SR/OIAF/2003-02

Analysis of S.139, the Climate Stewardship Act of 2003

June 2003

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

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Preface

On January 9, 2003, Senators John McCain and Joseph I. Lieberman introduced Senate Bill 139 (S.139), the Climate Stewardship Act of 2003, in the U.S. Senate. S.139 would require the Administrator of the U.S. Environmental Protection Agency (EPA) to promulgate regulations to limit greenhouse gas emissions. On January 28, 2003, Senator James M. Inhofe requested that the Energy Information Administration (EIA) perform a comprehensive analysis of S.139. On April 2, 2003, Senators McCain and Lieberman, cosponsors of S.139, made a further request for analyses of their bill. This Service Report responds to both requests.

To analyze S.139, EIA used an updated version of the *Annual Energy Outlook 2003* (*AEO2003*) reference case. *AEO2003* was generated using EIA's National Energy Modeling System (NEMS). S.139 proposes a detailed program for greenhouse gas emission monitoring and control and contains provisions that are either subject to varying interpretation or are intended to be defined after enactment. Based on EIA's interpretation of the S.139, modifications were made in NEMS to allow modeling of its specific provisions.

The report summarizes the provisions of S.139 and the requests from Senator Inhofe and Senators McCain and Lieberman. It discusses the methodology used for the analysis, the key assumptions made based on EIA's interpretation of the proposed bill, and lists the scenarios examined as part of the analysis. It presents the projected impact of S.139 on greenhouse gases and the role of offsets. The report examines the impacts of S.139 on the four end-use demand sectors—residential, commercial, industrial, and transportation—and on electricity supply. The analysis also examines the implications of S.139 for fossil fuel supplies, including production, prices, and employment. It discusses the macroeconomic impacts of S.139 under different policy assumptions. Appendix A presents the request letters and subsequent correspondence with the requesters' staff.

The legislation that established EIA in 1977 vested the organization with an element of statutory independence. EIA does not take positions on policy questions. It is the responsibility of EIA to provide timely, high-quality information and to perform objective, credible analyses in support of the deliberations of both public and private decisionmakers. This report does not purport to represent the official position of the U.S. Department of Energy or the Administration.

Within its Independent Expert Review Program, EIA arranged for leading experts in the fields of energy and economic analysis to review this analysis and provide comment. The reviewers provided comments on a draft version of the report, after an earlier meeting with EIA to discuss the methodology and preliminary results. All comments from the reviewers either have been incorporated or were considered for incorporation. Due to time limitations, EIA was not able to complete all the sensitivity cases suggested by the reviewers. The basis of the sensitivities included in this analysis was to respond to the requests of the Senators soliciting this analysis. As is always the case when peer reviews are undertaken, not all the reviewers are in agreement with all the methodology, inputs, and conclusions of the final report. The contents of this report are solely the responsibility of EIA. The assistance of the following reviewers in preparing the report is gratefully acknowledged:

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    Pew Center on Global Climate Change

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    Resources for the Future

Denny Ellerman
    Massachusetts Institute of Technology

W. David Montgomery
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    Electric Power Research Institute

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The projections in the reference case in this report are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The reference case projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. Thus, they provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of emerging regulatory changes, when defined, are reflected.

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Highlights

Introduction

This analysis of Senate Bill 139 (S.139), the Climate Stewardship Act of 2003, was requested by Senator James M. Inhofe, Chairman of the Senate Environment and Public Works Committee, and by Senators John McCain and Joseph I. Lieberman, who introduced the bill. The analysis responds to both requests.

Highlights of S.139

- S.139 would establish regulations to limit U.S. emissions of greenhouse gases, primarily through a system of tradable emission allowances and related emissions reporting requirements.

- The bill covers emissions of six greenhouse gases: carbon dioxide, methane, nitrous oxide, and three gases with high global warming potential (GWP)—hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. The bill's allowance requirements cover about 75 percent of direct emissions in the United States. Covered sources include entities in the commercial, industrial, and electric power sectors with annual greenhouse gas emissions above a threshold level of 10,000 metric tons carbon dioxide equivalent;[1] transportation uses of petroleum products; and producers and importers of high-GWP gases.

- Emissions sources excluded are entities in the residential and agriculture sectors with direct emissions and entities with annual emissions below 10,000 metric tons carbon dioxide equivalent (based on GWP). Noncovered entities are affected by the bill, however, because emissions from the electricity they use are subject to the bill's allowance program, and because prices for natural gas are expected to rise as demand for the low-carbon fuel increases under the program.

- Emissions allowance caps are introduced in two phases. Phase I allowance caps, in effect from 2010 to 2015, are based on the emissions from covered sources in 2000. The Phase II caps, in effect after 2015, are based on 1990 emissions. The bill provides incentives and flexibility measures to spur early action and give credit for past emission reduction efforts, including:

    - A banking provision that allows entities to save allowances for future use, providing an incentive to overcomply early, when the allowance limit is relatively low, easing the transition to more stringent limits in Phase II, beginning in 2016
    - Emission allocation rules that reward past reductions with increases in the initial allocation of allowances
    - Allocation of emission-based marketable credits to automotive manufacturers for corporate average fuel economy (CAFE) improvements that are more than 20 percent over the relevant standard
    - A Climate Change Credit Corporation, funded by allowance sales, with authority to provide programs for transition assistance and to reduce economic impacts, which could take the form of rebates for purchases of efficient appliances and other transfer payments.

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[1] Most commercial entities would not be covered. Most industrial and electric power companies would be covered.

Summary of the S.139 Analysis and Results

Total Greenhouse Gas Emissions Reach 2000 Levels by 2025. Total greenhouse gas emissions are estimated to reach 2000 levels by 2025, with the gradual decline in U.S. greenhouse gas emissions starting in 2010. Covered entities are expected to overcomply in Phase I, in order to bank allowances. Beginning in 2016, when the more stringent Phase II allowance caps go into effect, covered entities would use previously banked allowances, enabling them to reduce their emissions (about 75 percent of the total) to near 1990 levels over the next decade. Emissions from noncovered entities grow moderately through 2025. Total emissions (covered and noncovered) reach 2000 levels by 2025. These changes in emissions do not reflect increases in carbon sequestration and purchases of emissions reductions abroad that are also used to comply with the targets in the legislation.

Allowance Values Grow Over Time. Prices in the emission allowance program are expected to increase gradually from $79 per metric ton carbon equivalent in 2010 ($22 per metric ton carbon dioxide equivalent) to $221 per metric ton carbon equivalent in 2025 ($60 per metric ton carbon dioxide equivalent).[2] The S.139 provisions to allow banking of emissions allowances are expected to moderate price increases as arbitrage occurs in allowance trading and banking.

A Supplementary Market for Tradable Offsets Develops. The bill provides an incentive for noncovered entities to make reductions and register them, so that they can be sold to covered entities for use in place of allowances. An organized market for offsets is expected to develop, and covered entities are assumed to take advantage of the maximum allowable amount of offsets (15 percent of the allowance requirement in Phase I and 10 percent in Phase II). The offset limits, combined with the generally lower costs of initial reductions from offset sources, are expected to result in a lower market price for offsets than for allowances. Estimated prices of offsets in 2025 are $52 per metric ton carbon equivalent, well below the price of allowances ($221 per metric ton carbon equivalent).[3]

2025 End-Use Prices Increase by 27 Percent for Motor Gasoline and 46 Percent for Electricity. In the S.139 analysis case, gasoline prices increase by 19 cents per gallon in 2010 and by 40 cents per gallon in 2025 relative to the prices projected in the reference case. Electricity costs increase by 0.6 cents per kilowatthour in 2010 (9 percent) and by 3 cents in 2025 (46 percent). The average household's energy bill, including the fuel cost of personal transportation, is expected to increase by $444 dollars per year in 2025 (13 percent) relative to the reference case.

Allowance Proceeds Offset Consumer Impacts. The increase in the average household's energy expenses is significantly mitigated by appliance rebates, transition assistance, and other transfer payments provided by the Climate Change Credit Corporation, a new nonprofit organization created under the bill and funded with revenues from emission allowance sales.

By 2025, Average Delivered Prices to Covered Entities Increase by 31 Percent for Petroleum Products, 79 Percent for Natural Gas, and 485 Percent for Coal. Covered entities must hold allowances for their greenhouse gas emissions. The costs of the allowances add to the effective price of fossil fuels delivered to the covered sectors. The large percentage increase in the cost of coal reflects both its high carbon content and its relatively low initial price. On a dollar-per-Btu basis, coal remains the lowest cost fossil fuel under the bill, but its use is expected to be greatly reduced as a direct consequence of the allowance program.

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[2] Prices are in constant 2001 dollars, unless otherwise noted.

[3] In a sensitivity case without a binding offset limit, the use of offsets increases and the overall cost of compliance, as reflected in the allowance and offset prices from 2010 to 2025, decreases by about 20 percent.

Macroeconomic Impacts Reduce Gross Domestic Product (GDP). The economy's adjustment to increasing energy costs through 2025 under the bill is expected to reduce real GDP and disposable income, with the degree and timing of the impacts determined in part by how proceeds from allowance sales are distributed. Assuming that the amount of auctioned allowances grows over time, the maximum percentage reduction in projected GDP compared to the reference case in any year is 0.7 percent.[4] The projected average annual growth rate of GDP from 2001 to 2025 is 3.02 percent with the bill and 3.04 percent without it. Expressed in dollar terms, the reduction in the present discounted value of GDP over the forecast period is $507 billion (in 1996 dollars). In 2025, when the adjustment to the S.139 regime is largely complete, actual GDP in the S.139 case is $106 billion (0.6 percent) lower than in the reference case.

Personal Disposable Income Is Also Reduced. Reductions in disposable income are similar in magnitude to the reductions in GDP, with the greatest changes occurring in the 2010-2015 time frame, when the assumed percentage of allowances allocated to the Climate Change Credit Corporation and rebated to consumers is the lowest. Over the 22-year time frame of the analysis, the cumulative difference in discounted disposable income relative to the reference case is $1,037 per capita, or about $47 per person per year (1996 dollars). Without discounting, the cumulative difference in disposable income relative to the reference case is $2,459 per capita, or $112 per person per year.

The Electric Power Sector Dominates Emission Reductions. The electric power sector is expected to provide by far the greatest share of emissions reductions, mainly through fuel substitution on the supply side but also through demand changes from higher electricity prices. Total energy-related carbon dioxide emissions in 2025 are reduced by 752 million metric tons carbon equivalent relative to the reference case, with the electricity sector's reduction amounting to 663 million metric tons. The electricity sector is more flexible in reducing emissions because of its potential to substitute towards lower carbon fuels, adopt emission-free alternatives, and implement carbon sequestration technology for fossil-fueled plants. To a great extent, these options can reduce emissions at a lower per-ton cost than in other energy-consuming sectors.

Coal Use Declines Sharply; New Nuclear Power Plants Are Added; Use of Renewable Energy Increases. The use of coal, particularly for electric power, is expected to decline rapidly, with generators substituting capacity fueled by natural gas, nuclear, and renewable fuels, and building plants equipped with carbon sequestration technology. Geological sequestration of carbon dioxide for coal and natural gas plants is expected to become economical, resulting in 140 gigawatts of capacity equipped with this technology (38 gigawatts using coal) by 2025. Nuclear power, which produces no greenhouse gas emissions, becomes more economical under S.139. Nuclear generation is expected to increase by 50 percent by 2025, with investments in a new generation of advanced plants beginning as early as 2012. Renewable energy use increases under S.139, particularly in the electricity sector, as additions of biomass and wind capacity, along with more modest increases in geothermal and landfill gas capacity, increase relative to the reference case. The estimated share of generation supplied by renewables, including hydroelectricity, increases from 8 percent in the reference case in 2025 to 23 percent in the S.139 case.

Transportation Energy Use Falls. Transportation petroleum use declines by 0.3 quadrillion Btu (1 percent) in 2010 and 4.1 quadrillion Btu (10 percent) in 2025 under the bill, compared to the reference case level, as the prices of travel-related emission allowances are passed on to consumers, who respond by buying more fuel-efficient vehicles and traveling less. Automotive manufacturers, who are given incentives under the bill to exceed fuel economy standards by at least 20 percent, are expected to respond gradually to the incentives, while continuing to maintain vehicle comfort, safety, and performance. By

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[4] The maximum percentage change occurs in 2012 and amounts to a difference of $93 billion (1996 dollars).

2025, new light vehicle fuel economy (cars and light trucks together) reaches 29.0 miles per gallon, compared with 26.4 miles per gallon in the reference case.

Petroleum Imports Decline. U.S. petroleum demand is estimated to fall by 0.3 million barrels per day in 2010 and by 2.7 million barrels per day in 2025 compared to the reference case, reducing projected oil import dependence in 2025 from 67.8 percent to 64.7 percent of total U.S. oil supply.

Allowance Values and GDP Impacts Are Lower Under High Technology Assumptions. Under more optimistic assumptions about the future availability, costs, and performance of advanced energy-using technologies, the cost of compliance for S.139 is lower. In a high technology sensitivity case, allowance prices in 2025 are reduced by 28 percent compared to the S.139 case. The reduction in the size of the economy in 2025 is $106 billion in the S.139 case and $95 billion in the S.139 high technology case (1996 dollars).

A Lower Natural Gas Supply Outlook and Higher Natural Gas Prices Result in Greater Adoption of Nuclear and Renewable Technologies and Increase the Use of Coal with Carbon Sequestration. More pessimistic assumptions for natural gas supplies, including recoverable reserves and undiscovered resources, result in projected wellhead prices in 2025 that are 40 percent higher than in the reference case. An S.139 sensitivity case with higher gas prices results in changes in compliance strategies, particularly in the electricity sector. Generating capacity substituted for natural gas additions includes coal-fired plants with carbon sequestration, as well as nuclear and renewables. As a result, overall coal consumption in this sensitivity case is 237 million tons higher than in the S.139 case in 2025, but at 543 million tons it is significantly lower than in the reference case (1,466 million tons). The overall cost of compliance, as indicated by the allowance prices, is about 6 percent higher in the S.139 high gas price case than in the S.139 case.

The Results Are Inherently Uncertain. An assessment of the impact of S.139 over a 25-year period is subject to considerable uncertainty. The baseline forecast (which is itself uncertain) affects the amount of change needed to meet an emissions target, as do the modeling methodology and assumptions. Alternative assumptions about the cost, performance, and market acceptance of these technologies affect the results, as do other assumptions, including the distribution of emission allowances to covered entities, the availability and cost of international offsets, future policy changes affecting energy use, and the extent of coverage and reduction potential of emissions sources. Sensitivity analysis is used to address some of these issues but does not necessarily encompass the full range of plausible energy and economic outcomes that might follow from enactment of the bill.

Summary

On January 9, 2003, Senators John McCain and Joseph I. Lieberman introduced Senate Bill 139 (S.139), the Climate Stewardship Act of 2003, in the U.S. Senate.[5] S.139 would establish regulations to limit U.S. greenhouse gas emissions, primarily through a program of tradable emission allowances and related emissions reporting requirements. The emissions allowance program would apply to most greenhouse gas emissions sources, the exceptions being those in the residential and agriculture sectors, as well as organizational entities in all sectors whose annual emissions are less than a certain threshold.

On January 28, 2003, Senator James M. Inhofe requested that the Energy Information Administration (EIA) perform a comprehensive analysis of S.139. On April 2, 2003, Senators McCain and Lieberman made a further request for analyses of their bill (see Appendix A for copies of the requesting letters). This Service Report responds to both requests.

This report addresses the following specific elements of Senator Inhofe's request:

- Costs of the bill to the U.S. economy in employment and aggregate gross domestic product (GDP)
- Energy conservation effects of the bill
- Comparison of the bill's compliance period with those scheduled by China, Mexico, South Korea, India, and Brazil for their greenhouse gas reduction programs
- Demographic data (by household income class) on the distribution of energy consumption and expenditures from EIA's Residential Energy Consumption Survey.

The report also responds to the following specific elements of the request from Senators McCain and Lieberman:

- Projected impacts of the bill over a range of alternative percentages of total greenhouse gas allowances to be issued by the U.S. Government that might be allocated to the Climate Change Credit Corporation—a new nonprofit organization with responsibilities defined by the bill
- Impacts of early action compliance activities by both covered and noncovered entities on the total costs of compliance
- Impacts of new technologies that could be deployed to reduce greenhouse gas emissions on the costs of compliance
- Impacts of the "allowance banking" permitted under the bill
- Effects of the bill on future levels of U.S. emissions of energy-related carbon dioxide and other greenhouse gases
- Effects of compliance flexibility measures and additional incentives to reduce emissions, including allowance credits for:
    - Registered reductions in international emissions
    - Fleet fuel efficiency improvements 20 percent greater than required
    - Emissions reductions associated with electricity use in noncovered sectors
    - Biological carbon sequestration from agricultural and forestry activities
    - Reducing emissions to 1990 levels before the bill's required date of 2010.

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[5] See web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s139is.txt.pdf.

Summary of the Climate Stewardship Act of 2003

S.139 establishes a research program on climate change and related activities, a national greenhouse gas database and registry of reductions, and a system of tradable allowances to reduce greenhouse gas emissions. The greenhouse gases addressed by the bill are carbon dioxide, methane, nitrous oxide, and gases with high global warming potential (GWP): hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. The bill establishes requirements for mandatory emissions reporting by covered entities and for voluntary reporting of emissions reduction activities. The focus of this report is on the emission allowance program and the related incentives proposed in the bill.

The bill defines the covered sectors for the emission allowance program as the commercial, industrial, electric power, and transportation sectors. The residential and agriculture sectors are exempt from the emissions reporting and allowance provisions under the bill. Covered entities in the commercial,[6] industrial, and electricity sectors are those with annual greenhouse gas emissions greater than a threshold level of 10,000 metric tons carbon dioxide equivalent. All petroleum use in the transportation sector is covered, with refiners having the responsibility to obtain allowances for emissions related to petroleum sold for transportation use. The high-GWP gases are covered, with producers and importers of these gases having the responsibility to obtain allowances for emissions associated with their supply. The bill provides for the exemption of emission sources if the U.S. Environmental Protection Agency (EPA) deems their measurement or estimation to be impractical. This exemption would most likely apply to a large share of U.S. nitrous oxide and methane emissions, because many of their sources are difficult or uneconomical to measure.

The bill's market-driven system of emission allowances would control greenhouse gas emissions by creating a fixed number of tradable emission allowances each year. The EPA is charged with establishing the regulations to create the tradable allowances, and S.139 defines many of the provisions governing the allowances. The bill provides entities with options for banking and borrowing allowances; for limited use of registered reductions from noncovered entities in lieu of allowances;[7] and for obtaining allowance allocation credits to reward past emissions reductions and early action reductions. S.139 establishes a nonprofit Climate Change Credit Corporation (hereafter referred to as the Corporation) to facilitate the market in emission allowances, to buy and sell allowances, and to distribute proceeds from sales in order to reduce the economic impacts of the program. The bill gives responsibility to the Secretary of Commerce for defining the allocation of allowances to the covered sectors and to the Corporation, subject to the final approval of Congress.

Each emission allowance provides the right to emit one ton of greenhouse gases, measured in carbon dioxide equivalent units based on 100-year GWP. The number of allowances created each year effectively establishes a cap on total U.S. emissions; however, with the banking of allowances for future use permitted under the bill, emissions in any year may differ from the number of allowances issued.[8] The bill requires covered entities to submit allowances equal to their emissions but does not limit the emissions of individual entities. Entities are free to produce any amount of emissions as long as they obtain the same

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[6] The commercial sector includes government entities.

[7] The bill allows each covered entity to obtain a portion of its emission allowances from alternate compliance sources, including purchase of allowances from certified reduction or sequestration programs, both domestically and abroad. The alternate compliance limits are 15 percent from 2010 to 2015 (Phase I) and 10 percent thereafter (Phase II). As an incentive for early action, entities reducing their emissions below 1990 levels may be granted a limit of 20 percent of their target reductions from alternate compliance sources in Phase I.

[8] Covered entities must submit allowances for their covered emissions or, to a limited extent, offsetting emission reduction credits from noncovered entities. Therefore, the covered emissions, less any offset credits, are subject to the allowance cap.

amount of allowances. Entities may buy and sell allowances, and they may bank allowances for future use. Under limited conditions, covered entities can borrow against future emissions reductions.[9]

S.139 allows automotive manufacturers to sell credits to the greenhouse gas registry for exceeding fleet fuel economy standards by more than 20 percent. The credits would then be used to reduce a corresponding quantity of emission allowances allocated to the transportation sector.[10] This provision establishes an emissions-related economic incentive for manufacturers to supply more efficient vehicles. Because this opportunity supplements the incentives established by the emission allowance requirement, the bill provides a somewhat greater economic incentive for emission reductions in transportation than in other sectors.

The S.139 emission allowance program would go into effect in 2010. In Phase I, 2010 through 2015, the number of allowances issued annually is based on the aggregated emissions of the covered sectors in 2000 (but reduced by the emissions of noncovered entities in those sectors in 2000). In Phase II, beginning in 2016, the number of allowances issued is based on 1990 emission levels (and reduced by emissions of noncovered entities in 1990).[11] For purposes of this analysis, Phase II is assumed to continue indefinitely. The number of allowances created is to be reduced by an amount corresponding to the emissions from noncovered entities, such as those with emissions below the threshold level—an amount that will not be established until emissions reporting is in place. The number of emissions allowances to be issued by the Government and, consequently, the overall cap are not established exactly; however, roughly 75 percent of total U.S. greenhouse gas emissions are likely to be covered under the bill.[12]

The allocation of emissions allowances to covered sectors and entities is not completely fixed by the bill. Some of the Government-issued allowances are to be distributed directly to covered entities, and the rest are to be allocated to the Corporation. While a number of criteria for allocating emissions allowances are defined by the bill, neither the total percentage of allowances distributed free, nor the share distributed to each of the covered sectors, is defined in the bill. The bill does, however, describe an allocation procedure to reward entities for registered emissions reductions made since 1990 and reductions made in advance of the 2010 start date. Entities with creditable reductions are granted a corresponding increase in their future allocation of allowances in the compliance period beginning in 2010. These credits for early action do not affect the overall compliance cap; they only affect the allocation of free allowances to covered entities. Nevertheless, this provision provides an incentive to reduce emissions early as a means of obtaining greater allowance allocations in the future.

Approach and Scenarios

EIA analyzed the bill using the National Energy Modeling System (NEMS). The primary reference case for the analysis was based on the NEMS reference case results published in EIA's *Annual Energy Outlook 2003 (AEO2003),*[13] updated to reflect changes in electric generating capacity since the *AEO2003* was completed in January 2003; to incorporate revised expectations about near-term trends in natural gas

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[9] This provision requires the entity to show that a specific capital project is underway to reduce emissions, and any allowances borrowed must be returned at an effective interest rate of 10 percent per year. In addition, borrowed allowances count against the limit on alternate compliance offsets. Therefore, in the aggregate, allowance borrowing is likely to be minimal under the bill.

[10] The relationship between fuel economy credits and emission allowances is to be based on the emissions reductions attributable to the higher fuel economy, as determined by the Secretary of Transportation.

[11] These limits are subject to a biannual review for adequacy by the Under Secretary of Commerce for Oceans and Atmosphere.

[12] Because covered entities can, to a limited extent, fulfill their allowance requirement with registered reductions from abroad and by registered increases in net sequestration, their aggregate emissions would not necessarily reach 1990 levels.

[13] Energy Information Administration, *Annual Energy Outlook 2003,* DOE/EIA-0383(2003) (Washington, DC, January 2003), web site http://www.eia.doe.gov/oiaf/aeo/.

prices; and to reflect recent changes in corporate average fuel economy (CAFE) standards. In order to respond to the requests from Senators Inhofe, McCain and Lieberman, the following cases were analyzed with NEMS:

- ***S.139 Case***: This case simulates enactment of S.139, combined with *AEO2003* reference case assumptions for technology. This is the principal case used to represent the overall impacts of the bill. The other cases in the analysis are designed to test the assumptions incorporated in the S.139 case. The following assumptions are made in the S.139 case and are varied in the sensitivity cases:

    - **Allowance Banking**: Entities can overcomply (e.g., in Phase I) and bank allowances for future use (e.g., in Phase II). Arbitrage in allowance trading and banking is assumed to limit the annual growth rate of the allowance trading price.
    - **Alternate Compliance Percentage**: In aggregate, entities are assumed to obtain 16 percent of covered emissions allowances through the bill's alternate compliance provisions ("offsets") in Phase I (2010-2015), and 10 percent in Phase II (from 2016 on). Offsets come from: (1) emission reductions from noncovered entities (domestic); (2) increases in net biological carbon sequestration; and (3) international emissions reductions. The 16 percent reflects the bill's provision that some entities will be granted a 20 percent offset percentage (instead of 15 percent) in exchange for reducing their emissions to 1990 levels by 2010.
    - **Commercial Sector**: The S.139 case assumes that all entities in the commercial sector are exempt from emissions allowances and that all entities in the industrial sector are covered.
    - **Auction Percentage**: The S.139 case assumes that 20 percent of emissions allowances will be allocated to the Corporation in 2010, increasing linearly each year to 80 percent in 2025.
    - **Nuclear Power and Geological Sequestration**: The S.139 case assumes commercial availability of advanced nuclear plants and of geological carbon sequestration technologies in the electric power industry.

The following sensitivity cases were examined to analyze variations on the S.139 case:

- ***S.139 High Technology Case***: This case incorporates the high technology case assumptions.
- ***High Technology Reference Case***: This case combines the reference case assumptions with the high technology case assumptions in the *AEO2003* integrated high technology case and provides the basis for comparison with the S.139 high technology case
- ***No New Nuclear/No Sequestration Case***: This case shows the impacts of assuming that these advanced technologies would not be commercially available through 2025.
- ***S.139 High Natural Gas Price Case***: This case combines the high gas price reference case with enactment of S.139. It is intended to analyze the impact of higher natural gas prices on energy market decisions under S.139.
- ***High Natural Gas Price Reference Case***: This case assumes a more pessimistic outlook for domestic natural gas supply than in the reference case, resulting in higher natural gas prices.
- ***80 Percent and 20 Percent Allowance Auction Cases***: The S.139 case assumes that, initially, 20 percent of the emission allowances issued by the Government will be allocated to the Corporation, increasing to 80 percent by 2025. These cases show the impacts of two fixed percentages, 80 and 20 percent, allocated to the Corporation in each year of the forecast.
- ***Commercial Coverage Case***: This case assumes that all entities in the commercial sector are covered.
- ***No Banking Case***: This case assumes that the banking of emissions allowances for later use by covered entities is not incorporated as a compliance option. It is included to show the impacts of the banking provision included in S.139.

- ***S.139 International Offset Availability Cases***: This pair of cases examines the impact on the S.139 case of variability in international offset availability. The first case assumes no international offsets (low international offset supply case). The second assumes a doubling in the supply of offsets available at each price (high international offset supply case).
- ***S.139 High Percentage Offset Case***: This case examines the sensitivity of the S.139 case to increasing the percentage of allowance requirements that can be met by offsets to 50 percent in all years.

S.139 specifies the Phase I and Phase II emission allowance caps based on 2000 and 1990 data, excluding emissions from the residential sector, agriculture sector, and U.S. territories. The reference data cited in the bill are from the EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000*.[14] The bill specifies the annual allowances for Phase I and Phase II at 5,896 and 5,123 million metric tons carbon dioxide equivalent, respectively, adding the phrase "reduced by the amount of emissions of greenhouse gases . . . from noncovered entities." Noncovered entities include those not meeting the emissions threshold of 10,000 tons carbon dioxide equivalent, as well as emissions from sources deemed impractical by the EPA to measure.

The allowance caps for this analysis are based on: (1) energy-related carbon dioxide (CO_2) emissions as reported by EIA,[15] and (2) non-CO_2 emissions from a consolidated set of data provided by EPA that combines history, projections, and reduction potential. The allowance caps are derived by summing the CO_2 emissions from the affected energy sectors, the covered portions of methane and nitrous oxide emissions, and emissions of the high-GWP gases. Using these definitions, the Phase I and Phase II caps for covered entities are estimated at 5,372 and 4,613 million metric tons carbon dioxide equivalent. Except where otherwise noted, this report follows EIA's standard practice of reporting emissions of carbon dioxide and other greenhouse gases in carbon equivalent (rather than carbon dioxide equivalent) units, defined as the weight of the carbon content of carbon dioxide (i.e., just the "C" in CO_2). Emissions in carbon equivalent terms are converted to carbon dioxide equivalent terms by multiplying by 3.6667.[16] Thus, the Phase I and Phase II caps used in this report are 1,465 and 1,258 million metric tons carbon equivalent.

Greenhouse Gas Allowance Costs

The bill's allowance trading and offset provisions would result in markets for emission allowances and offset credits. The market for these allowances and related incentives is expected to result in a gradually increasing market-clearing price for allowances that reflects both the cost of reducing emissions and the impact of allowance banking. Because allowances can be sold or held for future use, covered entities will have an incentive to reduce emissions under the bill even if they are allocated sufficient allowances to cover their annual emissions. The two-phase compliance period provides an incentive for covered entities to overcomply and bank emission allowances during the first phase (2010-2015), when the allowance cap and offset limits are relatively lenient. The bank of allowances could then be used to reduce compliance costs under the more stringent Phase II allowance and offset caps.

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[14] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000,* EPA 430-R-02-003 (Washington, DC, April 2002).

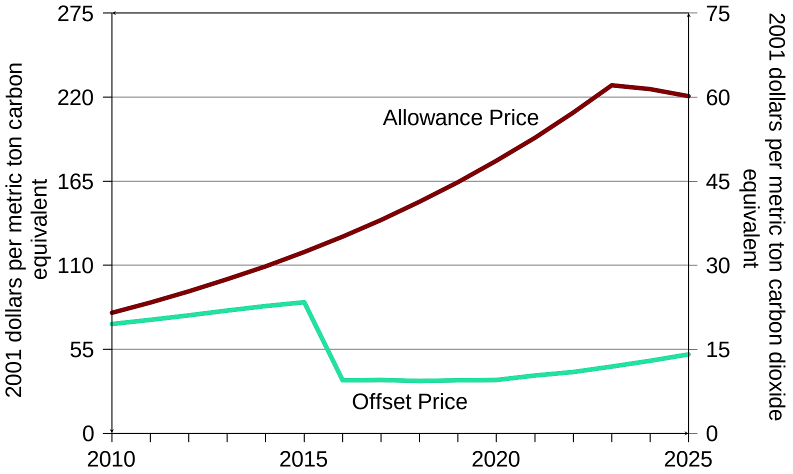
[15] Energy Information Administration, *Emission of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). There are several sources of difference between EIA's carbon dioxide emissions accounting and those in the EPA inventory. One is that EIA does not subtract emissions for military and international bunker fuels. Another is that EIA recently revised its energy data accounting for fossil fuels used to generate electricity.

[16] Conversely, emissions allowance prices in carbon equivalent terms are converted to carbon dioxide equivalent terms by dividing by 3.6667.

The decisions to sell or hold allowances for the future are expected to result in a gradually increasing allowance price that grows at a rate consistent with the rate of return for similar investments. This occurs because arbitrage in allowance trading tends to equate the current prices for allowances with the present discounted value of future allowances. For this analysis, a real discount rate of 8.5 percent was assumed. As a result, allowance prices are assumed to increase annually at a maximum rate of 8.5 percent. In practice, fluctuations in year-to-year prices would occur as a result of imperfect information and unexpected events.

The market for offset credits is conceptually similar to the allowance market. The bill provides an incentive for noncovered entities to make reductions and register them so they can be sold to covered entities. An organized market for these offsets is expected to develop, and almost all covered entities are expected to obtain and use the maximum allowable amount of offsets. In Phase I, covered entities can use offset credits to meet up to 15 percent of the allowance requirement (or 20 percent if they reach 1990 emissions levels by 2010). In Phase II, the offset limit is 10 percent. The offset limits, combined with the generally lower costs of initial reductions from offset sources, are expected to result in a lower market price for offsets than for allowances in the S.139 case (Figure S.1). If the limits on offsets were not binding, the market price for offsets and allowances would equalize.[17] In Phase II, the limit on offsets falls to 10 percent, which tends to lower the market-clearing price for offsets, because only the cheapest offset reductions are implemented to generate credits for use in meeting allowance requirements.

Figure S.1. Estimated Greenhouse Gas Allowance and Offset Prices in the S.139 Case, 2010-2025



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run MLBILL.D050503A.

Table S.1 compares the emissions-related results of the reference and S.139 cases for 2010, 2016, and 2025. For the most part, reductions in greenhouse gas emissions are expected to be phased in gradually, with some reductions occurring before the beginning of the first commitment period in 2010 (Figure S.2). The reductions occur both from the actions of covered entities and from the participation of noncovered entities that can register reductions voluntarily and sell them as offsets.

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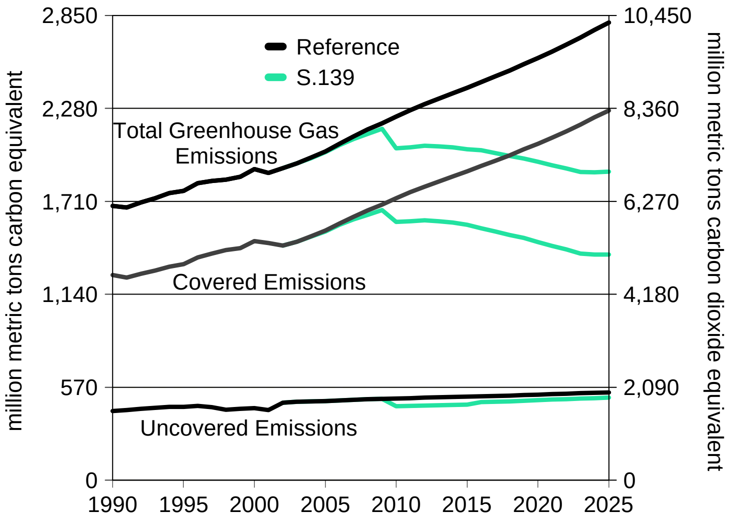
[17] A sensitivity case is used to test the effect of the offset limit. In that case, the prices of the offset and allowance market equalize.

Table S.1. Summary of Greenhouse Gas Emission Results, Reference and S.139 Cases, 2010, 2016, and 2025 (million metric tons carbon equivalent)

		2010		2016		2025	
	2001	Reference	S.139	Reference	S.139	Reference	S.139
Greenhouse Gas Emissions							
Energy-Related Carbon Dioxide	1,559	1,802	1,710	1,968	1,656	2,234	1,482
Non-Energy Carbon Dioxide	36	40	40	42	42	46	46
Methane	175	178	115	176	127	172	120
Nitrous Oxide	119	127	121	133	127	143	137
High-GWP Gases (HFCs, PFCs, and SF_6)	39	84	50	123	71	209	106
Total	**1,928**	**2,230**	**2,036**	**2,442**	**2,023**	**2,806**	**1,891**
S.139 Compliance Summary							
Covered Energy-Related Carbon Dioxide	1,379	1,605	1,513	1,763	1,452	2,014	1,257
Other Covered Emissions	75	124	70	163	91	251	128
Total Covered Emissions	**1,454**	**1,729**	**1,583**	**1,926**	**1,544**	**2,265**	**1,385**
Offset Reductions Purchased							
Noncovered Greenhouse Gases	—	—	49	—	36	—	39
Increases in Biological Carbon Sequestration	—	—	113	—	90	—	87
International Offsets	—	—	73	—	0	—	0
Total Offset Reductions	—	—	**235**	—	**126**	—	**126**
Covered Emissions, less Offsets	1,454	1,729	1,349	1,926	1,418	2,265	1,259
Emission Allowances Issued	—	—	1,465	—	1,258	—	1,258
Net Allowance Bank Change (+, deposit; -, withdrawal)	—	—	+117	—	-160	—	-1
Greenhouse Gas Emission Allowance Price							
(2001 dollars per metric ton carbon equivalent)	—	—	79	—	129	—	221
(2001 dollars per metric ton carbon dioxide equivalent)	—	—	*22*	—	*35*	—	*60*
Offset Trading Price							
(2001 dollars per metric ton carbon equivalent)	—	—	71	—	35	—	52
(2001 dollars per metric ton carbon dioxide equivalent)	—	—	*19*	—	*9*	—	*14*

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A. Data on greenhouse gas emissions for 2001 from Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2001*. Forecasts of reference case greenhouse gas emissions other than carbon dioxide from reference materials provided by the U.S. Environmental Protection Agency for a business-as-usual case, developed in preparing the *Climate Change Action Report 2001* and extrapolated to 2025. Chapters 2 and 3 discuss related issues and data sources in more detail.

Figure S.2. U.S. Greenhouse Gas Emissions in the Reference and S.139 Cases, 1990-2025



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

As a result of the allowance banking provisions, covered entities are expected to overcomply in Phase I (2010-2015). In 2010, total covered emissions are 1,583 million metric tons carbon equivalent and offset credits, which can be submitted in place of allowances, are 235 million metric tons carbon equivalent (Table S.1). Emissions allowances for the difference (1,349 million metric tons carbon equivalent) would be submitted in compliance with the bill. Given the estimated 1,465 million allowances issued in 2010, 117 million allowances can be banked for future use. The balance of banked allowances is expected to accumulate from 2010 to 2015, followed by its gradual depletion in Phase II (2016 and beyond). By the end of 2023, the bank balance is depleted, and emissions nearly level out, with the remaining growth coming from noncovered emission sources.[18]

NEMS simulates the energy market in detail and develops endogenous estimates of energy-related carbon dioxide emissions, the principal component of the greenhouse gases analyzed. The availability and costs of offsets, as well as the potential for reductions of covered greenhouse gases other than energy-related carbon dioxide, are based on assumptions exogenous to NEMS. These modeling assumptions are derived from reports and other research from the EPA. The assumptions are reflected in marginal abatement cost curves for greenhouse gas emissions and offsets from outside the energy sector. These assumptions, as well as other methodological issues, are discussed in Chapters 2 and 3. NEMS combines its estimates of carbon dioxide emissions with this information to simulate the allowance and offset markets.

NEMS estimates allowance prices and reflects the allowance prices in the costs of consuming fossil fuel. The demand for fossil fuel adjusts to the higher prices, thereby reducing the associated carbon dioxide emissions. Demand adjustments are varied and include short- and long-term changes, as discussed below. The impacts of allowance prices on energy costs and the economy are simulated in the macroeconomic component of NEMS, also discussed below. Offset prices are determined by the intersection of the offset supply curve and the cap on offsets specified by S.139.

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[18] Not reflected in Figure S.2 are changes in domestic biological carbon sequestration that are expected to be registered and purchased as offsets. In addition, some of the offsets purchased would be from international sources, as allowed in the bill. This topic is addressed in Chapter 3.

Energy Market Impacts

Energy consumers are expected to face higher effective costs of using energy as a result of the bill's allowance program. In the transportation sector, end-use consumers will face higher delivered prices of refined products, because refiners must obtain allowances for the greenhouse gas emissions associated with petroleum-based fuels sold for transportation. The cost of the allowances will be included in prices of the fuels.[19] Covered entities in the commercial,[20] industrial, and electric power sectors will implicitly face a higher cost of consuming fossil energy, because they will be required to obtain allowances for the carbon dioxide emitted in direct fuel use. To the extent that electricity generators can pass through the opportunity cost of allowances and related incremental capital costs to their customers, electricity prices will increase in all consuming sectors.[21] The increased energy costs, whether incorporated in delivered prices or reflected implicitly as opportunity costs of consuming energy, will affect all energy sectors of the economy. ***To simplify discussion of energy costs, the delivered prices of energy discussed in this section represent the effective delivered cost of using energy, including the direct and indirect costs of emissions allowances as applicable to the given sector***.[22]

Table S.2 presents a summary of the key energy-related results for 2010, 2016, and 2025 for the reference and S.139 cases, including the carbon dioxide emissions results. Tables of the complete results for all the cases are included in the full report, Appendixes C through I.

Delivered prices of coal, natural gas, petroleum, and electricity all increase in the S.139 case relative to the reference case (Figure S.3) as a consequence of the emissions allowance program. Figure S.4 shows the percentage change in delivered prices from the reference case to the S.139 case. In percentage terms, coal prices are most affected by S.139: the price in the S.139 case is 474 percent above the reference case price in 2025. Natural gas prices in the S.139 case are 46 percent above the reference case prices in 2025, average petroleum product prices are 29 percent higher, and prices for petroleum-based transportation fuels are 31 percent higher. These price changes reflect supply and demand shifts as well as allowance costs. For example, the reduced U.S. demand for oil in the S.139 case is expected to reduce the world oil price by 7 percent and help mitigate the price impact on final consumers. The increased U.S. demand for natural gas works in the opposite direction, increasing the market-clearing price of gas at the wellhead. Electricity prices, reflecting the higher cost of using fossil fuels for generation and the incremental cost of plant investments to reduce greenhouse gas emissions (e.g., by replacing coal-fired plants that do not sequester carbon dioxide), are 46 percent above the reference case level in 2025. Compared with the changes in coal prices, the average percentage increase in the remaining energy prices is relatively modest. This reflects both the substantially higher initial prices of other fossil fuels and their lower emissions of carbon dioxide per unit of energy.

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[19] Note that refineries, as industrial entities, would be required to obtain allowance permits for the fuel they burn in refining oil, in addition to allowances for downstream emissions of the transportation fuel they sell.

[20] While entities in the commercial and industrial sector with emissions greater than 10,000 metric tons of carbon dioxide per year are covered by the bill's allowance program, we have assumed in the S.139 case that no commercial entities are covered and that all industrial entities, with the exception of agriculture, are covered. This assumption is based partly on the lack of data on emissions by entities as defined by the bill. See Chapter 2 for a discussion of coverage assumptions.

[21] It is assumed that 90 percent of the allowance revenue acquired from the sale of greenhouse gas allowances by regulated utilities would be used to mitigate the electricity price increases of its customers and only 10 percent would be allocated to the shareholders as profits.

[22] The prices that do not include allowance costs are fossil fuels used by noncovered entities in the residential, commercial, and agricultural sectors, which do not need allowances.

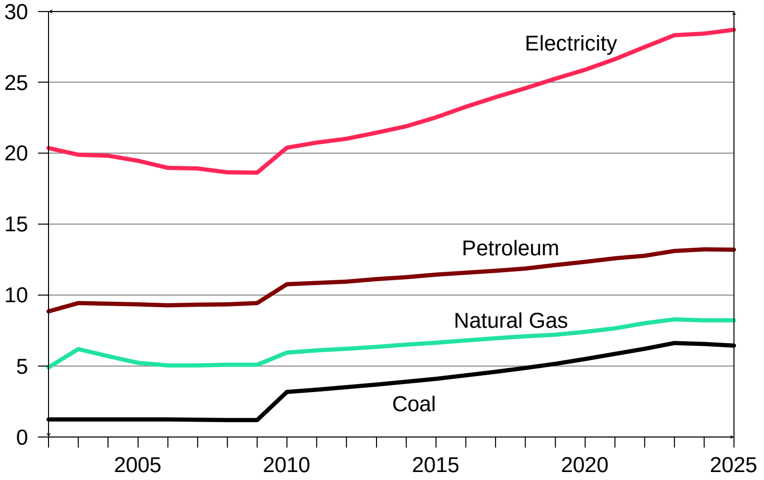
Table S.2. Summary of Energy Sector Results, Reference and S.139 Cases, 2010, 2016, and 2025

			2010		2016		2025	
Summary Indicators	**2000**	**2001**	**Reference**	**S.139**	**Reference**	**S.139**	**Reference**	**S.139**
Greenhouse Gas Allowance Cost (2001 dollars per metric ton)	—	—	—	79	—	129	—	221
Effective Delivered Energy Prices (2001 dollars per million Btu)								
Coal	1.24	1.26	1.18	3.18	1.16	4.34	1.12	6.44
Natural Gas	5.59	6.40	5.15	5.96	5.40	6.80	5.64	8.22
Motor Gasoline	12.42	11.57	11.45	12.98	11.33	13.70	12.07	15.31
Jet Fuel	7.26	6.20	5.66	7.10	6.03	8.24	6.72	10.35
Distillate Fuel	10.05	9.16	9.15	10.45	9.33	11.29	9.90	13.17
Electricity	20.18	21.34	18.76	20.40	19.28	23.28	19.66	28.70
Primary Energy Use (quadrillion Btu)								
Natural Gas	24.07	23.26	27.35	28.12	30.53	32.42	35.55	39.54
Petroleum	38.53	38.46	44.45	43.74	49.20	47.02	56.11	50.76
Coal	22.64	22.02	25.47	22.00	26.94	15.86	29.86	6.74
Nuclear	7.87	8.03	8.25	8.37	8.28	8.80	8.28	12.39
Renewable	5.95	5.32	7.30	9.03	7.94	12.76	8.77	16.22
Other	0.31	0.21	0.31	0.43	0.24	0.49	0.06	0.32
Total	**99.37**	**97.29**	**113.13**	**111.67**	**123.12**	**117.35**	**138.63**	**125.97**
Electricity Sales (quadrillion Btu)	11.73	11.65	14.00	13.82	15.53	14.75	17.90	15.87
Carbon Dioxide Emissions by Fuel (million metric tons carbon equivalent)								
Natural Gas	341	329	391	402	437	452	509	493
Petroleum	659	668	761	748	843	806	963	870
Coal	579	561	650	560	688	398	763	119
Total	**1,578**	**1,559**	**1,802**	**1,710**	**1,968**	**1,656**	**2,234**	**1,482**
Carbon Dioxide Emissions by Sector (million metric tons carbon equivalent)								
Residential	317	314	355	326	372	275	406	181
Commercial	274	279	320	291	352	251	411	166
Industrial	477	451	500	472	534	448	592	391
Transportation	510	514	628	622	709	681	826	744
Total	**1,578**	**1,559**	**1,802**	**1,710**	**1,968**	**1,656**	**2,234**	**1,482**
Electricity Generation	621	612	697	615	759	485	868	205
Carbon Dioxide Reductions by Sector (million metric tons carbon equivalent)								
Residential	—	—	—	29	—	97	—	225
Commercial	—	—	—	29	—	101	—	245
Industrial	—	—	—	28	—	86	—	201
Transportation	—	—	—	6	—	28	—	82
Total	—	—	—	**92**	—	**312**	—	**752**
Electricity Generation Component	—	—	—	82	—	274	—	663

Notes: “Other” includes net electricity imports, methanol, and liquid hydrogen. “Effective Delivered Energy Prices” include cost of greenhouse gas allowances.

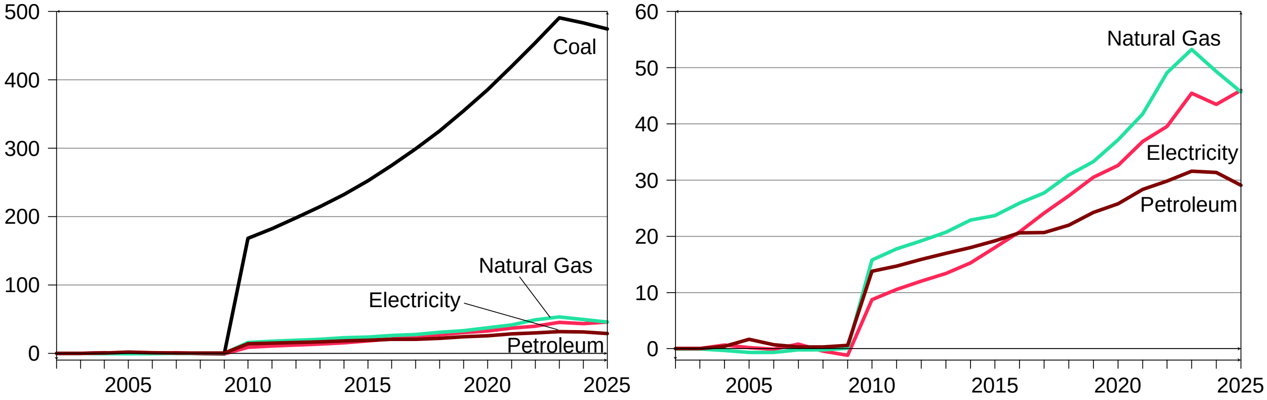
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure S.3. Effective Delivered Energy Prices in the S.139 Case, 2002-2025 (2001 dollars per million Btu)



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A.

Figure S.4. Effective Delivered Energy Prices in the S.139 Case: Change from Reference Case (percent)



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

The cap on greenhouse gas emissions imposed by S.139 favors fuels and technologies with low emissions. Because the carbon dioxide emissions factor for natural gas is 56 percent of the rate for coal,[23] natural gas use is expected to increase under the bill. More electricity is projected to be produced from renewable and nuclear power in the S.139 case, with fuel costs for these technologies unaffected by greenhouse gas allowance costs. Cost-of-service electricity pricing, which is assumed for some parts of the country, would ameliorate the impacts of S.139 to a certain extent, with consumers expected to benefit from allowances allocated freely to regulated utilities. In addition, nonfuel operating and maintenance costs and capital equipment costs have a larger role in setting electricity prices under cost-of-service

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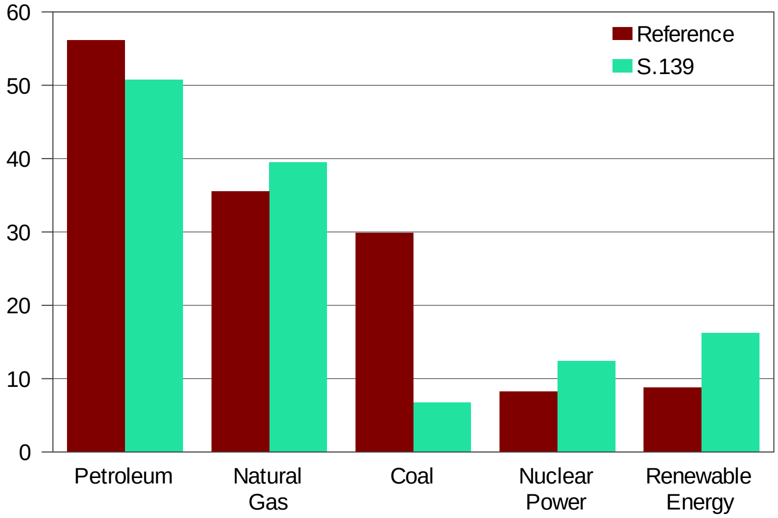
[23] The emissions factors cited reflect emissions per unit of fuel consumed and do not reflect differences in fuel efficiency related to the fuel's use (e.g., for electricity generation).

pricing. In regions where electricity prices are assumed to be set competitively on the basis of marginal costs, greenhouse gas allowance costs would have a more significant influence on electricity prices.

By 2025, the mix of fuels consumed in the S.139 case differs significantly from that in the reference case (Figure S.5). Changes in relative fuel prices cause a reduction in coal and petroleum use, along with a greater reliance on natural gas, renewable energy, and nuclear power. The use of coal, with its high carbon content and relatively low efficiency in existing steam generation, is greatly reduced under S.139. It is replaced by more use of natural gas, renewable fuels, and nuclear power in electricity generation. Coal's 2025 share of generation is reduced from 49 percent in the reference case to 11 percent in the S.139 case. Some reduction in coal use, compared with the reference case, occurs before the start of the S.139 reductions in 2010. These changes occur as the result of anticipatory behavior in the electricity industry, where capacity planning decisions in advance of 2010 are influenced by prospective allowance costs and incentives for early action. The specific results are sensitive to the characterization of technology costs, particularly for carbon dioxide capture and sequestration. They are also sensitive to the availability of natural gas and market acceptance of nuclear power.

Figure S.5. Primary Energy Consumption by Fuel in the Reference and S.139 Cases, 2025 (quadrillion Btu)



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Natural gas consumption is higher in the S.139 case than in the reference case as a result of greater use of natural gas in the electricity sector. Although more natural gas is used for electricity generation, the increase is relatively small compared to the more significant increase in the use of renewables. The response of the natural gas industry to the increased demand under S.139 is discussed in Chapter 6.

Petroleum use, particularly in the transportation sector, is reduced in the S.139 case. Motor gasoline demand, accounting for 46 percent of total petroleum consumption in 2025 in the reference case, is 13 percent lower in 2025 in the S.139 case than in the reference case. Consumers respond to higher gasoline prices by reducing miles driven and purchasing more efficient vehicles. The bill also provides automobile manufacturers with incentives to supply more efficient vehicles, as discussed in Chapter 4.

Nuclear power, which produces no greenhouse gas emissions, becomes more attractive under the S.139 reduction targets. In the S.139 case, 49 gigawatts of new nuclear capacity is projected to be built by 2025. As a result, the use of nuclear power for electricity generation is projected to be 50 percent higher in the S.139 case than in the reference case.

Consumption of renewable energy, which results in no net greenhouse gas emissions, is projected to be much higher under S.139. Most of the increase is for electricity generation, with additions primarily to biomass and wind generating capacity and more modest additions to geothermal and landfill gas capacity. The share of generation supplied by renewables, including hydropower, increases from 8 percent in 2025 in the reference case to 23 percent in the S.139 case. Steady growth in renewables begins even before the onset of Phase I of S.139 in 2010, due to the early compliance initiatives by generators and increases markedly after 2015, as higher market penetration of renewables reduces their costs and improves their performance over time.

Electricity generation, which accounted for 39 percent of energy-related carbon dioxide emissions in 2001, is significantly lower in the S.139 case than in the reference case. In the S.139 case, electricity sales in 2025 are 11 percent below the reference case projection, with the residential sector showing the largest reduction at 14 percent. Electricity demand in the residential sector shows a greater response to S.139 than does residential natural gas demand, because prices for electricity reflect the cost of emission allowances passed on to electricity consumers, whereas no allowances are required for consumption of natural gas in the residential sector. Consequently, the main impact of S.139 on the residential sector is higher electricity prices, leading to lower consumption of electricity.

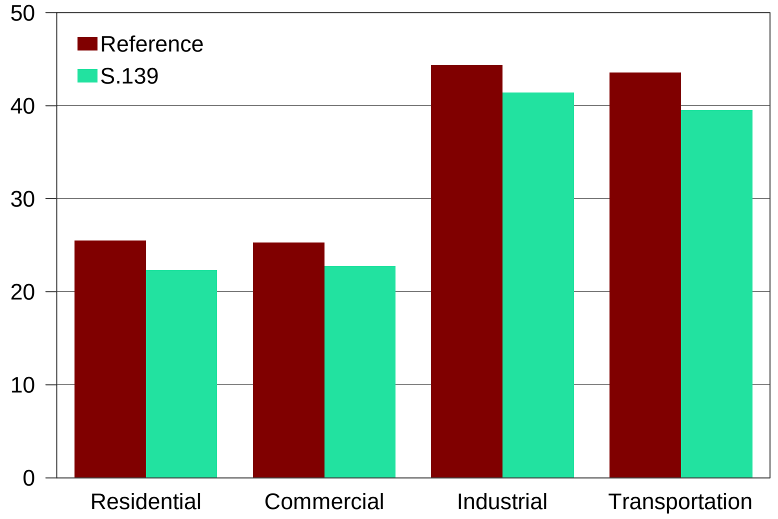
Sectoral Impacts

Energy demand across each of the end-use sectors—residential, commercial, industrial, and transportation—will respond in different degrees to the incentives imposed by S.139 (Figure S.6). Although the bill’s definition of covered entities effectively exempts the residential sector and most of the commercial sector from the requirement to purchase greenhouse gas emission allowances, consumers in those sectors still will face higher prices for electricity and natural gas due to S.139. The change in residential and commercial electricity prices reflects the power industry’s higher fuel supply costs, allowance costs, and incremental capital costs for lower-emitting generating technologies. The natural gas prices in these sectors reflect the pass-through of higher wellhead prices due to increased demand for natural gas.

In the industrial sector, consumers will face higher prices (including the cost of greenhouse gas allowances) for all fossil fuels and electricity, leading to greater incentives to conserve energy, switch to lower-carbon energy sources, and invest in more energy-efficient technologies. Transportation consumers will also face higher petroleum prices, because the cost of greenhouse gas emission allowances purchased by refiners will be included in prices for motor gasoline, diesel fuel, and jet fuel.

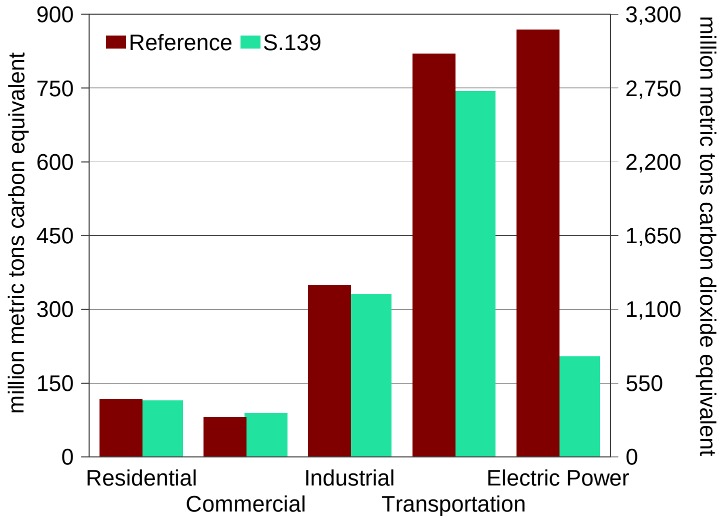
Figure S.7 illustrates the contribution of each sector in reducing energy-related carbon dioxide emissions in 2025 under the S.139 case. When the emissions from electricity are apportioned to the end-use sectors, the residential and commercial sectors account for the greatest reduction, and transportation accounts for the least. As also shown in Figure S.7, most of the carbon dioxide reductions for the four end-use sectors occur in electricity, stemming from both reduced electricity demand and the use of more efficient, less carbon-intensive sources of generation. Reductions in carbon dioxide emissions from electricity generation account for 88 percent of the total energy-related carbon dioxide reductions in 2025. A variety of factors contribute to the central role played by the electricity sector in meeting the greenhouse gas reduction targets: the industry’s current dependence on coal; the availability and economics of technologies to switch from coal to less carbon-intensive energy sources; and the comparative economics of fuel switching in other sectors. As discussed in more detail in Chapter 4, the extent to which end-use energy consumers respond to prices is often limited.

Figure S.6. Total Primary Energy Consumption by Sector in the Reference and S.139 Cases, 2025 (quadrillion Btu)



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure S.7. Carbon Dioxide Emissions in the Reference and S.139 Cases by Originating Sector, 2025



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

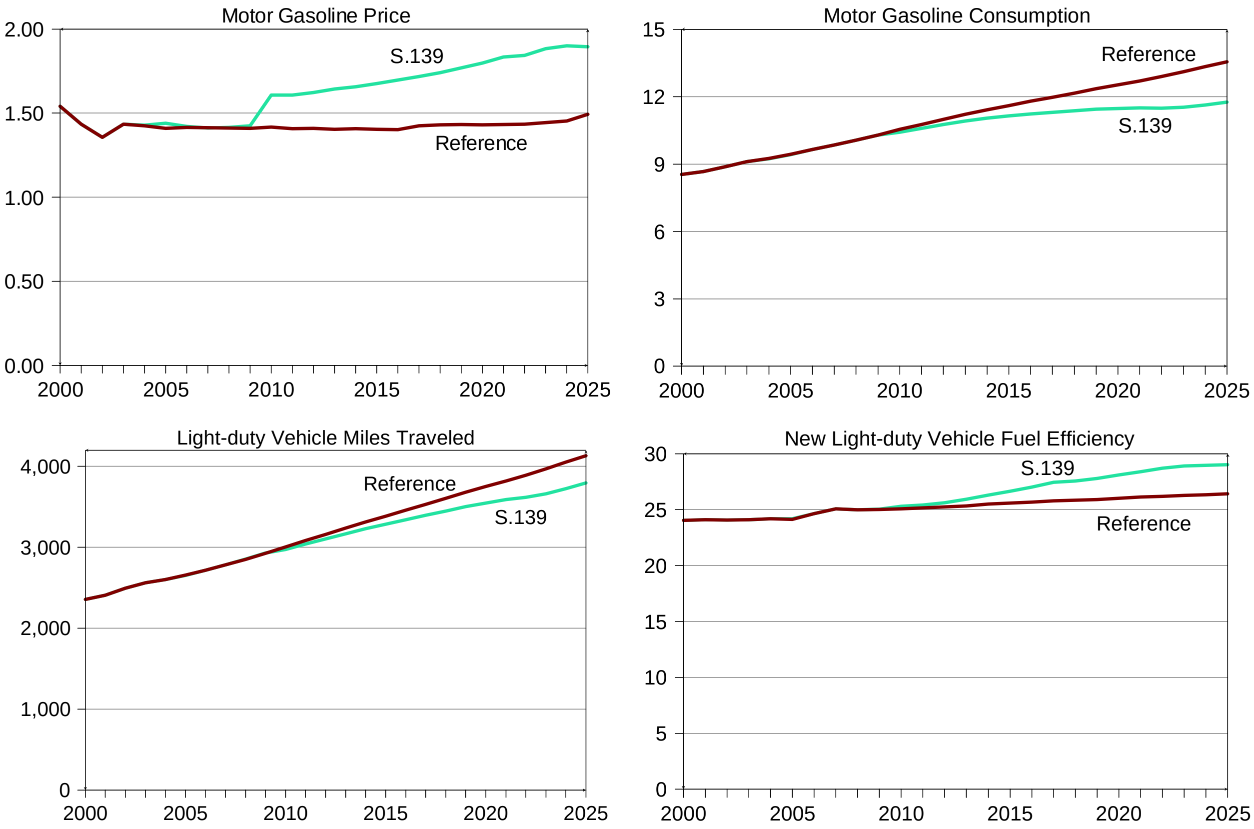
In the industrial sector, some carbon dioxide emission reductions under S.139 can be attributed to reductions in manufacturing output that result from the impact of higher energy prices (including greenhouse gas allowance costs) on the economy. In addition, industrial firms are expected to respond by replacing productive capacity faster, investing in more efficient technology, and switching to less carbon-intensive fuels. Improvements in efficiency are indicated by reductions in energy intensity, as measured by the energy use per dollar of GDP. In 2025, industrial energy intensity is reduced from 4.38 thousand Btu per 1996 dollar of GDP in the reference case to 4.14 thousand Btu per dollar in the S.139 case.

Taking into account fuel switching and efficiency improvements, carbon equivalent emissions per unit of GDP in 2025 for the industrial sector are reduced from 31 kilograms per thousand dollars of GDP in the reference case to 21 kilograms per thousand dollars of GDP in the S.139 case.

Carbon dioxide reductions in the transportation sector occur primarily as the result of reduced travel and the purchase of more efficient vehicles in response to higher energy prices and manufacturer incentives. Compared with the reference case, light-duty vehicle travel (cars, vans, pickup trucks, and sport-utility vehicles) in 2025 is lower by 8 percent in the S.139 case (Figure S.8). At the same time, more efficient cars and light trucks are purchased, raising overall fleet efficiency. By 2025, the average fuel efficiency for the light-duty vehicle fleet is 21.8 miles per gallon under S.139, compared with 20.5 miles per gallon in the reference case. The result of these travel and efficiency changes is a reduction of 13 percent from the reference case level of motor gasoline demand in 2025. Travel reductions and efficiency improvements also occur in the air and freight sectors, further reducing carbon dioxide emissions. Overall, transportation energy consumption in 2025 is 9 percent lower in the S.139 case than in the reference case.

Although the residential sector is exempt from emissions allowances and the commercial sector is assumed not to be covered in the S.139 case, these sectors show significant reductions in electricity-related emissions. Electricity consumers in these sectors are expected to respond to the higher electricity

Figure S.8. Motor Gasoline Consumption and Prices, Light-Duty Vehicle Miles Traveled, and New Light-Duty Vehicle Fuel Efficiency in the Reference and S.139 Cases, 2000-2025



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

prices by taking advantage of appliance rebates or related incentives that the bill provides to reduce its economic impacts.[24] Higher energy prices, particularly for electricity, encourage investments in more efficient equipment and building shells and also reduce the demand for energy services.

In the residential sector, delivered energy use per household in 2025 drops by 7 percent in the S.139 case compared with the reference case. Energy consumption for space conditioning accounts for 35 percent of the total change in residential delivered energy consumption in that year, with lighting accounting for 32 percent of the reduction. Those energy services for which relatively stringent appliance efficiency standards are already in place and for which little opportunity for direct energy conservation measures exist (such as for refrigerators and freezers) are not expected to change greatly under the bill. The current standards for some residential appliances reflect very efficient technology that already reduces fuel consumption substantially in the reference case. The fastest-growing segments of residential electricity consumption, including color televisions, personal computers, and other uses, accounted for approximately 25 percent of residential electricity consumption in 2001. Relative to the reference case, electricity consumption per household in these categories is 7 percent lower in the S.139 case than in the reference case by 2025.

In general, increases in energy costs tend to have a greater percentage impact on lower-income households, because energy expenditures are a higher percentage of their disposable income.[25] The impact on the residential sector from higher energy prices and expenditures could be mitigated by actions of the Corporation. The funds collected by the Corporation from allowance sales can be dispersed to residential energy consumers by various methods, including rebates, subsidies, and general transition assistance to displaced workers. It is assumed in the S.139 case that the Corporation will issue rebates for energy-efficient appliances, and that from 2010 through 2025, half of the incremental cost to purchase more efficient appliances is covered by rebates initiated by the Corporation. (See Chapter 4 for more on this assumption, which is not explicitly defined by the bill but is used as a proxy for potential options that could be used to reduce the economic impact on consumers.) Any funds above those for transition assistance collected by the Corporation and not rebated for appliances are assumed to be rebated to consumers through transfer payments or other rebates. As a result, S.139 has the potential to mitigate the adverse distributional impacts on households.

Because direct emissions in the residential sector are not covered by S.139, households heated primarily by natural gas and home heating oil will be less affected by the bill than those using electricity. This tends to introduce a geographical disparity in the bill's impact on households, in that residences dependent on electric heating tend to be located in regions with a milder climate. Similarly, because the bill is expected to result in higher natural gas prices while reducing heating oil prices somewhat, regions dependent on these fuels will face different outcomes under the bill, based on energy price changes alone.

For this analysis, the impacts on several prototype single-family homes using different fuels were analyzed. For the natural gas home, it is assumed that natural gas is used for space heating, water heating, cooking, and clothes drying. The home using oil for heating is assumed to use electricity for all other energy needs, and the all-electric home is assumed to use only electricity. On average, residents of an all-electric single-family home can expect to pay an average of $257 more per year for energy (in 2001 dollars), a 17 percent increase, in the S.139 case than in the reference case over the 2010 to 2025 period. The natural gas prototype home exhibits the least increase in average expenditures in the period, increasing by $154 per year over the same period, a 10 percent increase over the reference case. Because

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[24] See Chapters 2 and 4 for more on the assumptions and effects of appliance efficiency and other programs that could be funded by the Corporation to reduce the economic impacts of the bill.

[25] See Chapter 4 for a summary of data from EIA's Residential Energy Consumption Survey showing how home energy consumption varies by income cohort.

the oil heat prototype home relies on electricity for clothes drying, cooking, and water heating—services that can be provided by natural gas—the average expenditures over the 2010-2025 period increase more than those for the natural gas prototype home, even with lower delivered energy prices in the S.139 case, relative to the reference case. Residents of these homes can expect to pay an average of $169 per year more over the 2010-2025 period, a 9 percent increase over the reference case.

In the commercial sector, direct emissions of carbon dioxide increase slightly in the S.139 case compared to the reference case, as greater use of natural-gas-based combined heat and power is adopted. While this technology increases direct emissions in the commercial sector, overall emissions, including electricity-related emissions, are lower. Overall, delivered energy use per square foot of commercial floorspace in 2025 drops by 2 percent in the S.139 case compared with the reference case. As in the residential sector, significant energy reductions are projected for heating, cooling, and ventilation. However, the largest energy savings come in lighting, offset somewhat by increased use of energy for "other uses," which include such appliances as medical equipment and telecommunications equipment, as well as combined heat and power in commercial buildings. Because of the shift away from purchased electricity to combined heat and power, natural gas use increases in the S.139 case in 2025 compared to the reference case.

The electricity generation sector is expected to respond strongly to the incentives imposed by S.139. The mix of fuels used for electricity generation is projected to change rapidly as new plants come on line. In the aggregate, cumulative investments by generators to reduce carbon dioxide emissions tend to reduce generation from coal and petroleum and to increase the use of renewables, natural gas, and nuclear. Generation from coal, which currently accounts for about half of all electricity, drops significantly as the cost of coal (including allowance costs) to generators increases by a factor of almost 6 in the S.139 case compared to the reference case by 2025. To replace coal plants, generators build natural-gas-fired combined-cycle plants; extend the life of existing nuclear plants and build new ones; increase the use of renewables, particularly biomass and wind energy systems; and build both coal- and natural-gas-fired capacity that includes carbon sequestration technology, which becomes economical once a greenhouse gas emissions target is imposed. These changes, coupled with the expected reduction in electricity demand, result in carbon dioxide emissions from electricity generation of 205 million metric tons carbon equivalent in the S.139 case in 2025, compared with 868 million metric tons carbon equivalent in the reference case. Issues related to plant capacity changes in the electricity industry are discussed in detail in Chapter 5.

Macroeconomic Impacts

S.139 leaves the allocation of available allowances between the Corporation and covered emissions sources to be determined in a future administrative process.[26] It is assumed in the S.139 case that emission allowances are allocated to the Corporation, beginning with 20 percent in 2010 and rising to 80 percent by 2025. The Corporation is assumed to auction the allowances, thereby collecting substantial revenue.

As shown in Figure S.1 above, the allowance price rises steadily through 2023, leveling off as the amount of banked allowances approaches zero. In 2010, the aggregate value of allowances in nominal terms totals $116 billion, with $23 billion flowing to the Corporation from sale of its share of allowances. By 2025, the aggregate nominal value of allowances is $473 billion, with $378 billion flowing to the Corporation. The magnitude of the funds collected, the distribution of the permits between covered entities and the Corporation, and the ultimate use of these funds by the Corporation have impacts on the aggregate economy.

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[26] The bill does not specify the share of allowances that would be allocated to the Corporation, leaving this to be determined on an annual basis by the Secretary of Commerce, subject to the approval of Congress.

Under Section 352 of S.139, the Corporation must allocate a percentage of the proceeds from allowances to provide transition assistance to dislocated workers and communities. The percentage is specified to be 20 percent in 2010, reduced by 2 percentage points each year and reaching zero in 2020. The transition assistance amount, however, is a small share of the total allowance proceeds collected by the Corporation. After accounting for the transition assistance, the vast majority of the revenues collected by the Corporation remain to be spent or returned to the economy. As a central assumption of this analysis, the remaining funds are assumed to be transferred back to the consumer as a lump-sum transfer—a rebate check. This refund helps to compensate consumers for higher direct energy costs and higher prices for non-energy goods and services.

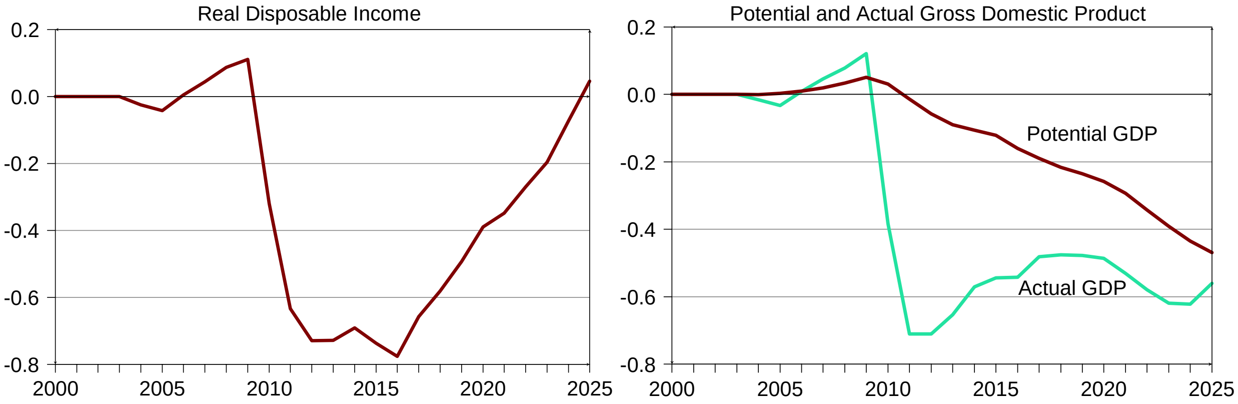
The consumer impacts of the bill are reflected by changes in disposable income (Figure S.9). Initially a low proportion of the funds is allocated to the Corporation, but the proportion increases over the forecast horizon. As the Corporation transfers these rising proceeds to consumers, real disposable income recovers rapidly. From a peak loss of around 0.8 percent ($81 billion in 1996 dollars) in 2016, real disposable income recovers to the reference case level by 2025.

As a consequence of the allowance program, energy prices in the U.S. economy are expected to rise, first driving up the wholesale prices of fuel and power. These price increases raise downstream prices for all goods and services in the economy, as reflected in the wholesale price index (WPI) and the consumer price index (CPI). Relative to the reference case, the WPI for energy is projected to increase in 2010 by 16 percent, the WPI for producer prices by 2.4 percent, and the CPI for goods and services by 0.6 percent. By 2025, the three measures rise by 57 percent, 9.0 percent, and 2.5 percent, respectively, relative to the reference case.

In the long run, higher energy costs reduce the use of energy by shifting production toward less energy-intensive sectors, by replacing energy with labor and capital in specific production processes, and by encouraging energy conservation. Although reflecting a more efficient use of higher-cost energy, this gradual reduction in energy use would tend to lower the productivity of other inputs in the production process. The ultimate impacts of greenhouse gas mitigation policies on the economy will be determined by interactions between elements of aggregate supply and demand and by monetary and fiscal policy decisions. Raising energy prices and, as a result, downstream prices in the rest of the economy is expected to introduce cyclical behavior in the economy, resulting in employment and output losses in the short run. The measurement of losses in output for the economy, or actual GDP, incorporates the transitional cost to the aggregate economy as it adjusts to its long-run path as reflected by potential GDP. Resources may be less than fully employed, and the economy may move in a cyclical fashion toward equilibrium as it adjusts to the initial cause of the disturbance—the increase in energy prices.

The expected interaction between these impacts is summarized in Figure S.9. The graph shows projected losses in potential and actual GDP as a result of S.139. The loss in actual GDP reflects the macroeconomic adjustment cost that is expected to result from higher energy prices as a result of the greenhouse gas mitigation policy. Cyclical adjustments in actual GDP are expected to occur in the short run, but actual GDP eventually converges toward potential GDP by 2025. Actual GDP, which incorporates adjustment costs associated with moving toward a new long-run equilibrium, shows a sharp decline of 0.7 percentage points in 2011 and 2012 (relative to the reference case). Thereafter, the economy begins to rebound from the initial price effects. However, there is a steady negative impact on the long-run supply potential of the economy as all segments adjust to the new pattern of energy use. While the two economic measures merge by 2025 at a loss of 0.6 percent of actual GDP and 0.5 percent of potential GDP, the process of adjustment for both real and potential output has not reached completion by the end of the forecast period.

Figure S.9. Change in Real Disposable Income, Potential GDP, and Actual GDP in the S.139 Case Relative to the Reference Case (percent)



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Given projected 2025 GDP in the reference case of $18.9 trillion (1996 dollars), the estimated losses in actual and potential GDP are large in dollar terms—$106 billion and $90 billion, respectively, with even larger cumulative impacts (Table S.3). However, the compounded GDP growth rates from 2001 to 2025 are virtually identical in the two cases: 3.04 percent per year in the reference case and 3.02 percent per year in the S.139 case. This suggests that the uncertainty in growth patterns related to other factors that drive the U.S. economy, such as labor force and productivity growth, are likely to play a larger role than decisions regarding the enactment of S.139 in determining the size of the U.S. economy in 2025.

