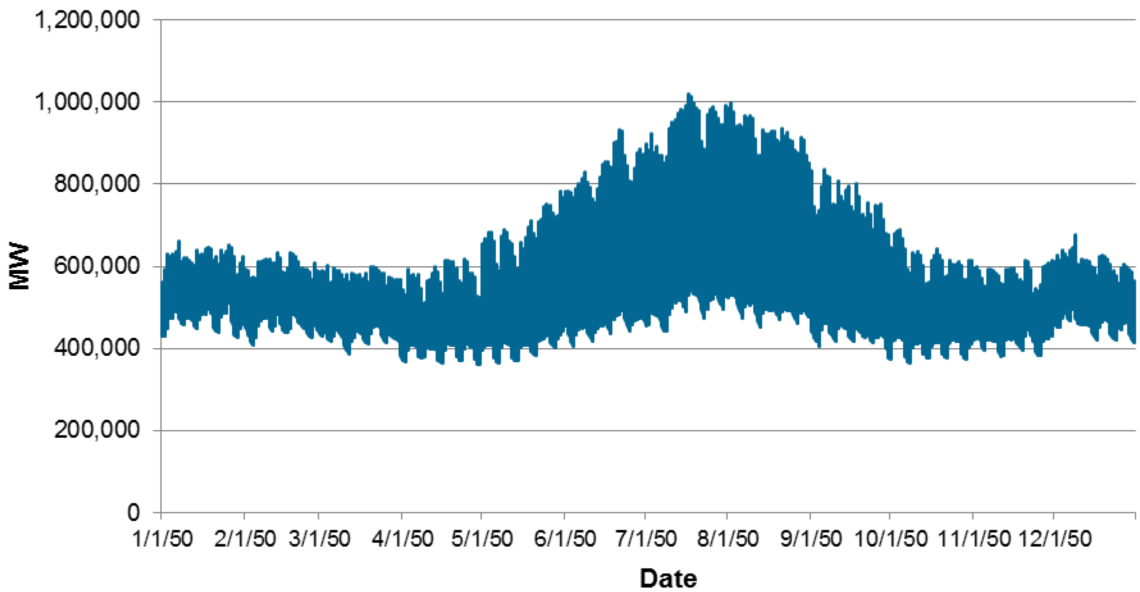

Figure 19-1. High-demand hourly load profile, 2050

[32] As described further in Appendix B, both the ReEDS and NEMS models use a set of representative load shapes to represent the 8,760 annual hourly loads.

The Low-Demand Baseline poses a different challenge. As discussed earlier, due to the uncertainties regarding which end-use technologies are likely to show the greatest efficiency improvement over the next 40 years, the approach used to project total consumption has taken a generally neutral stance on the future composition of end-use consumption.

There are two exceptions to this approach involving electricity, that used for air conditioning (space cooling) and that used for miscellaneous plug loads. These receive special treatment for different reasons, of which there are two for cooling. First, because cooling demand plays the major role in determining peak electricity demand in almost all regions of the United States, it represents a key driver of capacity expansion of the power sector and therefore necessary investment in renewable generation. Second, because the Regional Energy Deployment System (ReEDS) model is used in RE Futures to determine the deployment of thermal energy storage (TES), the potential for cooling load shifting was necessary as a separate load.

The basic assumption of the Low-Demand Baseline is that new technologies (influencing both cooling equipment and the building envelope) would keep pace with improvements in other technologies affecting other major end uses. The poorly understood, amorphous, and perpetually growing plug loads, usually termed "miscellaneous," are a concern for energy forecasting for buildings. If miscellaneous electricity intensity does not decline to the same degree as all other major building end-use intensities, the future share of electricity associated with all other end uses—including cooling—will decrease in the long run (Figure 19-2).[33]

The scenarios are generally based on the notion that future technologies will begin to have a significant impact on reducing these miscellaneous loads after the next decade. However, the inevitable development and adoption of new electricity-using devices, now unforeseen, will partially offset improvements in the efficiency of current and future devices. Therefore, in the long term, the shares of total electricity consumption devoted to miscellaneous equipment are expected to increase. Accordingly, these scenarios have the effect of slightly reducing peak loads associated with cooling, and thus flattening the building electricity hourly load profile over the coming decades. Appendix N contains the non-PEV hourly load shapes for each NEMS Electricity Market Module region for the year 2050.

[33] Appendix H provides some discussion of this uncertainty issue as well as a more detailed presentation of the overall approach to projecting the share of electricity used for cooling.

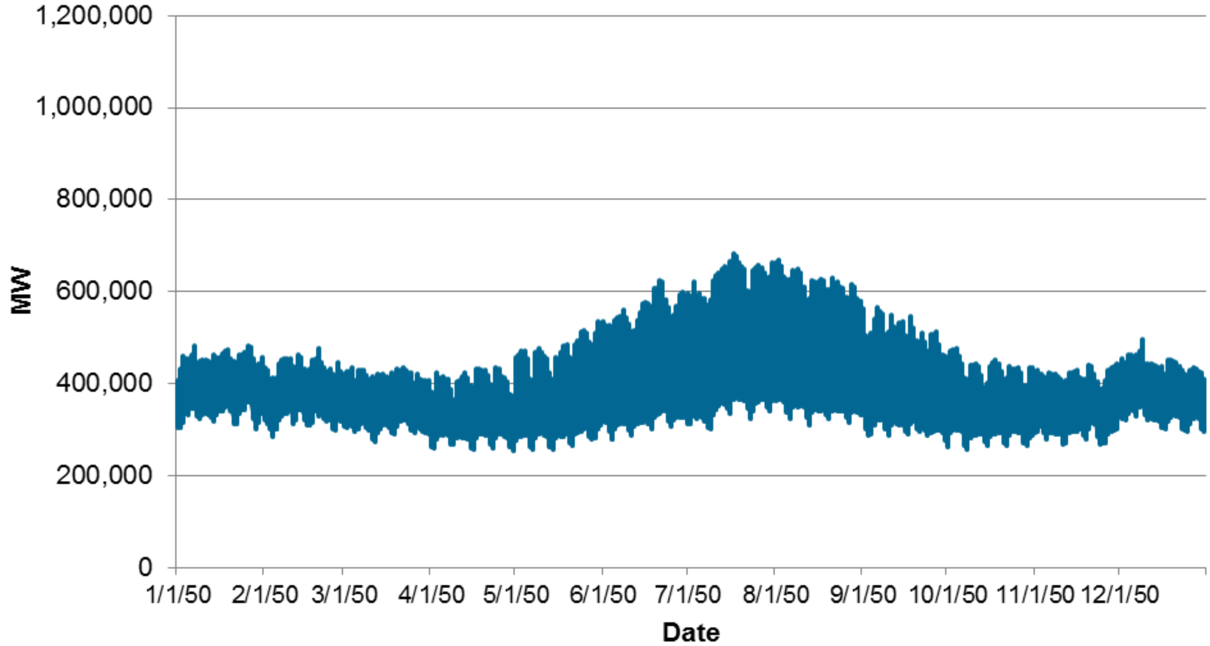

Figure 19-2. Low-demand hourly load profile, 2050

Chapter 20. Supply Curves for Thermal Storage

Within buildings, TES offers end users the option to lower peak electricity use by storing energy for later use. Although storage technologies exist for both space heating and space cooling, only those impacting space cooling were considered for RE Futures. Thermal heat storage was not included in the modeling because peak demands are generally not driven by heating and therefore would not be anticipated to be selected by the models as an option.[34] With respect to thermal cooling, pre-cooling using building mass was explored but was not included in the modeling effort because, unless additional mass is designed and built for such a purpose, there is no capital cost associated with the technology.

Thermal energy storage for space cooling can be used to lower peak electricity use in buildings by drawing upon cooled water or ice to supply some portion of the cooling requirements during the hot afternoon and early evening hours. TES is one of a number of storage technologies that can be employed to provide more flexibility for how electric utilities can more economically meet summer peak electricity loads. For RE Futures, TES was assumed to apply only to the commercial buildings sector.

For RE Futures, two types of thermal storage systems were considered, both of which are applicable to commercial buildings. For large buildings, the use of chilled water as a storage medium may be the most economical system. For smaller buildings, especially those using packaged air conditioning units,[35] ice storage may be the preferred storage technology. Based on a methodology developed in a 2000 "Federal Technology Alert" prepared for the Federal Energy Management Program (FEMP 2000) and more recent information from manufacturers and cost-estimation publications, cost estimates were developed for chilled water storage for a prototypical large office building. For ice storage, information from a 2009 E Source technical report was employed (Horsey 2009). A detailed description of how these data sources were employed is provided in Appendix L, which describes both the derivation of the cost values as well as how these values were incorporated in a series of cost curves that could be used by the models.

[34] If significant fuel switching from natural gas to electricity were to happen in the future, thermal heat storage may become a viable method to reduce winter peak loads.
[35] A packaged unit is a "unit built and assembled at a factory and installed as a self-contained unit to cool all or a portion of a building" (EIA 1989).

Chapter 21. Demand Response Capability

To determine the available demand response through 2050, the Federal Energy Regulatory Commission's (FERC's) *National Assessment of Demand Response Potential* database (FERC 2009) was used as a basis for the projections in RE Futures. The FERC report identified four levels of demand response: Business As Usual, Expanded Business As Usual, Achievable Participation, and Full Participation. These four cases were phased in over time, as detailed in Appendix M. Based on these demand response capacities, the percentage reductions were calculated from the system peak demand for each major end-use sector and census region, and then the 2050 system peak was multiplied by the percentage to find the sectoral demand response in gigawatts. From this, the price sensitivity curve for each sector was extracted from the FERC (2009) database and applied to the 2050 sector electricity price to find the demand response supply curve. These supply curves were provided as inputs to the models. The amount of demand response for each case was then determined within the models, and was used only to meet reserve requirements. A detailed explanation of the development of the demand response capability is included in Appendix M.

Conclusion

RE Futures developed two "bounding" scenarios and associated load shapes: a High-Demand Baseline and a Low-Demand Baseline. In looking at how electricity demand has changed over the past 40 years, it is difficult to determine with any certainty how electricity demand might evolve over the next 40 years. As such, these scenarios were designed to represent reasonable upper and lower boundaries for electricity demand, as opposed to attempting to project an "expected" level of demand.

Appendices

As input to RE Futures, two projections of electricity demand were produced representing reasonable upper and lower boundaries of electricity demand. The models used in RE Futures required underlying load shapes, however, so RE Futures also produced load shape data in two formats: in 2-year increments for 17 time slices as input to the ReEDS model, and 8760 data for the year 2050 for the GridView model.[36] The process for developing demand projections and load shapes involved many steps: discussion regarding the scenario approach and general assumptions, literature reviews to determine readily available data, and development of the demand curves and load shapes. Additionally, thermal energy storage and demand response within the end use sectors were considered.

These appendices contain the details underlying the electricity use presented in the main report as follows:

- Appendix G contains a comparison to other studies. The first part of the appendix addresses the potential impacts of climate change on projections of energy use. The second part of the appendix compares the energy intensity of RE Futures to other studies.
- Appendix H contains the development of the building sector electricity use and underlying load shapes.
- Appendix I contains the development of the industrial sector electricity use and underlying load shapes.
- Appendix J addresses combined heating, cooling, and power within the industrial sector.
- Appendix K contains the development of the transportation sector electricity use and underlying load shapes.
- Appendix L describes the development of the thermal energy storage cost curves used in the modeling effort.
- Appendix M details the development of the demand response potential within each sector.
- Appendix N contains the non-PEV hourly load shapes for each NEMS Electricity Market Module region for the year 2050.

[36] For information about GridView, see Appendix B (Volume 1).

Appendix G. Comparisons to Other Studies

Comparison of Climate Change Impacts on Energy Consumption

The incorporation of climate change into the projections of electricity use was beyond the scope of this study. However, a number of studies have been conducted that attempt to estimate the change in energy and electricity consumption under different climate change parameters. This section of the appendix reproduces comparisons of energy consumption changes in light of climate change, as included in Scott and Huang (2007) to provide some context regarding how climate change might impact the electricity use projections developed for RE Futures. Four tables are included: residential space heating, commercial space heating, residential space cooling, and commercial space cooling.

Table G-1. Effects of Climate Change on Residential Space Heating in U.S. Energy Studies[a]

Study	Change in Energy Consumption (%)	Temperature Change (°C) and Date for Change
National Studies		
Rosenthal et al. 1995	-14%	+1°C (2010)
Scott et al. 2005	-4% to -20%	About +1.7°C median (varies from 0.4° to 3.2°C regionally and seasonally) (2020)
Mansur et al. 2005	-2.8% for electricity-only customers; -2% for gas customers, -5.7% for fuel oil customers	+1°C January temperatures (2050)
Huang 2006	Varies by location and building vintage; Average HVAC changes: -12% heating in 2020 -24% heating in 2050 -34% heating in 2080	18 U.S. locations (varies by location, month, and time of day) Average winter temperature increases: +1.3°C in 2020 +2.6°C in 2050 +4.1°C in 2080
Regional Studies		
Loveland and Brown 1990	-44 to -73%	+3.7°C to +4.7°C (individual cities) (no date given)
Amato et al. 2005 (Massachusetts)	-7 to -14% natural gas -15% to -20% fuel oil	-8.6% in heating degree days (2020)
	-15% to -25% natural gas -15% to -33% fuel oil	-11.5% in heating degree days (2030)
Ruth and Lin 2006 (Maryland)	-2.5% natural gas -2.7% fuel oil	+1.7°C to +2.2°C (2025)

[a] Source: Scott and Huang 2007, Table 2.3

Table G-2. Effects of Climate Change on Commercial Space Heating in U.S. Energy Studies

Study	Change in Energy Consumption (%)	Temperature Change (°C) and Date for Change
National Studies		
Rosenthal et al. 1995	-16%	+1°C (2010)
Belzer et al. 1996	-29% to -35%	+3.9°C (2030)
Scott et al. 2005	-5% to -24%	About +1.7°C median (varies from 0.4° to 3.2°C regionally and seasonally) (2020)
Mansur et al. 2005	-2.6% for electricity-only customers; -3% for gas customers; -11.8% for fuel oil customers	+1°C January temperatures (2050)
Huang 2006	Varies by location and building vintage; Average heating changes: -12% heating in 2020 -22% heating in 2050 -33% heating in 2080	5 U.S. locations (varies by location, month, and time of day) Average winter temperature increases: +1.3°C in 2020 +2.6°C in 2050 +4.1°C in 2080
Regional Studies		
Loveland and Brown 1990	-37.3 to -58.8%	+3.7°C to +4.7°C (individual cities) (no date given)
Scott et al. 1994 (Minneapolis and Phoenix)	-26% (Minneapolis) -43.1% (Phoenix)	+3.9°C (no date given)
Amato et al. 2005 (Massachusetts)	-7 to -8% -8% to -13%	-8.6% in heating degree days (2020 -11.5% in heating degree days (2030)
Ruth and Lin 2006 (Maryland)	-2.7% natural gas	+1.7°C to +2.2°C (2025)

Source: Scott and Huang 2007, Table 2.3

Table G-3. Effects of Climate Change on Residential Space Cooling in U.S. Energy Studies

Study	Change in Energy Consumption (%)	Temperature Change (°C) and Date for Change
National Studies		
Rosenthal et al. 1995	+20%	+1°C (2010)
Scott et al. 2005	+8% to +39%	About +1.7°C median (varies from 0.4° to 3.2°C regionally and seasonally) (2020)
Mansur et al. 2005	+4% for electricity-only customers; +6% for gas customers; +15.3% for fuel oil customers	+1°C January temperatures (2050)
Huang 2006	Varies by location and building vintage; Average HVAC changes: +38% in 2020 +89% in 2050 +158% in 2080	18 U.S. locations (varies by location, month, and time of day) Average winter temperature increases: +1.7°C in 2020 +3.4°C in 2050 +5.3°C in 2080
Regional Studies		
Loveland and Brown 1990	+55.7% to +146.7%	+3.7°C to +4.7°C (individual cities) (no date given)
Sailor 2001	+0.9% (New York) to +11.6% (Florida) per capita	+2°C (no date given)
Sailor and Pavlova 2003 (four states)	+13% to +29%	+1°C (no date given)
Amato et al. 2005 (Massachusetts)	+6.8% in summer +10% to +40% in summer	+12.1% in cooling degree days (2020 +24.1% in cooling degree days (2030)
Ruth and Lin 2006 (Maryland)	+2.5% in May–September (high energy prices; +24% (low energy prices)	+1.7°C to +2.2°C (2025)

Source: Scott and Huang 2007, Table 2.3

Table G-4. Effects of Climate Change on Commercial Space Cooling in U.S. Energy Studies

Study	Change in Energy Consumption (%)	Temperature Change (°C) and Date for Change
National Studies		
Rosenthal et al. 1995	+15% (energy-weighted national averages of census division level data)	+1°C (2010)
Belzer et al. 1996	+53.9%	+3.9°C (2030)
Scott et al. 2005	+6% to +30%	About +1.7°C median (varies from 0.4° to 3.2°C regionally and seasonally) (2020)
Mansur et al. 2005	+4.6% for electricity-only customers; -2% for gas customers; +13.8% for fuel oil customers; a negative effect on electricity use for natural gas customers is statistically significant at the 10% level, but unexplained	+1°C January temperatures (2050)
Huang 2006	Varies by location and building vintage; Average HVAC changes: +17% in 2020 +36% in 2050 +53% in 2080	5 U.S. locations (varies by location, month, and time of day) Average winter temperature increases: +1.7°C in 2020 +3.4°C in 2050 +5.3°C in 2080
Regional Studies		
Loveland and Brown 1990 (general office buildings in 6 individual cities)	+34.9% in Chicago; +75% in Seattle	+3.7°C to +4.7°C (individual cities) (no date given)
Scott et al. 1994 (small office buildings in specific cities)	+58.4% in Minneapolis; +36.3% in Phoenix	+3.9°C (no date given)
Sailor 2001 (7 out of 8 energy-intensive states; one state – Washington – used electricity for space heating)	+1.6% (New York) to +5.0% (Florida) per capita	+2°C (no date given)
Amato et al. 2005 (Massachusetts)	Monthly per employee: +2% to +5% in summer +4% to +10% in summer	+12.1% in cooling degree days (2020 +24.1% in cooling degree days (2030)
Ruth and Lin 2006 (Maryland)	+10% per employee in April – October	+2.2°C (2025)

Source: Scott and Huang 2007, Table 2.3

Comparison of Electricity Demand Scenarios from Various Studies

This section of the appendix references the electricity demand scenarios made by several governmental and other organizations over the past several years, as included in Sections 16.3 and 17.3. The discussion in this volume helps to provide some perspective regarding how the electricity projections in RE Futures compare to these alternative scenarios.

Because the comparisons include studies with different initial electricity intensities, the intensities have all been converted to index numbers normalized to the current time frame. Indexing the intensities also helps to show more clearly the fractional improvement over time. Although the base years of the studies are not all the same, they are all sufficiently recent not to significantly distort the differences in the long-run projections. Therefore, the base-year intensity index is normalized to be 1.0 in 2010.

The key studies examined for the comparison are as follows:

1. ***Climate 2030: A National Blueprint for a Clean Energy Economy*** (Union of Concerned Scientists [Cleetus et al. 2009])

   Supported by a number of groups (such as the Avocet Charitable Lead Unitrust, David and Leigh Bangs, The Educational Foundation of America, and The Energy Foundation), Rachel Cleetus, Steven Clemmer, and David Friedman from the Union of Concerned Scientists' Climate Program discussed the impacts on carbon emissions and the potential savings for consumers and businesses resulting from a series of "smart climate and energy policies." The report explains a series of policies for the United States to reduce carbon emissions to 26% below 2005 levels by 2020, and 56% below 2005 by 2030 through cap-and-trade programs along with other complementary policies. Models in the report are largely based on a modified version of the DOE's NEMS (UCS-NEMS), supplemented by an analysis from the American Council for an Energy-Efficient Economy on the impact of greater energy efficiency in industry and buildings. The reference case assumed no new climate, energy, or transportation policies beyond those already in place as of October 2008.

2. ***California Energy Demand Scenario Projections to 2050*** (University of California–Davis [McCarthy et al. 2008])

   The *California Energy Demand Scenario Projections to 2050* report was written Ryan McCarthy, Christopher Yang, and Joan Ogden of the Institute of Transportation Studies at the University of California Davis as a support document for California's Advanced Energy Pathways Project. The report itself described five potential scenarios for the future energy demands in California, with the primary objective being to analyze the impacts of alternative transportation energy pathways on California's natural gas and electricity sectors between 2005 and 2050. The five scenarios included a minimum demand, maximum demand, and three alternative versions of a baseline demand scenario (one assuming high-efficiency, one low-efficiency, and the third being a continuation of historical and projected trends). All of the scenarios were created using data from the California Energy Commission's 2005 *Integrated Energy Policy Report* and projecting trends through 2050.

3. ***Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010–2030)*** (Global Energy Partners and EPRI [EPRI 2009])

   Sponsored by EPRI and prepared by Global Energy Partners and EPRI,[37] the report, *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010–2030),* examined the potential for electric end-use efficiency and demand response programs with the intended effect of reducing projected U.S. electricity consumption and summer peak demand through 2030. Specifically, the study was intended to advise utilities, electric system operators, and policymakers on efforts to develop end-use energy efficiency and demand response programs. Using the 2008 *Annual Energy Outlook*, the study assumed annual growth of peak demand in the United States would be at a rate of 1.5% from 2008 through 2030. The authors claimed this rate could "realistically" be reduced to 0.83% per year, and down to 0.53% per year under ideal conditions and aggressive use of energy-efficiency and demand response programs.

4. ***Energy Market and Economic Impacts of H.R. 2454.*** (Energy Information Administration, Report #: SR-OIAF/2009-05, August 4, 2009. [EIA 2009b])

   In 2009, the EIA responded to a congressional request to analyze the energy market and economic impacts of H.R. 2454, otherwise known as the American Clean Energy and Security Act of 2009 or the Waxman-Markey Climate Bill from 2009,[38] using the NEMS model. If enacted, the act would have regulated emissions of greenhouse gases through market-based mechanisms, efficiency programs, and economic incentives. Overall, the emissions reductions due to changes in fossil energy use within the residential, commercial, industrial, and transportation sectors would account for between 12% and 20% of the total reduction in energy-related CO_2 emissions compared to the 2009 AEO Reference Case in 2030.

   The EIA's analysis of the Waxman-Markey Climate Bill from 2009 (EIA 2009b) suggested little or no fuel switching in the residential sector. This result may stem from the prediction that residential electricity and natural gas prices would both increase about 17% in 2030 due to the legislation.

   With regard to fuel switching, an examination of space and water heating energy use indicated that the response to the electricity and natural gas price increases may be higher for electricity than for natural gas. In the EIA simulation output, electricity consumption for space heating is lower in 2030 by about 15%, compared to an approximate 10% decline for natural gas heating consumption. (On a site energy basis, *natural gas used for heating is still more than ten times greater than that for electricity*.) For water heating, total electricity use was lower by 9%, compared to 3% for natural gas. Unfortunately, these results cannot be used to address fuel switching directly because EIA did not publish tables that would indicate how many households switched from gas to electricity (or vice versa) with respect to their primary heating fuels. Clearly, the technical opportunities for improved equipment efficiency appear to be greater for electricity than natural gas, as evidenced by the response to the same relative price change. One can only

[37] The principal investigators involved in this study were I. Rohmund, G. Wikler, K. Smith, S. Yoshida, A. Faruqui, R. Hledik, and S. Sergici.

[38] For the full text of the bill (H.R. 2454), see http://www.govtrack.us/congress/bill.xpd?bill=h111-2454.

surmise that in the EIA projections, the number of households that may switch to electricity for their primary space or water heating fuel—thus offsetting some of the efficiency gains in the aggregate—is relatively small.[39]

5. ***Real Prospects for Energy Efficiency in the United States*.** (The National Academy of Sciences [NAS et al. 2009])

   In 2007, the National Academy of Sciences and the National Academy of Engineering initiated a major study of issues related to the future U.S. energy situation: *America's Energy Future: Technology Opportunities, Risks, and Tradeoffs* (the *Real Prospects for Energy Efficiency in the United States* report). Developed by a panel of industry, governmental, and academic experts, the study is one of a series of reports resulting from this overall initiative. In the buildings area, the panel decided to build upon the analytical framework initially developed in the 2000 study, *Scenarios for a Clean Energy Future*, which was subsequently updated by Brown et al. (2008) and considered specific energy efficiency measures for each end use in the residential and commercial building sectors. For each end use, a percentage savings estimate was developed based on a "supply curve" of energy savings potential at various costs. The study concluded that in both of the building sectors, energy consumption could be reduced by about 30%–35% at a cost less than current retail prices.

6. ***Unlocking Energy Efficiency in the U.S. Economy***. (McKinsey and Company [Granade et al. 2009])

   Another recent study of efficiency potential in the United States was conducted by McKinsey and Company (Granade et al. 2009). This report examined the potential of energy efficiency measures in 2020, using the 2008 *Annual Energy Outlook* projections as a business-as-usual case. Because the study focused on implementation of all cost-effective technologies (based on positive net present value criteria), the savings are considerably greater than the savings shown in the studies shown in Figure G-1 through Figure G-3. When converted to an index basis, the implied intensity indexes (2020 relative to a 2010 base) for the residential and commercial sectors from Granade et al. (2009) were 0.71 and 0.73, respectively. For the industrial sector using the 2008 base in Figure G-3, the McKinsey-developed index would be 0.68 in 2020.

Figure G-1 shows the projected intensities for the residential sector. As a business-as-usual case, the High-Demand Baseline (based on the *Annual Energy Outlook*) shows the least decline in intensity to the year 2030. Increases in "Other" electricity uses tend to actually increase the overall intensities in the last 10 years of the projection period. Shown only for the year 2030, the EPRI and cap-and-trade scenarios show a modest reduction in the intensity, on the order of 10%.

[39] Taking another approach to evaluating the EIA results, it may be useful to compare the percentage change in electricity use to that of heating use. The technical options for improved air conditioning efficiency are roughly equivalent to that for electric heating (comparing high-efficiency central air conditioners and heat pumps). In the case of the Waxman-Markey Climate Bill from 2009, electricity consumption for cooling declines by 9%, considerably less than that for heating. This result supports the notion that any fuel switching toward electricity is likely to be small in the simulation results because fuel switching would have tended to reduce the heating impact (i.e., offset the reduction). The fact that the heating consumption fell more than cooling consumption belies the notion that there was a significant fuel-switching offset to heating.

The UCS 2030 Blueprint scenario developed by the Union of Concerned Scientists (Cleetus et al. 2009) shows the greatest decline in intensity, with a potential reduction of approximately 45% by 2030.

The minimum demand scenario developed by the University of California Davis team (CA-Min Demand Case) for the California Energy Commission extends to 2050 (McCarthy et al. 2008). When converted to an intensity, a reduction in the overall residential electricity intensity (again, on a household basis) was projected to be approximately 40% by 2050. The near-term intensity decline for 2025 was approximately 18%.

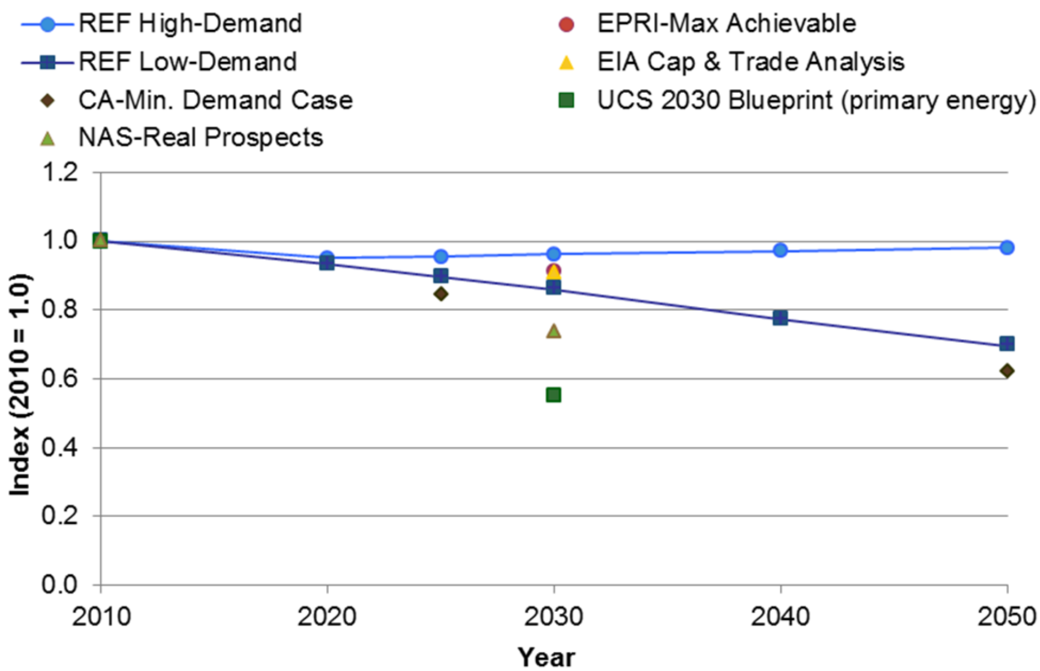

Figure G-1. Comparison of residential electricity intensities from various studies

Sources: EIA 2009b, EPRI 2009, Cleetus et al. 2009, McCarthy et al. 2008, NAS et al. 2009

The black squares connected by the solid line depict the high efficiency case developed for RE Futures. As shown in Figure G-1, this case falls within the range of intensity forecasts drawn from other studies.

Figure G-2 shows the scenarios from the same studies for the commercial sector. As compared to the residential sector, commercial sector electricity is expected to increase through 2030 as part of the reference (EIA 2009d) projection developed by EIA and represents the High-Demand Baseline. Again, the EPRI and cap-and-trade cases by 2030 showed the most modest reductions relative to the reference case. The Union of Concerned Scientists scenario showed the greatest decline in intensity, with commercial electricity intensity decreasing 40% by 2030.