Table S.3. Economic Impacts of S.139 (billion 1996 dollars and percent change relative to the reference case)

	Actual GDP	Potential GDP
Cumulative GDP Loss, 2004-2025 (billion 1996 dollars)		
Undiscounted	-1,354	-559
Discounted at 7 Percent per Year	-507	-165
Percent Change from Reference Case		
Undiscounted	-0.4%	-0.2%
Discounted at 7 Percent per Year	-0.3%	-0.1%
Economic Impact, 2025		
GDP Loss (billion 1996 dollars)	-106	-90
Percent Change from Reference Case	-0.6%	-0.5%

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Sensitivity Analyses

Long-term economic projections are highly uncertain in general, and even more so when legislation with the complexity of S.139 is being analyzed. One area of uncertainty is the growth in emissions that might occur in the bill's absence. The baseline forecast used affects the amount of change needed to meet an emission target, as do the modeling methodologies and assumptions. Issues regarding availability of low carbon emitting technologies and offsets from emissions other than carbon dioxide and from international sources affect the ability to comply with S.139 and the feasibility of the analytical results. Estimation of GWPs and historical emissions for non-energy-related greenhouse gases, while currently the best available, can still benefit from improved methodologies. Factors that influence the future development of energy markets, including technology development and resource availability and costs, also affect the results. Sensitivity cases were analyzed to evaluate the uncertainties. Other uncertainties, such as the potential for political and economic disruptions, are also important but are beyond the scope of this analysis.

Some of the sensitivity cases discussed below were designed to examine uncertainties particular to the proposed legislation, as well as the impact of some of its flexibility features.[27] Additional cases examine key technology assumptions and energy supply issues. The results of the sensitivity cases are summarized below.

High Technology Sensitivity Cases

The cost and performance of emerging technologies useful in reducing energy use or its greenhouse gas intensity are among the most important factors affecting the evaluation of S.139 impacts. Using the assumptions of the *AEO2003* high technology case for the four end-use sectors and the electric power sector, a high technology reference case and a high technology variation of the S.139 case were prepared. Assumptions in the high technology cases vary by sector but generally include earlier availability, lower costs, and higher efficiencies for advanced technologies than in the reference case.

Table S.4 provides key results that can be used to show how assumptions about the state of energy-related technology affect the impacts of S.139. Energy-related carbon dioxide emissions in the high technology reference case are 8 percent lower in 2025 than in the standard reference case. The smaller reduction in carbon dioxide emissions needed to comply with S.139 reduces the estimated allowance price in the S.139 high technology case in 2025 by 28 percent relative to its level in the S.139 case.

Two alternative comparisons can be used to gauge the economic effects of S.139 under high technology assumptions. The first, which focuses on the change in economic performance between the high technology reference case and the S.139 high technology case, implicitly assumes that the enactment of S.139 does not affect the set of available technologies, only what and how much is chosen from that set. Using this comparison, S.139 reduces accumulated actual GDP over the modeled 2004-2025 time frame by $1.035 trillion[28] (0.33 percent). In 2025, when the transition to the S.139 regime is largely complete, the overall size of the economy is reduced by $95 billion (0.50 percent).

Alternatively, economic performance in the S.139 high technology case and the standard reference case can be compared. This comparison implicitly assumes that S.139 is directly responsible for creating technologies with the cost and performance characteristics of EIA's high technology suite, which would not be available in its absence. Using this approach, S.139 reduces accumulated actual GDP over the modeled 2004-2025 time frame by $971 billion (0.31 percent). In 2025, the overall size of the economy is reduced by $94 billion (0.50 percent).

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[27] These cases are presented in response to the requests made by the solicitors of the analysis.

[28] GDP and disposable income values in this section are in 1996 dollars.

Table S.4. Comparison of Key Results in the Reference and High Technology Sensitivity Cases, 2010 and 2025

	2010				2025			
	Reference	High Technology Reference	S.139	S.139 High Technology	Reference	High Technology Reference	S.139	S.139 High Technology
Greenhouse Gas Emission Allowance Price (2001 dollars per metric ton carbon equivalent)	—	—	79	59	—	—	221	158
Electricity Price (2001 cents per kilowatthour)	6.40	6.29	6.96	6.71	6.71	6.25	9.79	8.57
Electricity Sales (billion kilowatthours)	4,104	4,020	4,050	3,965	5,246	4,997	4,653	4,481
Cumulative Incremental[a] Capacity Additions (gigawatts)								
Coal	12	9	0	0	81	60	38	18
Natural Gas Combined Cycle	32	30	60	51	162	183	260	262
Combustion Turbine/Diesel	9	4	4	1	52	17	4	1
Nuclear Power	0	0	0	0	0	0	49	41
Renewables	1	3	33	25	5	11	148	110
Distributed Generation	2	1	2	1	18	8	5	2
Total Additions	**57**	**47**	**98**	**77**	**318**	**280**	**503**	**433**
Energy Consumption (quadrillion Btu)								
Coal	25.47	24.85	22.00	22.47	29.86	26.89	6.74	8.00
Natural Gas	27.35	26.62	28.12	26.82	35.55	32.35	39.54	36.44
Petroleum	44.45	43.82	43.74	43.30	56.11	53.29	50.76	49.41
Nuclear	8.25	8.17	8.37	8.37	8.28	8.05	12.39	11.76
Renewable	7.30	7.71	9.03	9.03	8.77	10.28	16.22	15.60
Electricity Imports	0.31	0.27	0.43	0.41	0.06	0.05	0.32	0.11
Total	**113.13**	**111.44**	**111.67**	**110.39**	**138.63**	**130.90**	**125.97**	**121.31**
Carbon Dioxide Emissions by Fuel								
Coal	650	634	560	573	763	687	119	182
Natural Gas	391	381	402	383	509	463	493	451
Petroleum	761	750	748	740	963	911	870	844
Total	**1,802**	**1,764**	**1,710**	**1,696**	**2,234**	**2,060**	**1,482**	**1,477**

[a] Excludes plants under construction.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, MLBILL.D050503A, ML_HT.D050503A.

Analytical judgment and a recognition of inherent modeling limitations are needed to assess which approach is most likely to reflect the actual impact of “high technology” on the economic assessment of S.139. The major effect that S.139 has on delivered energy prices suggests that it should provide some incentive to research and develop new technologies to increase energy efficiency or reduce greenhouse gas intensity. If so, the first approach (comparison of two high technology cases) could overstate adverse economic impacts.

On the other hand, the second approach (comparison of the S.139 high technology case to the standard reference case) does not consider the cost of researching and developing new technologies. Moreover, NEMS does not explicitly represent the role of non-energy-related research and development (R&D) activities in supporting the baseline scenario of economic growth in its macroeconomic component. Therefore, NEMS cannot represent the macroeconomic impact of diverting R&D effort away from other sectors toward energy-related technologies. Such shifts in R&D effort would erode baseline growth to the extent that scarce R&D resources and technological progress in other areas of the economy were reduced.[29]

The analysis of these effects continues to be an active area of academic research. Based on its reading of the available literature, EIA’s view is that the first approach is most likely to provide estimates of economic impacts that are closest to the actual economic effects under a high technology scenario.

A separate issue related to technology is the possibility that one or more technologies superior to those identified in the “high technology” case could become available within the time frame of this analysis. While the high technology case assumptions are optimistic by design, there is always a potential for undiscovered or unanticipated technological developments to occur. The contribution of such technologies within the time frame of this analysis is likely to be limited by delays that often arise in the market penetration of new energy technologies, particularly when the new technologies are not readily compatible with the existing infrastructure.

No New Nuclear/No Sequestration Sensitivity Case

In the S.139 case, two of the key compliance strategies projected to be adopted in the electric power sector are geological carbon sequestration and advanced nuclear power. A sensitivity case, the no new nuclear/no sequestration case, was used to examine the results if neither of these technologies became competitively available by 2025. The estimated allowance prices for this sensitivity case (Figure S.10) are significantly higher than those in the S.139 case (34 percent higher in 2025), resulting in electricity prices that are 9 percent higher than those in the S.139 case in 2025. Without these technologies, the electricity sector is expected to rely more heavily on other low-emission technologies, particularly biomass, which substitutes for the baseload technologies no longer available. The electricity sector still remains the principal source of emissions reductions among the energy sectors. Table S.5 compares key results from the reference, S.139, and no new nuclear/no sequestration cases.

High Natural Gas Price Sensitivity Cases

Another area of uncertainty concerns technology advances and the resource costs of energy supply. Recently, much public attention has been focused on natural gas availability, with some analysts suggesting that EIA’s *AEO2003* reference case was too optimistic about the prospects for meeting significant growth in the demand for natural gas with the average wellhead price remaining below $4 per million Btu (2001 dollars) through 2025. Because fuel switching to natural gas is expected to be a key strategy for compliance with S.139, it is important to examine how a more pessimistic assessment of

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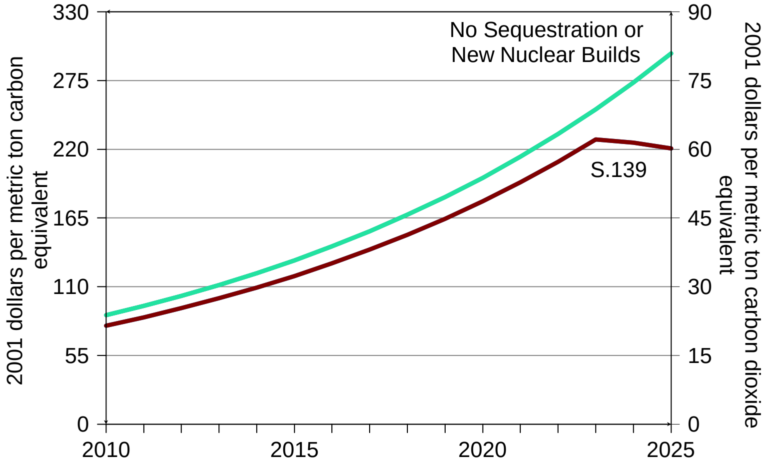
[29] This result would hold even with some net increase in total R&D activity

Figure S.10. Projected Allowance Prices in the S.139 and No New Nuclear/No Sequestration Cases, 2010-2025



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table S.5. Comparison of Key Results in the Reference, S.139, and No New Nuclear/No Sequestration Cases, 2025

	2025		
	Reference	S.139	No New Nuclear / No Sequestration
Cumulative Incremental[a] Capacity Additions (gigawatts)			
Coal	81	38	0
Natural Gas Combined Cycle	162	260	249
Combustion Turbine/Diesel	52	4	3
Nuclear Power	0	49	0
Renewables	5	148	206
Distributed Generation	18	5	6
Total Additions	**318**	**503**	**464**
Greenhouse Gas Emission Allowance Price			
(2001 dollars per metric ton carbon equivalent)	—	221	297
(2001 dollars per ton metric carbon dioxide equivalent)	—	*60*	*81*
Electricity Price (2001 cents per kilowatthour)	6.71	9.79	10.68
Electricity Sales (billion kilowatthours)	5,246	4,653	4,573
Carbon Dioxide Emissions by Fuel (million metric tons carbon equivalent)			
Coal	763	119	93
Natural Gas	509	493	582
Petroleum	963	870	859
Total	**2,234**	**1,482**	**1,534**[b]

[a] Excludes plants under construction.

[b] Total emissions are higher in this case than in the S.139 case, because previously banked allowances are still available to be used in 2025. In the S.139 case, the bank of allowances is depleted in 2023.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and ML0NUCSEQ.D050403A.

natural gas availability would affect the estimated impacts of S.139. Accordingly, a sensitivity case was developed assuming higher natural gas prices, more pessimistic assumptions for recoverable reserves and undiscovered resources, and limited alternative sources of supply.

Applying these assumptions in the reference case results in 40 percent higher wellhead prices in 2025. Applying the same assumptions in the S.139 case further increases natural gas prices and changes the mix of compliance strategies, particularly in the electricity sector. However, the overall cost of compliance, as indicated by the allowance prices, increases by no more than 6 percent from that in the S.139 case over the projection period. In the electricity sector, plant capacity substituted for natural gas additions includes coal with carbon sequestration, nuclear, and renewables (Table S.6). As a result, overall coal consumption in this sensitivity case is 238 million tons higher than in the S.139 case but, at 543 million tons, significantly lower than the 1,466 million tons projected in the reference case.

Allowance Allocation Sensitivity Cases

Two alternative allocation schemes were analyzed as sensitivity cases. The first case (corp20) holds the percentage allocated to the Corporation steady at 20 percent from 2010 to 2025; the second case (corp80) holds the Corporation share at 80 percent from 2010 through 2025. These sensitivity cases primarily influence the funds available to the Corporation from the sale of allowances, which are distributed to consumers to reduce the overall economic impact of the bill.[30] The two allocation sensitivity cases affect the cost of compliance, as revealed in the macroeconomic effects of the consumer rebate. There is no significant variation in allowance prices among the three cases.

Under the S.139 case, the funds (in nominal dollars) allocated to the Corporation rise from $23 billion in 2010 to $378 billion in 2025. In the corp20 sensitivity case, the funds also start at $23 billion but rise to only $93 billion in 2025, $285 billion less than in the S.139 case. In the corp80 case, the funds start at $94 billion and rise to $391 billion in 2025, $13 billion higher than in the S.139 case. The change in allocation of permits affects both the magnitude and the time profile of the economic impacts.

Figure S.11 compares real disposable income and actual GDP among the three cases. The S.139 case follows the corp20 case in the first few years but then begins to diverge as the S.139 case channels more funds back to the consumer when permits allocated to the Corporation continue to increase. By 2025, real disposable income in the S.139 case approximately matches that in the corp80 case; however, actual GDP in the S.139 case recovers more rapidly than in either of the sensitivity cases, and the negative effect on actual GDP is smaller. The difference lies in how the various cases affect consumption and investment, both in the short term and in the long term. By returning a greater amount of funds to consumers, the corp80 case leads to greater consumption, helping to moderate near-term impacts on the economy. The corp20 case generates a greater amount of investment, and toward the end of the forecast period boosts both potential and actual GDP. The S.139 case, which assumes an increasing rate of allowance allocations to the Coroporation over time, leads to the smallest long-term loss in actual GDP. The S.139 case differs fundamentally from the two sensitivity cases, because consumers see a steady improvement in disposable income and other factors over time, leading to a faster recovery than in the other two cases. Consumers are influenced not only by the amount of funds available to be spent, but also by expectations about the future.

Commercial Coverage Sensitivity Case

Under S.139, entities in the commercial sector would be covered by the allowance program if their annual greenhouse gas emissions were over 10,000 metric tons carbon dioxide equivalent. As discussed in Chapter 2, there are no data sources adequate to determine the extent of coverage in the commercial sector. Because rough estimates indicate that coverage of the commercial sector would be small, the

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[30] Some of the funds are used as rebates to buy down the cost of efficient appliances.

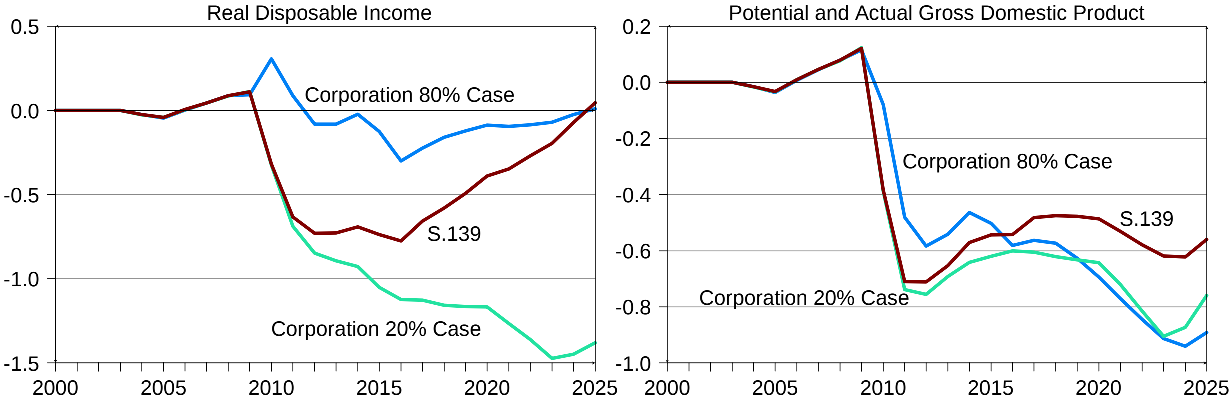
Table S.6. Comparison of Key Results in the Reference, S.139, and High Natural Gas Price Sensitivity Cases, 2010 and 2025

	2010				2025			
	Reference	S.139	High Natural Gas Price Reference	S.139 High Natural Gas Price	Reference	S.139	High Natural Gas Price Reference	S.139 High Natural Gas Price
Greenhouse Gas Emission Allowance Price (2001 dollars per metric ton carbon equivalent)	—	79	—	83	—	221	—	214
Natural Gas Wellhead Price (2001 dollars per thousand cubic feet)	3.39	3.51	3.81	3.86	3.95	4.36	5.55	5.70
Electricity Price (2001 cents per kilowatthour)	6.40	6.96	6.55	7.12	6.71	9.79	7.18	10.28
Electricity Sales (billion kilowatthours)	4,104	4,050	4,089	4,032	5,246	4,653	5,202	4,617
Cumulative Incremental[a] Capacity Additions (gigawatts)								
Coal	12	0	13	0	81	38	144	81
Natural Gas Combined Cycle	32	60	28	47	162	260	108	177
Combustion Turbine/Diesel	9	4	10	3	52	4	45	4
Nuclear Power	0	0	0	0	0	49	0	65
Renewables	1	33	2	41	5	148	7	178
Distributed Generation	2	2	2	1	18	5	16	4
Total Additions	**57**	**98**	**54**	**93**	**318**	**503**	**321**	**509**
Energy Consumption (quadrillion Btu)								
Coal	25.5	22.0	25.6	22.6	29.9	6.7	33.1	11.9
Natural Gas	27.3	28.1	26.6	27.0	35.5	39.5	30.1	30.5
Petroleum	44.4	43.7	44.5	43.7	56.1	50.8	57.1	51.3
Nuclear	8.2	8.4	8.2	8.4	8.3	12.4	8.3	13.7
Renewable	7.3	9.0	7.3	9.3	8.8	16.2	8.8	18.0
Electricity Imports	0.3	0.4	0.3	0.5	0.1	0.3	0.1	0.4
Total	**113.1**	**111.7**	**112.6**	**111.4**	**138.6**	**126.0**	**137.5**	**125.8**
Carbon Dioxide Emissions by Fuel (million metric tons carbon equivalent)								
Coal	650	560	652	577	763	119	846	192
Natural Gas	391	402	381	385	509	493	430	403
Petroleum	761	748	763	747	963	870	984	879
Total	**1,802**	**1,710**	**1,796**	**1,709**	**2,234**	**1,482**	**2,260**	**1,474**

[a] Excludes plants under construction.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Figure S.11. Changes in Real Disposable Income and Actual Gross Domestic Product Relative to the Reference Case in the S.139 and Two Allowance Allocation Sensitivity Cases, 2000-2025 (percent)



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A, ML_CCCC80.D050503A, and ML_CCCC20.D050503A.

S.139 case assumed no coverage in the commercial sector. A sensitivity case was analyzed to examine the effect of including all commercial sector entities under the bill’s coverage.

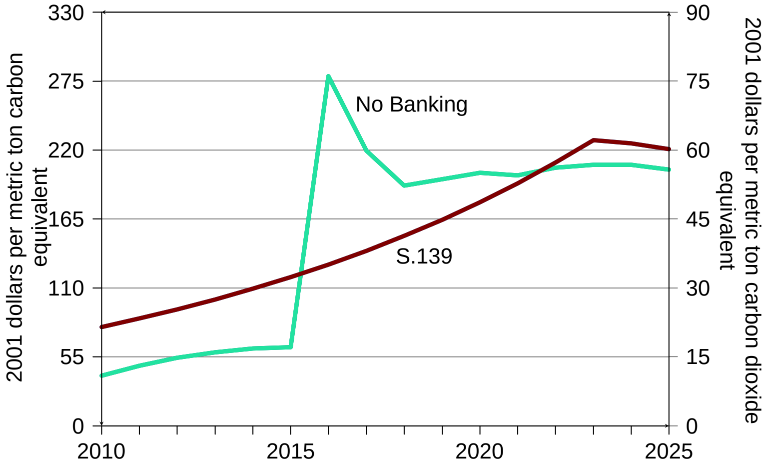
Including the commercial sector does not have a major impact on the results, because direct carbon dioxide emissions in the commercial sector make up only about 4 percent of total energy-related carbon dioxide emissions. Most of the energy used in the commercial sector is in the form of purchased electricity, which already is subject to higher prices in the S.139 case. The principal energy market effect of the commercial coverage sensitivity case is substitution of natural gas in the electricity sector for natural gas in the commercial sector. Most of the projected commercial sector additions to natural-gas-based combined heat and power capacity in the S.139 case (driven by higher electricity prices) are replaced by additions of combined-cycle capacity in the electric power sector in the commercial coverage sensitivity case.

No Banking Sensitivity Case

The allowance banking provision of S.139 provides entities with considerable flexibility in meeting allowance requirements. Because the second compliance phase reduces the allowances to 1990 emission levels, compliance is more difficult than in Phase I, which is based on 2000 emission levels. Allowing covered entities to overcomply in Phase I smoothes the transition to Phase II. As a result, the banking provision of S.139 is expected to result in steady, rather than sudden, growth in allowance prices from Phase I to Phase II.

A no banking sensitivity case was examined to assess the economic implications of the banking provision. This case requires that allowances must be used in the year in which they are issued, while retaining the Phase I and Phase II allowance totals. This case results in a time profile of allowances prices significantly different from that in the S.139 case (Figure S.12). Allowance prices in the no banking case are lower in Phase I, but there is a large jump in 2016, followed by a gradual return to the levels in the S.139 case.

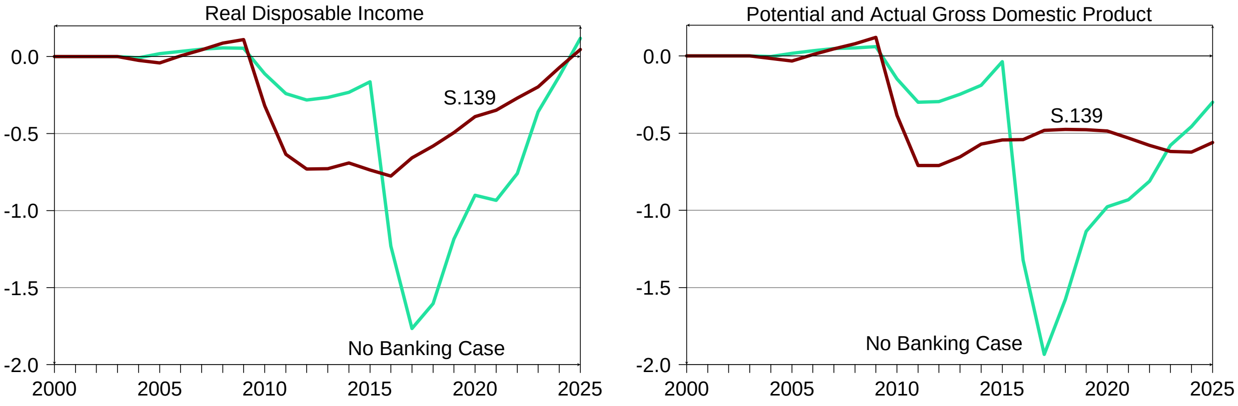
Figure S.12. Allowance Prices in the S.139 and No Banking Cases, 2010-2025



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A and ML_NOBANK_4.D051203A.

Figure S.13 compares the impacts on real disposable income and actual GDP in the S.139 case and the no banking sensitivity case. Through 2015, disposable income and actual GDP both decline by less in the sensitivity case than in the S.139 case. In 2016, however, energy prices rise sharply in response to the rise in the allowance price. Actual GDP and disposable income both decline sharply, reaching a peak loss in 2017, with actual GDP 1.9 percent lower and disposable income 1.8 percent lower than in the reference case. Thereafter, both recover rapidly as a result of a both sharp drop in energy prices as the allowance price declines and a large increase in the amount of funds distributed back to consumers and used for transition assistance in the post-2015 period.

Figure S.13. Changes in Real Disposable Income and Actual Gross Domestic Product in the S.139 and No Banking Cases Relative to the Reference Case (percent)



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and ML_NOBANK_4.D051203A.

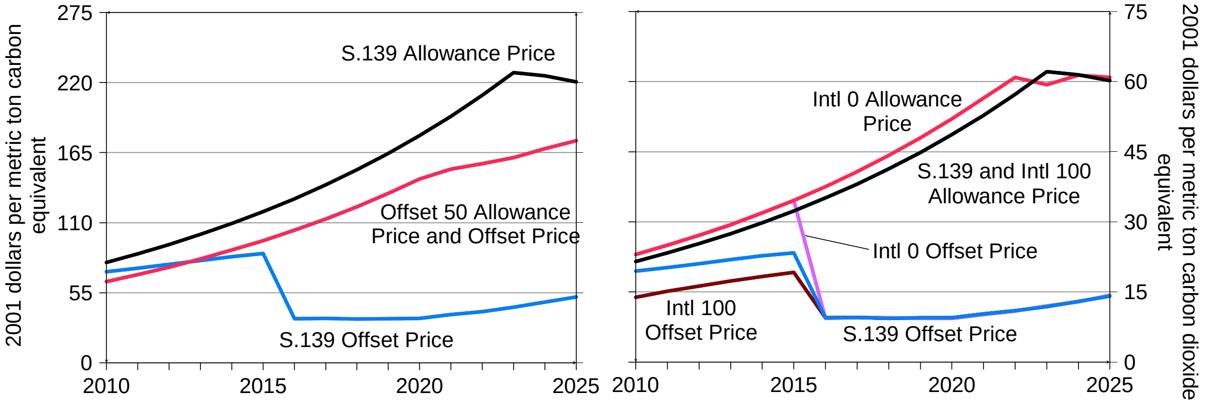
Offset Sensitivity Cases

Several sensitivity cases were used to examine the issue of compliance offsets. Covered entities may use offset credits from several sources, subject to an overall cap specified in S.139. The potential sources of offsets include registered reductions from noncovered entities, registered increases in biological carbon sequestration, and emission allowances from other countries. In one sensitivity case (offset50), the offset limit was increased to 50 percent. Two other cases were examined to test assumptions regarding the availability and costs of international emissions offsets (discussed in Chapter 3). In one case (intl100), the assumed supply curve of offsets from international sources was doubled. A second case (intl0) assumed that no international offsets would be available.

Figure S.14 compares the market-clearing prices for allowances and offsets in the three offset sensitivity cases with those in the S.139 case. In the offset50 case, the limit on offsets is not reached, and the trading prices of offsets and allowances are identical, at levels below the S.139 case. Table S.7 summarizes the energy market outcomes in the offset sensitivity cases. Because the offset50 case effectively reduces the amount of emissions reductions in the covered sectors, the magnitude of changes in the energy sectors to comply with S.139 is reduced. As a result, there is greater coal use and a reduced reliance on renewable, nuclear, and carbon sequestration in the electricity sector in the offset50 case.

In the intl100 case, the Phase I and Phase II limits on offsets are the same as in the S.139 case. As a result, the primary effect of this case is to alter the mix of offsets available from the three offset sources, increasing the international share relative to the domestic share. In the intl0 case, the unavailability of international offsets raises the offset price to equal the allowance price in Phase I, and the allowance price clears at a level above that in the S.139 case.[31] The unavailability of offsets in the intl0 case affects only the Phase I offset prices, which increase by a maximum of 48 percent in 2015 relative to the S.139 case. Figure S.15 compares the mix of offsets for 2010, 2016, and 2025 in the intl0, intl100, and S.139 cases. In the intl100 case, the lower price of international offsets is insufficient to make them competitive with domestic offsets in Phase II, and no international offsets penetrate. However, the Phase I offset prices are lower, and more international offsets are included in the mix.

Figure S.14. Comparison of Allowance and Offset Prices in the S.139 and Offset Sensitivity Cases, 2010-2025



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A, ML_INTL100.D052703A, and ML_INTL0.D051903A.

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[31] The exception is in 2023, as the allowance bank is depleted one year earlier in the intl0 case than in the S.139 case, and the price temporarily drops in the following year.

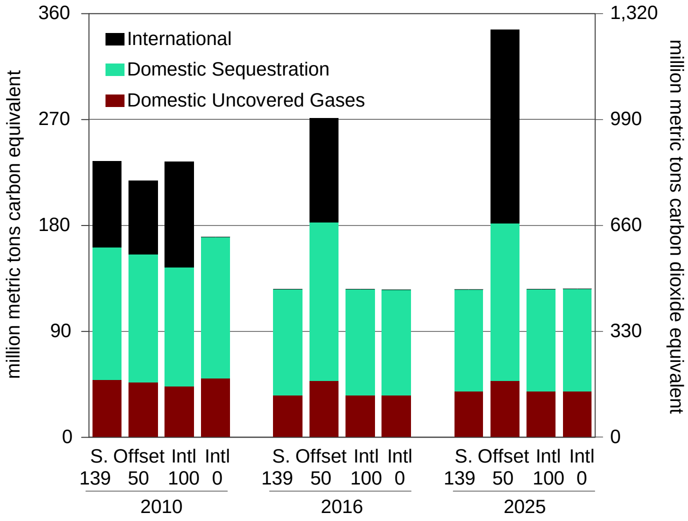
Under S.139, some emissions allowances would be distributed to covered entities, and some would be allocated to the Corporation to auction or otherwise sell in the emissions allowance market. The bill does not specify the allocation shares. For the S.139 case, our initial analysis assumed that in 2010, 80 percent of the allowances would be distributed to covered entities, and that the share would increase linearly each year to 20 percent in 2025. The rest of the allowances are allocated to the Corporation.

Table S.7. Comparison of Compliance Results in the S.139 and Offset Sensitivity Cases, 2010 and 2025 (million metric tons carbon equivalent)

	2010				2025			
	S.139	OFFSET 50	INTL 100	INTL 0	S.139	OFFSET 50	INTL 100	INTL 0
Greenhouse Gas Emissions								
Energy-Related Carbon Dioxide	1,710	1,737	1,710	1,704	1,482	1,697	1,482	1,482
Non-Energy Carbon Dioxide	40	40	40	40	46	46	46	46
Methane	115	117	120	114	120	111	120	120
Nitrous Oxide	121	121	121	121	137	137	137	137
High GWP Gases (HFCs, PFCs, and SF_6)	50	51	50	50	106	106	106	106
Total	**2,036**	**2,066**	**2,041**	**2,028**	**1,891**	**2,098**	**1,891**	**1,891**
S.139 Compliance Summary								
Covered Energy-Related CO_2	1,513	1,540	1,513	1,507	1,257	1,475	1,256	1,256
Other Covered GHG Emissions	70	71	70	70	128	128	128	128
Total Covered Emissions	**1,583**	**1,611**	**1,583**	**1,577**	**1,385**	**1,603**	**1,384**	**1,384**
Offset Reductions Purchased								
Noncovered Greenhouse Gases	49	47	43	50	39	48	39	39
Increases in Biological Carbon Sequestration	113	108	101	120	87	134	87	87
International Offsets	73	63	90	0	0	165	0	0
Total Offset Reductions	**235**	**218**	**234**	**170**	**126**	**346**	**126**	**126**
Covered Emissions, Less Offsets	1,349	1,393	1,349	1,407	1,259	1,256	1,258	1,258
Emission Allowances Issued	1,465	1,465	1,465	1,465	1,258	1,258	1,258	1,258
Allowance Bank Change (+, deposit; -, withdrawal)	+117	+72	+116	+58	-1	+1	0	0
Greenhouse Gas Emission Allowance Price								
(2001 dollars per metric ton carbon equivalent)	79	64	79	84	221	174	222	223
(2001 dollars per metric ton carbon dioxide equivalent)	*22*	*17*	*22*	*23*	*60*	*48*	*60*	*61*
Offset Trading Price								
(2001 dollars per metric ton carbon equivalent)	71	64	51	84	52	174	52	52
(2001 dollars per metric ton carbon dioxide equivalent)	*19*	*17*	*14*	*23*	*14*	*48*	*14*	*14*

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A, OFFSET50.D052303A, ML_INTL100.D052703A, and ML_INTL0.D051903A.

Figure S.15. Mix of Offset Compliance Sources in the S.139 and Offset Sensitivity Cases, 2010, 2016, and 2025



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A, OFFSET50.D052303A, ML_INTL100.D052703A, and ML_INTL0.D051903A.

Other Issues Addressed in the Report

Tax Versus Cap and Trade Program

In his request for an analysis of S.139, Senator Inhofe asked EIA to address the differences between S.139 and an equivalent greenhouse gas emission tax. An emissions tax could have advantages in terms of lower administrative costs, while providing greater certainty to emitters on the future cost of emitting greenhouse gases. Theoretically, it would be possible to specify an emissions tax that yields the same results as an allowance cap and trade system. In practice, however, the tax would have to be determined in advance such that it yielded the desired emissions reductions. Both programs are economically efficient in terms of assigning the compliance costs based on the quantity of emissions.

A primary distinction between a tax and a cap and trade system could be in distributional impacts, depending on the distribution of allowances. Under an allowance program where emissions rights are auctioned, the distributional impacts would be the same as for an emissions tax. However, if some or all the allowances are allocated for free, a redistribution of income occurs in favor of the allowance recipients.

A secondary difference could result if the allowance program and the tax applied to different segments of the economy. For example, the S.139 allowance program applies only to entities with emissions above a threshold. A tax system applied to fuels at the supplier level might more easily be applied broadly across all emissions sources (for example, for fossil fuels), compared to an allowance program, which may only be practical to administer for larger emission sources. A more detailed discussion of these issues is provided in Chapter 7.

International Sector Greenhouse Gas Activities and Their Relation to S.139

Senator James Inhofe requested that EIA provide information on the greenhouse gas commitments currently adopted by China, Mexico, South Korea, India, and Brazil.[32] These countries have ratified the United Nations Framework Convention on Climate Change (UNFCCC) and the Kyoto Protocol. Each of the five nations' governments has established an entity to coordinate climate change activities in the country. The five countries may also participate in the Kyoto Protocol through the Clean Development Mechanism (CDM), which enables entities in Annex I countries to acquire emission reductions generated in developing countries. In addition, all five countries have introduced specific initiatives to address climate change. However, none of the countries have adopted enforceable greenhouse gas emission targets. Based on S.139 criteria, they would be ineligible to provide allowances to covered entities as offsets. This topic is discussed more fully in Chapter 3.

Additional Context for the Report

Uncertainties

As with any mid- to long-term forecast there is considerable uncertainty surrounding the projections in this analysis. Reducing greenhouse gas emissions is expected to lead to significant increases in the use of energy production technologies that emit no (or low levels of) greenhouse gases, as well as more efficient energy consumption technologies. Currently, many of these technologies are not used or play fairly small roles in energy consumption and production. As a result, their potential cost and performance are relatively unknown. Alternative assumptions about the cost, performance, and market acceptance of these technologies could lead to different analysis results. Other key uncertainties include assumptions about the ways in which greenhouse gas emission allowances are distributed to covered entities, the availability of international offsets, and the degree to which covered entities will be allowed to purchase allowances in the international market. Nor does the analysis include any expectation about how S.139 might be amended based on application experience, or what limitations might be placed on greenhouse gas emissions.

Modeling Considerations

NEMS has many qualities, such as its technology representation, that make it a useful tool for analyzing the energy system and economic impacts of S.139. The high degree of energy detail within NEMS allows it to trace important energy linkages that would be difficult, if not impossible, to understand using models that represent the energy sector at a higher level of abstraction. The NEMS model forecasts to 2025. Capacity expansion decisions in the electricity generation sector and for combined heat and power production are based on expectations of fuel costs, capital and operating costs, and allowance prices over the next 20 years, assuming that the greenhouse gas targets and allowance prices remain at 2025 levels. NEMS does not address the impact of S.139 in the post-2025 period for the other sectors. While alternative modeling frameworks exist that provide different forecast horizons, those that extend beyond 2025 tend to limit the technological detail that is important in analyzing proposed legislation such as S.139. Many sensitivity cases are included in this analysis to address uncertainties in the modeling framework and assumptions; however, it is impossible to cover the full spectrum of possibilities with the time and resources available.

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[32] See Appendix A for a copy of the January 28, 2003, letter from Senator Inhofe to EIA.

Comparison With Other Modeling Results

Although the ideas behind S.139 have been widely discussed for some time within the environmental and energy policy community, S.139 is a new piece of legislation. There has been considerable discussion and speculation regarding its likely economic and energy impacts, but there are not yet many detailed studies with which the results obtained in this report can be compared or contrasted. One study to which the findings in this report might usefully be compared was recently issued by researchers at the Massachusetts Institute of Technology (MIT) in June 2003.[33] As might be expected, given the uncertainties and differences in modeling approaches, the results are similar in some areas but different in others.

The emissions allowance price is one key point of comparison across studies, because it adds directly to the cost of all fossil fuels used in the covered sectors (electricity generation, industry, and transportation) and also directly affects the price of electricity to consumers in all sectors. Table S.8 compares allowance prices from the MIT study's "scenario 7"—the scenario that incorporates the greenhouse emissions targets and offset limitations specified in S.139—with allowance prices in the S.139 and high technology S.139 cases of this analysis. Both the allowance prices and their temporal pattern are quite similar across the two studies.

Some important differences between the energy results from the MIT study and the present analysis also merit attention. In part these arise from differences in energy baselines before consideration of the effects of S.139 (Table S.8). The MIT baseline shows much higher use of coal and much lower use of natural gas than the EIA baseline. The MIT oil baseline also grows at a much slower rate than the EIA baseline.

Although the allowance prices are similar in the two studies, the nature and magnitude of the changes in energy mix in response to S.139 diverge significantly. Table S.8 summarizes oil consumption changes in response to S.139. Because two-thirds of all oil is used in the transportation sector and the use of oil for heating in the residential and commercial sector is not covered by S.139, the transportation sector is the focus of attention. Relatively small changes in the end-use price of petroleum fuels (changes that are smaller than the reported allowance value in cents per gallon, because both models assume that the world oil market price falls as demand is reduced) cause much larger changes in oil consumption in the MIT model than in the EIA model.

Changes in coal and natural gas demand also vary widely between the MIT and EIA analyses. The MIT study reports a significant reduction in coal consumption from the baseline level; in 2020, the MIT study reports 35 percent lower coal consumption than in the baseline projection, but the resulting level of coal consumption in 2020 is only 8 percent lower coal consumption in 2000. In EIA's S.139 case, coal consumption is projected to be 63 percent below the reference case level in 2020—55 percent below the 2000 level. In the MIT study, natural gas use is projected to increase by 14 percent between 2000 and 2020 in that study's S.139 scenario. In EIA's S.139 case, natural gas consumption is projected to increase by 53 percent between 2000 and 2020.

One explanation for the smaller amount of fuel switching between the MIT baseline and policy cases than between the EIA reference and S.139 cases is that the MIT results incorporate a larger reduction in total energy use between the baseline and policy cases. In 2020, the last year for which the results can be compared, EIA's analysis projects a 15.5 percent reduction in total energy use, compared with 19 percent in the MIT study. The percentage reduction in carbon dioxide emissions in 2020 is roughly 21 percent in

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[33] S. Palstev, J.M. Reilly, H.D. Jacoby, A.D. Ellerman, and K.H. Tay, *Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal*, Report No. 97 (Cambridge, MA: MIT Joint Program on the Science and Policy of Global Change, June 2003 [revised June 17]).

Table S.8. Comparison of Key Results from the EIA and MIT Analyses of S.139

	2000[a]	2010	2015	2020	2025
Greenhouse Gas Emission Allowance Price (2001 dollars per metric ton carbon equivalent)					
MIT, McL Case	—	78	102	134	NA
EIA, S.139 Case	—	79	119	178	221
EIA, High Technology S.139 Case	—	59	88	133	158
Fossil Fuel Use (quadrillion Btu)					
MIT, Base Case					
Coal	22.75	26.54	28.43	32.23	NA
Oil	36.96	41.70	45.49	47.39	NA
Natural Gas	20.85	22.75	24.64	25.59	NA
EIA, Reference Case					
Coal	22.58	25.47	26.68	27.88	29.86
Oil	38.40	44.45	48.47	52.15	56.11
Natural Gas	24.06	27.35	30.07	32.95	35.55
EIA, High Technology Reference Case					
Coal	22.58	24.85	25.56	26.05	26.89
Oil	38.40	43.82	47.09	49.95	53.29
Natural Gas	24.06	26.62	28.45	30.33	32.35
Petroleum Use (quadrillion Btu, unless otherwise noted)					
MIT, Base Case	—	41.70	45.49	47.39	NA
MIT, McL Case	—	36.96	38.86	39.81	NA
Percent Change from Base Case	—	-11.4%	-14.6%	-16.0%	NA
MIT, McL Case Emissions Allowance Price for Motor Gasoline (2001 cents per gallon)	—	18.55	24.14	31.77	NA
EIA, Reference Case	—	44.45	48.47	52.15	56.11
EIA, S.139 Case	—	43.74	46.62	48.65	50.76
Percent Change from Reference Case	—	-1.6%	-3.8%	-6.7%	-9.5%
EIA, S.139 Case Emissions Allowance Price for Motor Gasoline (2001 cent per gallon)	—	18.68	28.08	42.23	52.26
EIA, High Technology Reference Case	—	43.82	47.09	49.95	53.29
EIA, High Technology S.139 Case	—	43.30	45.79	47.45	49.41
Percent Change from High Technology Reference	—	-1.2%	-2.8%	-5.0%	-7.3%
EIA, High Technology S.139 Case Emissions Allowance Price for Motor Gasoline (2001 cents per gallon)	—	13.91	20.91	31.45	37.53

[a] MIT estimates for 2000 oil use are from 1.0 to 3.8 quadrillion Btu below EIA data for 2000; MIT estimates for 2000 natural gas use are from 2.7 to 3.7 quadrillion Btu below EIA data for 2000.

NA = not available.

Sources: **MIT:** S. Palstev, J.M. Reilly, H.D. Jacoby, A.D. Ellerman, and K.H. Tay, *Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal*, Report No. 97 (Cambridge, MA: MIT Joint Program on the Science and Policy of Global Change, June 2003 [revised June 17]), Base Case and Case 7 (0-cost credits to 15 and 10 percent limits), Tables 5 and 7. **EIA:** Projections—Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C, and ML_HT.D050503A; 2000 Fossil Fuel Use—Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(2003/04) (Washington, DC, April 2003), Table 1.3, web site http://tonto.eia.doe.gov/FTPROOT/multifuel/mer/00350304.pdf.

both studies. With a greater reduction in energy use in the MIT study, less fuel switching is needed to arrive at the same reduction in emissions.

Scope of This Report

The EIA analysis of S.139 contained in this report, like other EIA analyses, focuses on the impact of the provisions in the bill on energy choices made by consumers in all sectors and the implications of those decisions for the economy. This focus is consistent with EIA's statutory mission and expertise. The study does not quantify, or place any value on, possible health and environmental benefits of curtailing greenhouse gas emissions.

1. Introduction

Background

On January 9, 2003, Senators John McCain and Joseph I. Lieberman introduced S.139, the Climate Stewardship Act of 2003 (S.139), in the U.S. Senate.[34] S.139 would require the Administrator of the U.S. Environmental Protection Agency (EPA) to promulgate regulations to limit greenhouse gas emissions from large "entities"—almost all of the electric power, transportation, and industrial sectors and a small portion of the commercial sector as defined by EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks*.[35] It would also provide for the trading of emission allowances and reductions through a proposed greenhouse gas database to be established by the Federal Government, which would contain an inventory of emissions and registry of reductions.

On January 28, 2003, Senator James M. Inhofe requested that the Energy Information Administration (EIA) perform a comprehensive analysis of S.139. On April 2, 2003, Senators McCain and Lieberman, cosponsors of S.139, made a further request for analyses of their bill. This Service Report responds to both requests for analysis.

U.S. Greenhouse Gas Emissions

Total greenhouse gas emissions in the United States in 1990 were 1,683 million metric tons carbon equivalent,[36, 37, 38] of which 1,364 million metric tons, or 81 percent, consisted of carbon dioxide (CO_2) emissions from the combustion of energy fuels. By 2001, total U.S. greenhouse gas emissions had risen to 1,883 million metric tons carbon equivalent, including 1,579 million metric tons carbon equivalent from energy combustion. EIA's *Annual Energy Outlook 2003* (*AEO2003*)[39] projects that greenhouse gas emissions will reach 2,178 million metric tons carbon equivalent in 2010, 29 percent above the 1990 level. U.S. greenhouse gas emissions are projected to rise at an average annual rate of 1.5 percent a year between 2001 and 2025, reaching 2,683 million metric tons carbon equivalent in 2025, 59 percent above the 1990 level and 42 percent above 2001 levels. Because energy-related carbon dioxide emissions are a large portion of total greenhouse gas emissions, any effort to reduce greenhouse gas emissions will likely have a significant impact on the energy sector.

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[34] See web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s139is.txt.pdf.

[35] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000,* EPA 430-R-02-003 (Washington, DC, April 2002).

[36] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001) (Washington, DC, December 2002).

[37] Greenhouse gases differ in their impacts on global temperatures. For comparison of emissions from the various gases, they are often weighted by global warming potential (GWP), established by the Intergovernmental Panel on Climate Change, which is a measure of the impact of each gas on global warming relative to that of carbon dioxide, which is defined as having a GWP equal to 1.

[38] This analysis will report all greenhouse gas emissions in metric tons carbon equivalent (i.e., the weight of only the carbon of carbon dioxide gas). This is consistent with EIA's past practices in its reports. In future reports, EIA will conform to the changes in international procedures under the United Nations Framework Convention on Climate Change and express greenhouse gas emissions in carbon dioxide equivalent. To convert from carbon to carbon dioxide the ratio of 44/12 is multiplied times the value by weight of the carbon. Therefore, 1,000 metric tons carbon equivalent would be 3,667 metric tons carbon dioxide equivalent. The value for total greenhouse gases in 1990 (1,683 million metric tons carbon equivalent) is equal to 6,171 million metric tons carbon dioxide equivalent. The value for total greenhouse gases in 2001 is 1,883 million metric tons of carbon equivalent or 6,904 million metric tons of carbon dioxide equivalent.

[39] Energy Information Administration, *Annual Energy Outlook 2003,* DOE/EIA-0383(98) (Washington, DC, January 2003).

U.S. Greenhouse Gas Emissions
(continued)

To put U.S. emissions in a global perspective, the United States produced energy-related carbon dioxide emissions of 1.6 billion metric tons carbon equivalent or 23.9 percent of worldwide energy-related carbon equivalent emissions in 2001 (as noted in EIA's *International Energy Annual 2001*).[40] Although continued increases in emissions are expected for the United States and other industrialized countries, much more rapid emission increases are projected for developing countries in Asia, the Middle East, Africa, and Central and South America. According to EIA's *International Energy Outlook 2003* (*IEO2003*),[41] global carbon equivalent emissions from energy use are expected to increase at an average annual rate of 1.8 percent per year from 2001 (the base year in *IEO2003*) through 2010, reaching 7.7 billion metric tons carbon equivalent, to which the United States would contribute 23.4 percent. Over the entire period, from 2001 to 2025, global emissions from energy-related activities are projected to grow by 1.9 percent per year, reaching 10.4 billion metric tons carbon equivalent, with the United States accounting for 21.6 percent of the total in 2025.

Summary of S.139

Goal of the Bill. S.139 proposes a mandatory, domestic entity-level[42] greenhouse gas emissions reduction program. It would provide for a program of scientific research on climate change, establish a National Greenhouse Gas Database (NGGD) to track the level and reductions of greenhouse gas emissions by entity and covered sector,[43] and establish a market-driven system of tradable allowances that can be used interchangeably within the covered sectors as a way to accelerate the reduction of greenhouse gas emissions in the United States. The stated goals of S.139 are to reduce greenhouse gas emissions and to lessen U.S. dependence on foreign oil.

Summary of Key Elements. S.139 includes three titles. The first would establish a program of research to support implementation of the bill. The second would establish a National Greenhouse Gas Database and Registry to collect, verify, and analyze information on greenhouse gas emissions and track reductions by covered and noncovered entities. The third would establish the market-driven greenhouse gas emissions trading program. This report focuses on Titles II and III of the bill.

A. Title I—Federal Climate Change Research and Related Activities

Title I would establish a program of research both within and outside Federal agencies through the use of grants and program directives. Much of the research would be targeted at improving implementation of the remaining two titles of S.139. The goals of Title I fall within three categories: (1) Research Support

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[40] Energy Information Administration, *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, February 2003).

[41] Energy Information Administration, *International Energy Outlook 2003*, DOE/EIA-0484(2003) (Washington, DC, May 2003).

[42] A "covered entity" (including a branch, department, agency, or instrumentality of Federal, State, or local government) is defined as an entity that owns or controls a source of greenhouse gas emissions in the covered sectors, refines or imports petroleum products for use in transportation, or produces or imports hydrofluorocarbons, perfluorocarbons, or sulfur hexafluoride and emits over 10,000 metric tons of greenhouses gas per year (carbon dioxide equivalent), or produces or imports petroleum products, hydrofluorocarbons, perfluorocarbons, or sulfur hexafluoride, or other greenhouse gases that, when used, will emit over 10,000 metric tons of greenhouse gas per year.

[43] The "covered sectors" are defined as the electricity, transportation, industrial, and commercial sectors. The agricultural and residential sectors are excluded.

(to measure the impact of the bill, identify and remove barriers to technology transfer, and establish incentives for the development of more efficient technologies); (2) Improve Measurement Technologies; and (3) Provide Small Business Support (although few programs for small businesses are explicitly described in the bill as currently proposed).

B. Title II—National Greenhouse Gas Database

Title II would establish the National Greenhouse Gas Database and Registry. The main components of the proposed Database are an inventory of greenhouse gas emissions and a registry of greenhouse gas emissions reductions and increases in greenhouse gas sequestration. S.139 would require the EPA to promulgate regulations to implement a comprehensive system for greenhouse gas emissions reporting, inventorying, and reductions registration within 2 years of enactment. It would require the development and establishment of a comprehensive set of measurement and verification methods and standards for the reporting and recording of greenhouse gas emissions, emissions reductions, sequestration, and atmospheric concentrations for use in the registry. This title also outlines the rules for reporting the inventory of emissions and reductions for both covered and noncovered entities. Beginning no later than July 1, 2008, each "covered entity" is required to submit a report to EPA describing, for the preceding calendar year, entity-wide greenhouse gas emissions (at the facility level). It also provides for the reporting of voluntary greenhouse gas *reductions* by both covered and noncovered entities. It would also establish annual database reporting requirements for EPA under which EPA is required to publish an annual report that describes the total greenhouse gas emissions and reductions, provide entity-by-entity and sector-by-sector analyses of the emissions and reductions, describe current atmospheric concentrations, and provide a comparison of current and past atmospheric concentrations of greenhouse gases.

C. Title III—Market-Driven Greenhouse Gas Reductions

Title III outlines the key feature of S.139, the market-driven approach to greenhouse gas reduction. It establishes the rights and uses of tradable allowances, sets forth the requirement that covered entities must acquire one tradable allowance per metric ton of greenhouse gas emissions, creates the ability to bank and borrow allowances, provides for accelerated participation by covered and noncovered entities, and sets the proposed penalties when covered entities do not meet the requirements. Title III would also establish the Climate Change Credit Corporation (hereafter referred to as the Corporation) and outlines its function. It includes four subtitles.

1. Subtitle A—Emission Reduction Requirements; Uses of Tradable Allowances

Subtitle A establishes the greenhouse gas emissions reduction process and outlines the use of tradable allowances. It sets out some basic requirements as follows:

- Each covered entity must submit to the EPA Administrator one tradable allowance for every metric ton of greenhouse gases emitted.
- Producers or importers of non-CO_2 greenhouse gases must submit one tradable allowance for every metric ton they produce or import.
- Each covered petroleum refiner or importer must submit one tradable allowance for each unit of petroleum product they sell for transportation uses that will produce one metric ton of greenhouse gas. S.139 notes that EPA will define the amount of greenhouse gases emitted when petroleum products are used for transportation.

A covered entity is not required to submit tradable allowances for any amount of greenhouse gas if the emissions are deposited in an approved geological storage facility (geologic sequestration). An entity may submit allowances that were either allocated to it, acquired from another entity (either covered or noncovered), or acquired from the Corporation. EPA can grant an exemption from the requirements of S.139 if it is determined that it is not feasible to measure or estimate emissions from the source category; however, S.139 also states that EPA cannot grant an exemption for carbon dioxide produced from fossil fuel.

The subtitle also sets out some alternative means of compliance for the years 2010 through 2015. A covered entity may satisfy 15 percent of its total allowance requirement by submitting tradable allowances from another nation's market in greenhouse gas emissions, submitting a registered net increase in sequestration, submitting a greenhouse gas emissions reduction from a noncovered entity, or submitting credits obtained from EPA. The same alternative means of compliance still apply after 2015, but the portion that a covered entity may satisfy using this approach declines to 10 percent.

A covered entity can borrow tradable allowances from EPA for use in the current year based on anticipated emissions reductions in future years, but only from anticipated reductions in emissions that result from capital investment in equipment, the construction, reconstruction, or acquisition of facilities, or the deployment of new technologies for which the covered entity has executed a binding contract that will become operational within the current calendar year and will begin to reduce emissions from the covered source within 5 years after the year in which the credit is used. This loan is not free. There is a borrowing cost of 10 percent (in terms of tradable allowances) for each credit borrowed, multiplied by the number of years beginning after the year of use and before the year the reduction is expected to begin. If the covered entity fails to achieve the anticipated reduction, the covered entity's allowance requirements shall be increased by the amount of the credit plus the borrowing cost.

Subtitle A would also establish procedures for automobile manufacturers to receive tradable emissions allowances for exceeding applicable corporate average fuel efficiency (CAFE) standards. To receive the allowances, however, manufacturers must exceed fuel efficiency standards by more than 20 percent. The exact conversion factor for the tradable emissions allowances relative to fuel efficiency is not established in S.139. It is important to note that the total quantity of allowances does not change as a result of this provision. These allowances come out of the pool of total allowances available to all covered entities.

In addition to being sold, exchanged, purchased, or retired, other possible uses for the tradable allowances are established in Subtitle A. The Corporation may sell tradable allowances allocated to it to any covered entity or to any investor, broker, or dealer in tradable allowances. Tradable allowances can be banked by an entity for use in future years. A covered entity that has more than a sufficient amount of tradable allowances to satisfy current requirements may hold allocated allowances in order to sell, exchange, or use the tradable allowances in the future.

2. Subtitle B—Establishment and Allocation of Tradable Allowances

The tradable allowance program would take effect beginning in 2010. Subtitle B establishes and provides procedures for allocating the tradable allowances. EPA is instructed to establish regulations to create tradable allowances for calendar years 2010 to 2015 equal to 5,896 million metric tons carbon dioxide equivalent and, for calendar years after 2015, equal to 5,123 million metric tons carbon dioxide equivalent, reduced by the amount of emissions of greenhouses gases in calendar years 2000 and 1990, respectively, from noncovered entities as defined in the bill. Each tradable allowance is to be assigned a unique serial number.

Based on the number of allowances, from 2010 to 2015, the maximum allowable greenhouse gas emissions by a covered sector (Phase I allotment) is equal to a portion of year 2000 total covered sector emissions, based on the sector's percentage share of total covered sector emissions in the year preceding enactment.[44] After 2015, the maximum allowable emissions by the covered sector will be equal to its share of 1990 total covered sector emissions (Phase II allotment) using the same methodology for determining the shares as was used for the Phase I allotment.

The Secretary of Commerce is charged with determining each covered sector's Phase I and Phase II allotments and the amount allocated to the Corporation. Subtitle B lists certain factors that the Secretary of Commerce must consider in determining the number of allowances to be allocated, including:

- Effect on income distribution
- Impact on corporate income, taxes, and asset value
- Impact on consumer income levels and energy consumption
- Effects on economic efficiency
- Ability of entities to pass through compliance costs
- Whether allocation to covered sectors should decrease over time.

These are guiding principles. No other specifics about how the allocation should be computed are provided in S.139.

While the Secretary of Commerce determines the number of allowances to be allocated to each covered sector, EPA is charged with actually allocating the Phase I and II tradable allowances to each entity in the covered sector and to the Corporation. The Subtitle establishes that EPA will allocate the tradable allowances for the electricity generation, industrial, and commercial sectors to the entities owning or controlling point sources of greenhouse gas emissions within the sector. The same is true for producers or importers of hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. The tradable allowances for the transportation sector are to be allocated to petroleum refiners or importers that produce or import petroleum products that will be used as fuel for transportation.

Subtitle B establishes procedures for allocation of tradable allowances for early action and accelerated participation in the program. At the request of a covered entity that has registered reductions in a year before 2010 (early actions), EPA is required to allocate tradable allowances in an amount consistent with the registered reductions from the national greenhouse gas database, for use by the entity in the current year. The subtitle also establishes procedures for accelerated participation. If an entity executes an agreement with EPA under which it agrees to reduce its level of greenhouse gas emissions to an amount no greater than the level of emissions in calendar year 1990 by the year 2010, then for the 6-year period from 2010 to 2015, EPA will provide additional tradable allowances to that entity (the number or process for determining the number of additional tradable allowances is undefined in the bill). The total size of the allowance pool does not change when early participants are granted extra allocations. An entity can also satisfy 20 percent of its requirements (not 15 percent as previously specified) by submitting tradable allowances from another nation's market in greenhouse gases, submitting a registered net increase in sequestration, or submitting a greenhouse gas emission reduction that was registered in the National Greenhouse Gas Database by a noncovered entity.

This Subtitle also provides for a review of the number of allowances established under S.139 every 2 years after enactment, to determine whether the number of allowances established continues to be consistent with the objectives of the United Nations Framework Convention on Climate Change (UNFCCC). Given the importance of the 2010 and 2016 allowance levels and uncertainty about the date of enactment, it also calls for a specific review of the number of allowances in 2008 and 2012. Subtitle B

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[44] The actual number of allowances and, ultimately, greenhouse gas emissions from any covered sector will be less than the maximum, because a portion of the of the Phase I and II allotments will be allocated to the Corporation and the allocation will be reduced by a fraction of any initial allocations to early and accelerated participants. Under any circumstances, the total number of allowances cannot exceed the initial pool available to the covered sectors.

provides no additional information about what would occur if the number of allowances were found to be inconsistent with the objectives of UNFCCC.

3. Subtitle C—Climate Change Credit Corporation

Subtitle C would establish the Corporation as a nonprofit Federal corporation. The Corporation is charged with receiving and managing tradable allowances allocated to it by EPA. It can buy and sell tradable allowances in the market, but it may not retire tradable allowances that are unused. The Corporation is directed to use the tradable allowances and proceeds derived to reduce the costs borne by consumers as a result of the greenhouse gas reduction requirements of S.139. It establishes “possible” methods the Corporation can use (e.g., buydowns, subsidies, negotiation of discounts, and consumer rebates), but it does not explicitly state a mix or preference. Further, it requires that the proceeds derived from the Corporation’s actions be equitably distributed to the extent possible across all regions of the United States and that they may include arrangements for preferential treatment of low-income consumers. Subtitle C establishes that a percentage of the proceeds derived from trading activities, starting at 20 percent of the total proceeds in 2010, will be used to provide transition assistance. However, it also establishes that this transition assistance will be phased out over time (declining by 2 percent each year starting in 2011, but never reaching zero). No other specifics about the allocation of the proceeds are indicated.

4. Subtitle D—Sequestration Accounting; Penalties

Subtitle D establishes rules about the use of sequestration. Specifically, if a covered entity uses a registered net increase in sequestration to meet the required provision of one tradable allowance for each metric ton of greenhouse gas emissions emitted, the covered entity must submit information to EPA every 5 years to verify that the net increase in sequestration still exists. If EPA determines that the sequestration no longer exists, the entity must submit allowances to offset the loss of sequestration in the calendar year following the determination.

This subtitle also sets out the penalties for noncompliance with the provisions of S.139. If a covered entity fails to provide tradable allowances sufficient to cover its greenhouse gas emissions, it will be liable for civil penalties, payable to EPA, equal to three times the market value of the tradable allowances necessary to meet the requirements. The subtitle establishes no other specific penalties beyond this provision.

Unspecified Aspects of S.139 Necessary for Implementation and Analysis

S.139 stipulates a program for greenhouse gas emission monitoring and control. Some of the provisions are subject to varying interpretation and some will be defined only after passage of the Act by Congress and implementation by EPA, the Department of Commerce, or other parties and agencies. In addition to the usual challenges and uncertainties inherent in projecting the energy and economic effects of major policy changes, analysis of S.139 is further complicated by the uncertainty regarding how its provisions would be implemented. Key implementation features of S.139 that are not clearly specified include:

- **Definition of A Covered Entity:** S.139 defines a covered entity as an entity that owns or controls facilities that collectively emit more than 10,000 metric tons (carbon dioxide equivalent) of greenhouse gas per year. While substantial energy and economic data exist on whole industries or on specific facilities, little is available on individual entities. Further, the issue of control or ownership of an entity is unclear. For example, is each individual McDonald’s franchise an entity, or is control defined at the company level? If a company divests a portion of an entity so that its total emissions fall below the 10,000 metric ton threshold, is it no longer covered?

- **Mechanisms for Allocating Emissions Allowances:** In order to assess the macroeconomic impacts of S.139 on covered entities, two assumptions are needed. First, an assumption is needed regarding how emission allowances are allocated between covered sectors and the Corporation. The allocation has important implications for consumption and investment patterns that impact macroeconomic growth. Second, to assess the sectoral impacts of S.139, an assumption is needed regarding how emissions are allocated among covered entities. Both the allocation between the covered sectors and the Corporation and the allocation among covered sectors are to be defined by the Secretary of Commerce after passage of S.139. The bill provides guiding principles but little specific information on how these allocations are to be made.
- **Consumer Rebates:** S.139 allows the Corporation to allocate the revenue it collects from the sale of emission allowances as rebates or subsidies to consumers, especially those who can least afford the energy price increases that are likely to result from the proposed legislation. The amount of money available for these rebates or subsidies and their allocations is unspecified.
- **CAFE Credits:** S.139 includes a provision that allocates greenhouse gas emission allowances to manufacturers of light-duty vehicles whose CAFE exceeds the applicable CAFE standard by 20 percent. The provision states that the Secretary of Transportation, in consultation with the EPA Administrator, will determine the conversion factor used to translate fuel economy improvements into greenhouse gas emission reductions after the Act is passed. No additional information about the mechanism or conversion factor is included in S.139.

Focus of the Analysis

This study focuses on the questions posed in the two request letters,[45] subject to the limitation that we cannot address issues beyond EIA's expertise or capability.

Request from Senator Inhofe. Senator Inhofe requested that EIA examine the following:

- The effect of S.139 on global temperatures
- The number of "S.139-equivalent programs" that would be needed to reduce projected future temperature increases to "acceptable levels"
- The direct government cost entailed
- The cost to the U.S. economy in jobs and dollars
- The demographic spread of economic costs
- A comparison of the bill's compliance period to the scheduled commitments for reduction of greenhouse gases by China, Mexico, South Korea, India, and Brazil
- Energy "suppression" effects
- A comparison of the efficiency of the bill's regulatory mechanisms with that of a Btu tax mechanism.

In an initial reply to Senator Inhofe, EIA indicated that it would be able to fully address four of the eight items requested and to provide limited data and information on a fifth. The four items that EIA agreed to undertake were an analysis of the cost of the bill to the United States in employment and aggregate gross domestic product (GDP); estimation of energy conservation (suppression) effects related to the higher costs of energy that would be borne by consumers as a likely result of the bill; a comparison of the energy

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[45] See Appendix A for requesting letters and related correspondence.

and economic impacts of an equivalent carbon tax[46] with those of S.139; and a comparison of the bill's compliance period with those scheduled by China, Mexico, South Korea, India, and Brazil for their reductions of greenhouse gases. EIA also agreed to provide demographic data (by household income class) on the distribution of energy consumption and expenditures from its Residential Energy Consumption Survey, but not to forecast how such distributions might change as a result of S.139.

Request from Senators McCain and Lieberman. Senators McCain and Lieberman asked EIA to address the following:

- The impact of a range of alternatives for the percentage of greenhouse gas allowances that would be allocated to the Corporation
- The impact of early action compliance activities by both covered and noncovered entities on the costs of compliance
- The impact of a range of new technology deployment to reduce greenhouse gas emissions on the cost of compliance, and the likelihood of the technology being deployed
- The impact of banking by covered entities
- The impact of various "flexibility mechanisms," including: credit for reduction of non-CO_2 greenhouse gases; credits from international trading; credits and offsets from increased automobile fuel efficiency and additional demand reductions for electricity from noncovered sectors; credits for geological sequestration and forestry activities; "borrowing" of allowances from future years; and increasing the percentage of "offsets" allowed for those entities that reduce their emissions to 1990 levels before 2010 (rather than 2016 as required by the bill).

In its response to Senators McCain and Lieberman, EIA agreed to provide the analysis requested, subject to the limitations of available data. For example, the amount of greenhouse gas allowances available on the international market that could be purchased to offset domestic reductions is highly uncertain, depending in part on the mechanisms within other countries that would be created to certify and register such allowances. In the absence of specific guidance, EIA exercised informed judgment concerning the efficacy and application of such allowances. These judgments and others needed for the analysis are discussed in detail in the ensuing chapters.

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[46] The carbon tax analysis replaces the Btu tax comparison requested in Sen. Inhofe's letter, based on discussion with the Senator's staff. Subsequent to EIA's response, EIA received an e-mail from Aloysius Hogan of Senator Inhofe's staff on April 23 that asked EIA to postpone analysis of an equivalent carbon tax in consideration of time. The e-mail is included in Appendix A. The e-mail also requested EIA to provide a sensitivity case in which geological sequestration and new nuclear generating capacity are excluded as options.

2. Assumptions, Methodology, and Scenarios

This analysis of S.139 is based on comparisons with an updated version of the *Annual Energy Outlook 2003* (*AEO2003*) reference case. The *AEO2003* reference case was updated to reflect changes in electric generating capacity since the *AEO2003* forecast was completed (October 2002), to incorporate revised expectations about near-term trends in natural gas prices, and to reflect recent changes in corporate average fuel economy (CAFE) standards. Senators McCain and Lieberman explicitly requested that EIA update the projections for additions of new electricity generating capacity (see Appendix A).

S.139 proposes a detailed program for greenhouse gas emissions monitoring and control and contains provisions that are either subject to varying interpretation or are intended to be defined after enactment. This chapter outlines some of the key assumptions and methodology required to analyze S.139 and defines the various cases analyzed.

The National Energy Modeling System

The *AEO2003* projections are generated using EIA's National Energy Modeling System (NEMS). NEMS is a computer-based, energy-economy modeling system of U.S. energy markets for the mid-term period through 2025. Using a market-based approach to energy analysis, NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. In order to represent the regional differences in energy markets, NEMS functions at the regional level. In addition to its use for this analysis and for production of the *Annual Energy Outlook,* NEMS is also used in analytical studies requested by the U.S. Congress, other Federal Government agencies, and other offices within the Department of Energy. (See *The National Energy Modeling System: An Overview 2003*[47] for further details.)

NEMS calculates carbon dioxide emissions, the principal component of greenhouse gases, as the product of fossil energy use and fuel-specific emissions factors. While emissions of the greenhouse gases other than energy-related carbon dioxide are related to energy activities, estimating those emissions based on economic factors is outside the scope of NEMS. As a result, baseline emissions of gases other than energy-related carbon dioxide were obtained from the U.S. Environmental Protection Agency (EPA), as were estimates of the potential for reducing the emissions, reflected in cost functions known as marginal abatement curves (MACs).

Under S.139, emissions allowances must be submitted by covered entities for their greenhouse gas emissions. Covered entities obtain the allowances through the allocations from the Government or by purchasing allowances from other entities or the Climate Change Credit Corporation (hereafter referred to as the Corporation). The cost of the allowance increases the cost of using energy in the covered sectors, effectively increasing the price of fossil fuels to covered entities, as well as the cost of electricity to all sectors. As the allowance price changes and influences energy costs, the estimated demand for energy changes, as do the corresponding carbon dioxide emissions. For greenhouse gases other than carbon dioxide, emissions reductions in covered sectors are calculated based on the MACs. The emissions

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[47] Energy Information Administration, *The National Energy Modeling System: An Overview 2003,* DOE/EIA-0581(2003) (Washington, DC, March 2003). Detailed documentation is available on the EIA web site at http://www.eia.doe.gov/bookshelf/docs.html.

abatement at the current market price for allowances is subtracted from the baseline emissions to obtain the resulting emissions for the covered sources.

An emissions accounting structure was used to track allowance banking and the use of allowance offsets to comply with S.139, as well as to perform the marginal abatement calculations for other greenhouse gases. A methodology was also incorporated to estimate allowance and offset prices, given the banking provisions of S.139 and offset limitations. Documentation of these methodology changes, including the derivation and sources for marginal abatement curves, is provided in Appendix B.

As part of analyzing S.139, NEMS was updated to reflect changes in electric generating capacity since *AEO2003* was completed, to adopt recent changes in the CAFE standards, and to incorporate revised expectations about near-term natural gas price trends. The following summarizes these key updates.

Electricity Generating Capacity Updates

Within NEMS, only planned units that are reported as "under construction" are automatically included as being built during the forecast horizon. NEMS then forecasts the construction of additional unplanned capacity by type as needed to meet future demand.

For *AEO2003*, the information on planned generating units was based predominantly on 2001 data from industry filings on Form EIA-860, "Annual Electric Generator Report," which provides information from both utility and nonutility generators. The EIA-860 data were supplemented by a second data source, the NewGen database developed by Platts Database,[48] which is updated on a monthly basis. The NewGen database was used to update the EIA-860 information for more recent changes in plant operating status.

Based on new information available as of the end of March 2003, planned electric generating capacity included in the revised reference case used to analyze S.139 was updated from what was included in *AEO2003*. Additional units are represented as planned capacity in the S.139 reference case if they are reported as under construction in the NewGen database and as planned in the EIA inventory.

About 24 gigawatts of additional planned capacity was reported as being under construction as of March 2003, including 8.5 gigawatts in 2002, 14.3 gigawatts in 2003, and 1.2 gigawatts in 2004. About 16 gigawatts of the additions are gas-fired combined cycle, 4.6 gigawatts are gas-fired turbines, and 2 gigawatts are dual-fired combined-cycle units. The remaining 1.4 gigawatts consist of dual-fired turbines and internal combustion units, several renewable units, and a relatively small coal-fired unit.

Appendix B provides detailed information on the capacity changes made in the S.139 reference case by region relative to *AEO2003*.

CAFE Standards Update

On April 1, 2003, the National Highway Traffic Safety Administration announced an increase in the Corporate Average Fuel Economy (CAFE) standard from 20.7 miles per gallon (mpg) for light trucks to 21.0 mpg in 2005, 21.6 mpg in 2006, and 22.2 mpg for 2007 and beyond. These updates were included in NEMS for this analysis.

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[48] NewGen Data and Analysis, Platts Database (Boulder, CO, March 2003).

Near-Term Natural Gas Prices

Each month in the *Short-Term Energy Outlook* (*STEO*), EIA publishes 2-year projections of price, demand and supply, and stocks for each of the main energy sources. These projections are revised in response to observed changes in weather conditions, stock levels, and market conditions. For *AEO2003*, the September 2002 *STEO* was the basis of the short-term outlook. Since then, the natural gas price forecasts have changed significantly. For example, in the April 2003 *STEO*, the average natural gas wellhead price for 2003 was projected to be $4.52 (nominal dollars) per thousand cubic feet, 39 percent higher than the projection for 2003 used in *AEO2003*. To incorporate the more recent views of the market, the natural gas supply and price forecasts for this study were aligned with the April 2003 *STEO* forecasts. In particular, adjustments were made to natural gas production, imports, supplemental supplies, storage, consumption of lease, plant, and pipeline fuel, and prices at the wellhead and the burner-tip. These adjustments mainly affect the short-term projections; however, because decisions made in later years depend in part on earlier market conditions, the longer term projections are also affected.

Representing S.139

Definition of a Covered Entity

The proposed legislation explicitly defines a “covered sector” as including the electricity generation, transportation, industrial, and commercial sectors. It requires that “covered entities” in these sectors participate in the tradable allowance system and defines a covered entity as a person, company, organization, or agency (including a branch, department, agency, or instrumentality of Federal, State, or local government) that owns or controls facilities that collectively emit more than 10,000 metric tons (carbon dioxide equivalent) of greenhouse gases per year. Because nearly every electricity generating plant using fossil fuels would meet the emissions threshold, 100 percent of the electric sector is assumed to be covered for this analysis. Because no individual transportation vehicle and only the largest of fleets are likely to meet the emissions threshold, the bill covers transportation fuel use through refiners. Refiners and importers of petroleum products that provide fuel to the transportation sector and meet the 10,000 metric tons emissions threshold are covered entities and must obtain and provide allowances sufficient to cover those sales. Based on size limitations, difficulty in measurement, and the intent of the legislation’s authors,[49] the agricultural sector is not considered to be covered. As discussed below, coverage in the commercial sector and in other portions of the industrial sector is difficult to determine because of insufficient data.

The EIA commercial buildings survey data indicates that less than 0.01 percent of commercial buildings used enough fuel in 1999 to meet the emissions threshold.[50] While an entity owning or controlling several commercial buildings may exceed the threshold, there are no data sources that provide energy consumption or emissions at the entity level to make that determination. Given that the vast majority of buildings in the commercial sector would not meet the emissions threshold, it is assumed for this analysis that the commercial sector is not covered by the bill. A sensitivity case that treats the entire commercial sector as a covered entity is included to provide an understanding of the impact of treating this sector as covered.

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[49] This relies on a discussion of the legislative intent as outlined in a meeting with Tim Profeta of Senator Lieberman’s staff on April 16, 2003.

[50] Energy Information Administration, 1999 Commercial Buildings Energy Consumption Survey, Public Use Files (October 2002), available at web site http://www.eia.doe.gov/emeu/cbecs/1999publicuse/99microdat.html. These results are consistent with the results published in a recent journal article, which concluded that no commercial buildings would exceed the 10,000 ton threshold. See Tristam O. West and Naomi Pena, “Determining Thresholds for Mandatory Reporting of Greenhouse Gas Emissions,” *Environmental Science and Technology*, Vol. 37, No. 6 (2003), pp. 1057-1060, Table 3.

Is It a Facility or an Entity and Why Does It Matter?

A facility, for the purposes of S.139, is defined as "a building, structure, or installation located on any 1 or more contiguous or adjacent properties of an entity in the United States." As such, a facility may be a source of greenhouse gas emissions. By contrast, an entity, for the purposes of S.139, is a person, company, organization, or agency that owns or controls a source of greenhouse gas emissions, refines or imports petroleum products for transportation use, or produces or imports hydrofluorocarbons, perfluorcarbons, or sulfur hexafluoride. A single entity may own or control one or more facilities. The distinction between a facility and an entity is important to S.139 and to this analysis because greenhouse gas emissions at the entity level, not the facility level, determine who must participate in the tradable allowance system.

EIA collects energy use survey data at the sector level from energy suppliers and at the building (commercial) or facility (manufacturing, power sector) level. There is no data source that provides energy consumption (or emissions) at the entity level, complicating analysis of the proposed legislation.

Similar data problems exist for the industrial sector, because there are no data on energy consumption or emissions at the entity level. However, it has been estimated that approximately 7,000 manufacturing facilities would exceed the 10,000 metric ton threshold, accounting for 84 percent of manufacturing sector emissions in 1998.[51] Nearly all facilities in the most energy-intensive manufacturing sectors would exceed the threshold and be covered by S.139. The number of additional facilities required to report due to common ownership or control within each manufacturing sector is not currently known. For example, General Mills owned 95 food-related plants in the United States during 2002.[52] If any one of those plants, or any combination of plants, exceeded the emissions threshold, all the plants would be covered. Furthermore, conglomerates with holdings across several manufacturing sectors may also exceed the threshold. While it is difficult to estimate the overall industrial sector coverage which would result when these common ownership or control issues are resolved, the proportion of the industrial sector meeting the threshold is likely to be higher than the 84 percent coverage estimate. Therefore, this analysis assumes that the entire industrial sector is covered, with the exception of the agriculture industry.

It is also important to note that the person, company, organization, or agency that must hold a greenhouse gas emission allowance will vary by the covered sector. For example, electricity generators must obtain and provide allowances for their greenhouse gas emissions. A refiner must obtain and provide allowances for petroleum products sold for transportation applications and for the fuel used to refine crude oil to products. However, the refiner does not need to obtain allowances for petroleum products sold to the residential, commercial, or industrial sectors. Covered entities in the commercial and industrial sectors are required to obtain and provide allowances for greenhouse gas emissions resulting from their own energy use. While residential energy users are exempt, they will face higher energy, service, and product prices due to the cost of allowances purchased by electricity generators and industrial energy users, and any increase in prices that may result from the cost of fuel switching or investment in compliance options.

Phase I and II Allowance Caps

S.139 specifies the Phase I and Phase II emission allowance caps based on 2000 and 1990 data, excluding emissions from the residential sector, agriculture sector, and U.S. territories. The reference data cited in

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[51] Energy Information Administration, Office of Integrated Analysis and Forecasting.

[52] General Mills, Inc., Form 10K (2002), p. 9.

the bill are from the EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000*.[53] The bill specifies the annual allowances for Phase I and Phase II at 5,896 and 5,123 million metric tons carbon dioxide equivalent, respectively, adding the phrase "reduced by the amount of emissions of greenhouse gases . . . from noncovered entities." Noncovered entities include those not meeting the emissions threshold of 10,000 tons carbon dioxide equivalent, as well as emissions from sources deemed impractical by the EPA to measure. To derive the caps for modeling purposes, several sources of data other than the EPA inventory were used.

To determine the energy-related CO_2 portion of the cap, the data sources and accounting conventions for CO_2 emissions in EIA's *Emissions of Greenhouse Gases* report[54] were used. EIA sources on carbon dioxide were used because of their consistency in relating energy use by sector as modeled in NEMS to the corresponding historical data on energy use and carbon dioxide emissions. There are several areas of difference between EIA's emissions accounting and those in the EPA inventory. One is that the EIA energy-related emissions include emissions for military and international bunker fuels. These emissions sources are not separately broken out in NEMS and thus are included as though they were covered under S.139.[55] A second is that EIA recently revised its energy data accounting for fossil fuels used to generate electricity. A third is that EIA accounts for carbon dioxide emissions from metallurgical coal and coke as part of energy-related CO_2 emissions. A comparison of the EIA and EPA energy related CO_2 emissions is shown in Table 2.1.

Table 2.1. Fossil Fuel Carbon Dioxide Emissions by Sector, EPA Inventory and EIA, 1990 and 2000 (million metric tons)

Sector	1990		2000	
	EPA	EIA	EPA	EIA
Carbon Dioxide Equivalent				
Residential	332	329	375	373
Commercial	217	221	239	234
Industrial	872	1,050	829	1,046
Transportation	1,472	1,579	1,790	1,856
Electricity	1,859	1,805	2,353	2,278
Total	**4,752**	**4,985**	**5,585**	**5,787**
Carbon Equivalent				
Residential	91	90	102	102
Commercial	59	60	65	64
Industrial	238	286	226	285
Transportation	401	431	488	506
Electricity	507	492	642	621
Total	**1,296**	**1,360**	**1,523**	**1,578**

Note: S.139 reports total emissions allowances in carbon dioxide equivalent. Carbon equivalent is shown in this table for comparability with the balance of the report.

Sources: Energy Information Administration. *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001) (Washington, DC, December 2002); and U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000,* EPA 430-R-02-003 (Washington, DC, April 2002).

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[53] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000,* EPA 430-R-02-003 (Washington, DC, April 2002).

[54] Energy Information Administration, *Emission of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002).

[55] S.139 is not clear on whether military and international bunker fuels are covered or not. While EPA's inventory of US greenhouse gas emissions may exclude these sources in following the reporting conventions of the United Nations Intergovernmental Panel on Climate Change, S.139's provisions for transportation coverage do not exclude them explicitly.

For emissions other than energy-related CO_2, the EPA's Business-As-Usual (BAU) baseline emissions projections were used, along with EPA's corresponding estimated marginal abatement curves. To use EPA's projection and abatement curves in a consistent framework, the 1990 and 2000 data accompanying the projections were used to derive the cap. Some of the data (non-energy carbon dioxide, nitrous oxide, and high GWP gases) differs from the more recent data in EPA's 2002 inventory, due primarily to new accounting conventions in the EPA inventory. The most significant of the accounting changes concerns non-energy carbon dioxide, a category that is assumed not to be covered for the purposes of this report. A comparison of the emissions data available with the baseline projections with the corresponding data in the EPA Inventory is shown in Table 2.2.

To derive the cap, assumptions about what portion of the gases would be covered were made. Non-covered entities include those not meeting the emissions threshold of 10,000 tons carbon dioxide equivalent. In addition, emissions from sources deemed by EPA to be impractical to measure would be considered noncovered. For this analysis, the following assumptions were made about the coverage of several emissions sources, constrained by the level of aggregation of exogenous projections of greenhouse gases other than carbon dioxide (CO_2).

- **Nitrous Oxide:** Emissions from agriculture and mobile sources, accounting for about 87 percent of the nitrous oxide emissions, are assumed to be exempt from coverage based on the measurement and size threshold provisions. An "Other" category of nitrous oxide emissions, which includes emissions from adipic and nitric acid production, is included in covered emissions. While about 25 percent of the Other category includes potentially noncovered sources—stationary sources, human sewage, and waste combustion—the availability of projections for the category as a whole precluded a finer breakout for this analysis.

- **Methane:** Most methane emissions are assumed to be exempt based on the measurement and size provisions. The sources assumed to be noncovered are natural gas systems, landfills, and an "Other" category that includes agriculture, mobile, and stationary sources. Emissions from coal mining, treated in aggregate, are assumed to be covered. The ventilation and degasificaton sources would be expected to be measurable and, for the most part, controlled by entities above the size threshold. It is possible that a small share of the coal-related methane emissions, including emissions from surface mining and post-mining, might be excluded based on the measurement provision. For analysis purposes, the entire category is considered a covered source.

- **Non-energy CO_2:** This category is assumed to be noncovered based on the measurement and size threshold provisions. While some of the emissions is this category, such as those relating to cement manufacture, would probably be covered, a breakout of the projections for this category was unavailable. Since most of the emissions would probably be exempt, the entire category was treated as uncovered for analysis purposes. Note that EIA did not account for some of the new categories of emissions that EPA now accounts for as non-energy CO_2 in this category. The largest of these is carbon dioxide from the use of metallurgical coal, which EIA accounts for in the industrial sector as a covered source.

- **High Global Warming Potential (GWP) Gases:** S.139 specifies that producers and importers of these gases will be required to provide allowances based on the amounts of the gases supplied. However, the emissions data are based on emissions of gases rather than production. For modeling purposes, the emissions, rather than production, of the gases are included in the allowance cap for covered entities.[56]

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[56] As requested in Floyd DesChamps e-mail of May 2, 2003. See Appendix A.

Table 2.2. Comparison of Emissions Data Accompanying Baseline Projections with Data in the 2002 EPA Inventory, 1990 and 2000 (million metric tons)

	1990		2000	
	Data With Baseline Projections	**2002 EPA Inventory**	**Data With Baseline Projections**	**2002 EPA Inventory**
	Carbon Dioxide Equivalent			
Methane				
Landfills	217.4	217.4	208.6	208.6
Coal Mines	88.0	88.0	77.7	77.7
Natural Gas	121.0	121.0	131.3	131.3
Other	218.5	218.5	224.0	224.0
Total Methane	**645.0**	**645.0**	**641.7**	**641.7**
Non-Energy Carbon Dioxide				
New Categories, 2002 Inventory	NA	144.4	NA	119.1
Other Non-Energy CO_2	77.4	74.3	132.0	97.6
Total	**77.4**	**218.7**	**132.0**	**216.7**
Nitrous Oxide				
Agriculture	285.4	283.5	317.0	315.6
Mobile Combustion	54.3	50.9	62.0	58.3
Other	57.1	52.9	54.0	51.4
Total Nitrous Oxide	**396.7**	**387.3**	**433.0**	**425.3**
High GWP Gases	83.9	93.6	121.3	121.3
Total	**1,203.0**	**1,344.6**	**1,328.0**	**1,405.0**
	Carbon Equivalent			
Methane				
Landfills	59.3	59.3	56.9	56.9
Coal Mines	24.0	24.0	21.2	21.2
Natural Gas	33.0	33.0	35.8	35.8
Other	59.6	59.6	61.1	61.1
Total Methane	**175.9**	**175.9**	**175.0**	**175.0**
Non-Energy Carbon Dioxide				
New Categories, 2002 Inventory	NA	39.4	NA	32.5
Other Non-Energy CO_2	21.1	20.3	36.0	26.6
Total	**21.1**	**59.6**	**36.0**	**59.1**
Nitrous Oxide				
Agriculture	77.8	77.3	86.5	86.1
Mobile Combustion	14.8	13.9	16.9	15.9
Other	15.6	14.4	14.7	14.0
Total Nitrous Oxide	**108.2**	**105.6**	**118.1**	**116.0**
High GWP Gases	22.9	25.5	33.1	33.1
Total	**328.1**	**366.7**	**362.2**	**383.2**

Sources: U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000*, EPA 430-R-02-003 (Washington, DC, April 2002). Data for High-GWP Emissions, Nitrous Oxide and Non-energy CO_2 as included with projections is from EPA, *Climate Action Report 2001*, Tables 3-1 and 5-2. See web sites http://www.epa.gov/globalwarming/publications/car/index.html and http://www.epa.gov/globalwarming/publications/emissions/us2002/index.html).

The allowance caps are derived by summing the CO_2 emissions from the affected energy sectors, the covered portions of methane and nitrous oxide emissions, and emissions of the high-GWP gases. Using these definitions, the Phase I and Phase II caps for covered entities are estimated at 5,372 and 4,613 millions metric tons carbon dioxide equivalent. Except where otherwise noted, this report follows EIA's standard practice of reporting emissions of carbon dioxide and other greenhouse gases in carbon equivalent (rather than carbon dioxide equivalent) units, defined as the weight of the carbon content of carbon dioxide (i.e., just the "C" in CO_2). Emissions in carbon equivalent terms are converted to carbon dioxide equivalent terms by multiplying by 3.6667.[57] Thus, the Phase I and Phase II caps used in this report are 1,465 and 1,258 million metric tons carbon equivalent.

Table 2.3 summarizes the Phase I and Phase II caps as modeled in this analysis. As indicated above, emissions of most methane, nitrous oxide, and non-energy CO_2 are assumed to be exempt based on the bill's exemptions for entity size and measurement feasibility. The exceptions are for methane released in coal mining and nitrous oxide emitted in the production of adipic and nitric acid.

Table 2.3. Assumed Phase I and Phase II Allowance Caps (million metric tons)

	Carbon Dioxide Equivalent		**Carbon Equivalent**	
	Phase I Allowances (Based On 2000 Emissions)	**Phase II Allowances (Based On 1990 Emissions)**	**Phase I Allowances (Based On 2000 Emissions)**	**Phase II Allowances (Based On 1990 Emissions)**
Carbon Dioxide				
Industrial Sector[a]	986	997	269	272
Transportation Sector	1,855	1,580	506	431
Electricity Sector	2,277	1,804	621	492
Subtotal	*5,119*	*4,382*	*1,396*	*1,195*
High GWP Gases	121	84	33	23
Nitrous Oxide, Other[b]	55	59	15	16
Methane, Coal Mining	77	88	21	24
Total Covered Emissions	**5,372**	**4,613**	**1,465**	**1,258**

[a] Excludes the energy-related carbon dioxide emissions from the agriculture sector, normally included in emissions of the industrial sector, as these agricultural entities are assumed to be uncovered.

[b] Includes Adipic and Nitric Acid.

Sources: **CO_2:** Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Other Gases:** U.S. Environmental Protection Agency, Office of Air and Radiation, 1990 and 2000 data included with a Business as Usual forecast. S.139 cites the more recent data on emissions in EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000*, EPA 430-R-02-003 (Washington, DC, April 2002). The more recent data was not used so as to avoid bias from using updated history data with inconsistent forecasts and marginal abatement curves.

The bill allows each covered entity to obtain a portion of its emission allowances from alternate compliance sources, including purchase of allowances from certified reduction or sequestration programs, both domestically and abroad. These offset limits are 15 percent from 2010 to 2015 (Phase I) and 10 percent thereafter (Phase II). As an incentive for early action, entities reducing their emissions below 1990 levels may be granted a limit of 20 percent of their target reductions from alternate compliance sources in Phase I. To account for those covered entities that would take advantage of this incentive, an offset limit of 16 percent in Phase II was assumed.[58] Based on these assumptions, the offset limit in Phase I was 234 million metric tons carbon equivalent, and the limit in Phase II was 126 million metric tons.

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[57] Conversely, emissions allowance prices in carbon equivalent terms are converted to carbon dioxide equivalent terms by dividing by 3.6667.

[58] The 16 percent figure was derived by assuming that most of the estimated change in emissions in 2010 would be from entities that qualify for the incentive by reaching 1990 levels.

This analysis also assumes that the greenhouse allowance caps and allowance prices remain at the 2025 levels after 2025. Since capacity expansion decisions in the generating sector are based on capital and non-fuel operating costs and expectations about future fuel and allowance prices over the next 20 years, expected fuel and allowance prices after 2025 are important in influencing power generation capacity additions.

Representation of Non-CO_2 Greenhouse Gases

NEMS is used to simulate proposed limits on energy-related CO_2 emissions based on either a cap and trade allowance policy for CO_2 emissions or a CO_2 fee added to the price of fossil fuels. Since S.139 also includes non-CO_2 greenhouse gases, and since NEMS does not include economic or behavioral models to estimate potential capture of other greenhouse gases, the international and domestic offsets that would be available to the U.S. market were estimated through an external analysis and used for this study.[59]

An emissions accounting structure was developed to distinguish emissions from covered and noncovered entities. In addition, an exogenous set of curves was developed to reflect the potential for reductions in other greenhouse gases as a function of allowance prices. These cost functions are known as marginal abatement curves (MACs). Along with the associated baseline projections of emissions, the MACs were obtained from the EPA's Office of Air and Radiation. EPA provided EIA with MACs as developed in several recent studies.[60,61,62] At EIA's request, EPA also extended its BAU projections and MACs to 2025, the forecast horizon for this study.

The EPA BAU projections and MACs were used in this analysis because they are the only consistent and relatively complete source for such emission estimates.[63] EIA made two adjustments to the MACs: the first adjusts the MACs so that the reductions that are economical at zero or "negative" allowance prices are instead priced at $1 per ton. The second change was to reduce the quantities of international and domestic sequestration reductions available to the U.S. market for reasons to be discussed later in this Chapter. Assumptions regarding MACs are also presented in detail in Appendix B.

In this analysis, the exogenous MACs are treated as four classes:

- Emissions from non-CO_2 greenhouse gases from domestic covered sectors;
- Emissions of non-CO_2 greenhouse gases from domestic noncovered sectors;

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[59] Potential sources of international offset data, including the U.S. Environmental Protection Agency, its contractors, and the Energy Modeling Forum, were identified in the request letter from Senators McCain and Lieberman. The Energy Modeling Forum is an informal study group that has been institutionalized at Stanford University to study key energy, economic and environmental issues. The latest study, called EMF 21, focuses on non-CO_2 greenhouse gas emissions worldwide. Permission is required from John Weyant at Stanford to access the current assumptions on the international marginal abatement curves for non-CO_2 gases at http://www.stanford.edu/group/EMF/group21/index.htm.

[60] U.S. Environmental Protection Agency, *U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions,* EPA 30-R-99-013 (Washington, DC, September 1999), web site http://www.epa.gov/ghginfo/pdfs/07-complete.pdf; and *Addendum to the U.S. Methane Emissions 1990-2020: Update for Inventories, Projections, and Opportunities for Reductions* (December 2001), web site http://www.epa.gov/ghginfo/pdfs/final_addendum2.pdf.

[61] U.S. Environmental Protection Agency, *U.S. High GWP Gas Emissions 1990-2010: Inventories, Projections, and Opportunities for Reductions,* EPA 000-F-97-000 (Washington, DC, June 2001), web site http://www.epa.gov/ghginfo/pdfs/gwp_gas_emissions_6_01.pdf.

[62] U.S. Environmental Protection Agency, *U.S. Adipic Acid and Nitric Acid N2O Emissions 1990-2020: Inventories, Projections and Opportunities for Reductions* (Washington, DC, December 2001), web site http://www.epa.gov/ghginfo/pdfs/adipic.pdf.

[63] The curves are based on an EPA-funded evaluation of reduction opportunities available across a range of emission allowance prices and are consistent with EPA's BAU case. The BAU case has somewhat higher emissions than the policies and measures case published in EPA's *Climate Action Report 2001*. The BAU and the associated MACs generally (with one exception, methane emissions from gas production) assume that technological improvement does not occur and that trends in improved management practices to reduce emissions do not continue into the future. Such an approach overestimates both the BAU emissions and the economic reductions possible.

- Carbon sequestration[64] (agriculture and forestry), domestic; and
- International greenhouse gases and sequestration.

The emissions and MACs for the non-CO_2 greenhouse gases were used to estimate total covered emissions under the bill. Within this category, there is no limit on reductions specified in the bill, and the allowances for these emissions can be considered along with allowances for CO_2 emissions as a single market with unlimited trading.

Reductions in a noncovered entity's emissions, potential carbon sequestration, and international emission reductions are included to reflect the bill's alternative compliance provisions. Allowance credits may be obtained from these noncovered entities subject to the restrictions outlined in Chapter 1. The allowance credits from noncovered entities are commonly referred to as offsets. Offsets are capped at 15 percent and 10 percent limits of emissions from covered sectors.[65] The price at which offsets sell is determined by the intersection of the offset supply curve (or MAC) and the offset limit.

The covered non-CO_2 greenhouse gases consist of the high GWP gases, coal-related methane emissions, and a portion of nitrous oxide emissions from adipic and nitric acid production. The assumed MACs for non-CO_2 emissions in the *noncovered* sectors include reduction opportunities in natural gas operations and small landfills. The quantity of offsets from other non-CO_2 gases is small.

The carbon sequestration MACs are derived from the Forest and Agricultural Sector Optimization Model (FASOM-GHG), in consultation with the EPA.[66,67] The quantities from domestic agricultural offsets that are available for reduction are adjusted downward by 50 percent, consistent with an EPA study requested by Senators Smith, Voinovich, and Brownback.[68] The pricing and availability of agricultural offsets are deemed to be more uncertain than those for other domestic non-CO_2 offsets because of limited information, an inability to measure or verify the data, and administrative costs.[69]

International Offset Curves

Although NEMS is a detailed energy-economy model of the United States and uses consumer behavior to develop detailed projections of energy consumption, energy prices, macroeconomic activity, and carbon dioxide emissions, it does not include economic or behavioral models to estimate the other greenhouse gases covered in S.139. For this study, the offsets that would be available to the U.S. market were also estimated through an external analysis and used for this study.[70] (See Appendix B for details.)

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[64] Carbon sequestration is included for this analysis in 3 ways: domestic use of biofuels, geologic sequestration utilized by the power sector, and domestic and international sequestration from forestry and agriculture. The use of biofuels and geologic sequestration are part of the NEMS formulation while domestic and international forestry carbon sinks have been prepared and used for this study as exogenous inputs.

[65] The 15 percent limit is adjusted to 16 percent in this analysis to account for those entities qualifying for a bonus limit of 20 percent for early participation.

[66] D.M. Adams, R.J. Alig, J.M. Callaway, and B.A. McCarl, *The Forest and Agricultural Sector Optimization Model (FASOM): Model Structure and Policy Applications*, USDA Forest Service Report PNW-RP-495 (1996).

[67] B.A. McCarl and U.A Schneider, "Greenhouse Gas Mitigation in U.S. Agriculture and Forestry," *Science*, Vol. 294, No. 5551 (December 21, 2001), pp. 2481-2482, web site http://www.sciencemag.org/cgi/content/full/294/5551/2481.

[68] U.S. Environmental Protection Agency, "Analysis of Multi-Emission Proposals for the U.S. Electricity Sector" (November 2, 2001), web site http://www.epa.gov/air/meproposalsanalysis.pdf.

[69] It can be argued that all domestic offsets should be reduced by 50 percent as was done by EPA in its study for Senators Smith, Voinovich, and Brownback. Since the quantities of offsets available from domestic non-agricultural sources are small and prices are sharply rising, this study does not reduce the non-CO_2 abatement quantities.

[70] Potential sources of international offset data, including the U.S. Environmental Protection Agency, its contractors, and the Energy Modeling Forum, were identified in the request letter from Senators McCain and Lieberman. The Energy Modeling Forum is an informal study group that has been institutionalized at Stanford University to study key energy, economic and environmental issues. The latest study, called EMF 21, focuses on non-CO_2 greenhouse gas emissions worldwide. Although permission is required from John Weyant at Stanford to access the current assumptions on the international marginal abatement curves for non-CO_2 gases, the web site is http://www.stanford.edu/group/EMF/group21/index.htm.

S.139 provisions limit the sources and quantities of international offsets that qualify for purchase by U.S. entities. Another country's allowances may be used as offsets only if the country has a U.S-approved allowance trading program and an enforceable limit on greenhouse gas emissions under which the allowances were issued to implement. To date, only a fraction of the Annex B countries, as defined in the Kyoto Protocol,[71] could qualify as qualified programs. Annex B countries include Annex I[72] countries plus Lithuania, Slovenia, Croatia, and the Ukraine. This analysis assumes that all international trading will occur through Annex I countries, because they represent approximately 96 percent of all Annex B emissions and because consistent baseline emissions and the associated MACs were only available for Annex I countries. For this analysis, all Annex I countries are assumed to adhere to their Kyoto Protocol targets[73] through 2025.[74]The greenhouse gas emission targets of the Kyoto Protocol were used to develop the aggregate baseline and emission targets through 2025 for Annex I countries, excluding the United States (Table 2.4).

For Annex I, the Clean Development Mechanism (CDM) opportunities were assumed to add approximately 130 million metric tons of carbon equivalent. In 2010, sequestration and CDM represent about 50 percent of the required emissions reductions for Annex I. Although there is no good estimate of what proportion CDM will represent for Annex I, recent news from the United Nations (UN) suggest that CDM projects may be difficult to certify.[75] Reuters reported on June 10, 2003 that of the twelve projects submitted to the UN for certification, all twelve were denied although about half of them will be permitted to reapply. UN spokesperson Christine Zumkeller was quoted as saying:

> *"We have to answer the question: why would this not have happened anyway?*
>
> *A country with many fast-flowing rivers could, for example, argue it is helping the planet by building hydro-electric plants instead of burning fossil fuels, but regulators say that may not be a legitimate argument if the fossil fuel plant was not a viable alternative in the first place."*

The Energy Modeling Forum's 21 assumptions on the availability of non-CO_2 offsets were used to estimate the offset MACs available to Annex I countries excluding the United States. The CO_2 MACs and baseline for Annex I were provided by Pacific Northwest National Laboratory and used as a pair to maintain self-consistency.[76] Annex I minus the U.S. MAC was derived (Table 2.5) and used to identify the portion of the offsets that might be made available for U.S. purchase.

The uncertainty regarding the availability of international offsets is assumed to be equivalent to the uncertainty for domestic offsets from sequestration. Therefore, the offsets available from participating Annex I countries were reduced by 50 percent. That is, the portion of the reductions remaining after

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[71] See web site http://www.dti.gov.uk/ccpo/glossary_kyoto_1.htm.

[72] The Annex I countries are the 15 European Union countries plus Australia, Bulgaria, Canada, Czech Republic, Estonia, Hungary, Iceland, Japan, Latvia, Liechtenstein, Monaco, New Zealand, Norway, Poland, Romania, Russian Federation, Slovakia, Switzerland, and the United States. The United States is not a participant in the Marrakech Accords, which means that the U.S. has not accepted the limits placed on the use of agricultural sequestration -- less than 30 million metric tons per year -- to satisfy its Kyoto targets.

[73] "National Communications From Parties Included in Annex I to the Convention: Report on National Greenhouse Gas Inventory Data from Annex I Parties for 1990 to 2000", October 11, 2002, FCCC/SB/2002/INF.2, available at web site http://unfccc.int/program/mis/ghg/index.html (Table 4, page 10).

[74] Some experts like Dr. Denny Ellerman of MIT are skeptical that all of Annex I will participate in an emission control and trading program that satisfies the conditions of S.139. Others believe that marketers will play a large role to expand the certified reductions, which can then be sold to the U.S. markets. If larger amounts of low-cost credits were to be made available through marketers, the offset prices would fall, thereby reducing marketers role. Since the costs of CDM and sequestration are so uncertain, it is impossible to develop a good estimate of how the CDM market will evolve.

[75] http://www.planetark.org/dailynewsstory.cfm/newsid/21123/story.htm.

[76] Ron Sands email to Joseph Beamon dated March 27, 2003. Although EIA produces baseline for CO_2 emissions for Annex I or Annex B, EIA does not currently have a consistent CO_2 MAC.

Annex I requirements were met was reduced by 50 percent[77] (Table 2.6). The derivation of the international curves is provided in Appendix B. Table 2.6 implies that the Annex I allowance price would be between $20 and $30 per metric ton carbon equivalent in 2010,[78] between $40 and $50 in 2015, and between $50 and $75 in 2020 and 2025.

Table 2.4. Annex I Countries Greenhouse Gas Baseline Emissions, Excluding United States, Historical and Forecast (million metric tons carbon equivalent)

Year	GHG Baseline Emissions	Kyoto Target	Reductions Needed From Baseline To Meet Kyoto Target
1990.........	3,188		
1995.........	2,906		
2000.........	2,875		
2005.........	3,109		
2010.........	3,299	2,898	401
2015.........	3,462	2,898	564
2020.........	3,605	2,898	707
2025.........	3,688	2,898	790

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, calculations based on the EMF21/EPA IMAC model. See Appendix B.

Table 2.5. Aggregate Greenhouse Gas Marginal Abatement Curves for Annex I Countries, Excluding the United States, Adjusted for Agriculture and Forestry Sinks and CDM (reductions in million metric tons carbon equivalent)

Carbon Price (2001 dollars per metric ton carbon equivalent)	2010	2015	2020	2025
0........................	32	34	36	39
10........................	116	137	159	172
15........................	348	379	410	427
20........................	380	420	460	482
30........................	427	481	535	563
40........................	462	529	595	627
50........................	492	569	645	680
75........................	562	660	754	795
100........................	630	743	850	898
125........................	693	821	940	995
150........................	742	880	1,009	1,066
175........................	788	935	1,074	1,132
200........................	835	992	1,140	1,199
225........................	927	1,096	1,256	1,320

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. The results are the sum of Tables B11-B14 in Appendix B.

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[77] EPA's Smith, Voinovich and Brownback study assumed a reduction of 75 percent for international sequestration.

[78] Previous unrestricted *global trading* studies have suggested that greenhouse gas allowance prices would equilibrate on the lower end of the $5 to $ 25 per ton range in 2010 if the whole world participated in emissions reduction programs with relatively unrestricted CDM and sequestration. Since offsets in Annex I are more restricted than global trading schemes, price estimates in the middle to higher end of the price range for Annex I are more likely.

Table 2.6. Aggregate Greenhouse Gas Marginal Abatement Curves for Annex I Countries, Excluding the United States, Adjusted for Agriculture and Forestry Sinks, CDM, Kyoto Targets, After Reduction Factor (million metric tons carbon equivalent)

Carbon Price (2001 dollars per metric ton carbon equivalent)	2010	2015	2020	2025
0	0	0	0	0
10	0	0	0	0
15	0	0	0	0
20	0	0	0	0
30	13	0	0	0
40	31	0	0	0
50	45	3	0	0
75	81	48	23	3
100	115	90	71	54
125	146	129	116	102
150	170	158	151	138
175	193	186	183	171
200	217	214	216	205
225	263	266	274	265

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting calculations. See Appendix B for the calculations and methodology.

Uncertainties: Offsets and Sinks in S.139

Uncertainty about the quantities and prices of offsets under S.139 could have an effect on the U.S. energy-economy over the projection period. The possible impacts of price and supply uncertainty in the allowance market are addressed by analyzing two additional sensitivity cases: one that doubles the quantity of international offsets available at each price (200 percent of S.139) and one that eliminates international offsets (0 percent of S.139).

In addition to the question of which end-use sectors would actually be covered by the S.139 emissions caps, uncertainty surrounds the issue of how many offsets will truly be available to the market and at what price (true market potential). The issue relates to the well-known problem of differentiating between technical potential, economic potential, and actual market potential for each potential source of allowances or offsets. Some of the factors contributing to the uncertainty are discussed in the following paragraphs.

International Offset Limitation: S.139 defines strict qualifying standards for the sources and countries from which U.S. entities may purchase international offsets. U.S. entities may purchase offsets from those countries that have greenhouse gas emission reduction programs with proper measurement, certification, and registry rules. While some developing countries have “signed on” to the Kyoto Protocol, few have set caps on their greenhouse gas emissions. Currently under S.139, Annex B countries represent the largest group that can be considered as possible qualifying participants. While it is possible that all Annex B countries will be participants in a greenhouse gas emission reduction program, it is also unlikely that all will participate in a greenhouse gas trading program. By one estimate,[79] only the European Union is likely to have an operational greenhouse gas emission control and trading program.

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[79] Denny Ellerman, MIT Joint Program on the Science and Policy of Global Change, email to EIA staff on April 11, 2003.

Uncertainties: Offsets and Sinks in S.139 (continued)

Clean Development Mechanism (CDM) Limitation: Under the bill's provisions, bilateral CDM programs between the United States and developing countries are not allowed. Only offsets from CDM programs that are registered and certified by participants in the Annex B subgroup, if available, can be purchased by U.S. entities. The rules for such purchases have not yet been established.

Verifiability and Measurability: Before offset credits can be provided for greenhouse gas abatement, a system must be implemented that verifies the actions and the quantities abated. Many of the reductions in the agricultural sector and other noncovered sectors are small or difficult to validate. The difficulties in verification and measurement can pose a significant hurdle to participation in the abatement program.

Aggregation/Agglomeration: Small participants may be excluded from participation, even though the credits may be, in principle, economical on a per unit basis, because the transaction costs may be too high relative to the number of credits available.

Adequacy of Price Signal: Potential offsets in some markets could come from "players" whose primary interest is not sequestration. The price signal may need to be much greater than a standard "economic" price might indicate before any action to abate greenhouse gas emissions and claim or register credits is considered. For example, the control of manure-based methane from raising farm animals is of minor importance to farmers compared to their main business of raising and selling their farm animals or producing milk for sale. Behaviorally speaking, most small farmers are unlikely to pay much attention at prices developed using engineering-economic analysis.

Governance/Political Structure and Control: If the offsets are claimed from foreign investments in afforestation or other agricultural sequestration (e.g., no till farming), the longevity of such actions can be uncertain, because ownership of the lands or even the government could change, thus negating the carbon previously sequestered through such means. For example, agreements made for agricultural offsets may appear risky to a potential offset credit buyer if the buyer bears the risks of future compliance failures, because land used for afforestation/reforestation could later be converted to food production or urban growth and no longer represent an offset credit.

Treatment of "Hot Air:" The degree to which offsets from Russia and other Eastern Bloc countries whose credits result from lower economic growth might be available can significantly influence Annex B emission reduction strategies, particularly in the early compliance period. Although such credits would primarily serve to transfer wealth between nations without making real reductions in greenhouse gas emissions, they are included for the purposes of this analysis.

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[80] Because sources for international offsets of S.139 in this analysis of S.139 are restricted to a subset of Annex B, the uncertainty from this source was determined to be lower than the uncertainty that would have resulted from the remainder of the world's offsets assumed in EMF 21. EMF21 did not reduce the non-CO2 GHG offsets. Modelers were instructed to use their own judgment regarding their use. Unadjusted MACs for carbon dioxide, non-CO2 gases, sequestration and CDM were used to balance the demand for emission reductions with the supply for Annex I. A 50 percent adjustment factor was assumed on the remaining amount that might be available for sale to the United States. The adjustment factor was applied to the total remaining because it is uncertain whether or not such offset reductions will be undertaken and registered and because the MACs are based on engineering-economic estimates which are inadequate at predicting market adoption.

[81] Communication to Andy S. Kydes by Francisco DelaChesnaye.

[82] U.S. Environmental Protection Agency, "Analysis of Multi-Emission Proposals for the U.S. Electricity Sector" (November 2, 2001), web site http://www.epa.gov/air/meproposalsanalysis.pdf. EPA used a 75 percent reduction in the referenced study.

Uncertainties: Offsets and Sinks in S.139 (continued)

International MACs: The MACs provided by the Energy Modeling Forum for international non-CO_2 offset curves are not estimates of observed behavior. They are scenario assumptions provided by EPA, and they are the only available source for this information. The amounts of international offsets available from sequestration are even more uncertain.[80] For example, one EMF participant proposed model results for international sequestration that would offset the entire world's greenhouse gas emissions entirely through afforestation/reforestation four times over through the 21st century. EPA subsequently suggested that those estimates should not be used in this analysis.[81] If these quantities and prices for carbon sequestration offsets were accurate, one would have to conclude that there is no global climate change problem for the 21st century.

If Annex B or Annex I restricts the United States from participating in its trading program, there could conceivably be no international offsets for U.S. entities to buy. Such a restriction currently has not been adopted by the European Union.

The principal uncertainty of this analysis is whether the quantities estimated by EPA, EMF 21, or other sources will actually be available for purchase at the prices specified. That is, "do these MACs represent competitive market prices?" Because their estimates are highly uncertain, the international offsets available to the United States have been reduced by 50 percent for the representation of the S.139 case. The use of a 50 percent reduction is equivalent to the assumption that the uncertainty in the availability of international offsets as restricted by the bill can be characterized by a uniform distribution of the quantities available at each price point and year. Recent discussions with EPA have suggested qualitatively that such reductions are reasonable. EPA used somewhat more severe reductions in its study of the Smith, Voinovich, and Brownback request in 2002.[82] The derivation of the sinks and offsets for S.139 is described in detail in Appendix B.

Allocating Emissions Allowances

In order to assess the macroeconomic impacts of S.139, an assumption is needed regarding how emission allowances would be allocated among covered sectors and the Corporation. To assess the sectoral impacts of S.139, an additional assumption is needed regarding how emissions would be allocated among covered entities.

As long as emission allowances are allocated based on historical activities (emissions, production, etc.), the method used to allocate emissions will not affect a firm's behavior, although alternative methods will likely have some impact on macroeconomic activity. From a firm's perspective, the allocation of emission allowances is primarily an issue of equity and does not significantly affect energy pricing. However, there are special situations regarding regulated utilities where the allocation of emission allowances can impact energy pricing depending on regulatory decisions about the way in which the value of emissions allowances is apportioned between utility stockholders and ratepayers.

From a macroeconomic perspective with respect to S.139, the extent to which emission allowances are allocated to companies or the Corporation (which will sell them to entities) and the manner in which Corporation revenues are rebated to consumers and businesses are important.[83] For the S.139 case and

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[83] For a discussion of the treatment of Corporation revenues see Chapter 7.

Administrative Costs to the Federal Government

The administrative cost to the Federal Government of allocating allowances, monitoring the program, and enforcement could be significant, particularly when compared with the current electricity generation cap and trade program under the Clean Air Act. This is also true for the indirect costs of private industry (e.g., measurement and reporting costs and the administration costs of acquiring allowances). S.139 requires “entities owning or controlling” facilities that meet the 10,000 metric ton threshold to report their emissions and abide by the emissions limits. Because there is no existing data source that has either energy or emissions data at the entity level in the manufacturing or commercial sectors of the economy, the process of finding all the entities that are covered is likely to be costly.

Typically, carbon dioxide emissions are not actually measured but are calculated on the basis of energy consumption and process throughputs. Possibly several thousand entities will be required to report a calculation of carbon dioxide emissions, even though they are not required to report their energy consumption to any Federal agency. This requirement contrasts with the existing sulfur dioxide emissions program for utility and large industrial sources. In that program, the emissions typically are measured at the approximately 2,000 facilities covered by the program.[84] However, the sulfur dioxide emission program is far less extensive in coverage than would be the greenhouse gas emissions program proposed under S.139.

Appendix C of this report describes many of the accounting complexities associated with collecting and verifying emissions reductions under EIA’s Voluntary Emissions Reporting Program (1605b). An example of the quantity of voluntary emissions reductions and sequestration changes reported is provided. The estimates in Appendix C are an indication of the scope of reductions likely to be registered for early action credits under S.139. In addition, the accounting and program issues discussed highlight some of the challenges that would be posed under the S.139 provision for registering emissions reductions by noncovered entities for use as offsets by covered entities.

The Voluntary Emissions Reporting Program also provides an indication of the possible cost of collecting emissions information. In this program, EIA collects information from 228 respondents at a total annual operating cost, including Federal and contract personnel, of $563,000, which is equivalent to $2,469 per reporter. A recently published analysis of the number of facilities that could be affected by various emissions limits estimates that there are 11,626 facilities (7,777 industrial plants, 2,216 landfills, and 1,633 power plants) that have emissions in excess of 10,000 metric tons of carbon dioxide annually.[85] If the average administrative costs per facility under S.139 were equivalent to the average administrative cost per reporter to the Voluntary Reporting Program, then the Federal Government’s data collection cost under S.139 would be around $29 million a year. These costs, however, do not include system startup costs or enforcement costs required to ferret out entities that meet the threshold but do not report and to enforce the emissions limits for those entities that do report. Also not included in these cost estimates are the costs incurred by entities in reporting.

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[84] In 2001, there were 2,792 units affected by the sulfur dioxide provisions of the Acid Rain Program. Since a plant may have more than one unit, the number of respondents was somewhat less than the number of units. U.S. Environmental Protection Agency, *EPA Acid Rain Program, 2001 Progress Report* (Washington, DC, November 2002), p. 1.

[85] T.O. West and N. Pena, “Determining Thresholds for Mandatory Reporting of Greenhouse Gas Emissions,” *Environmental Science and Technology*, Vol. 37, No. 6 (2003), pp. 1057-1060, Table 3.

most sensitivity cases,[86] it is assumed that, in 2010, 80 percent of the allowances are initially allocated directly to the entities and 20 percent to the Corporation. The Corporation is assumed to sell the allowances allocated to it and use the proceeds to reduce the economic impact of the allowance program through transition assistance and other transfer payments. Starting in 2011, the share allocated to entities is decreased each year until it reaches 20 percent in 2025,[87] with the remainder going to the Corporation.

For those allowances that are allocated at no cost there are numerous options for determining how to distribute them. For example, they could be distributed to existing entities based on some recent year's emissions (what is often referred as grandfathering) or they could be distributed using some sort of output measure (such as generation in the power sector). In addition, the distribution could be a one-time event at the beginning of the program, or it could be updated annually or on some other schedule. For this analysis, it is assumed that the portion of allowances that are allocated freely is distributed based on an entity's share of historical emissions.

Rebates for Energy-Efficient Equipment

S.139 allows covered entities to purchase allowances from noncovered entities that register greenhouse gas reductions associated with reductions in their energy use. This implies that any reduction in energy use by a noncovered entity could be used as an offset by a covered entity as long as the reduction was properly registered. Examples of energy-reducing actions include normal replacement of old, less energy-efficient appliances and utility demand-side management (DSM) programs. Because the bill is likely to result in higher electricity prices, it is assumed that consumers will have an incentive to pursue demand reduction activities.

In addition, Section 352(b)(1)(A) of S.139 states that the Corporation may use "buy-down, subsidy, negotiation of discounts, consumer rebates, or otherwise," to reduce the costs of greenhouse gas emission reductions borne by consumers. No specific preference for any of these methods is indicated in S.139. Expenditures on efficient appliances by the Corporation could increase the market penetration of more efficient equipment. As a proxy to assess the potential impact of these options, it is assumed that the Corporation will offer rebates to reduce the cost of higher efficiency equipment and allow consumers to choose that equipment if the reduction in cost makes it economic, regardless of the fuel type of the appliance. In the S.139 case, for example, the price of the most efficient central air conditioner, which is 50 percent more efficient than the standard unit, decreases in price from $3,500 to $2,900, resulting in a $600 cost difference between the least efficient and most efficient unit available for purchase from 2010 to 2025. The approach adopted to reflect these rebates is described further as part of the residential sector discussion in Chapter 4.

Evaluation of CAFE Credits

S.139 includes a provision that allocates greenhouse gas emission allowances to light-duty vehicle manufacturers whose CAFE exceeds the CAFE standard by 20 percent. In order to achieve increases in CAFE, manufacturers can employ new technologies, downsize vehicles, or offer pricing incentives to shift consumers into more efficient vehicles. For this analysis, it is assumed that manufacturers will only adopt new technologies in their efforts to increase vehicle fuel economy, thus preserving vehicle utility, comfort, performance, and occupant safety.

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[86] For a description of the sensitivities, including the variation in banking options evaluated, see the section on Scenarios Included in this Study, below.

[87] S.139 does not prescribe how emissions should be allocated between covered entities and the Corporation. EIA's initial allocation of 80 percent to covered entities and 20 percent to the Corporation with a gradual increase in the amount allocated to the Corporation is based on comments received from EIA's Independent Expert Reviewers.

The provision states that the Secretary of Transportation, in consultation with the Administrator of the Environmental Protection Agency, will determine the conversion factor used to translate fuel economy improvements into greenhouse gas emissions. In order to estimate the lifetime greenhouse gas benefit of increased fuel economy one must make assumptions regarding the life of a vehicle and how that vehicle will be used over its lifetime. This study assumes 135,000 average lifetime miles of travel per light-duty vehicle. Assuming that a vehicle manufacturer meets the minimum required improvement in CAFE (20 percent) relative to the currently planned CAFE standards, this equates to approximately 2.0 metric tons of lifetime greenhouse gas savings per car and 2.4 metric tons of lifetime greenhouse gas savings per light truck.

To capture the impact of the CAFE provision, the transportation model was modified so that manufacturers evaluate the opportunity cost associated with meeting the 20 percent fuel economy improvement. As the model evaluates the decision for technology adoption, the opportunity cost associated with the potential fuel economy improvement is included in the cost evaluation, which reduces the cost of supplying fuel economy, shifting the fuel economy supply curve to the right. The structure of the algorithm reflects a gradual participation by vehicle manufacturers over time, accounting for the relative difficulty manufacturers will experience in improving CAFE based on their vehicle sales mix.

Allowance Banking Provisions

The cap and trade system in S.139 allows covered entities to buy and sell allowances and bank excess allowances for future use. Thus, the emissions of individual covered entities is not limited, and entities may over-comply to bank allowances for future use. S.139 also provides for the borrowing of allowances under specific limitations outlined in the bill, including a restriction that an entity may borrow against future emission reductions only if it can show it has a project underway to achieve those reductions, as well as a requirement that borrowed allowances must be returned with interest at 10 percent per year (in terms of allowances).

With allowance banking, the decisions to buy, sell, and hold allowances will depend on both the current and anticipated allowance prices. The allowance price path is assumed to be smoothed through expectations and arbitrage. If allowance prices grew rapidly in the future, high levels of early reductions and banking (or overcompliance) would tend to occur, because the cost of those reductions would be expected to be recoverable in the future. The buildup of high levels of banked allowances would then tend to lower expectations of prospective carbon prices and moderate banking of allowances.

The banking provisions are expected to smooth out the potential price increases that might otherwise occur during the transition from Phase I to Phase II. Details of the banking approach are discussed in Appendix B.

Scenarios Included in This Study

To respond to the requests from Senator Inhofe and Senators McCain and Lieberman, various cases showing the impacts of S.139 under a range of assumptions were analyzed. A short description of each of the cases follows.

- ***Reference Case***: This is an updated reference case based on the assumptions of the *Annual Energy Outlook 2003* reference case, with three additions. Because natural gas prices have been highly volatile, the reference case incorporates the near-term (through 2004) projections for natural gas prices from EIA’s April 2003 *Short-Term Energy Outlook*. This assumption mainly affects the near term but also has a slight effect on natural gas markets in the long term, generally raising prices from the *AEO2003* reference case projections.

The second assumption change from the *AEO2003* reference case is to supplement the near-term additions to electric generating capacity used in that document with additional capacity now expected to come on line through 2004. With new data available since preparation of the *AEO2003* reference case, approximately 24 gigawatts—mainly natural-gas-fired—is now expected to come on line through 2004. The impact of this assumption on the revised S.139 reference case is to increase near-term generating capacity additions but reduce later additions. Thus, there is little effect on the ultimate level of generating capacity.

Third, the assumptions used for *AEO2003* were updated to reflect the increase in CAFE standards announced on April 1, 2003, by the National Highway Traffic Safety Administration.

- ***S.139 Case***: This case simulates enactment of S.139, combined with *AEO2003* reference case assumptions for technology. This is the principal case used to represent the overall impacts of the bill. The other cases in the analysis are designed to test the assumptions incorporated in the S.139 case. The following assumptions are made in the S.139 case and are varied in the sensitivity cases:
    - **Allowance Banking**: Entities can overcomply (e.g., in Phase I) and bank allowances for future use (e.g., in Phase II). Arbitrage in allowance trading and banking is assumed to limit the annual growth rate of the allowance trading price.
    - **Alternate Compliance Percentage**: In aggregate, entities are assumed to obtain 16 percent of covered emissions allowances through the bill's alternate compliance provisions ("offsets") in Phase I (2010-2015) and 10 percent in Phase II (from 2016 on). Offsets come from: (1) emission reductions from noncovered entities (domestic); (2) increases in net biological carbon sequestration; and (3) international emissions reductions. The 16 percent reflects the bill's provision that some entities will be granted a 20 percent offset percentage (instead of 15 percent) in exchange for reducing their emissions to 1990 levels by 2010.
    - **Commercial and Industrial Sectors**: The S.139 case assumes that all entities in the commercial sector are exempt from emissions allowances and that all entities in the industrial sector are covered.
    - **Auction Percentage**: The S.139 case assumes that 20 percent of emissions allowances will be allocated to the Corporation in 2010, increasing linearly each year to 80 percent in 2025.
    - **Nuclear Power and Geological Sequestration**: The S.139 case assumes commercial availability of advanced nuclear plants and of geological carbon sequestration technologies in the electric power industry.

The following sensitivity cases were examined to analyze variations on the S.139 case:

- ***High Technology Reference Case***: This alternate reference case incorporates the high technology case assumptions and is designed for comparison with the S.139 high technology case. The high technology cases incorporate alternative assumptions for the four end-use demand sectors and the electric power sector. Assumptions in the high technology cases vary by sector but generally include earlier availability, lower costs, and higher efficiencies for advanced technologies than in the reference case.
- ***S.139 High Technology Case***: This case incorporates the high technology case assumptions used in the *AEO2003* integrated high technology case.[88]
- ***No New Nuclear/No Sequestration Case*:** This case shows the impacts of assuming that neither of these two technologies would be commercially available through 2025. There are siting,

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[88] See *Annual Energy Outlook 2003*, Appendix Table F4, p. 218.

environmental, political, and public opinion barriers to new nuclear capacity in the United States. Also, no generating facility with carbon capture and geological sequestration has been built, leading to considerable uncertainty over whether it will be technically and economically feasible in this time horizon.

- ***High Natural Gas Price Reference Case***: This case assumes a more pessimistic outlook for domestic natural gas supply than in the reference case, resulting in higher natural gas prices. This case assumes that the natural gas supply assumptions of the reference case are changed to reflect: (1) a 25 percent reduction in Canadian and U.S. resources, (2) a 25 percent reduction in the rate of technological advancement in Canada and the United States, (3) a 3-year increase in the total time required to construct the Alaska Natural Gas Transportation System, and (4) restrictions on new LNG facilities in the Gulf of Mexico, the Bahamas, and Baja, California. These assumptions ultimately lead to higher natural gas prices based on long-term changes in the fundamental drivers of natural gas supply.
- ***S.139 High Natural Gas Price Case***: This case combines the high gas price reference case with enactment of S.139. It is intended to analyze the impact of higher natural gas prices on energy market decisions under S.139.
- ***Commercial Coverage Case***: This case assumes that all entities in the commercial sector are covered. Under the S.139 case, the commercial sector is assumed not to be covered.
- ***80 Percent and 20 Percent Allowance Auction Cases***: The S.139 case assumes that, initially, 20 percent of the emission allowances issued by the Government will be allocated to the Corporation, increasing to 80 percent by 2025. These cases show the impacts of two fixed percentages, 80 and 20 percent, allocated to the Corporation in each year of the forecast.
- ***S.139 High Percentage Offset Case***: This case examines the sensitivity of the S.139 case to increasing the percentage of allowance requirements that can be met by offsets to 50 percent in all years.
- ***S.139 International Offset Availability Cases***: This pair of cases examines the impact on the S.139 case of variability in international offset availability. The first case assumes no international offsets (low international offset supply case). The second assumes a doubling in the supply of offsets available at each price (high international offset supply case).
- ***No Banking Case***: This case assumes that banking of emissions allowances for later use by covered entities is not a compliance option. It is included to show the impacts of the banking provision in S.139.

3. Greenhouse Gas Emissions, Allowances, Offsets and Commitments of Developing Countries

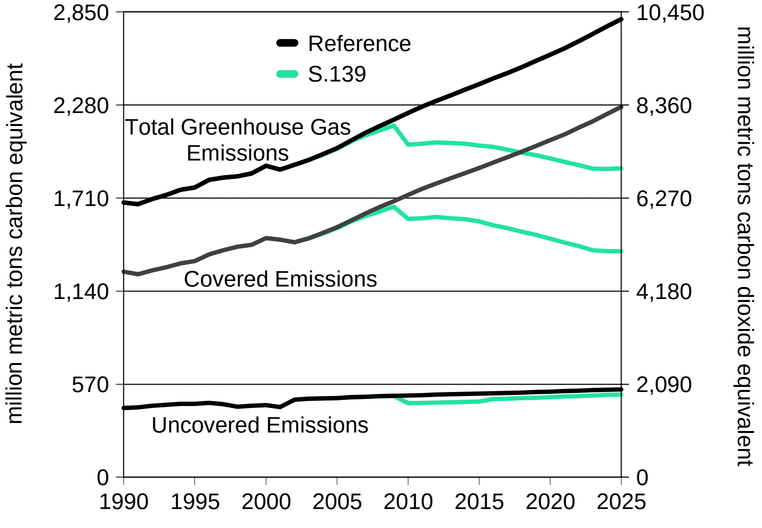
Greenhouse Gas Emission Levels

Although S.139 eventually caps covered entities' greenhouse gas emissions at their 1990 level, the flexibility mechanisms in the bill are projected to allow covered entities to continue to emit in excess of the target. Covered entities can comply with S.139 without directly reducing their emissions to the specified targets by purchasing credits from noncovered U.S. entities that register emissions reductions, allowances from qualified foreign trading programs, and credits from projects to enhance the biological sequestration of greenhouse gases (sinks).

The S.139 emissions allowance program is expected to have an effect on energy-related investment decisions soon after enactment, thus slowing the growth in emissions somewhat relative to the reference case (Figure 3.1). While the bill's emissions limits and allowance trading provisions do not start until 2010, credits for early action are expected to induce some changes in emissions before 2010. More significant reductions are expected to begin in 2010 when the Phase I limits go into effect. Emissions over the Phase I period drop beginning in 2010, as covered entities begin to take advantage of the banking provisions and overcomply so as to accumulate banked allowances. In addition, they are expected to purchase allowances from noncovered entities as allowed under the offset provisions of the bill.

Beginning in 2016, when the more stringent Phase II allowance caps go into effect, covered entities would use previously banked allowances, enabling them to reduce their emissions (about 75 percent of the total) to near 1990 levels over the next decade. Emissions from noncovered entities grow moderately through 2025. Total emissions (covered and noncovered) reach 2000 levels by 2025. These changes in emissions do not reflect increases in carbon sequestration and purchases of emissions reductions abroad that are also used to comply with the targets in the legislation.

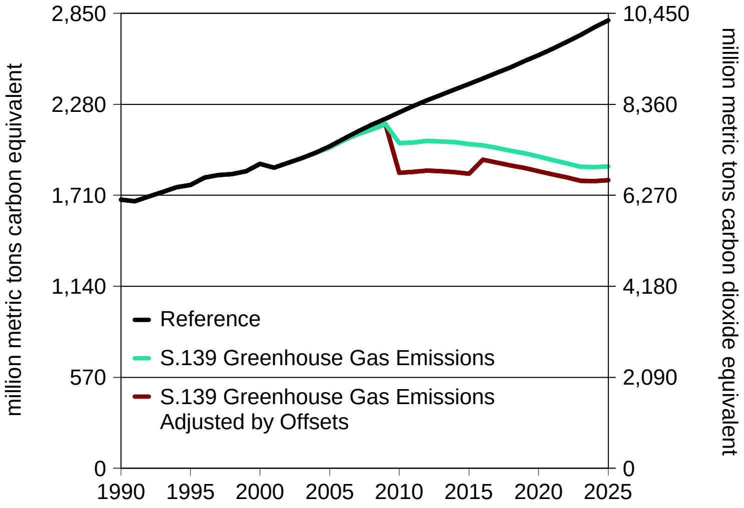
Figure 3.1. U.S. Greenhouse Gas Emissions in the Reference and S.139 Cases, 1990-2025 (million metric tons carbon equivalent)



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

S.139 is expected to induce increases in biological carbon sequestration in the United States and to result in some reduction of emissions abroad as U.S. entities purchase allowances from countries with verifiable emission inventories that provide compliance at lower cost. The alternative compliance provisions of the bill bring about these changes. These provisions allow noncovered entities to register reductions and receive allowance credits, which they can then sell to a covered entity. If the S.139 greenhouse gas emissions trend is adjusted to account for these changes, the adjusted emissions nearly reach 1995 emission levels by 2025 (Figure 3.2). The difference between the adjusted line and the S.139 case is larger during the 2010-2015 than the 2016-2025 period because of the larger amounts of offsets permitted for use in the first period. Thus, given an adjustment credit for the increase in carbon sequestration and the emission reductions abroad that are induced, S.139 results in adjusted U.S. emissions by 2025 equal to 7 percent above the estimated 1990 level of 1,672 million metric tons carbon equivalent (1,258 million metric tons carbon equivalent in the covered sectors and 414 million metric tons carbon equivalent in the noncovered sectors).[89]

Figure 3.2. Projected Greenhouse Gas Emissions, Adjusted for Sequestration and International Offsets, 1990-2025 (million metric tons carbon equivalent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050503a and MLBILL.D050503A.

S.139 provides some measures that give entities a certain amount of flexibility in complying with the emissions limits. These provisions include early action credits, allowance trading and banking, and a mechanism to allow participation from noncovered sources. These flexibility measures are expected to result in a relatively smooth transition through the first and second compliance periods. As a result, the economic burden of controlling emissions is rolled in gradually over time. The potential shock that might otherwise occur when the Phase II emissions limits take effect in 2016 is dampened through banking of allowances during the Phase I period (Figure 3.3). By overcomplying during Phase I, covered entities will accumulate a bank balance of allowances through 2015, then gradually withdraw the allowances over the following 5 to 10 years as they adjust to the Phase II limits. After the depletion of their banked allowances around 2020, covered entities are expected to start meeting their Phase II limit with minimal levels of aggregate banking or borrowing.

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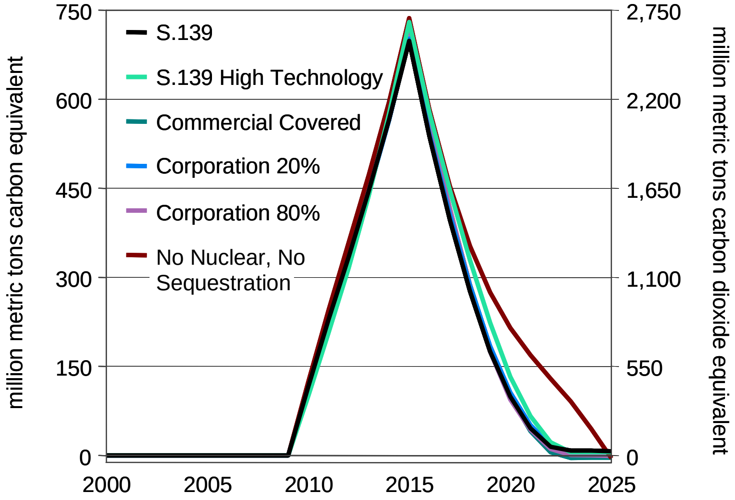
[89] Readily available historical data for the covered and noncovered sectors as defined in S.139 do not exist. These numbers are EIA estimates.

Figure 3.3. Projections of Cumulative Allowance Banking, 2010-2025 (million metric ton carbon equivalent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A, ML_HT.D050503A, ML0NUCSEQ.D050403A, ML_CCCC20.D050503A, ML_CCCC80.D050503A, and ML_COVER_K.D050603A.

Allowance and Offset Values

The trading market for allowances and offsets is expected to be affected by banking and arbitrage. The allowance price is expected to approach an equilibrium solution over time, characterized by growth at some aggregate discount rate. For this analysis, we have assumed that trading behavior will be based on a real, after-tax discount rate of 8.5 percent.[90] For this analysis, a discount rate equal to the real-after tax cost of capital was assumed in the electricity sector, as the most important capital decisions driving the emissions market are expected to take place in that sector. As a result, allowances prices growing at that discount rate are estimated such that the bank of allowances is cleared sometime after 2020, while meeting the bill's constraints on the use of offsets. After the bank balance reaches zero, the allowance prices are expected to increase by less than the discount rate. These assumptions generally lead to a leveling off of allowances prices after the banking period ends.

Since noncovered entities can obtain offset credits for verifiable emissions reductions, they can participate in the market-based compliance system of S.139. These offset allowances, however, are constrained in the bill. Generally, entities may only meet 15 percent of their Phase I limits through the use of offsets, and 10 percent in Phase II. As a bonus for early action, entities that reduce their emissions to below their 1990 level by 2010 are eligible to purchase 20 percent of their Phase I allowances from offsets.

As a result of the offset limits and the generally low costs of reductions from offset sources, the market price for offsets is expected to clear at prices well below the allowance market in most cases. In effect, two markets develop: one for allowances and one for offsets. If the limit on offsets were not reached in complying with the bill (i.e., if the constraint were nonbinding), the markets for offsets and allowances

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[90] The decisions to sell or hold allowances for the future are expected to result in a gradually increasing allowance price that grows at a rate consistent with the rate of return for similar investments. For this analysis, a real discount rate of 8.5 percent was assumed. This occurs because arbitrage in allowance trading tends to equate the current prices for allowances with the present discounted value of future allowances. In practice, fluctuations in year-to-year prices are likely to occur as a result of imperfect information and unexpected events.

would be expected to clear at the same price. This result occurs in a sensitivity case that substantially raises the limits on offset use specified in S.139.

Allowances

In S.139, the covered sector greenhouse gas target is 1,465 million metric tons carbon equivalent for 2010 to 2015 and 1,258 million metric tons for 2016 and beyond. This analysis assumes that, in aggregate, a Phase I limit of 16 percent[91] for offsets would apply, taking into account the additional use of offsets allowed for covered entities that take early action. Based on the derivation of the Phase I and Phase II limits (see Chapter 2), the amount of offsets purchased is expected to be capped at 234 and 126 million metric tons carbon equivalent, respectively. Because the Phase II target is more severe and offset flexibility is lower than in Phase I, additional allowances are projected to be banked from covered sectors in Phase I and used during Phase II, when allowance prices are expected to be high. The major effort to adhere to S.139 is borne by the domestic covered sectors, particularly in Phase II. In the S.139 case, allowance and offset prices diverge immediately, because the maximum allowable offsets are used in both periods and additional allowances are banked from domestic covered sectors, reflecting expected higher future allowance prices. Projected allowance prices in the S.139 case rise smoothly from about $79 per metric ton carbon equivalent to about $223 in 2023, when the allowance bank is depleted and prices become more volatile (Figure 3.4).

Excluding the no banking case, allowance prices in the major sensitivity cases are the most responsive to differences in technology assumptions (high technology and no new nuclear/no sequestration cases) and the least affected in the cases where the percentage allocation to the Corporation is varied. Allowance prices in the S.139, corp20, and corp80 cases[92] are virtually the same, because the total greenhouse gas emission reductions that are to be achieved from covered sectors remain nearly constant under the reference case technology menu. Consequently, the allowance prices remain nearly the same throughout the projection period for these three cases. The more interesting cases are the S.139 high technology case, the no banking case, and the no new nuclear/no sequestration case, which assumes that new nuclear power and carbon sequestration technologies are not successful in becoming commercially viable before 2025. Table 3.1 compares the analysis results in the S.139 case and these three cases (see also Figure 3.5).

In the commercial coverage case, where the commercial sector is included as a covered sector, the greenhouse gas emissions target for covered entities increases to 1,529 million metric tons carbon equivalent for 2010-2015 (instead of 1,465) and 1,318 million metric tons for 2016 and beyond (instead of 1,258). The maximum use of offsets allowed in this case is 245 million metric tons in Phase I and 132 million metric tons in Phase II. Allowance prices are nearly the same as in the S.139 case (Figure 3.5). Offset prices are slightly higher in both phases, however, because the higher base of covered sector emissions allows larger amounts of offsets to be purchased in each period. Because the marginal

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[91] The issue of how much of the covered sector market would undertake actions prior to 2010 to meet 1990 greenhouse gas emission levels is debatable. However, assuming that in each sector all of the entities that reduce emissions in 2010 achieve 1990 emission goals, then that estimate provides an upper bound on the number of entities that could achieve 1990 levels before 2010. For example, using this approach, the electric power sector, the most price-responsive market, yielded a 41 percent participation rate. If the electric sector were representative of the entire covered entity market, then the percentage of offsets allowed in 2010 to 2015 would be 17 percent (41 percent of the difference between 20 percent offsets and 15 percent offsets). However, the non-electric generation markets are much less likely to participate, reducing the calculated market increase for offset purchases to 16 percent.

[92] In S.139, the portion of the allowance credits allocated to the Climate Change Credit Corporation (hereafter referred to as the Corporation) and auctioned increases from 20 percent in 2010 to 80 percent in 2025. Corp20 is a sensitivity case that assumes that the Corporation is allocated 20 percent of the allowances for the entire forecast period. The corp80 case assumes that the share starts and remains constant at 80 percent. Although the S.139, corp20, and corp80 cases exhibit different impacts on the macroeconomy (as discussed in Chapter 7), they do not create significant differences in the U.S. covered sector market for allowances.

abatement cost curves are the same as in the S.139 case and larger amounts are taken, the resulting offset prices rise by as much as $8 per metric ton carbon equivalent relative to the S.139 case.

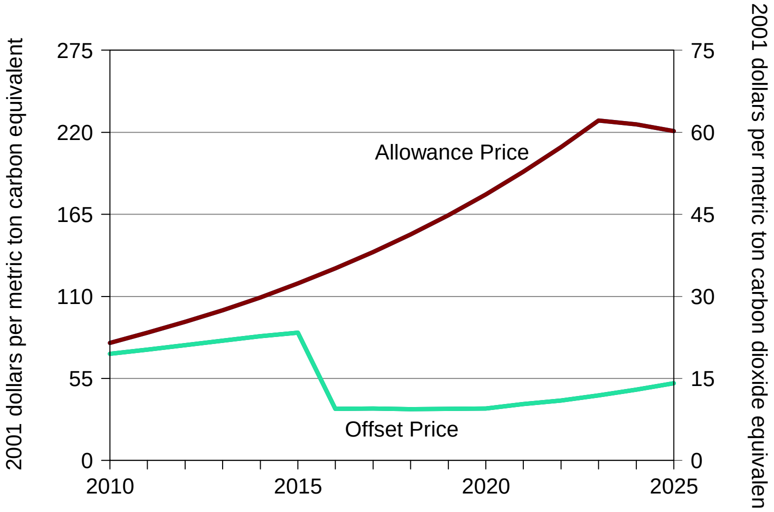
Table 3.1. Comparison of Compliance Results in the S.139 and Selected Sensitivity Cases (million metric tons carbon equivalent)

	2010				2025			
	S.139	S.139 High Tech	No New Nuclear, No Seq.	No Banking	S.139	S.139 High Tech	No New Nuclear, No Seq	No Banking
Greenhouse Gas Emissions								
Energy-Related Carbon Dioxide	1,710	1,696	1,703	1,747	1,482	1,477	1,534	1,485
Non-Energy Carbon Dioxide	40	40	40	40	46	46	46	46
Methane	115	119	115	125	120	120	120	120
Nitrous Oxide	121	121	121	121	137	137	137	137
High GWP Gases (HFCs, PFCs, and SF_6)	50	52	50	54	106	109	106	106
Total	**2,036**	**2,028**	**2,029**	**2,087**	**1,891**	**1,889**	**1,943**	**1,894**
S.139 Compliance Summary								
Covered Energy-Related CO_2	1,513	1,499	1,506	1,550	1,257	1,253	1,306	1,254
Other Covered GHG Emissions	70	72	70	75	128	131	128	128
Total Covered Emissions	**1,583**	**1,571**	**1,576**	**1,625**	**1,385**	**1,384**	**1,434**	**1,382**
Offset Reductions Purchased								
Noncovered Greenhouse Gases	49	45	49	40	39	39	39	39
Increases in Biological Carbon Sequestration	113	106	113	93	87	87	87	86
International Offsets	73	56	73	29	0	0	0	0
Total Offset Reductions	**235**	**207**	**235**	**162**	**126**	**126**	**126**	**126**
Covered Emissions, Less Offsets	1,349	1,365	1,341	1,464	1,259	1,258	1,307	1,257
Emission Allowances Issued	1,465	1,465	1,465	1,465	1,258	1,258	1,258	1,258
Allowance Bank Change (+, deposit; -, withdrawal)	+117	+101	+124	+1	-1	0	-50	+1
Greenhouse Gas Emission Allowance Price								
(2001 dollars per metric ton carbon equivalent)	79	59	87	40	221	159	297	204
(2001 dollars per metric ton carbon dioxide equivalent)	*22*	*16*	*24*	*11*	*60*	*43*	*81*	*56*
Offset Trading Price								
(2001 dollars per metric ton carbon equivalent)	71	59	72	40	52	52	52	51
(2001 dollars per metric ton carbon dioxide equivalent)	*19*	*16*	*20*	*11*	*14*	*14*	*14*	*14*

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A, ML_HT.D050503A, ML0NUCSEQ.D050403A, and ML_NOBANK_4.D051203A.

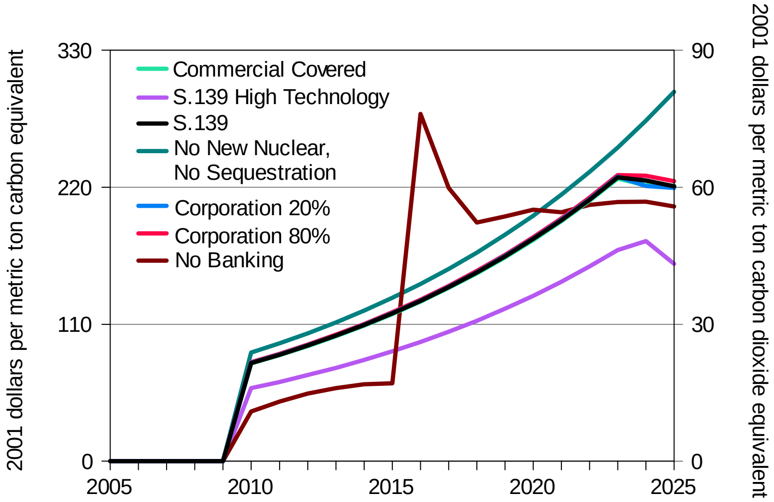
The no banking case illustrates the importance of allowing early actions to bank allowances. When banking is not permitted, allowance and offset prices are not only lower in Phase I but also equal to each other (in equilibrium), with prices ranging from $40 per metric ton carbon equivalent in 2010 to $63 in 2015 (Table 3.1 and Figures 3.5 and 3.6). Moreover, the total offsets purchased in Phase I range from 162 to 177 million metric tons carbon equivalent, far less than the allowed maximum of 234 million metric tons carbon equivalent. Although the power market in this analysis "sees" the need to meet a much tougher target in 2016 and takes some action with capacity planning to ameliorate the price impact, the

Figure 3.4. Allowance and Offset Price Projections in S.139, 2010-2025 (2001 dollars per million metric tons carbon equivalent)



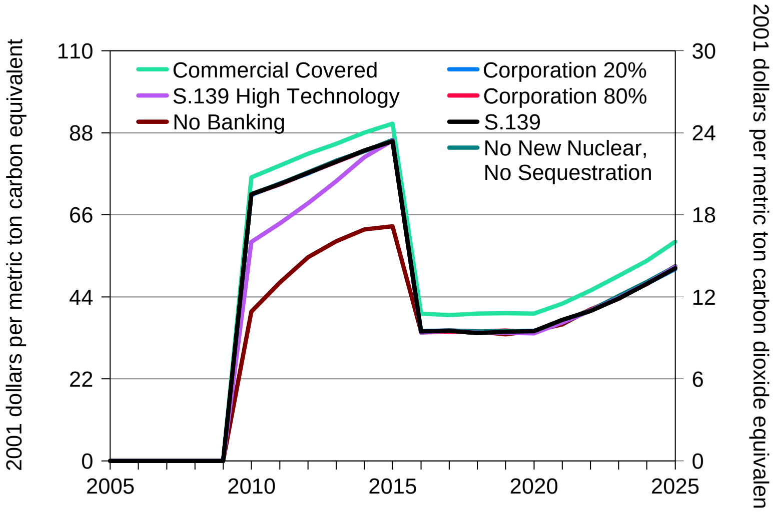
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System run MLBILL.D050503A.

Figure 3.5. Allowance Price Projections for Alternative Cases, 2010-2025 (2001 dollars per million metric tons carbon equivalent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A, ML_HT.D050503A, ML0NUCSEQ.D050403A, ML_CCCC20.D050503A, ML_CCCC80.D050503A, ML_COVER_K.D050603A, and ML_NOBANK_4.D051203A.

Figure 3.6. Offset Price Projections for Alternate Scenarios, 2010-2025 (2001 dollars per million metric tons carbon equivalent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A, ML_HT.D050503A, ML0NUCSEQ.D050403A, ML_CCCC20.D050503A, ML_CCCC80.D050503A, ML_COVER_K.D050603A, and ML_NOBANK_4.D051203A.

actions taken are far fewer than necessary to smooth the transition between phases. With no banking allowed, the value of early action is judged to be small by the market. As a result, the allowance price rises to nearly $280 per metric ton carbon equivalent in 2016 to satisfy the new emission target. The quantity of offsets purchased in Phase II is at the cap, 126 million metric tons. The power generation and transportation markets respond strongly to the large price signals in this case and take appropriate technology actions to lower allowance prices significantly. By 2022, the induced technological changes in this scenario are projected to be sufficient to make allowance prices fall temporarily and remain below the price levels in the S.139 case through 2025.

The no new nuclear / no sequestration case illustrates the value of having two carbon-free technologies in the arsenal to meet the requirements of S.139. The absence of these two technologies places a strain on the production from the remaining technologies that might be used to met the greenhouse gas emissions target. Because this case, like the S.139, corp80, and corp20 cases, uses the maximum offsets available in both periods, their offset prices are the same. However, the allowance price rises faster when new nuclear and sequestration technologies are assumed not to be commercially available. Because alternative marginal technology choices with larger abatement costs must be undertaken to satisfy the S.139 requirements, the allowance price starts higher and remains higher than in all other cases except the no banking case from 2016 to 2020. By 2025, the allowance price in the no new nuclear/no sequestration case is projected to reach nearly $300 per metric ton carbon equivalent.

The high technology case illustrates the value to the energy market of developing and providing an advanced technology menu. The accelerated availability of advanced technologies in the end-use and power generation sector is projected to reduce the difficulty of meeting the greenhouse gas emission targets of S.139. Consequently, allowance prices in the high technology case begin lower and remain lower than in all the other cases throughout the projection period, peaking at about $177 per metric ton carbon equivalent in 2024. Because the high technology case reduces the cost of domestic covered sector allowances, allowance and offset prices are in equilibrium from 2010 to 2014, when the maximum offsets permitted under S.139 (234 million metric tons carbon equivalent) are not purchased. Offset purchases range from 207 million metric tons carbon equivalent in 2010 to 230 million metric tons in 2014. The allowance and offset prices diverge after 2015, when the maximum available offsets are purchased.

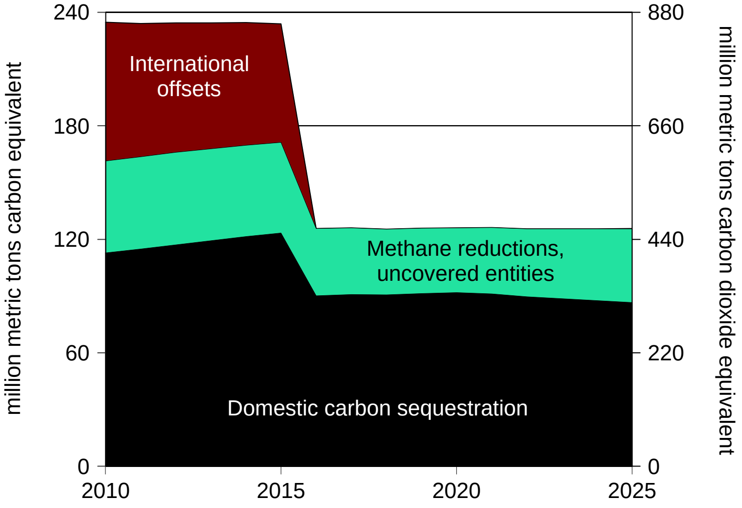
Offsets

The price at which offsets are available is based on a set of marginal abatement cost curves that represent the estimated supply of offsets (see Chapter 2 for an explanation). These curves establish the quantity of offsets for emissions reductions or carbon sequestration available at particular prices. Generally, the costs of a given level of abatement increase over time (particularly the international sequestration component). As a result, the Phase I offset price is estimated to clear at about $71 per metric ton carbon equivalent (2001 dollars) in 2010 and rise to about $86 in 2015 (Figure 3.6). These prices are somewhat below the emission allowance trading price of $79 to $119 per metric ton carbon equivalent over the same period. In Phase II, with a lower limit on offsets, the clearing price for offsets is projected to range from $35 to $52 per metric ton carbon equivalent.

In the sensitivity case where all entities in the commercial sector are assumed to be covered by the bill, the Phase I and Phase II allowance limits increase, as do the quantities of offsets allowed, because the level of covered emissions is larger and the percentage allowable is the same. In the commercial coverage case, the aggregate offset limits rise by 11 million metric tons carbon equivalent in Phase I and by 5 million metric tons carbon equivalent in Phase II. As a result, the offset prices are higher by $5 to $8 per metric ton carbon equivalent than in the S.139 case. In both the S.139 high technology case and the no banking case, the constraint on offset purchases is not binding in the Phase I period, allowing the offset price to match the allowance trading price.

The cost of offsets differs across the different sources modeled: sequestration, noncovered methane emissions, and international sources. As a result, the quantities of offsets available at the clearing price differ (Figure 3.7). The largest contribution from purchased offsets comes from agricultural and forestry sequestration. The contributions from noncovered methane offsets in 2010 to 2015 are slightly smaller than the international offsets. However, the importance and contributions of international offsets are

Figure 3.7. Composition of Alternative Compliance Offsets, S.139 Case, 2010-2025 (million metric tons carbon equivalent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A.

projected to decline somewhat over time. The price at which international offsets are available is based in part on the international demand for the offsets. As the international demand increases, the price rises, and U.S. purchases are reduced in favor of domestic offsets. Once the Phase II emissions limits go into effect in 2016, the international offsets or no longer competitive with domestic offsets.

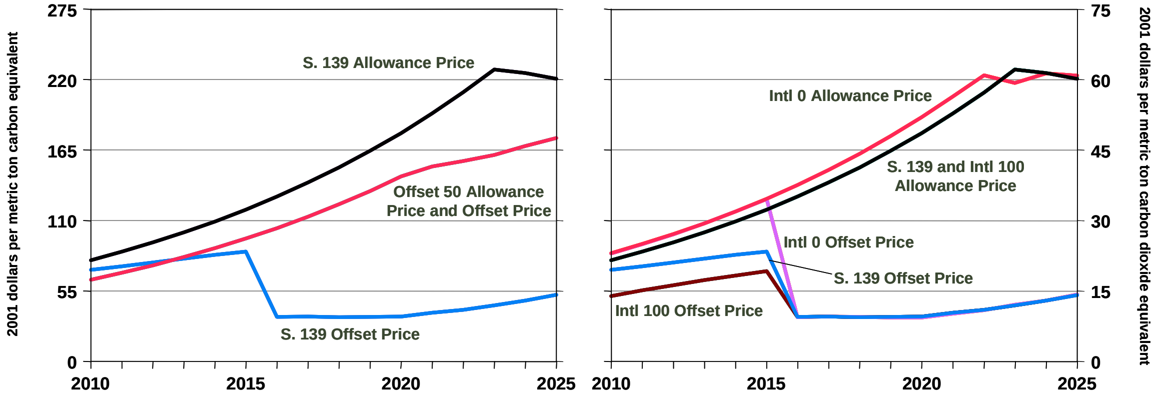
Offset Sensitivity Cases

Several sensitivity cases were used to examine the issue of compliance offsets. Covered entities may use offset credits from several sources, subject to an overall cap specified in S.139. The potential sources of offsets include registered reductions from noncovered entities, registered increases in biological carbon sequestration, and emissions allowances from other countries. In one sensitivity case (offset50), the offset limit was increased to 50 percent in both phases. Two other cases were examined to test assumptions regarding the availability and costs of international emissions offsets. In one case (intl100), the assumed supply curve of offsets from international sources was doubled. A second case (intl0) assumed that no international offsets would be available.