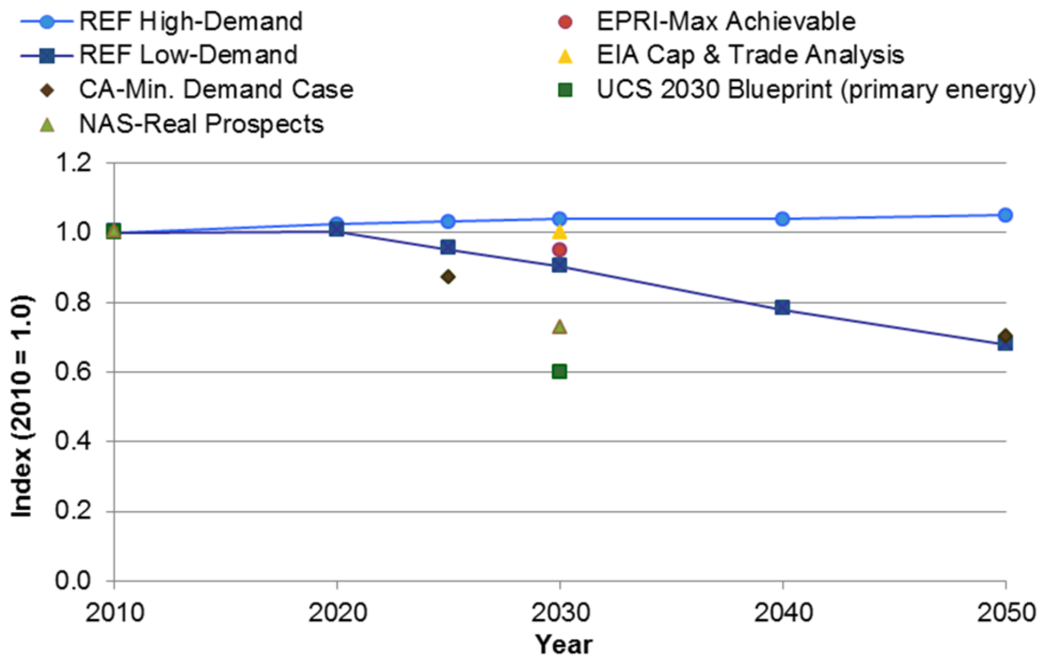

Figure G-2. Comparison of commercial electricity intensities from various studies

Sources: EIA 2009b, EPRI 2009, Cleetus et al. 2009, McCarthy et al. 2008, NAS et al. 2009

In between these studies are the projections for University of California Davis and the high-efficiency case for RE Futures. The RE Futures study suggests a somewhat greater decline in intensity in the commercial sector than in the residential sector by 2050, in contrast to the relative declines projected by University of California Davis. By 2050, electricity intensity under the high-efficiency case declines by approximately 32%, compared to the California projection of an approximate 30% reduction.

As was done with the residential and commercial buildings, a comparison of scenarios for the industrial sector was developed; it is shown in Figure G-3.[40] Both the reference and high-efficiency cases are taken from EIA model simulations. As with the building sectors, the reference case was based on the 2009 *Annual Energy Outlook* (EIA 2009d). The high-efficiency case was based on the cap-and-trade analysis performed by EIA, whose results here have been extrapolated to 2050 (EIA 2009b). Figure G-3 indicates that the high-efficiency case in this instance was reasonably close to the projections made by both EPRI and University of California Davis. The Union of Concerned Scientists scenario was again considerably lower, with industrial electricity intensity falling to less than half of its current value by 2030. The decline in projected electricity intensity may be due to the offshoring of energy-intense industries and other structural changes in the industrial sector.

[40] The base year for index numbers was moved back to 2008 for the industrial sector to avoid the distortion in the intensities for 2009 and 2010 caused by the economic recession and reflected in the 2009 *Annual Energy Outlook* (EIA 2009d).

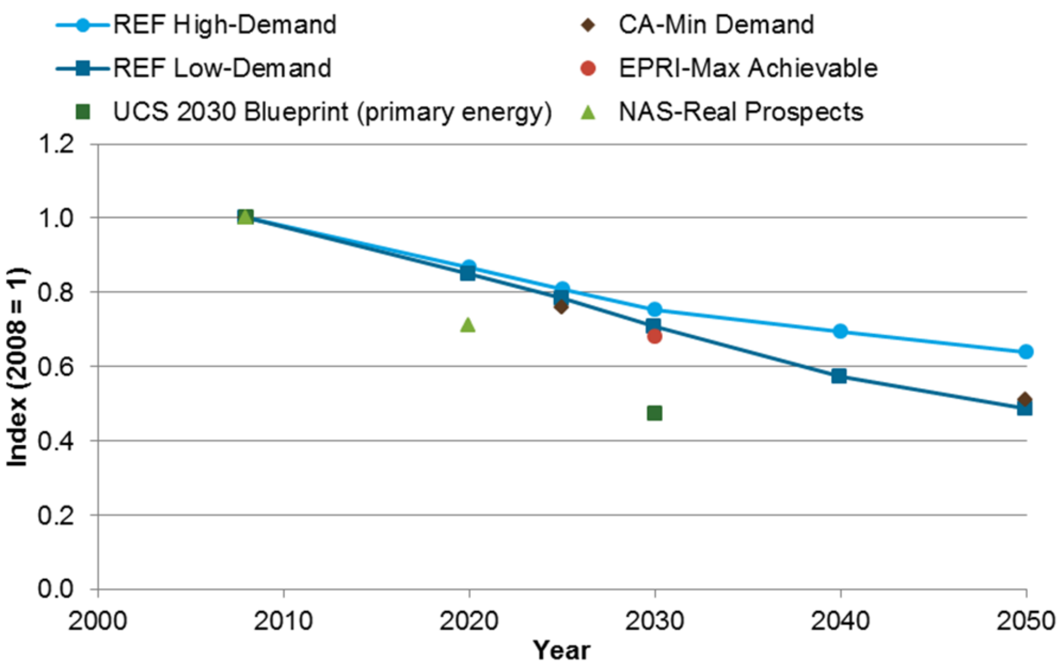

Figure G-3. Comparison of industrial electricity intensities from various studies

Sources: EIA 2009b, EPRI 2009, Cleetus et al. 2009, McCarthy et al. 2008, NAS et al. 2009

Appendix H. Development of Building Load Curves and Hourly Schedules

Building Sector Electricity Demand

The buildings sector dominates overall electricity consumption, representing almost 78% of the 2030 total in the AEO Reference Case (EIA 2010). Additionally, buildings electrical end uses are highly heterogeneous and changing over time.

Within the buildings industry, other trends continue to emerge. For new buildings, the "green" building movement, exemplified by the Leadership in Energy and Environmental Design certification program and more stringent building energy codes (along with more stringent appliance and equipment standards) are two of the most prominent factors that could have a major influence on energy use. The flurry of activity related to demand-side management programs of the 1980s and early 1990s has subsided, but in the past few years, resurgent state, local, and utility programs have aimed to significantly reduce energy use in existing buildings. Much of the current motivation for these programs is driven by concerns over climate change and other environmental issues as well as the desire to reduce the need for new generation capacity.

The DOE has been undertaking research programs designed to lead to ultra-efficient buildings. This objective for the DOE commercial research and development is specified in the Energy Independence and Security Act of 2007 (EISA 2007). Ultra-efficient buildings are designed and operated to generate as much on-site power (e.g., through rooftop photovoltaics) as the energy they consume. One of the keys to achieving this goal is by developing and applying extreme efficiency technologies. Under the DOE's Building America program,[41] the goal is to develop cost-effective solutions that reduce the average energy use of housing by 40% to 70% that, in turn, will provide a foundation for ultra-efficient homes. In terms of ultra-efficiency goals, the program aims to integrate on-site power systems leading to cost-effective, ultra-efficient homes by 2020. For commercial buildings, the DOE's Commercial Building Initiative[42] aims to achieve marketable ultra-efficient commercial buildings by 2025. Some states have similar goals (e.g., California Assembly Bill 2030 [AB 2030]). Within the context of the Low-Demand Baseline, RE Futures considered only the efficiency improvements required to create a building that is capable of having its energy needs met by on-site generation—this does not presume that all such ultra-efficient buildings will in fact be powered on site; rather, the determination of power provision is left to the ReEDS modeling effort.

The DOE programs working toward ultra-efficient buildings are based on a whole-building approach to achieve dramatically lower energy use. This perspective views the building as an integrated system with each component working together to achieve greater energy efficiency and comfort. The whole-building concept, as its name implies, is comprehensive and pays special attention to the control systems that operate buildings. It encompasses the specific building site; the envelope (roof, walls, and windows); the heating and cooling systems; lighting

[41] See http://www1.eere.energy.gov/buildings/building_america/ for more information about this U.S. Department of Energy program
[42] See http://www1.eere.energy.gov/buildings/commercial_initiative/ for more information about this U.S. Department of Energy program

and equipment (appliances); and controls. By integrating these components, economies can be realized in the construction of the building that can offer significant savings in energy use. For example, a properly sealed and insulated building that incorporates windows for natural lighting will be able to use a smaller, less expensive heating and cooling system. It will also require less energy for indoor lighting.

Electrification within Buildings Sector

Inaccuracy in future electricity demand forecasts arises in part from the considerable uncertainty regarding penetration of electric vehicles into the vehicle stock, and also electrification of transportation through greater use of mass transit. A similar but less-well recognized uncertainty concerns electrification in buildings. Electric vehicles may have dramatically lower carbon footprints than their petroleum-fueled counterparts, if the electricity supplied to them is low carbon. Likewise, if the electricity supplied to buildings were decarbonized, the use of electricity as a fuel would become more attractive. This argument is of particular interest here both because the nature of RE Futures directly addresses power generation decarbonization, and because the growing worldwide concern over the carbon footprint of the power sector would drive down the footprint of buildings. A key dissimilarity between transportation electrification and building electrification is that unlike the transportation sector, building energy services typically do not rely heavily on imported petroleum, making efficiency and fuel switching less of a national imperative from some perspectives.

Currently in a typical building, electrical end uses constitute the largest component of its carbon footprint.[43] This situation tends to make local thermal generation with heat recovery attractive from a carbon point of view, and likewise substituting direct combustion for electrical end uses tends to lower carbon emissions. In other words, avoiding the burden of carbon emissions caused by the waste heat of energy conversion at power plants tends to diminish the footprint of the whole system, and so does burning gas locally to displace coal combustion at power plants. However, if electricity supply is significantly decarbonized, the logic may reverse; that is, high-efficiency electrical equipment in buildings could provide energy services with a systemically lower carbon footprint than local combustion. Current resistance heating with a site coefficient of performance of less than 1 using electricity generated by coal cannot compete when evaluated on a carbon basis with direct space heating burning natural gas. However, if efficient heat pumps (e.g., ground source) are economically competitive with direct, on-site combustion and the electricity supplying them is decarbonized, the low carbon footprint option for heating is the electric heat pump.[44] In other words, the high efficiency of electrical end-use devices combined with low carbon electricity sources, both from the grid and locally, might further electrify the buildings sector, offsetting some fraction of the expected efficiency improvements achieved in other energy services. Conversely, direct combustion of sustainably produced biomass, local air quality conditions permitting, could also be a very low carbon footprint heating technology.

Thus, concern about a building's carbon footprint might encourage on-site combustion options when compared to electricity from high carbon sources in the near- to mid-term, but in the longer

[43] This assumption takes transmission and distribution losses into account and assumes that electricity is primarily being generated from fossil fuels.
[44] Depending on regional electricity prices and other factors, heat pumps with a coefficient of performance greater than 3 may be competitive on a carbon basis without decarbonized electricity.

term when electric power is produced by low carbon methods, electrical devices will be preferred over on-site fossil-energy-based options. In general, the forecasts made for RE Futures do not consider these issues. The High-Demand Baseline relies on the standard inter-fuel competition, as it exists in NEMS without any additional restriction on carbon emissions. Likewise, in the Low-Demand Baseline, the efficiency of buildings is assumed to increase significantly without attention to the competition between end-use equipment and the fuels it uses. In other words, fuel choice is purely economic.

Energy Intensity for New Buildings

The underlying assumptions for the Low-Demand Baseline for RE Futures are informed by the energy efficiency vision of the DOE's ultra-efficient building programs. Consideration of what level of energy consumption intensity must be achieved to reach ultra-efficiency motivates the overall approach to developing a possible trajectory of future energy demands for the residential and commercial buildings. The electricity demand forecast for residential and commercial buildings under the Low-Demand Baseline assumes a larger number of buildings to be ultra-efficient. At this point, the whole-building perspective suggests that DOE, as well as other building research and code-setting organizations, will intensify efforts to increase the energy efficiency of all building components and sub-systems, even if historically the most emphasis has been placed on heating, cooling, and lighting. This whole-building perspective of these efforts suggests that there is no reliable way to predict which technologies (and associated end uses) will offer the most promise to achieving these overall reductions in building energy use. Where future breakthroughs in energy efficiency will occur over the next four decades cannot be predicted at this point.[45]

Due to the inability to predict which technology and end-use consumption areas are most likely to show the greatest improvements, the approach of the Low-Demand Baseline is to focus only on the broadest measure of energy intensity, energy use per square foot (or per household) at the whole building level. Accordingly, the basic assumption for new buildings is that average energy intensity in 2050 will be 60% below that of new buildings being built today. This reduction is also assumed to occur along an annual percentage decline rate in energy consumption. Thus, absolute reductions in energy intensity are assumed to be greater in the immediate future than several decades from now.

For the residential sector, the assumed path of efficiency improvements implies that electricity intensity by 2025—the average of new houses built in that year—would be 30% below today's levels. That result may appear conservative in light of DOE's target of roughly a 50%–70% decline in energy intensity by this same year. These near-term reductions were assumed to be somewhat slower in commercial new buildings; the 2025 reduction in average new commercial building intensity was assumed to be about 22% lower than today.[46] Two considerations should

[45] For example, for the first time in a number of years, in 2009, the U.S. Department of Energy's Building Technologies Program Office issued several general requests for research and development proposals dealing with advanced, building-related efficiency technologies. The range of areas proposed covered advanced insulation and glazing materials as well as technologies that would dramatically reduce heating, cooling, and other equipment energy use. While not all of the proposals will be successful, a few "winners" may play significant roles in helping to achieve the long-term Ultra Efficient Building goals.

[46] A key element in reducing electricity growth in commercial buildings relates to the development of technologies to slow the growth of miscellaneous electricity (e.g., "plug loads"). Significant improvements in efficiency for this

be kept in mind. First, the DOE targets are couched in terms of market-acceptable designs that can be used by architect-engineering firms and builders. That is considerably different from achieving this level of efficiency in practice, and across all new construction in the United States. Moreover, while DOE's ultra-efficient buildings visions informed the approach in RE Futures, considerable research is still needed to find cost-effective and market-acceptable designs that will in fact reach these targets, especially when averaged across all types of buildings and climate zones. Research in these areas is under way; for example, a series of technical support documents are under development to explore the potential design and cost elements of achieving 50% energy savings compared to the American Society of Heating, Refrigerating, and Air-Conditioning Engineers 90.1-2004 for a number of commercial building classes (see Bonnema et al. 2010, Hale et al. 2008, Jiang et al. 2009, Leach et al. 2009, Leach et al. 2010, Thornton et al. 2009, and Thornton et al. 2010). Within the residential sector, DOE has funded the production of a series of climate-specific "Technology Information Packages" to support the work of its *Builder's Challenge* initiative (Roberts and Anderson 2009).

Another perspective is gained from potential goals associated with national building energy standards. Several current legislative proposals related to climate change include provisions for substantially more stringent building energy codes over the next 15 years. Generally, in the years immediately after 2020, both residential and commercial building codes would be mandated to be 50% more stringent than the codes that were in effect in the middle of the current decade (i.e., 2006 residential code and 2004 commercial code). However, even if these goals were met, it would not imply that new buildings would use 50% less electricity than the baseline codes just cited. First, one needs to distinguish between the development of a new (national model) code and having it actually adopted by all state and local jurisdictions. Second, achieving the specified energy savings requires that the codes have near full compliance, a situation that is not achieved in practice. Finally, but perhaps most importantly, 50% more stringent in terms of reducing total energy does not necessarily imply 50% electricity savings. The building codes currently do not cover all end uses, and those end uses not covered by codes are predominantly electricity-based. Some of these end-use devices, such as refrigerators and some other home appliances, are subject to other efficiency mandates, while others are not.

Energy Intensity for Existing Buildings

Due to the cost to substantially change the building envelope and heating and cooling system, the potential for large efficiency increases for existing buildings is much lower than that for new buildings. For the Low-Demand Baseline, intensity in existing residential buildings (e.g., pre-2010 homes still in the stock in 2050) was assumed to decline by 30% by 2050. For commercial buildings, the assumed decline by 2050 is somewhat greater at 40%. The larger decline for commercial buildings reflects an assumption that the amount of miscellaneous electrical uses in commercial buildings will be more amenable to reductions from policy, appliance and equipment standards, and new technology than those in the residential sector.

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end use is expected to take a decade or longer to achieve. Slower near-term efficiency improvement was also assumed for existing commercial buildings as shown in Figure H-3. Another factor assumed to result in *relatively slower* near-term reductions in intensity in the commercial sector relates to the recent step-up in federal policies to reduce energy use in the residential sector, namely from appliance rebates and weatherization efforts.

Several recent "meta-analyses" can be cited to generally support these assumptions. One recent study focused on efficiency potential in the south census region of the United States (Chandler and Brown 2009). The meta-study included six national studies, four (southern) regional studies, and eleven southern state studies. Because these studies covered a variety of time spans, the authors normalized the results in terms of percentage changes per year. The time horizons considered by the majority of studies ranged between 10 and 20 years.

A summary table in Chandler and Brown (2009) summarizes the "percent efficiency potential per year" across various geographic categories. The broadest category covers the state, regional, and national studies examined by Chandler and Brown (2009). Table H-1 shows the results of that analysis in terms of the average annual percentage reductions in energy intensity.

Table H-1. Summary of Results from Efficiency Potential Meta-Analysis

	Residential (percent reduction per year)	Commercial (percent reduction per year)
Moderate achievable	0.7% (10, 0.4%)	0.7% (8, 0.5%)
Maximum achievable	1.4% (7, 0.7%)	1.5% (7, 0.7%)

Source: Chandler and Brown (2009), Table 4
Numbers in parentheses are number of studies over which average was computed followed by the standard deviation of those studies

The Pacific Northwest National Laboratory conducted a second, more limited study for DOE (Belzer 2009). This study examined five state-level studies with a focus on efficiency potential for existing commercial buildings. Applying the same methodology as Chandler and Brown to normalize the efficiency potential across different time periods, the average percentage reduction for "economic potential" was 1.5% per year.[47] Under the assumption that the maximum achievable potential is approximately 80% of economic potential, then the annual percentage reduction drops to 1.3% per year.

Given the assumptions about the magnitude of the 2050 intensities for RE Futures (30% and 40% for the residential and commercial building sectors, respectively), the implied annual reductions are roughly 0.9% for the residential sector and 1.2% for the commercial sector. Thus, these changes appear to be roughly consistent with the meta-analyses summarized above.

Retrofits and Renovations

For a study with a long-term time horizon, one cannot assume that the intensity of buildings built today and in the near future will remain constant. Many ultra-high-efficiency technologies introduced in the latter years (2030–2050) will be adopted, through retrofits and renovations, in buildings built over the next 20 years. As a means of accounting for that phenomenon, the Low-Demand Baseline assumed that buildings (both residential and commercial) built over the next 20 years (2010–2030) will be retrofitted, or renovated, with more efficient equipment in the subsequent 20 years (2030–2050). Operationally, this assumption is implemented as a 15%

[47] The results for Vermont were dropped from this average because the very large potential from refrigeration improvement was deemed an outlier. The studies used in the average included those for California, Connecticut, Colorado, and the Pacific Northwest (Idaho, Oregon, and Washington). There was no overlap in the states considered in the Belzer 2009 study and those considered by Chandler and Brown 2009.

reduction in the electricity intensity for housing units and a 20% reduction in commercial buildings beginning in 2031. In other words, residential and commercial buildings built between 2010 and 2030 are "revisited" in the analysis 20 years later (e.g., buildings built in 2011 are revisited in 2031; buildings built in 2012 are revisited in 2032, and so on, through 2050), with the intensity reduction applied in the out years to account for the improvements in building and equipment practices.

As an example, Figure H-1 illustrates the intensity projections for new residential buildings. As can be seen on the figure, each point of the "2031–2050 retrofit" line is 15% lower than the equivalent point, 20 years earlier, on the "New" line.

Summary of Intensity Projections

Figure H-1 displays these assumed paths of intensity for the various segments of the future residential building stock, all defined in terms of total electricity use per household. The new and 2031–2050 retrofit intensities are reported as in-year intensities—that is, they represent the intensity of the buildings built or retrofit in that year. The pre-2010 intensity is a stock average, representing the decline over time as improvements are made to the pre-2010 stock. The higher intensity for new homes is largely a result of the larger size (areal square feet) of new homes compared to the stock of existing (pre-2010) homes. Over the forecast horizon, new home electricity intensity continues to be defined in terms of electricity intensity per household, even if new home size (areal square feet) continues to change.[48] Figure H-4 compares the overall energy intensity across all three categories (new, pre-2010, and 2031–2050 retrofit) for the High-Demand Baseline and the Low-Demand Baseline. By 2030, electricity use per household in the Low-Demand Baseline declines by approximately 14%, compared to a 4% decline in the High-Demand Baseline. By 2050, the average electricity intensity in the Low-Demand Baseline is reduced by 31% compared to 2010.

Figure H-3 and Figure H-4 show the same types of intensities for commercial buildings. Figure H-3 shows the projected intensities for existing (pre-2010) and new buildings as well as the intensities for the 2011–2030 vintage new buildings after undertaking substantial retrofits or a major renovation 20 years after initial construction. The increase in the intensities from 2010 to 2012 largely reflects the improved economic conditions (e.g., lower commercial vacancy rates) that will likely increase electricity intensity in the near term. Figure H-4 shows that overall Low-Demand Baseline electricity intensity is projected to decline by 10% between 2010 and 2030, in contrast to a 4% increase in the High-Demand Baseline. The average intensity in the energy efficiency scenario continues to fall over the last 20 years—for a total decline of 32% by 2050.[49,50]

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[48] While there has been a steady long-term trend toward larger homes, the average size of new single-family houses in 2008 showed the largest year-to-year decline in the 35 years that the U.S. Bureau of Census has collected data (from 2,277 to 2,215 square feet). It is therefore conceivable that future increases in average new home size may moderate, which would help to attain the intensity goals for the residential sector though increased energy efficiency.

[49] As cited, these percentage reductions use 2010 as a base year. The reductions are greater (by approximately 4 percentage points) if the comparison is made with regard to 2012, a year expected to display more normal economic activity.

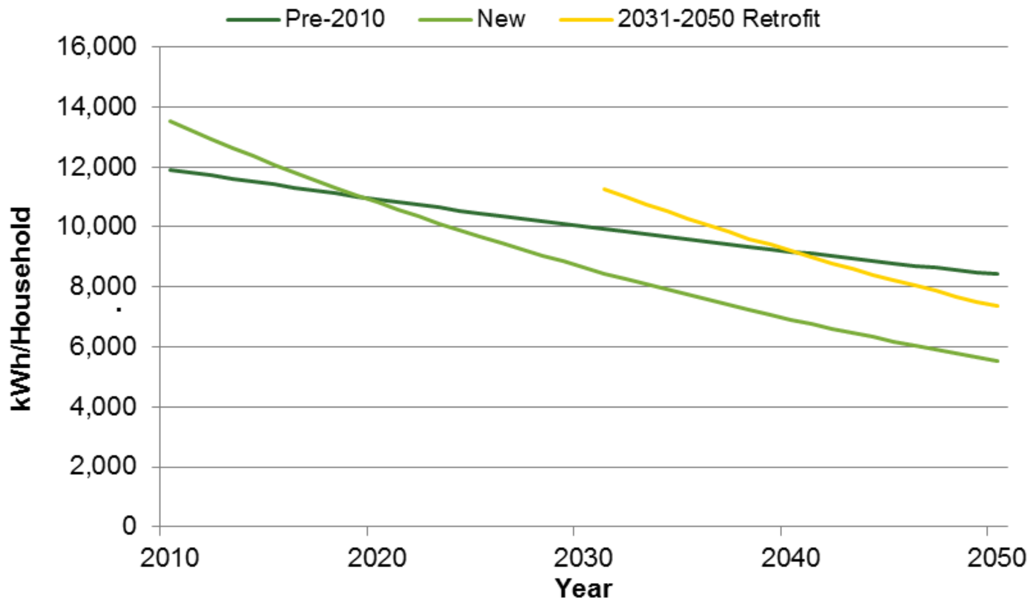

Figure H-1. Electricity intensities for residential building segments in the Low-Demand Baseline

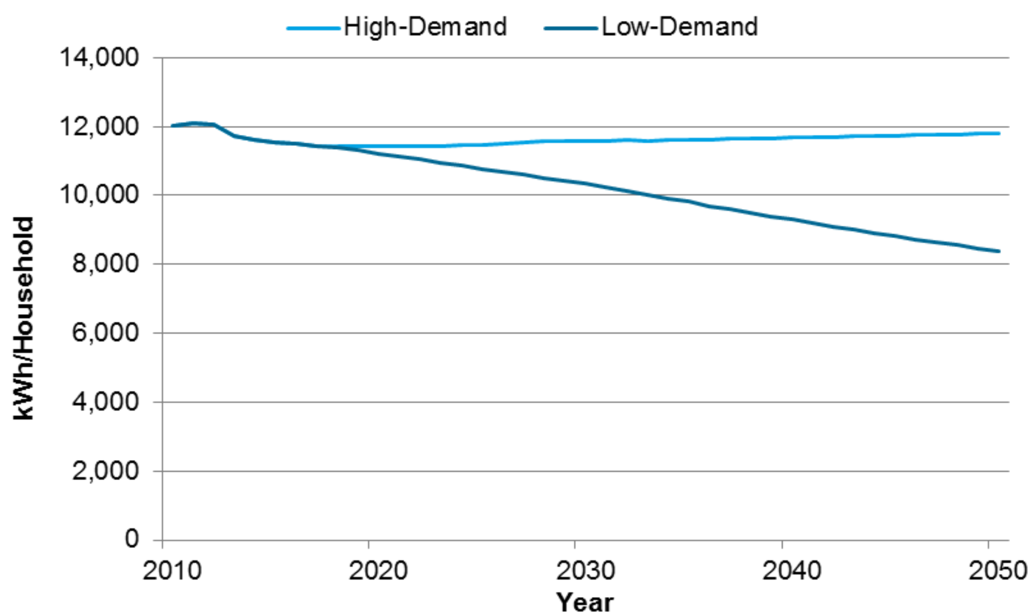

Figure H-2. Electricity intensities for residential buildings: High-Demand Baseline versus Low-Demand Baseline

[50] One additional segment of the commercial sector, not explicitly discussed above, is that for non-building electricity use. The largest uses within this segment include street lighting, water and sanitary treatment, and communication equipment. Non-building use was estimated to be 8% of overall commercial sector electricity use in 2009. For projection purposes, this electricity use was also formulated as an intensity (i.e., estimated electricity consumption divided by total floor space of commercial buildings). The overall intensity of this segment was assumed to decline by 10% by 2050.

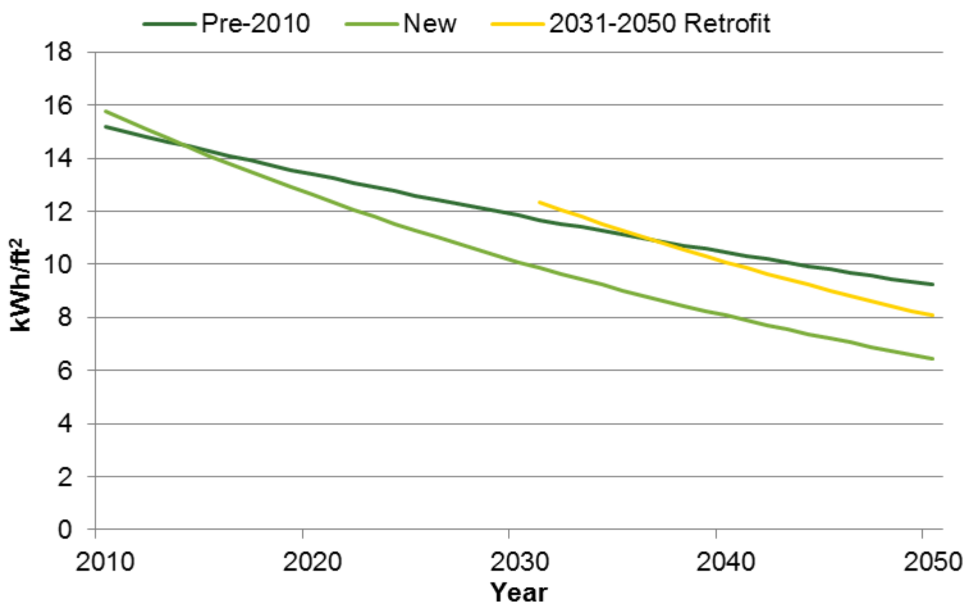

Figure H-3. Electricity intensities for commercial building segments in the Low-Demand Baseline

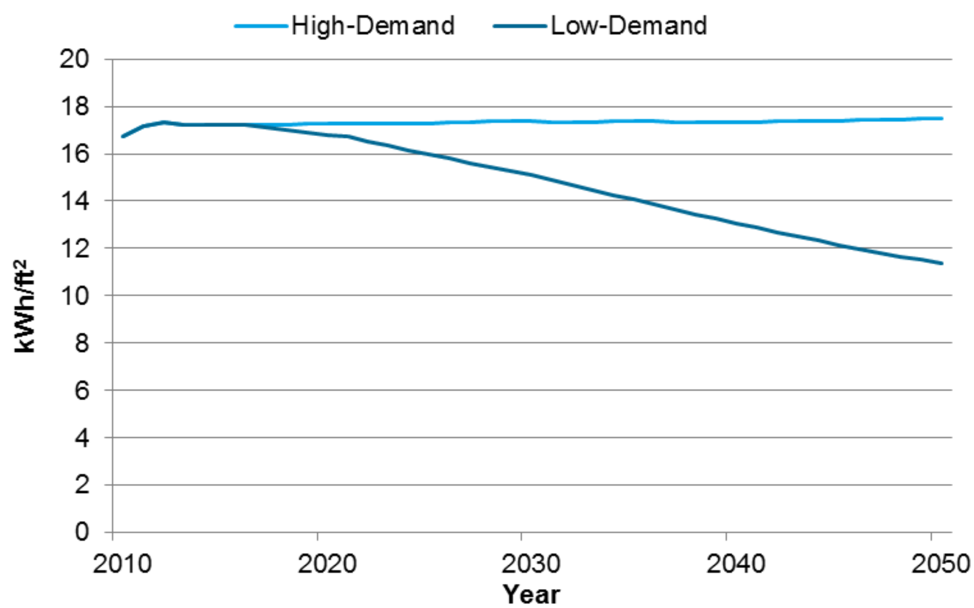

Figure H-4. Electricity intensities for commercial sector: High-Demand Baseline versus Low-Demand Baseline

The projected intensities are assumed to be feasible by sustained efforts on the part of government, businesses, and households—without major increases in electricity prices as a driver. For new buildings, the ultra-efficiency goals of DOE are predicated based on the whole-building efficiency improvements being cost effective (e.g., for the federal commercial building program, a 5-year payback criterion has been established).

Projections of Building Electricity Use

The final step in developing projections of total building energy use is to combine the intensity projections with those related to future building stock. For the period through 2030, projections of the number of households and total commercial floor space match those from the 2009 *Annual Energy Outlook*. Beyond 2030, projections of building stock depend to an approximate degree on population projections made by the Bureau of Census (U.S. Census Bureau 2008). Within these projections, AEO's assumptions (EIA 2010) regarding demolitions and other reductions of stock were maintained.

For the residential sector, the 2010 *Annual Energy Outlook* (EIA 2010) projected annual new housing units (i.e., new households) to average 1.7 million units between 2033 and 2035. For the next 20 years, new housing construction is assumed to be 1.7 million units per year. Given the population projections, this level of housing construction maintains a roughly constant household size over the study period (2010–2050). As projected in the 2009 AEO (EIA 2009d), households comprise an average of 2.67 persons in 2010 and 2.63 persons in 2030. Under the assumed construction activity over the subsequent 20 years, household size would grow slightly beyond that level to 2.71 persons in 2050. In aggregate terms, the total number of U.S. households would increase from 114 million in 2010 to 162 million in 2050.

The same general methodology was conducted for the commercial sector. The 2010 AEO (EIA 2010) projects annual new floor space to increase from 2.49 million square feet in 2020 to 2.57 million square feet in 2035. For RE Futures, annual new construction between 2036 and 2050 is assumed to remain constant at the 2035 value (2.57 million square feet annually). The projections in the 2010 AEO imply a roughly 8% decline in the total amount of commercial floor space per capita between 2010 and 2035. Under the assumed 2035–2050 construction activity, that ratio would fall another 3%. These declines in per capita floor space can be rationalized in terms of two factors: (1) absorption of often-cited current excess retail space and (2) greater use of all types of commercial floor space based on economic pressures, including web commerce, and concerns about sustainability and energy efficiency.

When multiplied by the intensity projections shown in Figure H-2 and Figure H-4, the projections of the number of households and commercial floor space then yield values for total sector electricity consumption. Figure H-5 compares the aggregate residential electricity projections from the High-Demand Baseline with the Low-Demand Baseline as constructed here.

Consistent with intensity projections, the High-Demand Baseline and Low-Demand Baseline in the residential sector begin to diverge significantly after 2020. By the end of the study period in 2050, the intensity reductions are sufficient to reduce aggregate residential use by 2% relative to 2010. Compared to the High-Demand Baseline, total electricity consumption is lower by 29%.

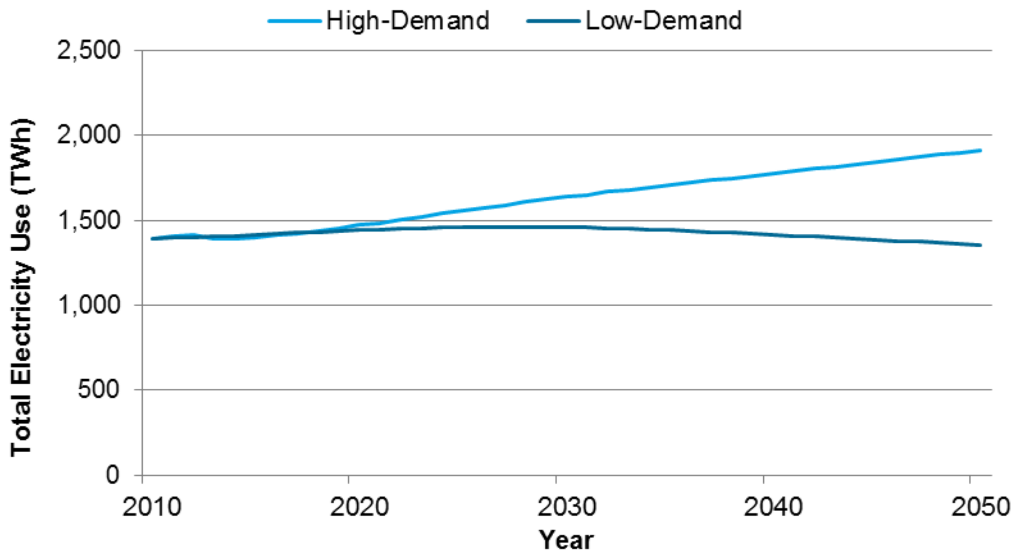

Figure H-5. Aggregate residential sector electricity projections: High-Demand Baseline versus Low-Demand Baseline

For the commercial sector, Figure H-6 shows total electricity consumption under the two scenarios. The differences here are more pronounced than the residential sector. In 2050, the energy efficiency case is 35% below the reference case. However, compared to the residential sector, the assumed declines in intensity for both new and existing buildings are not sufficient to keep projected 2050 consumption below the 2010 level. In this case, total electricity consumption is about 8% greater in 2050 compared to 2010.

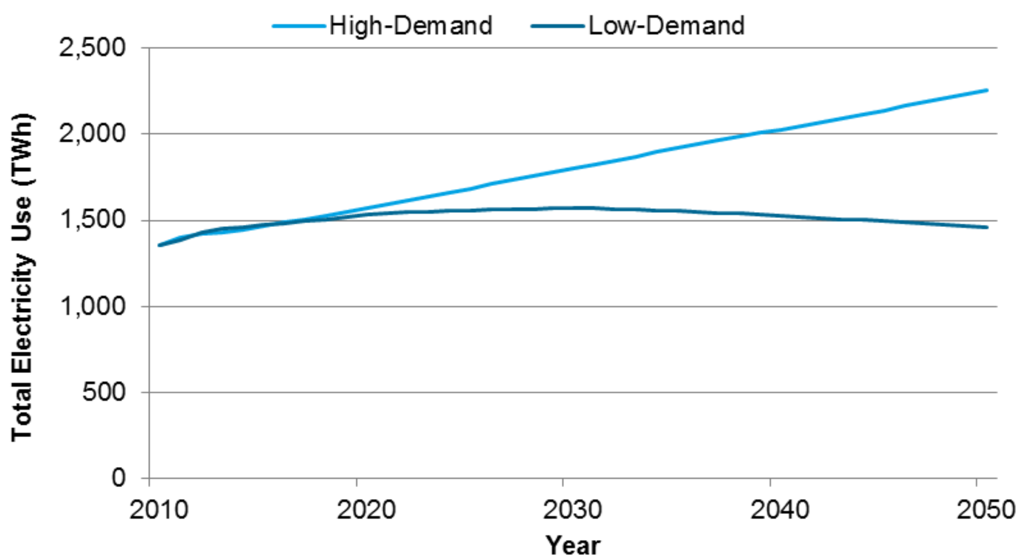

Figure H-6. Aggregate commercial sector electricity projections: High-Demand Baseline versus Low-Demand Baseline

Calculation of Building Load Shapes

The potential for renewable electricity production to meet a large portion of future electricity demand depends not only on the magnitude of that demand but also on its variability regionally, seasonally, and diurnally; therefore, the focus of RE Futures is on load shapes. The High-Demand Baseline is a simple extrapolation of the AEO Reference Case forecast (EIA 2009d), developed by EIA using NEMS, so its load curves could be directly accessed, with some complications, as discussed below. The Low-Demand Baseline poses a different challenge. As discussed earlier, due to the uncertainties regarding which end-use technologies are likely to show the greatest efficiency improvement over a 40-year future, the approach used to project total consumption has taken a generally neutral stance on the future composition of end-use consumption.

There are two exceptions to this approach involving electricity used for air conditioning (space cooling) and miscellaneous plug loads. These receive special treatment for different reasons. First, because cooling demands play the major role in determining peak electricity demand in almost all regions of the United States, it represents a key driver of capacity expansion of the power sector and therefore a necessary investment in renewable generation. Second, because ReEDS was used in RE Futures to determine the deployment of thermal energy storage, the potential for cooling load shifting was necessary to input as a separate load.

The basic assumption of the Low-Demand Baseline is that new technologies (both influencing cooling equipment and the building envelope) would keep pace with improvements in other technologies affecting other major end uses. The poorly understood, amorphous, and perpetually growing plug loads, usually termed “miscellaneous,” are a concern for this approach and for buildings energy forecasting in general. If miscellaneous electricity intensity does not decline to the same degree as all other major building end-use intensities, then the future share of electricity associated with all other end uses—including cooling—will fall, but overall demand will not decline as projected.

Given this framework, the approach used here makes assumptions about the rate of decline of electricity for these miscellaneous uses in comparison to all other end uses. For the residential sector, average electricity intensity for the miscellaneous end uses (accounting for an estimated 27% of current household electricity use) was assumed to remain constant through 2020 and then decline at 0.3 times the rate for overall electricity use. With this assumption, miscellaneous electricity use would increase to 36% of total electricity consumption in 2050. Given that result, the share of electricity consumption used for cooling would decline by 12% (as do the shares for all other major end uses).

For the commercial sector, a similar approach was followed. Currently, electricity used for computers, office equipment, and other miscellaneous equipment is estimated to be about 25% of total commercial building electricity use. Following no overall reduction in this intensity over the next decade, it is then assumed that it will decline at half the rate for all other end uses. The share of total electricity consumption for miscellaneous end use under this scenario would grow to 33% by 2050. Conversely, the shares of all other end uses, including cooling share, would fall by 11%.

The scenarios are generally based on the notion that future technologies will begin to have a significant impact on reducing these miscellaneous loads after the next decade. However, the inevitable development and adoption of new electricity-using devices, now unforeseen, will partially offset improvements in the efficiency of current and future devices. Therefore, in the long term, the shares of total electricity consumption devoted to miscellaneous equipment will continue to increase. Accordingly, these scenarios have the effect of slightly reducing peak loads associated with cooling, and thus flattening the building electricity hourly load profile over the coming decades.

Projected Shares of Electricity for Cooling in Buildings Sector

A key aspect to how the building sector will impact the electricity supply sector in the long term is the degree to which the relative importance of weather-related electricity demand will change. Because electricity for cooling is the primary influence on summer peak electricity loads, and therefore overall electricity capacity requirements, some extended consideration of this issue is warranted.

A conventional view is that efficiency improvements in the building envelope (primarily insulation and windows) and in lighting and HVAC systems will likely be greater than those related to computers, office equipment, home entertainment equipment, and all other types of miscellaneous electrical equipment (i.e., plug loads). Moreover, the percentage of total electricity consumption from these other uses appears to be growing—primarily as more and more electricity-using devices are used by households—and office automation and distributed computing are likely to continue to grow in commercial buildings (albeit, at perhaps at a somewhat slower pace than during the 1980s and 1990s). The implication of these trends, should they continue even at a somewhat slower rate in the future, is that the percentage of electricity for air conditioning in buildings will be lower in the future than it is today. Therefore, regardless of the annual level of overall consumption, the intensity of summer electricity peaks would moderate in the decades to come.

Unfortunately, to estimate the magnitude of this phenomenon is exceedingly difficult because it depends on the relative efficiency improvements in building design features and equipment that differentially affect cooling and non-cooling end-use consumption. It also depends on any changes in weather patterns due to climate change and the expected increase in summer air conditioning loads. Near-term studies of efficiency potential in existing residential and commercial buildings are of little use because they typically extend only 10–15 years into the future. A recent meta-analysis of six state and utility-specific studies of electricity efficiency potential in existing commercial buildings found that lighting and refrigeration improvements represented the largest and most cost-effective sources of electricity savings over the next decade or so (Belzer 2009). While some attention was focused on office equipment and computers in these studies, the primary energy savings measure involved power management of computer networks (including nighttime shutdown of desktop computers). The issue was raised regarding how effective these measures could be in the aggregate because nighttime file backup and automated software upgrades would appear to be incompatible with power management that completely turns off computers.

Other measures affecting computers and office equipment involve the use of the Energy Star program to promote adoption of the most energy-efficient models of such equipment. However, current Energy Star criteria provide little guidance regarding how far electricity use could be reduced for these types of equipment a quarter century or more into the future. The same issue applies to projecting the electricity requirement of home entertainment equipment (televisions, audio equipment, gaming consoles, etc.).

For new buildings, speculation about long-term efficiency potential generally does not consider how that potential may break out by end use. In DOE's planning for ultra-efficient residential and commercial buildings, the efficiency targets are all couched in terms of reducing overall site energy use to the point at which renewable energy (either at the building site, such as rooftop photovoltaic, or available elsewhere on the grid) would be able to meet the remaining energy requirements.

At least for commercial buildings, recent work sponsored by DOE may provide some hints regarding how new, highly efficient building designs may use energy. Over the past year, reports dealing with four different types of commercial building have been published that suggest how these buildings could reduce overall (site) energy by 50% compared to a recent building energy standard (ASHRAE Standard 90.1-2004).[51] This work is intended to support potential updates of the Advanced Energy Design Guides (AEDG) that have been previously published by the American Society of Heating, Refrigerating, and Air-Conditioning Engineers with support from DOE.

These studies involve simulations of prototypical buildings in a number of locations across the United States. To reach the 50% target, a wide variety of energy efficiency measures were considered, affecting energy consumption for all major end uses in the buildings. Pacific Northwest National Laboratory examined two building types (medium office [Thornton et al. 2009] and highway lodging [Jiang et al. 2009]), and the National Renewable Energy Laboratory examined two building types (medium box retail [Hale et al. 2008] and grocery stores [Leach et al. 2009]).

A scoping decision made early in RE Futures was to restrict the issue of changing electricity load profiles for buildings to that which could be measured by changes in the relative shares of cooling; therefore, only the specific results for cooling and all total electricity consumption for the baseline and advanced building designs need to be considered. While the studies performed simulations for as many as 15 locations across the United States, the brief survey here considers only five locations, representative of the largest (in terms of recent building construction activity) climate zones used by the building energy code organizations in the United States.

Medium Office Building

Table H-2 presents the summary results for the medium office building. In this case, two different types of HVAC systems are considered. In the base configuration and the initial advanced case, a typical variable-air-volume (VAV) HVAC system is modeled. Thornton et al.

[51] American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) and Illuminating Engineering Society of North America (IESNA). 2004. *Energy Standard for Buildings Except Low-Rise Residential Buildings*. ANSI/ASHRAE/IESNA Standard 90.1-2004, Atlanta, Georgia.

(2009) indicated that in some locations, it was difficult to be near or meet the 50% target with this conventional system. As a result, the packaged VAV system was replaced in a second set of simulations by a dedicated outdoor air system in combination with a hydronic radiant cooling and heating system (as shown in the third line of each panel, “Radiant-Adv”).

The results for Houston in the top panel of Table H-2 indicate that the shares of total electricity simulated as used for cooling would decline with either type of system. These increases are of course relative to a much lower overall level of electricity use (49% for VAV, 53% for the radiant system). The particular metric of interest is the relative (or percentage) change in this share. The last column shows that the cooling shares of total electricity in these advanced building designs would decrease by 11% and 14% for VAV and radiant systems, respectively.

The results in the lower panels of Table H-2 for the other locations generally show that the cooling shares would also decrease for the other locations. The much greater reduction for Las Vegas stems from the modeling assumption that an indirect evaporative cooling system is employed. This type of system can lead to substantially lower cooling electricity requirements in dry, hot climates.

Table H-2. Relative Changes in Cooling Electricity Share for Advanced Medium Office Building

City	System Type	Total Electricity (MMBtu)	Cooling (MMBtu)	Cooling Share (fraction)	Percent Change in Share (%)
Houston	VAV-Base	2,700	708	0.262	—
	VAV-Adv.	1,385	323	0.233	-11%
	Radiant-Adv.	1,257	283	0.225	-14%
Atlanta	VAV-Base	2,448	513	0.209	—
	VAV-Adv.	1,303	241	0.185	-12%
	Radiant-Adv.	1,187	214	0.180	-14%
Las Vegas	VAV-Base	2,527	538	0.213	—
	VAV-Adv.	1,255	140	0.112	-48%
	Radiant-Adv.	1,224	250	0.204	-4%
Baltimore	VAV-Base	2,443	488	0.200	—
	VAV-Adv.	1,145	255	0.189	-5%
	Radiant-Adv.	1,347	176	0.154	-23%
Chicago	VAV-Base	2,258	296	0.131	—
	VAV-Adv.	1,291	172	0.133	2%
	Radiant-Adv.	1,113	142	0.128	-3%

Highway Lodging Building

Table H-3 shows the summary results for the highway lodging prototypical building. The results in the first column present dramatic reductions in cooling electricity consumption. As in all the advanced building designs, reductions in cooling energy intensity result from an improved building envelope as well as reductions in internal gains from more efficient lighting and reduced plug loads. However, as with the medium office building, Modest efficiency improvement for the conventional type of HVAC system in most lodging buildings—room-packaged terminal heat pumps—generally inhibited meeting the targeted 50% reductions in overall electricity use (Jiang et al. 2009). Accordingly, the advanced designs for this building type incorporate water-source heat pumps. Each zone or space in the building has at least one water-source heat pump, which is connected to a two-pipe water loop. The water-source heat pumps either reject heat to, or extract heat from, the piping loop depending on whether they are cooling or heating the space.

Table H-3. Relative Changes in Cooling Electricity Share for Advanced Highway Lodging Building

City	Building Design	Total Electricity (MMBtu)	Cooling Electricity (MMBtu)	Cooling Share (fraction)	Percent Change in Share (%)
Houston	Base	2,371	551	0.232	—
	Advanced	1,244	167	0.134	-42%
Atlanta	Base	2,330	444	0.191	—
	Advanced	1,244	151	0.121	-36%
Las Vegas	Base	2,318	455	0.196	—
	Advanced	1,300	209	0.161	-18%
Baltimore	Base	2,285	315	0.138	—
	Advanced	1,211	112	0.092	-33%
Chicago	Base	2,283	258	0.113	—
	Advanced	1,201	96	0.080	-29%

As the first column of Table H-3 shows, the water-source heat pump system, combined with the other efficiency measures, can result in cooling energy use as low as one-third of that used in the base case. The last column reflects this reduced electricity for cooling. The shares of cooling electricity use of total electricity use are roughly between 30% and 40% lower than the base case for all locations, with the exception of Las Vegas (with an 18% reduction).

Retail Buildings

For retail buildings, two reports have been released dealing with medium box retail and grocery stores (Hale et al. 2008; Leach et al. 2009). NREL used its recently developed design optimization software OptiPlus together with EnergyPlus[52] to examine various strategies meeting the 50% energy reduction target.

For medium box retail stores, the prototypical buildings were divided into two classes depending on the amount of electricity used for plug loads. The low plug load store was considered to have an installed electricity density of 1.29 W/ft^2 and the high plug load store 1.32 W/ft^2. The low plug load level is meant to model stores such as bookstores, which have little to no accent lighting or plug-in merchandise. A typical high plug load store would be an electronics store, which has a much larger amount of plug-in merchandise and accent lighting.

[52] For more information, see http://apps1.eere.energy.gov/buildings/energyplus/.

Table H-4. Relative Changes in Cooling Electricity Share for Advanced Retail Building—Low Plug Load

City	Building Design	Total Electricity (kBtu/ft^2)	Cooling (kBtu/ft^2)	Cooling Share (fraction)	Percent Change in Share (%)
Houston	Base	99.4	36.8	0.37	—
	Advanced	40.5	16.8	0.41	12%
Atlanta	Base	67.7	16.8	0.25	—
	Advanced	30.0	9.3	0.31	25%
Las Vegas	Base	51.1	11.0	0.22	—
	Advanced	21.7	5.7	0.26	22%
Baltimore	Base	63.6	13.5	0.21	—
	Advanced	28.1	7.4	0.26	24%
Chicago	Base	46.3	7.2	0.16	—
	Advanced	24.5	4.0	0.16	5%

Table H-5. Relative Changes in Cooling Electricity Share for Advanced Retail Building—High Plug Load

City	Building Design	Total Electricity (kBtu/ft^2)	Cooling (kBtu/ft^2)	Cooling Share (fraction)	Percent Change in Share (%)
Houston	Base	128.7	41.1	0.32	—
	Advanced	61.3	20.0	0.33	2%
Atlanta	Base	94.0	19.6	0.21	—
	Advanced	47.0	9.8	0.21	0%
Las Vegas	Base	74.1	13.5	0.18	—
	Advanced	39.9	8.1	0.20	11%
Baltimore	Base	88.9	15.8	0.18	—
	Advanced	45.3	8.3	0.18	3%
Chicago	Base	68.6	8.7	0.13	—
	Advanced	38.0	5.1	0.13	6%

The simulation results for the low plug load store are given in Table H-4.[53] In contrast to the previous two building types considered, the shares of electricity for cooling increase in these simulated advanced buildings. This result is primarily caused by three factors:

1. Skylights reduce the consumption of electricity for lighting from 50% to 75%.
2. Improvements in fan efficiency and ventilation strategy reduce fan energy by roughly 70% in all locations.
3. The improvements in HVAC efficiency in the advanced case are relatively modest (i.e., the increase in the coefficient of performance is approximately 20%).

With major end-use loads from both lighting and fans in the base case, the dramatic reduction in their electricity consumption (relative to cooling) in the advanced building causes the cooling share to increase.

Table H-5 shows the results for the high plug load retail building. Here the cooling shares of total electricity also increase for the advanced design, although not to the same degree as in the low plug load case. Again, there are dramatic reductions in lighting and fan electricity use compared to a much more modest decline in electricity use, which yields an increase in the cooling share. However, the presence of much higher plug loads in this case (in both the base and advanced designs) results in smaller percentage increases in the cooling shares.

The last commercial building to be considered here is a grocery store ("supermarket"). The simulated results for this building are shown in Table H-6. For the baseline grocery store, electricity for refrigeration comprises roughly one-half to two-thirds of the total electricity consumption, depending on the location considered. For the advanced design, the efficiency improvements to this end use are estimated to be on the order of 50%. Because the sharp reductions in lighting and fan use (as carried over from the general merchandise stores) are not counteracted by the modest assumed efficiency increase in cooling equipment, the overall share of electricity used for cooling increases significantly for this building type.[54]

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[53] The absolute values in the first two columns are presented in terms of kilowatt-hour per square foot compared to total electricity use in million Btu for the entire building in the previous two tables.

[54] Examination of the list of efficiency measures for the advanced design in the grocery store technical report did not make it clear why the absolute amount of electricity increases for Las Vegas. It is possible that some combination of other measures in the optimization process yielded the increase, thus leading to a substantially higher relative change in the cooling electricity share compared to other locations.

Table H-6. Relative Changes in Cooling Electricity Share for Advanced Grocery Building

City	Building Design	Total Electricity ($kBtu/ft^2$)	Cooling ($kBtu/ft^2$)	Cooling Share (fraction)	Percent Change in Fraction (%)
Houston	Base	220	35.9	0.163	—
	Advanced	112	25.5	0.228	40%
Atlanta	Base	168.6	13.6	0.081	—
	Advanced	84.4	11.6	0.137	70%
Las Vegas	Base	160	6.3	0.039	—
	Advanced	75.4	7.2	0.095	143%
Baltimore	Base	163.1	10.9	0.067	—
	Advanced	83.1	9.1	0.110	64%
Chicago	Base	158.2	7.3	0.046	—
	Advanced	78.6	6.6	0.084	82%

Implications of Commercial Building Simulation Results

If these simulation results portend anything in how future high-efficiency buildings may be designed, it seems clear that there is considerable uncertainty regarding how the shares of electricity used for cooling may trend in the future. The results strongly depend on the type of building and the specific assumptions made about the relative improvements that can be achieved for equipment and envelope components affecting various end uses.

As a result, it is clear that to use these simulation results in some rigorous manner would be inappropriate in a study extending to the middle of this century. However, they still may perhaps give a glimpse of the overall proportion of cooling in advanced design. In qualitative terms, it is assumed that the results for the office and lodging buildings may be slightly more representative of what may transpire in the wider commercial building stock in the future. Several aspects of that assumption can be argued.

First, the truly low-efficiency building designs of the future may require the types of now unconventional HVAC systems as were used in the designs for the office and lodging buildings. These systems will permit substantially lower heating, cooling, and ventilation use in these buildings.

Second, the increases in cooling shares for the retail buildings are a result of the fact that the 50% overall energy efficiency goals could be achieved without advanced HVAC systems. The opportunities for skylights (leading to much lower lighting energy use) are particularly good for these types of buildings, but probably are not as effective for other types of commercial buildings. For grocery stores, the increases in the cooling shares may be anomalous as a result of the single, large end use (refrigeration) for which the efficiency improvement was assumed to be large.

Projections of the Aggregate Cooling Share of Electricity—Commercial Buildings

The previous discussion indicates that the variation in the simulation results does not lead to strong guidance regarding how to project the share of cooling electricity for the overall stock of commercial buildings. As such, a “top-down” approach has been conducted to support the modeling work for RE Futures.

The top-down approach is based on an assumed rate of intensity reduction for plug loads and miscellaneous electricity uses in commercial buildings compared to an assumption about the overall annual decrease in electricity consumption. The approach starts with the estimate from the 2003 Commercial Buildings Energy Consumption Survey that approximately 25% of the total electricity can be attributed to office equipment, computers, and other uses (EIA 2006b). (For brevity, the grouping of these end uses will be termed below as “miscellaneous end use.”) Lacking more recent data, this fraction is assumed to be the same in 2009. From this point, two assumptions are made with regard to how the overall intensity (kWh/ft^2) of these end uses will change over time:

- From 2009 through 2020, the aggregate intensity for miscellaneous end-use category will remain roughly the same, as overall end-use intensity declines.
- From 2021 through 2050, the aggregate intensity for these end uses will decline at 50% of the rate for all other electricity uses.

The notion behind these assumptions is that any increases in the efficiency (e.g., Energy Star promotion of efficient computers and office equipment or improved network management) will be largely offset by some continuing increase in the overall penetration of these types of equipment in commercial buildings. By 2020, it is anticipated that more focused research—by both government and manufacturers—to make more significant efficiency improvements will begin to show measurable impact. However, in the long term, the potential for improvement is still judged not to be as great as for HVAC systems, lighting, and refrigeration.

While this approach starts with these miscellaneous uses, it also implicitly assumes that the share of cooling relative to all other end-use electricity consumption remains roughly constant. As was shown above in the discussion of the advanced building designs, the relative shares of cooling will depend on decisions made with regard to unconventional HVAC systems, daylighting (and, perhaps, significantly greater lighting equipment based upon light-emitting diode devices in the future), and refrigeration efficiency. Dramatic reductions in these end uses are required to meet the goals of net zero commercial building in the future. Therefore, in the absence of more definitive evidence, it is assumed that the improved HVAC designs will yield reductions in cooling electricity use that approximately match the reductions in lighting and other end uses (excluding computers, office equipment, and other plug loads). This combination of assumptions leads to the projection that cooling electricity use will fall slightly in comparison to total electricity growth in the long term (and thus have some rough qualitative congruity to the simulations for the office and lodging buildings discussed earlier).

Table H-7 shows the results of these projections at 10-year intervals from 2010 through 2050. The first column shows the projected shares of miscellaneous end-use consumption (again, to clarify—office equipment, computers, and other uses). The share for all other major end uses is shown in the second column. By assumption, a constant fraction of that share is for cooling, but is not explicitly shown in the table. The key metric is the relative increase over time in the share of the cooling (as implied from its assumed constant share of the major end uses) compared to the base year (2009). This relative increase in the cooling share can be used as an adjustment factor for the baseline commercial sector electricity projection. Therefore, for example, the adjustment factor for 2020 is 0.964, which is derived by the ratio 0.723/0.750.

Assuming the rate of intensity reduction for the amalgamated miscellaneous category is smaller than for all other end uses (including cooling), then the adjustment factor falls continuously throughout the projection period. By 2050, the adjustment factor is approximately 0.89. This factor is then applied to the cooling electricity projection in the Low-Demand Baseline. This approach assumes that cooling shares in the Low-Demand Baseline will likely be relatively constant or rise only slightly.[55]

Table H-7. Development of Cooling Share Adjustment Factor for Commercial Buildings

Year	Electricity Share for Misc. Equipment	Electricity Share for Major End Uses	Cooling Share Adjustment Factor
2009	0.250	0.750	1.000
2010	0.248	0.752	1.003
2020	0.277	0.723	0.964
2030	0.292	0.708	0.944
2040	0.312	0.688	0.917
2050	0.333	0.667	0.890

Projections of the Aggregate Cooling Share of Electricity—Residential Buildings

DOE's Building America program has published a Best Practice series of builder guides for various climate areas aimed at roughly 30% savings compared to code-compliant homes; thus, they do not reflect the more aggressive designs that are anticipated in the future. The residential Best Practice guides do not contain simulation results or provide any quantitative estimates about how the overall efficiency improvements might break out by end use. This is in contrast to the commercial building Advanced Energy Design Guides work for which technical support documents with detailed simulation results were produced.

Most of the work on energy-efficient new homes has been directed at heating, cooling, and water heating and to a lesser extent on lighting and appliances. Relatively little attention has been paid to reducing energy use for small appliances, computers, televisions, and other uses. For the first time, the 2009 edition of the International Energy Conservation Code introduced requirements for lighting efficiency. Nevertheless, goals for future stringency changes in the residential energy code can generally be taken as applying to space conditioning, water heating, and lighting, although Energy Star requirements for major appliances that are often installed by the builder

[55] The adjustment factors are designed to be applied separately to each NERC region, each with different shares of cooling in the Low-Demand Baseline. Therefore, even after the application of the factors, there may still be an offsetting (positive) effect on the national cooling share as a higher fraction of the new buildings continues to be built in relatively warmer climate regions. The use of the adjustment factor approach is designed to at least show some degree of sensitivity to approximate changes in the cooling shares that might be expected under a low-demand or ultra-efficient building scenario. Obviously, a more thorough analysis would be required to better justify the absolute levels of cooling electricity use (in the latter years of the projection period) in both the High-Demand and Low-Demand Baseline*s*. An alternative approach is to apply the adjustment factors to the 2009 or 2010 ratios of cooling electricity consumption in each NERC region.

(dishwasher and cooking range) may also come under the scope of future code updates. Miscellaneous loads have not been considered because they are viewed as unable to be effectively regulated under a building code. This situation is somewhat different from that in the commercial sector, where the efforts of DOE and other organizations have explicitly considered all energy used in the building as suitable targets for efficiency (or, perhaps more accurately, intensity) improvements.

This lower level of attention to miscellaneous electricity use in the residential sector suggests that its relative importance (i.e., share of household electricity consumption) may grow faster than the corresponding miscellaneous electricity use in the commercial sector, where it is receiving substantial attention, even as overall energy use intensity declines. A similar approach to that underlying Table H-7 was employed for the residential sector. In this case, however, the reduction in miscellaneous electricity intensity was assumed to be only 0.3 times that of overall intensity declines (compared to the 0.5 fraction used for commercial).

The category of miscellaneous electricity uses was defined from the 2009 AEO as consisting of televisions (and set-top boxes), personal computers and related equipment, and other uses (EIA 2009a). For 2009, the share of electricity consumption for these uses was estimated in the AEO to be just under 30%. As for the commercial projection, it was assumed that the overall intensity for these uses, electricity use per household, remains constant until 2020.[56] From that point forward, the assumed reduction in intensity is assumed to be 0.3 times that of the overall electricity intensity reduction scenario.

Based on these assumptions, the second and third columns of Table H-8 display the projections of the electricity shares for the miscellaneous category and for the sum of all other major end uses. By 2050, the share of the miscellaneous category grows from 30% to 40%. Compared to the base year (2009), the share of cooling electricity falls by 13.4% (reflecting the 0.866 adjustment factor shown in the last column of the table.). The higher 2050 adjustment factor in the residential sector (13.4% compared to 11% in the commercial sector) reflects the higher initial level of miscellaneous electricity use as well as a more conservative assumption about its rate of intensity decline over time.