Figure 3.8 compares the market-clearing prices for allowances and offsets in the three offset sensitivity cases with those in the S.139 case. In the offset50 case, the limit on offsets is not reached, and the trading prices of offsets and allowances are identical, at levels below those in the S.139 case. Table 3.2 summarizes the energy market outcomes in the offset sensitivity cases. Because the offset50 case effectively reduces the amount of emissions reductions in the covered sectors, the magnitude of changes in the energy sectors to comply with S.139 is reduced. As a result, there is greater coal use and a reduced reliance on renewable, nuclear, and carbon sequestration technologies in the electricity sector in the offset50 case.

In the offset50 case, allowance prices and offset prices equilibrate to the same level throughout the forecast period, at prices that are lower than in the S.139 case. By 2025, the greenhouse gas price is $171 per metric ton carbon equivalent, compared with $221 in the S.139 case. In 2025, the quantity of offsets purchased is projected to increase from 126 million metric tons carbon equivalent in the S.139 case to 346 million metric tons carbon equivalent in the offset 50 case, thus increasing the transfer of funds to international markets by about $27 billion (2001 dollars) in 2025 or about 3.6 percent of net U.S. imports in 2025.

Figure 3.8. Comparison of Allowance and Offset Prices in the S.139 and Offset Sensitivity Cases, 2010-2025



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A, ML_INTL100.D052703A, and ML_INTL0.D051903A.

In the intl100 case, the Phase I and Phase II limits on offsets are the same as in the S.139 case. As a result, the primary effect of this case is to alter the mix of offsets available from the three offset sources, increasing the international share relative to the domestic share. In the intl0 case, the unavailability of international offsets raises the offset price to equal the allowance price in Phase I, and the allowance price

Table 3.2. Comparison of Compliance Results in the S.139 and Offset Sensitivity Cases (million metric tons carbon equivalent)

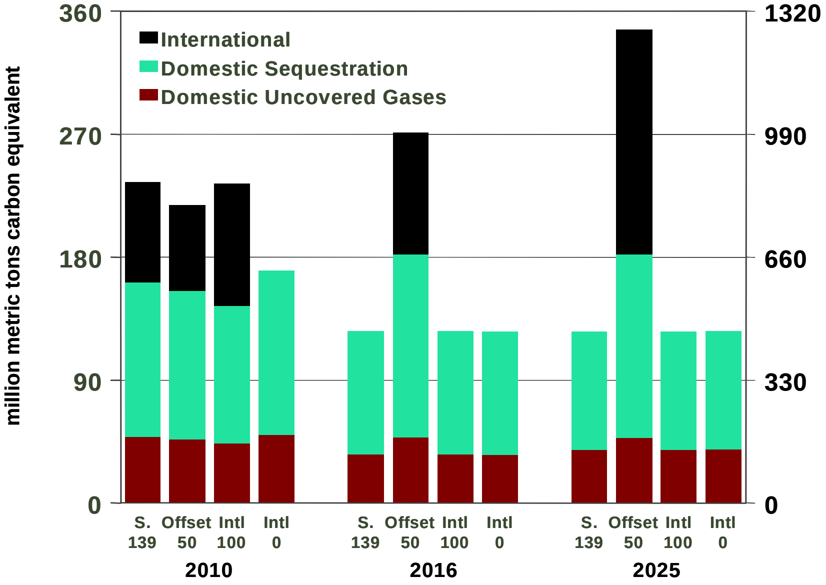
	2010				2025			
	S.139	**Offset50**	**Intl100**	**Intl0**	**S.139**	**Offset50**	**Intl100**	**Intl0**
Greenhouse Gas Emissions								
Energy-Related Carbon Dioxide	1,710	1,737	1,710	1,704	1,482	1,697	1,482	1,482
Non-Energy Carbon Dioxide	40	40	40	40	46	46	46	46
Methane	115	117	120	114	120	111	120	120
Nitrous Oxide	121	121	121	121	137	137	137	137
High GWP Gases (HFCs, PFCs, and SF$_6$)	50	51	50	50	106	106	106	106
Total	**2,036**	**2,066**	**2,041**	**2,028**	**1,891**	**2,098**	**1,891**	**1,891**
S.139 Compliance Summary								
Covered Energy-Related CO$_2$	1,513	1,540	1,513	1,507	1,257	1,475	1,256	1,256
Other Covered GHG Emissions	70	71	70	70	128	128	128	128
Total Covered Emissions	**1,583**	**1,611**	**1,583**	**1,577**	**1,385**	**1,603**	**1,384**	**1,384**
Offset Reductions Purchased								
Noncovered Greenhouse Gases	49	47	43	50	39	48	39	39
Increases in Biological Carbon Sequestration	113	108	101	120	87	134	87	87
International Offsets	73	63	90	0	0	165	0	0
Total Offset Reductions	**235**	**218**	**234**	**170**	**126**	**346**	**126**	**126**
Covered Emissions, Less Offsets	1,349	1,393	1,349	1,407	1,259	1,256	1,258	1,258
Emission Allowances Issued	1,465	1,465	1,465	1,465	1,258	1,258	1,258	1,258
Allowance Bank Change (+, deposit; -, withdrawal)	+117	+72	+116	+58	-1	+1	0	0
Greenhouse Gas Emission Allowance Price								
(2001 dollars per metric ton carbon equivalent)	79	64	79	84	221	174	222	223
(2001 dollars per metric ton carbon dioxide equivalent)	*22*	*17*	*22*	*23*	*60*	*48*	*60*	*61*
Offset Trading Price								
(2001 dollars per metric ton carbon equivalent)	71	64	51	84	52	174	52	52
(2001 dollars per metric ton carbon dioxide equivalent)	*19*	*17*	*14*	*23*	*14*	*48*	*14*	*14*

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A, OFFSET50.D052303A, ML_INTL100.D052703A, and ML_INTL0.D051903A.

clears at a level above that in the S.139 case.[93] The unavailability of offsets in the intl0 case affects only the Phase I offset prices, which increase by a maximum of 48 percent in 2015 relative to the S.139 case.

Figure 3.9 compares the mix of offsets for 2010, 2016, and 2025 in the intl0, intl100, offset50, and S.139 cases. In the intl100 case, the lower price of international offsets is insufficient to make them competitive with domestic offsets in Phase II, and no international offsets are purchased. In Phase I the offset prices are lower, and more international offsets are included in the mix.

Figure 3.9. Mix of Offset Compliance Sources in the S.139 and Offset Sensitivity Cases, 2010, 2016, and 2025



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A, OFFSET50.D052303A, ML_INTL100.D052703A, and ML_INTL0.D051903A.

An increase in the supply of international or domestic offsets, as in the intl100 case, can reduce the offset price. In the intl100 case, because the overall use of offsets is limited by the bill, larger available quantities of offsets (supply) yield a lower offset price in the 2010-2015 period (see Figure 3.8). The 100 percent increase in the supply of international offsets reduces the offset price in the 2010-2015 period, but the offset prices in 2016 and beyond are unchanged from the S.139 case because domestic offsets are cheaper than international offsets in the later period. The net impact of a doubling of international offset supplies is that the total cost of offsets is reduced by an average of about $1.6 billion per year (cumulatively, $24 billion in undiscounted dollars over the entire period)—about 0.3 percent of net U.S. imports in 2015.

When it is assumed that no international offsets are available, the domestic market must do more work to achieve the same emission reduction targets. More reductions in the domestic market result in higher allowance prices. The additional costs relative to the S.139 case derive primarily from higher allowance prices. In the 2010-2015 period, domestic allowance and offset prices in the intl100 case equilibrate at quantities below the allowed cap. Although funds expended for international offsets are reduced to zero, domestic offset and allowance prices are higher, because more expensive emission reduction sources are

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[93] The exception is in 2023, as the allowance bank is depleted one year earlier in the intl0 case than in the S.139 case, and the price temporarily drops in the following year.

tapped to meet the target. More offsets must be purchased from domestic sources, and more reductions must be achieved from carbon dioxide reductions in the energy system.

In summary, doubling the available offsets assumed in the S.139 case has a negligible impact on the economy and a small but beneficial impact on allowance costs relative to S.139. When international offsets are assumed to be zero, the negative impact on the cost to U.S. energy markets is more significant.

International Commitments of Selected Developing Countries

Senator James Inhofe requested that EIA provide information on the greenhouse gas commitments currently adopted by China, Mexico, South Korea, India, and Brazil.[94] The country-specific summaries below give overviews of greenhouse gas mitigation activities in those countries.

In contrast to the specific scheduled U.S. emission reduction targets for 2010 and 2016 proposed under S.139, the major developing countries of China, Mexico, South Korea, India, and Brazil have no binding obligations to limit or reduce emissions under the United Nations Framework Convention on Climate Change (UNFCCC) or the Kyoto Protocol. However, a number of the larger developing countries have introduced initiatives to address global climate change and limit growth in greenhouse gas emissions.

Brazil, China, India, Mexico and South Korea have ratified the UNFCCC and the Kyoto Protocol. Under the UNFCCC all signatories are responsible for preparing a national communication that includes an inventory of overall greenhouse gas emissions and an analysis of potential mitigation and adaptation measures. Each of the five nations' governments has established an entity to coordinate climate change activities in the country. The five countries may also participate in the Kyoto Protocol through the Clean Development Mechanism (CDM), which enables entities in Annex I countries to acquire emission reductions generated in developing countries. In addition, all five countries have introduced specific initiatives to address climate change.

Brazil. In 1996, Brazil established its Climate Change Program with resources from the Global Environment Facility of the United Nations Development Programme and the U.S. Country Studies Program, which supports non-Annex I countries in reporting their climate trends and adaptation measures under the UNFCCC. The Brazilian government is prioritizing work on its inventory of greenhouse gas emissions. A key focus is awareness building, education, and dissemination of information published in Portuguese. The government is also actively promoting projects for inclusion in the CDM. So far, two Brazilian projects have been approved by the Dutch government and one by the World Bank Prototype Carbon Fund (PCF).[95]

In 1999, Brazil's President ordered the creation of the Inter-Ministerial Commission on Global Climate Change, to coordinate the efforts of various agencies and public participation. The Commission's web site specifically states, "Brazil does not have commitments to reduce or limit its anthropogenic emissions of greenhouse gases." However, a number of general energy policies, according to a Pew Center report, have reduced emissions growth by almost 10 million metric tons carbon equivalent, including production and use of ethanol and sugar-cane bagasse, development of the natural gas industry, use of alternative energy sources for power generation, and promotion of demand-side management programs.[96]

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[94] See Appendix A for a copy of the January 28, 2003, letter from Senator Inhofe to EIA.

[95] PERSMAP CERUPT 2002, web site http://www.senter.nl/sites/erupt/contents/i001337/press_cerupt.doc; and PCF, web site http://www.prototypecarbonfund.org.

[96] W. Chandler et al., *Climate Change Mitigation in Developing Countries: Brazil, China, India, Mexico, South Africa, and Turkey* (Pew Center on Global Climate Change, October 2002).

China. In 1990, China established its Inter-Ministerial National Climate Change Coordinating Committee to address the issue of climate change. Since then, China has been actively engaged in negotiating the rules for the Kyoto Protocol and the CDM, and it is expected to attract a major share of CDM investment because of the comparatively low cost of emissions abatement in the country, particularly in the power sector. The Asian Development Bank estimates that the Chinese market for emissions reductions could amount to $13 billion per year,[97] and projects have already been initiated in anticipation of the CDM. In March 2003, the government of the Netherlands agreed to purchase emission reductions from a wind farm in Inner Mongolia, following the guidance set forth for the CDM.[98]

Although energy-related carbon dioxide emissions in China decreased by 5.63 percent between 1997 and 2000[99] through fuel switching and energy efficiency improvements, they have begun to rise again.[100] China's energy-related carbon dioxide emissions are expected to more than double between 2000 and 2025, rising from 780 million metric tons carbon equivalent in 2000 to 1,844 million metric tons in 2025.[101] As a result, a number of government studies have been undertaken to examine mitigation strategies. For example, China's Energy Research Institute and others have undertaken the China Energy and Carbon Scenarios Project to define future mitigation options.[102] Efficiency improvements in the power sector, development of a natural gas infrastructure, forest protection, and reforestation are listed as major ecological priorities in China. In addition, the Chinese government is sponsoring a pilot project to test methods for capturing carbon dioxide from power generation.

India. Due to rapid economic growth and continued reliance on fossil fuels, particularly coal, India's greenhouse gas emissions continue to rise. Although the Indian government has expressed its commitment to reduce greenhouse gas emissions, it is adamantly opposed to declaring a binding reduction target. Still, according to one estimate,[103] a number of energy-related policies, such as economic restructuring, enforcement of existing clean air laws by the courts, and renewable energy incentives and development programs have avoided an estimated 111 million metric tons of carbon emissions over the past decade.

To support the Kyoto Protocol in its current form, the Indian government has established national procedures for approving greenhouse gas reduction projects for inclusion in the CDM and has so far cleared six project proposals for potential transfer to the Netherlands and the World Bank's Prototype Carbon Fund. The Dutch government has agreed to purchase emission reductions from three wind and two biomass projects in India.[104]

Mexico. Mexico was the first major oil-producing nation to ratify the Kyoto Protocol and has established several policies consistent with greenhouse gas mitigation, including promotion of energy efficiency and conservation, renewable energy and clean fuels, forest conservation, and reforestation. According to one

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[97] T. Szymanski, "The Clean Development Mechanism in China," *The China Business Review*, Vol. 29, No. 6 (November-December 2002).

[98] "Chinese Wind Farm Makes Kyoto Profits From Dutch," *Planet Ark* (March 14, 2003), web site http://www.planetark.org/dailynewsstory.cfm/newsid/20156/story.htm.

[99] Energy Information Administration, *International Energy Annual 2001*, DOE/EIA-0219(2001) (Washington, DC, 2002).

[100] T. Szymanski, "The Clean Development Mechanism in China," *The China Business Review*, Vol. 29, No. 6 (November-December 2002).

[101] Energy Information Administration, *International Energy Outlook 2003*, DOE/EIA-0484(2003) (Washington, DC, 2003).

[102] W. Chandler et al., *Climate Change Mitigation in Developing Countries: Brazil, China, India, Mexico, South Africa, and Turkey* (Pew Center on Global Climate Change, October 2002).

[103] A. Garg and P.R. Shukla, *Emissions Inventory of India* (New Dehli: Tata-McGraw-Hill Publishing Company, 2002), cited by Chandler et al. (2002).

[104] PERSMAP CERUPT 2002, web site http://www.senter.nl/sites/erupt/contents/i001337/press_cerupt.doc.

estimate,[105] these policies have avoided 10 million metric tons of carbon emissions annually over the past decade.

Since 1992, Mexico has cooperated closely with the United States and other countries to address climate change. The EPA has helped to train Mexican staff in the areas of modeling Mexican greenhouse gas emissions and updating Mexico's emission inventory, as well as co-hosting joint workshops with Mexico. In 1992, Mexico signed, with 10 other countries, a treaty to establish the Inter-American Institute for Global Change Research, which provides training and technical support to participating countries in the areas of global change; earth, ocean, and atmospheric science; and technologies and economic aspects associated with mitigating and adapting to global change.[106] In 1996, Mexico and its neighboring Central American countries adopted a Plan of Action to advance the objectives of the San Jose Declaration, which promotes climate change issues and information exchange. During the June 29, 2001, meetings of the Council of the Commission for Environmental Cooperation established under the North American Agreement on Environmental Cooperation,[107] the EPA Administrator initiated a dialogue with the environmental ministers of Canada and Mexico to discuss global environmental concerns. The countries pledged "to explore further opportunities for market-based approaches for carbon sequestration, energy efficiency and renewable energy in North America." Finally, in March 2003, Mexico and the United States announced their intention to expand and intensify their existing bilateral efforts to address climate change and continue a bilateral dialogue to develop joint activities to combat climate change in such areas as emission inventories, economic and climatic models, energy, adaptation, agriculture/forests, earth observation systems, and carbon sequestration technologies.[108]

Finally, a number of local entities have shown interest in greenhouse gas emissions trading as a means to reduce emissions. Mexico City is developing a formal strategy for mitigating climate change and is a member of the Chicago Climate Exchange, which is a voluntary cap and trade program for reducing and trading greenhouse gas emissions, initially among U.S. and Canadian firms. In addition, Mexico's national oil company Petróleos Mexicanos (PEMEX) has adopted a voluntary and experimental internal emissions trading system based on the cap and trade concept.[109] Under the initial phase of the PEMEX cap and trade system, PEMEX reduced emissions by 3 million metric tons carbon equivalent. This was accomplished by an internal trading system between PEMEX's 25 business units. Beginning in 2003, the internal trading system will be based on actual money exchanges between business units to meet emission reduction targets.

South Korea. Since 1979, the Rational Energy Utilization Act has required a new 10-year plan to be revised every 5 years to reflect changes in economic and population growth. As forecast by the South Korean government in 1998, South Korea expected growth in carbon dioxide emissions of 5.2 percent annually from 1995 to 2010.[110] South Korea is also seeking bilateral cooperation with the United States and Japan.

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[105] O. Masera and C. Sheinbaum, "Mitigating Carbon Emissions while Advancing National Development Priorities: The Case of Mexico," *Climatic Change*, Vol. 47 (2000), pp. 259-282, cited by Chandler et al. (2002).

[106] Inter-American Institute for Global Change Research, *Agreement Establishing the Inter-American Institute for Global Change Research* (Montevideo, Uruguay, May 13, 1992), web site www.iai.int/files/agree_ENG.pdf.

[107] The Commission for Environmental Cooperation was established by the United States, Canada, and Mexico in August 1993 as part of the North American Agreement on Environmental Cooperation (an agreement signed as part of the North American Free Trade Agreement).

[108] U.S. Department of State, "Joint Statement of Enhanced Bilateral Climate Change Cooperation Between the United States and Mexico" (press release, March 18, 2003).

[109] Chandler et al. (2002).

[110] National Communication of the Republic of Korea, *Submission of the ROK Under the UNFCCC* (1998), web site http://www.unfccc.int/resource/docs/natc/kornc1.pdf. EIA currently projects that South Korea's energy-related carbon dioxide emissions will grow by 2.2 percent annually between 2001 and 2010. See Energy Information Administration, *International Energy Outlook 2003*, DOE/EIA-0484(2003) (Washington, DC, 2003).

The South Korean government is taking active measures to slow the growth in greenhouse gas emissions. According to the government's integrated energy price structure plan to be finalized by June 2006, which includes measures to reduce greenhouse gas emissions, South Korea will expand the use of liquefied natural gas by 77 percent and nuclear energy use by 69 percent by 2010.[111] The government will also focus on the use of solar power, wind power, fuel cell technology development projects, a 5-year energy conservation plan for energy-intensive companies, duties on petroleum imports, long-term DSM plans, reforestation, methane mitigation in rice paddies and animal husbandry, and waste management plans.

In 2002, the Commerce, Industry and Energy Minister of South Korea proposed the establishment of a national greenhouse gas emission registry system by 2004 in preparation for the international emissions trading system proposed under the Kyoto Protocol.[112] The registry and trading system will form part of the country's integrated energy price structure plan and will target greenhouse gas emissions from the manufacturing industry.

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[111] Kim Sung-jin, "Greenhouse Gas Emissions To Be Monitored," *The Korea Times* (September 19, 2002).

[112] Kim Sung-jin, "Greenhouse Gas Emissions To Be Monitored," *The Korea Times* (September 19, 2002).

4. End-Use Energy Demand

This chapter summarizes the impacts of S.139 on the four end-use demand sectors—residential, commercial, industrial, and transportation. As discussed in Chapter 2, this analysis assumes that S.139 covers greenhouse gas emissions in the industrial sector (excluding agriculture) and in the transportation sector, through a requirement that petroleum refiners and importers provide emission allowances for transportation fuels sold to the transportation sector. Primary energy use in the residential sector is not covered because it is exempt in the Bill. Primary energy use in the commercial sector is assumed not to be covered since the majority of the sector would not meet the 10,000 metric ton emissions minimum. However, a sensitivity is analyzed to examine the impact of including the commercial sector. Regardless of the coverage of primary energy use, both the residential and commercial sectors are generally expected to see higher energy prices, particularly electricity prices, through the impact of S.139 on the other sectors. The focus of the discussion in this chapter is on the impact of S.139 in 2025, because that year generally shows the largest differential from the reference case. The projected results for the intervening years are given in Appendix C.

In addition to comparing the S.139 case to a reference case, this chapter also discusses a number of alternative cases relevant to the end-use energy demand sectors, including an S.139 high technology case, a case with full coverage of the commercial sector, and a case in which new nuclear capacity and sequestration technologies are assumed not to be available as an option to limit greenhouse gas emissions. A description of all the cases analyzed in this study appears on pages 60-63 in Chapter 2. The alternative cases are summarized in Appendixes E through J.

Residential Sector

Background

As the largest electricity-consuming sector in the United States, households were responsible for 20 percent of all carbon dioxide emissions produced in 2001, of which 69 percent was directly attributable to the fuels used to generate electricity for the sector. Electricity is a necessity for all households. Because electricity generation is covered by S.139, residential consumers see higher electricity prices. In the reference case, electricity use per household is projected to grow at nearly 1 percent per year through 2010.

The number of occupied households is the most important factor in determining the amount of energy consumed in the residential sector. All else being equal, more households mean more total use of energy-related services. From 1980 to 2001, the number of U.S. households grew at a rate of 1.3 percent per year, and residential electricity consumption grew by 2.5 percent per year. In the reference case, the number of households is projected to grow by 1.1 percent per year through 2010, and residential electricity consumption is projected to grow by 2.1 percent per year. Strong growth in the South, which features all-electric homes more prominently than do other areas of the country, and the advent of many new electrical devices for the home (e.g., home entertainment systems and security systems) have significantly contributed to high electricity growth since 1980. Although these trends are projected to continue through 2010, efficiency improvements—due in part to recent Federal appliance standards, building codes, and non-regulatory programs (e.g., Energy Star)—should dampen electricity growth somewhat as residential appliances are replaced with newer, more efficient models.

Within the residential sector, all the major end uses (heating, cooling, lighting, etc.) are represented by a variety of technologies that provide necessary services. Technologies are characterized by their cost, efficiency, dates of availability, minimum and maximum life expectancies, and the relative weights of the choice criteria—installed cost and operating cost. The ratio of the weight of installed cost to that of operation cost gives an estimate of the "hurdle rate" used to evaluate the energy efficiency choice.[113] When more emphasis is placed on installed cost, the hurdle rate is higher. The hurdle rates in NEMS for residential equipment, which are based on the observed behavior of residential consumers, range from 15 percent for space heating technologies to more than 100 percent for room air conditioners. The range in part reflects differences in the way consumers purchase the two technologies. In the case of water heaters, for example, purchases usually occur at the time of equipment failure, which tends to restrict the choice to equipment readily available from the plumber. Space conditioning equipment, on the other hand, is not as critical as water heating during some parts of the year, allowing greater latitude in terms of timing the replacement of an older unit. In practice, however, most space conditioning equipment is also replaced when it fails. It is assumed that residential consumers expect future energy prices to remain at the current level at the time of purchase when calculating the future operating cost of a particular technology.

Technological advances and availability play a large role in determining future energy savings and carbon dioxide emission reductions. Even in today's marketplace, there exist many efficient technologies that could substantially reduce energy consumption and carbon dioxide emissions. However, the relatively high initial cost of these technologies restricts their widespread penetration. Over time, the costs of more advanced technologies are assumed to fall as the technologies mature (one example being natural gas condensing water heaters). In addition, technologies that are not available today, but are nearing commercialization, are assumed to become available in the future. Four technology menus are used in the analysis below: a reference technology menu; a "rebate adjusted" menu, which lowers the cost of the more efficient technologies based on assumptions regarding rebates that will be available through the Climate Change Credit Corporation (hereafter referred to as the Corporation) created by S.139; a high technology menu reflecting more aggressive research and development; and a "rebate adjusted" high technology menu. In both high technology cases, for example, the cost of a condensing natural gas water heater is assumed to fall by almost 38 percent by 2005, relative to the reference case, and a natural gas heat pump water heater becomes available for purchase by 2005.

In response to energy price changes, residential elasticities (defined as the percent change in energy consumed with a 1-percent change in price) range from -0.30 to -0.34 in the short run, depending on the fuel type, to -0.41 to -0.60 in the longer term, which are in the range cited in the literature.[114] The elasticities reported here are derived from NEMS by a series of simulations with only one energy price varying at a time, beginning in 2005.[115] These price elasticities reflect changes in both the demand for energy services and the penetration rate of more efficient technologies. In the absence of energy price

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[113] The "hurdle rate" for evaluating energy efficiency investments has also been referred to as the "implicit discount rate" (i.e., the empirically based rate required to simulate actual purchases—the one implicitly used). These rates are often much higher than would be expected if financial considerations alone were their source. Among the reasons often cited for relatively high apparent hurdle rates are uncertainty about future energy prices and future technologies, lack of information about technologies and energy savings, additional costs of adoption not included in the calculations, relatively short tenure of residential home ownership, hesitancy to replace working equipment, attributes other than energy efficiency that may be more important to consumers, limited availability of investment funds, renter/owner incentive differences, and builder incentives to minimize construction costs. For a good discussion of potential market barriers and the economics of energy efficiency decisions, see Jaffe and Stavins, "Energy Efficiency Investments and Public Policy," *The Energy Journal*, Vol. 15, No. 2 (1994), pp. 43-65.

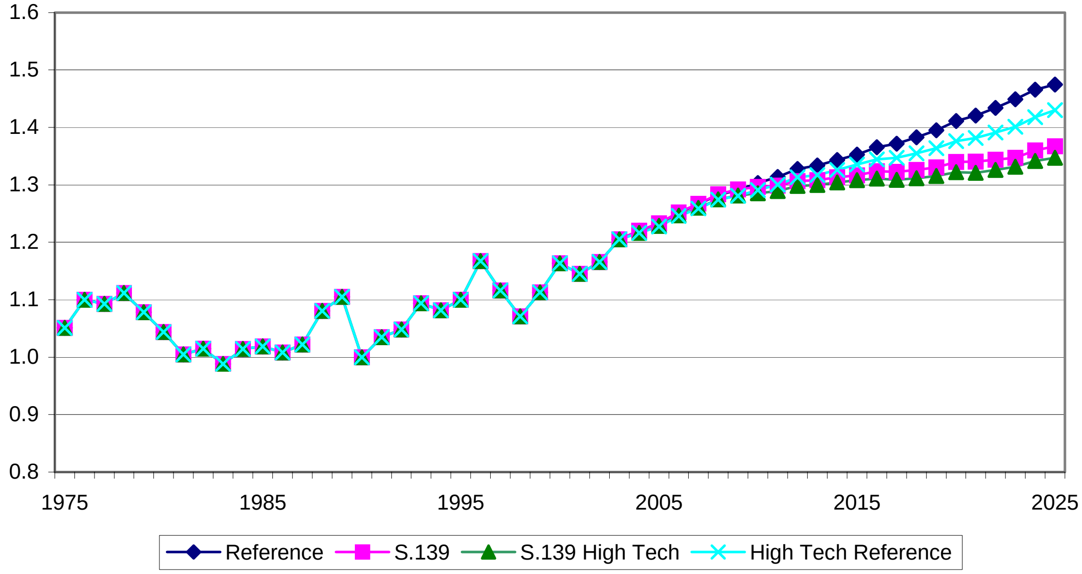
[114] Dahl (1993), "A Survey of Energy Demand Elasticities in Support of the Development of the NEMS," US DOE, Contract Number DE-AP01-93EI23499 (October 1993). The Dahl survey incorporated results from other survey articles and from newer studies, not reviewed previously. From prior surveys, the residential/commercial own-price elasticities for total energy ranged from -0.012 in the short run (SR) to -0.44 in the long run (LR). Focusing on studies of aggregate time series data, demand elasticities for electricity from more recent studies averaged from -0.22 (SR) to -0.91 (LR) for residential and -0.22 to -0.82 for commercial. For natural gas the averages from more recent studies were -0.13 (SR) to -0.68 (LR) for residential and -0.26 to -0.99 for commercial.

[115] The long-run elasticities reflect the effects of altered prices after 20 years for the last year of the forecast, 2025.

changes, household energy intensity (defined as delivered final residential energy consumption per household) declines at an average rate of 0.1 percent per year through 2025. This non-price-induced intensity improvement reflects the efficiency gain brought about by ongoing stock turnover, equipment standards, new housing stock, and the future availability of new technologies.

Energy consumption, including the combustion of various fossil fuels, is the major source of U.S. carbon dioxide emissions. Energy use in the residential sector is greatly affected by year-to-year variations in seasonal temperatures, particularly in the winter, as illustrated by the decline in delivered energy use in 1998 (Figure 4.1), which was one of the warmest winters on record. The projections in this analysis assume normal seasonal temperatures over the 2004-2025 forecast period.

Figure 4.1. Index of Residential Sector Delivered Energy Consumption, 1975-2025 (index, 1990=1.0)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System RUNS MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C, and ML_HT.D050503A.

This section will focus on four cases: the reference case, the S.139 case, the high technology case, and the S.139 high technology case. The two high technology cases are sensitivity cases that incorporate higher levels of technological optimism, in terms of cost reductions and/or increased efficiency, relative to the reference and S.139 cases.

Residential Energy Consumption Varies by Income Cohort

EIA's Residential Energy Consumption Survey (RECS) provides information on household energy consumption and many physical and demographic household characteristics. RECS is based on a representative statistical sample of nearly 6,000 U.S. households. Among the data available are household income categories, occupant information, energy expenditures and whether a household is eligible for government assistance with energy costs though programs related to the Department of Health and Human Services' Low Income Home Energy Assistance Program (LIHEAP). From these data,

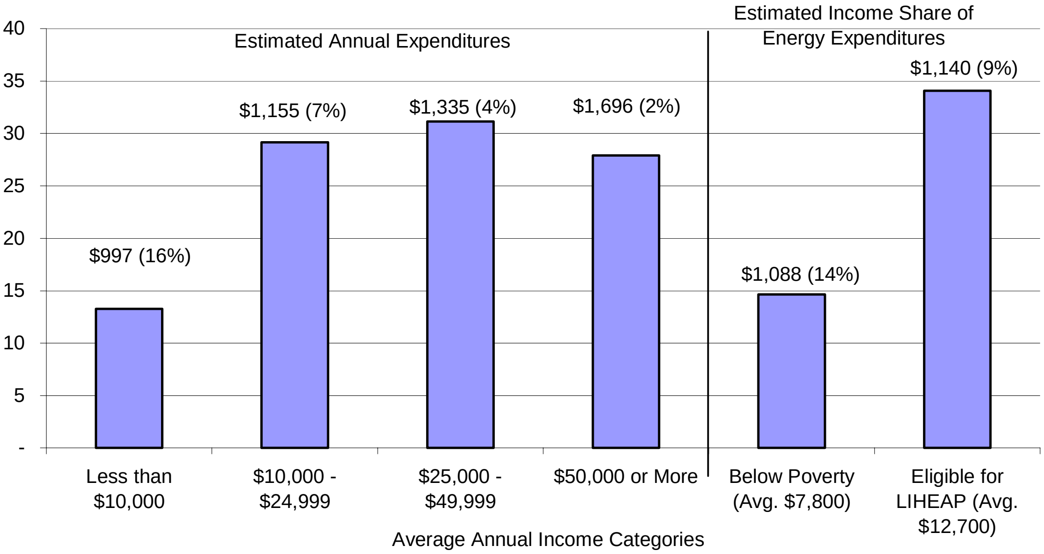
Residential Energy Consumption Varies by Income Cohort (continued)

poverty-level statistics and energy expenditure shares of income can also be calculated. The following discussion is based on RECS energy expenditures with adjustments for projected energy prices under the reference case and the S.139 case.

The most recent expenditure data available are from the RECS 1997 survey. A summary by income category, poverty status and eligibility for energy assistance programs is provided in Figure 4.2. The first four bars represent the number of households by four income categories as reported in the RECS summary report.[116] These four income categories account for all 101 million households in 1997. The fifth and sixth bars are subsets of total households drawn primarily from the two leftmost bars of the chart (i.e., the lower income levels). The fifth bar represents the subset of 15 million households that were classified as below the poverty line in 1997. The sixth bar represents the subset of 34 million households—including all of the below poverty households—that were eligible to receive energy assistance in 1997 (either below 150 percent of the poverty level or below 60 percent of median State income). Above each bar are the estimated annual expenditures on home energy as well as the average share of income spent on energy consumed in the home. (Note that RECS estimates of home energy exclude vehicle fuel which is not covered by the survey; however, vehicle fuel expenditures and energy consumption are covered in the transportation section of this report.)

A general observation from Figure 4.2 is that as income rises, expenditures on home energy rise; however, the rise is less than proportional. Thus, households earning less than $10,000 spent 16 percent

Figure 4.2. Total Number of Households by Average Annual Expenditures and Expenditure Shares of Income for Home Energy for 1997 (millions of households, 1997 dollars)



Note: Below Poverty and Eligible for LIHEAP households are from more than one category to the left of the vertical line and are non-additive when totaling households.
Source: Estimated from EIA, Residential Energy Consumption Survey, 1997, Public Use Database.

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[116] See Energy Information Administration, *A Look at Residential Energy Consumption in 1997*, DOE/EIA-0632(97), for further details.

Residential Energy Consumption Varies by Income Cohort (continued)

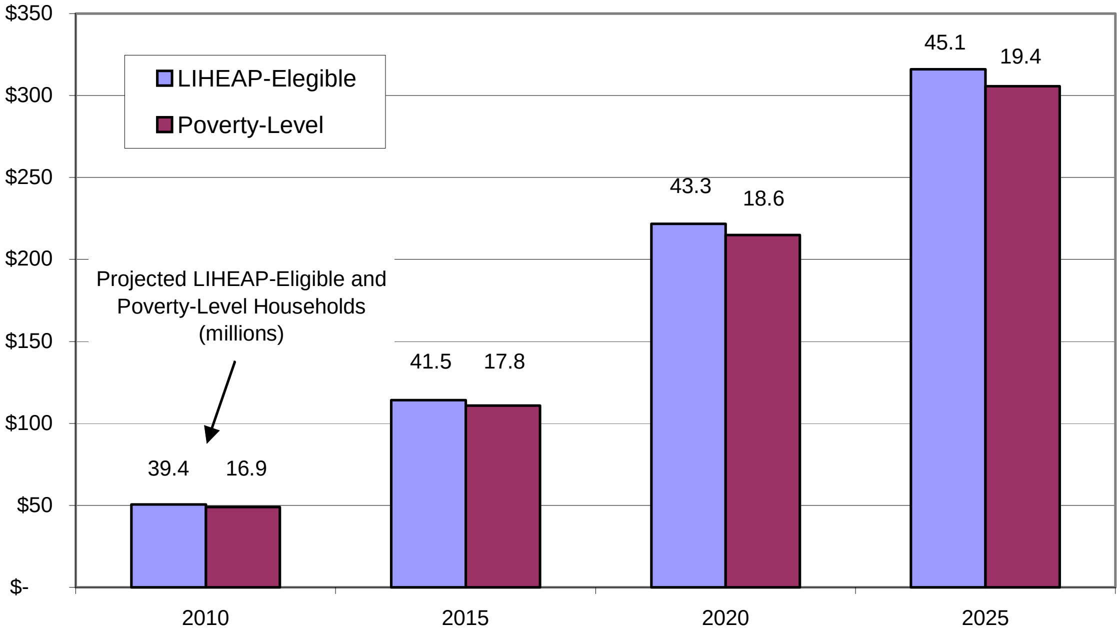
of their income on home energy, while households earning $50,000 or more, spent only 2 percent of their income on home energy.

Households below the poverty level had an estimated average income of $7,800 and spent on average $1,088 on home energy annually. Households eligible to receive assistance paying their energy bills in 1997 had an estimated average income of $12,700 and spent on average $1,140 on home energy. Total energy expenditures of poverty-level households in 1997 were $16.0 billion in 1997 dollars. Expenditures of the LIHEAP-eligible households were $38.9 billion in 1997 dollars.

Assuming that the 1997 shares of total households by income category remain fixed, the rising number of households over the projection interval implies a rising number either aid-eligible or classified as poverty level.[117] The expenditure data in the next figure are from RECS 1997 adjusted for projected prices and converted to 2001 dollars to be consistent with the financial data presented elsewhere in this report. A comparison of the number of projected households and average expenditures per household for the S.139 case versus the reference case is illustrated in Figure 4.3.

Under the projected provisions of the bill, annual energy expenditures per LIHEAP-eligible household and poverty-level household in 2025 increase by $316 and $306 over the reference case, respectively. These increases calculated as percentages of reference case expenditures, in both cases, round to

Figure 4.3. Additional Annual Home Energy Expenditures per LIHEAP-Eligible and Poverty-Level Household in the Reference and S.139 Cases (dollars per household, 2001 constant dollars)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs MLBASE.D050303A and MLBILL.D050503A.

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[117] This is clearly not a reasonable expectation, it is merely a convenient assumption since the NEMS residential model does not track households by income distribution. The proportion of future households with poverty level or aid-eligible incomes will depend on a number of factors and be either higher or lower than the constant shares assumed here.

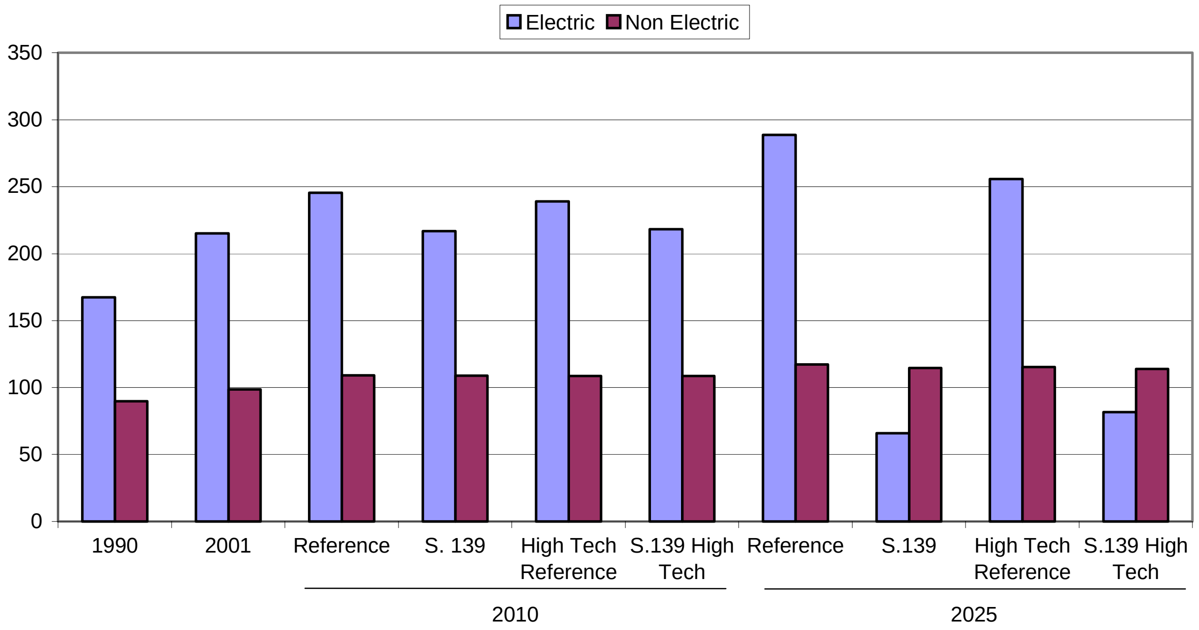
Residential Energy Consumption Varies by Income Cohort (continued)

27 percent. Also in both cases, higher electricity prices account for 95 percent of the increase in total annual expenditures. Higher electricity prices result, because the electricity sector is covered and greenhouse gas permit costs are reflected in residential electricity prices (via the cost of permits for the electricity generation sector).[118] The prices of other fuels do not include greenhouse gas permit costs, because the residential sector is not defined as a “covered” sector.

Greenhouse Gas Reduction Cases

Although households are specifically excluded from the emission limits proposed in S.139, secondary effects, such as potential increases in delivered energy prices, could have a significant impact on energy use and expenditures within the residential sector and, as a result, the greenhouse gas emissions associated with energy use. Carbon dioxide emissions associated with electricity generation are the largest component of emissions from the residential sector, in terms of both the levels and projected growth in the reference case, and in terms of the projected declines in the greenhouse gas reduction cases. In the reference case, which does not include legislation limiting greenhouse gas emissions, 80 percent of the projected increase in carbon dioxide emissions related to energy use in the residential sector by 2025 results from increasing electricity use and the fuels used for electricity generation. In the S.139 case, electricity-related carbon dioxide emissions decrease by 69 percent in 2025, relative to the 2001 level, due to a dramatic reduction in carbon intensity and energy conservation (Figure 4.4).

Figure 4.4. Residential Sector Carbon Dioxide Emissions, 1990, 2001, 2010, and 2025 (million metric tons carbon equivalent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C, and ML_HT.D050503A.

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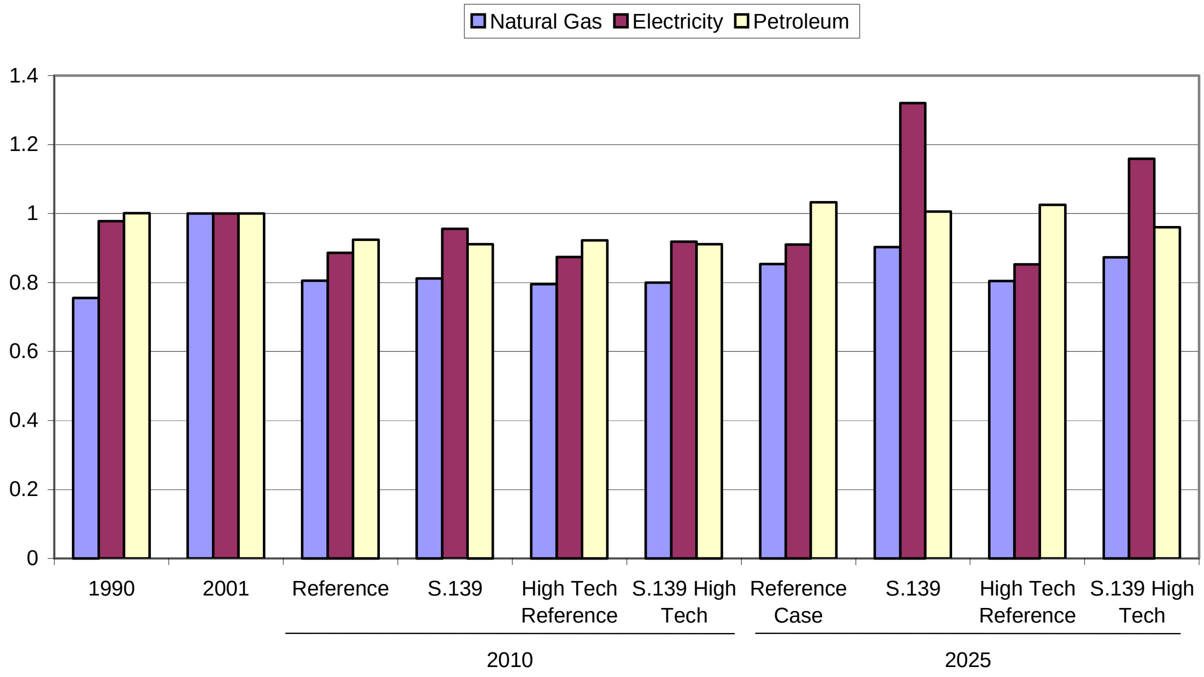
[118] See Chapter 5 on electricity supply for a description of how greenhouse gas permit costs are reflected in residential electricity prices.

Given the impact of emission constraints on the electric generating sector, electricity prices show the greatest increase in the S.139 case (Figure 4.5). By 2025, residential electricity prices rise by 32 percent in the S.139 case, relative to 2001 levels—a marked departure from the 9 percent decrease in real electricity prices projected in the reference case. In both cases, however, real disposable income per household increases by 57 percent over the same period. The price of petroleum products used in residences, primarily heating oil, are projected to remain about the same across the 3 cases shown in Figure 4.5, while natural gas prices are projected to rise by about 5 percentage points in the S.139 case, relative to the reference case, by 2025 due to the increase in the overall demand for natural gas. However, as shown in Figure 4.6, increased use of more energy-efficient technologies can mitigate projected price increases. As energy efficiency increases and demand for electricity and the fuels used to generate electricity decrease in the S.139 high technology case, relative to the S.139 case, electricity prices increase by 16 percent by 2025—half the increase projected in the S.139 case—causing energy expenditures to decrease on an annual basis relative to the S.139 case.

Figure 4.5. Index of Residential Sector Energy Prices, 1990, 2001, 2010, and 2025 (index, 2001 = 1.0)

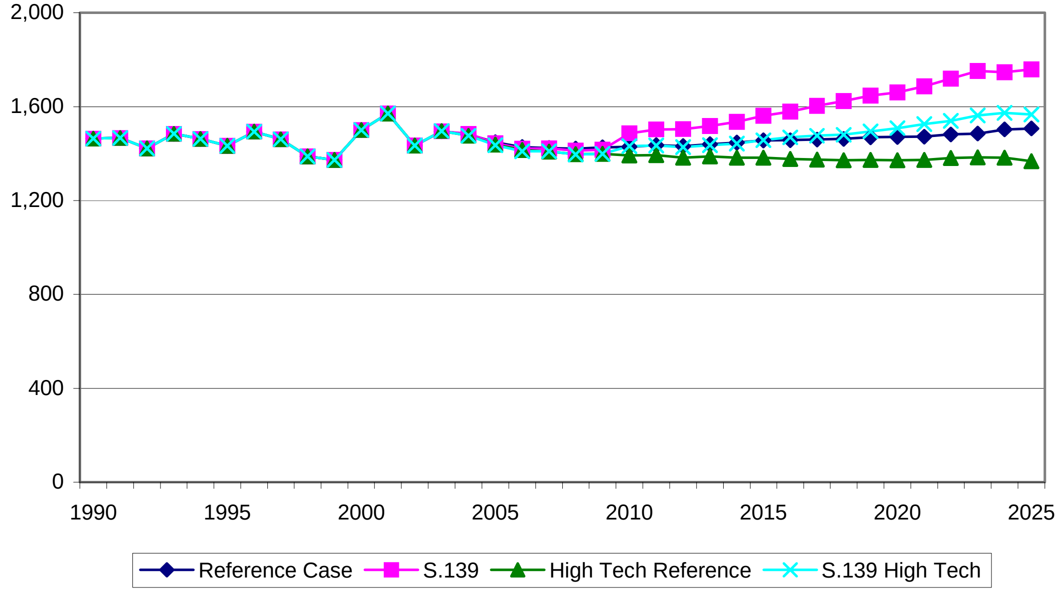


Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C, and ML_HT.D050503A.

As prices increase in the S.139 case due to stricter emissions requirements in the electric generation sector, households can expect to pay more in annual energy costs. As noted earlier, projected increases in electricity prices in the S.139 case cause household expenditures for energy to increase as well, while energy expenditures in the S.139 high technology case are suppressed to levels slightly above those projected in the reference case (Figure 4.6). This results mainly from increased household energy efficiency and the resulting lower residential (and overall) electricity demand, causing less upward pressure on electricity prices for both the residential sector and the economy as a whole.

As outlined in S.139, the Corporation has the authority to mitigate the adverse effects of greenhouse gas emission restrictions on non-covered entities. The funds collected by the Corporation through the auction of emission permits can be dispersed to residential energy consumers by various methods, including

Figure 4.6. Projected Energy Expenditures per Household in the Residential Sector, 1990-2025 (2001 dollars)



Note: Does not include coal or wood.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C, and ML_HT.D050503A.

rebates, subsidies, and general transition assistance to displaced workers. In 2010, 20 percent of this fund must be dispersed for transition assistance, leaving 80 percent of the auction proceeds available for rebates and/or subsidies that must be dispersed on a geographically equal basis across the United States. Because S.139 does not specify a particular method of disbursement, an assumption must be made regarding how and by how much the Corporation might allocate the funds it collects. Since the disbursements must be made on a geographically equal basis, it is assumed that the Corporation will pursue rebates for energy-efficient appliances, as opposed to weatherization or similar programs, which tend to affect those homes with higher heating and/or cooling loads. In order to represent the rebates in this analysis, it is assumed that from 2010 through 2025, half of the incremental cost to purchase more efficient appliances is covered by rebates initiated by the Corporation (Table 4.1). For example, the first row in Table 4.1 details a heat pump available between 2020 and 2025 that achieves a 16 percent increase in efficiency over the least efficient unit available for purchase in the same period. Without the 50 percent rebate on the incremental cost ($191 is 50 percent of $382), the new unit would cost $3,881—11 percent more than the $3,500 cost of the least efficient unit available.

Because the range of efficiency options varies by end-use service, some appliances will have several options for rebates, while others may have only one, or none in the case of cooking and clothes dryers. It should be noted that the costs and efficiencies of the more efficient appliances change over time, depending on the appliance, resulting in different efficiency, cost, and rebate amounts. Between 2010 and 2025, an average of $10 billion annually (in 2001 dollars)—17 percent of the monies collected by the Corporation over this 15-year period—is dispersed by the Corporation in the form of rebates for energy-efficient appliances. These rebates spur additional investment in energy-efficient appliances and somewhat mitigate the effect of higher energy prices in the S.139 case.

Changes in energy prices and efficiency have a direct effect on the amount of money spent on energy services by individual households in a given year. Figure 4.7 details the per household energy expenditures for the three major fuels used in the residential sector for two historical years as well as the projections for 2010 and 2025 in the reference case, the high technology reference case, the S.139 case, and the S.139 high technology case. Because electricity is used for more services than either natural gas or distillate, and because electricity is the most expensive form of delivered energy on a Btu basis, the average annual energy bill for electricity is greater than for the other two fuels shown in all years. In 2025, the average annual electricity bill is projected to increase by $249 per household (24 percent) in the S.139 case, relative to the reference case. Expanded and accelerated availability of highly efficient technologies can mitigate some of this increase: relative to the high technology reference case, the average annual electricity expenditures in the S.139 high technology case are only $185 per household higher. In both the S.139 and S.139 high technology cases, petroleum expenditures are lower, relative to the reference case because of lower distillate prices caused by lower world oil prices resulting from lower U.S. demand for petroleum. In 2025, natural gas expenditures are about the same in the reference and S.139 cases, as the lower demand per household in the S.139 is offset by the higher natural gas prices caused by an increase in natural gas demand economy-wide, keeping expenditures about the same.[119] In

Table 4.1. Household Appliances Targeted by Corporation Rebates (year 2010, except where noted)

Appliance	Percent Increase in Efficiency Over Least Efficient Unit	Percent Increase in Price Without Rebate	Equipment Price Without Rebate (2001 dollars)	Rebate Amount (2001 dollars)
Air-Source Heat Pump 1 (2020-2025, cooling efficiency cited)	16	11	3,881	191
Air-Source Heat Pump 2 (cooling efficiency cited)	25	30	4,563	532
Air-Source Heat Pump 3 (cooling efficiency cited)	50	60	5,600	1,050
Central AC 1 (2020-2025)	16	10	2,540	120
Central AC 2	25	26	2,900	300
Central AC 3	50	52	3,500	600
Ground-Source Heat Pump (cooling efficiency cited)	56	18	12,320	961
Gas Furnace 1	15	31	1,700	200
Gas Furnace 2	21	88	2,450	575
Gas or Distillate Boiler 1	11	24	3,065	293
Gas or Distillate Boiler 2	21	47	3.650	585
Distillate Furnace	9	46	1,900	300
Room AC 1 (2020-2025)	14	10	595	27
Room AC 2	24	41	760	110
Clothes Washer (motor efficiency cited)	27	10	850	40
Dishwasher 1 (motor efficiency cited)	54	129	800	225
Dishwasher 2 (motor efficiency cited)	104	271	1,300	475
Gas Water Heater	43	426	2,000	810
Electric Water Heater 1	6	10	550	25
Electric Water Heater 2	189	120	1,100	300
Distillate Water Heater	5	7	780	27
Refrigerator	16	58	950	175
Freezer	23	31	500	60

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on technology data from Arthur D. Little, Inc., EIA – Technology Updates – Residential and Commercial Building Technologies – Reference Case, October 2001.

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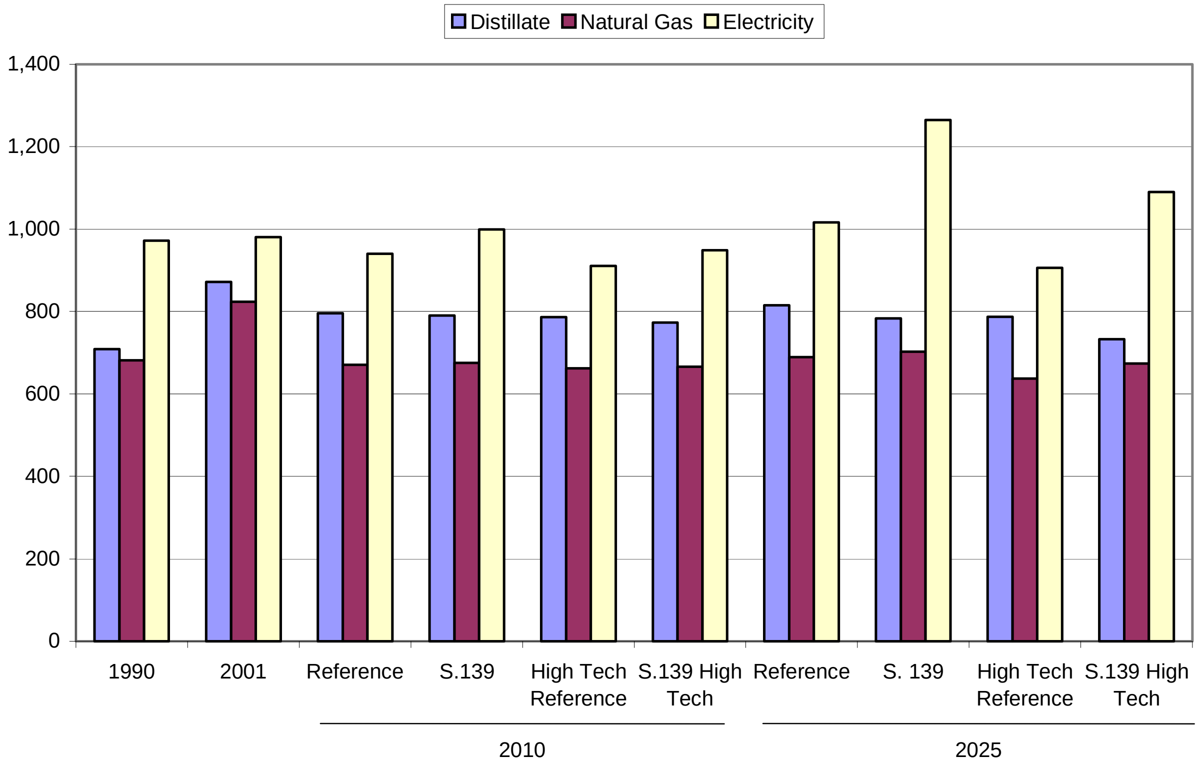
[119] This does not mean that the own-price elasticity of natural gas demand is unitary elastic. Part of the increase in natural gas demand is due to cross-price effects with the increased electricity price relative to the reference case.

Figure 4.7. Annual Household Energy Expenditures by Major Fuel, 1990, 2001, 2010, and 2025 (2001 dollars)



Note: Natural gas and distillate households are defined as those that use the fuel for main space heating.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C, and ML_HT.D050503A.

the two high technology cases, natural gas expenditures in 2025 are slightly lower than in the reference case, even though natural gas prices in the S.139 high technology case are higher than those in the reference case.

Because the residential sector is specifically excluded from S.139, there are fewer areas to explore in terms of sensitivities relative to the S.139 case then in other sectors. However, in order to gauge the effects of increased energy efficiency with respect to the implementation of S.139, a S.139 high technology case was analyzed (and has been discussed briefly in the previous section). In the S.139 high technology case, several emerging energy-efficient technologies are introduced earlier in the projection period, generally at a lower cost than projected in the reference case.[120] As shown in Figure 4.6, the increased energy efficiency projected in the S.139 high technology case, relative to the S.139 case, causes projected energy expenditures to fall nearly to the levels projected in the reference case, notwithstanding the projected 27 percent increase in electricity prices in 2025, relative to the reference case. This implies that increases in energy efficiency and conservation can offset potentially higher energy expenditures resulting from higher prices. Without the effects of higher prices under the S.139 high technology case, residential expenditures in the high technology reference case are lower in total than those in any of the other cases, reflecting projected efficiency gains even without the additional S.139 price incentives.

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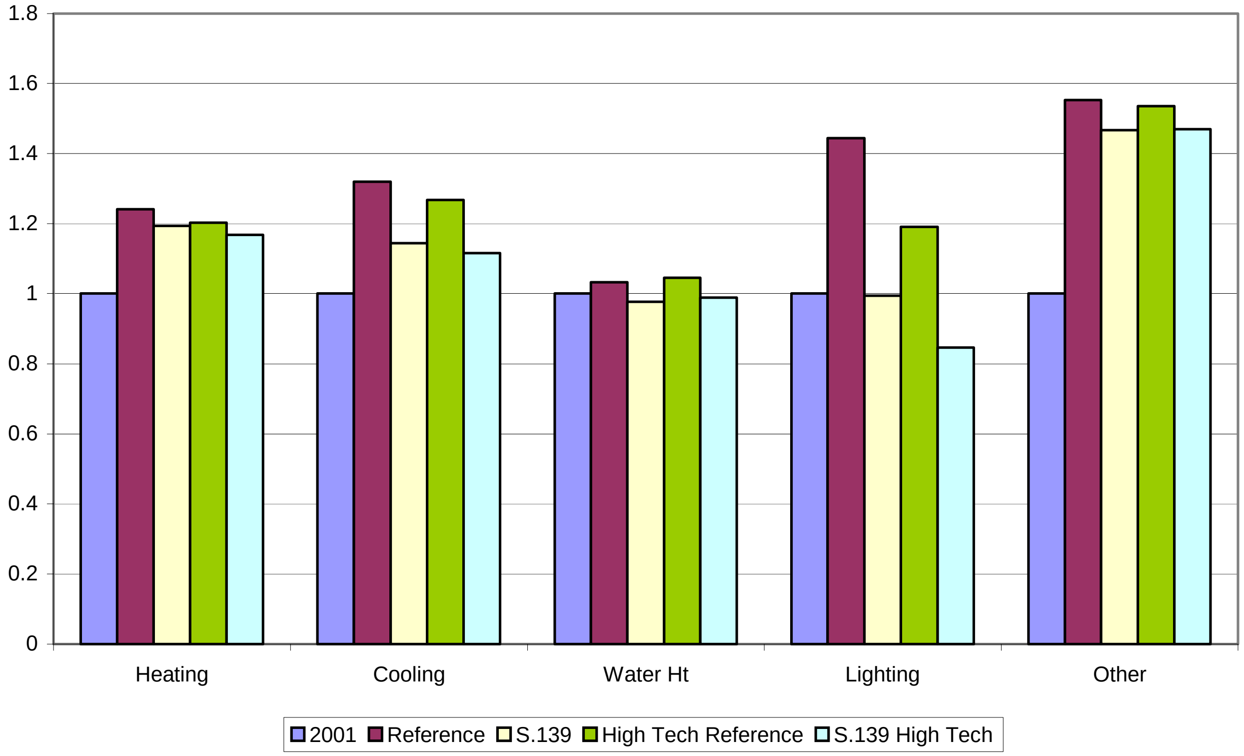
[120] For more details of the assumptions in the high technology case, see Energy Information Administration, *Assumptions to the Annual Energy Outlook 2003*, web site http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2003).pdf.

Projected increases in energy prices, coupled with more aggressive assumptions regarding the cost and availability of more efficient technologies in the future, act to reduce energy demanded by households due to both conservation and energy efficiency in the high technology cases. Figure 4.8 shows the difference in energy consumption by service in the high technology cases, relative to the reference and S.139 cases. For most end-use services, the S.139 high technology case technology assumptions bring about less energy demand in 2025, because technology improvements in the S.139 high technology case have a larger impact than lower energy prices, relative to the S.139 case. Lighting, which has relatively inexpensive energy-efficient technology options, exhibits the greatest percent reduction in demand in the S.139 high technology case. Compact fluorescent bulbs, which are widely available today, can significantly decrease the demand for electricity if used on a wide scale. Water heating, on the other hand, exhibits little opportunity for efficiency improvements in the S.139 high technology case, given the limited technological options and lower delivered energy prices, relative to the S.139 case. This holds true for the "other uses" category as well.

Figure 4.8. Index of Residential Sector Delivered Energy Consumption by End Use, 2001 and 2025 (index, 2001 = 1.0)



Note: Other includes cooking, refrigerators, freezers, clothes washers, dishwashers, clothes dryers, color televisions, personal computers, furnace fans, and many other small uses.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C, and ML_HT.D050503A.

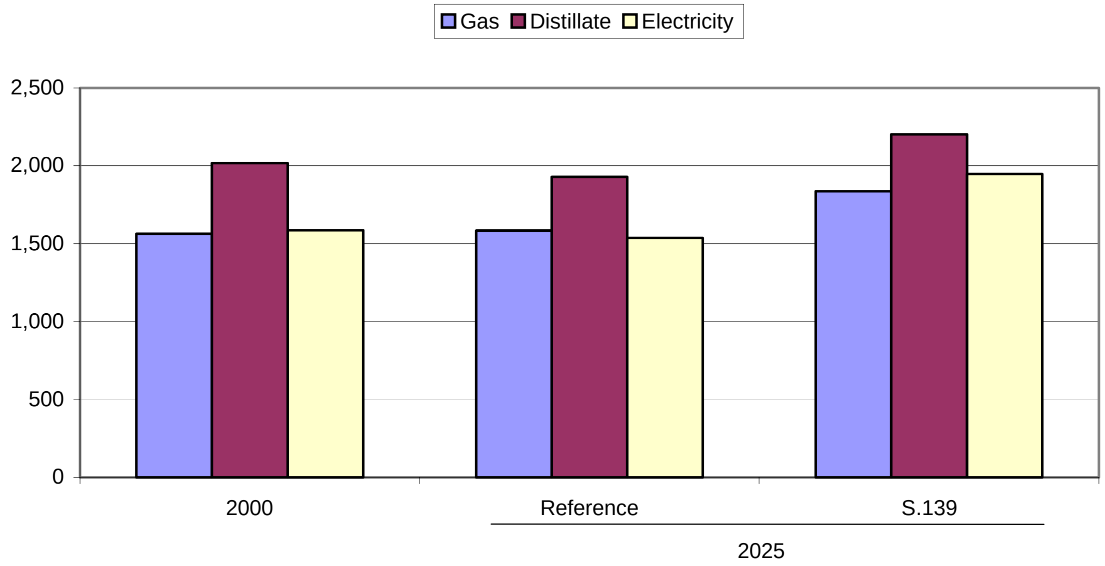
Impacts on All Electric and Mixed-Fuel Homes

Given that electricity prices increase by more than the price of any other fuel delivered to the residential sector in the S.139 case, it is important to differentiate the projected impacts in this case based on the mix of fuels used in the home. Because natural gas and distillate are important fuels for space heating, it is likely that homes that heat with these fuels, as opposed to electricity, will see less projected increases in their energy bills in the S.139 case, since natural gas prices do not increase as much as electricity prices, and distillate prices delivered to the residential sector decline. Likewise, natural gas is a popular fuel for water heating, cooking, and clothes drying, while distillate's use is mainly for space heating.

For this analysis, detailed results from the NEMS residential sector module were examined to develop prototypical all electric and mixed-fueled single-family homes.[121] For the natural gas home, it is assumed that natural gas is used for space heating, water heating, cooking, and clothes drying, while only space heating is considered for the distillate home.[122] For both the mixed-fuel and all electric homes, it is assumed that space cooling is present and used at the same level of intensity. Similarly, it is assumed that all other electric services, such as personal computers, color televisions, and refrigerators are used at the same level of intensity across the three prototypes described here.

Figure 4.9 details the increase in expenditures in the S.139 case, relative to the reference case for the all electric home, as well as the two mixed-fuel homes. As expected, expenditures in the all electric home increase more than in the two mixed fuel homes. On average, an all electric single-family home can expect to pay $257 more per year (in 2001 dollars), a 17 percent increase, from 2010 to 2025, in the S.139 case than in the reference case. The natural gas prototype home exhibits the least increase in average expenditures in the period, increasing by $154 per year over the same period, a 10 percent increase over the reference case. Since the distillate prototype home relies on electricity for clothes drying, cooking, and water heating—services that can be provided by natural gas—the average expenditures over the 2010-2025 period increase more than those for the natural gas prototype home, even with lower delivered energy prices in the S.139 case, relative to the reference case. These homes can expect to pay $169 per year more over the 2010-2025 period, a 9 percent increase over the reference case.

Figure 4.9. Energy Expenditures in Three Prototypical Homes in Two Cases, 2025 (2001 dollars)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

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[121] Single-family homes are chosen because the occupants are more likely to pay their own energy bills and because they tend to use more energy.

[122] Because the number of homes that heat with distillate is less than half the number that use distillate for water heating, electricity is assumed to be the fuel of choice for water heating.

Commercial Sector

Background

The commercial sector consists of businesses and other organizations that provide services. Stores, restaurants, hospitals, and hotels are included, as well as a wide range of facilities that would not be considered "commercial" in a traditional economic sense, such as public schools, correctional institutions, and fraternal organizations. In the commercial sector, energy is consumed mainly in buildings, and relatively small amounts are used for services, including streetlights and water supply.

The commercial sector is currently the smallest of the four demand sectors in terms of energy use, accounting for 12 percent of delivered energy demand in 2001. The commercial sector was also responsible for fewer carbon dioxide emissions than the other sectors (18 percent of total U.S. carbon dioxide emissions) in 2001. The sector has a larger share of emissions than its share of energy use because of the importance of commercial electricity use. The emissions associated with electricity-related losses are included in the calculation of emissions from electricity use. As a result, 77 percent of commercial carbon dioxide emissions in 2001 were indirect emissions associated with electricity use, while 23 percent were from direct fossil fuel use in the commercial sector.

Several factors determine energy use and, consequently, carbon dioxide emissions in the commercial sector. One of the most important is floorspace. Building location, age, and type of activity also affect commercial energy use. Currently, total commercial floorspace in the United States exceeds the area of the State of Delaware and amounts to over 200 square feet for every U.S. resident. Mercantile (retail and wholesale stores) and service businesses are the most common type of commercial buildings, and offices and warehouses are also common.[123]

Because of the relatively long lives of buildings, the characteristics of the stock of commercial floorspace change slowly. Almost half of the commercial buildings in the United States were built before 1970. The reference case used for this analysis projects that total commercial floorspace will grow at about 1.5 percent annually through 2025. This limits the effects that new, more efficient building practices can achieve in the near term, but as time passes and building stock "turnover" occurs, current and future building practices will have a greater effect on commercial energy use.

The composition of end-use services is another determinant of the amount of energy consumed and the type of fuel used. The majority of energy use in the commercial sector is for lighting, space heating, cooling, and water heating. In addition, the proliferation of new electrical devices, including telecommunications equipment, personal computers, and other office equipment, is spurring growth in commercial electricity use. Electricity use currently accounts for 49 percent of delivered energy consumption in the sector, and that share is projected to grow to 52 percent by 2010. In terms of primary energy use, including electricity losses, electricity accounts for 76 percent of total commercial energy use, growing to 77 percent by 2010.

Consideration of end-use services leads to another determining factor in commercial energy consumption—the effects of turnover and change in end-use technologies. The stock of installed equipment changes with normal turnover as old, worn-out equipment is replaced and new buildings are

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[123] General characteristics of the commercial sector provided in the above paragraphs are from the Energy Information Administration's 1999 Commercial Buildings Energy Consumption Survey (CBECS) Detailed Tables, available at http://www.eia.doe.gov/emeu/cbecs/detailed_tables_1999.html; and Energy Information Administration, *A Look at Commercial Buildings in 1995: Characteristics, Energy Consumption, and Energy Expenditures,* DOE/EIA-0318(95) (Washington, DC, September 1998).

outfitted with newer versions of equipment that tend to be more energy-efficient. Equipment with even greater energy efficiency is expected to be available to commercial consumers in the future. Energy prices have both short-term and long-term effects on commercial energy use. Fuel prices influence energy demand in the short run by affecting the use of installed equipment and in the long run by affecting the stock of installed equipment.

Legislated efficiency standards also affect energy use, by imposing a minimum level of efficiency for purchases of several types of equipment used in the commercial sector. Two mandates currently affect commercial appliances: the National Energy Policy Act of 1992 (P.L. 102-486, Title II, Subtitle C, Section 342), which specifically targets larger-scale commercial equipment and fluorescent lighting, and the National Appliance Energy Conservation Amendments (NAECA), which affect commercial buildings that install smaller residential-style equipment. Examples include standards for heat pumps, air conditioning units, boilers, furnaces, water heating equipment, and fluorescent lighting.

The degree to which energy-efficient equipment can affect energy consumption, and in turn carbon dioxide emissions, in the commercial sector is limited by the level of efficiency available to commercial consumers and the rate at which more efficient equipment is purchased. Technologies for all the major end uses (lighting, heating, cooling, water heating, etc.) are defined by their installed cost, operating cost, efficiency, average useful life, and first and last dates of availability. These parameters are considered, along with fuel prices at the time of purchase, in the selection of technologies that provide end-use services. Commercial consumers are not assumed to anticipate future changes in fuel prices when choosing equipment. The commercial sector encompasses a wide variety of buildings, and not all consumers will have the same requirements and priorities when purchasing equipment. Major assumptions that take these differences in behavior into account and affect commercial technology choices are described below.

In making the tradeoffs between equipment cost and equipment efficiency, the diversity in purchase behavior of the commercial sector is represented by distributing floorspace over a variety of hurdle rates. The distribution is constructed to allow the model to represent the observed decisions regarding the selection and use of energy-using equipment in the commercial sector. Floorspace is distributed over hurdle rates that range from the 10-year treasury bond rate to rates high enough to cause choices to be made solely by minimizing the costs of installed equipment (i.e., future potential energy cost savings are ignored at the highest hurdle rate).[124] The distribution of hurdle rates used in all the cases for this analysis is not static: as fuel prices increase, the nonfinancial portion of each hurdle rate in the distribution decreases.[125]

For a proportion of commercial consumers, it is assumed that newly purchased equipment will use the same fuel as the equipment it replaces. This proportion varies by building type and by type of purchase—whether it is for new construction, to replace worn-out equipment, or to replace equipment that is economically obsolete. Purchases for new construction are assumed to show the greatest flexibility of fuel choice, while purchases for replacement equipment have the least flexibility. For example, when space-heating equipment in large office buildings is replaced, 8 percent of the purchasers are assumed to

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[124] Rates of return on investments in energy efficiency (referred to in financial parlance as “internal rates of return”) are required to meet or exceed the hurdle rate. The hurdle rates include both financial and nonfinancial considerations, as described in the residential footnote on hurdle rates. For more information on the distribution of commercial hurdle rates please see page 32 of Energy Information Administration, *Assumptions for the Annual Energy Outlook 2003*, DOE/EIA-0554(2003) (Washington, DC, January 2003), and Chapter 4 of Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M066(2003) (Washington, DC, March 2003).

[125] For the purposes of this study, the financial portion of the hurdle rates is considered to be 15 percent in real terms. A more detailed discussion of the hurdle rate response to increases in fuel prices is provided on page 32 of Energy Information Administration, *Assumptions for the Annual Energy Outlook 2003*, DOE/EIA-0554(2003) (Washington, DC, January 2003).

consider all available equipment using any fuel or technology, while 92 percent select only from technologies that use the same fuel as the equipment being replaced. The proportions used are consistent with data from EIA's Commercial Buildings Energy Consumption Survey and from published literature.[126] Considerations such as owner versus developer financing, past experience, ease of installation, and fuel availability all play a role in fuel choice. This assumption also accounts for some of the factors that influence technology choices but cannot be measured. For example, a hospital adding a new wing has an economic incentive to use the same fuel that is used in the existing building.

The availability and costs of advanced technologies affect the degree to which they can contribute to future energy savings and carbon dioxide emission reductions. Many efficient technologies currently available to commercial consumers could significantly reduce energy consumption; however, high purchase costs and the current low level of fuel prices have limited their penetration to date. As more advanced technologies mature over time, their costs are expected to decline (compact fluorescent lighting is an example). New technologies, beyond those available today, may also enter the market in the future. For example, the S.139 high technology case, described below, assumes that by 2005 a triple-effect absorption natural-gas-fired commercial chiller will be available.

The combination of technology and behavior assumptions determines the commercial-sector price elasticity for each of the major fuels—that is, how commercial sector demand projections are affected by changes in energy prices. Specifically, the commercial-sector price elasticity for a particular fuel is the percent change in demand for that fuel in response to a 1-percent change in its delivered price. Short-run price elasticities for fuel use in the commercial sector range from -0.20 to -0.29, representing behavioral changes in the use of equipment, such as adjusting thermostats or turning lights off in unoccupied areas. Long-term price elasticities range from -0.39 to -0.45, reflecting changes in both the use of existing equipment and the adoption rates for more efficient equipment.[127] These values are within the range cited in the literature.[128]

The reference case projects slightly declining electricity and natural gas prices compared to the relatively high prices experienced in 2001. Commercial electricity and natural gas prices are projected to show an average decline of 0.4 and 0.6 percent per year, respectively, between 2001 and 2025, reducing the incentive for commercial consumers to invest in energy-efficient equipment. Projected commercial prices for petroleum products decline in the near term, and then rise steadily through the end of the forecast, resulting in an average annual increase of 0.3 percent between 2001 and 2025.

S.139 Case

The S.139 case assumes that the commercial sector is not covered by the emissions limits specified in the proposed legislation, although the commercial sector can provide credit for reductions to covered sectors. As discussed in Chapter 2, this assumption is based on the level of the emissions threshold. A commercial coverage case, which assumes that the entire commercial sector is covered, was also examined. The

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[126] Current assumptions use an analysis of data from EIA's 1995 commercial buildings survey. Sources for data on consumer behavior are listed on page A-27 of Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M066(2003) (Washington, DC, March 2003).

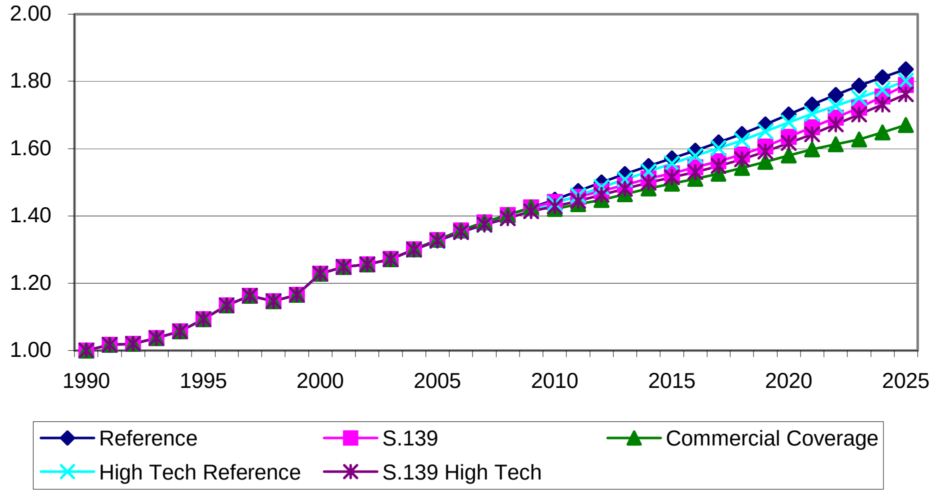
[127] As in the residential model, the long-run elasticities are for 2025 and represent the effects after 20 years of altered price regimes.