[56] This assumes that any efficiency improvements (e.g., greater penetration of Energy Star computers and other devices) are offset by greater numbers of devices in the average home.

Table H-8. Development of Cooling Share Adjustment Factor for Residential Buildings

Year	Electricity Share for Misc. Equipment	Electricity Share for Major End Uses	Cooling Share Adjustment Factor
2009	0.298	0.702	1.000
2010	0.296	0.704	1.002
2020	0.319	0.681	0.970
2030	0.338	0.662	0.943
2040	0.364	0.636	0.905
2050	0.392	0.608	0.866

Load Shape Translation

Once the projections of buildings consumption were determined, the next task was to develop the buildings sector loads by NEMS Electricity Market Module regions, shown in Figure H-7. The same regional definitions employed by NEMS are used in ReEDS. The buildings sector loads are added to the industrial and transportation demand. Whereas the buildings' load shapes have relied on the end-use load shapes used by NEMS, the industrial loads have been developed based on prior work using FERC rate class loads. For the buildings sector, RE Futures used Lawrence Berkeley National Laboratory's spreadsheet model, the Building End-Use Loads Forecaster. It applies the dimensionless NEMS end-use load shapes extracted from the Electricity Market Module together with energy forecasts of the 10 residential and 10 commercial building end uses to deliver buildings sector load profiles in the NEMS format for each of the 13 Electricity Market Module regions (Figure H-7). One particular source of confusion about NEMS load shapes is the correction sometimes called the "squelch" that NEMS uses to calibrate bottom-up results to historic reported system loads.[57] The squelch is incorporated into the Building End-Use Loads Forecaster so the resulting loads are what the Electricity Market Module would see when entering its capacity expansion and dispatch simulations. In other words, the Building End-Use Loads Forecaster produces the loads the Electricity Market Module would use if faced with a similar forecast by building end use made by the respective demand modules within NEMS. Within NEMS, however, the squelch is only applied at the system level, so its reliability for this application remains unproven.

[57] See Hamachi-LaCommare et al. (2002)

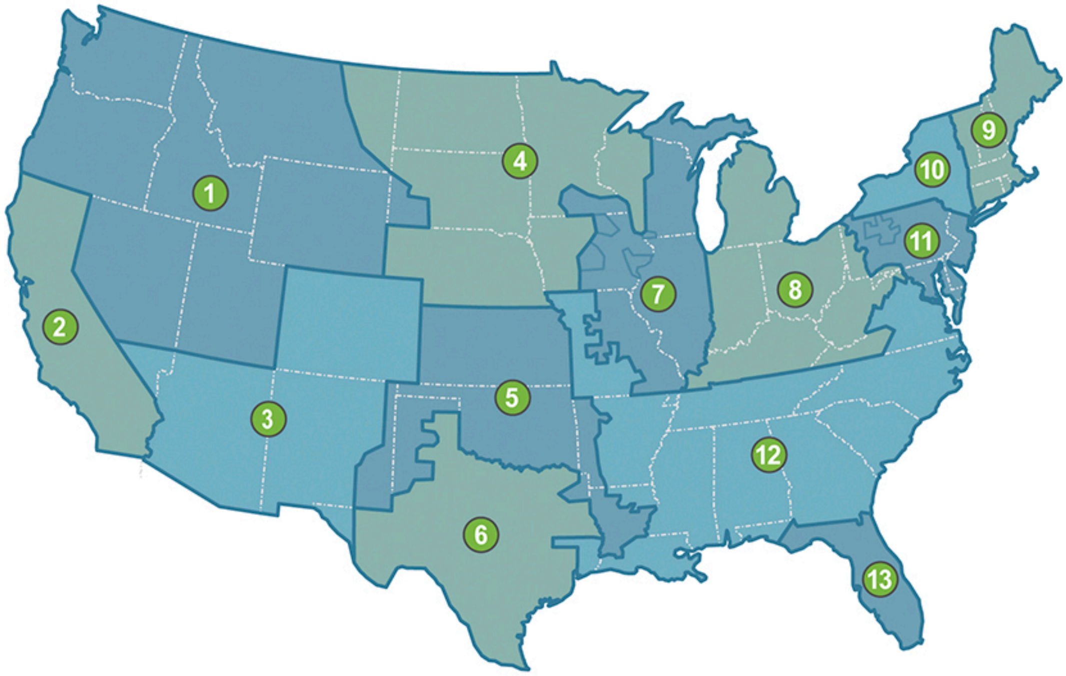

Figure H-7. Electricity market module regions from the National Energy Modeling System, also used by the Regional Energy Deployment System

1. Northwest Power Pool
2. California
3. Rocky Mountain Power Area—Arizona, New Mexico, Colorado, southern Nevada
4. Mid-Continent Area Power Pool
5. Southwest Power Pool
6. Electric Reliability Council of Texas
7. Mid-America Interconnected Network
8. East Central Area Reliability Coordination Agreement
9. New England
10. New York
11. Mid-Atlantic Area Council
12. Southeastern Electric Reliability Council
13. Florida Reliability Coordinating Council

Source: EIA 2010

Applying exogenously derived energy forecasts sacrifices the numerous interactions that NEMS accounts for, but it permits modeling of arbitrary end-use energy requirements and forecasting beyond 2030. Applying the Building End-Use Loads Forecaster to extreme end-use demands (e.g., ones that might characterize diffusion of ultra-efficient buildings) can deliver scenarios that would be impossible to implement within the rigid constraints of NEMS itself.

The High-Demand Baseline is based on a standard EIA NEMS reference case, so the end-use energy consumption is available directly from NEMS. The current end uses available in NEMS are shown in Table H-9.

Table H-9. National Energy Modeling System End Uses by Sector

Residential	Commercial
Heating (primary)	Heating
Cooling	Cooling
Water Heating	Water Heating
Cooking	Ventilation
Clothes Dryers	Cooking
Refrigerators	Lighting
Freezers	Refrigeration
Lighting	Office Equipment (PC)
Other	Office Equipment (non-PC)
Heating (secondary)	Other

The Low-Demand Baseline energy forecast was conducted independently of NEMS. In this case, the Building End-Use Loads Forecaster was used to forecast loads for the two end uses to match the energy forecast.

Appendix I. Development of Industrial Load Curves and Hourly Schedules

High-demand industrial demands provided to ReEDS were based on the electricity sales to industry reported in the AEO Reference Case (EIA 2009d) with a simple extrapolation beyond 2030. The low-demand industrial demand forecast, however, is derived in a quite different manner. It is based on a second HR2454Cap NEMS Case,[58] which, as its name suggests, includes a carbon cap and trade policy roughly equivalent to the provisions of the Waxman-Markey Climate Bill from 2009. Given that this case would evoke a significant efficiency boost, RE Futures believes its consumption level represents a reasonable energy efficiency trajectory, and it is adopted as the Low-Demand Baseline—but it does not include a carbon cap. Because NEMS only models through 2030, the demands were extrapolated to 2050 using the 2020–2030 growth rate. Additional calculations explained within Appendix M found the results for each North American Electric Reliability Corporation (NERC) region and converted them to hourly profiles.

Determination of Efficiency Change between High-Demand and Low-Demand Baselines

To further understand the changes in industrial electricity demand, RE Futures determined the electricity purchases for each of the 19 industrial sectors that NEMS models. Figure I-1 and Figure I-2 show the demands for each of the scenarios. In both scenarios, the bulk chemicals sector reduces its power purchases significantly over time, while several other smaller markets also contribute to the decline. In the Low-Demand Baseline, Paper Products show the most significant reductions on a terawatt-hour basis versus the High-Demand Baseline, followed by balance of manufacturing, mining, and refining. The sector growth rates between 2010 and 2030 provide insight into which industrial sectors grow or shrink the most (Figure I-1and Figure I-2). Table I-1 summarizes the growth rates by sector for the period 2020–2030.

[58] This is the Basic Case described in EIA 2009b.

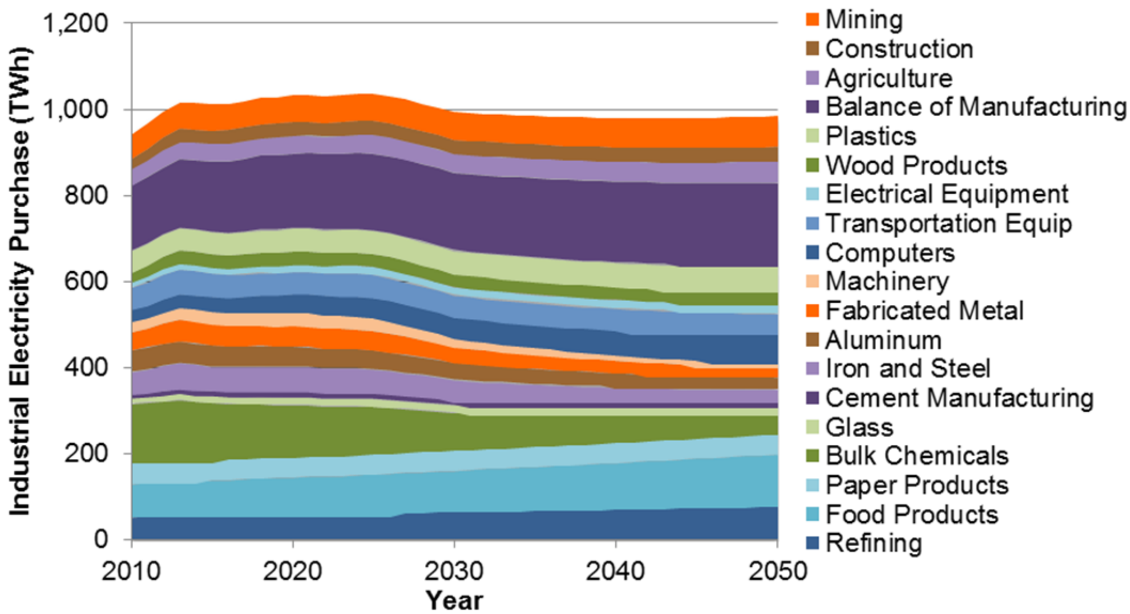

Figure I-1. Industrial electricity purchases by sector in the High-Demand Baseline

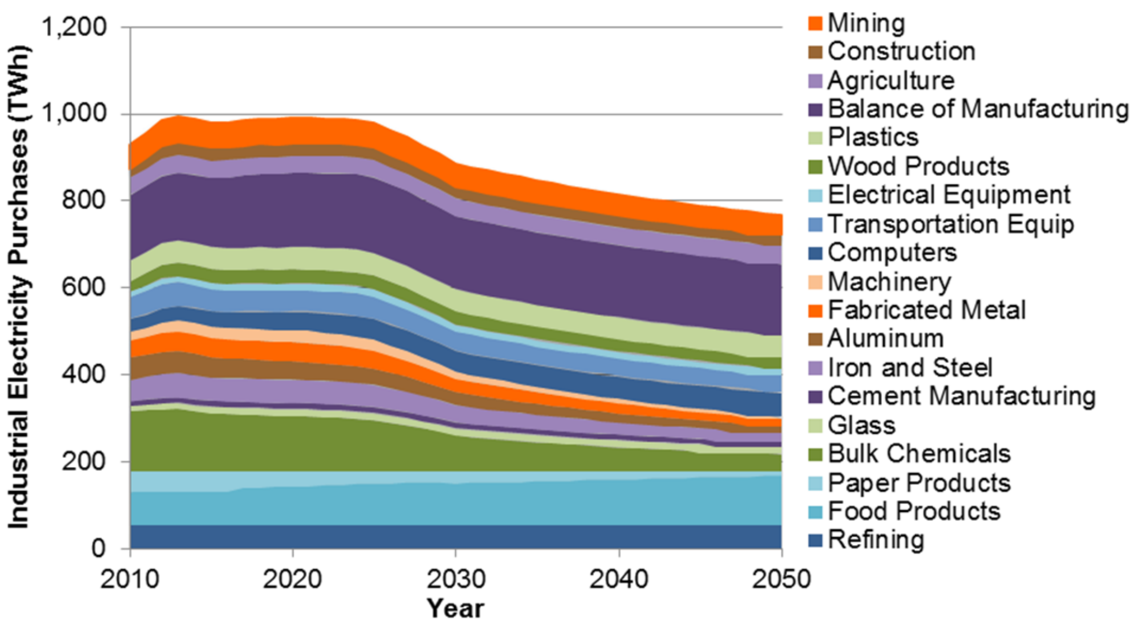

Figure I-2. Industrial electricity purchases by sector in the Low-Demand Baseline

Table I-1. Electricity Purchases Annual Growth Rates for Each Industrial Sector, 2020–2030

Sector	High Demand	Low Demand	Difference
Refining	0.9%	0.2%	-0.7%
Food Products	1.2%	0.7%	-0.4%
Paper Products	0.1%	-3.2%	-3.3%
Bulk Chemicals	-3.3%	-3.9%	-0.6%
Glass	0.2%	-0.2%	-0.4%
Cement Manufacturing	0.0%	-0.8%	-0.8%
Iron and Steel	-2.3%	-3.0%	-0.7%
Aluminum	-1.9%	-3.4%	-1.5%
Fabricated Metal	-2.4%	-3.0%	-0.5%
Machinery	-4.2%	-5.0%	-0.8%
Computers	1.6%	0.9%	-0.7%
Transportation Equipment	-0.1%	-0.8%	-0.7%
Electrical Equipment	0.3%	-0.3%	-0.6%
Wood Products	-0.2%	-0.6%	-0.4%
Plastics	0.4%	-0.1%	-0.5%
Balance of Manufacturing	0.4%	-0.1%	-0.5%
Agriculture	0.7%	0.2%	-0.5%
Construction	0.2%	-0.4%	-0.5%
Mining	0.5%	-0.8%	-1.3%
Total	-0.4%	-1.1%	-0.7%

While the above analysis shows the change in electricity purchases by each sector, a different question arises: How much of this change is due to efficiency and how much is due to reduced production? NEMS provides data on shipments from each sector, so evaluating trends in energy per dollar of shipment should show the relative efficiency gains for each sector. The two figures below show the change in electricity use per dollar output for each of the 19 sectors. All have declining lines except Aluminum, which declines early in the period but then rises post-2024 because the value of shipments drops faster than the electricity amount used. Refining shows a smaller increase because its electricity use increases faster than the value of shipments. Continuation of the 2020–2030 trend to 2050 further increases its electricity purchases per dollar of output. (Values for 2000–2001 are not in the NEMS results for most sectors.)

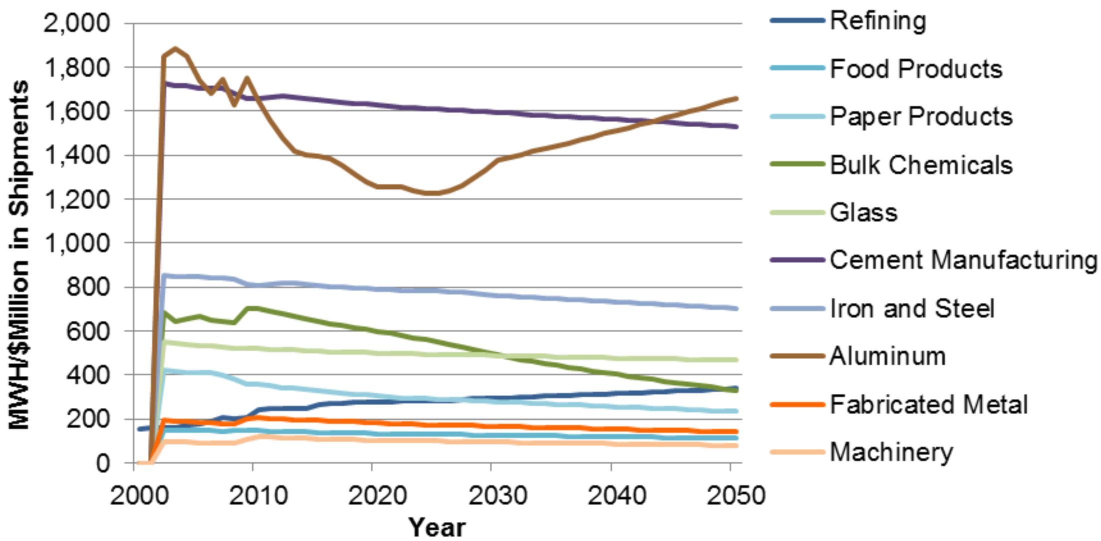

Figure I-3. Sectors' electricity purchased per dollar output from the High-Demand Baseline (Industries 1–10)

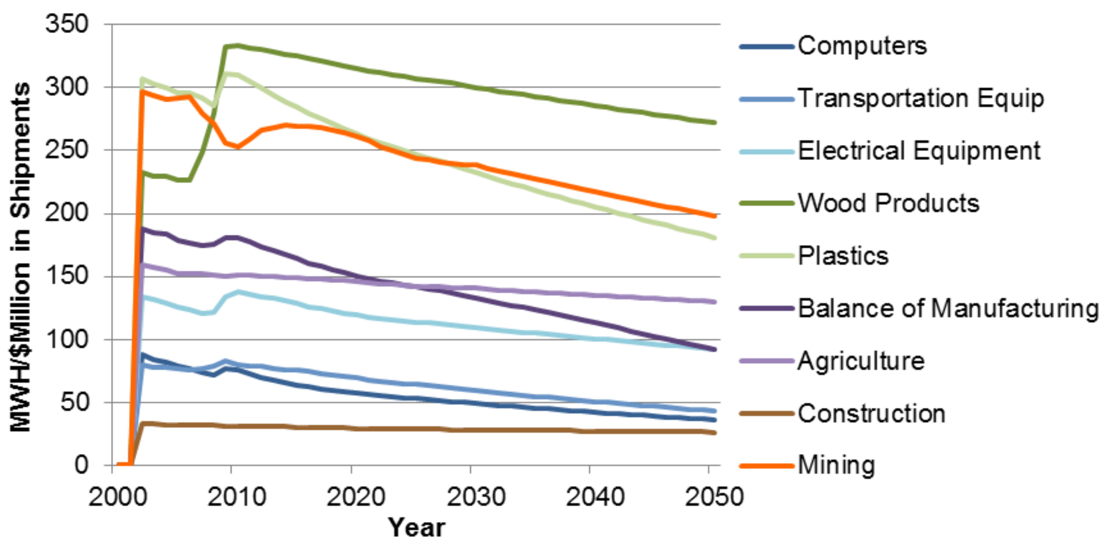

Figure I-4. Sectors' electricity purchased per dollar output from the High-Demand Baseline (Industries 11–19)

The Low-Demand Baseline results show very similar trends to the curves in Figures I-3 and I-4. Rather than repeat the curves, Table I-2 compares the ratio of the purchased electricity per shipment between the two scenarios. Through 2030, most of the sectors show an improvement in efficiency of less than 10% over and above that in the High-Demand Baseline. Paper products show the biggest decrease in purchased electricity at 40% by 2030.

Table I-2. Reduction in Low-Demand Purchased Electricity per Shipment Values versus High Demand

Sector	2010	2020	2030	2040	2050
Refining	0%	1%	-3%	-7%	-11%
Food Products	-1%	0%	-4%	-7%	-11%
Paper Products	-1%	-16%	-40%	-57%	-69%
Bulk Chemicals	-1%	0%	-6%	-11%	-16%
Glass	0%	-3%	-7%	-10%	-13%
Cement Manufacturing	0%	-7%	-12%	-18%	-23%
Iron and Steel	0%	-3%	-6%	-9%	-13%
Aluminum	-1%	-7%	-7%	-7%	-7%
Fabricated Metal	-4%	-5%	-8%	-11%	-15%
Machinery	-9%	-9%	-13%	-17%	-21%
Computers	-1%	-2%	-7%	-12%	-17%
Transportation Equip	-1%	-1%	-5%	-10%	-14%
Electrical Equipment	-4%	-5%	-8%	-11%	-14%
Wood Products	0%	0%	-2%	-4%	-6%
Plastics	-1%	-2%	-5%	-9%	-12%
Balance of Manufacturing	-1%	-2%	-6%	-10%	-14%
Agriculture	0%	-4%	-9%	-13%	-17%
Construction	0%	-5%	-9%	-13%	-17%
Mining	-1%	-5%	-10%	-15%	-19%

Note: Values are calculated as: (MWh/Million $ shipment from Low Demand) / (MWh/Million $ shipment from High Demand)

Industrial and Non-PEV Sector Loads

Several resources were used to create the set of demand curves for each region. The industrial and non-PEV transportation loads were calculated through applying all sectoral loads from EIA NEMS runs to the regional hourly load shapes from 2006. The resulting industrial and non-PEV transportation amounts were kept for the final analysis while the residential and commercial sectoral loads were overridden with the results from Appendix H.

Extrapolation of National Energy Modeling System Reference Run Sectoral Demands, 2030–2050

RE Futures compiled and ran the ftab.exe program provided with NEMS archives to generate electric power projections for each NERC region (Table I-3). For the High-Demand Baseline, the updated 2009 AEO Reference Case, called “stimulus,” was used because it includes the effects of recent economic activities and the Recovery Act (EIA 2009d). For the Low-Demand Baseline, the basic scenario from the EIA analysis of HR2454 (EIA 2009b) was used. Because NEMS only runs to 2030, the annual growth rate was calculated between 2020 and 2030, and that factor was applied to extrapolate to 2050. These were applied to three categories of factors: the net energy for load, electricity sales by sector, and electricity prices by sector. Because the NEMS report shows sectoral sales only after transmission and distribution losses, the values need to be raised by the ratio of the net energy for load to the sum of sectoral sales.

Use of Hourly Loads from Utilities to Establish North American Electric Reliability Corporation Region Hourly Loads

Each year, utilities report their hourly loads for the previous year to FERC in their FERC 714 report. The 2006 and 2007 data were downloaded and converted for many utilities across the United States as part of a study on extended Daylight Saving Time (Belzer et al. 2008). Each utility was tagged according to the NERC region to which it belongs and then the utilities' data were summed for each hour for each region. The resulting sum was then "ratioed" to the regional net energy for load from the NEMS run for 2006 and then adjusted further by the growth in the net energy for load to any given from 2006. This created an adjustment factor for each hour that would create an initial hourly system load for each region for any year.

Determination of Template Load Factors for Each Sector from Electric Power Research Institute

The load factor is the ratio of the average load to the peak load. The system load factor can be found from the hourly loads determined in the previous section, but the load factors for each end-use demand sector can differ from this value. Typically, the residential sector has the lowest load factor and the industrial sector has the highest. Residences are not occupied during much of the day and have low appliance demands during the night while industries tend to operate fairly constantly over more hours of the day (and night, if multiple shifts.) Regions with lighter industry may have lower load factors because nighttime use may see lighter loads. Table 3.5 in the EPRI report, *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.* (EPRI 2009) includes a table showing the 2008 residential, commercial, and industrial load factors for the four main regions of the United States (Table I-3).

Table I-3. Load Factors by Sector and Region, 2008

Sector	Northeast	Midwest	South	West	United States
Residential	40%	38%	44%	42%	42%
Commercial	74%	53%	56%	67%	60%
Industrial	49%	87%	69%	59%	68%
Total	53%	53%	53%	54%	53%

Source: EPRI 2009

Conversion of System Load into Load Duration Curve

A load duration curve (LDC) rearranges the hourly loads from highest to lowest so that the curve shows the number of hours that demand exceeded the power level shown. For example, demand by definition meets or exceeds the minimum load 100% of the year; it exceeds the peak load by 0%. Figure I-5 shows a representative set of LDCs for the East Central Area Reliability Coordination region. The load factor described above is equal to the area below the LDC divided by the peak load. For each sector (residential, commercial, industrial, and transportation), the load factors above, along with an estimate of the fractions of the system's demand at minimum and at maximum, were used to estimate the LDCs for each demand sector.

Use of Excel to Determine Load Curves for Each Sector

As can be seen in Table I-3, the sectors can have different load factors.[59] In addition, the system load factor for a region may not necessarily match the values shown in the table. Total electricity sales for each sector must match the amount from NEMS, and the load factors for each sector should approximate the values defined by EPRI, for lack of better data. (The data may not match the EPRI results due to different data years and region definitions between the studies.) Therefore, first, the fractions at minimum and maximum were set for one of the sectors—in this case, the commercial sector—to be equal to one minus the fractions of the other sectors. This ensures that the sum of the sectors' loads equals the system load.

A goal seek function was then used to change the values of the maximum and minimum for each of the sectors so that the area under their LDCs equals the total sales for that sector. Then the difference of the resulting load factor for each was compared to the target load factor from Table I-3. The variance (sum of the square of the difference) of both the load factor and the electric sales was determined for each of the sectors and a Solver routine was used to minimize that variance by altering the percentages and the minimum and maximum. Lastly, those minimum and maximum values were modified so the electric sales match the NEMS values. This defined LDCs for each of the end-use sectors that matched both the LDC template from 2006 and the total sectoral sales from the NEMS run. As an example, Table I-4 shows the factors involved for the East Central Area Reliability Coordination region, while Figure I-5 shows the resulting LDCs. These factors, along with the system maximum and minimum loads, can be used to calculate the hourly demand for the industrial and transportation sectors, based on the corresponding system load.

Table I-4. Load Duration Curve Definition Factors for East Central Area Reliability Coordination Agreement, 2050

Region 1	Residential	Commercial	Industrial	Transportation
% of Peak	43%	39%	17%	0.568%
% of Min	23%	39%	37%	0.568%
Max Power	60,525	54,749	24,111	796
Min Power	12,679	21,874	20,737	316
Calc TWh	255	290	192	4.2
EPRI Load Factor	38%	53%	87%	—
Calc Load Factor	48%	61%	91%	60%

Note: The calculated load factors may not match the EPRI results due to different data years and region definitions between the studies.

[59] RE Futures recognizes that the sectoral load factors are not likely to remain constant throughout the study period because the relative sectoral mix changes over time; however, annual load factor calculations were beyond the scope of this study.

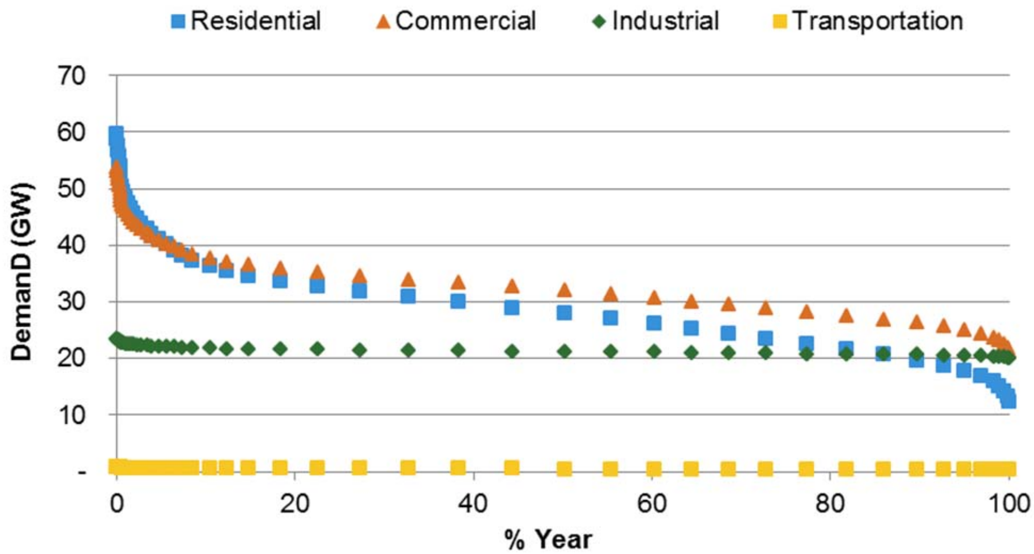

Figure I-5. Calculated load duration curves for East Central Area Reliability Coordination Agreement in 2050

Sectoral 8760 Hour Load Schedules

While the calculations described in the previous section provided hourly loads for all four of the sectors, the residential and commercial sectors did not use the same methodology. The commercial and residential sectors used the load curve methodology from NEMS, as described in Appendix H. Using the sectoral hourly loads for each month and region, hourly loads for the average weekday (Daytype 1), average weekend (Daytype 2), and peak weekday (Daytype 3) were calculated. Values were calculated for 2006, 2008, 2010, and every 5 years thereafter up to 2050. Different demands were calculated for the High-Demand Baseline and the Low-Demand Baseline.

These average values for weekday and weekend are sufficient to calculate the ReEDS time slices. However, they produce the same load shape for every day of the month they represent, and there is no variation due to weather. In order to create a semblance of a fluctuating load demand based on historical data, algorithms were created to modify the loads for individual days depending on the relative system load for the region in that year (using the 2006 load shapes). At the same time, the average for the month was formulated to still match the values calculated earlier and used in the ReEDS work.

As an example, the calculations using the residential data set for 8:00 a.m. 7/11/2020 Region 1 are as follows:

- Find the average and peak system load (Sa and Sp) for 8:00 a.m. on a weekday in July:

Sa = Σ (8 a.m. weekday system loads) / 21 weekdays = 71,701 MW and

Sp = Max (8 a.m. weekday system loads) = 81,082 MW

- Find the average residential load for 8 a.m. on a weekday from the Building dataset:

Ra = (20 x Daytype 1 from dataset + Daytype3 from dataset) / (20+1) = 20,946 MW

Rp = Daytype 3 for the peak day = 23,490 MW

R = [(S - Sa)/(Sp - Sa)] * (Rp - Ra) + Ra

Where:

R = Adjusted Residential Load
S = the system load for any weekday hour in July (70,394 MW on 7/11)
Sa = the average system load for that same hour in July (71,701 MW)
Sp = the peak system load for that same hour in July (81,082 MW)
Ra = average residential load for that hour (20,946 MW)
Rp = the peak residential load for that hour (23,490 MW)

So R = [(70,394 -71,701) / (81,082 – 71,701)] * (23,490 - 20,946) + 20,946

= 20,592 MW

The weekend calculations are a bit simpler (but less accurate) because peaks for the weekend values for residential and commercial are not available, just the average:

R = Adjusted Residential*(weekend) = S/Sa * Ra

So for 8 a.m. on 7/9/2020

R = Adjusted Res = [53,377 / 59,489] * 18,548 = 16,643 MW

Commercial calculations are done similarly.

Because the residential and commercial load shapes from the Buildings analyses do not match the actual load shapes within a given day or month, the resulting system loads (residential + commercial + industrial + non-PEV transportation) do not necessarily match the 2006 load shape template.

Adjustment to Updated National Energy Modeling System Run and Sectoral Energy Intensities

Each of the sector energy intensities were modified, as detailed in the corresponding appendices, and the load growth from the most recently released AEO report were combined to create new expectations of loads for these two regions. Rather than recalculate the daily load shapes for each region for the commercial and residential sectors, the ratio of each sector's new national annual load to its previous national annual load was determined. Each hourly load for the sector and region was then multiplied by that year's value. This implies that within the sector, the changes apply equally to each hour and to every region.

Application of Algorithm to Calculate Hourly Sectoral Demands

Once each sector's hourly loads were calculated as described above, the hourly system load for any year and region could be calculated by summing the individual sectors. Figure I-6 shows the representative load shape for the East Central Area Reliability Coordination region in 2050.

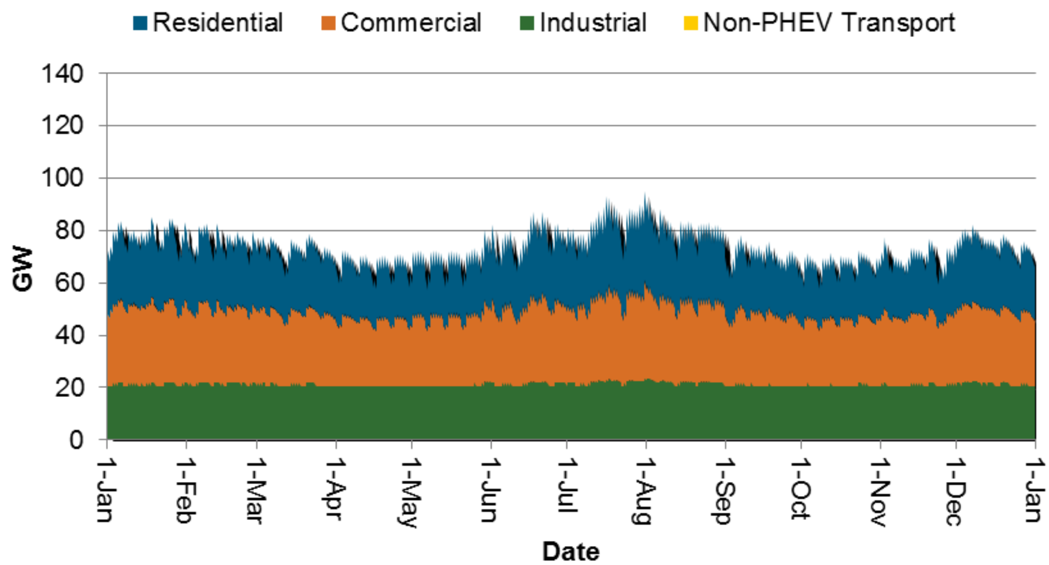

Figure I-6. Calculated hourly loads by sector for East Central Area Reliability Coordination Agreement in 2050, High-Demand Baseline

Average Demands for Each Regional Energy Deployment System Time Slice

The ReEDS model uses only 17 time slices to model the system LDC. Once the hourly loads are known for each sector, the average amount of electricity demand in each time slice can be calculated. The top 40 hours of the summer peak season are pulled out of the summer afternoon slice H3 to make slice H17. Table I-5 shows the resulting time slices for the East Central Area Reliability Coordination for 2050. *The system peak shows the power level in the highest hour and is therefore a bit higher than the average over the top 40 hours.* In addition, the PEV loads are not included in the transportation sector described here. Rather, PEV loads were calculated separately as described in Appendix K.

Table I-5. East Central Area Reliability Coordination Agreement Average Loads for High-Demand Baseline 2050 for Regional Energy Deployment System Time Slices

Slice Name	Hours	Residential	Commercial	Industrial	Transportation	Total
H1	736	21.1	26.7	21.1	0.4	69.3
H2	644	29.4	34.5	21.5	0.5	86.0
H3	328	39.2	39.5	21.9	0.6	101.2
H4	460	38.5	36.5	21.9	0.6	97.4
H5	489	17.5	23.8	20.7	0.4	62.3
H6	427	24.3	29.0	21.1	0.5	74.9
H7	244	27.1	30.5	21.2	0.5	79.3
H8	305	27.0	29.1	21.3	0.5	77.9
H9	960	20.5	26.9	21.0	0.4	68.8
H10	840	27.1	31.1	21.4	0.5	80.0
H11	480	25.4	29.1	21.3	0.5	76.3
H12	600	27.4	30.1	21.5	0.5	79.5
H13	735	18.0	24.6	20.7	0.4	63.7
H14	1,104	25.6	28.7	21.1	0.5	76.0
H15	368	25.6	29.0	21.1	0.5	76.3
H16	40	49.7	44.4	22.8	0.7	117.6
System Peak (GW)		55.7	46.9	23.4	0.8	123.8
Sector Sales (TWh)		222.9	258.2	185.8	4.1	671.0

Appendix J. Combined Cooling, Heating, and Power within the Industrial Sector

The industrial demands provided to ReEDS are based on the electricity sales to industry reported in the NEMS 2009 runs Stimulus (representing the High-Demand Baseline) and HR2454Cap (representing the Low-Demand Baseline). These demands represent the sales (not including transmission and distribution losses) that the electricity sector makes to the industrial sector. Separately, the industrial sector can generate some of its own power needs through dedicated electricity plants or the combined cooling, heating, and power plants. Some of this power generated may also be sold to the electric sector for sale to other sectors. As with the industrial demand for grid-based electricity, NEMS also provides a forecast of industrial end-use (or on-site) generation. This appendix attempts to quantify the NEMS results in more detail. Total industrial electricity demand is the sum of purchased electricity and electricity generated less electricity sold to the grid. Figure J-1 shows the gross industrial demand (including the generation used internally) and the net demand (the amount purchased from the electricity sector and used in ReEDS).

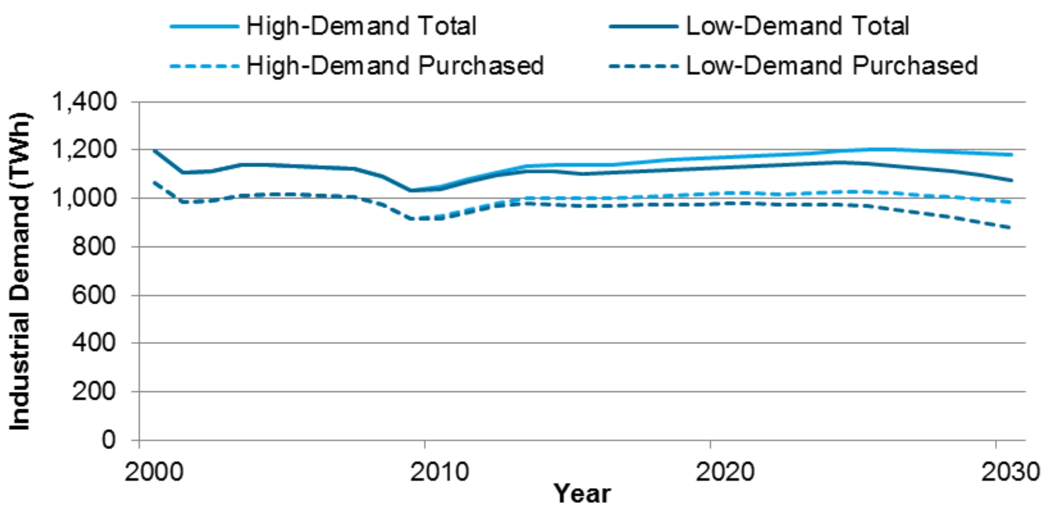

Figure J-1. Industrial electricity demands before and after internal generation (TWh)

Industrial end-use generation (both dedicated and cooling, heating, and power production) is calculated for each of the major industrial sectors in NEMS (Figure J-2). The bulk of the generation comes from three sectors: refining, paper production, and bulk chemical production. Under the Low-Demand Baseline, refining and paper products show some increase in production by 2030, but the others show slight decreases.

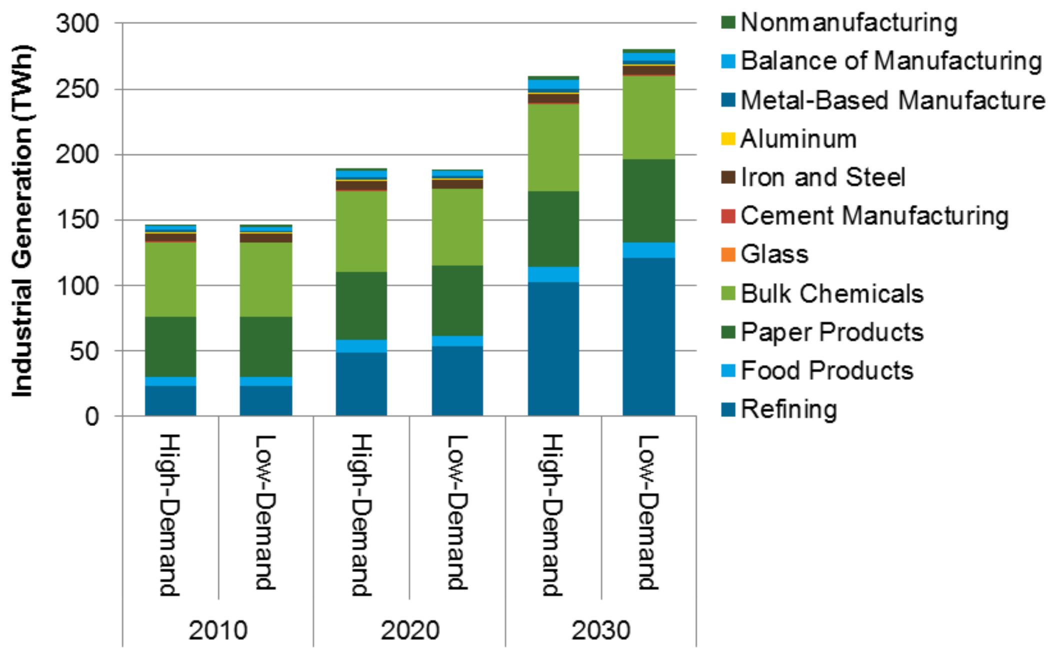

Figure J-2. Industrial sector electricity generation for High-Demand and Low-Demand Baselines (TWh)

End-use generation as a percentage of total demand increases over time in both scenarios, with a larger increase in the Low-Demand Baseline (Figure J-3). The top lines show the total generation by industry, but some of this generation is sold to the grid. The bottom set of lines show the generation that is used internally, with the difference being the amount sold to the grid. As can be seen, both the internally used generation and the amount sold to the grid increase over time, with a higher growth under the Low-Demand Baseline.

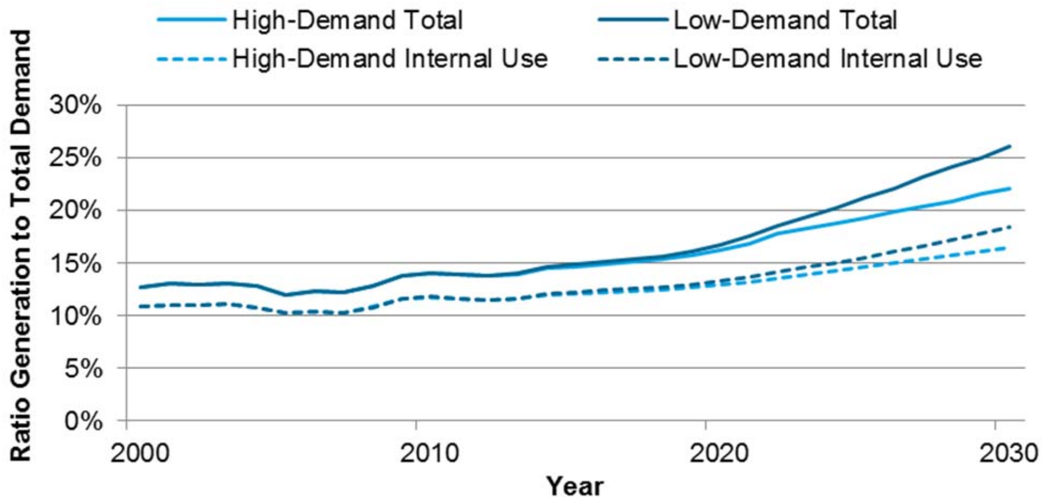

Figure J-3. Industrial generation as a fraction of industrial demand

The fuels used for the generation are a mixture of fossil energy and renewable resources (Figure J-4). NEMS does not break down the renewable resources for the industrial sector alone, but does for all end-use sectors (residential, commercial, and industrial) (Figure J-5). In the early years, most end-use generation is from industrial sources with only 10 TWh from non-industrial sources, but by 2030 about 60 TWh of electricity is produced by the residential and commercial sectors. The Low-Demand Baseline has higher end-use generation because that lowers overall energy demand (being more efficient) and also lessens grid-based electricity requirements, the focus of this study. The ReEDS analysis would create a different mix of fuels to be used for generation due to the difference in costs and modeling involved in the two studies. It is also important to note that carbon capture and sequestration may be difficult to do for these widely dispersed and relatively small-scale uses of fossil energy to generate on-site power.

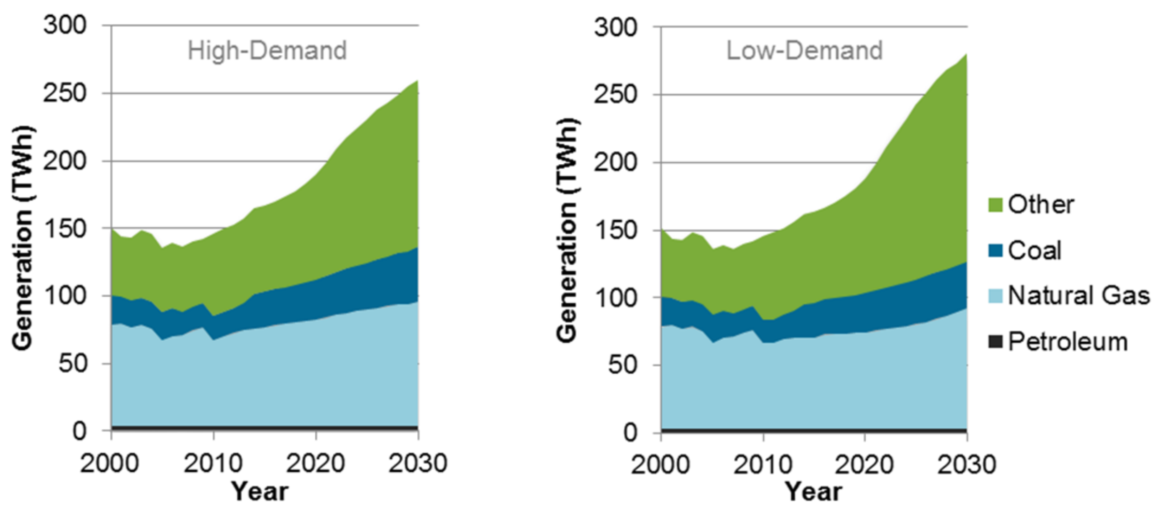

Figure J-4. Fuels used for industrial on-site generation (TWh)

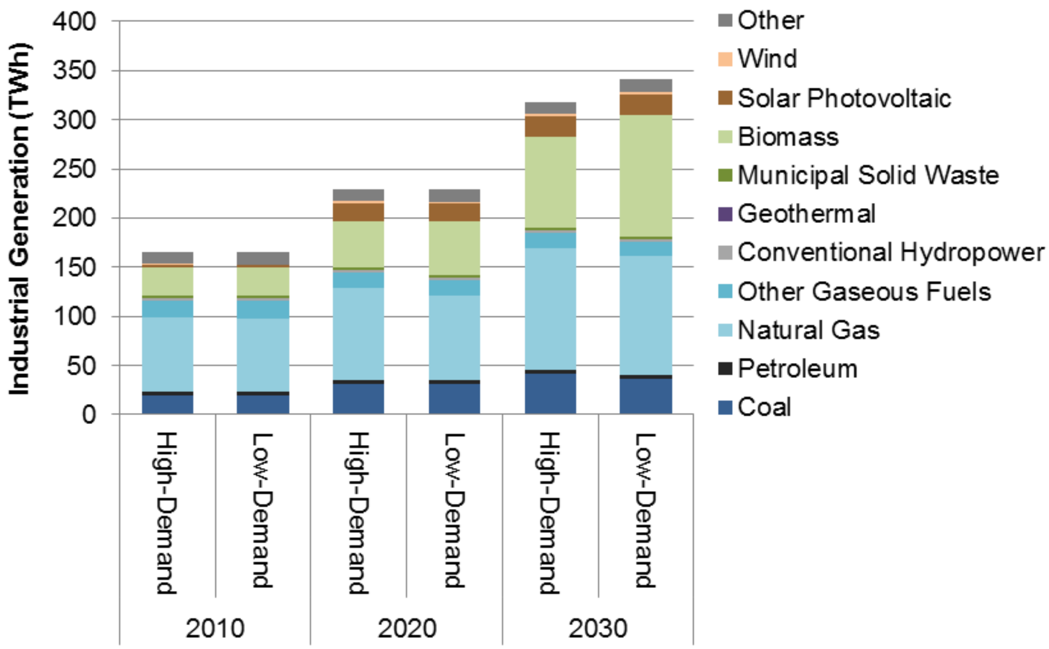

Figure J-5. Fuel sources used for all end-use generation (TWh)

The industrial generation that is sold to the grid, either from cooling, heating, and power or from their dedicated plants, is not captured in the ReEDS analysis. By 2030, this equals 83 TWh in the Low-Demand Baseline. However, this represents less than 2% of total electricity demand in that year. The generation used internally is not explicitly captured either. Rather, the industrial demands are reduced by this generation within the NEMS results, and only the industrial requirements placed on the electricity sector are fed to ReEDS (Figure J-6).

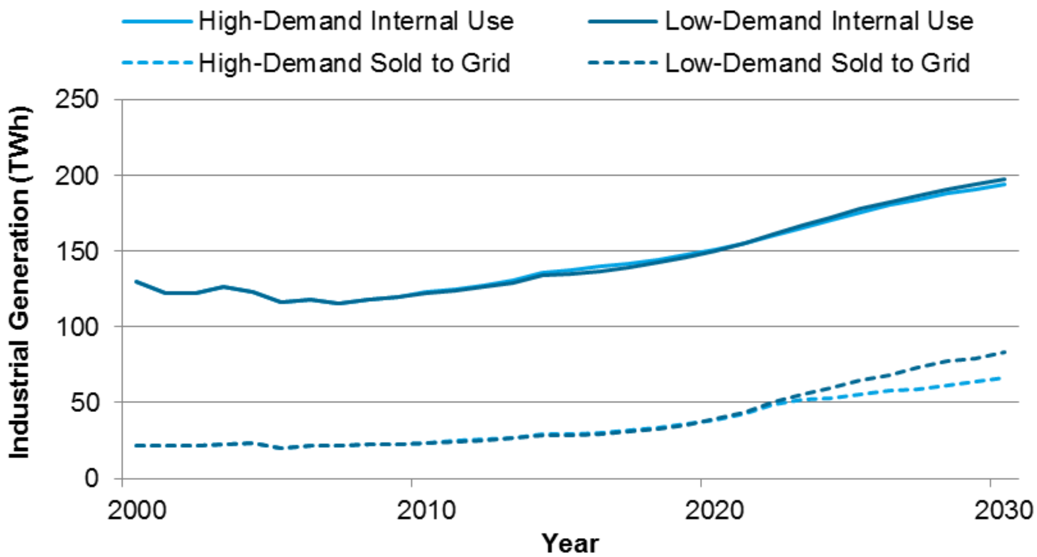

Figure J-6. Industrial generation used internally or sold to the grid (TWh)

Similarly, the generation from the other end-use sectors is not directly captured in ReEDS. Some of this may be captured as a reduction in demand on the grid. Of course, the other end-use sectors' demands are not based solely on the NEMS scenarios but rather involve a build-up of demands from end uses. Especially, the fuel sources used in the ReEDS analysis will be different from the NEMS results due to the different assumptions about and modeling of these technologies.

Appendix K. Transportation Electrification Load Development

Electrification of the transportation sector offers the opportunity to significantly reduce petroleum consumption. The transportation sector accounts for 70% of U.S. petroleum consumption. The transition to electricity as a fuel will create a new load for electricity generation. In support of a high renewable electricity generation scenario analysis, regional hourly load profiles for electrified vehicles within the time frame of 2010—2050 were created. The transportation electrical energy was determined using regional population forecast data, historical vehicle per capita data, and market penetration growth functions to determine the number of PEVs in each analysis region. To represent a bounding case, a single market saturation scenario of 50% of sales being PEVs consuming on average approximately 6 kWh per day was considered. Results were generated for 3,109 counties and were consolidated to 134 BAs for the use in regional generation planning analysis tools. PEV aggregate load profiles from previous work were combined with vehicle population data to generate hourly loads on a regional basis. A transition from consumer-controlled charging toward utility-controlled charging was assumed such that by 2050, approximately 45% of the transportation energy demands could be delivered across four daily time slices under optimal control from the utility perspective. No other literature has addressed the potential flexibility in energy delivery to electric vehicles in connection with a regional power delivery study. This electrified transportation analysis resulted in an estimate for both the flexible load and fixed load shapes on a regional basis.

Introduction

PEVs offer the opportunity for the transportation sector to significantly reduce petroleum consumption through electrification. PEVs may have a moderately sized energy storage system and a combustion engine to ensure most miles are electrified while retaining the range capability of today's vehicles. Other PEVs may be entirely battery dependent and provide complete petroleum displacement for certain vehicle sectors. As of 2010, the timeline for vehicle introduction was to start in 2011 with several manufacturers adding to the options over a 2–3-year period toward market creation. Based on past technology markets, maturity would likely occur within 25–30 years from introduction.[60]

Infrastructure for delivering electricity to these vehicles is also under development. For short-range vehicles, common 110-volt service outlets would generally suffice while owners of vehicles with longer range will likely prefer moderate charge rates from 240-volt service. From a utility perspective, 110 volts or level I (typically 1.4 kW) charging has limited impact on infrastructure but has less value than a flexible load. Vehicles and infrastructure delivering 240 volts or level II (typically 6 kW to 7 kW) charging offers more opportunity for load shaping and management because individual vehicle needs can be delivered and scheduled optimally to match generation opportunities.

Many analyses have been conducted and papers published that include PEV market projections. Electric Power Research Institute and Natural Resources Defense Council collaborated on a

[60] Penetration curves of common products can be seen at http://people.hofstra.edu/geotrans/eng/ch1en/conc1en/telecomdiffusionUS.html.

foundational study highlighting the nationwide greenhouse gas and pollutant emissions impacts of PEVs on the U.S. electricity grid on a regional basis (EPRI 2007). The fleet makeup assumed approximately 40% PEVs by 2030 and 60% by 2050. An aggregate hourly load profile was assumed in which 74% of the energy was delivered during the off-peak period and 26% during the daytime. Both Scott et al. (2007) and Hadley and Tsvetkova (2008) have assessed regional PEV penetrations and future load characteristics. Belzer (2009) considered the situation in which all of the electric vehicle loads could be managed and fit into the low points of the daily utility load curve (Scott et al. 2007). Hadley and Tsvetkova (2008) considered a variety of charge levels and loading scenarios to understand their regional capacity and emissions impacts. This work expands upon past activities to uniquely define both a transitioning fixed load for the transportation sector and a load portion that can be dynamically managed by utilities for integration with high renewable energy integration analyses.

Approach

As input to RE Futures, an hourly PEV load profile and energy demand for the fleet of PEVs by region over time was developed. The approach was as follows:

1. Use population growth forecasts and historical vehicle ownership trends to estimate vehicle population by region.
2. Use a market evolution model to estimate the fraction of vehicles that will be PEVs throughout the study period.
3. Develop a vehicle fleet energy demand profile based on those from past studies that transitions from market introduction with no utility control to one in which the utility is able to manage a portion of the vehicle load.

In developing the electrified transportation loads and energy requirements, the following simplifying assumptions were made:

1. There will be no significant change in transportation mode selection and miles driven. Personal vehicles will continue to be the mode of choice. As a result, loads due to mass transit are neglected.
2. Transportation electrical energy demands will not vary significantly in amount or timing between seasons of the year. PHEVs are expected to make up the majority of the stock, meaning that electrical energy is likely to provide the majority of, but not all of, the energy needed. The hybrid combustion engine would likely make up any limitations of the electric drive system, and would therefore allow the vehicle owner to go beyond the electric range without any mileage limitations.
3. The PEV fleet load shapes are based on historical consumer travel survey data and assume 110-volt, 1.4-kW charge rates from widespread infrastructure. Level II, 240-volt charging, was not considered for the loads not under utility control. Level II charging may be necessary to achieve the utility-managed flexible loads assumed.
4. PEV load curves are based on PEVs with 20 miles of electric range and urban power capability. On average, this results in approximately 6 kWh of energy per PEV per day. Some vehicle designs and some vehicle usage profiles may use more or less energy.

5. Cars and pickup trucks were assumed to have similar energy needs expressed as mile-per-gallon fuel consumption.
6. No vehicle-to-grid or grid services functions are specifically considered. The utility-controlled vehicle loads could be considered controlled as a grid service tool.
7. It has been assumed that there are no differences in regional penetration rates.
8. There is no differentiation in the growth rate among counties in the same state.

Results Analysis

Data on population growth projections to 2030 by state available from the U.S. Census Bureau provide the starting point for projecting the energy demands of electric vehicles. Figure K-1 shows the consolidated growth rates for the nine census regions (U.S. Census Bureau 2005). The projections for each state were fit with either a linear or quadratic function, whichever provided the best fit and extended to 2050. Table K-1 highlights the states with the least and greatest calculated rates of change in population growth between 2010 and 2050.

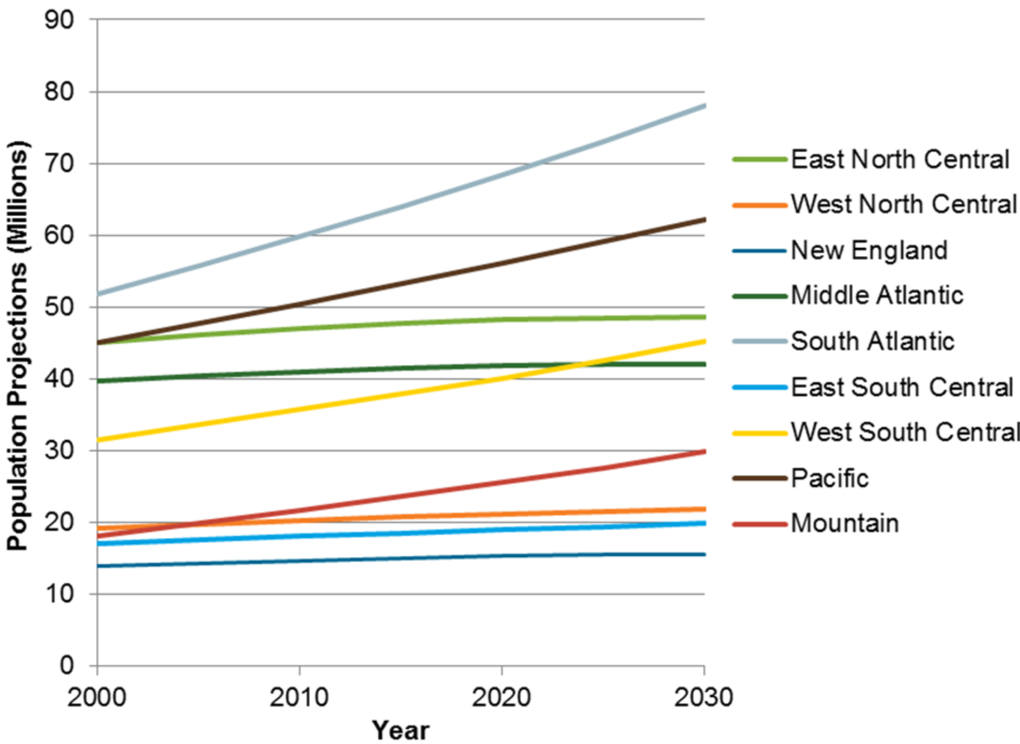

Figure K-1. Regional population projections to 2030 (U.S. Census)

Table K-1. Ten States with Least and Greatest Percent Change in Population, 2010–2050

Least Percent Change		Greatest Percentage Change	
State	**Population Change 2050 Relative to 2010 (%)**	**State**	**Population Change 2050 Relative to 2010 (%)**
District of Columbia	65	Nevada	211
West Virginia	77	Arizona	209
Iowa	87	Florida	185
Wyoming	88	Texas	166
North Dakota	94	Utah	163
Ohio	94	Idaho	159
New York	95	North Carolina	159
Pennsylvania	105	Washington	154
South Dakota	108	Georgia	153
Nebraska	108	Oregon	149

Using data from a Polk database query, 2005 county population measurements were extended to estimate county population between 2010 and 2050 using the state-level population growth trends. It was assumed that all counties within a state grow at the state rate.

The population estimates on a county basis were then scaled to estimate the number of motor vehicles on a county basis. Historical data from the Federal Highway Administration present the number of motor vehicles per capita between 1960 and 2007 (FHA 2007). The past 20–30 years of data fit a logarithmic function. This trend suggests that between 2010 and 2050, the number of motor vehicles per capita is likely to grow from just more than 0.8 to a little more than 0.9 motor vehicles per person.[61] These analyses are summarized in Figure K-2.

[61] The possibility of vehicle saturation within the United States was not considered here.

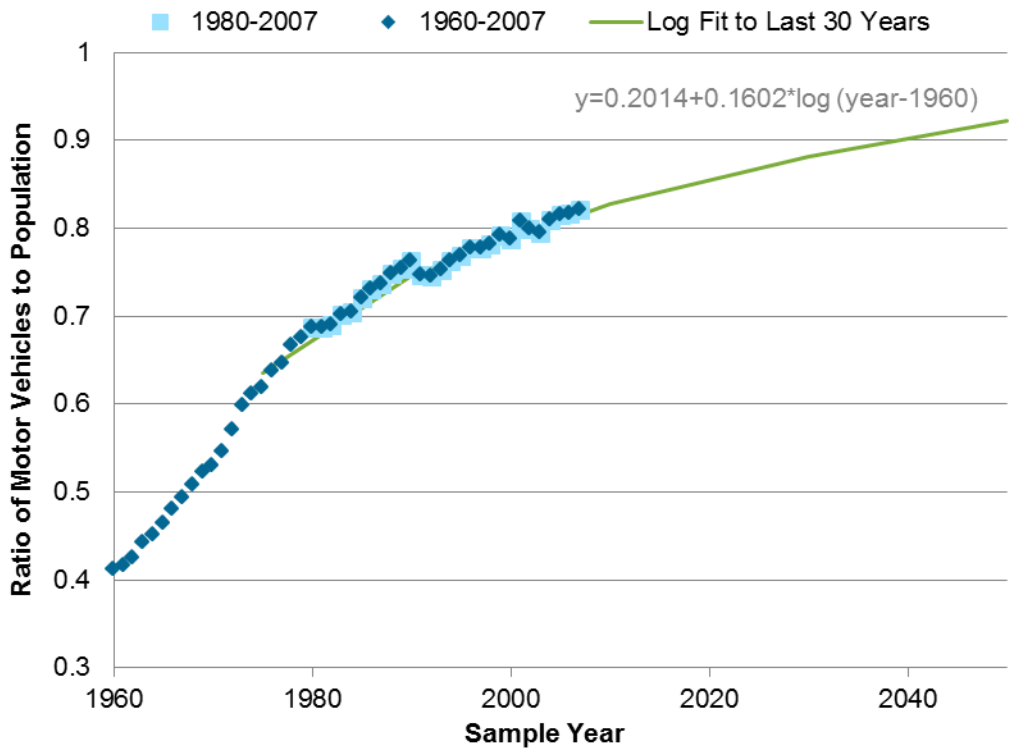

Figure K-2. Historical and projected motor vehicles per capita (FHA 2007)

A PEV market growth and saturation model was used with the motor vehicle estimates to determine the number of PEVs likely to be in use on a county level over the time period of the study. The market model represents a slow ramp toward consistent market growth and a final tapering of growth to saturation. The model used is represented with the following equation:

$$N(t) = \frac{\kappa}{1 + \exp(-\frac{\ln(81)}{\Delta t}(t - t_m))}$$

Where:

$\kappa =$ maximum market share potential

$\Delta t =$ time to grow from 10% to 90% of potential (years)

$t_m =$ year in which 50% of potential is reached

A single bounding scenario was defined in which the sales of PEVs saturate at a 50% market share after approximately 50 years. The parameter values for this scenario are shown in Table K-2. A comparison of the sales rates, vehicle stock, and historical hybrid electric vehicle sales shifted by introduction year are shown in Table K-2. The rates in this scenario are consistent with results recently developed by Zenhong Lin and David Greene (Lin and Greene 2010).