[128] Dahl (1993), "A Survey of Energy Demand Elasticities in Support of the Development of the NEMS," US DOE, Contract Number DE-AP01-93EI23499 (October 1993). The Dahl survey incorporated results from other survey articles and from newer studies, not reviewed previously. From prior surveys, the residential/commercial own-price elasticities for total energy ranged from -0.012 in the short run (SR) to -0.44 in the long run (LR). Focusing on studies of aggregate time series data, demand elasticities for electricity from more recent studies averaged from -0.22 (SR) to -0.91 (LR) for residential and -0.22 to -0.82 for commercial. For natural gas the averages from more recent studies were -0.13 (SR) to -0.68 (LR) for residential and -0.26 to -0.99 for commercial.

results of this sensitivity case are discussed following the discussion of commercial sector results for the S.139 case.

In the S.139 case, commercial sector delivered energy use in 2025 is projected to be 3 percent lower (Figure 4.10), and carbon dioxide emissions attributable to the commercial sector, including emissions from electricity generation, are projected to be 60 percent lower relative to reference case projections, despite 1.5-percent annual growth in commercial floorspace from 2001 to 2025. Commercial energy consumption in the S.139 case is impacted primarily by higher projected electricity prices—46 percent higher in 2025 compared with the reference case. Although the commercial sector is not required to participate in the emissions allowance system under the assumptions for the S.139 case, the power sector is expected to pass a share of the opportunity costs of allowances on to ratepayers. Commercial sector purchased electricity use in 2025 is expected to be 12 percent lower in the S.139 case than in the reference case due to the increased prices (Figure 4.11). Natural gas consumption as a whole is projected to increase in the S.139 case relative to the reference case, exerting upward pressure on projected natural gas prices to the commercial sector. Covered sectors shift toward natural gas use and away from fossil fuels that produce higher emissions. Higher projected electricity prices increase the attractiveness of distributed generation, including combined heat and power, in the commercial sector, contributing to increased use of natural gas.

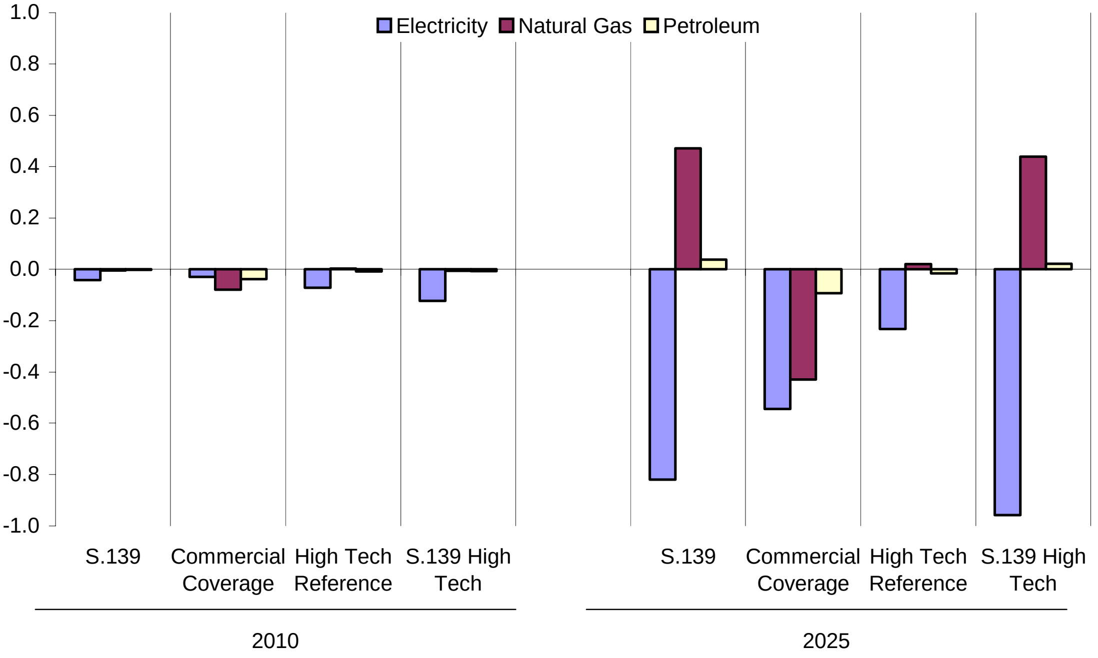
Figure 4.10. Index of Commercial Sector Delivered Energy Consumption, 2001-2025 (index, 1990 = 1.0)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_COVER_K.D050603A, MLBASE_HT.D052003C, and ML_HT.D050503A.

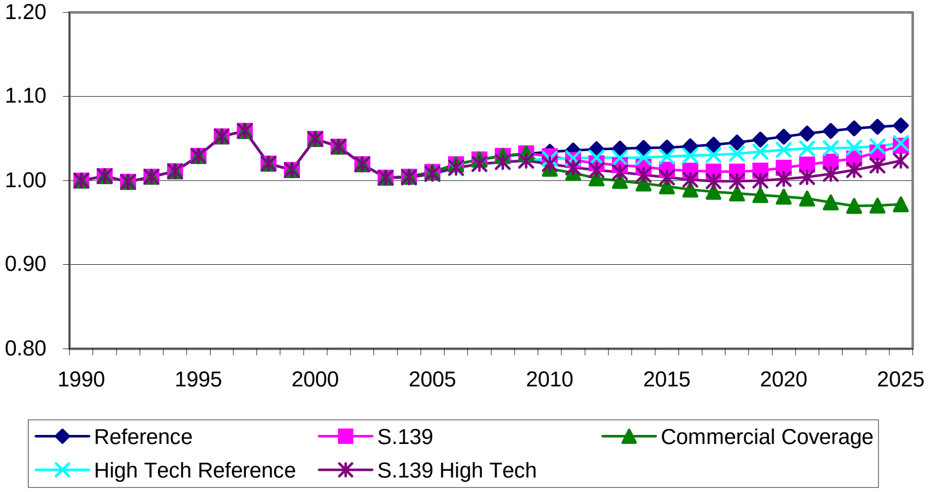
Floorspace expansion in the commercial sector will lead to growth in energy consumption if other factors remain the same. Figure 4.12 removes the effects of floorspace growth by presenting commercial energy intensity in terms of delivered energy consumption per square foot of commercial floorspace. Delivered energy intensity in the reference case is projected to increase very slightly, 0.1 percent per year, between 2001 and 2025. Projected growth in commercial demand for services is offset by the availability and continued development of energy-efficient technologies, existing equipment efficiency standards, and voluntary programs. In the S.139 case, with higher energy prices, the projection for commercial delivered energy intensity in 2020 is 4 percent below the reference case projection, slightly below its current (2001) level. Reduction in delivered energy intensity relative to the reference case narrows to 2 percent by 2025 due to increased use of natural gas.

Figure 4.11. Change in Commercial Delivered Energy Consumption Compared with the Reference Case, 2010 and 2025 (quadrillion Btu)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_COVER_K.D050603A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Figure 4.12. Index of Delivered Energy Intensity in the Commercial Sector, 1990-2025 (index, 1990 = 1.0)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_COVER_K.D050603A, MLBASE_HT.D052003C, and ML_HT.D050503A.

When energy prices rise, consumers are expected to reduce energy use by purchasing more efficient equipment and by altering the way they use energy-consuming equipment. In addition to buying more efficient boilers and chillers, commercial customers in the S.139 case are expected to choose more heat pump water heaters and more efficient lighting technologies than they would in the reference case (Table 4.2).

Table 4.2. Market Share for Selected Commercial Technologies in the Reference and S.139 Cases, 2010 and 2025 (percent)

Technology	2010		2025	
	Reference	S.139	Reference	S.139
High-Efficiency Boiler Share of All Boilers	8	12	14	26
High-Efficiency Chiller Share of All Electric Chillers	3	4	5	15
Heat Pump Water Heater Share of Electric Water Heating Market	3	3	3	7
Compact Fluorescent Share of Incandescent-Style Lighting Market	66	68	77	96
Reflectors, Lighting Controls, and Advanced Technology Share of 4 Foot Fluorescent Lighting Market	14	15	19	48

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

The adoption of more efficient technologies reflects the reaction to rising fuel prices and a change in the way commercial consumers are expected to look at purchase decisions involving energy efficiency if electricity-related carbon dioxide emissions are limited. Most commercial consumers give some consideration to fuel costs when buying equipment. A significant increase in fuel prices is expected to cause consumers to give energy costs greater weight in the purchase decision, by seeking out more information about energy efficiency options and by accepting a longer time period to recoup the additional initial investment typically required to obtain greater energy efficiency. While taking client comfort and employees' working conditions into consideration, commercial energy consumers would also be expected to turn thermostats down (up) a few degrees during cooler (warmer) weather and to be more conscientious about turning off lights and office equipment not in use.

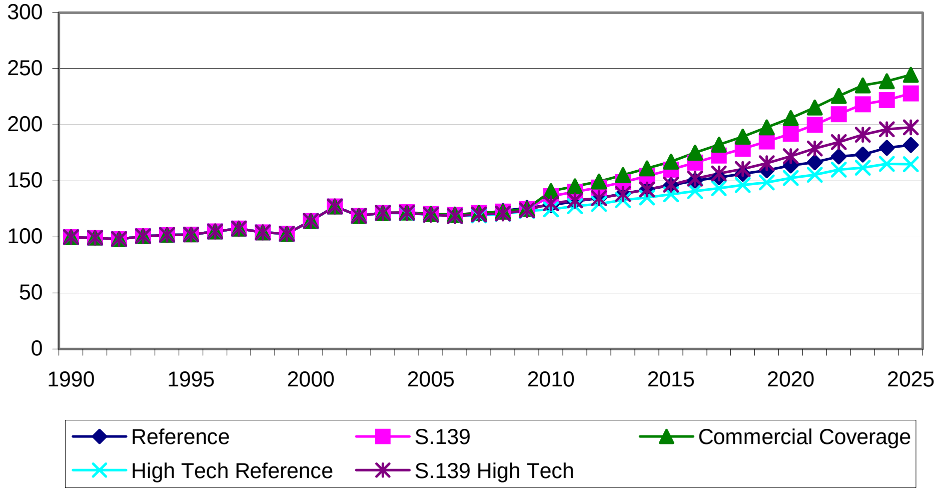
The fastest-growing commercial end uses, under reference case assumptions, include office equipment and miscellaneous devices powered by electricity (e.g., telecommunications equipment, medical imaging equipment, ATM machines), which are continuing to penetrate the commercial sector. Although electricity consumption for these end uses would be responsive to the price signals resulting from emissions reduction efforts in the power sector, their growth still is expected to be faster than growth in the end uses that directly consume fossil fuels (primarily space heating and water heating).

The vast majority of the projected commercial sector reductions in carbon dioxide emissions in the S.139 case are related to electricity use. Two factors contribute to electricity-related carbon dioxide savings: reductions in the level of carbon dioxide emitted during the generation of a given amount of electricity (as discussed in Chapter 5), and reductions in electricity consumption. The projection for delivered electricity consumption in the commercial sector in 2025 for the S.139 case is 12 percent lower than the reference case projection. Electricity-related carbon dioxide emissions in 2025 attributable to the commercial sector are 77 percent lower in the S.139 case relative to the reference case, highlighting the result that the vast majority of reductions in electricity-related emissions in the S.139 case are due to abatement efforts by the power sector rather than reductions in demand for purchased electricity.

Because the requirement for the power sector to hold emissions allowances causes a greater percentage increase in electricity prices than natural gas prices relative to those in the reference case, commercial consumers are expected to adopt distributed generation technologies, including combined heat and power, to a much greater extent in the S.139 case than in the reference case. The impacts are most pronounced toward the end of the forecast period, when projected cost declines for advanced technologies such as fuel cells and microturbines are expected to occur. In keeping with the typical power and heating requirements of commercial establishments, the size and use of the distributed generation/combined heat and power systems adopted in the S.139 case are assumed to remain well under the threshold requiring participation in the proposed emissions allowance system. [129]

The energy price impacts of the proposed emissions allowance system are seen in the effects on commercial consumers' energy bills, in addition to the effects described previously (Figure 4.13). Commercial sector energy expenditures in the S.139 case are 11 percent ($16 billion in 2001 dollars) higher than reference case expenditures in 2016 when emissions allowances for covered sectors are tightened to 1990 levels. By 2025, commercial consumers are projected to pay 25 percent ($46 billion) more for energy in the S.139 case relative to 2025 energy costs in the reference case.

Figure 4.13. Projected Energy Expenditures in the Commercial Sector, 1990-2025 (billion 2001 dollars)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_COVER_K.D050603A, MLBASE_HT.D052003C, and ML_HT.D050503A.

The costs of S.139 expected to be borne by commercial consumers include investments in energy-efficient equipment as well as the energy expenditures discussed in the previous paragraph. The proposed legislation attempts to reduce the cost burden to consumers by directing the Corporation to use the proceeds collected through the auction of emissions allowances for that purpose. A share of the proceeds, starting at 20 percent in 2010 and declining at 2 percent per year, is to be used for transition assistance to dislocated workers and communities. The remainder of the proceeds is available for buydowns, rebates, or other forms of subsidy to lessen the costs to consumers, to be distributed equitably across all U.S. regions. As described in Chapter 2, the S.139 case includes rebates for energy-efficient equipment for the major commercial end-use services (space heating, space cooling, lighting, etc.) starting in 2010. Rebates

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[129] A quantitative discussion of combined heat and power in the S.139 case is included in the Industrial section of this chapter. Figure 4.21 and its associated text include commercial and residential combined heat and power projections in addition to industrial sector projections.

to commercial consumers from the Corporation are projected to average $303 million (2001 dollars) per year between 2010 and 2025 in the S.139 case.

Sensitivity Cases

The majority of the sensitivity cases included in this analysis use the same commercial sector assumptions as those used in the S.139 case. Two sensitivity cases were analyzed that involve changes to commercial assumptions. The results of those cases are discussed here. The commercial coverage case requires the entire commercial sector to participate in the emissions allowance system proposed in S.139. This sensitivity case was included to explore the potential impact on emission allowance costs of broader energy use coverage. To make the commercial assumptions in the commercial coverage case comparable with those for other covered sectors, rebates from the Corporation for energy-efficient equipment are not provided to the commercial sector in this case. The S.139 high technology case includes high technology assumptions for all end-use demand sectors and the power sector, as described in Chapter 2. While the commercial sector is excluded from coverage in the S.139 high technology case, the menu of technologies available reflects increased research and development into more advanced technologies relative to the technology menu in both the reference case and the S.139 case. Corporation rebates to commercial consumers for energy-efficient equipment are included in the S.139 high technology case. The S.139 high technology case will be compared to the high technology reference case described in Chapter 2.

In the commercial coverage case, commercial delivered energy use in 2025 is projected to be 7 percent lower than in the S.139 case (see Figure 4.10) as allowance requirements drive up the costs of fossil fuel use. Carbon dioxide emissions attributable to the commercial sector in the commercial coverage case are 11 percent (18 million metric tons carbon equivalent) below the S.139 case projection for 2025. When the commercial sector is required to hold emissions allowances, the projected adoption of distributed generation/combined heat and power decreases significantly compared to the S.139 case, reducing on-site emissions from natural gas use but increasing the need for purchased electricity. The increased cost of energy-efficient equipment (due to the lack of Corporation rebates) contributes to projected commercial use of purchased electricity that is 5 percent (81 billion kilowatthours) higher in 2025 than in the S.139 case (see Figure 4.11). Conversely, commercial natural gas use in 2025 is projected to be 18 percent lower in the commercial coverage case than in the S.139 case as emissions limits lead to lower adoption of distributed generation/combined heat and power and slightly lower consumption for end-use services such as space and water heating.

Although treating the commercial sector as covered results in lower commercial energy use and carbon dioxide emissions, directly limiting commercial sector emissions has little impact on the projected allowance price (Figure 4.14). Projected allowance prices in the commercial coverage sensitivity case and in the S.139 case are virtually the same from 2010 through 2025, with less than one dollar difference between the two cases in 2025. Mandatory commercial sector participation in the tradable allowance system increases the total covered sector emissions and, consequently, the number of offsets allowed in the 15 percent and 10 percent cap allowed in the bill’s alternative compliance provisions. As a result, the cost of offsets increases in this case relative to the S.139 case.[130] By 2016, the projected offset price in the commercial coverage case is 14 percent higher than in the S.139 case, and that difference is generally maintained through the end of the forecast.

Annual energy expenditures by commercial consumers in the commercial coverage case, including allowance costs, total $244 billion by 2025—7 percent above projected 2025 expenditures in the S.139

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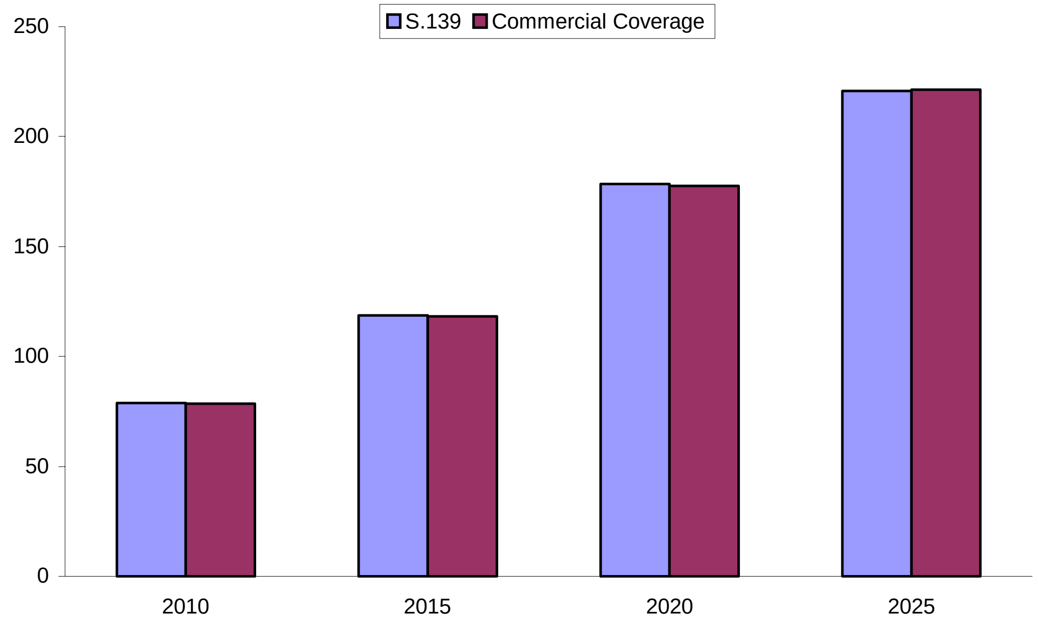
[130] In most cases, the market price for offsets is expected to clear at prices below the allowance market due to offset limits and generally low costs of reductions from offset sources. Chapter 3 of this report includes a detailed discussion of the trading markets for allowances and offsets.

Figure 4.14. Projections of Allowance Prices in Two Alternative Cases, 2010, 2015, 2020, and 2025 (2001 dollars per metric ton of carbon equivalent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A, and ML_COVER_K.D050603A.

case and 34 percent higher than projected in the reference case (see Figure 4.13). Projected electricity prices in this case are comparable to those projected in the S.139 case, but the imposed limit on commercial emissions increases the effective prices of fossil fuels, resulting in higher commercial energy expenditures.

The S.139 high technology case results in lower projected commercial energy use through the end of the forecast, relative to the high technology reference case (see Figure 4.10). Projected commercial carbon dioxide emissions in 2025 are 51 percent lower in this case than in the high technology reference case due to lower electricity-related commercial emissions. By 2025, the projected commercial electricity price is 36 percent higher in the S.139 high technology case than in the high technology reference case, as the power sector passes a share of the costs of compliance on to consumers in the form of higher prices. The combination of higher electricity prices, and Corporation rebates that mitigate the net added cost of efficient equipment keeps projected commercial electricity consumption in the S.139 high technology case 11 percent below that of the high technology reference case by 2025. Higher electricity prices increase the projected use of commercial fossil-fuel-fired distributed generation/combined heat and power relative to the high technology reference case. Projected natural gas prices are higher in the S.139 high technology case than in the high technology reference case—9 percent higher by 2025. However, the relative increase in natural gas prices is smaller than the increase in electricity prices between the two cases, leading to greater projected adoption of natural-gas-driven distributed generation/combined heat and power in the S.139 high technology case. In the case of solar photovoltaic systems, the optimistic technology assumptions of the high technology cases and the higher electricity prices of the S.139 high technology case, relative to the high technology reference case, result in an additional 311 million kilowatthours (15 percent) of projected electricity generation by commercial photovoltaic systems in 2025.

Higher projected energy prices outweigh lower energy demand, resulting in higher commercial energy bills in the S.139 high technology case relative to the high technology reference case (see Figure 4.13). Commercial energy expenditures projected for 2025 in the S.139 high technology case are 20 percent ($33 billion) above projected expenditures in the high technology reference case. Rebates to commercial consumers from the Corporation in the S.139 high technology case are projected to average $300 million per year between 2010 and 2025.

Industrial Sector

Background

The industrial sector includes agriculture, mining, construction, and manufacturing activities.[131] The sector consumes energy as an input to processes that produce the goods that are familiar to consumers, such as cars and computers. The industrial sector also produces a wide range of basic materials, such as cement and steel, which are used to produce goods for final consumption. Energy is an especially important input to the production processes of industries that produce basic materials. Typically, the industries that are energy-intensive are also capital-intensive. Industries within the sector compete among themselves and with foreign producers for sales to consumers. Consequently, variations in input prices can have significant competitive impacts. The most significant determinant of industrial energy consumption is demand for final output.

Although energy is an important factor of production, it is not large in terms of annual manufacturing expenditures. In 2001, for example, purchased energy expenditures were 2.8 percent of annual manufacturing outlays.[132] New technology usually plays a minor role in the pattern of energy consumption, because technology tends to be used to produce new and improved final products rather than to reduce energy consumption; however, when new investments are undertaken to introduce improved production technology, steps to increase energy efficiency also are undertaken. Overall, energy prices and technological breakthroughs tend to have a rather small impact on industrial energy consumption.[133]

The industrial demand model forecasts energy consumption for fuels and feedstocks for nine manufacturing industries and five nonmanufacturing industries. The model includes electricity generated through combined heat and power systems that is either used in the industrial sector or sold to the electricity grid. Projections of traditional combined heat and power capacity additions are based on steam demand from the buildings and the process and assembly components of the industrial sector. These

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[131] The NEMS industrial model is summarized in more detail in Energy Information Administration, *Assumptions to the Annual Energy Outlook 2003*, DOE/EIA-0554 (2003) (January 2003), pp. 39-51, web site http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2003).pdf. Complete documentation for the NEMS industrial model is provided in Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-MO64(2003) (January 2003), web site http://tonto.eia.doe.gov/FTPROOT/modeldoc/m064(2003).pdf.

[132] Calculated from U.S. Department of Commerce, *Statistics for Industry Groups and Industries: 2001* (January 2003) using Table 1 and Table 4.

[133] For a variety of views, see Doblin, “Declining Energy Intensity in the U.S. Manufacturing Sector,” *The Energy Journal*, Vol. 9, No. 2 (1988); Howarth, “Energy Use in U.S. Manufacturing: The Impacts of the Energy Shocks on Sectoral Output, Industry Structure, and Energy Intensity,” *The Journal of Energy and Development*, Vol. 14, No. 2 (1991); Jacard, Nyober, and Fogwill, “How Big is the Electricity Conservation Potential in Industry?” *The Energy Journal*, Vol. 14, No. 2 (1993); Steinmeyer, “Energy Use in Manufacturing,” in Hollander, ed., *The Energy-Environmental Connection* (Island Press, 1992), Chapter 10; and Unander et al., “Manufacturing Energy Use In OECD Countries: Decomposition of Long-Term Trends,” *Energy Policy*, Vol. 27 (1999).

projections are based on an economic evaluation of 8 prototype combined heat and power systems,[134] given the prices of electricity and natural gas.

The industrial sector consists of numerous heterogeneous industries. The industrial model classifies these industries into three general groups: energy-intensive industries, non-energy-intensive industries, and non-manufacturing industries (Table 4.3). There are eight energy-intensive manufacturing industries; seven of these are modeled in the industrial model: food, pulp and paper, bulk chemicals, glass, cement, steel, and aluminum. Also within the manufacturing group are metal-based durables and the balance of manufacturing. The eighth energy-intensive industry, petroleum refining, is modeled in detail in the Petroleum Market Model, a separate module of NEMS, and the projected energy consumption is included in the manufacturing total. The forecasts of lease and plant fuel and cogeneration consumption for oil and gas are modeled in the Oil and Gas Supply Module and included in the industrial sector energy consumption totals (see Chapter 6 for a discussion of the impacts on these sectors and industries).

Table 4.3. Industrial Sectors

Industry	NAICS Codes
Energy-Intensive Manufacturing	
Food	311
Pulp and Paper	322
Bulk Chemicals	32B
Glass	3272
Cement	32731
Steel	331111
Aluminum	3313
Non-Energy-Intensive Manufacturing	
Metal-Based Durables	332-336
Balance of Manufacturing	All remaining manufacturing NAICS
Nonmanufacturing	
Agriculture	111-115
Coal Mining	2121
Oil and Gas Extraction	211
Other Mining	2122-2123
Construction	233-235

NAICS: North American Industry Classification System.

Note: 32B includes 325110, 325120, 325181, 325188, 325192, 325199, 325211, 325212, 325222, 325311, and 325312.

Source: Energy Information Administration, *Industrial Sector Demand Module of the National Energy Modeling System, Model Documentation 2003*, DOE/EIA-MO64(2003) (January 2003), web site http://tonto.eia.doe.gov/FTPROOT/modeldoc/m064(2003).pdf.

The influence of energy prices on industrial energy consumption is modeled in terms of the efficiency of use of existing capital, the efficiency of new capital additions, and the mix of fuels used. This analysis uses “technology bundles” to characterize technological change in the energy-intensive industries. This approach is dictated by the number and complexity of processes used in the industrial sector and the absence of systematic cost and performance data for the components. These bundles are defined for each production process step (e.g., coke ovens) for five of the industries and for each end use (e.g., refrigeration) in four of the industries. The process-step industries in the NEMS model are pulp and paper, glass, cement, steel, and aluminum.[135] The industries for which technology bundles are defined by end use

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[134] Energy Information Administration, *Assumptions to the Annual Energy Outlook 2003*, DOE/EIA-0554 (2003) (January 2003), p. 47, web site http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2003).pdf.

[135] The refining industry is modeled separately in the Petroleum Market Module of NEMS.

are food, bulk chemicals, metal-based durables, and the balance of manufacturing. Energy conservation from technological change is represented over time by trend-based technology possibility curves. These curves represent the aggregate efficiency of all new technologies that are likely to penetrate the future markets as well as the aggregate improvement in efficiency of 1998 technology. Higher projected energy prices increase the rate of movement along the technology possibility curve, which reduces energy intensity more rapidly than if prices remained constant. Industrial price elasticity of demand for energy is an outcome of the model rather than an input assumption. The resulting elasticities range from -0.3 to -0.5.

During 2001, the industrial sector used 32.7 quadrillion Btu of primary energy (including allocated electricity losses), which accounted for a little over one-third of U.S. primary energy consumption.[136] The associated carbon dioxide emissions of 451 million metric tons carbon equivalent, including 178 million metric tons attributed to purchased electricity, accounted for 29 percent of U.S. carbon dioxide emissions.

In the reference case, most industrial energy prices are projected to fall slightly for the first few years of the projection period and then begin to increase slowly. Two important examples are the prices of natural gas and electricity. Compared with 2001, both these prices are projected to fall slightly, by 0.2 percent annually. However, between 2010 and 2025, these prices are projected to begin increasing, with the electricity price projected to increase by 0.3 percent annually and the natural gas price by 1.0 percent annually. Industrial energy intensity is projected to fall by 1.3 percent annually over the projection period despite these falling or modestly increasing energy prices. The factors that are expected to produce the decline in industrial energy intensity despite moderate changes in energy prices include a relative shift from energy-intensive to less energy-intensive industries; replacement of existing equipment with less energy-intensive equipment as existing capacity is retired; adoption of improved and less energy-intensive technologies; and the pressures of international competition.

Covered Industrial Entities

S.139 requires that any entity in the industrial sector that emits over 10,000 metric tons of greenhouse gas per year, measured in units of carbon dioxide equivalence, redeem permits for all such emissions. The calculations shown in Table 4.4 have been used to determine the percentage of emissions from combustion of fossil fuels within each manufacturing sector that would come from entities above the threshold. The calculations do not include indirect emissions from purchased electricity, emissions from renewable energy sources, or emissions from process activities.

The estimated coverage within the manufacturing sector is similar to that calculated by West and Pena.[137] There are four major differences in the methodology in this analysis: emissions imputations in this analysis are based on value of shipments, rather than number of employees; the 10,000 metric ton cutoff was applied at the company, rather than facility level;[138] the results were extrapolated to 2001; and the calculations were made for the sectoral aggregations in the NEMS Industrial Demand Module, rather than at the 3-digit NAICS[139] manufacturing level.

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[136] Non-combustion uses of energy of 5 quadrillion Btu accounted for 19.8 percent of delivered energy consumption in the industrial sector. These non-combustion uses of energy were inputs as feedstocks in the chemical industry and as construction materials in the construction industry.

[137] West and Pena, “Determining Thresholds for Mandatory Reporting of Greenhouse Gas Emissions,” *Environmental Science & Technology*, Vol. 37, No. 6 (2003), Table 3.

[138] The 1997 Economic Census–Manufacturing provides numbers of establishments in 10 different size groups for each industry, based on number of employees, but provides only the number of companies for the overall industry. The average number of establishments per company was calculated from the industry totals and was assumed to be the same for all size groups.

[139] North American Industry Classification System.

Table 4.4. Estimated Emissions and Facility Coverage Under S.139

NAICS Code	Manufacturing Sector	Total Number of Establishments	Total Annual CO_2 Emissions (million metric tons CO_2 equivalent)	Number of Establishments Covered	Percentage of Sector's CO_2 Emissions Covered
311	Food	26,302	46.1	1,353	51.8
322	Paper	5,868	66.1	457	81.1
324110	Petroleum Refineries	244	168.0	227	100.0
32B	Bulk Chemicals	2,935	226.7	1,605	97.9
3272	Glass	2,269	8.7	300	94.6
327310	Cement	279	25.8	279	100.0
331111	Steel	279	98.3	181	99.9
3313	Aluminum	400	11.7	211	95.2
332 - 336	Metal Based Durables	130,235	42.4	501	29.2
31-33 nec[a]	Balance of Manufacturing	194,018	94.1	1,843	38.0
	Manufacturing Total	**362,829**	**787.9**	**6,957**	**83.6**

[a] nec=not elsewhere classified.

Sources: Energy Information Administration (EIA), *1998 Manufacturing Energy Consumption Survey*, http://www.eia.doe.gov/emeu/mecs/MECS98/datatables/contents.html; Energy Information Administration, *Annual Energy Outlook 2003*, DOE/EIA0383(2002) (Washington, DC, January 2003); and U.S. Census Bureau, *1997 Economic Census – Manufacturing*, EC97M31S-GS, U.S. Department of Commerce, Economics and Statistics Administration (Washington, DC, 2001).

The number of additional facilities required to report due to common ownership or control is not known. However, the 84 percent coverage estimate will increase as additional facilities fall into the covered category. Since the equilibrium emissions allowance price is determined primarily in the power sector, the model results differ very little if one assumes that 100 percent of manufacturing would be covered. Consequently, for analysis purposes the main case assumes that the entire manufacturing sector is covered.

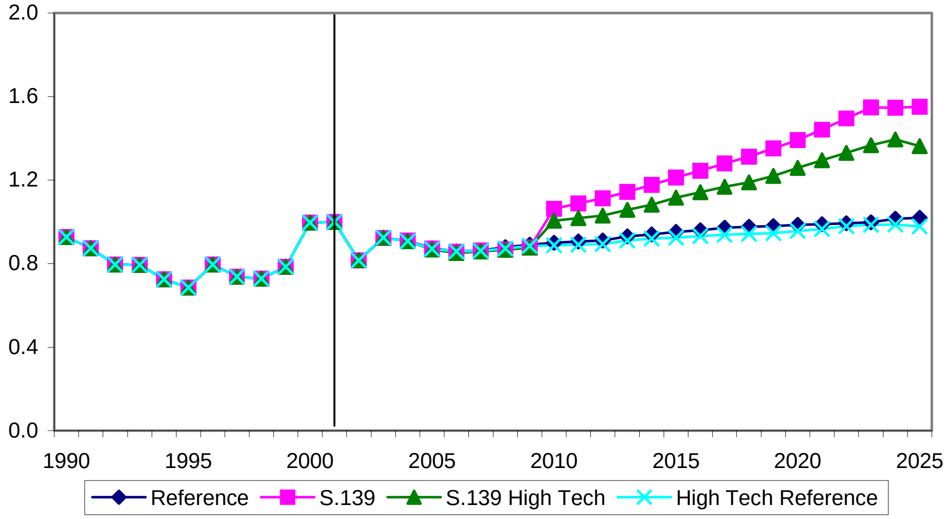
For purposes of modeling S.139, the agriculture sector is excluded from the emissions limits. This assumption is based on the size limitation, difficulty in measurement, and the apparent intent of the legislation's authors.

S.139 Results for the Industrial Sector

The combined effect of higher energy prices and reduced demand for U.S. industrial products results in lower energy consumption in the S.139 case than in the reference case. In the S.139 case the projected average industrial energy price is more than 50 percent higher than the projected average energy price in the reference case (Figure 4.15). The effective price of all fuels, including the cost of greenhouse gas allowances, is projected to be higher in the S.139 case. Compared with the projected prices for 2025 in the reference case, coal prices are projected to be 412 percent higher, natural gas prices 77 percent higher, and electricity prices 55 percent higher. The projected price increase for coal is attributable solely to the projected emissions allowance price, whereas both the emissions allowance price and higher demand contribute to the projected increase in natural gas prices.

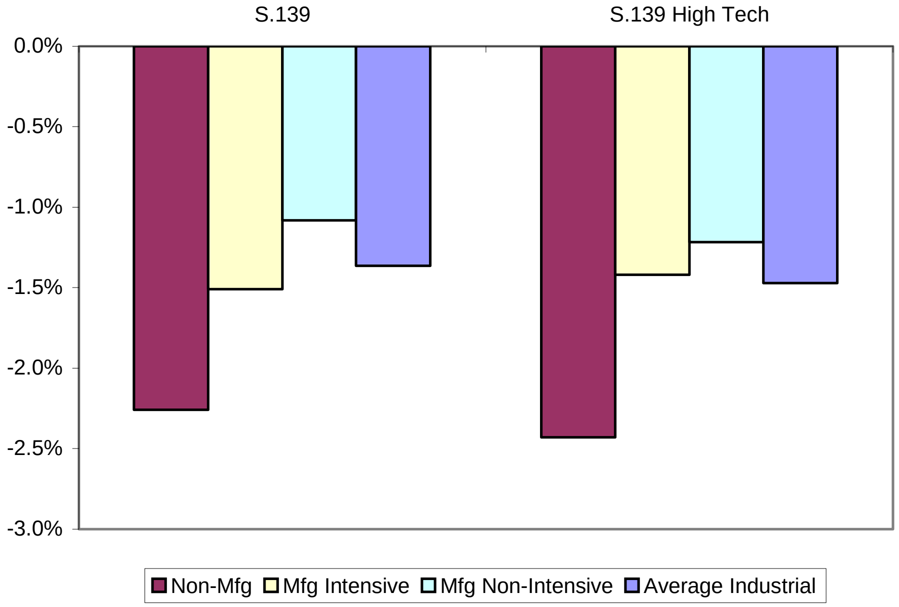
Compared with the reference case in 2025, industrial output is $138 billion (1.4 percent) lower in the S.139 case (Figure 4.16). The non-manufacturing sector incurs the largest percentage reduction in value of shipments, with shipments in the S.139 case 2.3 percent lower than in the reference case, followed by

Figure 4.15. Industrial Energy Prices in Alternative Scenarios (index, 2001 = 1.0)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C, and ML_HT.D050503A.

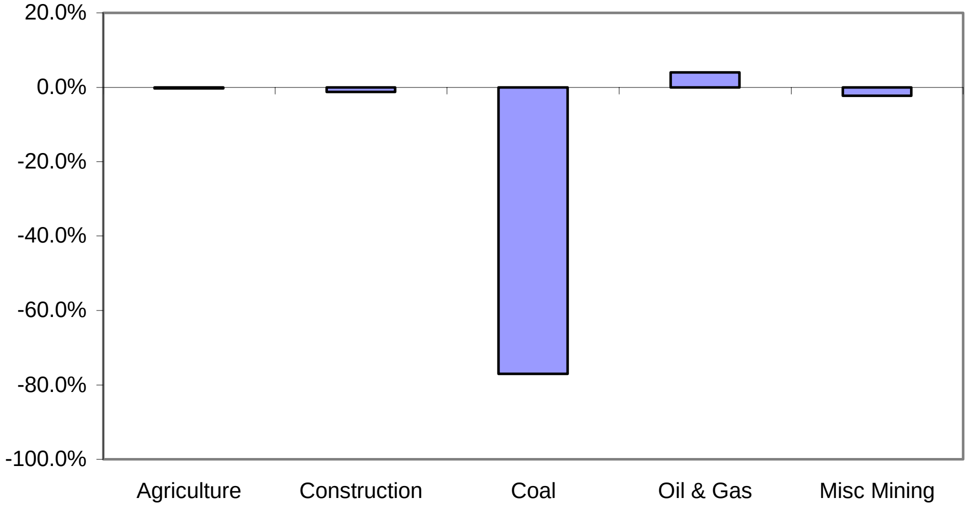
Figure 4.16. Change in Industrial Value of Shipments Compared with Reference Case, 2025 (percent change from reference case)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303, MLBILL.D050503A, and ML_HT.D050503A.

the energy-intensive manufacturing industries, which are 1.5 percent lower than in the reference case. The non-manufacturing result is due to the countervailing impact of an increase in the value of shipments of oil and gas being more than offset by a large fall in the value of coal shipments (Figure 4.17). While the value of oil and gas shipments is projected to increase by 4 percent, the value of coal shipments is projected to be 77 percent lower than in the reference case.

Figure 4.17. Change in Value of Shipments for the Non-Manufacturing Sectors in the S.139 Case Relative to the Reference Case, 2025 (percent change from reference case)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Within the manufacturing sector, the hardest hit industries are aluminum, bulk chemicals and steel, all of which see their shipments in 2025 fall by more than 2.6 percent in the S.139 case compared with the reference case (Figure 4.18). These three industries participate in highly competitive international markets and would be expected to lose markets if domestic energy prices increase relative to foreign energy prices. Projections of lower industrial output and higher energy prices reduce the projections for delivered energy consumption in the industrial sector by 1.8 quadrillion Btu (5.2 percent) in the S.139 case (Figure 4.19).

Coal consumption is projected to drop sharply in the two S.139 cases, given its extreme price disadvantage. In the S.139 case, coal consumption in 2025 is lower by 383 trillion Btu (19 percent) than in the reference case. About two-thirds of the projected reductions in coal consumption are due to projected reductions in boiler fuel use, with the remainder due to reduced use of metallurgical coal in the steel industry.

The industrial sector consumes coal mainly as a boiler fuel and for production of coke in the iron and steel industry. For example, 67 percent of manufacturing consumption of coal was used in boilers in 1998.[140] Coal-fired boilers have substantially higher capital costs than do gas-fired boilers, because of their materials handling requirements. For large steam loads, however, coal's price advantage over natural gas offsets its capital cost disadvantage in the reference case. In the carbon reduction cases, coal suffers

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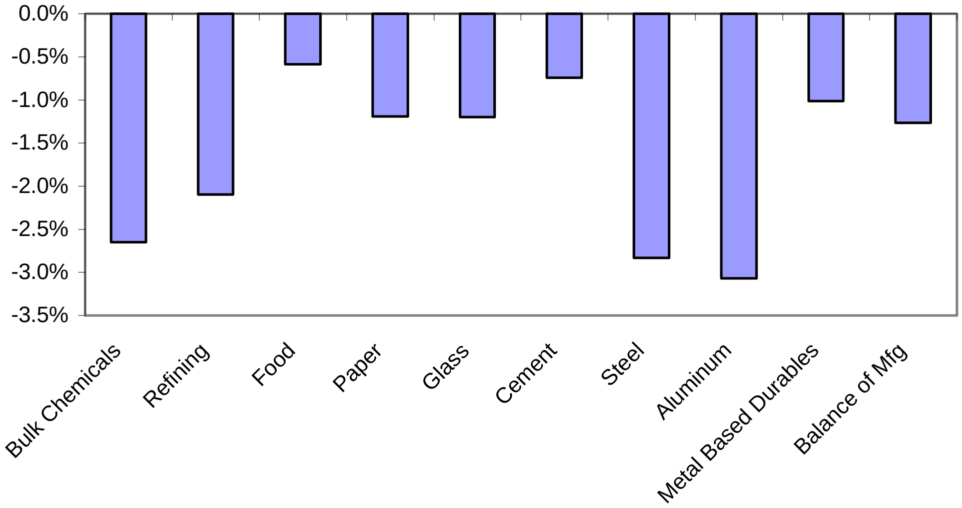
[140] Energy Information Administration, *Manufacturing Consumption of Energy 1998*, http://www.eia.doe.gov/emeu/mecs/mecs98/datatables/d98n6_2.htm.

from both a capital cost and a fuel cost disadvantage. As a result, a substantial amount of boiler fuel use switches from coal to natural gas and petroleum products.

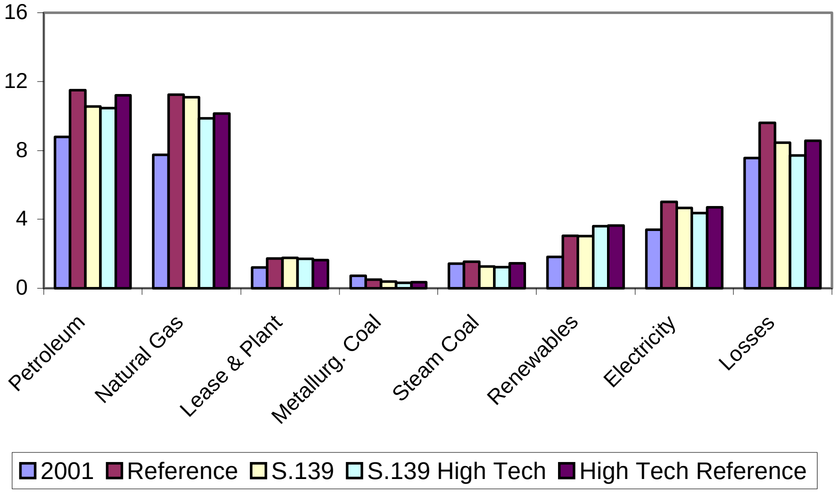
The steel industry uses coal coke in the steel production process. The coal coke is either produced domestically from metallurgical coal or is imported from other countries. In the S.139 case, metallurgical coal consumption is projected to be 21 percent lower than the reference case in 2025. The reduction has several causes: substitution of natural gas in production processes, replacement of domestic coke

Figure 4.18. Change in Value of Shipments for the Manufacturing Sectors in the S.139 Case Relative to the Reference Case, 2025 (percent change from reference case)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure 4.19. Industrial Energy Consumption in Alternative Scenarios (quadrillion Btu)



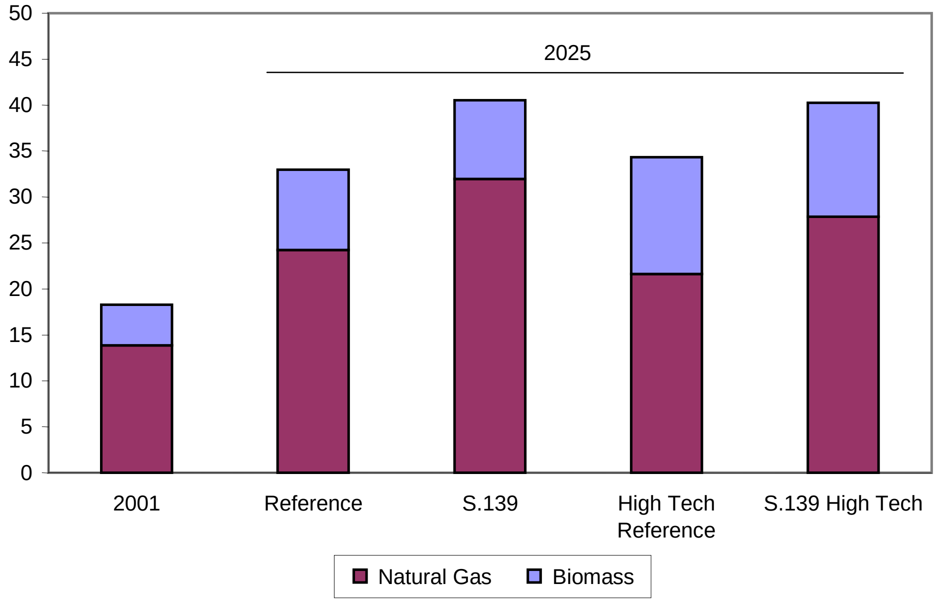
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C, and ML_HT.D050503A.

production with coke imports, replacement of some coke-based steel production capacity with electricity-based capacity, and reduced production of domestic steel.

Natural gas consumption is subject to two countervailing effects. The effect of generally higher energy prices, and consequently lower levels of industrial activity, is to reduce natural gas consumption. On the other hand, due to its lower carbon content, natural gas prices do not increase by as much as the prices of competing fuels. Since electricity prices are also higher, there is a greater incentive to use combined heat and power technologies to reduce purchased electricity requirements. Consequently, there is an incentive to increase use of natural gas.

Compared with the reference case, additions to industrial (including refining and oil and gas production) natural-gas-fired combined heat and power capacity are projected to increase by more than 70 percent in the S.139 case (Figure 4.20). In the reference case, natural-gas-fired combined heat and power capacity is projected to increase by 10.3 gigawatts (75 percent) by 2025, while in the S.139 case, natural gas capacity is projected to increase by 18.0 gigawatts (128 percent). In the S.139 case, industrial natural gas consumption is projected to be about the same as in the reference case because the impact of increased combined heat and power use offsets the reduction caused by lower industrial output.

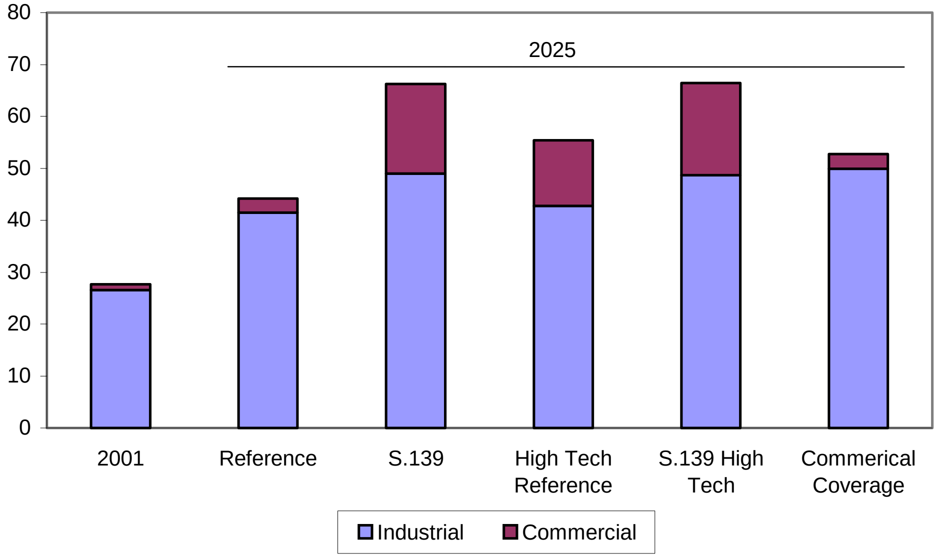
Figure 4.20. Industrial Combined Heat and Power Capacity, 2001 and 2025 (gigawatts)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C,and ML_HT.D050503A.

The buildings sector, which consists of the residential and commercial sectors, also reacts to the improved economics of combined heat and power in the S.139 case. Buildings and industrial combined heat and power capacity for several cases are shown in Figure 4.21. Note that in the S.139 case, the commercial sector is not covered by the emissions restraints. The commercial sector does incur sharply higher electricity prices due to cost increases in the electricity sector. At the same time, the effective natural gas price does not reflect the carbon price. Consequently, additional combined heat and power becomes an attractive option. In the S.139 case, the buildings sector in 2025 adds 16.2 gigawatts of total combined heat and power capacity, compared with 1.6 gigawatts in the reference case. However, in the commercial

Figure 4.21. Total End-Use Combined Heat and Power Capacity, 2001 and 2025 (gigawatts)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C, ML_HT.D050503A, and ML_COVER_K.D050603A.

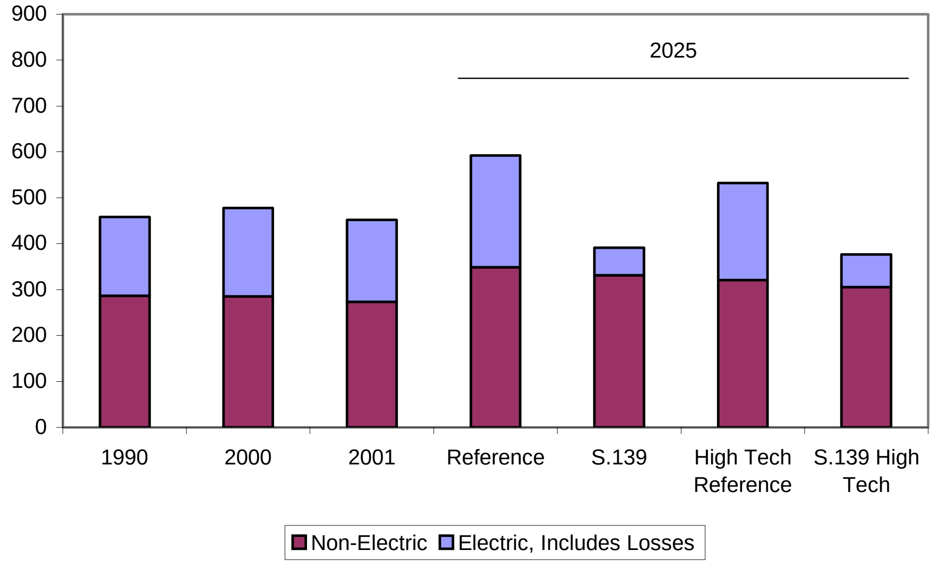
coverage case, where both electricity and natural gas prices are higher for the commercial sector, total combined heat and power capacity additions in the buildings sector are reduced to only 1.8 gigawatts.

In the reference case, industrial carbon dioxide emissions are projected to be 140 million metric tons higher in 2025 than they were in 2001 (Figure 4.22). Emissions attributable to increased electricity consumption account for almost half the increase. In the S.139 case, electricity-based carbon dioxide emissions in 2025 are 183 million metric tons (75 percent) lower than in the reference case. In the S.139 case, total industrial carbon dioxide emissions are projected to be 391 million metric tons, which is 15 percent lower than industrial sector emissions in 1990 (458 million metric tons).

Part of the reduction in electricity-based carbon dioxide emissions for the industrial sector is due to 7 percent lower electricity consumption in the S.139 case. The largest portion of the reduction results from sharply lower carbon intensity of electricity production. In the reference case, approximately 16.6 million metric tons carbon equivalent is emitted per quadrillion Btu of energy consumption in the electricity sector in 2025, as compared with only 4.6 million metric tons in the S.139 case.

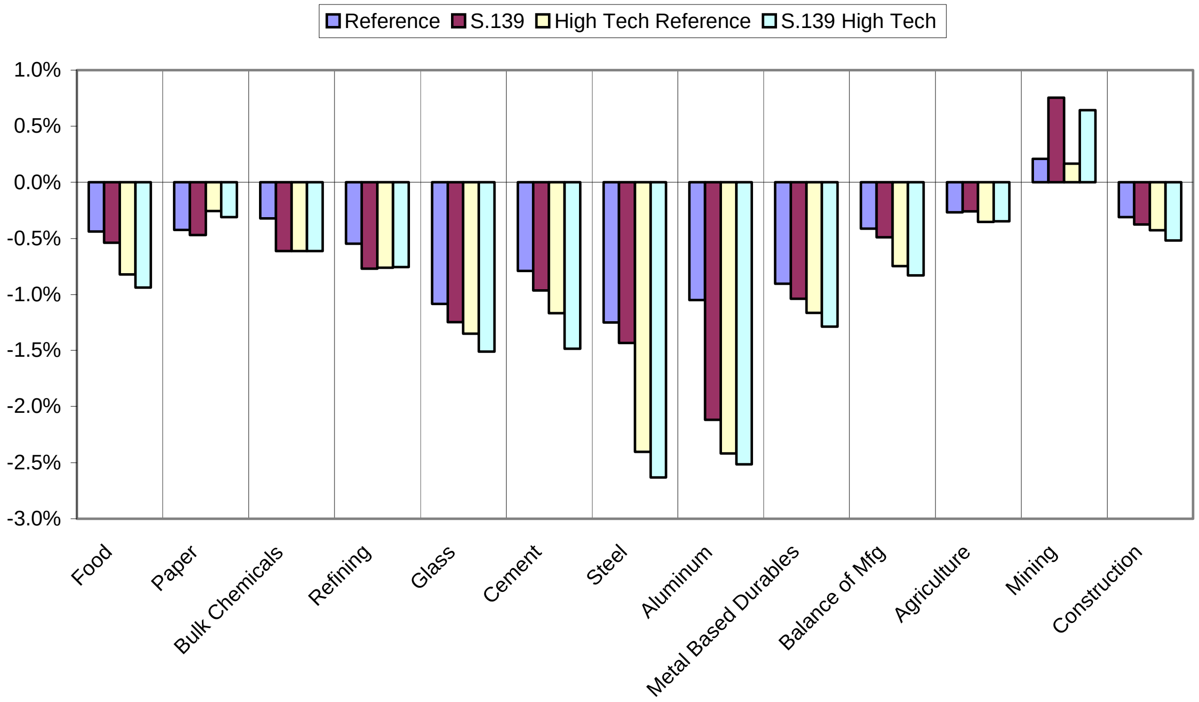
In 2001, approximately 6,023 Btu of energy was required to produce a dollar’s worth of industrial value of shipments. In the reference case energy intensity continues to fall, and in 2025 it is projected that only 4,379 Btu will be required for each dollar value of industrial shipment. The impact of S.139 on industrial energy intensity results from opposing effects. The effect of higher energy prices is to reduce energy intensity, whereas reduced or falling output growth limits the amount of new, less energy-intensive capital equipment that will be added to the existing stock, thereby retarding the rate of decline in energy intensity. Additional structural shifts in the composition of industrial output further reduce energy intensity. As shown in Figure 4.23, the change in energy intensity varies widely by industry. Even though agriculture is not a covered sector, this sector does respond to the higher electricity prices that all sectors would incur.

Figure 4.22. Industrial Carbon Dioxide Emissions in Alternative Scenarios, 1990, 2000, 2001, and 2025 (million metric tons carbon equivalent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C, and ML_HT.D050503A.

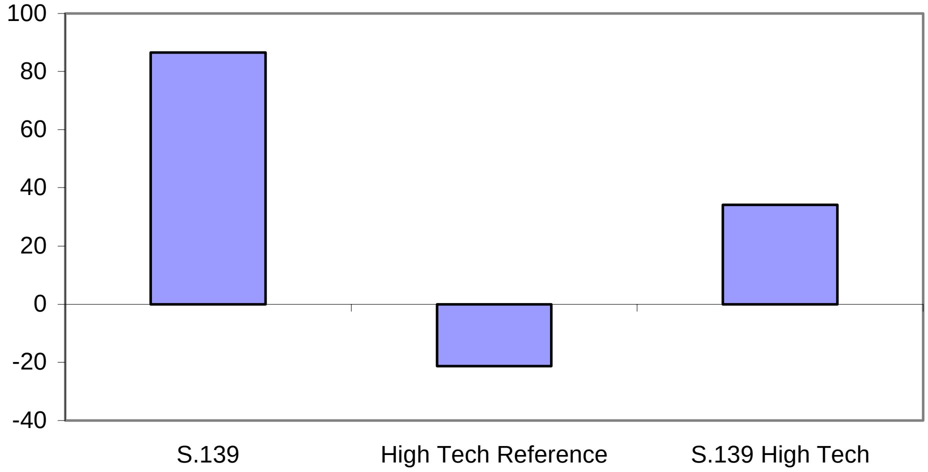
Figure 4.23. Industrial Energy Intensity Changes, by Subsector, in Alternative Scenarios (percent change from 2001)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Total expenditures for energy purchases in the industrial sector are projected to be $191 billion (2001 dollars) in 2025 in the reference case. In the S.139 case, the effects of higher energy prices are reduced by fuel switching and reduced consumption. Nevertheless, energy expenditures in 2025 are projected to be $86 billion (45 percent) higher in the S.139 case (Figure 4.24). The increased industrial energy expenditures equates to 60 percent of the manufacturing sector's capital expenditures of $144 billion in 2001.[141]

Figure 4.24. Industrial Energy Expenditures in 2025, Change from Reference Case (billion 2001 dollars)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C, and ML_HT.D050503A.

High Technology Cases

The projections of industrial sector energy consumption and expenditures in the S.139 case are based on the reference case assumptions about technology improvements and likely industrial responses to higher energy prices. A more optimistic technology outlook would reduce energy consumption and expenditures. The S.139 high technology case examines this possibility by imposing the high technology assumptions that were used in the *Annual Energy Outlook 2003.*

In the S.139 case, industrial primary energy consumption is 3.0 quadrillion Btu lower in 2025 than in the reference case (see Figure 4.19). In the S.139 high technology case, energy consumption is 5.0 quadrillion Btu lower in 2025 than in the reference case. Due to the lower level of energy demand, the average industrial energy price in the S.139 high technology case is 12 percent lower than in the S.139 case (see Figure 4.15). Energy intensity in the industrial sector (thousand Btu per 2001 dollar of value of shipments) declines by an average of 1.5 percent per year between 2001 and 2025 in the S.139 case, compared with an average decline of 1.3 percent in the reference case. If the technology outlook were more optimistic, as in the S.139 high technology case, the energy intensity decline would be 1.7 percent per year. For the paper industry, energy intensity does not decline quite as rapidly in the S.139 high technology case, due to an increase in biomass consumption (18 percent higher than the reference case in 2025).

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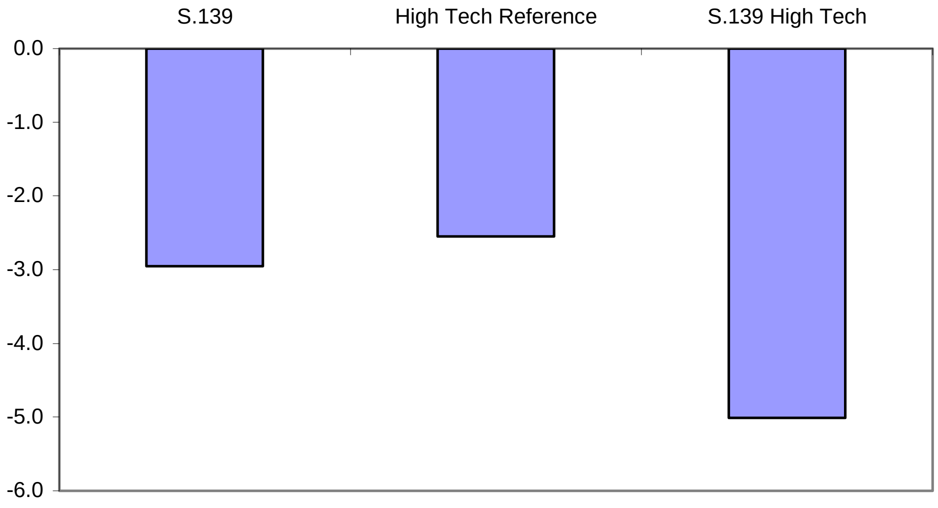
[141] Calculated from U.S. Department of Commerce, *Statistics for Industry Groups and Industries: 2001* (January 2003) using Table 5.

Industrial energy expenditures increase by $86 billion in 2025 in the S.139 case (see Figure 4.24). However, in the S.139 high technology case industrial energy expenditures increase by only 40 percent of the S.139 case level, or $34 billion, in 2025. This smaller increase in energy expenditures is due to the combined effects of lower industrial energy consumption and lower energy prices than projected in the S.139 case.

Imposing the high technology assumptions on the reference case would lower industrial energy consumption by 2.5 quadrillion Btu in 2025 (Figure 4.25). In comparison, the S.139 case with reference case assumptions regarding technology, projects industrial energy consumption to be 3.0 quadrillion Btu lower than the reference case in 2025. Imposing the industrial sector's high technology assumptions on the S.139 case yields an additional 2.1 quadrillion Btu of energy reductions in 2025. In short, the high technology case and the S.139 case yield energy reductions of the same order of magnitude. However, when the two cases are combined, the results are not quite additive. If the results were strictly additive, energy consumption in the S.139 high technology case would have been 5.5 quadrillion Btu lower than the reference case as opposed to the projected reduction of 5.0 quadrillion Btu in 2025.

Figure 4.25. Change in Industrial Primary Energy Consumption in High Technology Scenarios Relative to the Reference Case, 2025 (quadrillion Btu)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Transportation Sector

Background

Based on primary energy use in 2001, transportation sector carbon dioxide emissions were the highest among the end-use demand sectors and close to the level of carbon dioxide emissions from electricity generation. About 33 percent of all carbon dioxide emissions and 75 percent of carbon dioxide emissions from petroleum consumption originate from the transportation sector. In 2001, almost all (97 percent) of transportation sector emissions resulted from the consumption of petroleum products, which supply 97 percent of the energy consumed for transportation activities. Of the 13.6 million barrels per day oil equivalent consumed by the transportation sector in 2001, 62 percent was motor gasoline consumption in light-duty vehicles. Diesel fuel for heavy trucks (15 percent) and jet fuel for aircraft (11 percent), accounted for most of the remainder. Increased fuel use by light vehicles accounted for the majority (52 percent) of the growth in carbon dioxide emissions from 1990 to 2001, but emissions from heavy trucks and commercial aircraft increased at much faster rates, 2.4 percent per year and 4.4 percent per year, respectively. This compares to an average annual growth in light vehicle greenhouse gas emissions of 1.6 percent. The increase in greenhouse gas emissions for all modes is due primarily to increased demand for travel and relatively stagnant fuel efficiency

In order to examine the growth in transportation energy demand and transportation-related greenhouse gas emissions, the NEMS transportation model addresses all modes of travel, including light vehicle, heavy vehicle, air, rail, marine, and pipeline. Within the light vehicle mode, new vehicle fuel economy, sales, and travel are addressed for 12 vehicle size classes, 16 fuel and propulsion system configurations, and 63 vehicle subsystem technologies. Sales and stocks of vehicles are estimated for the household and fleet markets, and the vintage of vehicle stocks is tracked. The NEMS transportation model allows consumers to switch to either smaller size classes or smaller vehicles within a size class. These size class shifts are dependent on per capita income, fuel prices, and fuel economy. In addition to size class shifts, the NEMS transportation model also allows for consumer shifts away from light trucks (vans, sport utility vehicles, and pickups) to cars based on increases in fuel prices.

Heavy vehicles are modeled by fleet and non-fleet applications for 3 vehicle size classes (Class 3, Classes 4-6, and Classes 7&8). New heavy vehicle fuel economy is estimated for 4 fuel types using a menu of 37 subsystem technologies. The projections assume the new emissions standards for heavy trucks beginning in 2007 and also assume use of ultra-low-sulfur diesel fuel.

The NEMS transportation model also estimates travel by mode: light vehicle travel is determined by the cost of driving per mile and per capita income, heavy vehicle travel is a function of industrial output, and air travel is a function of per capita income and ticket price. In addition, the transportation model estimates travel demand by mass transit (bus and rail). Because S.139 does not provide policy specifically addressing the use of mass transit, it was assumed that Federal, State, or local governments would not institute programs designed to shift personal travel to mass transit as a strategy to further reduce greenhouse gas emissions in the transportation sector.

Reference Case

Similar to historic trends, projected transportation energy use shows a continued reliance on petroleum fuels, with petroleum fuels providing approximately 97 percent of the energy demanded by the sector throughout the forecast. Due to continued demand for transportation services, energy demand increases from 13.6 million barrels per day oil equivalent in 2001 to 21.7 million barrels per day oil equivalent in 2025. Light vehicle energy demand is responsible for the majority (64 percent) of the increased demand for energy in the transportation sector. The heavy truck and air modes do not show significant increases in energy demand until 2005, at which time heavy truck travel increases by 2.8 percent annually and air travel demand increases by 3.6 percent annually. Travel demand for all modes is projected to increased through 2025. Between 2001 and 2025, light vehicle travel is projected to increase by 2.3 percent annually, heavy vehicle travel by 2.6 percent annually, and air travel by 3.0 percent annually.

Vehicle efficiency in the reference case is projected to increase moderately over the projection period for all modes of travel. For light-duty vehicles, new vehicle efficiency increases from 24.1 miles per gallon in 2001 to 26.4 miles per gallon in 2025.[142] This increase reflects the new corporate average fuel economy (CAFE) standard for light trucks (22.2 miles per gallon by 2007) as well as fuel economy improvements resulting from the increased used of advanced technologies. Heavy-duty vehicle fuel economy increases

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[142] New light vehicle fuel economy estimates provided in this report reflect tested values.

from 6.0 miles per gallon in 2001 to 6.5 miles per gallon in 2025 in the reference case. Increases in heavy truck fuel economy are slowed significantly through 2010 as the new emissions standards come into effect in 2007. The 2007 emissions standards will require new emission control equipment, such as NO_x adsorbers, which will have an adverse effect on fuel economy. Aircraft efficiency is projected to increase from 51.2 seat-miles per gallon in 2001 to 60.7 seat-miles per gallon in 2025. Efficiency improvements are realized through improved load factors as well as increased aircraft efficiency.

The reference case projects that emissions of carbon dioxide from the transportation sector grow at an average annual rate of 2 percent through 2025, making it the largest and fastest growing source of new carbon dioxide emissions among the end use sectors. Comparatively, carbon dioxide emissions from the residential sector increase by 1.1 percent annually, carbon dioxide emissions from the commercial sector increase by 1.6 percent annually, and carbon dioxide emissions from the industrial sector increase by 1.1 percent annually. By 2010, greenhouse gas emissions from the transportation sector increase to 628 million metric tons carbon equivalent (a 22 percent increase over 2001 levels) and by 2025, greenhouse gas emissions increase to 826 million metric tons carbon equivalent (a 61 percent increase over 2001 levels).

S.139 Case

Under S.139, refiners and importers are required to purchase greenhouse gas emission allowances for petroleum products sold for transportation use. Refiners are also required to purchase allowances for fuel consumed in the refining of crude oil. The effective price (including greenhouse gas allowance costs) of petroleum products consumed in the transportation sector is higher in all greenhouse gas reduction cases because of the cost of the greenhouse gas allowances (see Chapter 6 for a detailed discussion of fuel price impacts). Among highway fuels, gasoline is the petroleum product most affected due to its large consumption in the transportation sector. As a result, there is a measurable impact on energy demand for transportation.

S.139 provides a framework for reducing transportation sector greenhouse gas emissions through the allocation of tradeable greenhouse gas credits for improved fuel economy. Under the bill, light vehicle manufacturers can earn greenhouse gas credits if their measured CAFE exceeds the CAFE standard by 20 percent in years 2010 and beyond. Manufacturers' decisions to participate will be driven by the required improvement in their CAFE, the number of allowances awarded, and the market value of those allowances. In order to achieve increases in CAFE, manufacturers might employ new technologies, downsize vehicles, or offer pricing incentives to shift consumers into more efficient vehicles. For this analysis, it is assumed that manufacturers will choose only to adopt new technologies in their efforts to increase vehicle fuel economy, thus preserving vehicle utility, comfort, performance, and occupant safety.

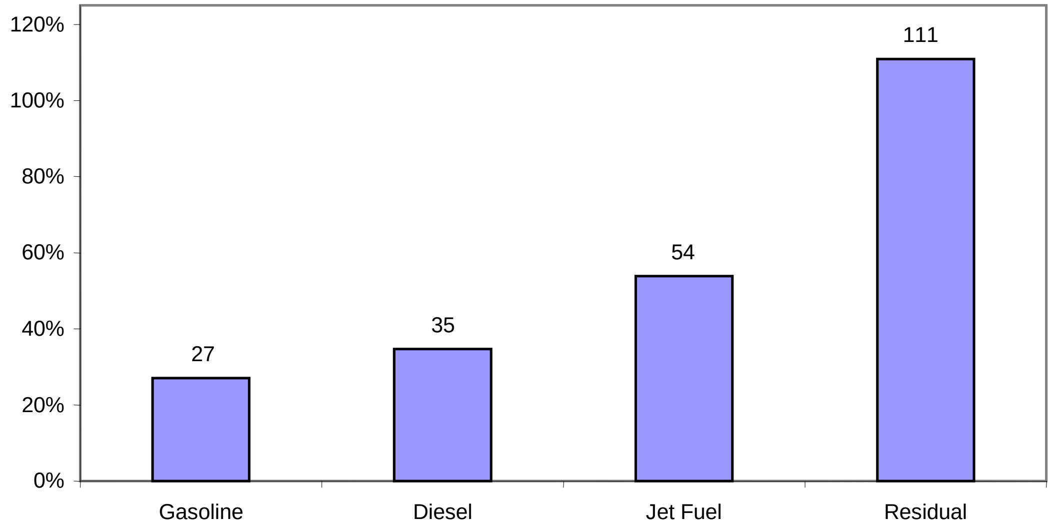
The NEMS transportation demand model estimates fuel economy through two separate submodules: (1) the Manufacturer Technology Choice Model (MTCM) and (2) the Consumer Vehicle Choice Model (CVCM). The MTCM is an engineering based model that examines a menu of 63 subsystem technologies for fuel economy improvement, performance improvement, or to meet legislative requirements (safety and emissions standards). Subsystem technology penetration is estimated by comparing technology cost to consumer willingness to pay for fuel economy improvement and/or increased horsepower. CAFE fines related to non-compliance also impact a manufacturers' decision to adopt new subsystem technology for fuel economy improvement. Subsystem technology adoption is estimated for 16 vehicle types (conventional gasoline, diesel, hybrid, fuel cell, etc.) by 12 vehicle size classes (6 car and 6 light truck). The CVCM estimates vehicle type market penetration by vehicle size class. This submodule employs a multinomial nested logit model with coefficients for 9 vehicle attributes (vehicle price, range, acceleration, fuel cost, fuel availability, maintenance cost, multi-fuel capability, battery replacement cost, and luggage space) that vary by size class.

To capture the impact of the CAFE provision in S.139, the NEMS transportation model was modified so that manufacturers evaluate the opportunity cost associated with meeting the 20 percent fuel economy improvement. As the model evaluates the choice decision for technology adoption, the opportunity cost associated with the potential fuel economy improvement is included in the cost equation, similarly to the way a manufacturer might evaluate a CAFE fine for noncompliance. The analysis reflects a gradual increase in participation by vehicle manufacturers over time, accounting for the relative difficulty manufacturers will experience in improving CAFE based on their vehicle sales mix. For example, in 2001, domestically manufactured Toyota and Honda passenger cars and imported Suzuki passenger cars had CAFE ratings that exceeded the current CAFE standard by 20 percent, but several other manufacturers failed to meet the standard, including BMW, Porsche, Lotus, and Fiat.[143] The variation in CAFE achieved by these manufacturers is a reflection of the mix of vehicles sold and the performance characteristics of those vehicles. The largest disparity in measured CAFE was between domestically produced Hondas (36.3 mpg) and imported Fiats (13.7 mpg).

Delivered energy prices for the transportation sector increase significantly in the S.139 case compared to the reference case (Figure 4.26). In the S.139 case, gasoline fuel price in 2001 constant dollars increases by 40 cents per gallon (27 percent) above the reference case price, while diesel increases by 52 cents per gallon (35 percent). By themselves, these increases in fuel prices move consumers toward more fuel-efficient vehicles signaling a market for increased fuel economy, which provides additional incentive for manufacturers in meeting the CAFE threshold. Jet fuel and residual fuel both experience significantly higher increases compared to the reference case at 54 percent (49 cents per gallon) and 111 percent (66 cents per gallon), respectively.

In the S.139 case, gasoline prices in 2010 are 13 percent higher when compared to the $1.42 per gallon price in the reference case. By 2025, gasoline prices increase to $1.90 per gallon, $0.40 higher than the

Figure 4.26. Increase in Transportation Fuel Prices in the S.139 Case Relative to the Reference Case, 2025 (percent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

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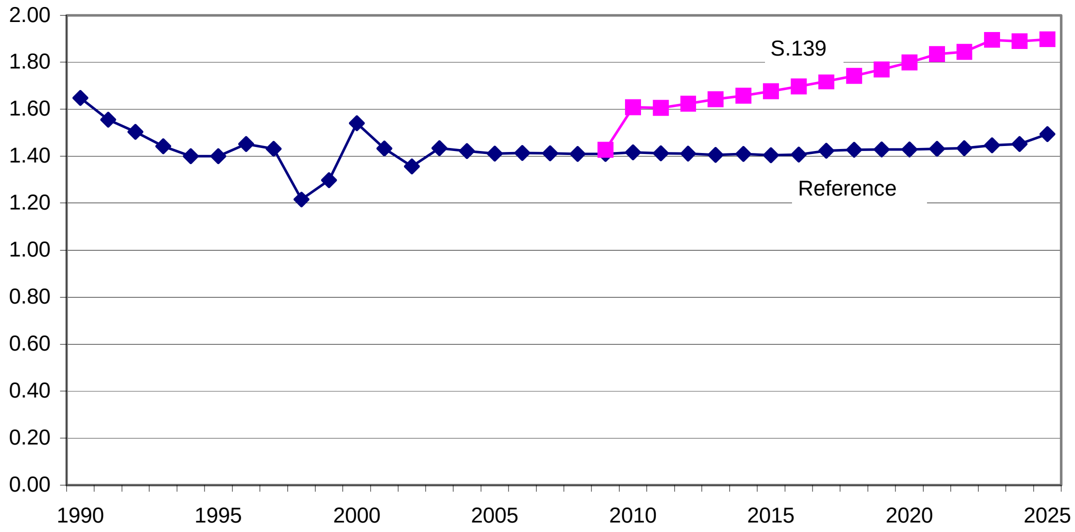
[143] U.S. Department of Transportation, National Highway Transportation Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, March 2002), p. 6.

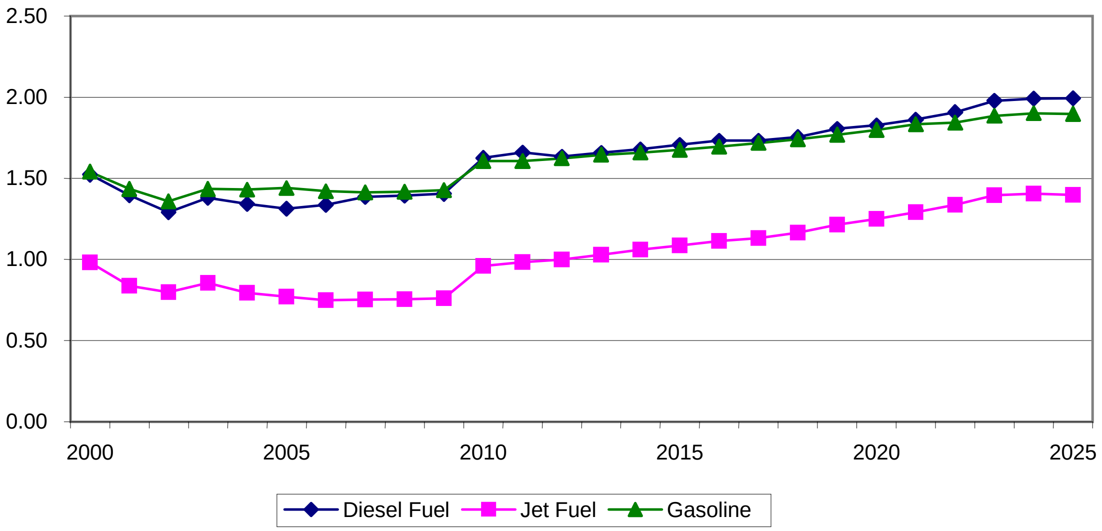
reference case (Figure 4.27). In addition, other petroleum-based fuel prices continue to increase over the projection period, as the transportation sector purchases additional greenhouse gas allowances to comply with the greenhouse gas cap. As shown in Figure 4.28, the other transportation fuels follow price trajectories similar to those for gasoline, with diesel fuel increasing to $1.99 per gallon by 2025. Petroleum product prices increase in 2003 as a result of higher world oil prices. The price increase subsides in subsequent years as the projected world oil price first decreases from current levels and then slowly rises.