Table K-2. Market Penetration Model Parameter Values for Plug-in Electric Vehicles

Parameters	Value
κ	50%
Δt	30
t_m	25

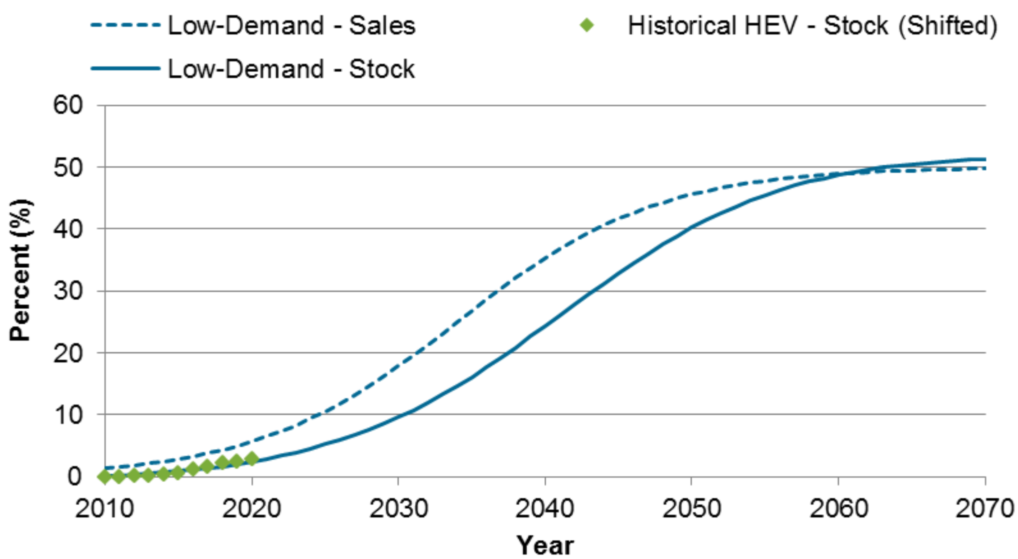

Figure K-3. Market penetration for plug-in electric vehicles

It is possible—using the PEV market models, number of vehicles per capita, and county population estimates—to calculate the number of PEVs on a county and state basis. Table K-3 summarizes the PEV population estimates for several points in time on a state level for those states with the greatest number of PEVs. The vehicles in these 15 states highlighted comprise nearly 70% of the total U.S. PEV population. The PEV population growth trend for these 15 states is shown in Table K-3. The resulting shape is a function of both population growth and PEV market growth and saturation (Figure K-4).

Table K-3. United States and Top 15 States with Stock Distribution of Plug-in Electric Vehicles (millions)

State	2010	2030	2050	2050 Percent of United States	2050 Cumulative Percent
United States	0.283	31.07	154.43	100	—
California	0.035	4.01	20.58	13.32	13.32
Texas	0.023	2.85	15.49	10.03	23.36
Florida	0.018	2.45	13.83	8.96	32.32
New York	0.018	1.67	6.88	4.45	36.77
North Carolina	0.009	1.04	5.55	3.59	40.36
Georgia	0.009	1.05	5.55	3.59	43.95
Illinois	0.012	1.17	5.33	3.45	47.41
Arizona	0.006	0.89	5.26	3.41	50.81
Pennsylvania	0.011	1.10	4.93	3.19	54.01
Virginia	0.007	0.85	4.36	2.83	56.83
Michigan	0.010	0.93	4.26	2.76	59.59
Ohio	0.011	0.99	4.08	2.64	62.23
New Jersey	0.008	0.84	4.01	2.60	64.83
Washington	0.006	0.73	3.87	2.51	67.33

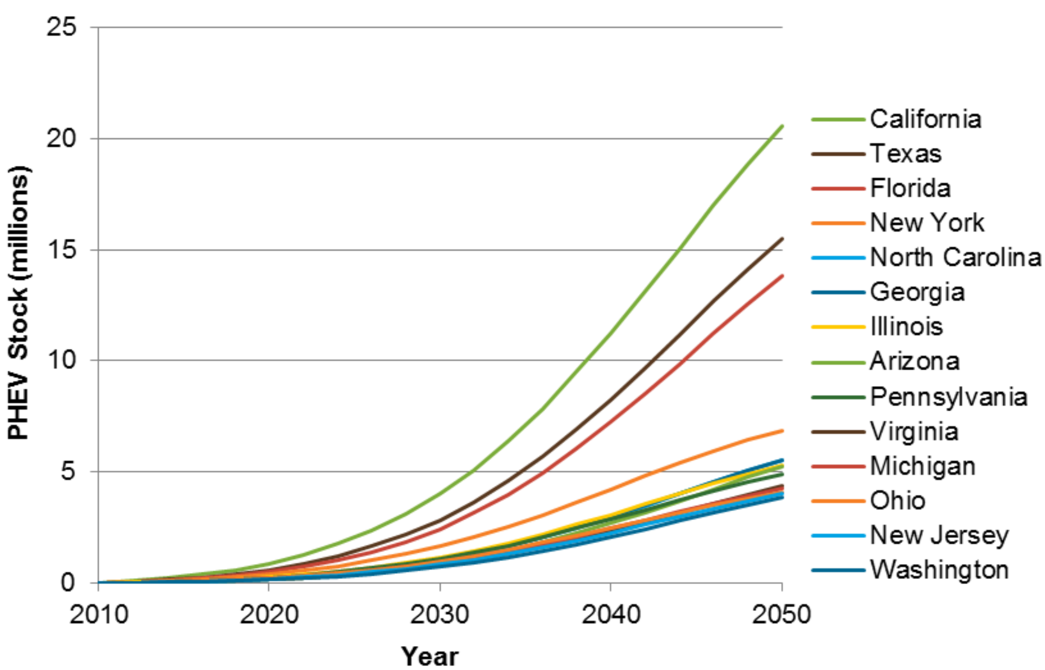

Figure K-4. Growth trends of stock in plug-in electric vehicles for states with greatest plug-in hybrid electric vehicle population in 2050

Hourly load shapes for PEVs have been presented in several locations (EPRI 2007; Scott et al. 2007; Hadley and Tsvetkova 2008). RE Futures used three profiles from previous work based on detailed vehicle system simulations using second-by-second vehicle speed and trip profile characteristics collected using global positioning system units on board a vehicle. These data were collected under a periodic household travel survey from the St. Louis metropolitan area and were based on 227 24-hour driving profiles for unique vehicles. Three scenarios defined in previous work (Parks et al. 2009; Markel et al. 2009) were applied and are shown in Figure K-5. In the first case, the consumer is allowed to plug in and charge as soon as the vehicle ends the last trip for the day. This case is called No Utility Control because the vehicle load occurs on consumer demand and charges until complete or the consumer starts another trip. A second scenario is labeled Opportunity, and under this case, it is assumed that charging infrastructure is prevalent and the consumer will choose to plug in anytime the vehicle is parked regardless of stop duration. This scenario leads to significantly more fuel savings but also increases the daytime electric vehicle loads, total energy demands, and potential battery wear. Finally, a Valley Fill/Managed scenario is used. Originally, this scenario was implemented such that the utility had full control to deliver the daily energy needs as best fit with the evening low point of a typical daily utility load curve. However, as it pertains to the high renewable penetration case, it may be most beneficial for a utility to charge vehicles at times scattered throughout the day. As a result, the Valley Fill/Managed load curve is used to create an energy demand that must be met during the day but no constraints have been placed on it regarding when during the day it must be delivered. Both the No Utility Control and Opportunity scenarios assumed 110-volt, 1.4-kW charge rates while the Valley Fill/Managed curve allowed 3-kW charging to match best the energy demands with the utility valley shape.

It was assumed that over the duration of RE Futures, utilities would find managed charging of vehicles to be of value to system operations and therefore drivers would be incentivized toward participating in a managed charging program. Initially, all consumers would charge at home without utility controls and as public infrastructure is created and consumers learn to optimize the value of their investment in vehicle technology, the growth of the opportunity charging would occur. The transition between the three scenarios over time is summarized in Figure K-6.

Figure K-7 shows how the average per vehicle energy demand grows slightly over time due to the increasing portion of the vehicles that are being Opportunity charged. It also shows that the Valley Fill/Managed portion of total vehicle energy demands grows to approximately 45% of the total energy demands by 2050.

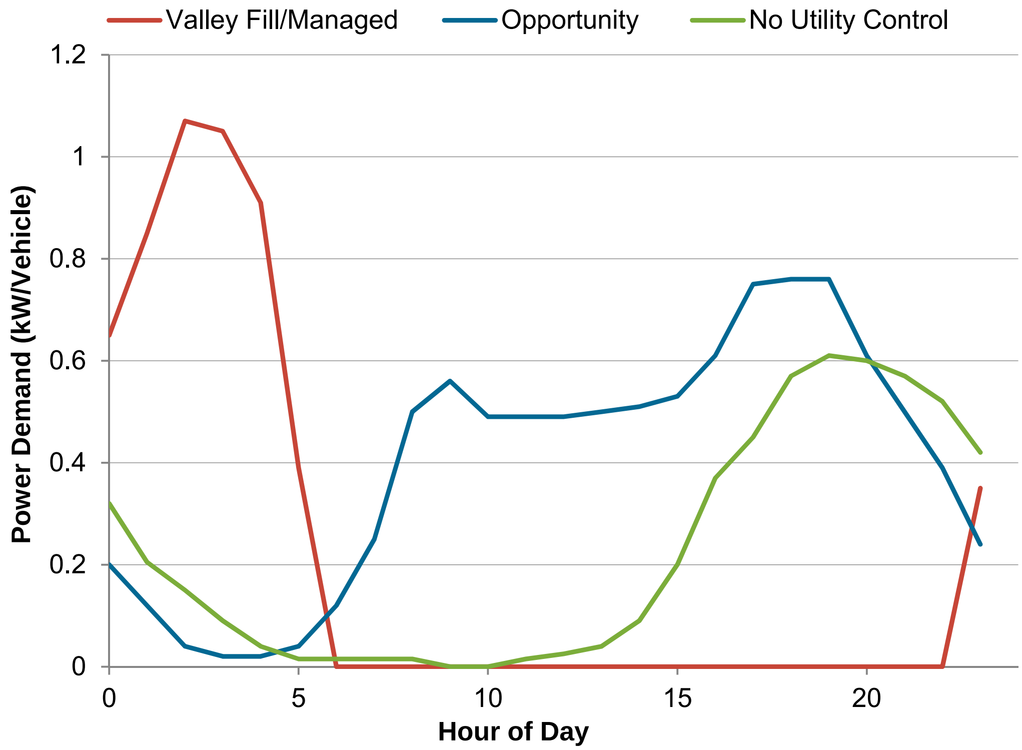

Figure K-5. Three fleet charging profiles for plug-in electric vehicles based on 227 driving profile vehicle simulation results

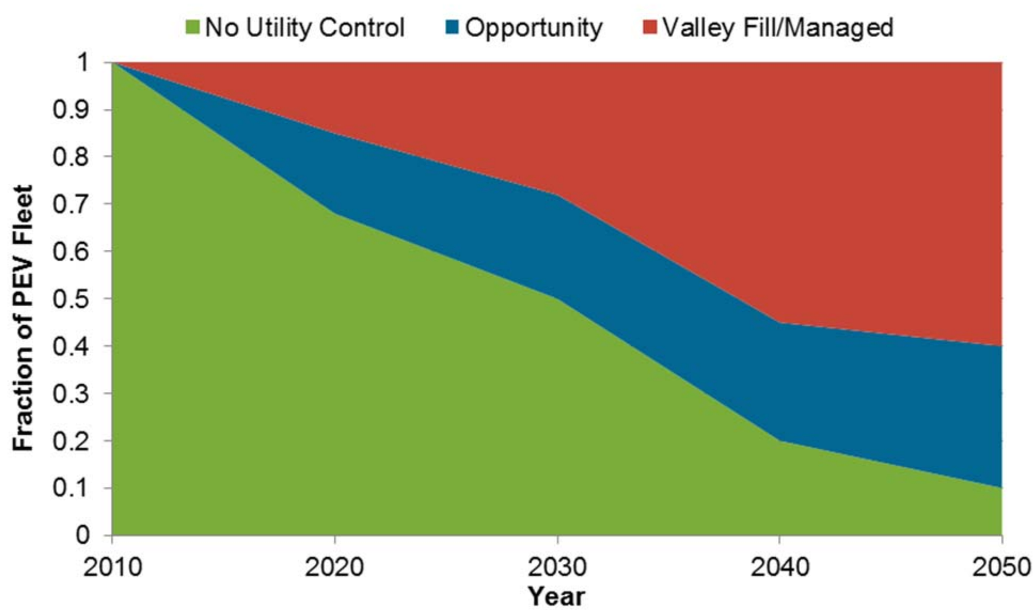

Figure K-6. Transition assumptions from No Utility Control to Opportunity and Valley Fill/Managed scenarios

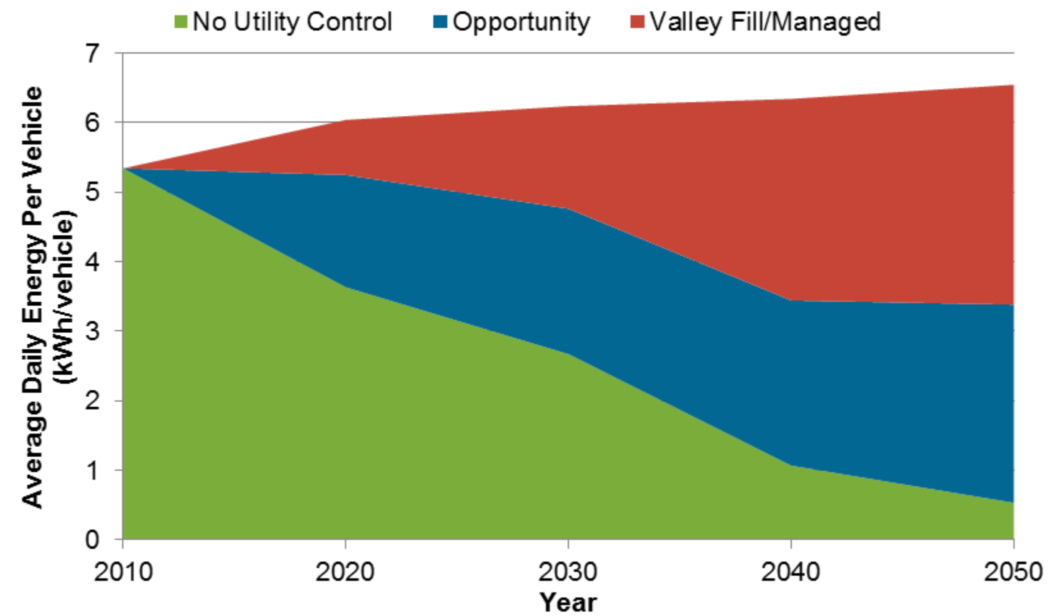

Figure K-7. Average daily per vehicle energy demands by charging scenario

By combining the hourly load profile results from previous work and the transition assumptions over the study period, an aggregate per vehicle load profile that changes shape over time is generated and shown in Figure K-7. Figure K-7 only shows the fixed portion that is not under the control of the utility. This includes the No Utility Control profile and the Opportunity profile. The transition from a high percentage of vehicles in the No Utility Control scenario in 2010 to a growing percentage of vehicles in the Opportunity scenario by 2050 is observed in Figure K-6 by comparing the shape of the 2010 and 2050 curves to those in Figure K-7.

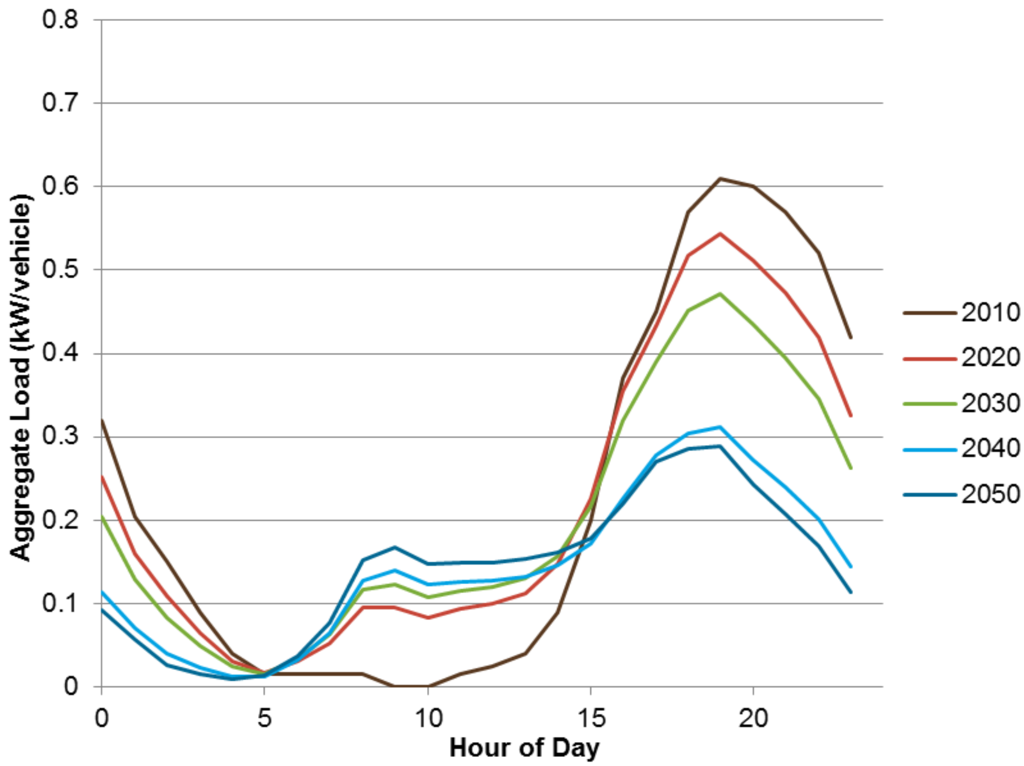

Figure K-8. Shape and transition of fixed hourly aggregate load profile for plug-in electric vehicles

The aggregate load shape in Figure K-8 only represents the fixed load profile. From Figure K-7, the dynamic portion under utility control (Valley Fill/Managed) grows from 0% of the load in 2010 to approximately 45% of the total load in 2050.

The ReEDS model assesses energy delivery by 134 BAs. Load profiles were generated on a county basis. A consolidation from 3,109 counties in the contiguous United States to 134 BAs was completed.

Figure K-9 shows the total annual energy demand for PEVs. Both the fixed and dynamic portions are highlighted. In 2030, the fixed demand is approximately 50 TWh, accounting for approximately 80% of the total load. By 2050, the total load grows to 350 TWh, and the fixed portion is approximately 180 TWh or 55% of the total load. Lin and Greene (2010) predict the total annual PEV energy demand as approximately 100 TWh in 2050 in a PEV Success scenario. Several assumptions contribute to these differences:

- Lin and Greene assumed mostly PHEV10 with a few PHEV40 vehicles, while this RE Futures study bases the energy demands and load curves on a PHEV20 design.
- Lin and Greene assumed a single charge per day, while this RE Futures study includes opportunity charging that increases daily electrical energy consumption per vehicle.

As a result, the total annual energy for PEVs is approximately three times greater than suggested by Lin and Greene's work. This is approximately 9% of the total electrical demand in the core 80% RE scenario.

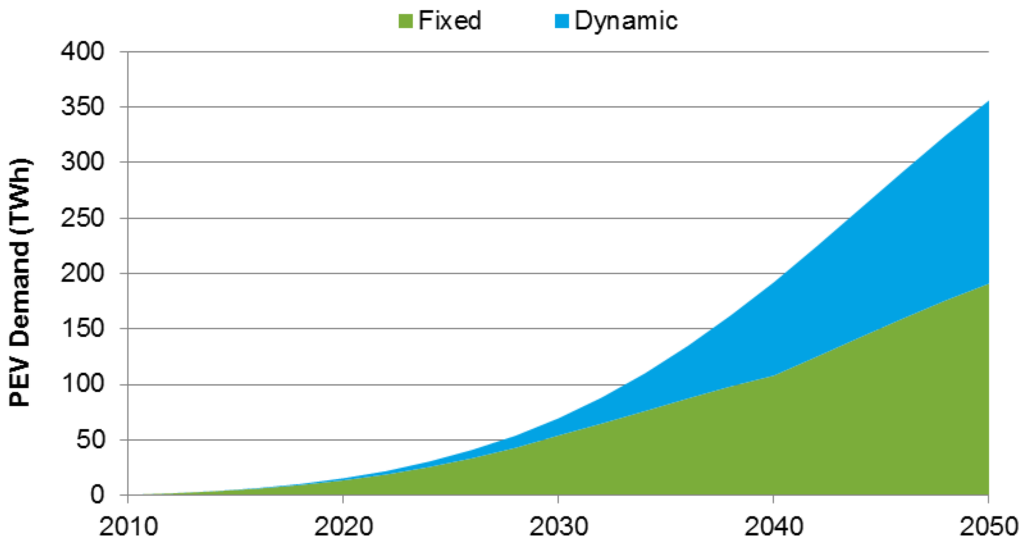

Figure K-9. Projected fixed and dynamic annual energy demand plug-in electric vehicles for Low-Demand Baseline

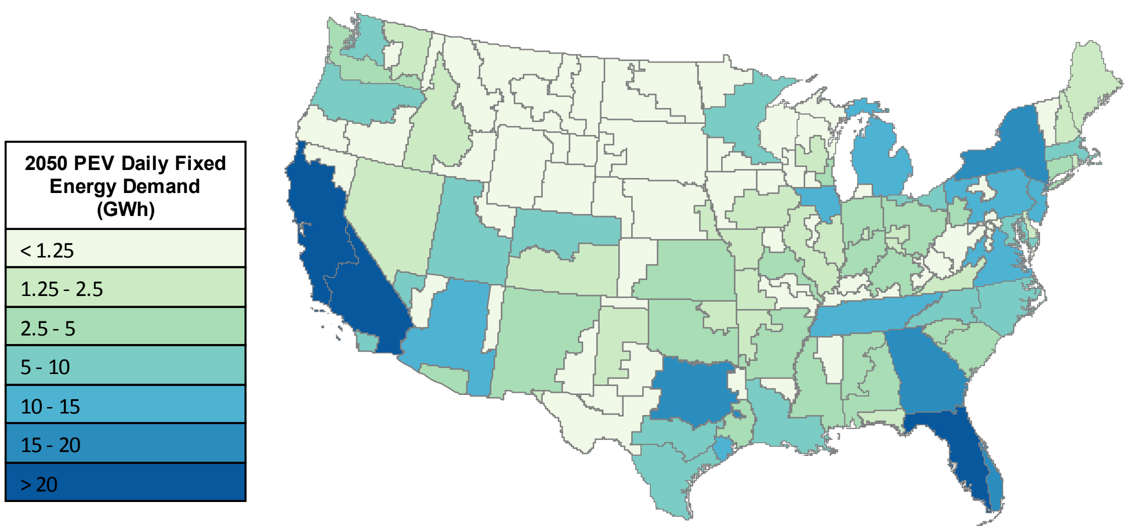

Figure K-10. Daily fixed energy demand for plug-in electric vehicles by balancing area, 2050

Figure K-10 provides a breakdown of the fixed portion of the daily energy demands for PEVs by BA region in 2050. The energy shown is approximately 55% of the total load in 2050. PEV population growth follows general population growth in RE Futures; therefore, highly populated areas are highlighted as PEV load centers.

Conclusion

The introduction of PEVs creates opportunities for the reduction of petroleum and the creation of new flexible load that can be integrated in utility operations with a high penetration of renewables to achieve a long-term strategy of creating a more sustainable transportation system. This work developed energy system load characteristic forecasts on a regional basis during the study period for the PEV market penetration scenario to be used in RE Futures. The work builds upon past travel survey data analyses, regional population forecasts, and assumptions regarding incentivization of charge management scenarios. A single scenario was developed, assuming a high penetration of PEVs. This scenario mirrors trends in the historical hybrid electric vehicle market stock to date. Three PEV charge scenarios were considered, including No Utility Control, Opportunity, and Valley Fill/Managed. The energy needed in the Valley Fill/Managed scenario was assumed to be flexible in terms of when it needs to be delivered throughout the day and thus provides the utility with a flexible load that can be managed to improve renewable generation asset utilization. According to the scenario, by 2050, 45% of the total vehicle energy demand of 350 TWh is under managed control while the remaining 55% is a fixed load to be planned for and met by utility assets. The hourly load profile of the fixed transportation energy demand also shifted over the time period from mainly No Utility Control toward Opportunity charging. RE Futures is the first study to assume that a variety of vehicle load shapes will exist and may transition over time, resulting in a unique fixed load and functional flexible load for integration into utility operational planning tools.

Appendix L. Cost Functions for Thermal Energy Storage in Commercial Buildings

TES for space cooling can be used to lower peak electricity use in buildings by drawing upon cooled water or ice to supply some portion of the cooling requirements during the hot afternoon and early evening hours. These technologies are gaining wider application as building owners see the potential to lower electricity costs by allowing electricity-intensive cooling equipment to be used to a greater degree in off-peak hours when electricity rates are lower. For RE Futures, TES is viewed as one of several technologies that can be used to better align future electricity demand with a more renewable-intensive electricity supply.

Segment Definitions for Supply Curve for Thermal Energy Storage

A stepped supply curve was developed for thermal energy storage based on several key assumptions. Four steps of the cost function were defined according to the type of thermal storage, type of air conditioning equipment, and building vintage. Table L-1 shows these steps and identifies the building segments to which they apply.

Table L-1. Segments of Supply Curves for Thermal Energy Storage

Cost Segment	Type of Storage	Building Category
1	Ice storage	New buildings with packaged A/C units[a]
2	Ice storage	Existing building with packaged A/C units
3	Chilled water	New buildings with chillers used for cooling
4	Chilled water	Existing buildings with chillers used for cooling

[a] A packaged A/C unit is a “unit built and assembled at a factory and installed as a self-contained unit to cool all or portion of a building” (EIA 1989).

Development of Cost Estimates for Thermal Energy Storage

An estimate of the cost per kilowatt shifted was developed for each of the four segments in Table L-1. For ice storage systems, a recent report by E Source, an energy consulting and information company located in Boulder, Colorado, was employed (Horsey 2009). For chilled water storage, the costs were derived primarily from the cost functions and methodology originally developed for the DOE Federal Energy Management Program under a Federal Technology Alert (FEMP 2000).

Cost Estimates for Ice Storage Systems

A recent resource report by E Source (Horsey 2009) was used to derive the cost estimates for ice storage systems. Given the proprietary nature of some of the information in the E Source report, only a sketch of the relevant facts is provided here. While ice storage systems can be built up from a component level (as described subsequently for chilled water), the market is likely to be dominated by manufactured package systems. At present, two U.S. manufacturers are the major competitors in this market. The E Source report describes some of the recent studies that have examined the first-generation models from these manufacturers as well as the projected cost and performance of more advanced models.

The technologies used by both of these manufacturers are similar. An extended quote from the E Source report (Horsey 2009) provides a summary of the basic technologies involved:

> They [the storage technologies] charge an ice storage system during cooler nighttime temperatures and meet the entire daytime cooling load by discharging the stored ice. The systems store cooling energy using the ice-on-coil method, where heat transfer coils, made of plastic or copper tubing, are arranged in an insulated storage tank and surrounded by water. In charging mode, ice forms on the heat transfer surface as evaporating refrigerant or a water/glycol solution flows through the coils, freezing up to 95% of the water. In discharge mode, condensing refrigerant or warm water/glycol solution flow through the coils, melting the ice and delivering cooling to the DX unit. The differences between the two systems are in the ice-making process and in the choice of heat transfer fluid.

The available cost information for the first generation unit from one of these manufacturers comes from a report prepared for the Southern California Public Power Authority. In that report, the installed cost per kilowatt across nine different installations ranged between $2,300 and $5,000 (with one outlier at more than $8,000). Field tests with the first generation of the second manufacturer's system estimated an installed cost of approximately $2,500/kW (Horsey 2009).

One of the manufacturers is targeting an installed cost of $2,100 for its second-generation unit. However, this cost assumes a market scale in which a large number of units might be installed, with promotion by one or more utility incentive programs. As yet, there is no field experience to suggest that this target-installed cost is achievable in the near term. One of the key installation issues involves the location of the ice-making unit. Because the weight of the unit can approach three tons, additional costs may be incurred for roof-mounted systems in some buildings in order to provide additional structural support.

For the purposes of RE Futures, it was assumed that the initial cost (in 2012) of a ice-based TES system was $2,200/kW for new buildings. This assumption, in essence, tempers the optimism of the declared near-term cost target. For existing buildings, the impediments to an optimal design (layout) and the potential need to increase the structural integrity of the roof is assumed to add another $300/kW to the cost.

Costs for Chilled Water Systems

The Federal Technology Alert presented a methodology through which a preliminary cost estimate could be developed for a chilled water or ice storage system in a commercial facility (building) (FEMP 2000). The methodology begins with estimates of the hourly cooling demand for the building under peak conditions. Given this profile of cooling demand, a decision must be made regarding the degree to which storage will be used to meet the cooling demand during the peak afternoon hours of the day. For the analysis here, a "load-leveling" approach was assumed. Under this approach, the chiller is assumed to run continuously at the same intensity over a 24-hour period; during the night hours, its output is used to chill water in a storage tank, and during the afternoon, the chiller is employed along with the stored chilled water to meet the peak cooling demand.

Several energy simulations were made of a large office building using DOE's EnergyPlus software. The large office was one of the benchmark buildings developed by the Building

Technology Program within the Office of Energy Efficiency and Renewable Energy. The benchmark large office is a 12-story building of approximately 500,000 ft^2 of floor space. Simulations were made for three locations—Chicago, Phoenix, and Houston—to represent cold, hot and dry, and hot and humid climates.

Under the load leveling approach, the key outputs from the simulation are the total amount of cooling required over the peak day (converted to ton-hours) and the maximum cooling load for a single hour. In a conventional system without TES, the capacity of the chiller must be sized to meet the peak hourly load. Using TES, the chiller output can be lower because the chiller only needs to meet the *average* hourly cooling load over the 24 hours of the peak-cooling *day*. The storage capacity of the TES system must be able to provide cooling during those hours of the day when the cooling load exceeds the capacity of the chiller. This value can be derived from the hourly profile of the hourly cooling loads and is measured in ton-hours. Table L-2 shows the cooling capacity to meet the peak hourly load, the cooling capacity to meet average hourly cooling load, and the TES capacity for the three locations simulated.

Table L-2. Peak Hour, Average Hourly Cooling Load, and Thermal Energy Storage Capacity for Large Office Benchmark, by Location

Location	Peak Hourly Cooling Load (tons)	Average Hourly Cooling Load (tons)	TES Capacity (ton-hours)
Chicago	707	412	3,041
Houston	780	490	2,840
Phoenix	736	465	2,584

Costs for conventional and TES cooling systems for RE Futures were developed with methods similar to that described in the 2000 Federal Energy Management Program report. The cost of the chilled water storage (basically a steel tank) was represented by the equation: $2{,}197 * TH^{0.677}$. This cost was increased by 31% to account for additional expenses for design, overhead, and miscellaneous auxiliary costs.[62] Using Houston as an example, this formulation results in an estimated $626,600 for the cost of the TES system.

The second largest cost component involves the chiller. Based on information from RSMeans (2009), Trane (2000), and E Source (Horsey 2009), an updated cost function for a large water-cooled centrifugal chiller was developed (updated from the cost function shown in the 2000 Federal Energy Management Program report). A reasonable representation of current chiller costs was judged to follow a linear function: $40,000 + $330/ton. To convert cooling loads to the required cooling *capacity* of the chiller, the cooling loads from the simulations were adjusted upward by 10% to represent non-standard operating conditions (i.e., to account for actual capacity compared to rated capacity at Air-Conditioning and Refrigeration Institute [ARI] conditions). For Houston, these adjustments result in a chiller capacity of 867 tons for the conventional system and 544 tons for a TES system. Thus, again using Houston as an example, the cost of the chiller in the TES system was estimated to be $40,000 + $330 * 544 = $220,500.

[62] The cost equation for the storage tank itself was based on budget estimates provided by Chicago Bridge and Iron to Pacific Northwest National Laboratory on June 27, 2006. The costs were adjusted for price changes (downward) between 2006 and 2009 by the price index for heat exchangers and tanks from *Chemical Engineering* magazine.

For the conventional system with a required capacity of 867 tons for the chiller, the chiller cost would be approximately $326,000.

The final major component of a chiller-based system is a cooling tower. As with the chiller, a single cost curve was developed based on examining information from a private sector cost database (Richardson's Cost Data Online, Inc.), Trane, and RSMeans. The resulting cost function again took the form of an exponential function to represent economies of scale: $C = \$1{,}726 * T^{0.62}$, where T = cooling tower capacity in tons. Continuing the example with respect to Houston, where the cooling capacity in the conventional system was estimated to be 780 tons, this function yields a cost estimate of $114,000 for the cooling tower (and associated piping costs). For the lower overall cooling capacity required with the TES system (544 tons), the cooling tower might be sized somewhat smaller with a cost of approximately $86,000.

To calculate the cost per kilowatt of peak electricity saved, the analysis first compares the total cost of a TES system to a conventional system. While the TES system involves the additional thermal storage system, the assumed load leveling system results in lower capacity requirements for both the chiller and cooling tower. Thus, the savings from these components can be used to partially offset the cost of the storage system. Taking this approach in the case for Houston, the resulting incremental cost of a TES system over a conventional chiller-only system was estimated to be $521,000.

For the magnitude of the kilowatt peak savings, the capacity output of the chiller at the peak hour must first be converted from tons to electricity consumption. Assuming an average coefficient of performance of 5.0 for the chiller and auxiliary equipment,[63] peak hour electricity consumption for the conventional system (on the peak day) is 545 kW, and the average hourly electricity consumption of the chiller in the TES system (also during the peak day) is 342 kW. Thus, the amount of electricity consumption shifted to off-peak hours is 203 kW. Dividing the incremental cost of $521,000 by 203 kW yields a cost per kilowatt shifted of $2,568.These estimates were assumed to apply only to new buildings in which the chiller and storage system can be designed and sized in an integrated manner. For existing buildings, it was assumed that the TES could be installed, but with a cost premium of 10% to cover the additional cost of renovating the building or reconfiguring outside space to accommodate an appropriate location for the storage tank. This addition of TES was assumed to be coordinated with a chiller replacement, so that the lower costs of a new, smaller chiller could be used to offset some of the TES cost. Under these assumptions, the cost per kilowatt was calculated to be $2,877.

The numbers cited in the previous discussion apply to Houston. Table L-3 shows the estimated cost per kilowatt for all three locations—for new and existing buildings. The cost estimation methodology yields only about a 7% difference in cost between higher and lower cost locations (Phoenix and Houston).

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[63] The coefficient of performance of the chiller itself was assumed to be 7.0 (roughly corresponding to 0.5 kW/ton). Fan energy use for the cooling tower was derived from the EnergyPlus simulations. The standard output from EnergyPlus does not break out the electricity use for condenser pumps. For RE Futures, it was assumed that the electricity use for the pumps would be 10% of the chiller electricity use. As a result, for Houston the cooling tower and pumps added an additional 39% to electricity used by the chiller itself. This additional electricity use on a percentage basis was somewhat lower for the Chicago and Phoenix simulations.

Table L-3. Estimated Costs for Chilled Water Thermal Energy Storage per Kilowatt Shifted

Location	$/kW (new)	$/kW (existing)
Chicago	$2,731	$3,059
Houston	$2,568	$2,877
Phoenix	$2,763	$3,094

Assumed Cost Reductions in the Future

For both chilled water and ice-based storage systems, the RE Futures analysis assumes that costs will decline in the future as more of these systems are installed. However, there is no interaction between the number of these systems installed, as modeled in ReEDS, and the price (indicating cost reduction through learning and economies of scale). Therefore, the cost reductions are based on the judgment of the analyst. Because the chilled water storage was deemed a more mature technology (in the sense that a major cost item is simply the cost of the tank), future cost reductions for chilled water were assumed to be lower than those for ice storage. For the chilled water systems, the rate of cost reduction was assumed to be 0.25% per year from 2012 to 2050. For ice-based systems, the cost reduction was assumed to be 1.5% per year up to 2020 and 0.25% per year thereafter.

Table L-4 shows the cost assumptions corresponding to the steps of the cost curve for NERC region 1, represented by the Chicago location (as per Table L-3).[64] The cost estimates are shown for even years, following the 2-year time interval used in ReEDS. While the cost of ice storage for new buildings is initially $2,200 in 2012, it falls to approximately $1,950 by 2020. Thus, over the next decade it is assumed that the target cost set by one of the manufacturers discussed in a previous section, Cost Estimates for Ice Storage Systems, is achieved. By 2050, the cost falls by another $150 per kilowatt.

[64] Given the sources and methodology used to develop these costs, a natural question is why the costs for ice storage per kilowatt shifted may be lower than those for a chilled water system. The relative costs depend on the cost of the storage system and the efficiency of the cooling equipment. Other things being equal, the higher the efficiency of the equipment, the greater the cost per kilowatt—in part explaining why the chilled water system displays a higher overall cost per kilowatt.

Table L-4. Cost Assumptions for Thermal Energy Storage, by Step—North American Electric Reliability Corporation Region 1

Year	Step 1: Ice Storage—New	Step 2: Ice Storage—Existing	Step 3: Chilled Water—New	Step 4: Chilled Water—Existing	Step 5: All Other Buildings
2012	$2,200	$2,500	$2,731	$3,059	$10,000
2014	$2,134	$2,425	$2,717	$3,044	$10,000
2016	$2,070	$2,352	$2,704	$3,029	$10,000
2018	$2,008	$2,282	$2,690	$3,014	$10,000
2020	$1,948	$2,213	$2,677	$2,999	$10,000
2022	$1,938	$2,202	$2,663	$2,984	$10,000
2024	$1,928	$2,191	$2,650	$2,969	$10,000
2026	$1,919	$2,180	$2,637	$2,954	$10,000
2028	$1,909	$2,169	$2,624	$2,939	$10,000
2030	$1,899	$2,158	$2,610	$2,924	$10,000
2032	$1,890	$2,148	$2,597	$2,910	$10,000
2034	$1,880	$2,137	$2,584	$2,895	$10,000
2036	$1,871	$2,126	$2,571	$2,881	$10,000
2038	$1,862	$2,116	$2,559	$2,866	$10,000
2040	$1,852	$2,105	$2,546	$2,852	$10,000
2042	$1,843	$2,095	$2,533	$2,838	$10,000
2044	$1,834	$2,084	$2,520	$2,824	$10,000
2046	$1,825	$2,074	$2,508	$2,810	$10,000
2048	$1,816	$2,063	$2,495	$2,795	$10,000
2050	$1,807	$2,053	$2,483	$2,782	$10,000

Note: The cost assumptions above correspond to buildings in steps. Step 1 refers to new buildings with packaged A/C units; Step 2 refers to existing buildings with packaged A/C units; Step 3 refers to new buildings with chillers used for cooling; Step 4 refers to existing buildings with chillers used for cooling; and Step 5 refers to all other buildings.

Potential for Thermal Energy Storage by Region

The amount and percentages of total thermal storage demand by each step were based on the amount of floor space represented by the type of building corresponding to Steps 1 through 5, as explained in the note to Table L-4.The estimation procedure simply assumes that, to a first approximation, cooling demand per square foot of floor space is the same across all types of floor space.[65] The procedure would be significantly complicated if an effort had been made to distinguish cooling loads by building type. The 2003 Commercial Building Energy Consumption Survey was used to derive the amount of floor space served by different cooling systems. The Commercial Buildings Energy Consumption Survey indicated that approximately 22% of the total commercial floor space employs chillers or district chilled water for cooling. The corresponding percentage for packaged air conditioning equipment is 46%. It is assumed that these shares remain constant over time and across regions.

These percentages are used to develop the (horizontal) magnitudes for the cost curve in each model year. As discussed above, ReEDS operates on even-numbered years to 2050. The first (and third) cost segments apply only to new construction. Based on a model run of the NEMS for 2009, projections of new commercial floor space by census region were obtained. These values were converted to fractions of total floor space for the 2-year time step of the model. For Step 1, these fractions were multiplied by 0.22 to represent floor space of buildings served by packaged air conditioning systems. For Step 3, the new floor space fractions were multiplied by 0.46 to represent large buildings using chillers or district chilled water. A conversion matrix was constructed to allocate the nine census division estimates to the 13 NERC regions used by ReEDS.

For existing buildings, it was assumed that the amount of potential TES storage was constrained by the amount of floor space replacing air conditioning equipment. Assuming a 25-year life for chillers, an approximation to the percentage of floor space that would replace a chiller would be 4%. Given the 2-year time step of ReEDS, this percentage is doubled to represent replacements over 2 years. A final (judgmental) adjustment of 10% is added to account for the fact that potential installations of TES systems are likely to have higher than average cooling loads. Combining these factors yields a fraction of 0.088 of existing stock as the maximum fraction of floor space (and, thus, peak cooling load) for which a chilled water TES system could be installed to shift peak electricity demand. This fraction is multiplied by the percentage of pre-2010 buildings in the stock estimated to use chillers (i.e., the 22% value cited previously). This same logic is also applied to packaged air conditioning systems, for which a 20-year lifetime is assumed to generate the approximate fraction of replacement systems (yielding 11% of floor space in an existing building with packaged air conditioning).

One final adjustment is made to account for replacement of systems in buildings constructed after 2010. Starting in 2030, the first replacement of chiller or packaged air conditioning system

[65] Total cooling demand across various time periods of the day is provided as another separate input to ReEDS. The discussion here relates to how total cooling demand can be allocated across the various segments of the TES cost curve. For example, one question concerns what percentage of cooling demand can be attributed to new large buildings (using chillers) that have been built in the current 2-year time step of the ReEDS model.

was assumed to be required in 90% of the floor space in these recently built buildings.[66] For each 2-year period beginning in that year, the approach considers the amount of floor space construction in the 2-year period 20 years prior (e.g., the period ending 2034 would consider floor space built between 2013 and 2014 for replacement).

The results of these calculations are shown in Table L-5. The table shows the fractions of floor space—representing the constraints on the fractions of total cooling demand that could employ TES in each ReEDS time period—for each of the four steps of the cost function for NERC Region 1. The shares attributable to new construction (Steps 1 and 3) generally fall over time, as growth in new buildings moderates over the forecast horizon.

Table L-5 shows the stepped cost function for 2012 for NERC region 1. To repeat, the fraction along the horizontal axis can be interpreted as the total amount of cooling in this region for which TES can be applied in the time step ending in 2012. Thus, about 9% of the cooling peak cooling demand could be shifted due to TES installations during this period.

[66] The 90% assumption is designed to roughly measure the fraction of buildings that may be demolished after 20 years.

Table L-5. Limiting Fractions of Total Cooling Demand, by Step—North American Electric Reliability Corporation Region 1

Year	Step 1: Ice Storage—New	Step 2: Ice Storage—Existing	Step 3: Chilled Water—New	Step 4: Chilled Water—Existing
2012	0.0170	0.0483	0.0082	0.0187
2014	0.0191	0.0464	0.0092	0.0180
2016	0.0198	0.0446	0.0096	0.0172
2018	0.0192	0.0428	0.0093	0.0165
2020	0.0183	0.0411	0.0088	0.0159
2022	0.0174	0.0396	0.0084	0.0153
2024	0.0172	0.0381	0.0083	0.0147
2026	0.0176	0.0366	0.0085	0.0142
2028	0.0180	0.0351	0.0087	0.0136
2030	0.0168	0.0464	0.0081	0.0192
2032	0.0155	0.0449	0.0075	0.0185
2034	0.0154	0.0452	0.0074	0.0188
2036	0.0153	0.0447	0.0074	0.0187
2038	0.0152	0.0432	0.0074	0.0181
2040	0.0152	0.0415	0.0073	0.0174
2042	0.0151	0.0397	0.0073	0.0166
2044	0.0150	0.0386	0.0073	0.0162
2046	0.0149	0.0378	0.0072	0.0159
2048	0.0149	0.0372	0.0072	0.0157
2050	0.0148	0.0353	0.0072	0.0149

Note: Step 1 refers to new buildings with packaged air conditioning units; Step 2 refers to existing buildings with packaged air conditioning units; Step 3 refers to new buildings with chillers used for cooling; Step 4 refers to existing buildings with chillers used for cooling.

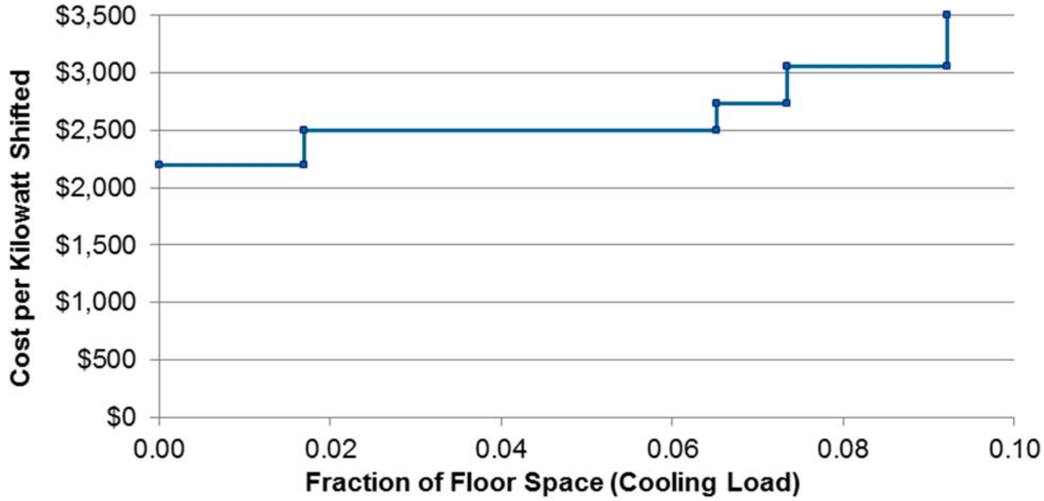

Figure L-1. Stepped cost curve for North American Electric Reliability Corporation Region 1, 2012

One final aspect of the implementation of the cost curve in ReEDS is how to account for vintages—installations of TES systems in previous time periods. If TES were cost-effective from an electric utility perspective, the inputs shown in Figure L-1 would indicate that 8%–10% of the total stock (i.e., total cooling demand) could be augmented with TES in each 2-year time step of the model (the sum of the four steps in any given year of Table L-5). Thus, in a limiting case, all commercial floor space could employ TES systems after a 20–25-year time frame. Installations in subsequent time periods (in existing buildings) would be nonsensical because the resulting amount of floor space served by TES would then exceed total floor space.

As discussed at the outset, the maximum penetration of TES in commercial floor space has been assumed to be limited by the fraction of floor space in buildings served by chillers and packaged air conditioning equipment. According to the 2003 Commercial Buildings Energy Consumption Survey (EIA 2006b), this fraction was approximately 0.68. Thus, for the implementation of TES in ReEDS linear programming framework, an overall constraint of 0.7 times the total cooling demand in each region was applied in all time steps of the model. More sophisticated procedures would be needed to ensure that fractions of cooling demand served by chilled water or ice storage were consistent with the allocation by type of cooling system (e.g., chilled water TES systems would be limited to approximately 20% of the total cooling demand).

Appendix M. Development of Demand Response Amounts

Demand Response Potential

There were a number of steps involved in calculating the demand response potential for each end-use sector.

National Assessment of Demand Response Database

In June 2009, the Federal Energy Regulatory Commission released the study *A National Assessment of Demand Response Potential* (FERC 2009). The authors calculated the potential amounts for four end-use categories (Residential, Small Commercial & Industrial, Medium Commercial & Industrial, and Large Commercial & Industrial). They subdivided the sectors based on enabling technologies and the availability of central air conditioning. Five different types of demand response were used: dynamic pricing with enabled technology, dynamic pricing without enabling technology, automated or direct load control, interruptible tariffs, and other demand response (such as capacity bidding).

They calculated the amount of demand response available for each state for the years 2010–2019 and used four scenarios: Business-As-Usual (BAU), Expanded BAU, Achievable Participation, and Full Participation. The BAU case assumed that existing and planned demand response programs would continue unchanged over the next 10 years. Expanded BAU assumed an expansion into all states of the current mix of demand response programs, partial deployment of an advanced metering infrastructure, and availability of dynamic pricing to customers with 5% choosing dynamic pricing. The Achievable Participation case assumed that an advanced metering infrastructure was universally deployed, that dynamic pricing tariffs represented the default condition, and that other demand response programs were available to those customers opting out of dynamic pricing. The Full Participation case assumed that an advanced metering infrastructure was universally deployed, that the default tariff was dynamic pricing, and that all customers used proven enabling technologies where cost-effective (FERC 2009). Achievable Participation amounts were price sensitive to the ratio of the new peak price to the old average price. Because RE Futures studied years up to 2050, it was assumed that Full Participation amounts were achieved by that time.

The authors released the spreadsheet model they used to calculate the amount of savings. It included a summary table that shows the sector demand response savings for each U.S. census region for 2019 for the different scenarios and types of demand response. Table M-1 shows the amount for the East North Central census region as an example. The model also reports the expected system peak for that year, shown in the bottom right corner.

Table M-1. Summary of FERC Estimated Demand Response Potential Savings (MW) in 2019 for East North Central Region

Scenario/ Demand Response Type	Residential	Small	Medium	Large	Total
BAU					
Pricing With Enabling Technology	0.0	0.0	0.0	0.0	0.0
Pricing Without Enabling Technology	0.8	6.0	0.0	119.0	135.1
Automated or Direct Control Demand Response	1,008.6	115.8	34.5	0.0	3,453.1
Interruptible Tariffs	0.0	0.0	12.0	2,068.2	1,787.3
Other Demand Response	0.0	0.0	0.2	3,041.4	1,299.3
TOTAL	1,009.4	121.8	46.7	5,228.6	6,406.5
Expanded BAU					
Pricing With Enabling Technology	0.0	0.0	0.0	0.0	0.0
Pricing Without Enabling Technology	153.7	8.0	31.8	147.2	135.1
Automated or Direct Control Demand Response	2,348.1	136.7	104.5	0.0	3,453.1
Interruptible Tariffs	0.0	0.0	194.6	3,892.3	1,787.3
Other Demand Response	0.0	0.0	0.6	6,417.8	1,299.3
TOTAL	2,501.8	144.8	331.5	10,457.4	13,435.4
Achievable					
Pricing With Enabling Technology	1,947.4	787.4	499.6	650.5	3,885.0
Pricing Without Enabling Technology	3,464.6	47.6	444.1	1,184.3	5,140.5
Automated or Direct Control Demand Response	1,204.1	121.2	62.3	0.0	1,387.5
Interruptible Tariffs	0.0	0.0	194.6	3,892.3	4,086.9
Other Demand Response	0.0	0.0	0.4	3,928.6	3,929.0
TOTAL	6,616.1	956.1	1,201.0	9,655.7	18,428.9
Full Participation					
Pricing With Enabling Technology	4,555.4	1,841.9	1,460.9	1,902.2	9,760.4
Pricing Without Enabling Technology	3,500.1	28.7	347.2	1,534.0	5,410.1
Automated or Direct Control Demand Response	1,008.6	115.8	34.5	0.0	1,158.9
Interruptible Tariffs	0.0	0.0	194.6	3,892.3	4,086.9
Other Demand Response	0.0	0.0	0.2	3,041.4	3,041.6
Totals	9,064.1	1,986.4	2,037.4	10,369.9	23,457.9
Region Peak Demand					147002.5

Source: A National Assessment of Demand Response Potential (FERC 2009)

Because the amounts are calculated in the form of megawatt potential, each amount was divided by the system peak for 2019 to determine the fraction of peak demand that can be reduced by demand response. These percentages could then be multiplied by the peak demand for a given region and sector for a given year.

The FERC data represent the data based on four rate classes: residential and small, medium and large commercial and industrial. To convert these data to data used for RE Futures, the small and half of the medium commercial and industrial were assigned to the commercial sector, and the large and half of the medium large commercial and industrial were assigned to the industrial sector.

Sectoral Demand Response (GW)

The next step was to calculate the gigawatts of demand response available in each region for each year. Because the report generated values for the nine census regions instead of the 13 NERC regions used by NEMS, RE Futures assigned the nine regions to the appropriate NERC regions, as shown in Table M-2. The table also shows how the EPRI regions in Table M-2 were assigned to the NERC regions.

Table M-2. Census and Electric Power Research Institute Region Assignments to North American Electric Reliability Corporation Regions

NERC Region	Name	EPRI Region	Census Region
1	ECAR[a]	East	East North Central
2	ERCOT[b]	Central	West South Central
3	MAAC	East	Middle Atlantic
4	MAIN	Central	East North Central
5	MAPP	Central	West North Central
6	NPCC[c]/NY	East	Middle Atlantic
7	NPCC/NE	East	New England
8	FRCC[d]	East	South Atlantic
9	SERC[e]	East	South Atlantic + East South Central
10	SPP[f]	Central	West South Central
11	WECC[g]/NWP	Pacific	Pacific
12	WECC/RMP	Mountain	Mountain
13	WECC/CA	Pacific	Pacific

[a] East Central Area Reliability Coordination Agreement
[b] Electric Reliability Council of Texas
[c] Northeast Power Coordinating Council
[d] Florida Reliability Coordinating Council
[e] SERC Reliability Corporation
[f] Southwest Power Pool
[g] Western Electricity Coordinating Council

With an increasing acceptance and penetration of demand response within the utility system, RE Futures assumed a change in the level of demand response participation, from BAU, to Expanded BAU, to Achievable Participation, to Full Participation. The initial years used 100% of the BAU estimates, with a gradual shift to 100% Achievable Participation amounts by 2020. After 2030, the amount available through Full Participation was gradually applied such that demand response achieved 100% Full Participation by 2040. These fractions by year are shown in Table M-3, with the sum of each row adding up to 100%.

Table M-3. Shift of Market Penetration Categories for Demand Response

Year	BAU	Enhanced BAU	Achievable	Full Participation
2006	100%	–	–	–
2008	100%	–	–	–
2010	100%	–	–	–
2012	75%	25%	–	–
2014	50%	50%	–	–
2016	25%	50%	25%	–
2018	–	50%	50%	–
2020	–	–	100%	–
2022	–	–	100%	–
2024	–	–	100%	–
2026	–	–	100%	–
2028	–	–	100%	–
2030	–	–	100%	–
2032	–	–	80%	20%
2034	–	–	60%	40%
2036	–	–	40%	60%
2038	–	–	20%	80%
2040	–	–	–	100%
2042	–	–	–	100%
2044	–	–	–	100%
2046	–	–	–	100%
2048	–	–	–	100%
2050	–	–	–	100%

Price Calculation

The ReEDS model requires prices for the amount of demand response available in order for it to compete against other forms of reserve supplies. The first two demand response types use pricing as the drivers for the demand response, and the FERC model includes the sensitivity curves for each of the end-use sectors. The price-response curves for these, when normalized to the peak value at eight times the base price, are the same for each region and are shown in Figure M-1. These curves show that if peak prices are eight times the base price, then 100% of the estimated demand response is available for that region. If the price ratio is lower, then only a fraction of that demand response is realized. RE Futures used the curves for the demand response with enabling technologies because it is expected that enabling technologies will be more widespread by 2050.

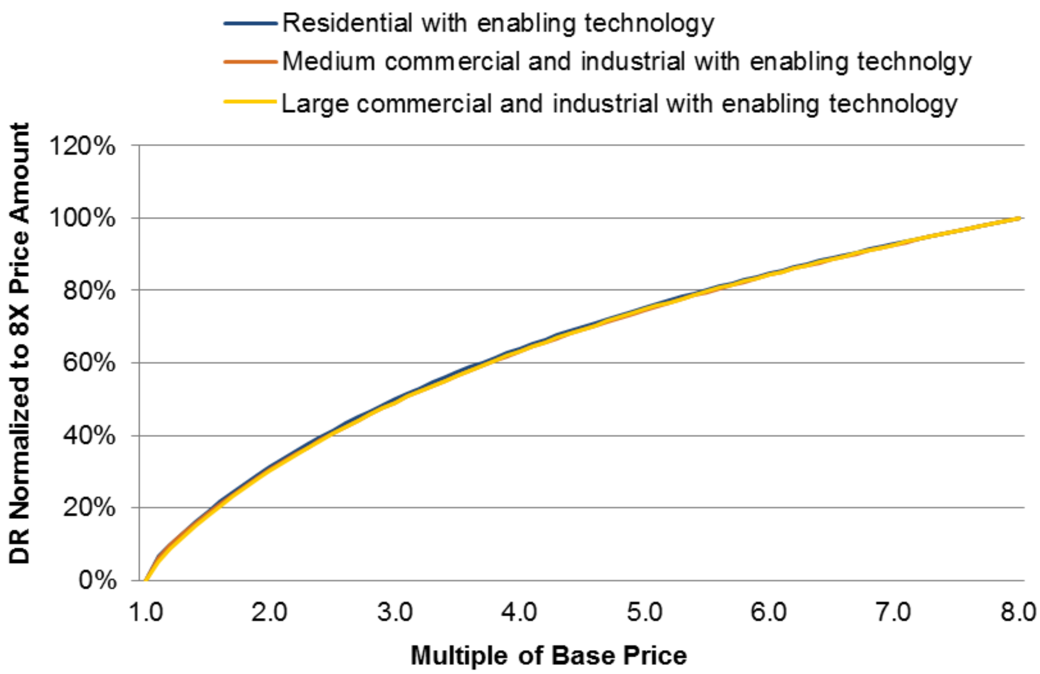

Figure M-1. Relationship of demand response to price for each sector

Application of 2050 Sector Electricity Price to Curve to Find Supply Curve for Demand Response

The values calculated in Figure M-1 are based on dynamic prices eight times the average price. The average prices for each sector are reported in NEMS, so they were used as the basis to calculate the price for the price-sensitive demand response for use within ReEDS.

The last three demand response technologies are not explicitly price sensitive in the FERC analysis. For these, it may be most appropriate to model them in ReEDS as price takers. Their main competition is natural gas–fired combustion turbines, so these were entered into ReEDS at the quantities calculated above and with a capital cost and operating cost reflective of the price of peaking plants.

Appendix N. Hourly Load Shapes

This appendix contains graphs (Figure N-1 through Figure N-13) of the resulting non-PEV hourly load shapes by region (see Figure H-7 for the region map). The hourly loads from 2006 were initially used as templates. Load duration curves for each sector and the system as a whole were calculated, as described in Appendix I. The 2006 hourly loads were adjusted such that each sector's load requirements were fulfilled and the 2006 pattern of peaks and valleys was maintained. Commercial and residential load shapes were calculated for the average weekday, peak day, and average weekend day for each month for each year. Within each month, the hourly loads for each sector were adjusted so that the 2006 pattern was maintained and the average weekday, average weekend, and peak day loads were kept. Industrial loads were calculated to maintain the overall load factor while mimicking the 2006 system load shape. The underlying data, which are further broken out by sector, are available upon request.