Figure 4.27. Motor Gasoline Prices, 1990-2025 (2001 dollars per gallon)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

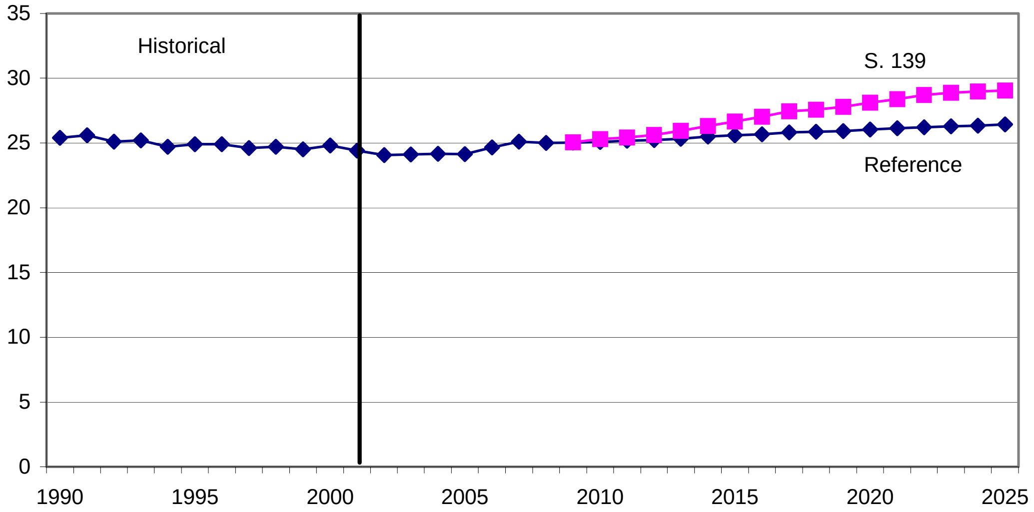
Figure 4.28. Transportation Fuel Prices in the S.139 Case (2001 dollars per gallon)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A.

In the S.139 case, new light vehicle fuel economy in 2025 is 29.0 miles per gallon, compared with 26.4 miles per gallon in the reference case (Figure 4.29). Increased fuel economy results from the adoption of new subsystem technologies to meet the 20 percent CAFE threshold for light-duty vehicle manufacturers to receive an allocation of greenhouse gas emission allowances under S.139, as well as a slight shift in demand for smaller size class vehicles. Due to the market for specialty vehicles (high-performance sports cars, for example), some manufacturers will opt not to participate in the CAFE credit program on certain nameplates. As a result, fuel economy for the new vehicle fleet does not achieve a full 20 percent increase above the required standard.

Figure 4.29. New Light Vehicle Fuel Economy (miles per gallon)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

New cars and light trucks contribute equally to the increase in average light vehicle fuel economy. Fuel economy for cars in 2025 increases from a reference case value of 30.1 miles per gallon to 32.9 miles per gallon in the S.139 case, an increase of 9.5 percent (Figure 4.30). New light truck fuel economy in 2025 increases from 23.5 miles per gallon in the reference case to 25.8 in the S.139 case, an increase of 9.5 percent. New car fuel economy in 2025 is 19.6 percent higher and new light truck fuel economy is 16.1 percent higher than the CAFE standards.

The impact of S.139 was also examined without the provision for providing an allocation credit for a 20 percent increase in new light vehicle fuel economy. In this case, fuel economy for new light-duty vehicles increases to 27.8 miles per gallon in 2025, compared to 29.0 miles per gallon in the S.139 with CAFE credit case. Compared to the CAFE standards, new car fuel economy in 2025 is 14.4 percent higher (31.5 miles per gallon) and new light truck fuel economy is 11.2 percent higher (24.7 miles per gallon).[144] Light-duty vehicle fuel use increases in this case relative to the S.139 case, which results in higher fuel prices due to increased carbon allowance costs. As a result of higher energy prices and lower vehicle efficiencies, the cost of driving increases, which in turn causes a decrease in light vehicle travel relative to the S.139 case.

The transportation sector is the only end use sector that does not reach 1990 carbon dioxide emissions levels by 2025 in the S.139 case (Figure 4.31), as is expected under a trading system, where more

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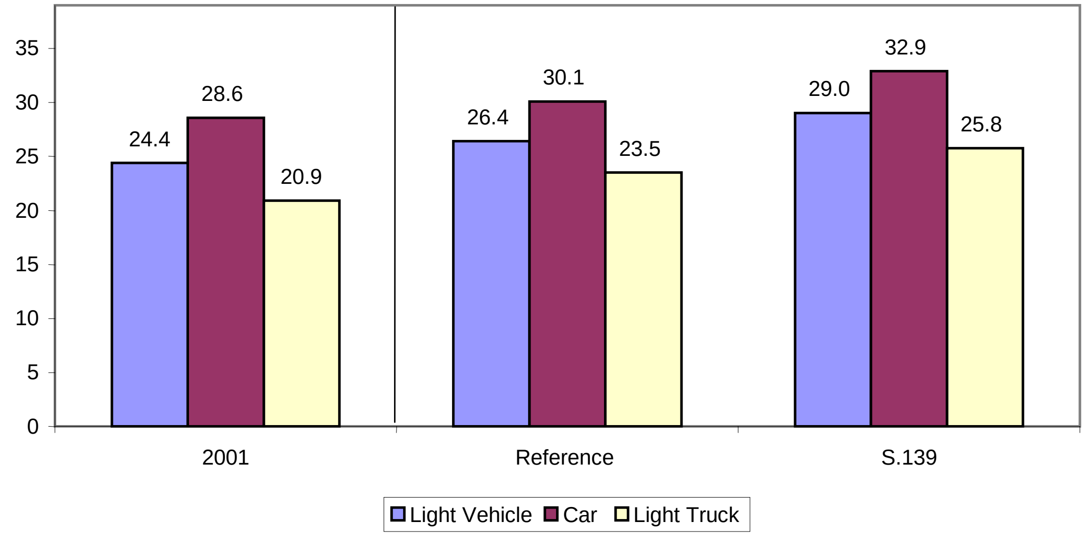
[144] Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System run MLBILL.D061703A.

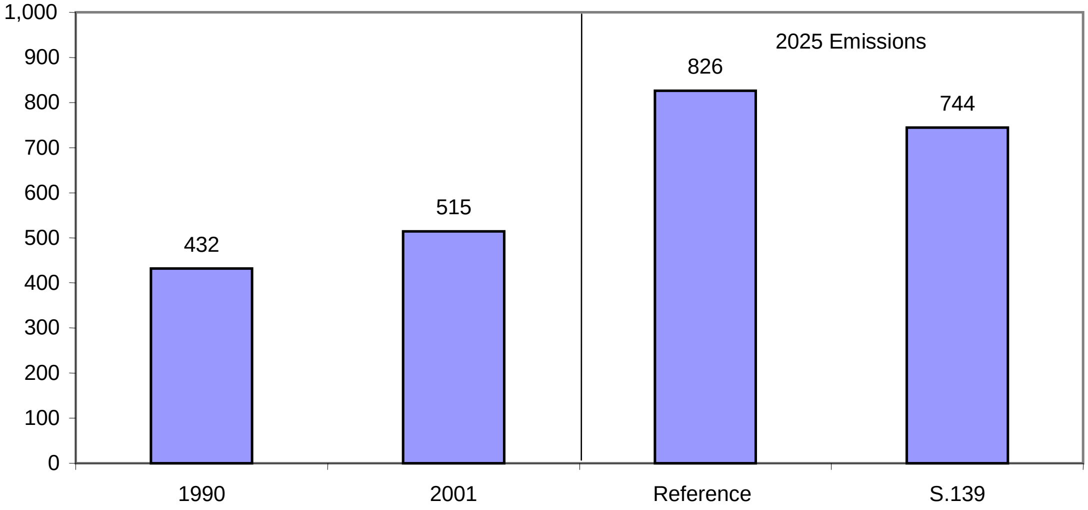
cost-effective reductions are achieved in other energy sectors. For this case, carbon dioxide emissions are reduced by 10 percent compared to the reference case. Almost all of the transportation-related greenhouse gas emission reductions in the S.139 case result from decreased energy demand in the light vehicle mode. In the S.139 case, light vehicle energy use in 2025 is reduced by 12 percent (1.68 million barrels per day), accounting for 87 percent of the total reduction in greenhouse gas emissions from the transportation sector. The remainder of the total reduction in transportation-related greenhouse gas emissions results from reduced energy demand for heavy trucks (accounting for 6.0 percent of the sector's total emissions

Figure 4.30. New Light Vehicle Fuel Economy in 2025 Compared to 2001 (miles per gallon)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure 4.31. Transportation Carbon Dioxide Emissions in 2025 Compared to 1990 and 2001 Levels (million metric tons carbon equivalent)

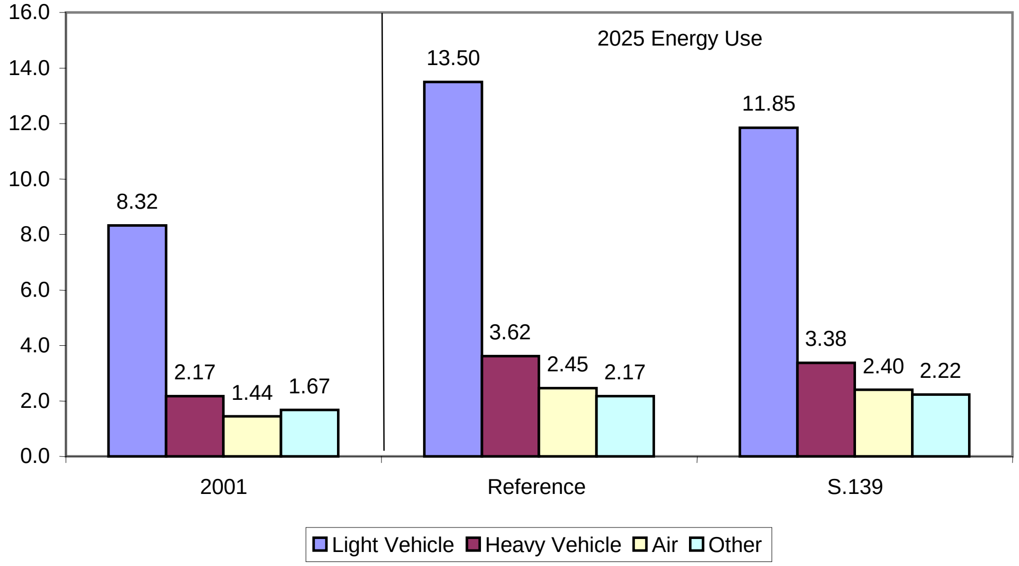


Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

reduction), air travel (2.6 percent), and other travel modes (4.2 percent). For light-duty vehicles, decreased energy use results from increased fuel economy and reduced travel. As discussed above, new vehicle fuel economy increases by 2.6 miles per gallon over the reference case by 2025, and the average fuel economy for all vehicles in the fleet increases by 1.3 miles per gallon (6 percent). The average annual growth in light vehicle travel decreases from 2.3 percent in the reference case to 1.9 percent in the S.139 case. This equates to an annual reduction in light vehicle travel of 338 billion miles (8.2 percent) by 2025.

Total energy demand by mode is illustrated in Figure 4.32. Higher fuel prices do not result in a significant change in heavy truck efficiency because of the high power requirements of the engines. As a result, by 2025, new heavy truck fuel economy in the S.139 case increases by 4 percent, to 6.8 miles per gallon. The main source of reductions in diesel fuel use is the response to overall lower economic activity and demand for goods, which leads to lower freight travel. Reduced industrial output results in a 1 percent decrease in heavy truck travel by 2025, relative to the reference case.

Figure 4.32. Transportation Energy Use by Mode (million barrels per day)



Note: Other includes rail, marine, and lubricants.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

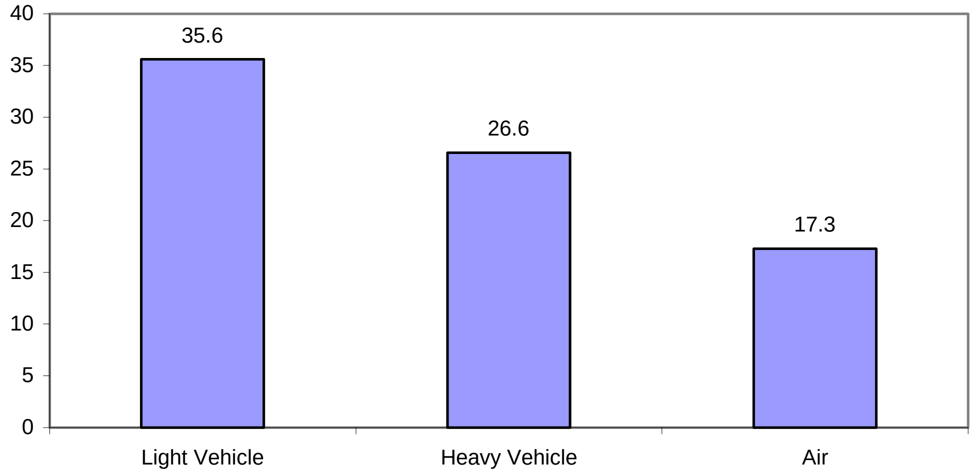
Personal, business, and international air travel are expected to decline marginally (1.2 percent) due to higher ticket prices and decreased disposable income compared to the reference case. Aircraft efficiency, measured as seat-miles per gallon, is projected to increase by 1.0 percent over the reference case by 2025.

The remaining reductions in energy use are due primarily to reduced freight shipments by rail, which result from decreased coal shipments as utilities shift demand to natural gas and other low greenhouse gas fuel sources to generate electricity. In the S.139 case, 2025 freight travel by rail is 32 percent lower than in the reference case.

As a result of the increased fuel prices, fuel expenditures increase for all modes of travel, with the exception of rail, in the S.139 case compared to the reference case. Even though light vehicle travel decreases and light vehicle fuel economy increases, by 2025 annual light vehicle fuel expenditures in the S.139 case are $35.6 billion (11.5 percent) higher than in the reference case in constant 2001 dollars (Figure 4.33). Compared to the reference case, annual fuel expenditures for heavy truck travel increase by

$26.6 billion (34.8 percent) by 2025 in S.139 case and fuel expenditures for air travel increase by $17.3 billion (50.7 percent).

Figure 4.33. Increase in Transportation Fuel Expenditures in the S.139 Case Relative to the Reference Case, 2025 (billion 2001 dollars)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

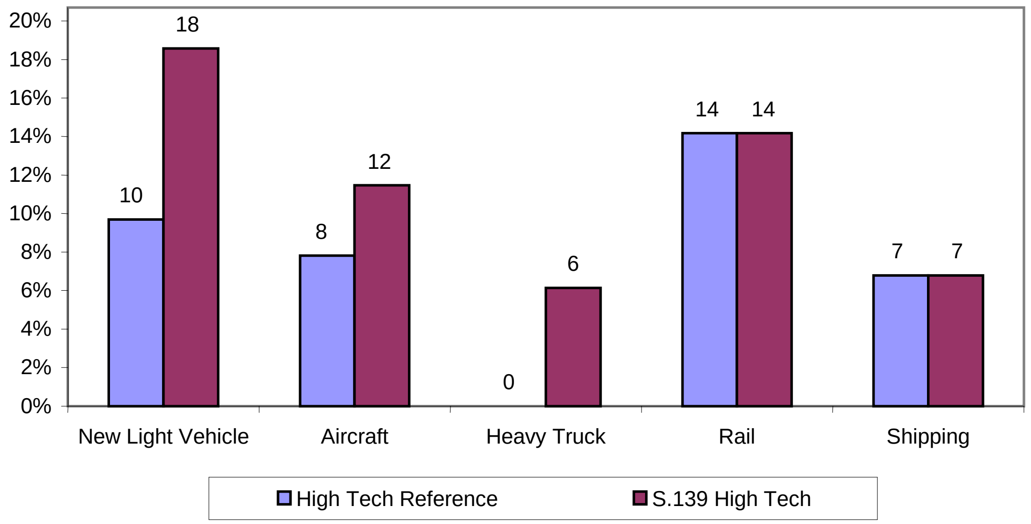
S.139 High Technology Case

The transportation assumptions for the high technology cases reflect lower costs, higher efficiencies, and earlier introduction dates for new technologies. The high technology reference case is based on these assumptions alone, whereas the S.139 high technology case includes the optimistic technology assumptions and the manufacturer CAFE incentive proposed in S.139. Figure 4.34 illustrates the percent increase in efficiency by mode of travel for the high technology cases relative to the reference case. For the high technology reference case no additional fuel efficiency improvement is projected for new heavy vehicles due to the lack of economic incentives (higher fuel prices) and due to the significant investment in emission control technologies needed to meet the Environmental Protection Agency’s 2007 and 2010 Rules. Relative to the high technology reference case, efficiency improvements are realized for the light vehicles, heavy vehicles, and aircraft in the S.139 high technology case. The more optimistic assumptions reflected in the S.139 high technology case provide the economic incentive needed to increase the penetration of advanced fuel efficiency technologies in the heavy truck market. Efficiency of rail and marine travel shows closely matched improvements in the two high technology cases, because the maximum efficiency improvement is achieved in both cases. In the S.139 high technology case, new light vehicle fuel economy increases by 18.6 percent (4.9 miles per gallon), heavy truck efficiency increases by 6.1 percent (0.4 miles per gallon), aircraft efficiency (seat miles per gallon) increases by 11.5 percent, rail efficiency (tons-miles per Btu) increases by 14.2 percent, and marine efficiency (ton-miles per Btu) increases by 6.8 percent relative to the reference case.

As shown in Figure 4.35, the lower costs and advanced introduction dates assumed in the high technology cases provide light vehicle manufacturers the ability to achieve higher fuel economies in their new vehicles. Compared to the reference case, by 2025 new vehicle fuel economy is 2.5 miles per gallon higher (9.6 percent) in the high technology reference case and 4.9 miles per gallon higher (18.5 percent) in the S.139 high technology case. The majority of the fuel economy improvement gained in the high technology reference case occurs between 2010 and 2015, but in the S.139 high technology case fuel economy continues to increase as a result of the CAFE credit program and higher fuel prices realized from enacting the proposed S.139 legislation. As a result of this, as well as efficiency improvements realized across all sectors, carbon allowance prices are lower in this case, leading to lower fuel prices than in the S.139 case.

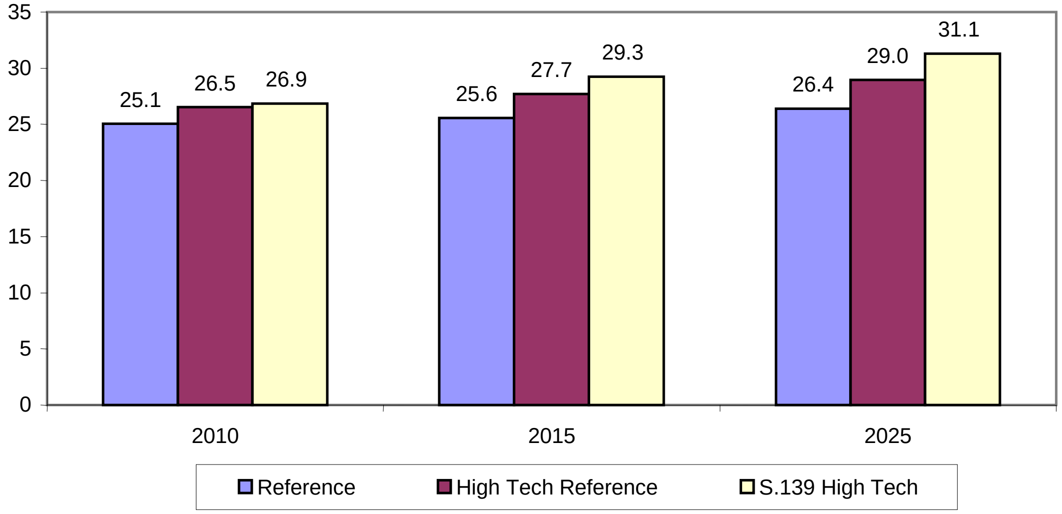
Figure 4.36 shows transportation fuel prices for the reference, high technology reference, S.139, and S.139 high technology cases. For the high technology reference case, all fuel prices, except residual fuel, decrease relative to the reference case as a result of reduced energy use achieved from improved efficiency. Fuel prices for both cases evaluating proposed S.139 legislation show the increases in fuel

Figure 4.34. Efficiency Improvements by Mode in the High Technology Cases Relative to the Reference Case, 2025 (percent)



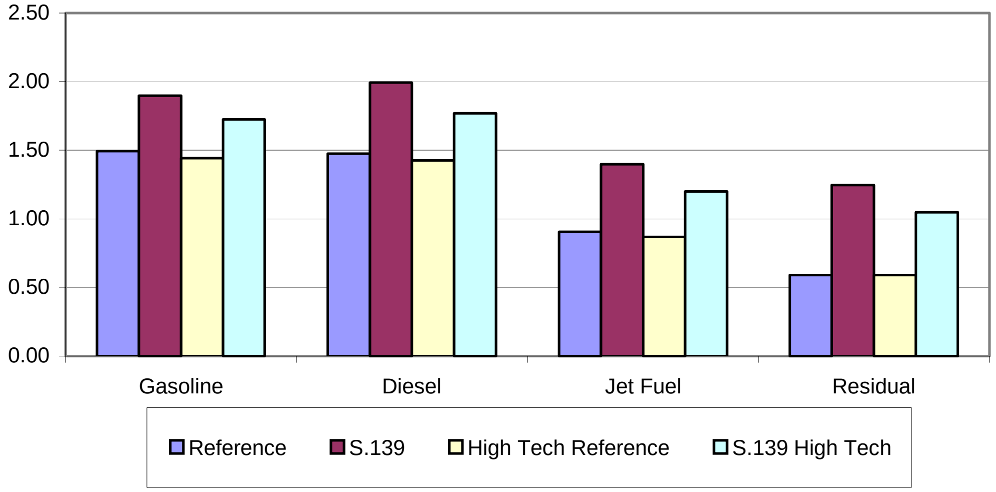
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Figure 4.35. New Light Vehicle Fuel Economy Across Cases (miles per gallon)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Figure 4.36. Transportation Fuel Prices Across Cases, 2025 (2001 dollars per gallon)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, MLBILL.D050503A, and ML_HT.D050503A.

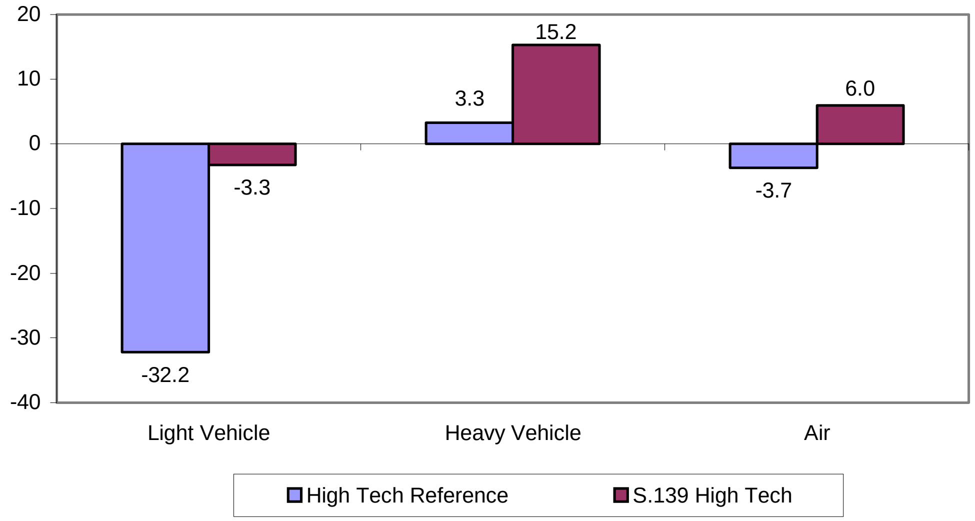
price resulting from imposed caps on greenhouse gas emissions. Comparing the S.139 and S.139 high technology cases, residual fuel and jet fuel show the largest declines in price in 2025, decreasing by 17.1 percent and 15.0 percent, respectively, in the high technology case.

Compared to the high technology reference case, vehicle efficiency increases in the S.139 high technology case, but the higher fuel prices result in increased travel costs, which reduce travel demand. The average annual growth in light vehicle travel is 2.2 percent in the S.139 high technology case, 0.1 percentage points lower than the growth projected in the reference case. This equates to an annual decrease in light vehicle travel of 134 billion miles (3 percent) by 2025 in the S.139 high technology case compared to the high technology reference case. In the S.139 high technology case, highway freight and air travel remains at levels similar to those projected in the high technology reference case, while 2025 rail and domestic marine travel decrease relative to the high technology reference case.

Figure 4.37 shows 2025 incremental fuel expenditures for the high technology cases compared to the reference case. Because fuel prices decrease and vehicle efficiency increases in the high technology reference case relative to the reference case, fuel expenditures for light vehicle and air travel decrease relative to the reference case. By 2025, annual light vehicle fuel expenditures in the S.139 high technology case increase by $28.9 billion in constant 2001 dollars relative to the high technology reference case. In 2025, annual fuel expenditures for heavy truck travel increase by $11.9 billion and air travel fuel expenditures increase by $9.7 billion by 2025 in the S.139 high technology case relative to the high technology reference case.

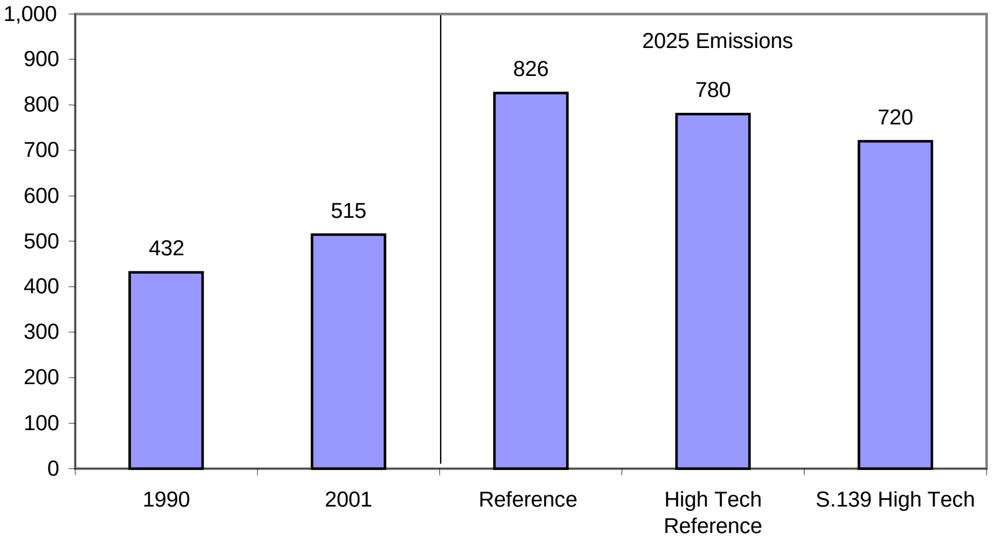
As a result of the increased fuel efficiency in highway vehicles and aircraft in the high technology reference case, 2025 carbon dioxide emissions are reduced 46 million metric tons in the transportation sector relative to the reference case. As illustrated in Figure 4.38, carbon dioxide emissions from the transportation sector are reduced an additional 60 million metric tons (7.7 percent) in the S.139 high technology case when compared to the high technology reference case. In 2025, transportation carbon dioxide emissions projected for the S.139 high technology case exceed 2001 levels by 205 million metric tons carbon equivalent (40 percent).

Figure 4.37. Change in Transportation Fuel Expenditures in the High Technology Cases Relative to the Reference Case, 2025 (billion 2001 dollars)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE_HT.D052003C , and ML_HT.D050503A.

Figure 4.38. Transportation Carbon Dioxide Emissions in 2025 Compared to 1990 and 2001 Levels (million metric tons carbon equivalent)



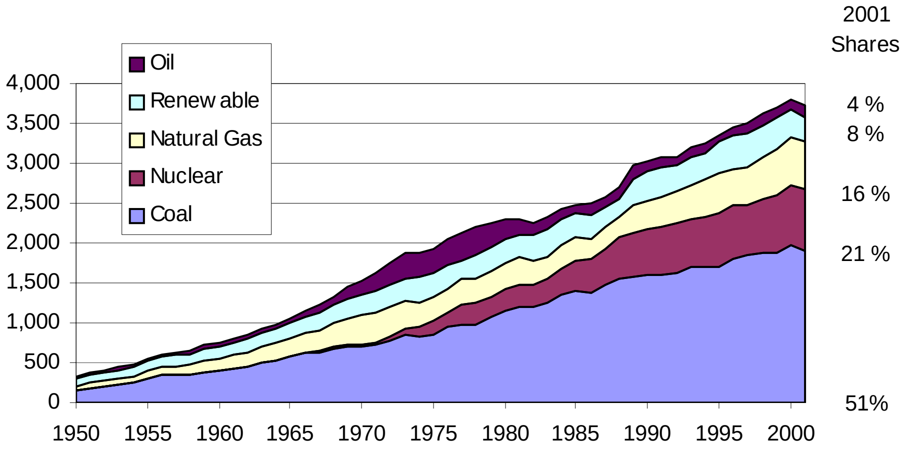
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C , and ML_HT.D050503A.

5. Electricity Supply

Background

Historically, the electricity supply sector has used a diverse mix of fuels to meet consumers' electricity needs (Figure 5.1). The fuels used include coal, oil, natural gas, nuclear, hydroelectric, wood, waste, geothermal, solar, and wind. In the early 20th century the industry began with small hydroelectric facilities built to provide electricity for city lights. As the uses of and demand for electricity grew, the industry increasingly turned to fossil fuels—coal, oil, and natural gas. By 1950 fossil fuels accounted for nearly 70 percent of total U.S. electricity generation, and their share continued to grow, exceeding 82 percent by 1970. Through the 1970s and 1980s the growth of nuclear and hydroelectric power, together with the declining use of oil, reduced the role of fossil fuels in electricity production. By 1990, the share of electricity accounted for by fossil fuels was just under 70 percent. Since 1990, however, almost all the new capacity added has been fueled by natural gas. Even with the increasing output from existing nuclear plants and the growth in some renewable technologies—particularly wind—the share of electricity accounted for by fossil fuels has again started to grow.

Figure 5.1. Electricity Generation by Fuel, 1950 to 2001 (billion kilowatthours)



Source: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), Table 8.2a.

Because of its strong dependence on fossil fuels, the electricity supply sector accounted for 39 percent of total U.S. carbon dioxide emissions in 2000.[145] As a result, the imposition of a greenhouse gas emissions limit will affect all aspects of the electricity supply sector. It will affect the choice of fuels used to produce electricity, the types of plants built to meet growing consumer electricity needs, the future price of electricity that consumers will face and their responses to them, and the level of other emissions—sulfur dioxide, nitrogen oxide, and mercury—often associated with electricity production from fossil fuels. As might be expected, numerous uncertainties exist. Key uncertainties for the electricity sector include the role that new technologies might or might not play, and how emission allowances might be treated in electricity pricing in various regions of the country.

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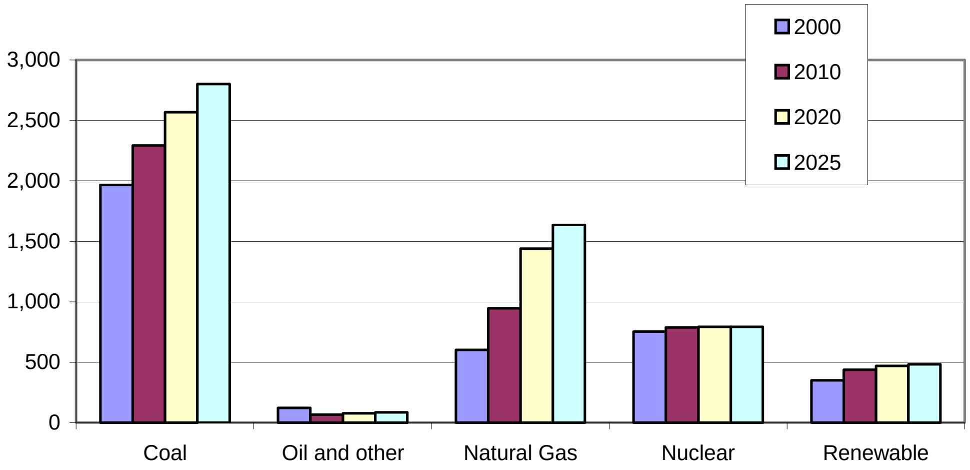
[145] While S.139 targets all greenhouse gases, the balance of this chapter will focus on energy-related carbon dioxide emissions.

Generation by Fuel

Over the next 20 years, without a greenhouse gas emissions cap, the power sector is projected to remain heavily dependent on fossil fuels, particularly coal, and, to a growing degree, natural gas. In the reference case, fossil fuels are projected to account for 76 percent of total generation in 2020 and 78 percent in 2025 (Figure 5.2). The vast majority of new power plants built over the next 20 years are expected to be fueled by natural gas. Relative to other technologies, new natural gas combustion turbine and combined cycle plants are less expensive to build, and their improving efficiencies help to offset the higher cost of natural gas relative to other fuels, such as coal. As the price of natural gas rises over time, new coal plants are projected to become increasingly economical later in the projections. Without a greenhouse gas emissions limit, new plants using non-carbon-based fuels such as renewables and nuclear are not expected to be widely competitive when new generating capacity is needed. New renewable plants, particularly new wind plants, are projected to play a role in some areas, but not enough to increase their share of total generation. Total renewable generation is projected to accounted for 9.8 percent of total generation in 2010, 8.9 percent in 2020 and 8.4 percent in 2025. Between 2000 and 2025 wind capacity, stimulated in part by State and Federal programs, is projected to more than quadruple; however, generation from wind plants still is expected to account for just over 0.5 percent of total generation in 2025.

Figure 5.2. Reference Case Electricity Generation by Fuel, 2000, 2010, 2020, and 2025 (billion kilowatthours)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System run MLBASE.D050303A.

The role of non-carbon-based fuels in the generation of electricity is projected to change dramatically if a greenhouse gas emissions cap is imposed. In addition, generation from fossil technologies equipped with carbon capture and sequestration equipment is also expected to grow (Table 5.1). As discussed in previous chapters, the electric power sector is projected to account for a large portion of the greenhouse gas emission reductions needed to meet the cap on the covered sectors. To do so, the electric power sector will have to increasingly turn to low- or zero-carbon technologies.

To comply with the greenhouse gas limit the electric power sector is projected to turn away from coal generation towards renewable, natural gas and nuclear generation (Figures 5.3 and 5.4). By 2025, coal generation is projected to be 2,243 billion kilowatthours (80 percent) lower in the S.139 case than in the reference case. In contrast, renewable generation is projected to be 699 billion kilowatthours

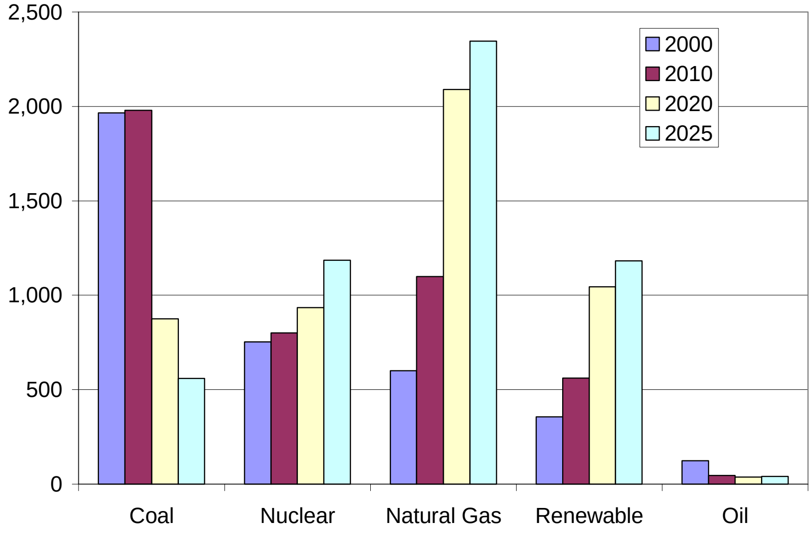
Table 5.1. Key Electricity Sector Results, 2010, 2020, and 2025

		2010				2020				2025			
	2000	**Refer-ence**	**S.139**	**Corp20**	**Corp80**	**Refer-ence**	**S.139**	**Corp20**	**Corp80**	**Refer-ence**	**S.139**	**Corp20**	**Corp80**
Generation By Fuel (billion kilowatthours)													
Coal	1,966	2,293	1,980	1,984	1,986	2,568	876	910	887	2,803	560	649	541
Oil and Other	121	63	46	45	45	73	45	46	45	81	47	47	47
Natural Gas	601	946	1,095	1,094	1,079	1,441	2,077	2,066	2,013	1,637	2,332	2,317	2,320
Nuclear	754	790	801	801	801	793	934	933	938	793	1,186	1,186	1,190
Renewable	356	442	566	564	565	474	1,051	1,064	1,065	489	1,188	1,184	1,200
Total	3,798	4,534	4,488	4,488	4,476	5,349	4,982	5,020	4,949	5,803	5,314	5,385	5,298
Generating Capacity (gigawatts)													
Coal	310.6	315.3	293.4	292.9	292.7	348.6	200.3	197.5	203.3	380.8	104.8	107.2	103.2
Coal with Sequestration	0.0	0.0	0.0	0.0	0.0	0.0	12.2	16.1	11.1	0.0	37.7	50.6	35.5
Coal Subtotal	*310.6*	*315.3*	*293.4*	*292.9*	*292.7*	*348.6*	*212.5*	*213.6*	*214.4*	*380.8*	*142.5*	*157.9*	*138.7*
Other Fossil Steam	136.0	79.0	81.8	81.7	82.1	73.0	65.9	68.0	63.3	72.2	54.1	55.1	56.4
Combined Cycle	46.0	181.3	208.0	209.1	208.1	265.9	306.7	310.6	305.2	311.1	305.0	309.2	303.5
Combined Cycle with Sequestration	0.0	0.0	0.8	0.9	1.0	0.0	45.4	42.7	30.3	0.0	102.1	104.4	92.8
Combined Cycle Subtotal	*46.0*	*181.3*	*208.9*	*210.0*	*209.1*	*265.9*	*352.1*	*353.3*	*335.5*	*311.1*	*407.1*	*413.6*	*396.3*
Combustion Turbine	81.8	131.7	128.5	128.9	128.8	153.3	126.7	126.6	126.1	169.5	123.4	123.9	123.7
Nuclear	98.0	98.7	100.3	100.3	100.3	99.0	117.2	117.2	117.7	99.0	149.2	149.2	149.7
Renewable	88.4	97.4	129.2	128.7	128.8	101.2	225.3	226.7	230.9	102.8	245.8	243.9	249.2
Other	19.8	22.1	22.1	22.0	22.1	32.2	25.5	25.3	25.0	38.2	25.5	25.5	25.1
Total	**780.6**	**925.6**	**964.2**	**964.5**	**963.9**	**1,073.4**	**1,125.1**	**1,130.7**	**1,112.9**	**1,173.7**	**1,147.6**	**1,168.9**	**1,139.0**
Electricity Demand (billion kilowatthours) and Prices (2001 cents per kilowatthour)													
Electricity Sales	3,438	4,104	4,050	4,056	4,039	4,848	4,467	4,525	4,423	5,246	4,653	4,770	4,621
Electricity Prices	6.89	6.40	6.96	6.96	7.23	6.66	8.83	8.43	9.05	6.71	9.79	9.05	9.82
Emissions (million tons SO_2 and NO_x, tons of mercury, and million metric tons carbon)													
Sulfur Dioxide	11.2	9.7	9.8	9.9	9.8	8.9	5.9	5.9	6.1	8.9	1.9	1.9	2.1
Nitrogen Oxide	5.1	3.9	3.5	3.5	3.5	4.0	1.5	1.5	1.5	4.1	0.7	0.7	0.7
Mercury	50.3	53.6	48.7	48.5	48.2	54.1	19.1	19.3	19.0	54.8	7.2	7.2	6.9
Carbon	621.1	697.4	614.8	616.4	614.6	802.5	351.9	358.0	357.0	867.8	204.8	208.3	206.7

Note: Capacity excludes end-use combined heat and power.

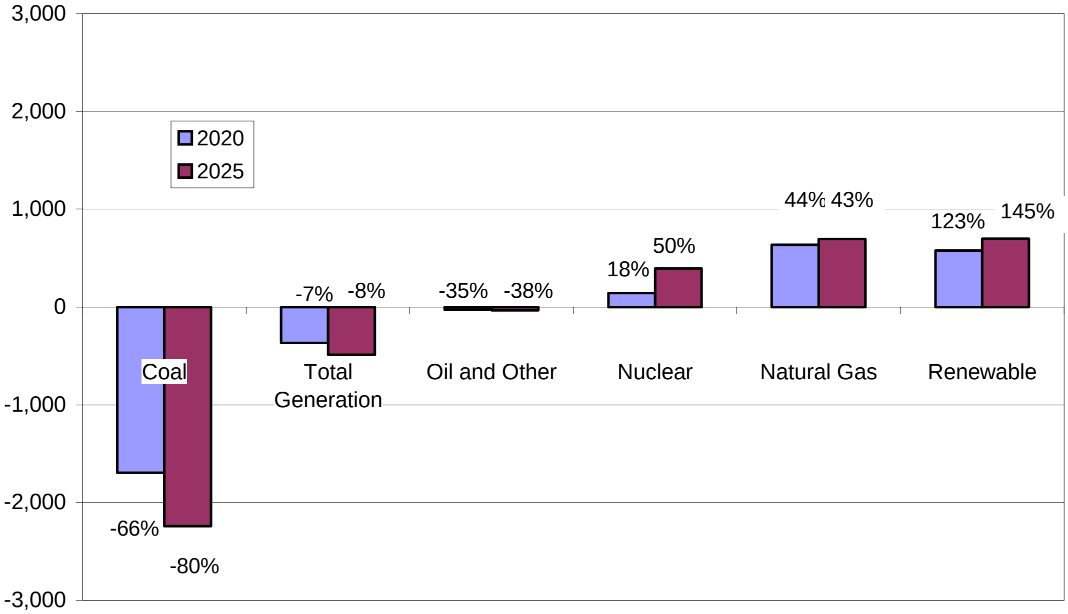
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Figure 5.3. Electricity Generation by Fuel in the S.139 Case, 2000, 2010, 2020, and 2025 (billion kilowatthours)



Sources: History: Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), Table 8.2a. Projections: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System run MLBILL.D050503A.

Figure 5.4. Change in Electricity Generation Fuel Mix, 2020 and 2025 (billion kilowatthours and percent change from reference case)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

(143 percent) higher in the S.139 case than in the reference case in 2025. Natural gas (695 billion kilowatthours and 42 percent) and nuclear (393 billion kilowatthours and 50 percent) generation are also projected to be higher in the S.139 case in 2025, while overall electricity demand is lower by 593 billion kilowatthours (11 percent) as consumers reduce their use of electricity. The imposition of a greenhouse gas emission cap simply makes it uneconomical to continue using coal in existing plants without carbon capture and sequestration equipment. For example, in 2025 in the S.139 case, the delivered price of coal to the power sector is projected to be $0.90 per million Btu, $0.21 less than the $1.11 price projected in the reference case. However, the effective cost of coal to the power sector in the S.139 case is projected to be $6.53 per million Btu - $0.90 per million Btu for the coal plus the $5.62 per million Btu for the allowances needed to use it. In effect, coal costs in the S.139 case in 2025 are 488 percent higher than the $1.11 per million Btu projected in the reference case.

In the S.139 case, renewable power sources, especially biomass, wind, and geothermal energy resources, are projected to play an increasing role in meeting the growing demand for electricity while also helping to reduce greenhouse gas emissions. Renewable energy resources are generally considered to be net zero emitters of carbon. Electric generation from most renewable resources, such as wind, solar, hydroelectric, or geothermal, involves no direct emissions of carbon dioxide or other gaseous carbon compounds. On the other hand, the use of biomass and other organic materials does produce direct carbon emissions when electricity is produced. However, biomass fuel sources, such as agricultural wastes, urban wastes, or dedicated energy crops, all fix atmospheric carbon on a short enough time scale (years or at most a few decades) to be effectively considered net zero emitters of carbon in the mid- to long term. In other words, while carbon is released when biomass is burned, almost the same amount of carbon is “captured” when the biomass products—agricultural wastes, urban wastes, or dedicated energy crops—are grown, resulting in near zero net emissions over time.

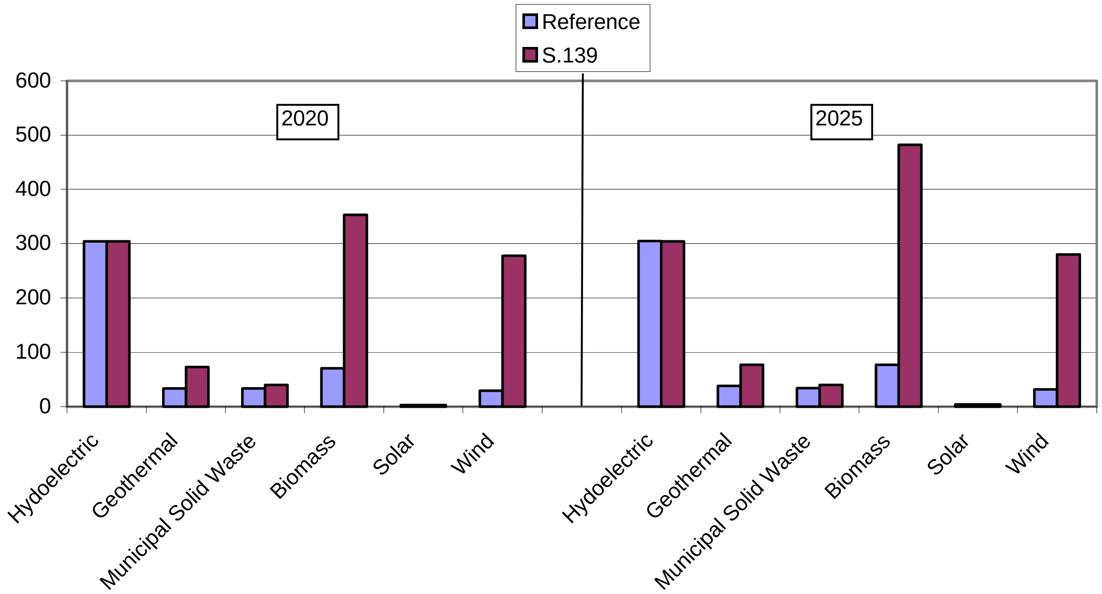
Among the renewables, the largest response to the greenhouse gas emissions cap is projected to come from biomass, wind, and, to a lesser extent, geothermal (Table 5.2 and Figure 5.5). For example, in 2025, biomass, wind and geothermal generation in the S.139 case are projected to be 406, 248, and 39 billion kilowatthours, respectively, above the reference case level. In terms of generation shares, biomass, wind, and geothermal account for 1.3, 0.6, and 0.7 percent of total generation, respectively, in 2025 in the reference case, and are projected to account for 9.1, 5.3 and 1.5 percent of total generation, respectively, in the S.139 case. The imposition of a greenhouse gas emissions cap is expected to make new dedicated

Table 5.2. Renewable Generation by Fuel in the Reference and S.139 Cases, 2010, 2020, and 2025 (billion kilowatthours)

Fuel	2000	2010		2020		2025	
		Reference	S.139	Reference	S.139	Reference	S.139
Hydroelectric	275.3	305.1	305.1	304.3	304.2	304.6	304.3
Geothermal	14.1	22.0	44.6	33.4	73.1	38.1	77.2
Municipal Solid Waste	22.6	31.4	37.3	33.8	39.8	34.0	40.0
Biomass	37.8	59.0	64.4	70.5	352.7	76.8	482.5
Solar	0.5	1.8	1.8	2.9	3.2	3.8	4.3
Wind	5.6	22.9	112.5	29.2	277.7	32.0	280.1
Total	**355.9**	**442.3**	**565.8**	**474.1**	**1,050.6**	**489.4**	**1,188.4**

Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure 5.5. Renewable Generation in the Reference and S.139 Cases, 2020 and 2025 (billion kilowatthours)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

biomass[146] and wind plants relatively attractive. Except for a small amount of carbon released through the use of fossil fuels in the cultivation and transportation of biomass material, new biomass plants will be part of a closed loop system, sequestering carbon during the growing of the crops and releasing it when the crops are gasified and burned. Total net carbon emissions from biomass are expected to be near zero. Wind and geothermal produce no greenhouse emissions. New dedicated biomass plants are especially attractive because they are fully dispatchable,[147] whereas new wind plants produce power intermittently, only when the wind is blowing. Biomass can also be used in conjunction with other fuels, particularly coal (often referred to as biomass co-firing).

Capacity Additions and Retirements by Plant Type

The change in capacity additions generally parallels the change in generation by fuel. As mentioned, in the reference case, over the next 20 years or so the vast majority of new power plants built are expected to be fueled by natural gas. In fact, of the 440 gigawatts of new capacity projected to be added in the power sector in the reference case, 347 gigawatts (79 percent) is expected to be natural gas combustion turbine, combined-cycle, fuel cell, or distributed generation plants (Figure 5.6). In the later years of the projections, as natural gas prices rise, new coal plants become increasingly economical. A relatively small amount of new renewable capacity is also projected. No new nuclear plants are expected in the reference case.

The introduction of a greenhouse gas emissions cap is projected to lead to a dramatic change in the mix of new capacity built and capacity retired. To meet the greenhouse gas emissions limit, electricity suppliers

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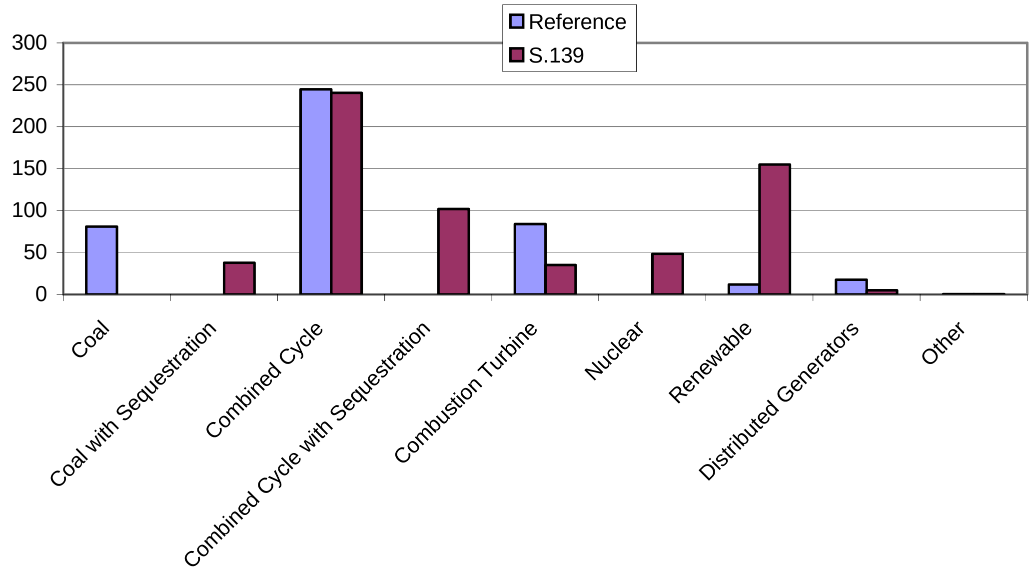
[146] Dedicated biomass plants are plants built specifically to burn biomass, normally co-located with a biomass crop facility.
[147] Fully dispatchable means that the plant can be run whenever called upon by the system operator.

Figure 5.6. Capacity Additions by Plant Type, 2001-2025 (gigawatts)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

are expected to turn to new renewable, nuclear, and fossil (with carbon capture and sequestration) plants. These technologies are generally uneconomical in the reference case. For example, construction costs for new natural gas plants with carbon capture and sequestration equipment are about 75 percent more than the costs of similar plants without such equipment (Table 5.3). In addition, the efficiency of such a plant is approximately 25 percent less than that of a plant without carbon capture and sequestration equipment.

In all cases, as the commercialization of a technology progresses, capital costs are assumed to decline as a result of “learning-by-doing” effects, which indicate that costs fall as experience increases. This is represented by assuming a specified cost reduction for each doubling of capacity. The greatest amount of learning is assumed to occur during the initial stages of development. As a technology matures, the cost declines due to learning slow down.

New technologies are projected to become more competitive in a case that assumes more rapid technological improvement (as shown in the high technology assumptions in Table 5.3). The newer technologies tend to experience a greater relative reduction in cost and greater performance improvement over time than do the existing commercial technologies. Thus, the competitive gap closes with more rapid technology improvement.

Among the renewables a large increase in biomass, wind, and to a smaller extent, geothermal capacity is projected when a greenhouse gas emission cap is imposed. Solar and conventional hydroelectric capacity is not expected to be significantly affected. Although they are available throughout the United States, biomass resources generally are better in some portions of the country than others. For electric generation, biomass fuel is utilized both to “co-fire” with coal in existing coal-steam plants or as the primary fuel in dedicated biomass power plants. The first option, co-firing, is characterized by low capital costs and short lead times. In both the reference case and the S.139 case, co-firing grows significantly between 2005 and 2010. However, in the S.139 case, generation from co-firing declines precipitously from its 2009 peak

Table 5.3. Cost and Performance of Selected New Generating Technologies in 2002

Analysis Case	Overnight Costs (2001$/kW)	Variable O&M (2001 mills/kWh)	Fixed O&M (2001$/kW)	Heat Rate in 2002 (Btu/kWh)	Heat Rate nth-of-kind (Btu/kWh)
Advanced Nuclear					
Reference	2,118	0.4	58.5	N/A	N/A
High Technology.........	1,801	0.4	58.5	N/A	N/A
Advanced Coal					
Reference	1,367	2.0	33.7	8,000	7,200
High Technology.........	1,162	2.0	33.7	8,000	6,120
Advanced Coal With Sequestration					
Reference	2,070	2.5	40.0	9,600	7,920
High Technology.........	1,760	2.5	40.0	9,600	6,732
Advanced Gas Combined Cycle					
Reference	608	2.0	10.2	7,000	6,350
High Technology.........	562	2.0	10.2	7,000	5,874
Advanced Gas CC With Sequestration					
Reference	1,068	2.6	14.8	8,750	7,300
High Technology.........	908	2.6	14.8	8,750	6,205
Biomass					
Reference	1,764	3.1	46.0	8,911	8,911
High Technology.........	1,495	3.1	46.0	8,911	8,911
Wind					
Reference	1,004	0.0	26.1	N/A	N/A
High Technology.........	928	0.0	26.1	N/A	N/A

Note: Costs include adjustments for technological optimism and contingencies.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

and ceases to provide significant generation by 2012 as host coal capacity declines and biomass feedstocks find higher value use in dedicated biomass facilities. Growth in dedicated facilities in the early portion of the forecast is limited by long construction lead times for the plants, high capital costs relative to co-firing, and a small existing capacity base, with resulting low levels of the knowledge and infrastructure necessary to sustain quick and large levels of market growth. Further limiting early-year growth is the limited supply of urban and agricultural wastes used for low-cost supply. Establishment of dedicated energy crop feedstocks is not expected to occur before 2010, but this source of supply provides a significant source of fuel for the fast growing biomass sector in the later years of the forecast. Through most of the forecast period, the expansion rate of dedicated biomass capacity in the S.139 case is limited primarily by the high costs imposed through production bottlenecks encountered with any fast growing technology. Despite these growth limits, biomass becomes the leading renewable fuel by 2025 in the S.139 case, with more generation than all other renewable fuels combined, although only half as much as either natural gas or nuclear capacity.

High-quality, economically exploitable wind resources are somewhat more widespread than some other renewables, such as geothermal, but they still are not available throughout the United States. Projected to be nearly cost competitive in the base case, wind generation becomes highly competitive early in the S.139 case forecast despite the assumed expiration of the production tax credit in 2003.[148] With relatively short project lead times and the higher costs of fossil alternatives when a greenhouse gas emissions cap is imposed, wind power reaches 83 gigawatts of capacity in the S.139 case, compared with just 11 gigawatts

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[148] The EPACT 10-year renewable electricity production tax credit for new wind and some biomass plants originally expired on June 30, 1999. It was extended twice, first to December 31, 2001 and then retroactively through December 31, 2003, by the Job Creation and Worker Assistance Act of 2002 (P.L. 107-147). This analysis assumes the expiration of the production tax credit at the end of 2003.

in the reference case. At this level, wind contributes 5.8 percent of total U.S. generation sold to the grid. In the S.139 case, most of this growth occurs in the years from 2005 to 2015. By 2015, despite the tightening greenhouse gas emissions cap, further development of wind is increasingly curtailed by the rising costs of integrating this intermittent generation source into regional grid operations, the need to upgrade transmission networks to access ever more remote wind resources, and the increasingly competitive costs of other low-carbon or carbon-free resources such as biomass and nuclear fuels. In the best wind regions, wind power produces as much as 20 percent of electric generation. At these levels, wind may require extensive "backup" from firm generating capacity resources (such as combustion turbines or hydropower) to ensure grid reliability, and some wind output may have to be curtailed to avoid operational difficulties with the few remaining coal and increasingly important nuclear plants in the regions. Furthermore, at these levels it is likely that most of the prime, low-cost sites with easy access to load centers will already be developed. Additional development will require utilizing sites that are more expensive to develop and require costly upgrade or expansion of transmission systems to bring the power where it is needed. These expenses begin to manifest themselves in the face of declining costs and increasing availability of competing non-carbon resources such as biomass and nuclear fuels.

Although the growth of geothermal capacity in the S.139 case is significant relative to the reference case, with over 80 percent more installed capacity by 2025, the overall contribution of the resource to national electricity supply is still somewhat limited. While relatively inexpensive to exploit, high-quality geothermal resources are limited. Taking advantage of naturally occurring formations of underground steam or high-temperature/high-pressure water, the known supply of geothermal resources in the United States is limited to 51 sites in a few western States and Hawaii. Technology to exploit the "hot dry rock" formations that underlie the entire continent has not yet been developed and is not projected to be available in the forecast horizon.

Although central-station solar electric capacity remains too expensive for adoption in the S.139 case, end-user installed photovoltaics are projected to show substantial growth relative to the reference case. Central-station solar technologies, including solar thermal and photovoltaic systems, are hampered by high capital costs and low utilization rates and are unable to compete in wholesale power markets, even with substantial price support that might come from greenhouse gas allowance trading. However, distributed photovoltaic applications, such as panels installed on commercial buildings or residential rooftops, do not require investment in transmission or distribution facilities, and with higher retail electricity rates they are competitive.[149]

With respect to conventional hydroelectric power, the prime, low-cost, high-output hydroelectric sites in the United States are already largely developed. Remaining sites face numerous obstacles to significant future development, including small capacity potential at most sites, legal constraints on developing "wild and scenic rivers," and other environmental sensitivities, even if no legal prohibition exists at a site. The incentives from greenhouse gas allowance trading may serve to make development of remaining sites more attractive, but the possible increase in hydroelectric capacity would expected to be small. While not addressed in this report, the expansion or development of some sites is possible, but it is not expected to amount to a large amount of capacity.

While the last nuclear plant order in the United States occurred 30 years ago, the imposition of a greenhouse gas emissions cap is projected to make new advanced nuclear technologies economical in the future. In the S.139 case 17 gigawatts of new nuclear capacity is projected to be built by 2020 and 49 gigawatts by 2025. The first new nuclear plants are expected to be quite expensive, costing about $2,100 per kilowatt (in 2001 dollars). However, as with most new technologies, their costs are expected to

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[149] Penetration in end-use applications is still limited by the high cost of the technology and also by the underlying turnover rates in the U.S. stock of buildings.

decline after the initial units are brought on, so they become increasingly competitive in the later years of the projections as the greenhouse gas emissions cap tightens, natural gas prices rise, and the most attractive sites for new renewable plants are exploited. By 2020 in the S.139 case, the cost of new nuclear plants is projected to have fallen to $1,660 per kilowatt. While there is uncertainty about the costs of these new plants, they are also likely to face more difficulty in siting and permitting than other technologies. The results of a sensitivity case discussed later will illustrate the impact of an assumption that neither this technology nor fossil plants with carbon capture and sequestration equipment will be available.

The same behavior is expected for new fossil plants—both natural gas and coal—with carbon capture and sequestration equipment. Initially they are expected to be quite expensive, but after the initial projects penetrate the market their costs are expected to fall. For example, new coal plants with carbon capture and sequestration equipment are projected to cost $2,070 per kilowatt initially, but by 2020 in the S.139 case their costs are projected to have fallen to approximately $1,660 per kilowatt. Similarly, new gas plants with carbon capture and sequestration are initially projected to cost $1,068 per kilowatt, but in the S.139 case their costs drop to approximately $780 per kilowatt. In the S.139 case 45 gigawatts of natural gas combined-cycle capacity with sequestration is projected to be built by 2020, and 102 gigawatts is projected by 2025. For coal with sequestration, the amount is 12 gigawatts by 2020 and 38 gigawatts by 2025. As with new nuclear plants, there is uncertainty about the costs and performance of these new plants. It is possible that some insurmountable engineering obstacle will arise that causes costs to remain relatively high. Again, the results of a sensitivity case discussed later will illustrate the impact of this technology not being available.

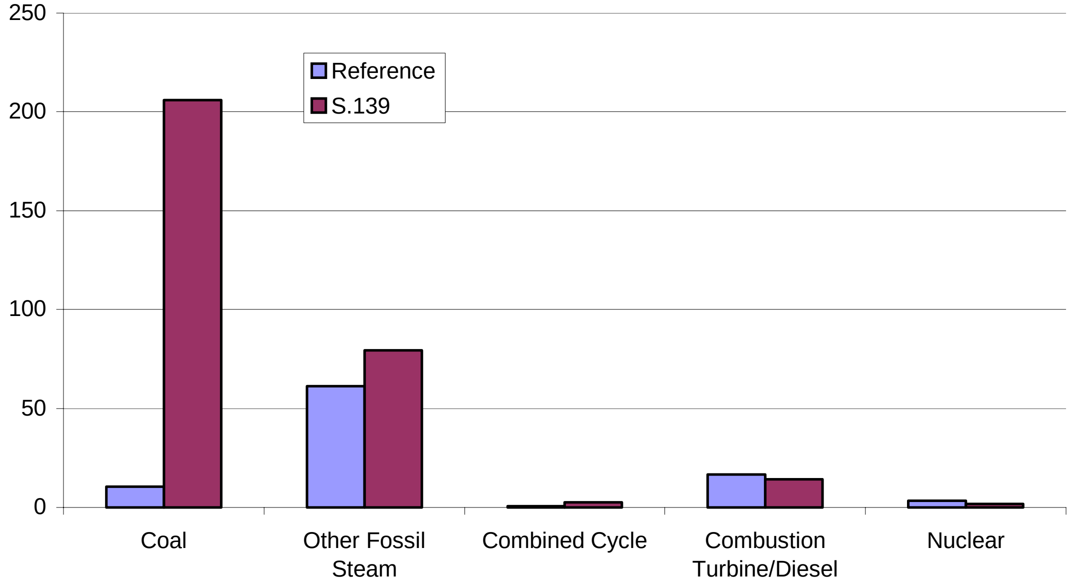
The rapid expansion of the markets for new nuclear capacity and fossil capacity with carbon capture and sequestration equipment could also face significant market hurdles. As mentioned earlier, it has been 30 years since the last order for a new nuclear plant was made in the United States. The infrastructure needed to plan, site, build and maintain the amount of new advanced nuclear capacity projected in the S.139 case could take considerable time to develop. The same is true for fossil plants with carbon capture and sequestration. Industry—and the public that will have to accept them—currently has little or no experience with these technologies. If expanded very rapidly, their costs could be higher than expected.

In addition to changing the mix of new capacity added, the imposition of a greenhouse gas emissions cap also has an impact on projected capacity retirements (Figure 5.7). In the reference case, almost all existing coal capacity is projected to continue operating. On the other hand, a significant amount of the existing oil and gas steam capacity is expected to retire. Typically older oil and gas steam plants are relatively inefficient and as natural gas prices rise and new more efficient gas capacity is added, it will no longer be economical to continue operating these plants.

In the S.139 case, a large proportion of existing coal capacity is projected to be retired. It is simply not economical to continue operating these plants. For example, in 2020 with a greenhouse gas allowance costing $178 per metric ton carbon equivalent, the effective cost of coal is projected to be $5.53 per million Btu (the $0.99 per million Btu delivered price of coal plus the $4.54 per million Btu cost of the allowances needed to use it for a plant without carbon capture and sequestration equipment), 394 percent above the cost projected in the reference case. Even with lower electricity demand, because of the large number of projected retirements, the total amount of new capacity added in the S.139 case exceeds that added in the reference case by more than 185 gigawatts.

It is impossible to say which of the relatively low carbon technologies discussed—new nuclear, biomass, geothermal, wind, gas with sequestration, or coal with sequestration—might prove the most attractive over the next 20 years or so. Any one of them might hit cost or performance hurdles that cannot be overcome, or, vice versa, one or more of them might prove extremely economical and capture a very large portion of the market for low-carbon generating technologies. The mix of technologies chosen is also

Figure 5.7. Capacity Retirements by Plant Type, 2001-2025 (gigawatts)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

sensitive to the assumed cost of capital. Some of these technologies are very capital intensive; for others, operating costs are more important. As a result, changes in the assumed cost of capital can lead to a different mix of technologies being built.

Electricity Prices and Consumer Demand

The National Energy Modeling System explicitly reflects the status of electric industry regulation by region.[150] The handling of the electric power sector's opportunity costs[151] of allowances varies depending on the status of regulation in the region. For this analysis, the opportunity cost of allowances is included in the generation price in competitive regions, when a fossil-fired unit is on the margin and sets the market-clearing price in the region.

The opportunity costs of allocated allowances are handled differently in cost-of-service regulated regions. In cost-of-service regulated regions, Public Utility Commissions will determine how they are treated for ratemaking purposes. They might only allow the recovery of allowance costs in electricity prices if they were purchased by the utility, requiring that any revenue associated with allowance sales be returned to ratepayers. However, if regulators followed this strategy completely they would significantly reduce the incentive for utilities to reduce emissions. For this analysis, it is assumed that regulators will apportion the benefits of freely allocated allowances, with ratepayers receiving 90 percent of the benefits and

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[150] For a list of the regional status assumed see, Energy Information Administration, *Annual Energy Outlook 2003,* DOE/EIA-0383(2003), p. 69.

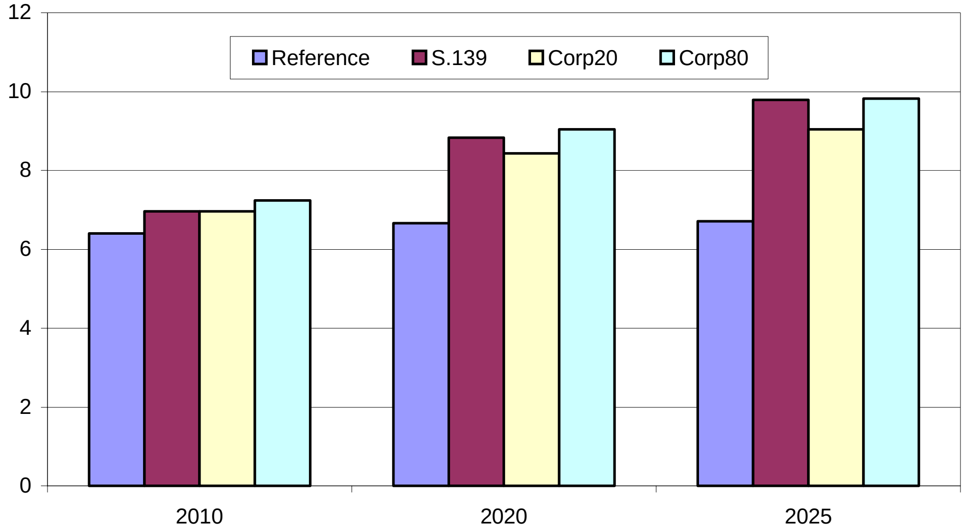
[151] When a company is allocated allowances by the government at no cost, there is still a "cost" associated with using them. The company could simply sell the allowances in the open market and retain the revenues if it did not use them to cover its own emissions. Therefore, the market price of the allowances is used to represent this forgone benefit.

company shareholders receiving 10 percent of the benefits. This will act to encourage cost-of-service regulated utilities to make optimal environmental compliance decisions while distributing most of the benefit to ratepayers.[152] This distribution is based on analysis of the regulatory treatment of freely allocated SO_2 allowances under the SO_2 allowance-trading program created in the Clean Air Act Amendments of 1990.[153, 154]

The imposition of a greenhouse emission cap on the electric, transportation, and industrial sectors is projected to lead to significant increases in electricity prices (Figure 5.8). The higher prices result from the increased reliance on higher cost generating technologies and the need to hold allowances for all generation from fossil fuel plants without carbon capture and sequestration equipment.[155] In the early years of the greenhouse gas reduction efforts the relatively low cost of greenhouse gas allowances, $79 per metric ton carbon equivalent in 2010, is projected to lead to an increase in electricity prices of 9 percent above the reference case level. However, the impact on electricity prices grows in the later years. Relative to the reference case, the price of electricity is projected to be 33 percent higher in 2020, and 46 percent higher in 2025, in the S.139 case. As mentioned earlier, the effective cost of using fossil fuels—where the effective cost of the fuel is its delivered price plus the cost of allowances needed when it is used—in plants without carbon capture and sequestration equipment is much higher in cases with a greenhouse gas emission cap.

For example, in 2020 in the S.139 case, the greenhouse gas allowance price is $178 per metric ton carbon equivalent. Translating this into its impact on the delivered price of fossil fuels results in $4.54 per

Figure 5.8. Electricity Prices in Alternative Cases (2001 cents per kilowatthour)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

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[152] It is assumed that this sharing of benefits is enough to encourage regulated utilities to behave competitively pursuing all economical greenhouse gas reduction opportunities.

[153] E.M. Bailey, *Allowance Trading Activity And State Regulatory Rulings: Evidence From The U.S. Acid Rain Program* (Massachusetts Institute of Technology, March 1998), available at web site http://web.mit.edu/ceepr/ www/98005.pdf.

[154] To determine the impact of allowance purchases or sales on revenue requirements in cost-of-service regions, it is assumed that power sector allowances are allocated based on each region's share of year 2000 carbon emissions. Actual emissions in each year are then compared to the number of allowances that were freely allocated, and the net purchase/sale revenue is calculated and added/subtracted to the revenue requirements.

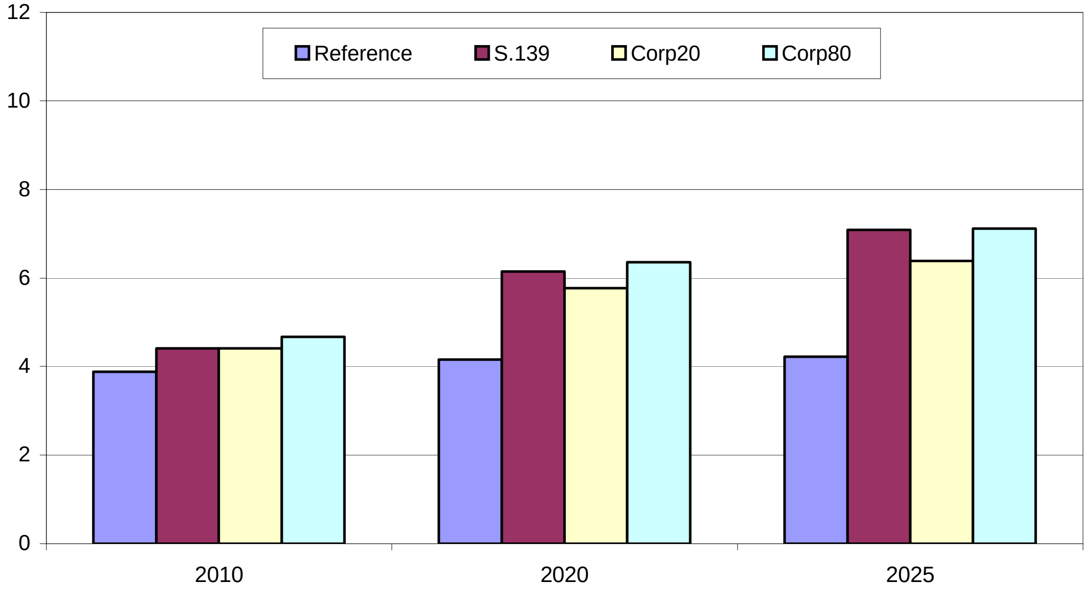
[155] It is assumed that the carbon capture and sequestration equipment will remove 90 percent of the facilities' carbon dioxide emissions. Allowances will be required for the remaining 10 percent.

million Btu for coal and $2.57 per million Btu for natural gas. The higher value for coal results from its greater carbon content. Translating this into the cost of running the power plants would mean a 4.5-cent per kilowatthour increase for a coal plant and a 1.9-cent per kilowatthour increase for a natural gas combined cycle plant.[156] The larger impact on the operating cost of the coal plant is driven by both the higher carbon content of coal and the fact that the coal steam plant is less efficient—consuming more Btu per kilowatthour generated—than a natural gas combined-cycle plant.

If one looks at the generation component of electricity prices, excluding the costs of transmitting and distributing the power, the projected changes in electricity prices are even larger (Figure 5.9). In all cases the price of electricity distribution and transmission services is assumed to continue to be based on cost-of-service regulation. Because no greenhouse gas emissions occur in the transmission or distribution of electricity, these sectors of the market are not directly impacted by the imposition of a greenhouse gas emission limit. Focusing solely on generation prices illustrates the impacts of the greenhouse emission cap on the price of producing electricity. In 2020, generation prices in the S.139 case are projected to be 48 percent above those in the reference case, and by 2025 the difference is 68 percent.

The allowance cost regulatory treatment assumed in this report leads to different electricity price impacts in the cases where the share of allowances going to the Climate Change Credit Corporation (hereafter referred to as the Corporation) is changed from the main S.139 case (see Figure 5.8 and Table 5.1).[157]

Figure 5.9. Generation Prices in Alternative Cases (2001 cents per kilowatthour)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

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[156] In this illustrative example, a 10,000 Btu per kilowatthour heat rate is assumed for the coal plant, while a 7,500 heat rate is assumed for the natural gas combined cycle plant. The differential grows further in the later years of the projections as the heat rate for new combined-cycle plants improves to 6,350.