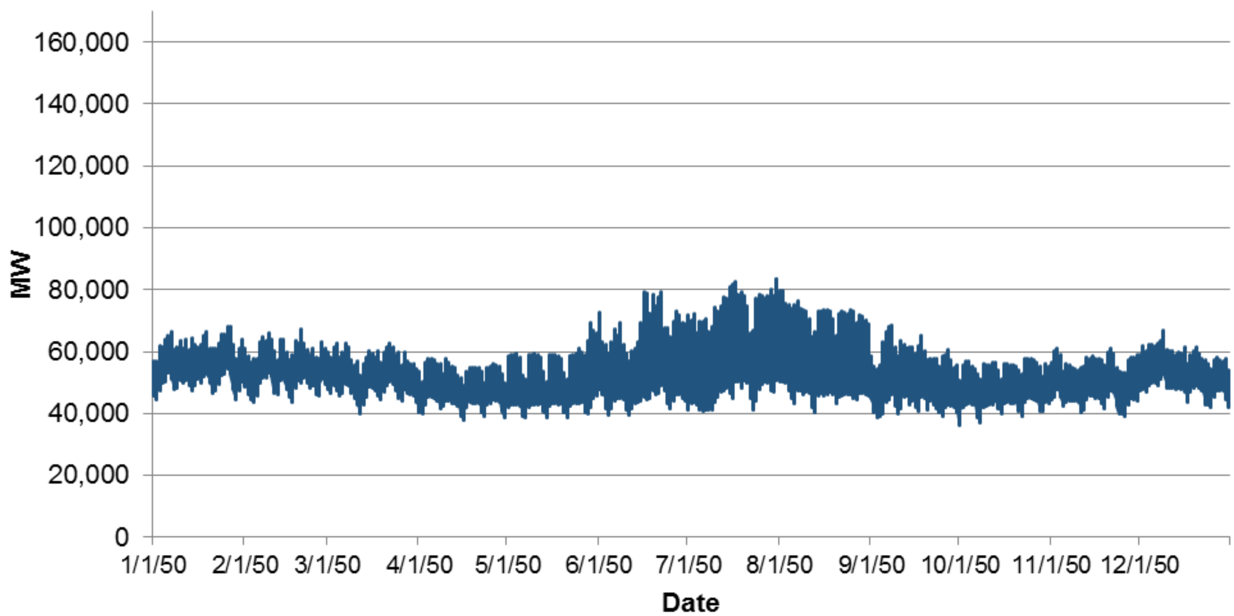

Figure N-1. Non-PEV hourly demand in 2050, Region 1 (East Central Area Reliability Coordination Agreement)

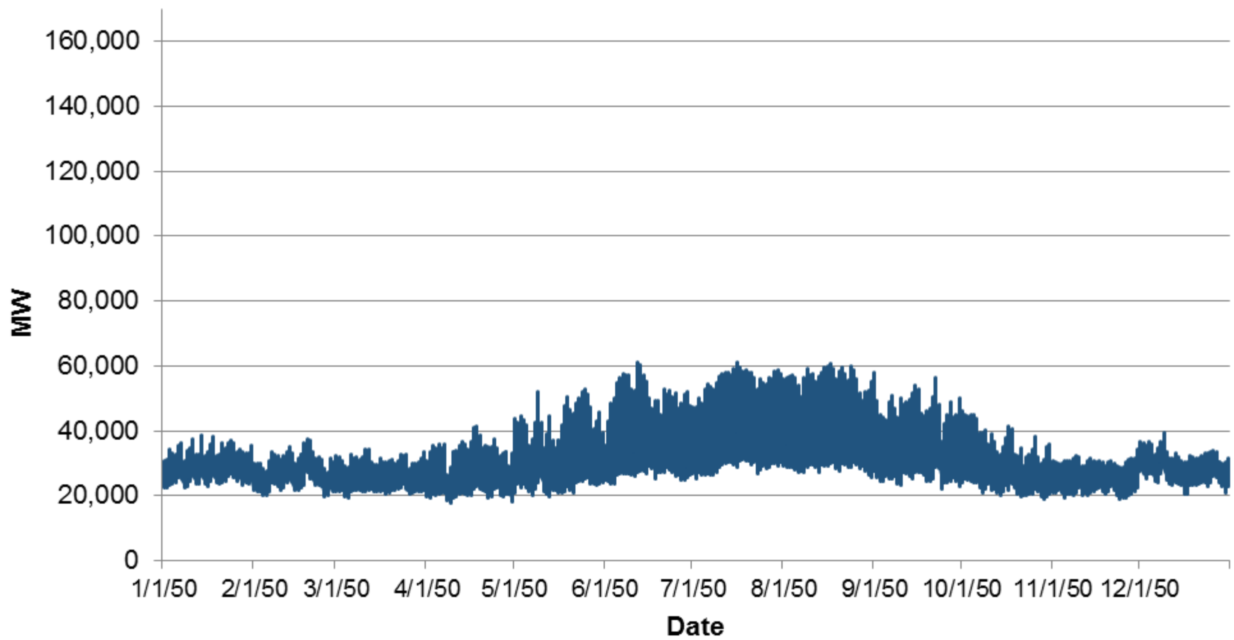

Figure N-2. Non-PEV hourly demand in 2050, Region 2 (Electric Reliability Council of Texas)

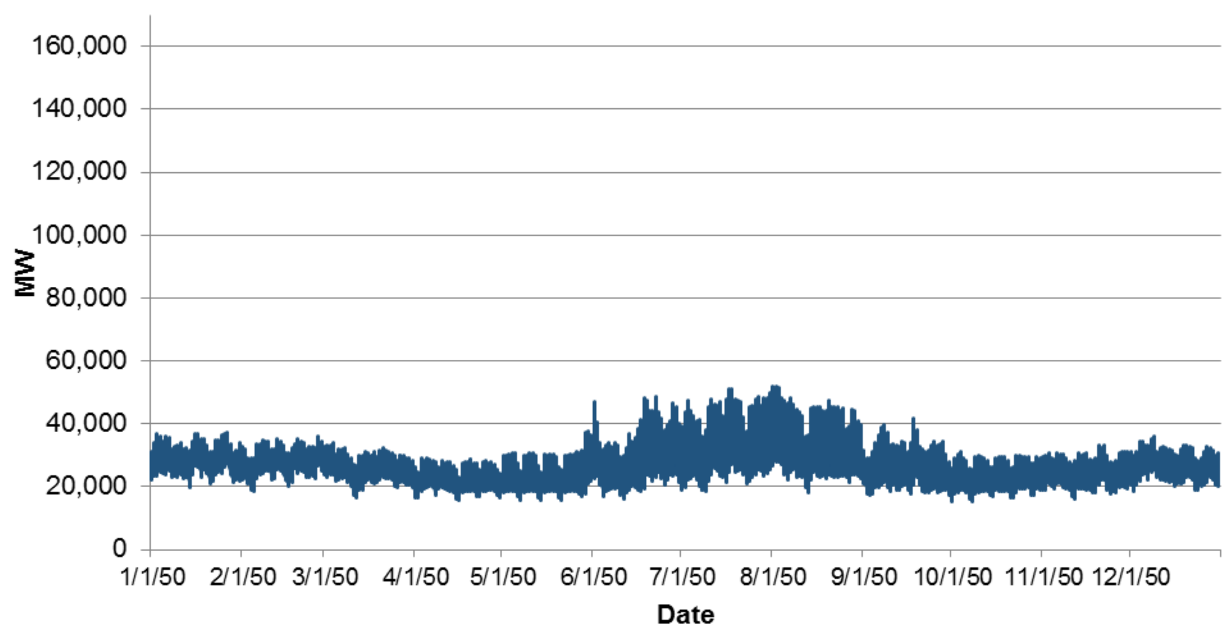

Figure N-3. Non-PEV hourly demand in 2050, Region 3 (Mid-Atlantic Area Council)

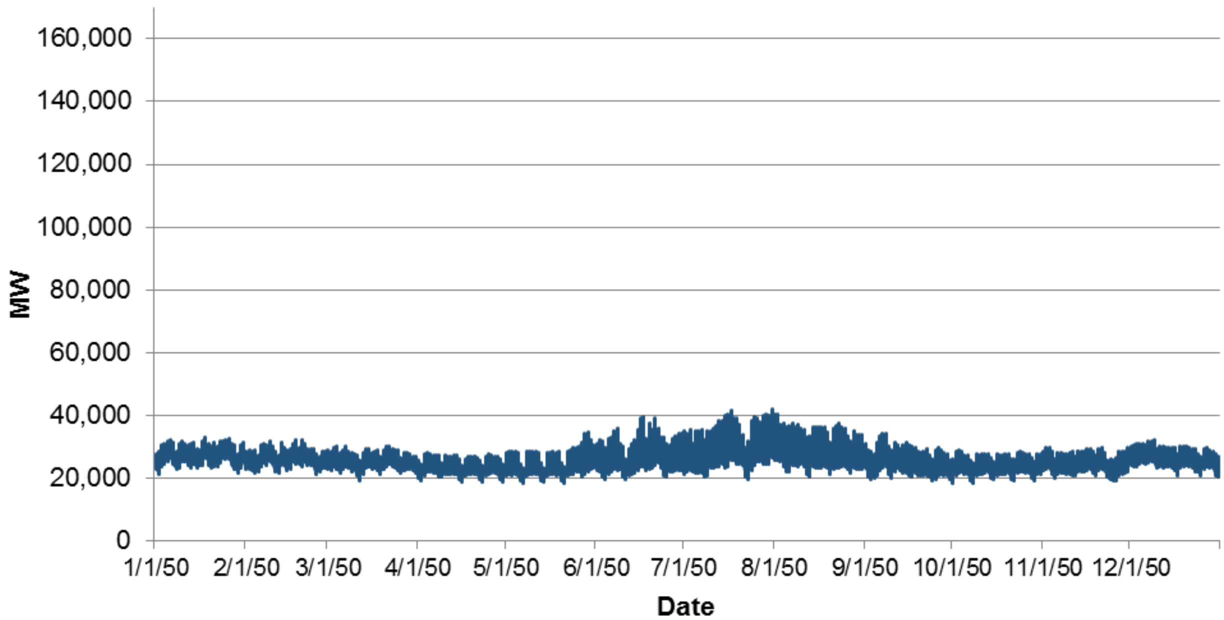

Figure N-4. Non-PEV hourly demand in 2050, Region 4 (Mid-America Interconnected Network)

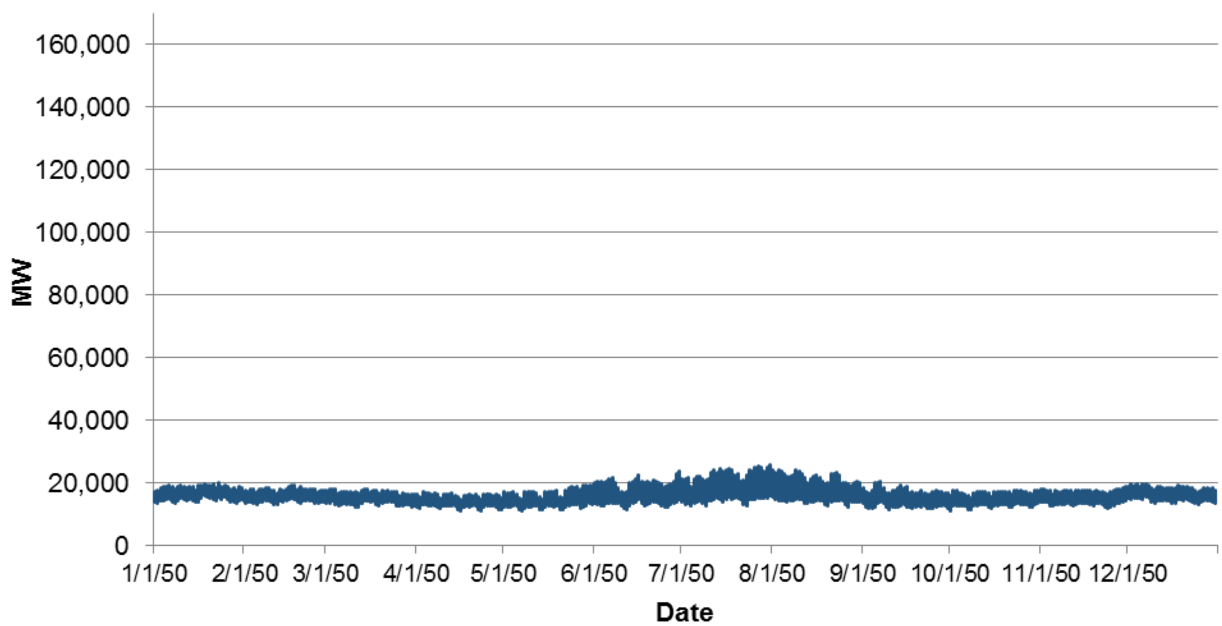

Figure N-5. Non-PEV hourly demand in 2050, Region 5 (Mid-Continent Area Power Pool)

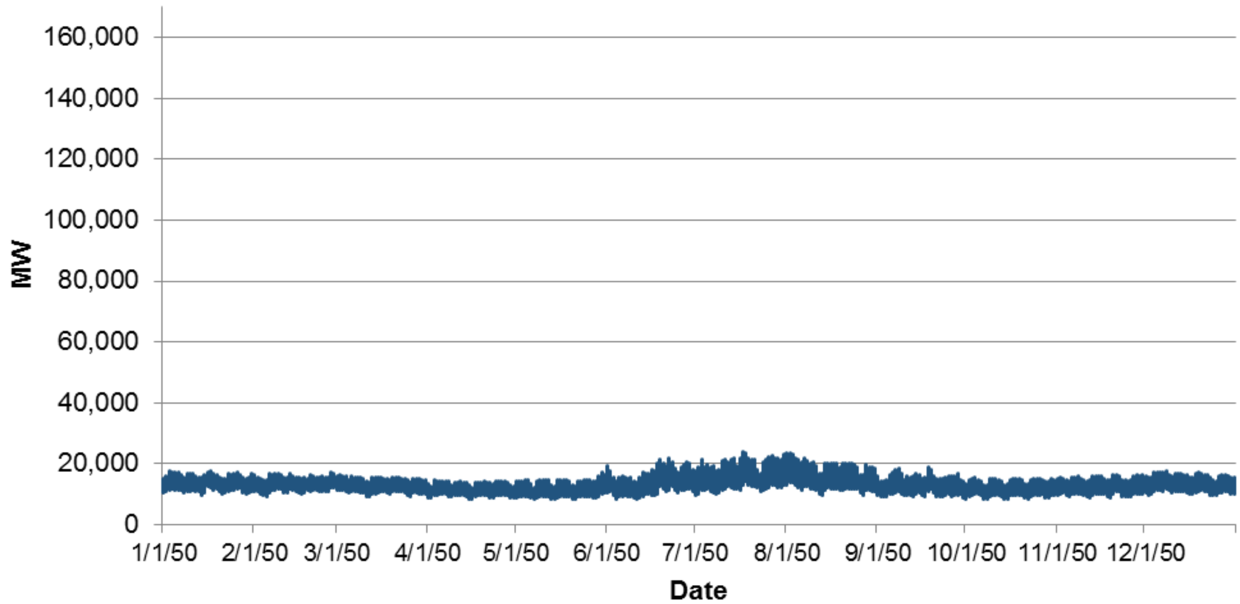

Figure N-6. Non-PEV hourly demand in 2050, Region 6 (New York)

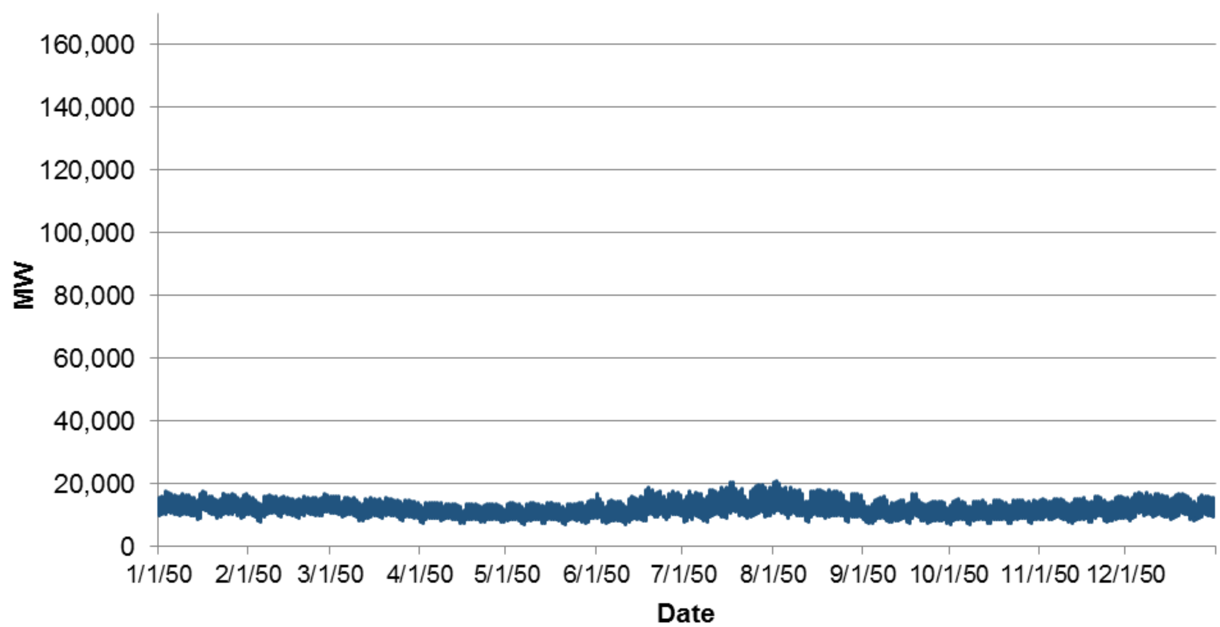

Figure N-7. Non-PEV hourly demand in 2050, Region 7 (New England)

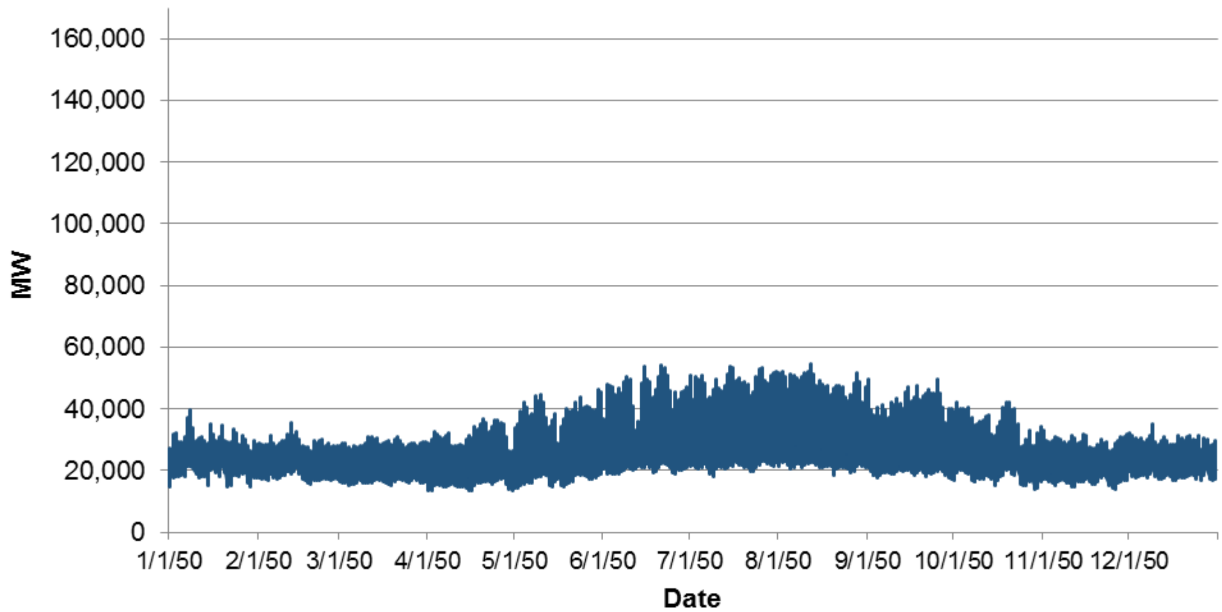

Figure N-8. Non-PEV hourly demand in 2050, Region 8 (Florida Reliability Coordinating Council)

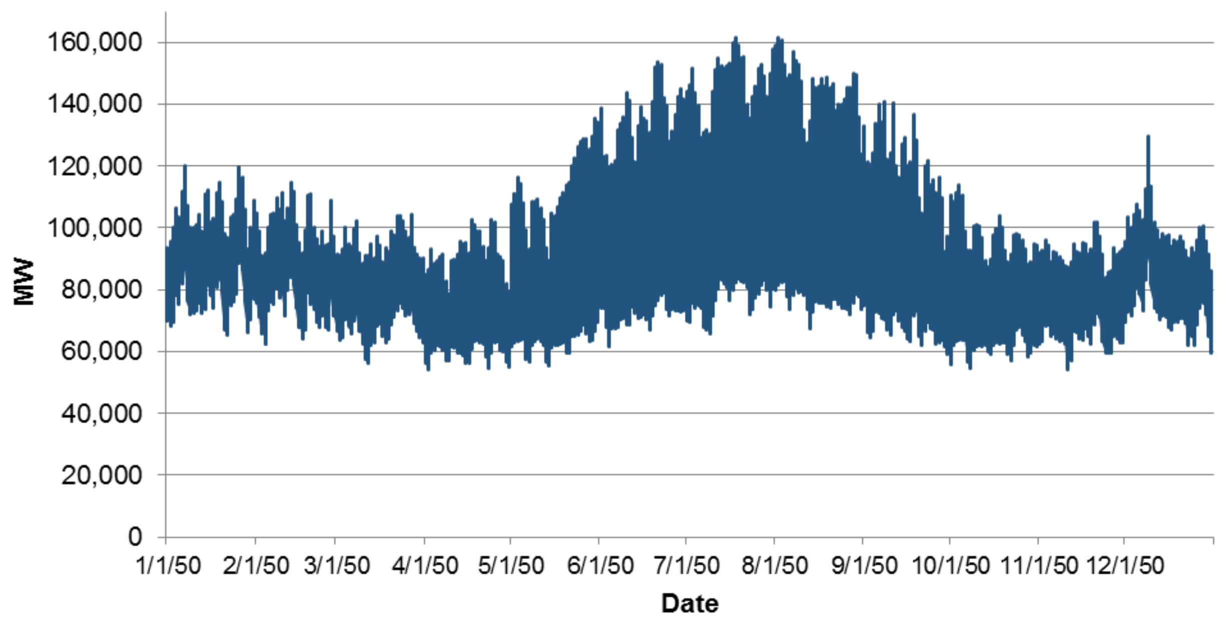

Figure N-9. Non-PEV hourly demand in 2050, Region 9 (Southeastern Electric Reliability Council)

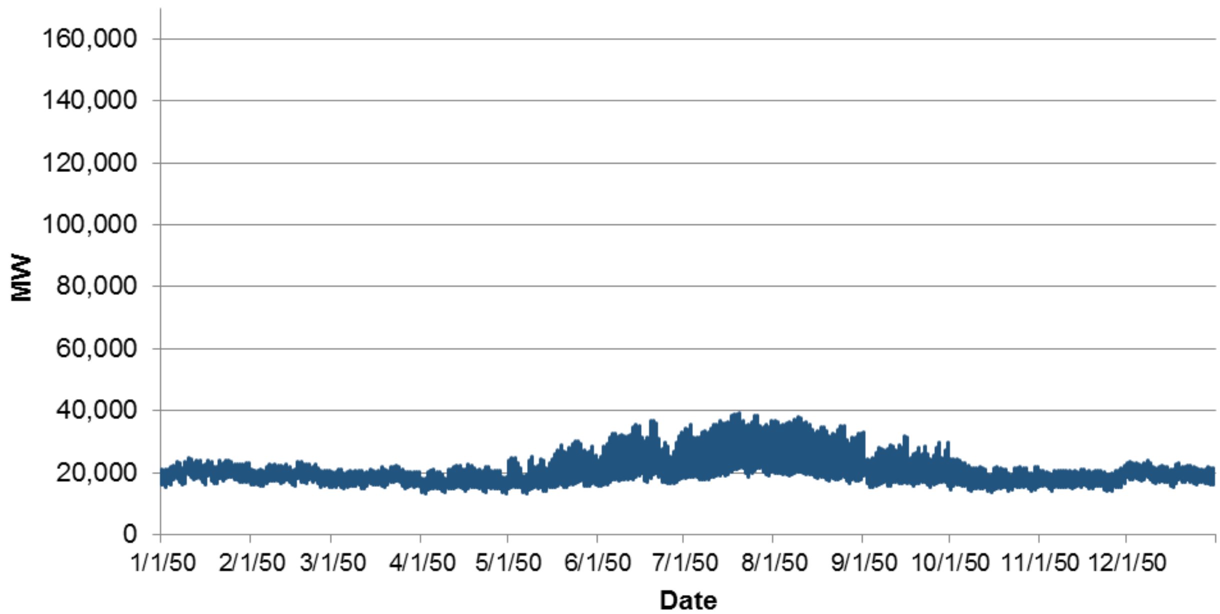

Figure N-10. Non-PEV hourly demand in 2050, Region 10 (Southwest Power Pool)

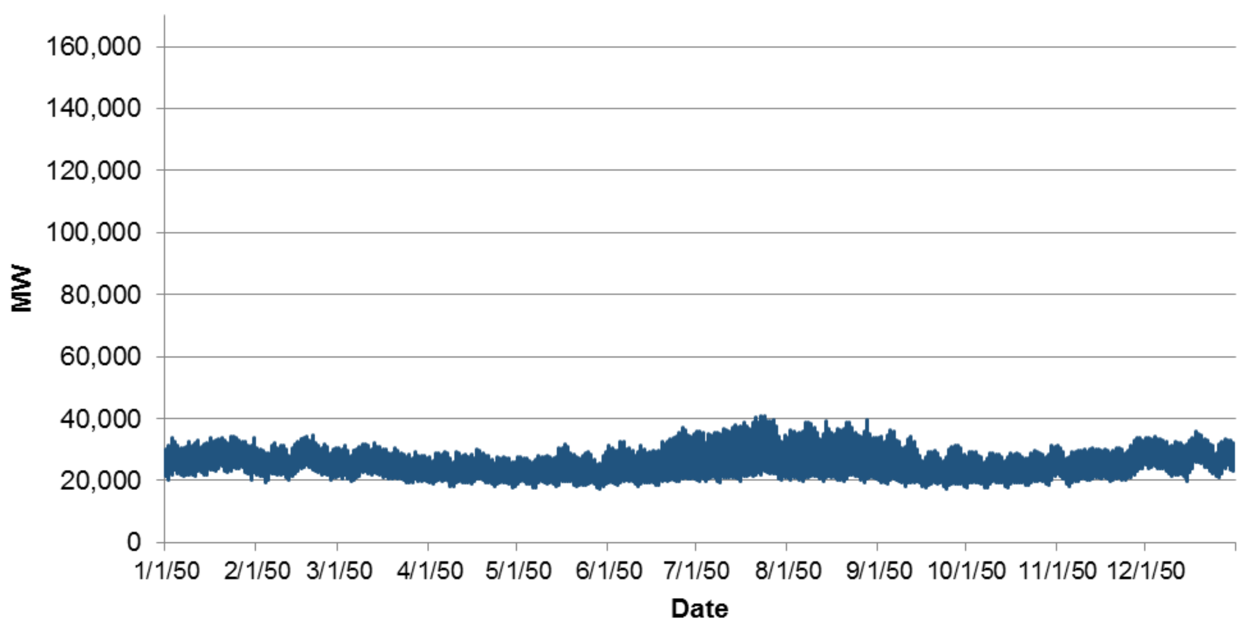

Figure N-11. Non-PEV hourly demand in 2050, Region 11 (Northwest Power Pool)

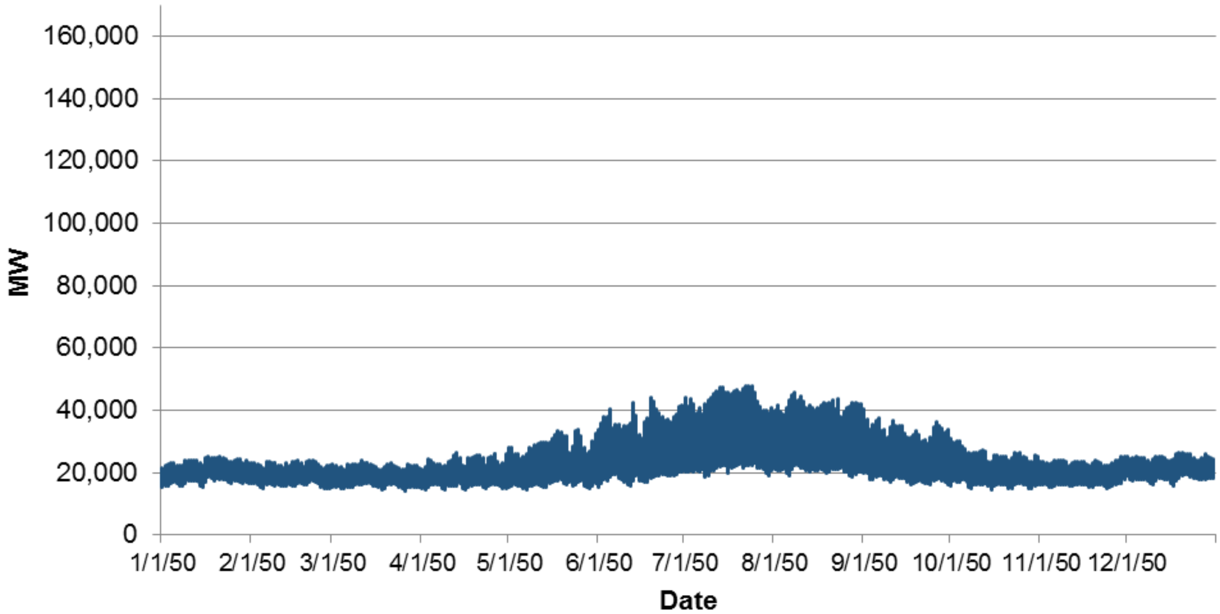

Figure N-12. Non-PEV hourly demand in 2050, Region 12 (Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada)

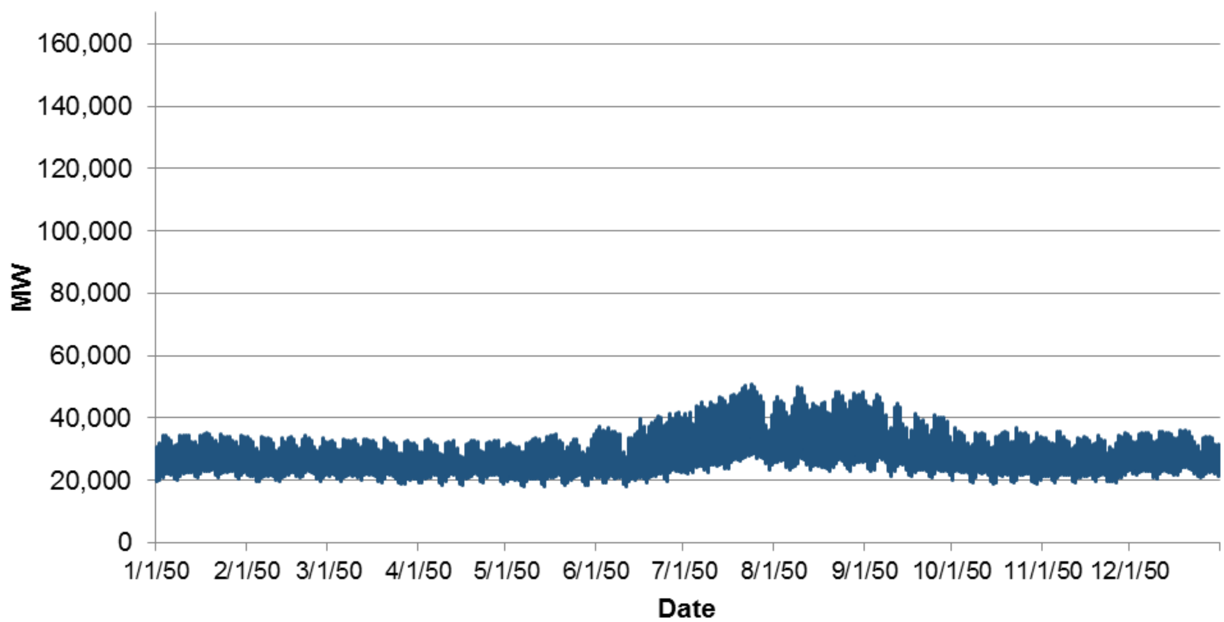

Figure N-13. Non-PEV hourly demand in 2050, Region 13 (California)

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