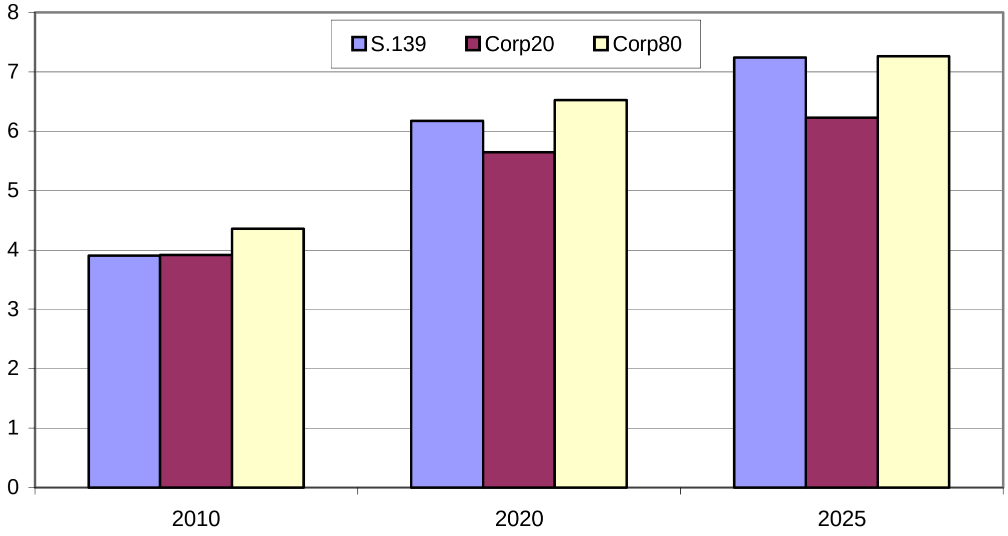
[157] Though not discussed in this report, the approach used to allocate allowances can have economic efficiency and distributional impacts. For a discussion of these issues see, Beamon, Leckey, and Martin, *Power Plant Emissions Reductions Using a Generation Performance Standard,* web site http://www.eia.doe.gov/oiaf/servicerpt/gps/pdf/gpsstudy.pdf; and Burtraw, *Carbon Emission Trading Costs and Allowance Allocations: Evaluating the Options,* web site http://www.rff.org/resources_archive/pdf_files/145_burtraw.pdf.

When allowances are allocated to the Corporation and then purchased by a cost-of-service regulated entity, their costs will be fully passed onto consumers. Thus, in the case where it is assumed that 80 percent of the allowances are allocated to the Corporation (the corp80 case), electricity prices are projected to show a larger price impact than in the case where only 20 percent of the allowances are assumed to be allocated to the Corporation (the corp20 case). In 2025, electricity prices in the corp80 case are projected to be 9.8 cents per kilowatthour, 3.11 cents per kilowatthour (46 percent) higher than in the reference case. Conversely, in the corp20 case electricity prices in 2025 are projected to be 9.05 cents per kilowatthour, 2.34 cents per kilowatthour (35 percent) higher than the reference case. Note that the projected electricity prices in the S.139 case are close to those in the corp20 case in the early years and close to those in the corp80 case in the later years. This occurs because the share going to the Corporation in the S.139 case is assumed to start at 20 percent in 2010 and gradually increase to 80 percent by 2025.

The electricity price differences across these cases are even more pronounced at the individual cost of service regional level (Figure 5.10). For example, electricity prices in the Southeastern Electric Reliability Council (SERC) region (southeastern states) are assumed to continue to be set using cost of service procedures. As a result, full allowance costs will only be reflected in prices when they are purchased. Thus, in the case where it is assumed that 80 percent of the allowances are allocated to the Corporation, the electricity price impacts in SERC will be relatively large because most of the allowances needed in the region will have to be purchased. In 2025, generation prices in SERC for the corp80 case are projected to be 7.3 cents per kilowatthour, 3.5 cents per kilowatthour (90 percent) higher than in the reference case. In the corp20 case electricity prices in SERC in 2025 are projected to be 6.2 cents per kilowatthour, 2.4 cents per kilowatthour (63 percent) higher than the reference case.

Because the opportunity costs of holding allowances are always assumed to be passed on in regions where electricity prices are set competitively and fossil fuel plants set the marginal electricity price, those

Figure 5.10. Electricity Prices in the SERC Region in Alternative Cases (2001 cents per kilowatthour)



Note: SERC, the Southeastern Electric Reliability Council, is the North American Electric Reliability Council region including Virginia, North Caroline, South Carolina, Georgia, Alabama, Mississippi, and Tennessee, together with parts of Louisiana, Arkansas, and Missouri.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

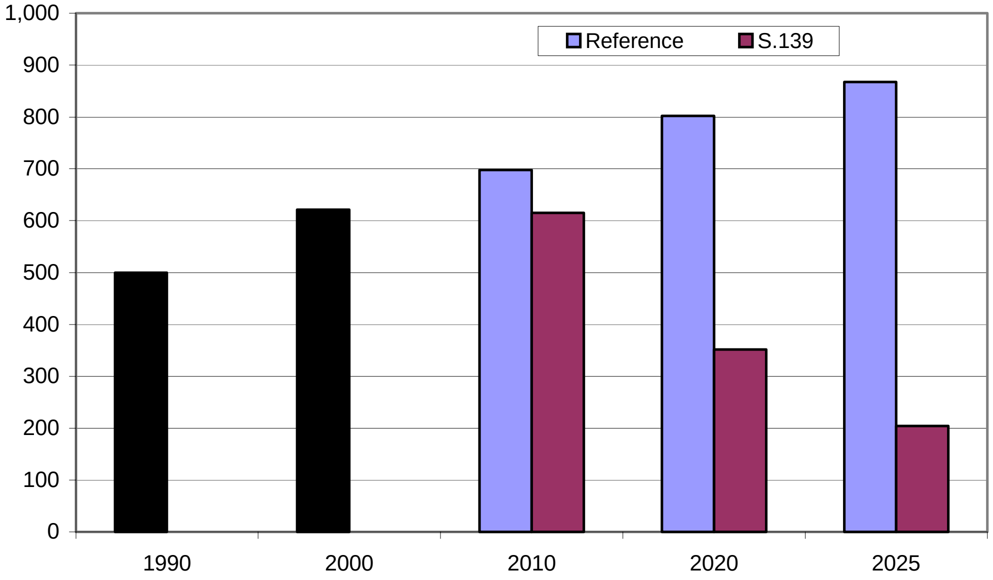
regions do not see significant prices differences in the corp20 and corp80 cases. Their prices always reflect the full costs of holding allowances. The different regional impacts may lead regulators and legislators to look for ways to allocate allowances to reduce the divergent regional price impacts. To the extent that this is achieved by reducing or eliminating the full passthrough of the allowance value into electricity prices in competitive areas, electricity demand reductions will be less than projected. In such a scenario, allowance prices would have to rise above the levels projected in this study to achieve the emissions targets in S.139.

Consumers are projected to respond to the higher electricity prices by reducing their use of electricity. For example, in 2010 in the S.139 case electricity sales are projected to be 54 billion kilowatthours (1.3 percent) below the reference case level. This difference is projected to increase to 381 billion kilowatthours (7.9 percent) in 2020 and 593 billion kilowatthours (11.3 percent) in 2025. (See Chapter 4 for more information on consumers' responses to fuel price changes.)

Emissions

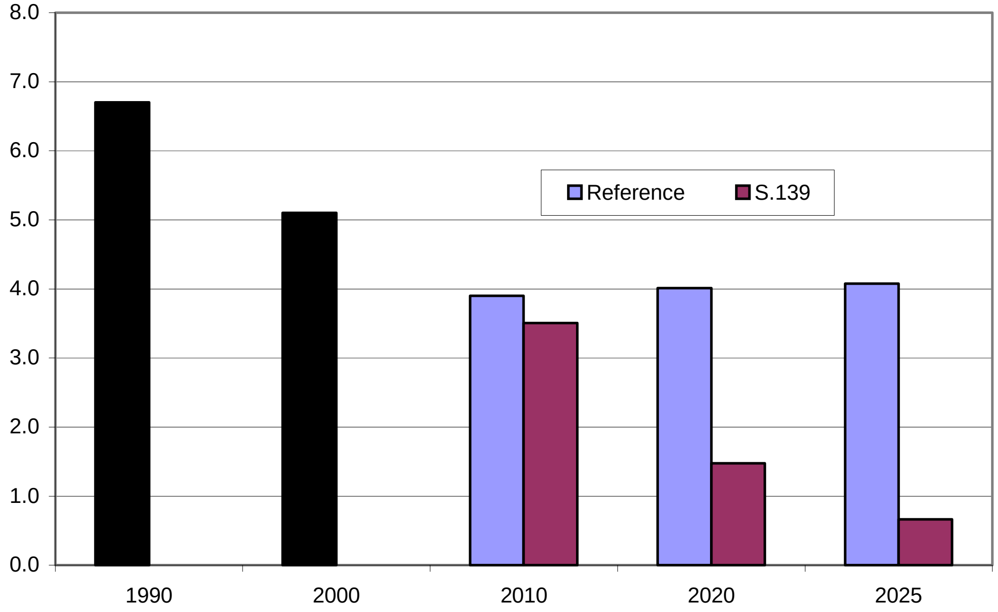
In addition to carbon dioxide emissions reductions, efforts to comply with the greenhouse gas emissions cap are also projected to lead to large reductions in power sector emissions of NO_x, SO_2, and mercury (Figures 5.11, 5.12, 5.13 and 5.14). The reference case incorporates the existing national SO_2 cap and trade program and the 19-State NO_x cap and trade program. Pending regulations, such as those that may be required to reduce mercury or fine particulate emissions, and proposed legislation such as the President's Clear Skies proposal are not represented. In the S.139 case, power sector carbon dioxide emissions are expected to be fall well below their reference case level. For example, in 2020, power sector carbon dioxide emissions are projected to be 802 million metric tons in the reference case and 352 million metric tons in the S.139 case. By 2025, the difference grows even larger, 868 million metric tons in the reference case and 205 million metric tons in the S.139 case. To put this change in perspective it should be noted that the 1990 greenhouse gas emissions in the power sector were close to 500 million metric tons. Thus, the level expected in 2025 in the S.139 case is almost 60 percent below the 1990 level.

Figure 5.11. Power Sector Carbon Emissions (million metric tons carbon equivalent)



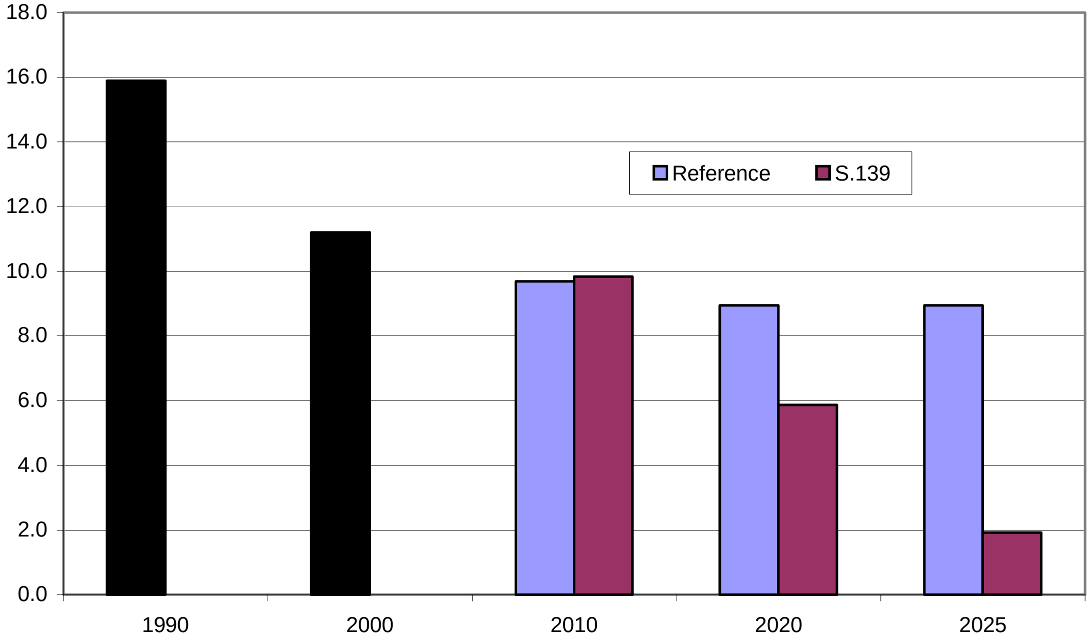
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure 5.12. Power Sector Nitrogen Oxide Emissions (million tons)



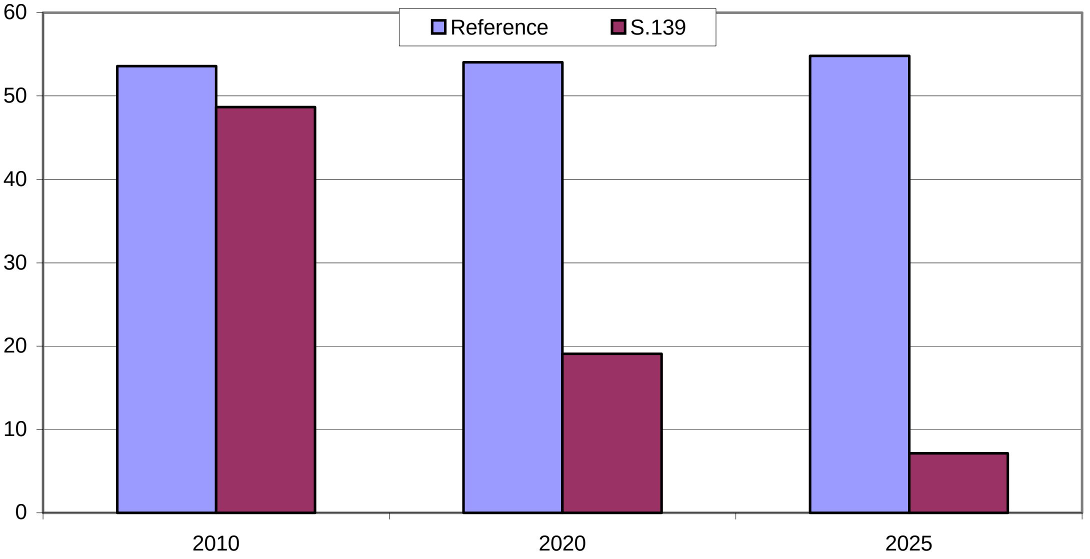
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure 5.13. Power Sector Sulfur Dioxide Emissions (million tons)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure 5.14. Power Sector Mercury Emissions (tons)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

The actions taken to lower carbon dioxide emissions—reduced use of coal and the increased use of nuclear, renewables, and natural gas in electricity generation—in the S.139 case also lead to reductions in power sector NO_x, SO_2, and mercury emissions. By 2020 power sector NO_x emissions are projected to be 1.5 million tons in the S.139 case, 63 percent below the reference case level and 68 percent below the level seen in 2001. By 2025, the power sector NO_x emissions level is projected to fall further to 0.7 million tons. In fact, power sector NO_x emissions in the S.139 case are projected to fall below the lowest level seen in the last 30 years or so—the 4.75 million tons emitted in 2001. The story is similar for power sector SO_2 emissions. In the S.139 case, power sector SO_2 emissions are projected to be 5.9 million tons in 2020 and 1.9 million tons in 2025. This compares to emissions of 17.3 million tons in 1970 and 10.6 million tons in 2001. The results are similar for mercury, with projected emissions in the S.139 case falling to 19.1 tons in 2020 and 7.2 tons 2025, as compared to 54.1 and 54.8 tons in the reference case.

Uncertainties and Sensitivity Cases

As with any mid- to long-term forecast there is considerable uncertainty surrounding the projections. In the power sector, the cost and performance of new generating technologies, especially those that are relatively low carbon emitters, is an important area of uncertainty. While the cost and performance improvement that is typically seen as new technologies enter the market is represented in the reference and S.139 cases, it is possible that the changes could be better or worse than projected, or that technologies that do not penetrate the market under normal circumstances might play a bigger role when a greenhouse gas emission cap is imposed. To assess the impact of more rapid improvements in the cost and performance of new technologies—in the residential, commercial, industrial, transportation, and electricity sectors—high technology assumptions have been incorporated into both the reference and S.139 cases (Table 5.4). The results of these cases should not be seen as predicting which of the emerging technologies might prove most successful in the marketplace but, rather, as indicative of the impacts of a general improvement in all these technologies.

In the electricity sector, the greenhouse gas emissions cap in S.139 is projected to result in lower electricity demand, higher electricity prices, and reliance on a mix of new technologies—coal and gas plants with sequestration equipment, new nuclear plants, and new renewable facilities. The improved

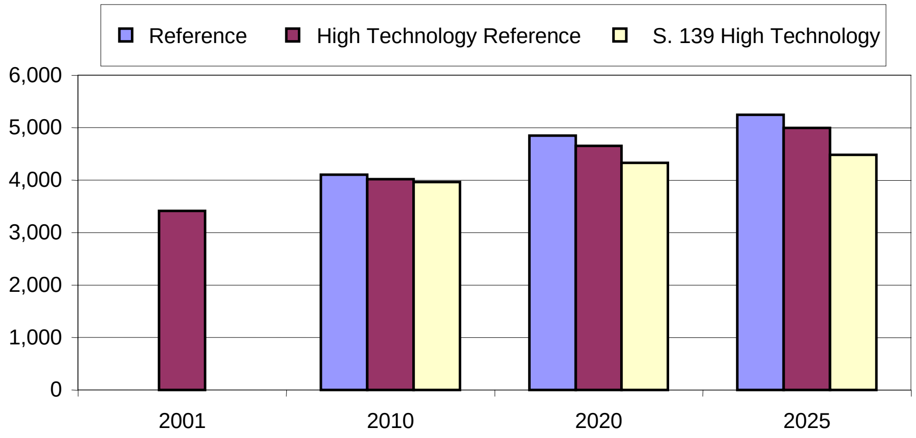
Table 5.4. Key Electricity Sector Results in Sensitivity Cases—High Technology

		2010			2020			2025		
	2000	Reference	Reference W/High Technology	S.139 W/High Technology	Reference	Reference W/High Technology	S.139 W/High Technology	Reference	Reference W/High Technology	S.139 W/High Technology
Generation by Fuel (billion kilowatthours)										
Coal	1,966	2,293	2,247	2,031	2,568	2,450	1,150	2,803	2,615	696
Oil and Other	121	63	57	41	73	54	33	81	59	36
Natural Gas	601	946	910	988	1,441	1,347	1,812	1,637	1,549	2,256
Nuclear	754	790	783	801	793	779	912	793	771	1,126
Renewable	356	442	456	546	474	520	940	489	550	1,029
Total	**3,798**	**4,534**	**4,454**	**4,406**	**5,349**	**5,150**	**4,847**	**5,803**	**5,543**	**5,142**
Generating Capacity (gigawatts)										
Coal	310.6	315.3	311.7	291.1	348.6	336.7	220.9	380.8	359.5	159.4
Coal with Sequestration	0.0	0.0	0.0	0.0	0.0	0.0	5.2	0.0	0.0	17.5
Coal Subtotal	310.6	315.3	311.7	291.1	348.6	336.7	226.1	380.8	359.5	176.9
Other Fossil Steam	136.0	79.0	77.1	78.0	73.0	68.2	58.8	72.2	65.2	54.7
Combined Cycle	46.0	181.3	178.4	199.4	265.9	280.8	294.7	311.1	331.8	294.5
Combined Cycle with Sequestration	0.0	0.0	0.0	0.6	0.0	0.0	43.9	0.0	0.0	115.8
Combined Cycle Subtotal	46.0	181.3	178.4	200.1	265.9	280.8	338.5	311.1	331.8	410.3
Combustion Turbine	81.8	131.7	127.1	125.3	153.3	126.7	120.2	169.5	133.7	119.0
Nuclear	98.0	98.7	97.7	100.3	99.0	97.0	114.8	99.0	95.9	141.5
Renewable	88.4	97.4	99.2	120.5	101.2	106.1	196.8	102.8	108.9	207.8
Other	19.8	22.1	21.6	21.3	32.2	25.1	22.3	38.2	28.6	22.6
Total	**780.6**	**925.6**	**912.8**	**936.6**	**1,073.4**	**1,040.6**	**1,077.6**	**1,173.7**	**1,123.6**	**1,132.9**
Electricity Demand (billion kilowatthours) and Prices (2001 cents per kilowatthour)										
Electricity Sales	3,438	4,104	4,020	3,965	4,848	4,652	4,331	5,246	4,997	4,481
Electricity Prices	6.89	6.40	6.29	6.71	6.66	6.32	7.93	6.71	6.25	8.57
Emissions (million tons SO_2 and NO_x, tons of mercury, and million metric tons of carbon)										
Sulfur Dioxide	11.2	9.7	9.7	9.9	8.9	8.9	8.8	8.9	8.9	4.2
Nitrogen Oxide	5.1	3.9	3.8	3.6	4.0	3.8	2.0	4.1	3.8	1.1
Mercury	50.3	53.6	53.2	49.5	54.1	53.2	27.9	54.8	53.6	13.3
Carbon	621.1	697.4	677.3	616.1	802.5	735.4	406.3	867.8	768.5	251.2

Note: Capacity excludes end-use combined heat and power.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE_HT.D052003C, MLBILL.D050503A, and ML_HT.D050503A.

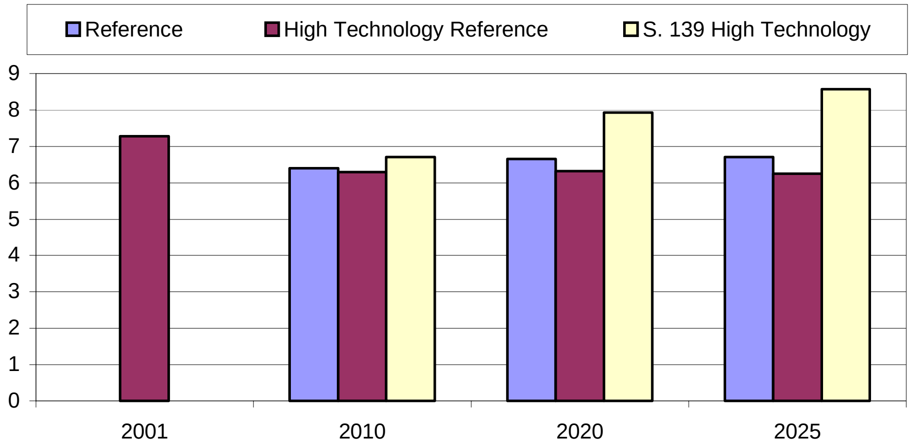
technology cost and performance assumptions reduce the impact of the greenhouse gas emissions cap, but lower electricity demand and higher electricity prices still are projected. Compared to the high technology reference case, there is also projected to be a greater reliance on new technologies in the S.139 high technology case—coal and gas plants with sequestration equipment, new nuclear plants, and new renewable facilities. The improved technology assumptions in the residential, commercial, and industrial sectors contribute to lower electricity demand in both of the high technology cases (Figure 5.15). Consumers also reduce their demand further in response to higher electricity prices (Figure 5.16) when the greenhouse emission cap is imposed in the S.139 high technology case.

Figure 5.15. Electricity Sales in the Reference, High Technology Reference, and S.139 High Technology Cases (billion kilowatthours)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE_HT.D052003C, MLBILL.D050503A, and ML_HT.D050503A.

Figure 5.16. Electricity Prices in the Reference, High Technology Reference, and S.139 High Technology Cases (2001 cents per kilowatthour)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE_HT.D052003C, MLBILL.D050503A, and ML_HT.D050503A.

Compared to the high technology reference case, the electricity price in 2020 is about 25 percent higher in the S.139 high technology case and the greenhouse gas allowance price is projected to be $133 per metric ton carbon equivalent. In contrast, the corresponding greenhouse gas allowance price in the S.139 case is projected to be $178 per metric ton carbon equivalent in 2020. By 2025, the demand for electricity is projected to be 4,481 billion kilowatthours in the S.139 high technology case, compared to 4,997 billion kilowatthours in the high technology reference case and 4,653 billion kilowatthours in the S.139 case. Note that the end-use efficiency improvements in the S.139 high technology case lead to lower electricity demand than in the S.139 case, even though electricity prices are not projected to be as high. For example, in 2025 electricity prices are projected to be 6.7 cents per kilowatthour in the reference case, 6.3 cents per kilowatthour in the high technology reference case, 9.8 cents per kilowatthour in the S.139 case, and 8.6 cents per kilowatthour in the S.139 high technology case. Thus, relative to the reference case, the high technology assumptions reduce the projected increase in electricity prices. However, when compared to the high technology case, electricity prices in 2025 in the S.139 high technology case are 37 percent higher. Relative to the S.139 case, the lower greenhouse gas allowance prices in the S.139 high technology case allow power companies to continue operating more of their existing coal plants (those without carbon capture and sequestration equipment), leading to higher power sector emissions in the later projection years.

As shown in Table 5.1, the S.139 case results indicate that technologies which under reference case conditions are projected to play a fairly small role in the power sector over the next 20 years—i.e., coal and natural gas generators with carbon capture and sequestration, advanced nuclear, wind and biomass—are expected to be important options for reducing greenhouse gas emissions. However, the future availability, cost, and performance of these technologies cannot be known with certainty. Also other factors, including their environmental impacts and/or their lack of public acceptance, might limit their market penetration. An alternative case that assumes that new nuclear plants and fossil plants with carbon capture and sequestration equipment are not available was prepared for this analysis (Table 5.5). The results in this case should not be seen as predicting that these technologies might not be available or economical but rather as illustrating the impact on the results if their development or deployment were not successful.

Without new nuclear plants or fossil plants with carbon capture and sequestration equipment, meeting the greenhouse gas emission cap will be more difficult, requiring a higher greenhouse gas allowance fee. For example, in 2025 the greenhouse gas allowance fee is projected to be $221 per metric ton carbon equivalent in the S.139 case, but $297 in the no nuclear, no geologic sequestration case. The higher allowance cost leads to higher electricity prices and lower electricity demand. Relative to the S.139 case, electricity prices in 2025 are projected to be 9.3 percent higher, 10.68 cents per kilowatthour versus 9.79 cents per kilowatthour (Figure 5.17). Electricity sales in 2025 are lower at 4,573 billion kilowatthours in the no nuclear, no geological sequestration case, compared with 4,653 billion kilowatthours in the S.139 case and 5,246 billion kilowatthours in the reference case (Figure 5.18). Without nuclear or geologic sequestration technologies, the power sector is projected to turn to even more renewables than are expected in the S.139 case. When compared to the S.139 case, nearly 60 gigawatts of additional renewable generating capacity is expected to be added in the no nuclear, geologic sequestration case. Most of this additional increase in renewable capacity is projected come from newly dedicated biomass and, to a lesser extent, new wind plants. The dedicated biomass plants are attractive because they can be used to replace retiring baseload coal plants, whereas wind plants are only available intermittently.

Another critical factor that could impact efforts to reduce greenhouse gas emissions in the power sector is the extent to which companies can use offsets to meet their allowance requirements. As discussed in Chapter 2, S.139 places explicit limits—no more 15 percent in Phase I and 10 percent in Phase II—on the share of a company's allowance requirements that can be satisfied with offsets. To test the sensitivity of

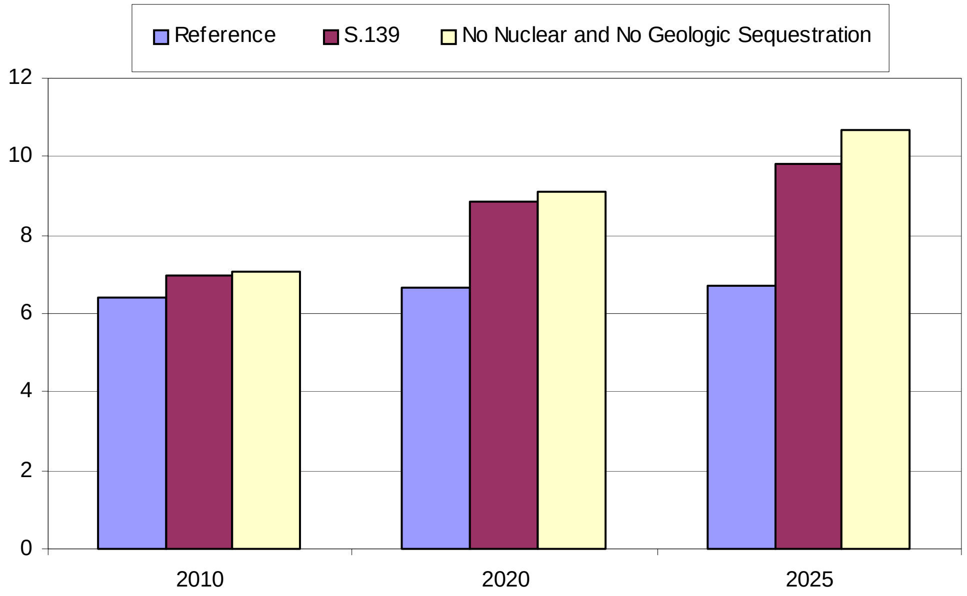
Table 5.5. Key Electricity Sector Results in Sensitivity Cases—No Nuclear or Geological Sequestration

		2010			2020			2025		
	2000	**Reference**	**S.139**	**No Nuclear or Geological Sequestration**	**Reference**	**S.139**	**No Nuclear or Geological Sequestration**	**Reference**	**S.139**	**No Nuclear or Geological Sequestration**
Generation by Fuel (billion kilowatthours)										
Coal	1,966	2,293	1,980	1,957	2,568	876	607	2,803	560	206
Oil and Other	121	63	46	47	73	45	47	81	47	52
Natural Gas	601	946	1,095	1,101	1,441	2,077	2,173	1,637	2,332	2,623
Nuclear	754	790	801	801	793	934	804	793	1,186	804
Renewable	356	442	566	575	474	1,051	1,311	489	1,188	1,564
Total	**3,798**	**4,534**	**4,488**	**4,481**	**5,349**	**4,982**	**4,943**	**5,803**	**5,314**	**5,250**
Generating Capacity (gigawatts)										
Coal	310.6	315.3	293.4	293.2	348.6	200.3	185.9	380.8	104.8	109.2
Coal with Sequestration	0.0	0.0	0.0	0.0	0.0	12.2	0.0	0.0	37.7	0.0
Coal Subtotal	*310.6*	*315.3*	*293.4*	*293.2*	*348.6*	*212.5*	*185.9*	*380.8*	*142.5*	*109.2*
Other Fossil Steam	136.0	79.0	81.8	86.9	73.0	65.9	67.7	72.2	54.1	54.5
Combined Cycle	46.0	181.3	208.0	209.6	265.9	306.7	351.2	311.1	305.0	398.0
Combined Cycle with Sequestration	0.0	0.0	0.8	0.0	0.0	45.4	0.0	0.0	102.1	0.0
Combined Cycle Subtotal	*46.0*	*181.3*	*208.9*	*209.6*	*265.9*	*352.1*	*351.2*	*311.1*	*407.1*	*398.0*
Combustion Turbine	81.8	131.7	128.5	126.7	153.3	126.7	125.2	169.5	123.4	126.1
Nuclear	98.0	98.7	100.3	100.3	99.0	117.2	100.7	99.0	149.2	100.7
Renewable	88.4	97.4	129.2	132.3	101.2	225.3	272.0	102.8	245.8	303.3
Other	19.8	22.1	22.1	22.4	32.2	25.5	24.9	38.2	25.5	26.8
Total	**780.6**	**925.6**	**964.2**	**971.3**	**1,073.4**	**1,125.1**	**1,127.6**	**1,173.7**	**1,147.6**	**1,118.5**
Electricity Demand (billion kilowatthours) and Prices (2001 cents per kilowatthour)										
Electricity Sales	3,438	4,104	4,050	4,044	4,848	4,467	4,424	5,246	4,653	4,573
Electricity Prices	6.89	6.40	6.96	7.04	6.66	8.83	9.12	6.71	9.79	10.68
Emissions (million tons SO2 and NOx, tons of mercury, and million metric tons of carbon)										
Sulfur Dioxide	11.2	9.7	9.8	9.6	8.9	5.9	4.6	8.9	1.9	1.6
Nitrogen Oxide	5.1	3.9	3.5	3.5	4.0	1.5	1.2	4.1	0.7	0.6
Mercury	50.3	53.6	48.7	47.4	54.1	19.1	15.4	54.8	7.2	4.6
Carbon	621.1	697.4	614.8	609.4	802.5	351.9	343.1	867.8	204.8	272.9

Note: Capacity excludes end-use combined heat and power.

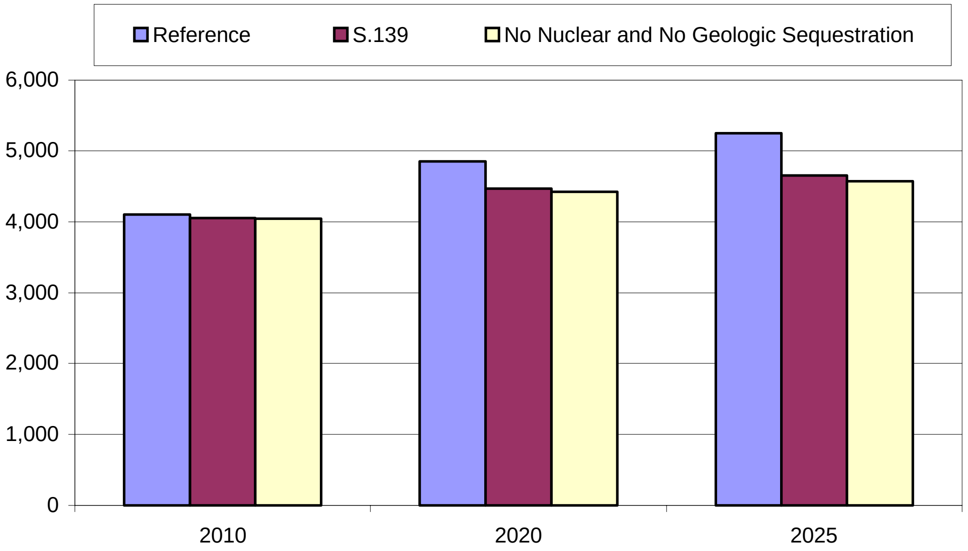
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and ML0NUCSEQ.D050403A.

Figure 5.17. Electricity Prices in the Reference, S.139, and No New Nuclear / No Geological Sequestration Cases (2001 cents per kilowatthour)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and ML0NUCSEQ.D050403A.

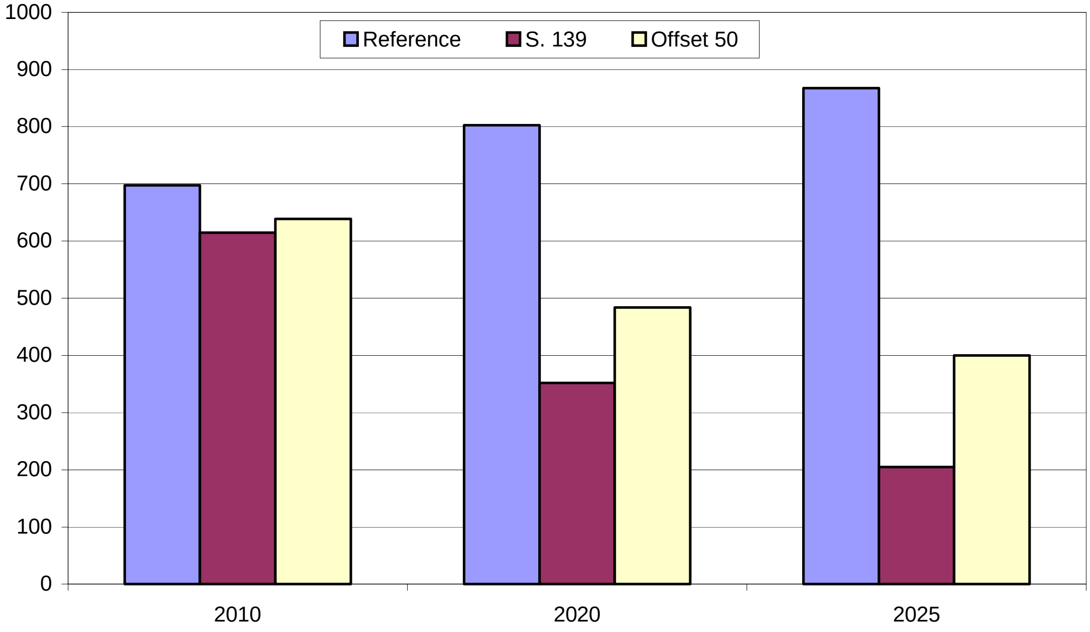
Figure 5.18. Electricity Sales in the Reference, S.139, and No New Nuclear / No Geological Sequestration Cases (billion kilowatthours)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and ML0NUCSEQ.D050403A.

the analysis to these limits, a case was prepared in which the maximum offset share was increased to 50 percent. In the power sector this change has a significant impact on greenhouse gas emissions, electricity prices, and the technologies chosen to meet future electricity demand. When the share limit is raised to 50 percent, power companies are projected to purchase additional offsets instead of reducing their own emissions as much as they did in the S.139 case (Figure 5.19). For example, in 2020, the power sector is projected to emit 132 million metric tons less carbon in the offset 50 case than in the S.139 case, and the difference continues to grow over time, reaching 195 million metric tons in 2025.

Figure 5.19. Electricity Sector Carbon Dioxide Emissions in the Reference, S.139, and Offset 50 Cases, 2010-2025 (million metric tons carbon equivalent)



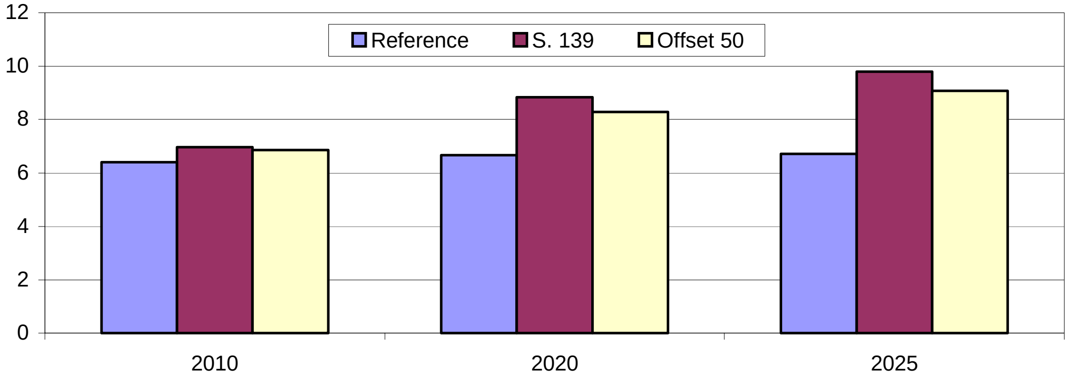
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and OFFSET50.D052303A.

Because the ability to use more offsets eases the need for power companies to reduce their own emissions, the increase in electricity prices in the offset 50 case is smaller than in the S.139 case (Figure 5.20). In 2020, electricity prices in the S.139 case are projected to be 8.8 cents per kilowatthour; in the offset 50 case they are 8.3 cents per kilowatthour, or 6 percent lower. Electricity prices in 2025 are projected to be 9.8 cents per kilowatthour in the S.139 case and 9.1 cents in the offset 50 case.

With less pressure to reduce their own emissions in the offset 50 case, relative to the S.139 case, power generators are projected to reduce their dependence on low- or zero-carbon technologies, particularly new coal and gas plants with carbon capture and sequestration equipment (Table 5.6). New renewable and nuclear technologies are projected to continue to play an important role in the offset 50 case, but the penetration of fossil plants with carbon capture and sequestration is much lower than projected in the S.139 case.

Another factor that could significantly affect the selection of technologies used to reduce power sector greenhouse gas emissions is the price of fuels—particularly, natural gas. To test this sensitivity, a case was prepared in which higher natural gas prices were assumed. With higher natural gas prices, the power sector is projected to rely more on new coal plants with carbon capture and sequestration equipment, nuclear plants, and renewable plants (Table 5.7). In the S.139 high gas price case, coal-fired electricity generation in 2025 is projected to be 59 percent below the projected level in the reference case and 40 percent below the 2001 level. This is much less than the 80 percent reduction from projected levels in the S.139 case. Coal generation and production actually begin to increase in the last few years of the projection period as the power sector builds additional coal plants with carbon capture and sequestration equipment.

Figure 5.20. Electricity Prices in the Reference, S.139 and Offset 50 Cases, 2010-2025 (2001 cents per kilowatthour)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and OFFSET50.D052303A.

Table 5.6. Unplanned Capacity Additions in the S.139 and Offset 50 Cases (gigawatts of capacity added through 2025)

Technology	S.139	Offset 50
Coal with Sequestration	37.7	5.0
Advanced Gas without Sequestration	156.5	191.2
Advanced Gas with Sequestration	102.1	13.3
Nuclear	48.5	48.6
Renewables	148.2	135.3
Wind	75.1	64.7
Biomass	65.2	62.3

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table 5.7. Unplanned Capacity Additions in the S.139 and S.139 High Gas Price Cases (gigawatts of capacity added through 2025)

Technology	S.139	S.139 High Gas Price
Coal with Sequestration	37.7	80.9
Advanced Gas without Sequestration	156.5	127.7
Advanced Gas with Sequestration	102.1	49.4
Nuclear	48.5	64.6
Renewables	148.2	177.7
Wind	75.1	83.9
Biomass	65.2	85.2

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503A and MLBILL_HGP.D052303A.

6. Fossil Fuel Supply

The impact on fossil fuel supplies and prices from S.139 largely depends on the impact of S.139 on demand. Because of the broad nature of S.139 (all greenhouse gases), the method of allowance allocation (relying on historical 1990 and 2000 rather than current greenhouse gas emissions as a benchmark), the ability to trade allowances, the inclusion of specific regulations aimed at reducing petroleum consumption as a way to reduce import dependence, and the requirement that the Climate Change Credit Corporation use its funds to blunt the impact of the cost of the greenhouse gas emission reductions on selected groups (e.g., reducing the cost to consumers through the use of buy-downs, subsidies, negotiation of discounts, and consumer rebates, with a particular emphasis on low-income consumers), the impact on supply and price can vary extensively by consuming sector and fuel. As result, the impact on fossil fuel supply is not always intuitively obvious, although it is likely to be inversely correlated with the relative carbon content of the fuel. This chapter examines the projected impacts of S.139 on fossil fuel supplies and prices.

Natural Gas Industry

Natural gas is a clean, widely available fuel used in about 55 million homes for space heating[158] and in about 66 percent of the manufacturing plants[159] in the United States. Almost one-quarter of the energy consumed in the United States comes from natural gas. Most of the natural gas consumed in the United States is produced domestically from wells in the south central part of the Nation. Gas is transported by pipelines from the production areas to consumers and becomes more expensive the farther the gas is shipped. Natural gas is typically cheaper than petroleum products and more expensive than coal on the basis of heating values.

Carbon Dioxide Emissions From Natural Gas Combustion

In 2001, combustion of natural gas by the end-use sectors and for the generation of electricity produced carbon dioxide emissions of 329 million metric tons carbon equivalent in the United States, about 21 percent of the U.S. total.[160] The industrial sector was responsible for the biggest share of those emissions, about 31 percent, followed by electricity generation, which contributed 28 percent of the carbon dioxide emissions from natural gas combustion. Natural gas consumption in the residential, commercial, and transportation sectors accounted for the remaining 41 percent of the carbon dioxide emissions from natural gas combustion.

Policies designed to reduce carbon dioxide emissions would generally boost natural gas consumption, principally because natural gas consumption would displace coal consumption in the electricity supply sector. Higher levels of gas production would require the development of more costly domestic gas resources, thereby pushing up wellhead gas prices. Higher prices for natural gas would eventually bring gas into competition with conservation (i.e., demand reduction) and alternative fuels, slowing the growth of gas consumption and prices.

In the reference and S.139 cases, cumulative carbon dioxide emissions from natural gas combustion from 2001 through 2025 are projected to be 10.4 and 10.5 billion metric tons carbon equivalent, respectively.

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[158] Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002), Table 2.8, p. 59.

[159] Energy Information Administration, *Manufacturing Consumption of Energy 1998*, web site http://www.eia.doe.gov/emeu/mecs/contents.html, Table C3.1

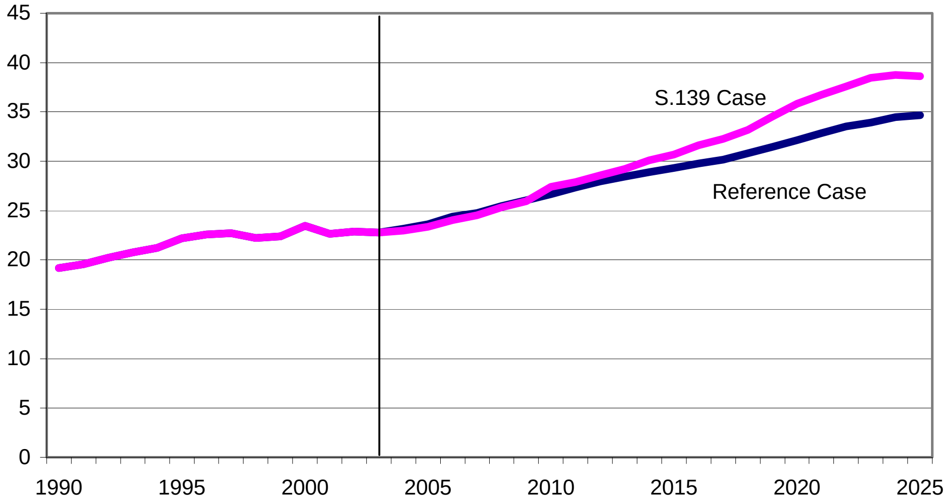
[160] Energy Information Administration, *Emissions of Greenhouse Gas in the United States 2001*, Table 4, p. 32. The 2001 carbon dioxide emissions figure is preliminary.

Although natural gas consumption from 2001 through 2025 is projected to be about 5 percent greater under S.139 than in the reference case on a cumulative basis, carbon dioxide emissions are only 1 percent greater because of the sequestration facilities projected to be built in conjunction with new natural-gas-fired combined-cycle electricity generation plants.

Natural Gas Consumption

S.139 is expected to affect future natural gas supply and prices primarily by changing future projected natural gas consumption. Relative to the reference case, S.139 is projected to increase total natural gas consumption, on a cumulative basis from 2001 through 2025, by a total of 37.7 trillion cubic feet (Figure 6.1). In the reference case, total annual gas consumption is projected to be 34.7 trillion cubic feet in 2025, compared with 38.6 trillion cubic feet under S.139.

Figure 6.1. Natural Gas Consumption in the Reference and S.139 Cases, 1990-2025 (trillion cubic feet)

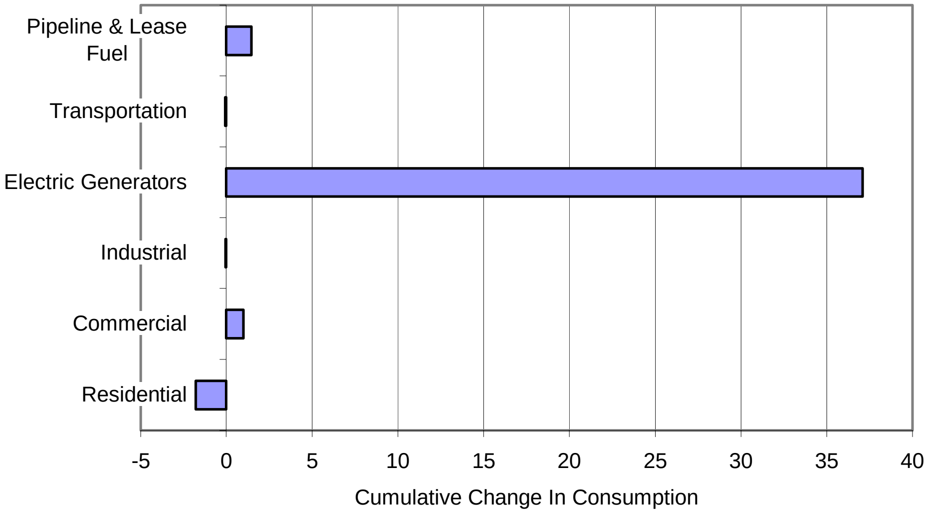


Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

The increase in natural gas consumption under S.139 also increases the natural gas share of total U.S. energy consumption. In the reference case, natural gas is projected to be 26 percent of 2025 total U.S. energy consumption. In contrast, the natural gas share of total U.S. energy consumption under S.139 is expected to be 31 percent in 2025. Gas' share increases because gas consumption is higher while total energy consumption is lower in the S.139 case (126.0 quadrillion Btu) than in the reference case (138.6 quadrillion Btu).

Most of the increase in natural gas consumption under S.139 over reference case levels occurs in the electricity generation sector. The large electric power sector increase in natural gas consumption results because S.139 is projected to substantially raise the cost of coal-fired electricity generation, which makes gas-fired plants the lowest cost option for generating electricity. Of the 37.7 trillion cubic foot increase in cumulative gas consumption from 2001 to 2025, 37.1 trillion cubic feet is projected to occur in the electric power sector (Figure 6.2).

Figure 6.2. Cumulative Change in U.S. Natural Gas Consumption Resulting from S.139 by End-Use Sector, 2001-2025 (trillion cubic feet)



Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Other sectors projected to post increases in natural gas consumption include the commercial sector, with an expected cumulative increase of 1.0 trillion cubic feet, and pipeline and lease fuel consumption,[161] which accounts for another 1.5 trillion cubic feet of the cumulative increase. The increase in gas pipeline and lease fuel usage is a direct result of the increase in domestic gas production and transportation. Commercial gas consumption increases because the higher electricity cost projected in the S.139 case is expected to cause a significant increase in the volume of gas consumed in the production of electricity at commercial facilities. The growth of on-site commercial electricity generation is projected to outweigh the effect that higher gas prices have on reducing commercial gas consumption.

The residential and industrial sectors are projected to consume less natural gas under S.139 than in the reference case, on a cumulative basis from 2001 through 2025. The residential sector is projected to post a 1.8 trillion cubic foot cumulative reduction in gas use because of higher natural gas prices resulting from the overall increase in gas consumption and the lack of fuel switching options. Although gas prices to the residential sector increase, electricity prices increase by even more, thereby reducing the attractiveness of centrally generated electricity as a substitution option. On-site renewable energy continues to be more expensive that natural gas.

Cumulative industrial natural gas consumption declines by only 50 billion cubic feet in the S.139 case because of two countervailing effects. On one hand, the industrial sector is subjected to both higher gas prices and emissions allowance costs, which act to depress industrial natural gas consumption. On the other hand, high electricity prices encourage industrial entities to build more electric cogeneration facilities, which act to increase industrial natural gas consumption. Because these countervailing effects neutralize each other, industrial gas consumption remains relatively unchanged.

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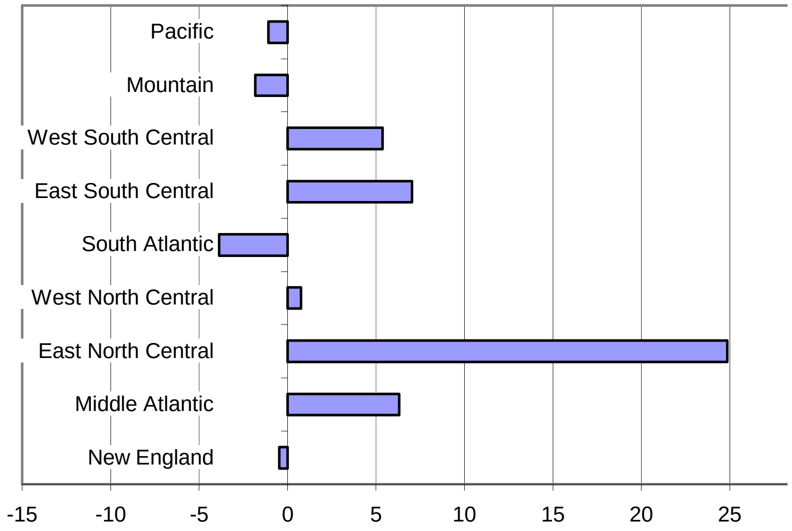
[161] Natural gas is consumed by pipelines in the transportation of gas from the well to the consumer. Lease and plant gas consumption is gas consumed near the field both to run production equipment and to separate methane from oil, low molecular weight hydrocarbons (i.e., ethane, butane, propane, etc.), water and other inert gases such as nitrogen, carbon dioxide, hydrogen sulfide, etc.

Total cumulative gas consumption in electricity generation from 2001 through 2025 is 20 percent greater in the S.139 case than in the reference case. A more detailed examination of gas consumption in electricity generation shows, however, that while S.139 total gas consumption is projected to increase significantly from 2001 through 2025, gas consumption in electric power generation is projected to decline in some regions (Figure 6.3). Specifically, the South Atlantic, Mountain, New England, and Pacific Census Divisions are projected to cumulatively reduce the volume of gas consumed in electric generation from 2001 through 2025 by 22, 16, 4, and 3 percent, respectively. These electricity gas consumption reductions occur primarily due to the higher price of gas under S.139 and the regional availability of lower cost substitutes, such as nuclear and renewable energy.

Figure 6.3. Cumulative Incremental Natural Gas Consumption for Electricity Generation Under S.139 by U.S. Census Division, 2001-2025 (trillion cubic feet)



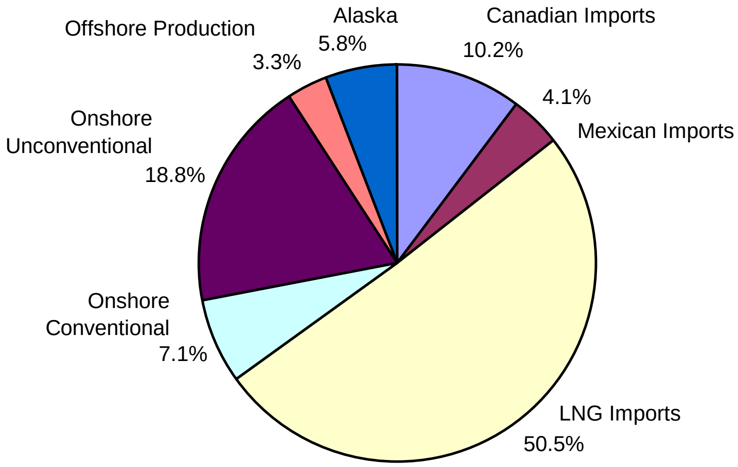
Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

In those Census Divisions where natural gas consumption in electricity generation is projected to grow, the increases in natural gas consumption are generally quite large. The largest percentage increases in regional projections of gas-fired electricity occur in (1) the East North Central Census Division, with a 117 percent increase, (2) West North Central with a 39 percent increase, (3) East South Central with a 38 percent increase, (4) Middle Atlantic with a 31 percent increase, and (5) West South Central with an 11 percent increase. Generally, S.139 causes higher natural gas consumption levels (primarily in the electric power sector), which result in higher delivered gas prices. The higher prices tend to dampen natural gas consumption in the end-use sectors.

Natural Gas Supply

The cumulative 37.7 trillion cubic foot increase in natural gas consumption from 2001 through 2025 is matched by a commensurate increase in natural gas supplies. Of the increase in gas supplies, 13.2 trillion cubic feet, or 35 percent, is projected to come from an increase in domestic natural gas production, while the remaining 24.5 trillion cubic feet, or 65 percent, is projected to come from increased natural gas imports (Figure 6.4).

Figure 6.4. Natural Gas Supply Sources Serving the Incremental 2001-2025 Increase in Natural Gas Consumption Resulting from S.139



Total = 37.7 trillion cubic feet

Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Of the 13.2 trillion cubic foot cumulative increase in domestic natural gas production from 2001 through 2025, 7.1 trillion cubic feet, or 54 percent, comes from onshore unconventional natural gas supply sources.[162] Another 2.7 trillion cubic feet, or 20 percent of the cumulative increase in domestic gas production, is produced from onshore conventional gas supplies; and another 1.2 trillion cubic feet, or 9 percent, is projected to come from increased offshore natural gas production.

The remaining 2.2 trillion cubic foot increase in cumulative gas production from 2001 through 2025 is projected to come from Alaska. This cumulative increase in Alaskan natural gas production results from an earlier construction and operation date for the Alaskan gas pipeline. In the reference case, the Alaskan natural gas pipeline goes into operation in 2020, followed by a capacity expansion during 2025. In the S.139 case, the pipeline goes into operation 1 year earlier, in 2019, due to the higher future gas prices projected for the S.139 case. Similarly, the higher gas prices also cause the Alaskan pipeline expansion to go into operation 1 year earlier than the 2025 date projected in the reference case. In both the reference and S.139 cases, the MacKenzie Delta pipeline comes into operation in 2015, which makes currently stranded Canadian Arctic gas available to U.S. gas consumers.

Natural gas resources appear to be adequate to satisfy the production levels projected in both scenarios. In the reference case, between 2001 and 2025, domestic wells are projected to produce 564 trillion cubic feet out of an estimated technically recoverable resource base of 1,289 trillion cubic feet. In contrast, domestic wells are projected to produce a total of 577 trillion cubic feet under S.139. From 2001 through 2025, 44 percent of the technically recoverable gas resource base is produced in the reference case, compared with 45 percent in the S.139 case.

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[162] "Unconventional" natural gas refers to gas produced from tight (low permeability) sandstones, gas shales, and coalbeds.

Of the 37.7 trillion cubic foot increase in cumulative 2001 to 2025 gas supplies, 24.5 trillion cubic feet is imported. Of the 24.5 trillion cubic feet, 78 percent or 19.1 trillion cubic feet is imported as liquefied natural gas (LNG), 16 percent or 3.9 trillion cubic feet is imported from Canada, and the remaining 6 percent or 1.6 trillion cubic feet is imported from Mexico.[163]

The large cumulative increase in LNG imports under S.139 is expected to result from (1) the accelerated construction of new LNG terminals already projected to be built in the reference case, (2) the accelerated expansion of existing LNG terminals, and (3) the construction of additional new LNG terminals not projected to be built in the reference case. Generally, the higher gas prices associated with S.139 accelerate LNG construction schedules by about 2 years. In the reference case, total LNG deliveries are projected to be 6.6 billion cubic feet per day in 2025. In the S.139 case, total U.S. LNG deliveries are projected to be 91 percent higher, at 12.6 billion cubic feet per day in 2025. In the reference case, all new LNG terminals are projected to be built along the Gulf of Mexico and in the Bahamas.[164] In the S.139 case, the bulk of LNG capacity is built in the Gulf and Bahamas, with some additional capacity being built in the South Atlantic Census Division.

Because natural gas imports account for 65 percent of total incremental supply, the relative proportions of each major gas source change significantly by the end of the forecast for S.139, relative to the reference case. As shown in Table 6.1, in 2025 the S.139 case projects gas imports to provide 28 percent of total U.S. gas supply, compared with 23 percent in the reference case. The increase in gas imports is largely attributable to an increase in the LNG import share of gas supply, which is projected to increase from 7.0 percent in the reference case to 12.0 percent in the S.139 case. The portion of supply expected to come from pipeline imports in 2025 increases slightly, from 16.0 percent in the reference case to 16.4 percent in the S.139 case.

Onshore conventional gas resources are projected to show the largest percentage point reduction in share of total gas supply, falling from 23.8 percent in the reference case to 21.6 percent in the S.139 case. In

Table 6.1. Composition of Natural Gas Supplies in 2025 by Major Source for the Reference and S.139 Cases (percent of total U.S. gas supply)

Gas Supply Source	Reference Case	S.139 Case
Lower 48 Onshore Conventional	23.8	21.6
Lower 48 Onshore Unconventional	28.0	27.3
Lower 48 Offshore	16.7	15.1
Alaska	8.3	7.4
Total U.S. Production	**76.8**	**71.4**
Net Pipeline Imports from Canada & Mexico	16.0	16.4
Liquefied Natural Gas Imports	7.0	12.0
Total Imports	**23.0**	**28.4**
Supplemental Gaseous Fuels	0.3	0.3
Total Gas Supply	**100.0**	**100.0**

Note: Totals may not equal sum of components due to independent rounding.
Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

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[163] Much of the natural gas imported from Mexico is expected to be coming from LNG regasification terminals that are close to the U.S.-Mexico border.

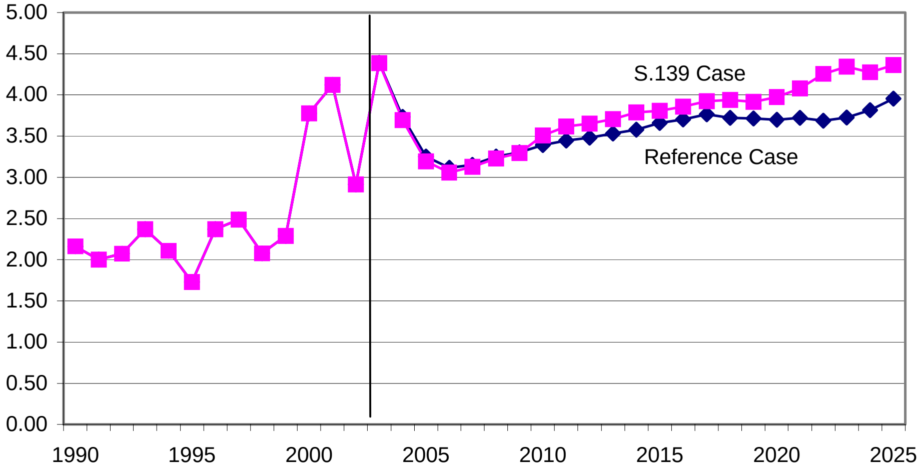
[164] The LNG capacity projected for Florida is expected to be located in the Bahamas. The LNG delivered to the Bahamas would be transported in a gaseous state to Florida through an undersea pipeline.

contrast, the other three domestic gas sources are projected to show less pronounced market share declines.

Natural Gas Prices

The primary effect of S.139 is to raise natural gas consumption, supply, and prices after 2010 (Figure 6.5). Gas prices are slightly lower prior to 2010 under S.139 than in the reference case. Consumers are expected to bank emissions credits by reducing their gas consumption prior to the effective date of the S.139 greenhouse gas emission limits. The reduction in pre-2010 gas consumption weakens gas prices during that period.

Figure 6.5. Projected U.S. Lower 48 Natural Gas Wellhead Prices in the Reference and S.139 Cases, 1990-2025 (2001 dollars per thousand cubic feet)



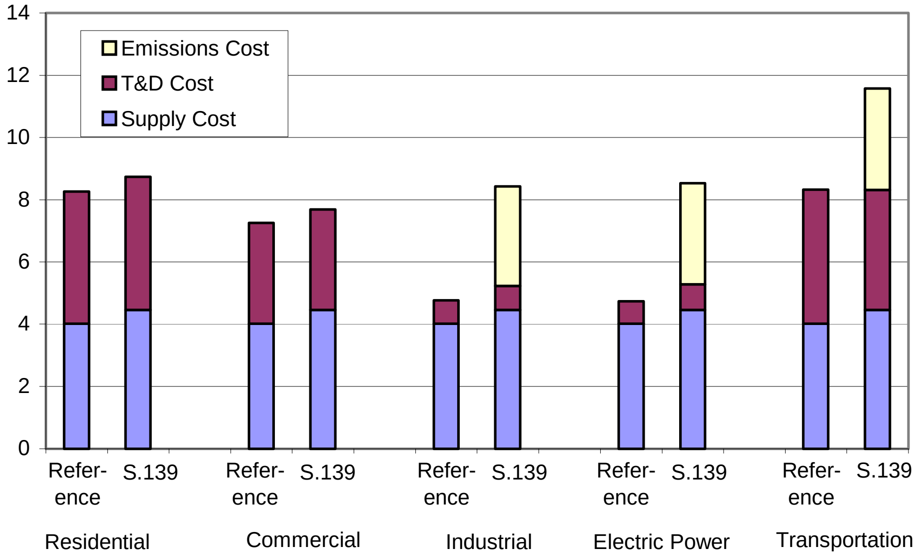
Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

After 2010, S.139 is projected to result in higher natural gas prices than are projected in the reference case. The higher gas prices under S.139 result from higher projected gas consumption. Higher gas consumption levels under S.139 deplete domestic gas resources at a faster rate, resulting in the development of higher cost gas supplies.

In 2025 in the S.139 case, the average lower 48 wellhead natural gas price is 41 cents per thousand cubic feet higher (in 2001 dollars) than is projected in the reference case ($4.36 per thousand cubic feet versus $3.95 per thousand cubic feet). The price differential between these cases changes over time. Because the construction of an Alaskan natural gas pipeline and of new LNG terminals adds large “lumpy” increments of new gas supply capacity, gas prices weaken until this new capacity is fully absorbed by the growth in gas consumption. Because this new infrastructure is built at different times in the two cases, wellhead price softness is also projected to occur during different timeframes for the two cases. As a result, the gas price for the two cases has a tendency to weaken at different times, thereby causing the price spread between the two cases to change over time. The largest lower 48 wellhead price spread occurs in 2023 at 62 cents per thousand cubic feet.

Delivered natural gas *prices* equal the wellhead gas price plus transmission and distribution markups. The *effective delivered cost* of consuming gas, however, also includes the cost associated with purchasing emissions allowances for fuel consumption in the industrial (including petroleum refining), electric power, and transportation sectors. Figure 6.6 compares the 2025 effective delivered cost of gas, by cost component, for each end-use sector, for the reference and S.139 cases. In the industrial, electric power, and transportation sectors, the effective delivered cost of gas in 2025 is higher in the S.139 case (relative to the reference case) primarily due to the cost of emissions allowances, and secondarily due to the higher cost of gas supplies. In 2025, the greenhouse gas emissions cost for the industrial, electric power and vehicular transportation sectors is projected to average $3.25 per thousand cubic feet under S.139. Residential and commercial gas consumers do not bear a greenhouse gas emissions cost in the S.139 case, so the higher delivered gas prices for the residential and commercial sectors under S.139 directly result from the higher wellhead gas price associated with higher gas consumption levels.

Figure 6.6. Effective Delivered Cost of Natural Gas by End-Use Sector in the Reference and S.139 Cases, 2025 (2001 dollars per thousand cubic feet)



Note: Includes delivered price of natural gas and cost of greenhouse gas emissions allowances.
Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure 6.7 shows the change in the effective delivered cost of gas to each of the end-use sectors over time due to S.139, and relative to the reference case. The effective delivered cost of gas to the industrial, electric power, and transportation sectors rises over most of the forecast period, because the cost of emissions allowances increases steadily through 2023 and then declines slightly until 2025. The change in the effective delivered cost of gas to the residential and commercial sectors primarily reflects the wellhead price differential between the reference and S.139 cases.

Natural Gas Pipelines

The construction of interstate pipeline capacity directly reflects changes in intraregional gas consumption and supply. The National Energy Modeling System does not constrain gas pipeline construction; that is, sufficient new capacity is built to accommodate the projected changes in regional consumption and supply.[165]

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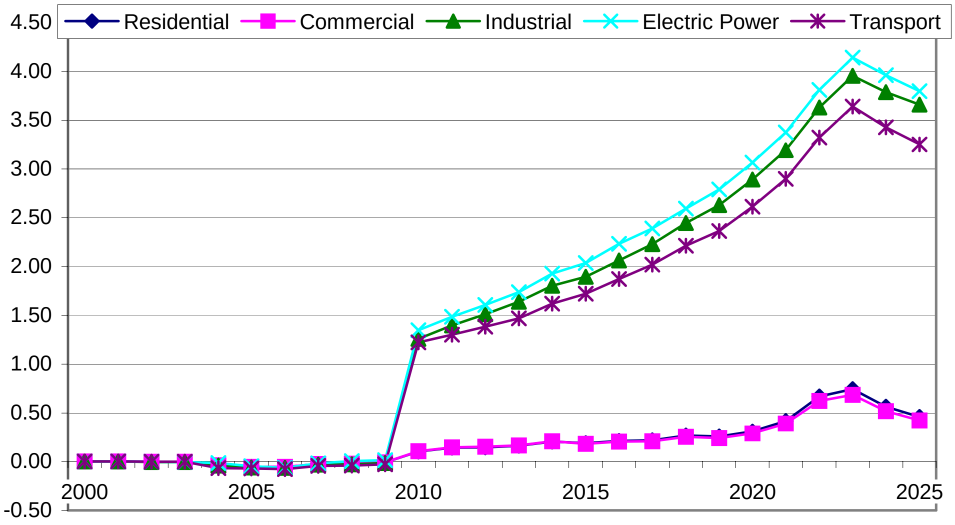
[165] In reality, new pipeline construction could be constrained in the short-term due to delays in planning and construction and due to public opposition.

Figure 6.7. Change in Effective Delivered Cost of Natural Gas, Including Greenhouse Gas Emission Allowance Costs for the Covered Sectors Under S.139, by End-Use Sector, 2000-2025 (2001 dollars per thousand cubic feet)



Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

As mentioned earlier, the MacKenzie Delta pipeline comes into operation in 2015 and the Alaskan North Slope pipeline is projected to go into operation in both scenarios, albeit at slightly different dates, that is 2020 in the reference case and 2019 in the S.139 case.

As noted earlier, the primary impact of S.139 is the projected increase in gas-fired electricity generation, which occurs primarily in the East North Central Census Division, with smaller regional increases occurring in the West and East South Central Census Divisions and the Middle Atlantic Census Division. Cumulative incremental gas supplies are expected to come from the following regions, in their order of relative importance: (1) LNG imports into the Gulf Coast, (2) Canadian imports, (3) Rocky Mountain gas production, (4) onshore Gulf of Mexico gas production, (5) lower 48 offshore gas production, and (6) Alaskan gas production. As a result of these changes in supply and consumption under S.139, additional new pipeline capacity is expected to be built along three major transportation corridors: (1) from Canada through the West North Central and into the East North Central and possibly further on into the Middle Atlantic; (2) from the Rocky Mountains through the West North Central and into the East North Central; and (3) from the coast of the Gulf of Mexico through the East South Central and into the East North Central, South Atlantic, and eventually the Middle Atlantic region.

Upstream Natural Gas Employment

The U.S. Department of Labor reports two data series regarding employment in the domestic petroleum exploration and production (E&P) industry: 1) eeu10131001(n), which pertains to oil and gas company employment, and 2) eeu10138001(n), which pertains to petroleum field service company workers. These employment data series do not differentiate between employees engaged in oil-related E&P activities and those working on gas-related E&P activities.[166] In order to develop separate estimates for each fuel, the

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[166] The first employment data series pertains to the industrial SIC 131 (crude petroleum and natural gas). The second employment data series pertains to the industrial SIC 138 (oil and gas field services).

projected petroleum employment levels were allocated to oil and to gas based on the projected relative proportions of future domestic oil and gas production, as measured on a Btu basis.

In 2001, the Department of Labor reported that 334,000 employees worked in oil and gas E&P activities. Because 12.3 quadrillion Btu of oil and 20.0 quadrillion Btu of gas were produced in 2001, gas E&P activities in 2001 are estimated to have employed 207,000 workers.

In the reference case, gas production grows throughout the forecast and so does gas E&P employment. Gas E&P employment is projected to grow to 273,000 people in 2025. Over the entire period spanning 2001 through 2025, the cumulative increase in gas E&P employment is 5.79 million person-years.

In comparison, the S.139 case projects higher gas employment levels due to higher gas production levels. From 2001 through 2025, the S.139 case projects a cumulative employment level of 5.93 million person-years and a 2025 employment level of 287,000 people. Compared with the reference case, the cumulative employment impact of the S.139 case from 2001 through 2025 is projected to be an additional 136,000 person-years. Natural gas E&P employment under S.139 does not increase to the same degree as the projected gas consumption levels, because natural gas imports are projected to account for 65 percent of the incremental gas supply projected under S.139 from 2001 through 2025.

Alternative Scenarios

The results from five alternate scenarios are discussed in this section: (1) the high technology reference case, (2) the S.139 high technology case, (3) the S.139 no new nuclear, no sequestration case, (4) the high gas price case, and (5) the high gas price S.139 case. The high technology reference case assumes high performance characteristics for the end-use demand and electricity generation sectors, similar to the assumptions made in EIA's *Annual Energy Outlook 2003* integrated high technology case.[167] The high technology reference case projects an energy future in the absence of S.139 enactment. The S.139 high technology case incorporates the same technology assumptions as the high technology reference case, but assumes the enactment of S.139. The S.139 no new nuclear, no sequestration case assumes S.139 enactment, and also assumes that neither of these two technologies would be commercially available through 2025. The high gas price case and high gas price S.139 case were developed to examine how S.139 might affect an energy future where gas prices are considerably higher than those projected in the reference case. These cases provide some insight as to the potential range of outcomes relative to natural gas supply, consumption, and prices that might result from passage of S.139. Generally, both high technology cases project lower future natural gas consumption. In contrast, the S.139 no new nuclear, no sequestration case projects higher future natural gas consumption than the S.139 case. The high gas price case and the high gas price S.139 case project both lower total gas consumption and less incremental gas consumption. Table 6.2 summarizes the projected results of five cases on natural gas consumption, supply, prices, greenhouse gas emissions, and employment relative to the reference case and the S.139 case.

A. High Technology Cases

The two high technology cases discussed in this analysis—the high technology reference case and the S.139 high technology case—assume that increased spending on research and development will result in earlier introduction, lower costs, and higher efficiencies for end-use technologies than in the reference case. The cost and efficiencies of the advanced fossil-fired and new renewable generating technologies are also assumed to improve relative to reference case values. The technological improvements assumed

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[167] Energy Information Administration, *Annual Energy Outlook 2003,* DOE/EIA-0383(2003) (Washington, DC, January 2003), Appendix Table F4, p. 218.

Table 6.2. Comparison of U.S. Natural Gas Projections in Seven Cases

	Reference	S.139	No New Nuclear, No Sequestration	High Technology Reference	S.139 High Technology	High Gas Price	High Gas Price S.139
Cumulative 2001-2025 Natural Gas Consumption (Tcf)	708	746	753	672	703	668	679
Cumulative 2001-2025 Natural Gas Consumption In Electric Power (Tcf)	188	225	231	166	196	162	177
Cumulative 2001-2025 Natural Gas Production (Tcf)	564	577	579	543	558	514	520
Cumulative 2001-2025 Net Natural Gas Imports (Tcf)	138	162	168	123	138	147	152
2025 Natural Gas Consumption (Tcf)	34.7	38.6	39.6	31.6	35.6	29.3	29.8
2025 Natural Gas Consumption In Electric Power (Tcf)	10.4	14.0	15.3	8.6	12.4	6.7	7.5
2025 Natural Gas Production (Tcf)	26.4	27.3	27.9	24.7	26.3	21.8	21.9
2025 Net Natural Gas Imports (Tcf)	7.9	10.9	11.4	6.4	8.9	7.1	7.4
2025 Natural Gas Lower 48 Average Wellhead Price (2001$/Mcf)	$3.95	$4.36	$4.70	$3.51	$4.09	$5.55	$5.70
2025 Average Delivered Price of Natural Gas (w/o emissions costs) (2001$/Mcf)	$5.80	$6.19	$6.54	$5.43	$5.94	$7.45	$7.66
2025 Average Industrial & Electric Power Emissions Allowance Cost (2001 $/Mcf)	N/A	$3.23	$4.33	N/A	$2.32	N/A	$3.11
Cumulative 2001-2025 Carbon Dioxide Emissions From Natural Gas (billion metric tons carbon equivalent)	10.4	10.5	11.1	9.9	9.9	9.8	9.7
Cumulative Gas Exploration and Production Employment From 2001 to 2025 (thousand person-years)	5,790	5,926	5,940	5,673	5,789	5,500	5,850

Note: Totals may not equal the sum of the components due to independent rounding. In addition, there is a discrepancy between total production, consumption, and imports due to natural gas “lost” as a resulting of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type.

Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML0NUCSEQ.D050403A, MLBASE_HT.D052003C, ML_HT.D050503A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

for these two cases reduce future energy requirements in general, and natural gas consumption in particular. For example, the high technology reference case projects significantly lower levels of future natural gas consumption than the reference case. On a cumulative basis from 2001 through 2025, the high technology reference case projects total gas consumption to be 672 trillion cubic feet, which is 5 percent less than the cumulative gas consumption projected for the reference case. The lower gas consumption level of the high technology reference case also reduces gas imports, domestic production and prices. In 2025, for example, the average lower 48 wellhead gas price is 44 cents per thousand cubic feet lower than projected in the reference case (i.e., $3.95 per thousand cubic feet in the reference case and $3.51 per thousand cubic feet in the high technology reference case).

In the remainder of this subsection, the impacts of S.139 will be appraised relative to the projections expected for the high technology reference case, comparing the S.139 high technology case projections with those of the high technology reference case. Relative to the high technology reference case, cumulative 2001-2025 gas consumption is projected to increase in the S.139 high technology case. Total cumulative gas consumption from 2001 through 2025 in the S.139 high technology case is projected to be 703 trillion cubic feet, which is 5 percent larger than the 672 trillion cubic feet projected for the high technology reference case. The 30.4 trillion cubic foot increase in cumulative natural gas consumption in the S.139 high technology case is largely attributable to the 29.7 trillion cubic foot cumulative increase in electric power gas consumption, relative to the high technology reference case.

The 2025 gas consumption level in the S.139 high technology case is higher than that projected in the high technology reference case, 35.6 trillion cubic feet versus 31.6 trillion cubic feet. Again, the higher 2025 gas consumption levels in the S.139 high technology case are largely attributable to higher electric power gas consumption. Under S.139, gas consumption in the electric power sector is 12.4 trillion cubic feet in 2025, compared with 8.6 trillion cubic feet in the high technology reference case.

In the S.139 high technology case, the higher gas consumption levels are matched by a commensurate increase in gas supply. Of the cumulative 30.4 trillion cubic foot increase in gas supplies from 2001 through 2025, 14.9 trillion cubic feet comes from gas imports, and the remaining 15.5 trillion cubic feet comes from domestic gas production. With respect to gas imports, 10.6 trillion cubic feet of the cumulative 2001-2025 increase in gas imports is projected to be imported as LNG.

With respect to domestic gas supplies, the 15.5 trillion cubic foot cumulative increase in domestic production in the S.139 high technology case is projected to be satisfied by a 7.1 trillion cubic foot cumulative increase in unconventional gas production, a 5.7 trillion cubic foot cumulative increase in Alaskan gas production due to the earlier construction and operation of a gas pipeline from Alaska to the lower 48 States, a 2.1 trillion cubic foot cumulative increase in conventional onshore gas production, and a 600 billion cubic foot cumulative increase in offshore gas production.

As before, the higher gas consumption levels in the S.139 high technology case are projected to result in higher gas prices relative to the high technology reference case. In 2025, the lower 48 average wellhead gas price is projected to be $4.09 per thousand cubic feet (in 2001 dollars), which is 58 cents per thousand cubic feet higher than the $3.51 per thousand cubic feet wellhead gas price projected in the high technology reference case.

Because cumulative incremental gas production is expected to increase in the S.139 high technology case relative to the high technology reference case, gas exploration and production industry employment levels are higher in the S.139 high technology case. Cumulative incremental 2001-2025 gas employment in the S.139 high technology case is projected to be higher by 116,000 worker-years than the high technology reference case, but 137,000 worker-years lower than the S.139 case.

B. No New Nuclear, No Sequestration Case

The no new nuclear, no sequestration case reduces the energy sector's flexibility to comply with S.139 greenhouse gas emissions limits. The absence of new nuclear plants raises gas consumption. The absence of sequestration technology raises the cost of emission allowances. Not surprisingly, the no new nuclear, no sequestration case projects the highest level of gas consumption among the five cases discussed in this section. Because the no new nuclear, no sequestration case was developed to be consistent with the reference case, this discussion will compare the no new nuclear, no sequestration case to the reference case.

Cumulative 2001-2025 gas consumption in the no new nuclear, no sequestration case is projected to be 753 trillion cubic feet, which is 6 percent higher than in the reference case. As in the reference case, virtually all of this increase in cumulative gas consumption occurs in the electric power sector. Total cumulative 2001-2025 gas consumption is 45.1 trillion cubic feet greater in the no new nuclear, no sequestration case than in the reference case. Of this 45.1 trillion cubic foot increase in gas consumption, the electric power sector is projected to account for 43.7 trillion cubic feet of the incremental increase. The industrial and vehicular end-use sectors are expected to experience virtually no change in cumulative gas consumption, while the 1.6 trillion cubic foot increase in cumulative commercial gas consumption is more than offset by the 1.8 trillion cubic foot decline in cumulative residential consumption. Pipeline, plant and lease gas consumption is projected to increase by 1.6 trillion cubic feet on a cumulative basis, because of the higher level of domestic gas production.

The cumulative increase in gas consumption of 45.1 trillion cubic feet in the no new nuclear, no sequestration case is matched by a commensurate increase in natural gas supplies. As in the S.139 case, most of the increased gas consumption is supplied through gas imports. Net gas imports are projected to incrementally supply 30.3 trillion cubic feet from 2001 through 2025, for 67 percent of the total incremental gas supply. In the no new nuclear, no sequestration case, 23.9 trillion cubic feet of these incremental gas imports are projected to be delivered as LNG. Canada and Mexico are respectively projected to supply 3.3 and 3.1 trillion cubic feet of incremental gas supplies to the United States from 2001 through 2025.

U.S. domestic gas production is projected to cumulatively supply 14.8 trillion cubic feet of the incremental gas supply from 2001 through 2025. Onshore unconventional natural gas production is projected to account for 8.4 trillion cubic feet of the total, while onshore conventional gas contributes 3.6 trillion cubic feet and Alaska provides an incremental 2.2 trillion cubic feet. The offshore's cumulative contribution to total gas supply increases by only 0.7 trillion cubic feet over the forecast period.

Natural gas E&P employment levels are projected to increase in the S.139 no new nuclear, no sequestration case, relative to both the reference and S.139 cases, due to higher gas production levels. In this case, 2025 gas E&P employment is projected to be 290,000, and cumulative 2001-2025 incremental employment is projected to be an additional 150,000 person-years, relative to the reference case.

In the no new nuclear, no sequestration case, the higher gas production rates deplete a higher proportion of the estimated gas resource base, thereby making the remaining gas resources more costly to produce. By 2025, in the no new nuclear, no sequestration case, the lower 48 wellhead gas price is projected to reach $4.70 per thousand cubic feet (in 2001 dollars), or 75 cents per thousand cubic feet greater than the 2025 wellhead gas price projected in the reference case.

The effective delivered cost of natural gas in the no new nuclear, no sequestration case is projected to be much higher than projected in the reference case, because both wellhead gas prices and greenhouse gas emission allowance costs are much higher. In 2025, the average lower 48 wellhead gas price is projected to be $4.70 per thousand cubic feet (in 2001 dollars) in the no new nuclear, no sequestration case, which is 75 cents per thousand cubic feet higher than the $3.95 per thousand cubic foot prices projected in the reference case. In 2025, greenhouse gas emission allowance costs are projected to average $4.35 per thousand cubic feet for the electric power, industrial, and transportation sectors.

C. High Natural Gas Price Cases

The high gas price cases[168] were designed to analyze the effects associated with S.139 if natural gas prices were higher than projected in the reference case. The high gas price cases embody plausible assumptions regarding the causes for higher future gas prices. Those assumptions are:

- Both U.S. and Canadian gas resources are 25 percent less than the current resource base estimates assumed in the reference case.
- The petroleum industry's future rate of technological progress is 25 percent lower than that observed historically (the reference case assumes the historical rate of technological progress).
- The Alaskan natural gas pipeline takes 10 years to plan, permit, and build rather than the 7 years expected in the reference case.
- New domestic LNG facilities cannot be constructed on the East and West coasts, but only in the Gulf of Mexico and in Florida,[169] whereas the reference case allows LNG facilities to be built in all three regions (i.e., East Coast, West Coast, and Gulf of Mexico).

With the exception of these four assumptions, the high gas price case uses all the other reference case assumptions. The high gas price S.139 case uses the same assumptions as the high gas price case, but also assumes the enactment of S.139.

These four gas supply assumptions create a more constrained gas supply picture, because there is less foreign gas potentially available to the market, which makes the country more dependent on domestic gas supplies, and because domestic gas is more expensive to produce. For example, the reference case projections are based on an estimated 1,289 trillion cubic feet of technically recoverable gas resources. By 2025, in the reference case, domestic gas wells are projected to produce 44 percent of the estimated technically recoverable resource base of 1,289 trillion cubic feet. In the high gas price cases, the technically recoverable gas resources base is assumed to be 967 trillion cubic feet. Between 2001 and 2025, the high gas price case is projected to cumulatively produce 514 trillion cubic feet, which is 53 percent of the assumed resource base. Gas prices are higher partly because there is a smaller domestic gas resource base, which experiences a greater degree of resource depletion than in the reference case projection. Moreover, the assumption that future technological progress in gas drilling and production will advance at a rate 25 percent below the historic trend also contributes to the higher gas prices projected for the two high gas price cases.

Figure 6.8 shows projected lower 48 average wellhead gas prices for both high gas price cases and for the reference case. Generally, the reference case projects lower prices because gas supplies are less constrained. Reference case wellhead gas prices are projected to rise gradually to $3.95 per thousand cubic feet (in 2001 dollars). In contrast, 2025 wellhead gas prices are projected to reach $5.55 per thousand cubic feet in the high gas price case and $5.70 per thousand cubic feet in the high gas price S.139 case. In both high gas price cases, the higher prices are projected to cause the Alaskan natural gas pipeline to begin planning and permitting around 2008, so that it becomes operational in 2018. In the

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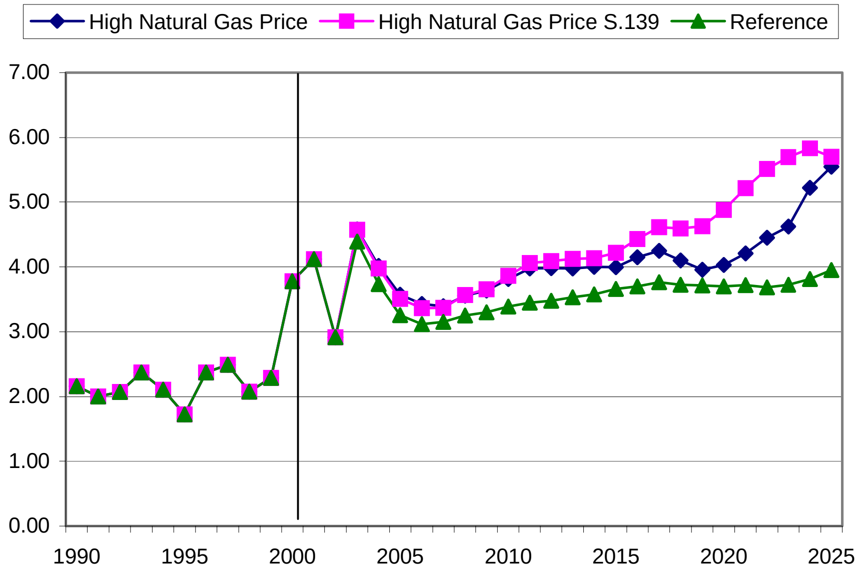
[168] The high natural gas price cases were completed in response to a request from Senator Inhofe's staff. The e-mail requesting this particular case is included in Appendix A.

[169] The LNG terminal is in the Bahamas and natural gas is transported to Florida via an undersea pipline.

Figure 6.8. Projected U.S. Lower 48 Natural Gas Wellhead Prices in the High Natural Gas Price Case and in the High Natural Gas Price S.139 Case, 1990-2025 (2001 dollars per thousand cubic feet)



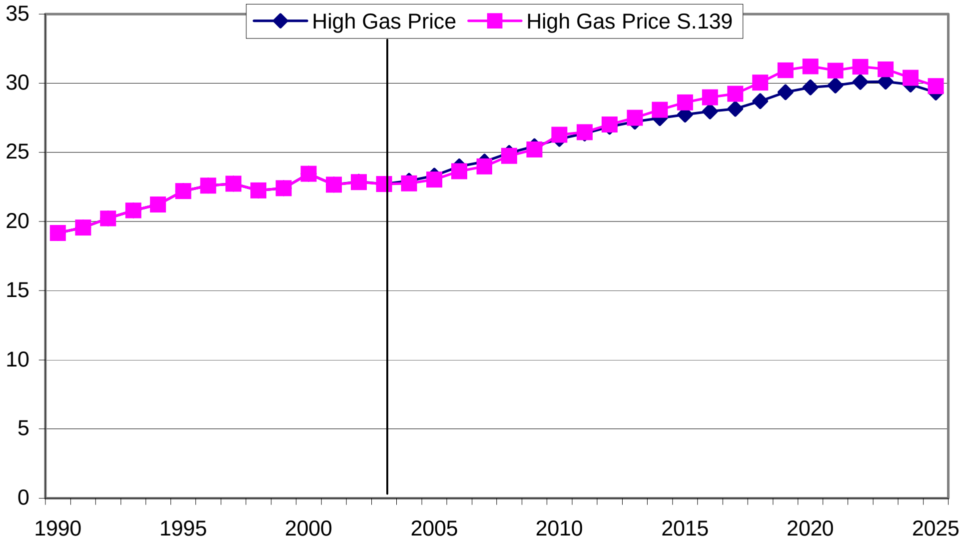
Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

reference case, however, the Alaskan gas pipeline comes into operation in 2020, with planning and permitting starting around 2014.

In the high gas price cases, the initiation of Alaskan gas pipeline operations in 2018 adds a large increment to domestic gas supply, thereby causing wellhead gas prices to weaken. Lower 48 wellhead prices are projected to remain more constant for the high gas price S.139 case than the high gas price case, because under S.139 any weakening in gas prices is immediately counterbalanced by an increase in gas consumption. In the high gas price case, the average lower 48 wellhead gas price rises by 38 percent after 2020, from $4.03 per thousand cubic feet (in 2001 dollars) in 2020 to $5.55 per thousand cubic feet in 2025. In the high gas price S.139 case, wellhead gas prices exceed $4 per thousand cubic feet in 2011 and continue to rise until peaking in 2024 at $5.83 per thousand cubic feet, then decline slightly to $5.70 per thousand cubic feet in 2025. In the high gas price S.139 case, the high gas prices just prior to 2025 cause both gas consumption to decline and domestic gas supplies to increase (as measured by gas reserve levels), thereby causing gas prices to decline slightly in 2025.

As shown in Figure 6.9, the high gas price cases differ from the other scenarios in one crucial respect, namely, that domestic gas consumption declines in both cases by the end of the forecast period. In the high gas price case, total U.S. natural gas consumption peaks in 2023 at 30.1 trillion cubic feet and declines to 29.3 trillion cubic feet in 2025. In the high gas price S.139 case, gas consumption peaks in 2020 at 31.2 trillion cubic feet and declines to 29.8 trillion cubic feet in 2025. The high gas price cases project a decline in consumption because high gas prices encourage consumers both to be more efficient in their use of natural gas and to substitute alternative energy sources wherever it is economically feasible.

Figure 6.9. Total U.S. Natural Gas Consumption in the High Gas Price and High Gas Price S.139 Cases, 1990-2025 (trillion cubic feet per year)



Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE_HGP.D052103A and MLBILL_HGP.D052303A.

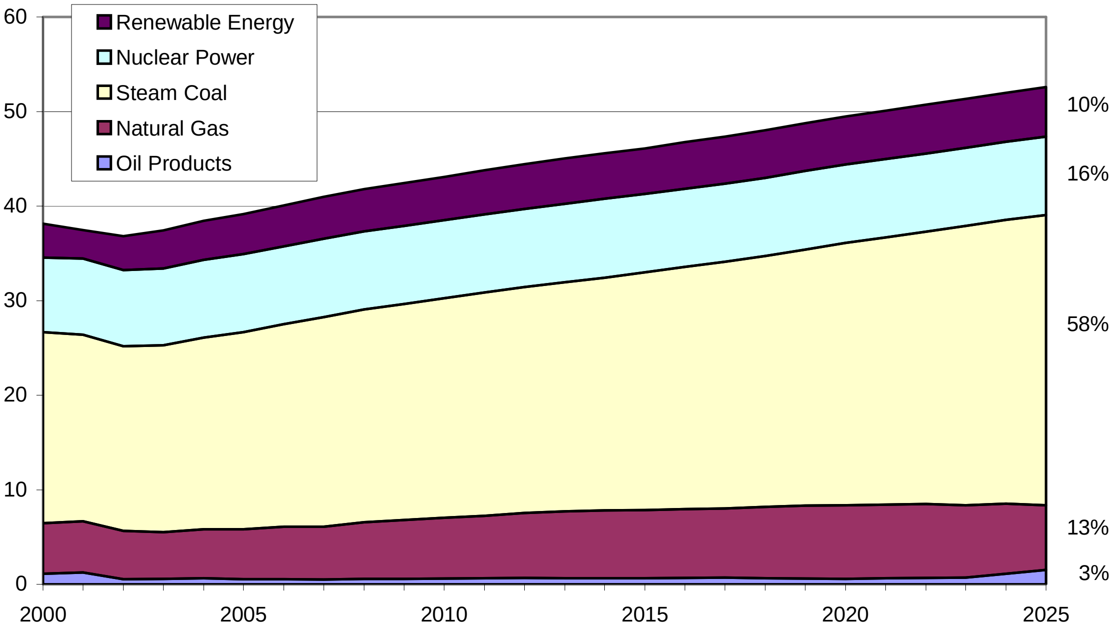
Although total gas consumption declines toward the end of the forecast, the decline is not equally distributed among the end-use sectors. With the exception of a 20 billion cubic foot decline in residential gas consumption at the very end of the forecast, the sector primarily responsible for the overall decline in total gas consumption is electric power generation. In the high gas price case, electric power gas consumption peaks in 2022 at 7.6 trillion cubic feet and then declines to 6.7 trillion cubic feet in 2025. As shown in Figure 6.10, in the high gas price case, natural gas consumption in the electric power sector is reduced in the later years of the forecast by increased consumption of coal and petroleum fuels, which is a fuel substitution effect, caused by high gas prices.

Other than the decline in electric power gas consumption toward the end of each high gas price case projection, the gas consumption profile of the high gas price S.139 case relative to the high gas price case is similar to those projected for S.139 in the other alternate scenarios. Specifically, the enactment of S.139 under high gas prices increases total cumulative incremental gas consumption from 2001 through 2025 by only 11.4 trillion cubic feet, relative to the high gas price case.

Because the high gas prices in these cases make the use of natural gas less economically attractive, in the high gas price S.139 case, the electric power sector's cumulative increase in gas consumption from 2001 through 2025 is only 14.2 trillion cubic feet more than in the high gas price case. In comparison, the cumulative increase in electric power gas consumption for the S.139 case relative to the reference case is projected to be 37.1 trillion cubic feet. Thus, the higher gas prices associated with these high gas price scenarios reduce the cumulative increase in electric power gas consumption by 62 percent relative to the reference case and S.139 case projections.

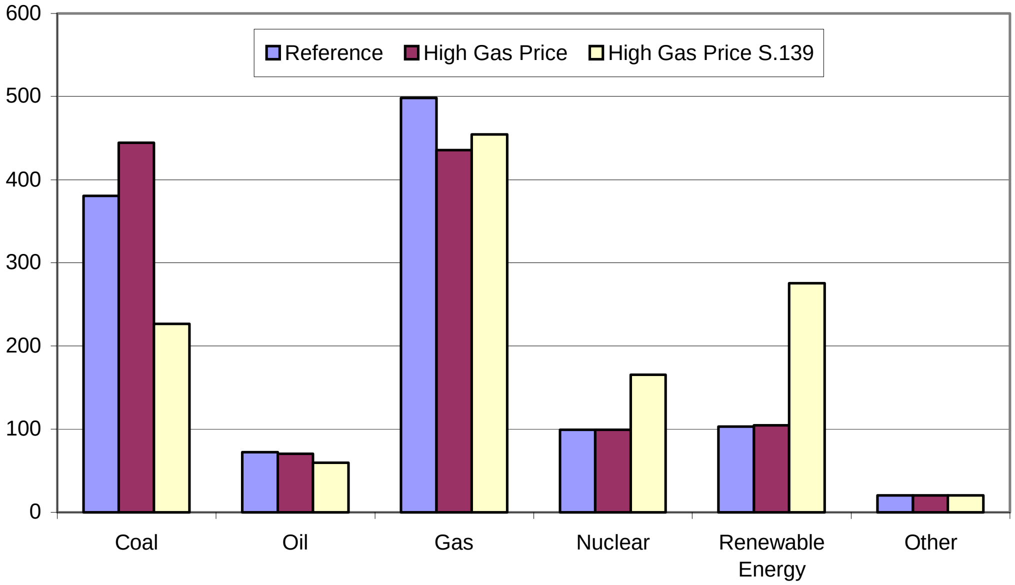
The impact of high gas prices on the electric power sector is also illustrated in the profile of electric generation capacity for the two high gas price cases. As can be seen in Figure 6.11, enactment of S.139 is

Figure 6.10. Electric Power Sector Fuel Consumption in the High Natural Gas Price Case, 2000-2025 (quadrillion Btus per year)



Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System run MLBASE_HGP.D052103A.

Figure 6.11. Total U.S. Electricity Generation Capacity by Energy Source in the Reference and High Gas Price Cases, 2025 (gigawatts)



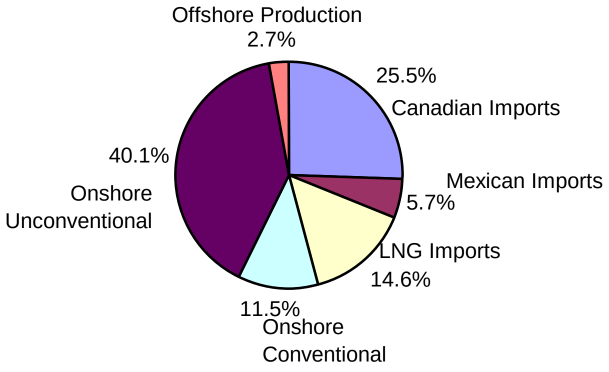
Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE_HGP.D052103A and MLBILL_HGP.D052303A.

projected to reduce 2025 coal-fired generation capacity by 218 gigawatts.[170] Because of high gas prices, total natural gas generation capacity is projected to increase by only 19 gigawatts between the two cases in 2025. In contrast, both nuclear and renewable energy are projected to show large incremental increases in capacity between the two cases, as an offset to the decline in coal-fired capacity. In 2025, in the high gas price S.139 case, nuclear power capacity is 66 gigawatts greater than projected in the high gas price case. Similarly, in 2025, renewable energy capacity is 171 gigawatts greater in the high gas price S.139 case than in the high gas price case.[171] The net effect of high gas prices is to increase the economic attractiveness of nuclear, renewable energy, and coal sequestration technology relative to gas-fired capacity. If S.139 were enacted under these conditions, the electric power industry would be expected to build primarily new nuclear, renewable energy, and coal sequestration facilities to reduce the carbon emissions produced by coal-fired electricity generation.

In the high gas price cases, the other end-use sectors also react in a similar manner to enactment of S.139. Residential and industrial gas consumption levels are projected to decline on a cumulative basis from 2001 through 2025—by 2.2 and 1.7 trillion cubic feet, respectively—due to the higher gas prices. In the industrial sector, the reduction in natural gas consumption reflects the overall drop in industrial energy use.[172] The commercial sector, in contrast, is projected to show a cumulative increase in commercial gas consumption, due to the sector's ability to employ distributed electricity generation facilities as a means of avoiding the higher electricity prices projected as a result of S.139 enactment.

Because these high gas price cases are the result of a more constrained gas supply picture, relative to the alternate scenarios discussed earlier, they are significantly different with respect to the incremental sources of gas supply used to meet S.139 greenhouse gas emissions limits. Figure 6.12 shows the cumulative increase in gas supplies provided by the various supply sources from 2001 through 2025 for

Figure 6.12. Cumulative Incremental Natural Gas Supply Sources in the High Gas Price S.139 Case Relative to the High Gas Price Case, 2001-2025



Total = 11.2 Trillion Cubic Feet

Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE_HGP.D052103A and MLBILL_HGP.D052303A.

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[170] Total 2025 electric power generation capacity is 27 gigawatts less in the high gas price S.139 case than in the high gas price case.

[171] The incremental increase in renewable energy electricity generation capacity between the two cases is as follows: wood and other biomass with 85 gigawatts, wind with 80 gigawatts, geothermal with 5 gigawatts, and municipal waste with about 1 gigawatt.

[172] In 2025, total industrial energy use is 2.6 quadrillion Btus less in the high gas price S.139 case, relative to the high gas price case. This reduction in industrial energy use occurs for all major fuel types (i.e., oil, gas, coal, electricity and renewable energy).

the high gas price S.139 case relative to the high gas price case. The limitations placed on Canadian and LNG imports significantly reduce their role in providing incremental gas supplies in the high gas price S.139 case.

In the prior scenarios, about two-thirds of cumulative 2001-2025 incremental gas supply came from natural gas imports and about one-third came from domestic production. In the high gas price gas cases, gas imports account for 46 percent of the cumulative 2001-2025 incremental gas supplies and domestic gas supplies account for the remaining 54 percent of cumulative 2001-2025 incremental gas supplies.

Because gas imports are limited both by smaller Canadian resources and the inability to build new LNG capacity on the East and West coasts, domestic supplies are required to make up the difference. Of the domestic gas supply sources, unconventional natural gas is projected to contribute 40 percent of the incremental gas supply projected for the high gas price S.139 case relative to the high gas price case.

Petroleum Industry

Nearly 40 percent of the Nation’s energy comes from petroleum, with two-thirds of that amount consumed in the transportation sector. The industrial sector accounts for 24 percent of the petroleum consumption, with the remaining 9 percent consumed by residential and commercial users and for power generation. Fifty-five percent of the Nation’s crude and petroleum products were imported at a cost of $89 billion in 2001, of which 61 percent was from Canada, Saudi Arabia, Venezuela, and Mexico. Domestic oil is produced mainly in Texas, Alaska, Louisiana, and California.

U.S. oil consumption is expected to increase by 9.23 million barrels per day between 2001 and 2025 in the reference case, despite a projected decline in domestic oil production. Most of the growth is expected in the transportation sector, where oil consumption is projected to increase by 7.98 million barrels per day from 2001 to 2025. About 61 percent of the increase comes from light-duty vehicle travel and 13 percent from increased air travel, with the remaining from the demand growth in the industrial, commercial, and residential sectors. Oil use in the industrial sector is projected to increase by about 35 percent between 2001 and 2025, mostly in refining and petrochemical feedstocks. As a result of these increases, petroleum’s share of the energy market is projected to increase slightly over time.

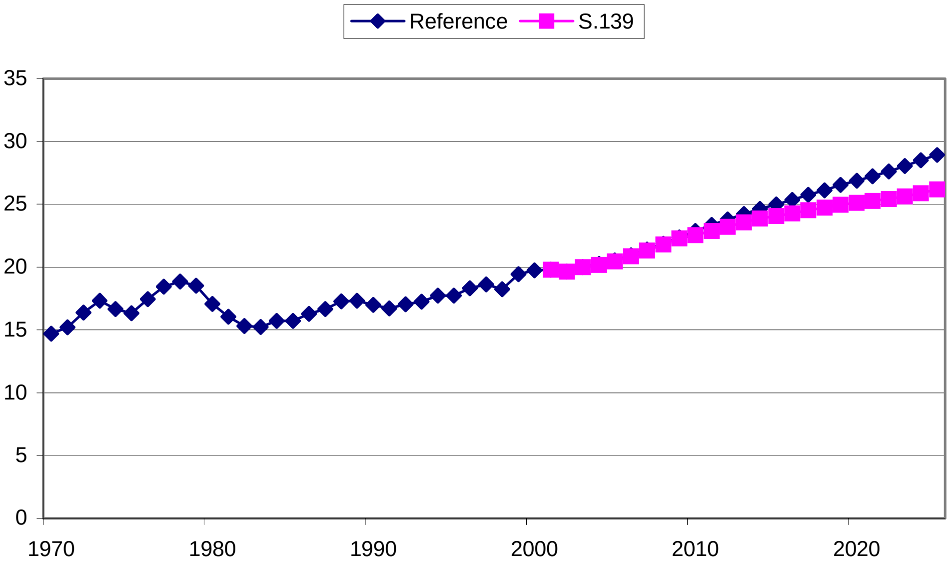
While petroleum production from conventional sources in the lower 48 States is expected to fall between 2001 and 2025, offshore and Alaskan production (excluding any future contribution from the Alaskan National Wildlife Refuge) are expected to increase, but not enough to prevent an overall decline. Net imports of crude oils and petroleum products are projected to rise to make up the difference between consumption and production. In the reference case, about 68 percent of the U.S. petroleum supply in 2025 is projected to come from imports, with two-thirds of total imports entering the country in the form of crude oil and the rest as finished or unfinished products.

Policies aimed at reducing greenhouse gas emissions would lead to lower consumption, production, imports, and refinery margins for the U.S. oil industry. However, end-use prices would be higher for consumers in sectors covered by S.139. Higher end-use prices—including the cost of greenhouse gas emission allowances—would reduce consumption in the greenhouse gas reduction cases, lessening the need for foreign imports. Refinery margins in those cases would be lower, because consumption of petroleum products and expansion of refinery capacity are projected to be lower than in the reference case. Petroleum’s share of the energy market is not expected to change significantly as a result of S.139, because there are limited alternatives to petroleum-based transportation fuels through the forecast period.

Petroleum Consumption

Petroleum consumption is expected to be lower in the greenhouse gas reduction cases than in the reference case (Figure 6.13). Consumption rises throughout the forecast in the reference case, from 19.69 million barrels per day in 2001 to 28.92 million barrels per day by 2025. In the greenhouse gas reduction cases, the allowance prices necessary to meet the greenhouse gas reduction in S.139 lead to lower levels of petroleum consumption in 2025—26.18 million barrels per day in the S.139 case. This trend follows closely the projected greenhouse gas allowance prices—the higher the allowance price, the greater the decline in consumption.

Figure 6.13. Petroleum Consumption in the Reference and S.139 Cases, 1970-2025 (million barrels per day)



Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Consumption in the transportation sector is particularly affected by the greenhouse gas limits. Seventy-seven percent of the difference in petroleum consumption (2.74 million barrels per day) between the reference case and the S.139 case in 2025 is in the transportation sector. The rest of the difference comes mostly from the industrial sector. Eighty-five percent of the decline in the transportation sector in the S.139 case relative to the reference case comes from a decline in gasoline consumption (1.79 million barrels per day), with most of the rest of the decline from highway diesel (269,000 barrels per day). The reduction in motor fuels consumption is the direct result of reduced vehicle miles traveled and improved vehicle fuel efficiency caused by demand reactions to the greenhouse gas allowance price imposed on transportation fuels. The reduction in petroleum consumption accounts for about 42 percent of the reduction in total U.S. energy consumption by 2025 in the S.139 case.[173]

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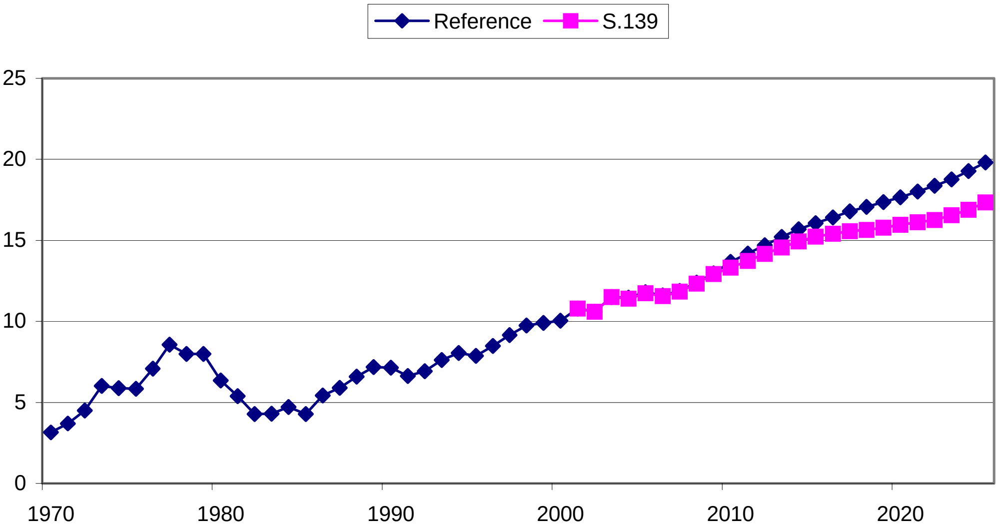
[173] If world oil prices were higher, then S.139 would have less impact on consumption, because higher product prices reduce overall demand.

Petroleum Supply

In the reference case, total lower 48 States crude oil production is projected to increase from 4.84 million barrels per day in 2001 to 5.29 million barrels per day in 2007, then to decline to 4.13 million barrels per day by 2025. The projected peak in 2007 is attributable primarily to offshore oil production (including the Gulf of Mexico and offshore California), which is more sensitive to changes in technology than onshore production. Roughly equal amounts of the lower 48 States onshore and offshore crude oil production are projected between 2007 and 2025, either on an annual or cumulative basis. Alaskan crude oil production in the reference case is expected to decline to 640,000 barrels per day in 2010. After 2010, the projected drop in oil production is expected to be offset by new oil production from the National Petroleum Reserve—Alaska (NPR-A), with the Alaskan crude oil production growing to a peak of 1.28 million barrels per day in 2021 through 2023, then to decline to 1.17 million barrels per day by 2025.

The greenhouse gas reduction cases have much less impact on U.S. domestic oil production than on imports. Domestic oil production in the greenhouse gas reduction cases are slightly lower than that projected in the reference case, resulting in negligible changes in oil production employment. The institution of greenhouse gas allowance prices depresses oil demand, but most of the decline in petroleum supply is from imports (Figure 6.14). The projections for net imports of crude oil and petroleum products are lower in the greenhouse gas reduction cases, with domestic sources providing a greater share of the Nation’s oil needs. As a share of total consumption, net oil imports reach 68 percent in 2025 in the reference case but only 65 percent in the S.139 case.

Figure 6.14. Net Petroleum Imports in the Reference and S.139 Cases, 1970-2025 (million barrels per day)



Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

The Nation’s oil import dependence still grows in the S.139 case, although at a more modest pace relative to the reference case. In 2025, net petroleum imports (including both crude oil and petroleum products) in the S.139 case are projected to be 2.67 million barrels per day less than in the reference case. Natural gas plant liquids production grows by 100,000 barrels per day in 2025 in the S.139 case to compensate mostly for the reduction in petroleum production and imports to meet the demand, largely because of natural gas plant liquids’ lower carbon content per unit volume. Petroleum product imports account for 84 percent of the total reduction in oil imports in the S.139 case, with a 2.26 million barrel per day reduction in 2025. Mirroring the reduction in consumption, gasoline accounts for most of the reduction in petroleum product imports, with 1.79 million barrels per day in 2025, followed by 340,000 barrels per day for distillate (including diesel), 197,000 barrels per day for liquefied petroleum gas (LPG), and 50,000 barrels per day for jet fuel. Crude oil imports decline by 416,000 barrels per day in 2025 in the S.139 case because it is less expensive to produce petroleum products domestically than to import them. The greenhouse gas allowance prices in the greenhouse gas reduction cases yield larger shifts in product imports than in crude oil imports.

Finished petroleum products carry higher wholesale prices than crude oil. All greenhouse gas reduction cases result in substantial reductions in petroleum product imports, thus leading to substantial cost savings. In the reference case, the Nation is projected to spend $206 billion (2001 dollars) on petroleum imports in 2025 alone, an increase of $117 billon from 2001. In the S.139 case the spending on petroleum imports is projected to reach $159 billon by 2025, $47 billion lower than the reference case, mostly from importing less petroleum products. Most significantly, the cumulative savings in petroleum imports from 2010 to 2025 in the S.139 case relative to the reference case is $358 billion.

U.S. dependence on foreign oil is not significantly reduced prior to 2010 in the greenhouse gas reduction cases before the Phase 1 allotment for greenhouse gas emissions (benchmarked at the 2000 level) becomes effective. After 2010, due to the banking provisions of S.139, the effect of the Phase 2 allotment gradually phases in, because the overall tradable allowances are further limited starting in 2016. The impact of the Phase 2 allotment becomes more pronounced in the later forecast years because the limit is set without regard to economic growth.

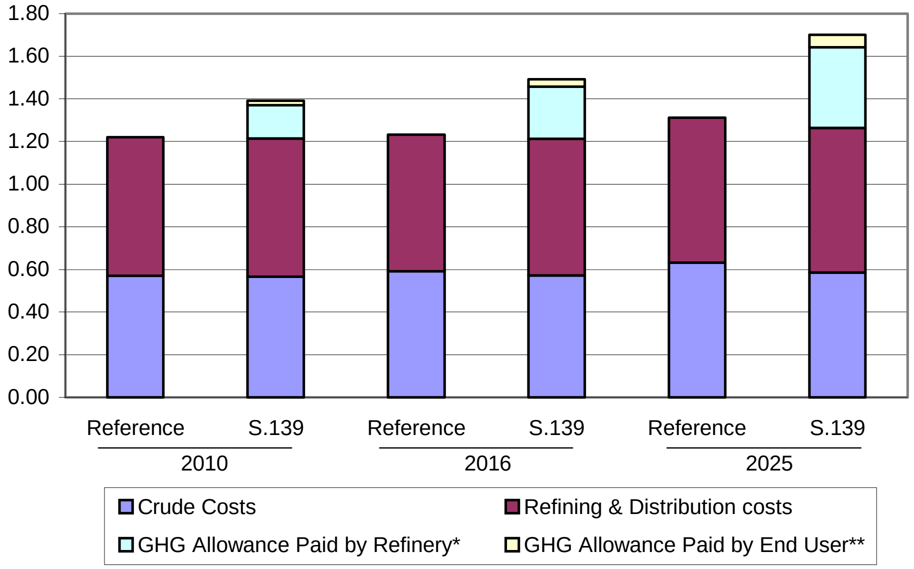
Petroleum Product Prices

Under S.139, refiners and importers are required to purchase greenhouse emission allowances for petroleum products sold for transportation use. Refiners are also required to purchase allowances for fuel consumed in the refining of crude oil. For all other petroleum products, covered end-use consumers would need to purchase allowances. The effective price (including greenhouse gas allowance costs) of petroleum products consumed in the industrial, utility, and transportation sectors is higher in all greenhouse gas reduction cases because of the cost of the greenhouse gas allowances. The average effective price (including all greenhouse gas allowance costs) for all petroleum products in the S.139 case is $0.171 per gallon higher in 2010 when the Phase 1 allotment of the greenhouse gas emissions takes effect, and $0.261 per gallon higher in 2016 as a result of the Phase 2 allotment, and $0.390 per gallon higher in 2025 relative to the reference case (Figure 6.15).

Gasoline is the most affected petroleum product due to its large consumption base among all petroleum products. As a result, its price increases in the S.139 case parallel that of all petroleum products combined, rising $0.190 per gallon in 2010, $0.294 per gallon in 2016, and $0.402 per gallon in 2025 (Figure 6.16). The rise in the gasoline price in 2025 in the S.139 case is almost four times the Federal gasoline tax (discounted to the 2001 value). Diesel is more carbon-intensive than gasoline on a per-gallon basis and therefore is more sensitive to greenhouse gas emission caps. The increases in highway diesel prices range from $0.211per gallon in 2010 and $0.320 per gallon in 2016 to $0.516 per gallon by 2025.

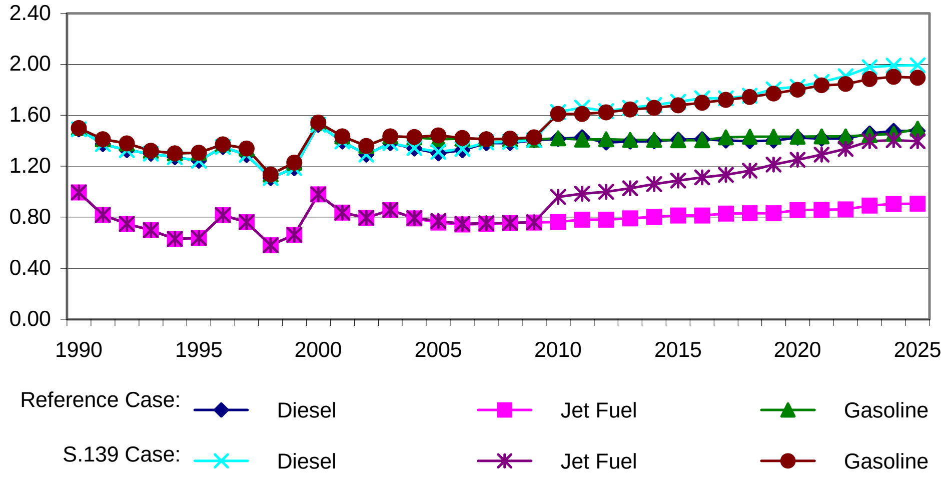
Prices for the LPG, distillate, and residual fuels used in the residential and commercial sectors are marginally lower in the S.139 case, because these two sectors are not assumed to be covered under S.139 and overall petroleum consumption is lower relative to the reference case. These fuels could differ significantly in prices depending on the end use. For example, in the S.139 case in 2025, the price for distillate used in the residential sector is projected to be $1.19 per gallon (2001 dollars), while the effective price for distillate used in the industrial sector is projected to be $1.51 per gallon since the price of the greenhouse gas allowance is included.

Figure 6.15. Components of Average Petroleum Product Costs in the Reference and S.139 Cases, 2010, 2016, and 2025 (2001 dollars per gallon)



* Includes greenhouse gas (GHG) allowance costs for petroleum products consumed in the transportation sector and greenhouse gas allowance costs for energy used at the refinery.
** Includes GHG allowance costs for petroleum products consumed in other covered sectors, mostly industrial.
Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure 6.16. Transportation Fuel Price Increases in the Reference and S.139 Cases, 1990-2025 (2001 dollars per gallon)



Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Refineries

U.S. refineries as a whole are more complex than foreign refineries due largely to the stringent transportation fuel specifications and a larger market share for gasoline consumption. Because of the economy of scale in making large quantities of transportation fuels that meet the U.S. specifications, it is generally cheaper to supply petroleum products by processing the crude oils domestically rather than importing finished products from foreign sources. However, because of construction permitting restrictions and environmental regulations, it is difficult to expand domestic refinery capacity. As a result, much of the projected growth in petroleum product supply is met with imported product.

In the reference case, the crude oil processed in domestic refineries amounts to 16.8 million barrels per day in 2001, 19.1 million barrels per day in 2016, and 19.8 million barrels per day in 2025. By comparison, in the S.139 case U.S. domestic crude oil processing capacity is 19.0 million barrels per day in 2016 and 19.3 million barrels per day in 2025, slightly less than in the reference case. Thus, almost all reductions in the Nation's petroleum consumption in the greenhouse gas reduction cases are attributable to reductions in petroleum product imports as the marginal source of petroleum product supply.

The average utilization rate projected for domestic refineries through the forecast horizon is slightly lower in the S.139 case than in the reference case, but the difference is within 0.5 percent. In the reference case the utilization rate (the ratio of actual crude oil throughput in a refinery to its capacity) is projected to be 93.1 percent in 2010 and to rise to 94.6 percent in 2025. In comparison, the utilization rates in the S.139 case are projected to be 92.8 percent in 2010 and 94.6 percent in 2025. Because most of the reduction in petroleum consumption is projected to result in reduced petroleum product imports, S.139 is not projected to cause refinery closures or underutilization due to the reduction in petroleum consumption.

Between 2004 and 2025, a cumulative $59 billion (2001 dollars) is projected to be invested by U.S. domestic refiners for expansions and updates in the reference case. During the same period, $53 billion is invested in the S.139 case, $6 billion lower. The reductions in investments are significant even though the projected domestic refinery capacities and utilizations are not very different compared to the reference case. This is because domestic production of gasoline and diesel is reduced in the S.139 case relative to the reference case. Because of the changes in the domestic refinery product slate, smaller investments for clean-fuel production are needed to meet Tier 2 low-sulfur gasoline and ultra-low-sulfur diesel (ULSD) standards.

Ethanol and Biodiesel

In the S.139 case ethanol and biodiesel are assumed to be exempt from the greenhouse gas allowances required for gasoline and diesel fuel. Growing additional corn to produce ethanol or growing additional soybeans to produce biodiesel absorbs an amount of carbon dioxide equal to the carbon dioxide emissions from the production and consumption of these fuels. However, the greenhouse gas allowance prices for gasoline and diesel fuel do not increase the overall prices of these fuels enough to significantly increase the penetration of ethanol or biodiesel. Table 6.3 shows that the price of ethanol per gasoline gallon equivalent is well above the price of gasoline in all cases. Energy costs are the sole reason for variation in ethanol production cost. Ethanol production requires natural gas and electricity. The prices of both sources of energy vary according to the greenhouse gas allowance price. The price of corn to ethanol producers, the largest single ethanol cost component, is projected to be $1.79 per gasoline gallon equivalent in 2025 in all cases since agriculture is exempt from coverage under S.139.[174] A gasoline gallon equivalent of ethanol is 1.5 gallons of ethanol, because a gallon of ethanol contains only 67 percent of the energy of a gallon of gasoline.

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[174] The projected price of corn in 2025 is $3.15 per bushel. A yield of 2.65 gallons of denatured ethanol per bushel of corn is assumed.

Table 6.3. Ethanol and Conventional Gasoline Prices in Fourteen Cases, 2025 (2001 dollars per gasoline gallon equivalent)

Case	Ethanol Production Cost	Federal Excise Tax Credit	Net Price, Ethanol Plant Gate	Conventional Gasoline, Including Greenhouse Gas Allowance Price, Refinery Gate
Reference	2.59	-0.42	2.17	0.98
High Technology Reference	2.56	-0.43	2.14	0.92
High Natural Gas Price Reference	2.68	-0.42	2.25	0.97
S.139	2.82	-0.41	2.41	1.39
S.139 High Technology	2.74	-0.41	2.32	1.22
S.139 High Natural Gas Price	2.89	-0.41	2.47	1.38
Commercial Coverage	2.81	-0.41	2.40	1.39
No New Nuclear, No Sequestration	2.91	-0.41	2.49	1.51
20-Percent Auction	2.81	-0.42	2.39	1.38
80-Percent Auction	2.82	-0.41	2.41	1.39
No Banking	2.78	-0.41	2.37	1.32
100% International Sequestration MACs	2.82	-0.41	2.41	1.39
0% International Sequestration MACs	2.83	-0.41	2.42	1.40
50% Uncovered Offsets	2.77	-0.42	2.35	1.29

Note: The Federal excise tax credit for blending ethanol into gasoline is assumed constant at a nominal 51 cents per gallon, or 76.5 cents per gasoline gallon equivalent, after 2004. The NEMS Macroeconomic model projects different rates of inflation in each case, hence the different projected real values of the excise tax credit in 2025.

Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, MLBASE_HGP.D052103A, MLBILL.D050503A, ML_HT.D050503A, MLBILL_HGP.D052303A, ML_COVER_K.D050603A, ML0NUCSEQ.D050403A, ML_CCCC20.D050503A, ML_CCCC80.D050503A, ML_NOBANK_4.D051203A, ML_INTL100.D052703A, ML_INTL0.D051903A, and OFFSET50.D052303A.

The price of virgin oil biodiesel at the plant gate in 2025 is projected to be $3.17 per diesel gallon equivalent in all cases. The price of non-virgin oil biodiesel at the plant gate in 2025 is projected to be $1.77 per diesel gallon equivalent in all cases.[175] A diesel gallon equivalent of biodiesel, whether from virgin oil or non-virgin oil, is 1.12 gallons of biodiesel, because a gallon of biodiesel contains only 89 percent of the energy of a gallon of diesel. The U.S. average price of ULSD at the refinery gate, including the cost of the greenhouse gas allowance, is projected to be $1.40 per gallon in 2025 in the S.139 case.

Production of biodiesel from soybean oil in all greenhouse gas reduction cases is exactly the same as in the base case, because the carbon savings are not large enough in any case to induce additional demand. The Department of Agriculture's Commodity Credit Corporation provides funding for new and expanded soybean oil biodiesel production through 2007. After 2007, biodiesel production is expected to grow at the same rate as diesel production. Under these assumptions, 63 million gallons of biodiesel will be produced from soybean oil in 2025.

S.139 has competing effects on the demand for ethanol for gasoline blending. Demand for ethanol decreases because of decreased demand for gasoline, but demand for ethanol increases because it is exempt from the greenhouse gas allowance program. Because of the economics of ethanol production, ethanol production decreases once the greenhouse gas allowance program begins in 2010. By 2025, ethanol production is 475 million gallons per year below the reference case. Although ethanol is not competitive with gasoline as a source of energy, the greenhouse gas allowance exemption makes ethanol more attractive as a source of octane, as a sulfur dilutant, and as a toxics dilutant. As a result, even though

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[175] The projected price of soybean oil in 2025 is $0.28 per pound. A yield of one gallon of biodiesel per 7.65 pounds of soybean oil is assumed.

the total amount of ethanol blended gasoline has been reduced, the remaining blends contain a slightly higher percentage of ethanol. This effect translates to an additional 24 million gallons of ethanol blended to gasoline in 2025 than would be expected without the greenhouse gas allowance exemption. Ethanol production is projected to reach 3.483 billion gallons per year in 2025 in the S.139 case. Only one new ethanol plant, with an annual capacity of about 40 million gallons will be needed to supplement the existing 2.894 billion gallons of operable capacity and the 547 million gallons of new and expanded capacity due by January 1, 2005.[176]

Alternative Scenarios

Among all greenhouse gas reduction cases, the S.139 high technology case results in the most reduction in petroleum consumption. The Nation's petroleum consumption is projected to reach 25.52 million barrels per day in 2025 in the S.139 high technology case, 1.95 million barrels per day less than in the high technology reference case (Table 6.4). The large reduction in petroleum consumption in the S.139 high technology case is attributed to two factors—more efficient energy use and greenhouse gas allowance costs. The efficiency improvements assumed in end-use, fossil electricity, and renewable technologies, as represented in the high technology reference case, result in a reduction in petroleum consumption of 1.45 million barrels per day in 2025 relative to the reference case. The greenhouse gas allowance cost leads to further reduction in petroleum consumption between the S.139 high technology case and the high technology reference case. The reduction in petroleum consumption in the high technology reference case helps to reduce petroleum imports as well, 1.25 million barrels per day less than the reference case in 2025. With the greenhouse gas allowance cost imposed, such as in the S.139 high technology case, the net petroleum imports in 2025 are projected to decrease by 1.86 million barrels per day relative to the high technology reference case.

Table 6.4. Comparison of U.S. Petroleum Projections in Four Cases, 2025

Projection	Reference Case	S.139 Case	No New Nuclear, No Sequestration	High Technology Reference Case	S.139 High Technology Case
Petroleum Consumption (MMBbl per day)....	28.92	26.18	25.97	27.47	25.52
Net Petroleum Imports (MMBbl per day)	19.61	16.94	16.74	18.37	16.52
Average Petroleum Product Price (2001dollars per gallon)...............................	$1.31	$1.70	$1.82	$1.27	$1.53
Gasoline Price (2001 dollars per gallon).......	$1.49	$1.89	$2.01	$1.44	$1.73
Diesel Price (2001 dollars per gallon)...........	$1.37	$1.83	$1.99	$1.34	$1.62
Jet fuel Price (2001 dollars per gallon)	$0.91	$1.40	$1.57	$0.87	$1.19
Cumulative Savings from Reduced Imports (billion 2001 dollars)	0	$358	$395	$147 (0)*	$459 (312)*

***** Parenthetical values compare S.139 high-tech with high-tech reference case

Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML0NUCSEQ.D050403A, MLBASE_HT.D052003C, and ML_HT.D050503A.

The no new nuclear, no sequestration case also results in a reduction in petroleum consumption. The Nation's petroleum consumption is projected to reach 25.97 million barrels per day in 2025 in the no new nuclear, no sequestration case, lower than the S.139 case total of 26.18 million barrels per day in 2025 and about 3 million barrels per day lower than the reference case total of 28.92 million barrels per day. In

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[176] Renewable Fuels Association online list of ethanol plants as of April 2003, web site http://www.ethanolrfa.org/eth_prod_fac.html.

the no new nuclear, no sequestration case, the options for producing less greenhouse gas emissions are severely limited, thus leading to a further reduction in petroleum consumption. Net petroleum imports in the no new nuclear, no sequestration case are 200,000 barrels per day less than in the S.139 case. In the no new nuclear, no sequestration case, the average petroleum product price is projected to go even higher at $1.82 per gallon in 2025.

Coal Markets

Background

Coal provides the largest share, nearly 33 percent, of U.S. domestic energy production. In 2001, coal accounted for 51 percent of total U.S. electricity generation, including output at combined heat and power plants. In turn, coal consumed for electricity generation during 2001 represented 91 percent of total domestic coal consumption.[177] Steam coal is also consumed in the industrial sector to produce process heat, steam, and synthetic gas and to cogenerate electricity, and metallurgical coal is used to make coke for the iron and steel industry. In the reference case, coal production and domestic consumption (expressed in tons[178]) are projected to increase at rates of 1.0 and 1.4 percent per year, respectively, primarily reflecting the continued growth of coal consumption for electricity generation.

The proposed limitations on greenhouse gas emissions will have a significant negative impact on the coal industry. In the greenhouse gas reduction cases analyzed here, the advantages of the low carbon content of natural gas and the zero net greenhouse gas emissions that are associated with nuclear and renewable fuels offset the relatively low fuel cost of coal for use in electricity generation. Thus, coal markets are projected to be severely affected, in terms of both overall sales and supply patterns, as the need to reduce greenhouse gas emissions results in significant shifts away from coal consumption to natural gas, nuclear, renewable energy, and efficiency improvements in the demand sectors.

Carbon Dioxide Emission Considerations

Coal, oil, and natural gas respond differently to restrictions on greenhouse gas emissions. Of the three, coal is most affected for reasons that relate to the nature of its markets and its chemical structure. Electricity generation markets, by far the largest market for coal, are becoming increasingly competitive and cost-conscious as various restructuring initiatives are acting to gradually transform the industry from a mostly regulated (cost-of-service pricing) market to a competitive market. Fossil fuels derive their energy content primarily from oxidation of their carbon and hydrogen contents. A constraint on the allowed amount of greenhouse gas emissions through the required use of allowances places a cost on greenhouse gas emissions from burning fossil fuels (i.e., a greenhouse gas allowance price) which falls most heavily on coal, primarily because coal derives a higher percentage of its energy content from the oxidation of carbon than either oil or natural gas. Carbon dioxide emissions per unit of energy obtained from coal are nearly 80 percent higher than those from natural gas and about 35 percent higher than from motor gasoline. The lower average conversion efficiency of coal-fired power plants relative to natural-gas-fired plants results in yet a higher carbon emissions factor per unit of electricity generation. In 2001, average carbon dioxide emissions per unit of generation from coal-fired plants were 85 percent higher than from natural gas plants.

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[177] Excludes coal consumed at combined heat and power plants in the industrial sector.

[178] In this section, physical quantities of coal are expressed in short tons, a unit of weight equal to 2,000 pounds. Carbon dioxide emissions are reported in metric tons carbon equivalent. A metric ton is a unit of weight equal to 2,204.6 pounds.

Coal is heterogeneous in terms of both its energy content and carbon content, although, compared with differences in energy content, variations in carbon dioxide emissions factors are relatively minor across coal supply regions and types of coal. For example, the carbon dioxide emissions factors represented in the National Energy Modeling System range from a low of 24.91 million metric tons carbon equivalent per quadrillion Btu for bituminous coal mined at surface mines in the Eastern Interior supply region (Illinois, Indiana, and western Kentucky) to a high of 26.79 million metric tons carbon equivalent per quadrillion Btu for North Dakota lignite. Thus, the largest carbon dioxide emissions factor represented for coal is only about 8 percent higher than the smallest emissions factor. In general, lower ranked lignite and subbituminous coals derive a higher proportion of their energy from carbon than does bituminous coal. As a consequence, restrictions on carbon dioxide emissions will increase the end-use price of coal sourced from the Northern Great Plains (Wyoming and Montana), North Dakota, and Texas by more than the price of coal sourced from bituminous coalfields such as those in Colorado and Utah, the Appalachian States, and the Eastern Interior region. Variations in hydrogen content in part explain the variations in carbon dioxide emissions factors across coal ranks, with subbituminous and lignite typically containing smaller quantities of hydrogen than bituminous coal.[179] On a pound-for-pound basis, the combustion of hydrogen generates about four times the amount of heat than the combustion of carbon.[180]

Although carbon capture and sequestration technologies for coal-fired power plants are currently not economically attractive, these technologies may become a commercially viable option in the carbon reduction scenarios, with new plants projected to be built between 2015 and 2025. However, because these technologies are in the early stages of commercialization, there is considerable uncertainty about their future. An alternative case was developed in which sequestration was assumed to be unavailable. The primary sequestration technology represented in the National Energy Modeling System is an integrated gasification combined cycle coal plant supplied with additional equipment designed to capture 90 percent of the plant’s carbon dioxide emissions. The combined capital, operating, and maintenance costs for these plants also include the costs of sequestering the captured carbon dioxide emissions into a geological reservoir. (For a discussion of the estimated cost and performance characteristics of new generating technologies used by EIA for this study and their relative competitiveness based on projected levels of both fuel and greenhouse gas allowance costs, see the discussion on Electricity Supply in Chapter 5.)

Coal Consumption

In the reference case, domestic coal demand is projected to increase by 416 million tons, from 1,050 million tons in 2001 to 1,466 million tons in 2025 (Table 6.5), almost entirely because of projected growth in coal use for electricity generation. Total coal demand in other domestic end-use sectors is projected to remain relatively constant.

Coal consumption for electricity generation is projected to increase from 957 million tons in 2001 to 1,371 million tons in 2025 as the utilization of existing coal-fired generation capacity increases and, in later years, new capacity is added. The average utilization rate (excluding combined heat and power plants) is projected to increase from 69 percent in 2001 to 83 percent in 2025. Coal-fired generating capacity increases from 315 gigawatts in 2001 to 386 gigawatts in 2025, the net result of 81 gigawatts of projected new coal builds less 10 gigawatts of retirements. Despite increased utilization of coal plants and considerable additions of new capacity, coal’s share of total electricity generation is projected to decline slightly from 51 percent in 2001 to 48 percent by 2025, primarily due to a substantial increase in

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[179] “Analysis of the Relationship Between the Heat and Carbon Content of U.S. Coals,” prepared for the Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, by Science Applications International Corp., September 1992, pp. 15-18.

[180] Energy Information Administration, *Coal Data: A Reference*, DOE/EIA-0064(93) (Washington, DC, February 1995), p. 5.

Table 6.5. Coal Industry Related Statistics in Five Cases, 2001-2025 (million short tons per year, unless otherwise noted)

		2010					2020					2025				
	2001	Reference	S.139	No New Nuclear, No Seq.	High Tech Reference	S.139 High Tech.	Reference	S.139	No New Nuclear, No Seq.	High Tech Reference	S.139 High Tech.	Reference	S.139	No New Nuclear, No Seq.	High Tech Reference	S.139 High Tech.
Production 1/																
East of the Mississippi	539	527	518	506	526	518	529	286	231	512	357	554	182	115	521	200
West of the Mississippi	599	723	563	549	695	580	839	199	139	765	266	902	132	58	798	184
Bituminous	603	612	581	568	602	581	620	318	251	588	400	653	201	126	598	230
Sub-Bituminous	445	540	406	391	517	421	663	122	81	598	169	719	89	34	630	114
Lignite	80	87	83	85	91	85	73	34	27	79	43	73	17	9	80	32
Waste Coal	11	11	11	11	11	11	11	11	11	11	11	11	7	4	11	8
Total	**1,138**	**1,250**	**1,081**	**1,055**	**1,221**	**1,098**	**1,367**	**485**	**370**	**1,277**	**623**	**1,456**	**315**	**173**	**1,319**	**384**
Consumption by Sector																
Residential and Commercial	4	5	5	5	5	5	5	5	5	5	5	5	6	6	5	6
Industrial 2/	63	67	61	61	66	61	70	59	58	67	58	71	58	55	67	57
Coke Plants	26	24	24	24	21	21	20	17	17	15	10	18	14	14	13	8
Electric Generators 3/	957	1,146	966	955	1,120	996	1,274	390	272	1,193	522	1,371	227	85	1,240	305
Total	**1,050**	**1,242**	**1,055**	**1,044**	**1,212**	**1,083**	**1,369**	**471**	**352**	**1,281**	**595**	**1,466**	**306**	**160**	**1,325**	**375**
Average Minemouth Price																
(2001 dollars per short ton)	17.59	15.06	15.84	15.83	15.09	15.68	14.34	15.27	14.86	14.20	15.51	14.39	13.67	13.40	14.05	13.29
(2001 dollars per million Btu)	0.83	0.73	0.76	0.76	0.73	0.75	0.70	0.71	0.68	0.70	0.72	0.71	0.63	0.60	0.69	0.63
Delivered Price with GHG Cost (2001$/short ton) 4/																
Industrial	32.83	30.11	73.69	78.31	30.01	62.48	28.45	123.14	132.54	27.97	98.97	28.04	143.97	184.22	27.32	109.86
Coke Plants	46.42	41.27	96.11	101.91	40.91	81.74	38.08	162.07	175.21	37.28	128.81	36.67	189.79	242.35	35.73	145.24
Electric Generators																
(2001 dollars per short ton)	25.04	23.63	65.08	69.29	23.60	54.35	22.44	116.04	125.12	22.05	92.74	22.27	136.11	177.05	21.68	101.17
(2001 dollars per million Btu)	1.25	1.17	3.17	3.39	1.17	2.66	1.12	5.53	5.98	1.10	4.39	1.11	6.53	8.37	1.08	4.96
Average	26.05	24.33	66.29	70.56	24.26	55.34	22.98	118.63	128.82	22.54	93.96	22.74	140.21	185.65	22.10	103.44

Table 6.5. Coal Industry Related Statistics for Five Cases, 2001-2025 (continued)

		2010					2020					2025				
	2001	**Refer-ence**	**S.139**	**No New Nuclear, No Seq.**	**High Tech Refer-ence**	**S.139 High Tech.**	**Refer-ence**	**S.139**	**No New Nuclear, No Seq.**	**High Tech Refer-ence**	**S.139 High Tech.**	**Refer-ence**	**S.139**	**No New Nuclear, No Seq.**	**High Tech Refer-ence**	**S.139 High Tech.**
Coal-Fired Generating Capacity (Gigawatts)																
Conventional	305	309	288	288	300	286	339	197	182	298	217	369	102	106	297	156
Advanced w/o Sequestration	0	2	0	0	7	0	5	0	0	34	0	7	0	0	58	0
Advanced with Sequestration	0	0	0	0	0	0	0	12	0	0	5	0	38	0	0	18
CHP: Electric Power Sector	5	5	4	4	5	4	5	3	3	5	3	5	3	3	5	3
CHP: Industrial Steam Coal Sector	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Total Coal-Fired Generating Capacity	**315**	**320**	**298**	**298**	**316**	**296**	**353**	**217**	**191**	**341**	**231**	**386**	**147**	**114**	**364**	**182**
Coal-Fired Generation (Billion Killowatthours)																
Conventional	1,846	2,224	1,925	1,904	2,143	1,975	2,477	746	569	2,141	1,069	2,692	246	174	2,128	530
Advanced w/o Sequestration	2	13	1	1	48	2	35	0	0	253	0	55	0	0	431	0
Advanced with Sequestration	0	0	0	0	0	0	0	91	0	0	39	0	281	0	0	130
CHP: Electric Power Sector	33	33	30	29	33	30	33	16	15	33	19	33	10	8	33	13
CHP: Industrial Steam Coal Sector	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total Coal-Fired Generation	**1,904**	**2,293**	**1,980**	**1,957**	**2,247**	**2,031**	**2,568**	**876**	**607**	**2,450**	**1,150**	**2,803**	**560**	**206**	**2,615**	**696**
Coal Share of Total Electricity Generation (Percent)	51	51	44	44	50	46	48	18	12	48	24	48	11	4	47	14
Average Coal Capacity Factor (Percent) 5/																
Conventional and Advanced w/o Sequestration	69	82	76	75	81	79	83	43	35	82	56	83	27	19	82	39
Advanced with Sequestration	N/A	N/A	N/A	N/A	N/A	N/A	N/A	85	N/A	N/A	85	N/A	85	N/A	N/A	85
Average Capacity Factor for All Coal Plants	69	82	76	75	81	79	83	45	35	82	57	83	43	19	82	43

1 Includes anthracite, bituminous, subbituminous, lignite, and waste coal delivered to independent power producers.
2 Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
3 Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat to the public.
4 Sectoral prices weighted by consumption tonnage; weighted average excludes residential/commercial prices and export free-alongside-ship (f.a.s.) prices.
5 Excludes capacity and generation from combined heat and power plants.

Btu = British thermal unit. N/A = Not applicable. CHP = Combined Heat and Power.

Note: Totals may not equal sum of components due to independent rounding. Some of the data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: **History:** Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002); EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML0NUCSEQ.D050403A, MLBASE_HT.D052003C, and ML_HT.D050503A.

generation from new gas-fired plants. The share of total generation fueled by natural gas is projected to increase from 17 percent in 2001 to 28 percent by 2025.

In the S.139 case, requirements to reduce greenhouse gas emissions in all sectors of the economy (excluding the residential and commercial sectors), lead to a large shift in U.S. energy consumption away from coal to lower carbon-emitting fuels such as natural gas, renewable energy, and nuclear. The strong negative impact on U.S. coal consumption is primarily the result of three key factors: 1) high carbon dioxide emission factors for coal; 2) greater opportunities for fuel substitution in the electricity sector than in other sectors of the economy; and 3) relatively low emission abatement costs for greenhouse gases in the electricity sector, which leads to greater reductions of greenhouse gas emissions in this sector than in other sectors. In the S.139 case, carbon dioxide emissions in the electricity sector by 2025 are projected to be 76 percent less than the amount projected in the reference case. By comparison, total U.S. carbon dioxide emissions by 2025 are projected to be 34 percent less than in the reference case, and emissions in the industrial and transportation sectors in 2025 are 34 and 10 percent less, respectively, than in the reference case.

In the S.139 case, coal consumption for electricity generation is projected to increase from 957 million tons in 2001 to 966 million tons in 2010, but then declines precipitously to 227 million tons by 2025. Electricity coal consumption in the S.139 case is 16 percent less than in the reference case in 2010 and 83 percent less in 2025.

Except for new integrated gasification combined cycle coal plants equipped with carbon capture and sequestration equipment, coal-fired capacity in the S.139 case gradually transitions from a position of primarily baseload capacity to one of intermediate capacity. Due to increasing greenhouse gas emission allowance costs in the S.139 case over the forecast horizon, natural gas, nuclear and renewable fuels plants gradually displace existing coal-fired capacity as lower cost sources of electricity generation. In addition to the cost of greenhouse gas allowances, operating and maintenance costs per unit of electricity generated will increase for coal plants run at low capacity utilization rates because of thermal fatigue and the inefficiencies of starting and stopping units that were designed for baseload operation. In the S.139 case, the average utilization rate of coal-fired generating capacity (excluding combined heat and power plants) is projected to decline from 69 percent in 2001 to 43 percent by 2025. Because the new integrated gasification combined cycle coal plants with carbon sequestration equipment are projected to be highly utilized in the S.139 case, the average capacity utilization factor for the remaining capacity not equipped with carbon sequestration technologies is projected to be considerably less than the average for all plants, declining to a low of 27 percent by 2025.

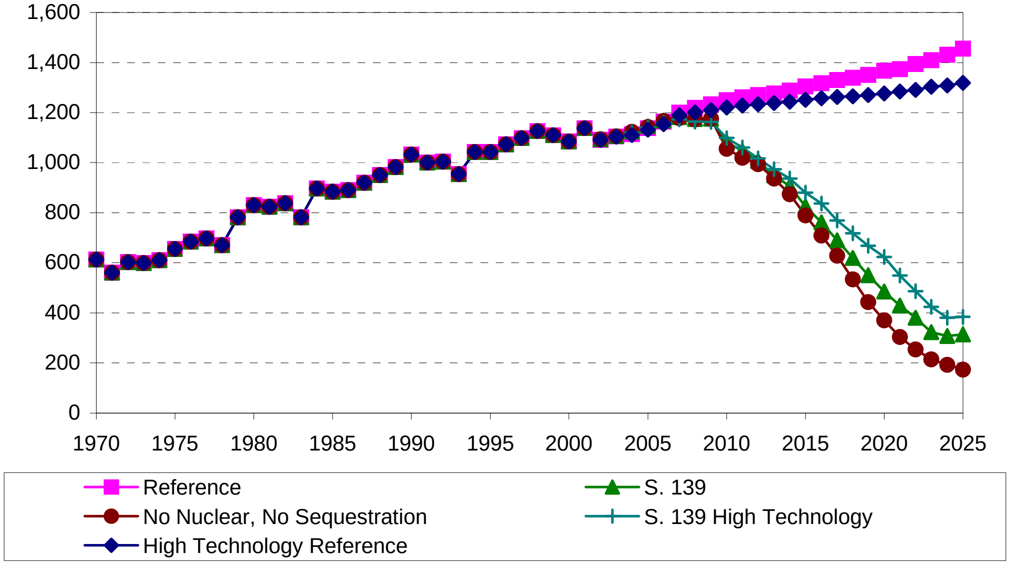
Coal-fired generating capacity is projected to decline from 315 gigawatts in 2001 to 147 gigawatts in 2025, the net result of 38 gigawatts of projected new integrated gasification combined cycle coal plants (with carbon capture and sequestration equipment) less 206 gigawatts of retirements. Coal’s share of total electricity generation is projected to decline from 51 percent in 2001 to 44 percent by 2010 and to 11 percent by 2025.

Due to gradually increasing greenhouse gas emission allowance costs over the forecast period, coal use in the industrial steam and coking sectors, taken together, is also projected to fall over the forecast period, from 89 million tons in 2001 to 73 million tons by 2025. Relative to the reference case, coal consumption in the industrial steam coal sector is 18 percent less in the S.139 case by 2025, and consumption in the coking coal sector is 21 percent lower.

Coal Production

In the reference case, U.S. coal production rises from 1,138 million tons in 2001 to 1,456 million tons in 2025 (Figure 6.17), an increase of 318 million tons. In the S.139 case, U.S. coal production is projected to remain fairly constant through 2010, but then declines precipitously to 315 million tons by 2025. The last time that the U.S. coal industry recorded a smaller amount of annual production was in 1902 when production was 302 million tons.[181] Relative to the reference case, coal production in the S.139 case is 13 percent lower by 2010 and 78 percent lower by 2025.

Figure 6.17. U.S. Coal Production, 1970-2025 (million short tons)



Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML0NUCSEQ.D050403A, ML_HT.D050503A, and MLBASE_HT.D052003C.

Reductions in coal consumption are expected to occur in all regions and consuming sectors, but they will be of different magnitudes and affect different coal types. As a result, regional production patterns in the carbon reduction cases will shift differentially across regions relative to the reference case, rather than on a basis that is strictly proportional to national levels of coal consumption.

In the electricity sector, the sharp reductions in overall coal consumption after 2010 in the S.139 case will make it easier to achieve the sulfur dioxide (SO_2) emissions target of 9 million tons as specified in the Clean Air Act Amendments of 1990, with the result that prices for the SO_2 allowances will be driven to zero by approximately 2015. This eliminates the added benefit of using low-sulfur coals from the Central Appalachian and Western regions that exists throughout the entire reference case.

Coal of bituminous rank, however, will gain a slight price advantage over lower-ranked subbituminous and lignite coals in the S.139 case, because of its lower carbon dioxide emissions factor. This advantage becomes more pronounced after 2015, as the additional reduction in greenhouse gas emissions targets from 2000 levels to 1990 levels in 2016 leads to substantially higher prices for greenhouse gas emissions. Projected additions of new integrated gasification combined cycle plants with carbon sequestration

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[181] Energy Information Administration, *Coal Data: A Reference*, DOE/EIA-0064(93) (Washington, DC, February 1995), Tables 18 and 19.

technologies, particularly after 2020, effectively negate the carbon disadvantage of lower ranked coals at these facilities. In the S.139 case, the new integrated gasification combined cycle plants are projected to produce 10 percent of total coal-fired generation by 2020 and 50 percent by 2025.

Relative to the electricity sector, the slower decline in coal consumption in the industrial and coking coal sectors in the S.139 case will translate into relatively less severe production cuts in regions that currently supply these markets than the reductions in those regions that depend more heavily on electricity generators. The potential for western subbituminous coal to expand into most industrial applications is limited by its lower heat content and other physical characteristics, such as moisture content and handling problems.

There will be some upward pressure on coal transportation rates, as a result of the higher effective prices for diesel fuel (fuel cost plus greenhouse gas allowance costs) used for rail, barge, and truck transportation. Conversely, lower quantities of coal shipments could place downward pressure on transportation rates.

In the reference case, the share of total U.S. coal production originating from mines west of the Mississippi River increases from 53 percent in 2001 to 62 percent in 2025, primarily as a result of its lower cost and the growing requirements for low-sulfur coal under the Clean Air Act Amendments of 1990. In contrast, the western share decreases to 42 percent by 2025 in the S.139 case. Of the 467-million-ton reduction in western coal production projected to occur over the forecast period in the S.139 case, 71 percent is borne by subbituminous surface mines in the Powder River Basin. The low-sulfur coal from these mines is used almost exclusively for electricity generation and must be transported over relatively long distances to reach many of the markets that are projected to expand in the reference case.

Coal Prices

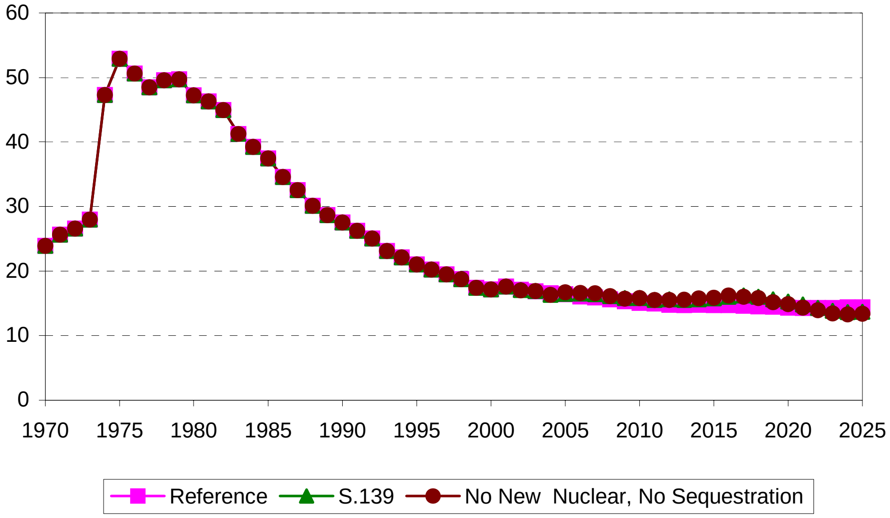
Because coal is heterogeneous in terms of heat content, sulfur level, and other physical properties, trends in national average prices are affected substantially by the relative shares of the various coal types produced and sold and by the units in which prices are reported. For example, coal from the Powder River Basin is generally the lowest-priced coal per ton on a minemouth basis; however, because Powder River Basin coal has roughly two-thirds the heat content of bituminous coal, its cost advantage is somewhat less on a Btu basis and may be nonexistent when delivered to distant markets.

In general, to the extent that market share shifts away from Powder River Basin coal, which has a low minemouth price, to higher-priced bituminous coal, the national average minemouth price will increase. This compositional effect offsets the reduction in minemouth prices at the regional level that is likely to occur because of intraregional competition and the lower production quantities that occur when carbon restrictions take effect. The regional productivity improvements projected in the reference case are assumed to occur at the same rates in all the carbon reduction cases given the same rate of technological progress. However, if the level of investment in new capital equipment is severely constrained, there could be adverse impacts on productivity.

Similar to coal transportation, higher fuel prices in the greenhouse gas reduction cases also will act to increase coal mining costs, which, in turn, will affect minemouth coal prices. U.S. coal producers consume considerable amounts of diesel fuel and electricity, with underground mines relying heavily on electricity and surface mines consuming substantial quantities of both diesel fuel and electricity. In the S.139 case, diesel fuel prices (inclusive of the greenhouse gas allowance cost) are projected to rise to $10.89 per million Btu by 2025, and the price of electricity in the industrial sector is projected to rise to $20.86 per million Btu. These price projections for diesel fuel and electricity in 2025 are 51 percent and 55 percent higher than in the reference case, respectively.

In the reference case, the average minemouth price of coal (in constant 2001 dollars) is projected to decline from $17.59 per short ton in 2001 to $14.39 per short ton in 2025 (Figure 6.18). In the S.139 case, the minemouth price of coal is projected to decline to $13.67 per ton, 5 percent less than in the reference case. On a supply region basis, projected declines in minemouth coal prices in the S.139 case typically exceed the decline in the national level price. For example, under the carbon restrictions specified in the S.139 case, the average minemouth price of coal projected for Central Appalachia (southern West Virginia, eastern Kentucky, and Virginia) in 2025 is 22 percent lower than in the reference case, and the average price of coal produced at mines in the Powder River Basin (Wyoming and Montana) in 2025 is 53 percent lower than in the reference case.

Figure 6.18. Average U.S. Minemouth Coal Prices, 1970-2025 (2001 dollars per short ton)



Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and ML0NUCSEQ.D050403A.

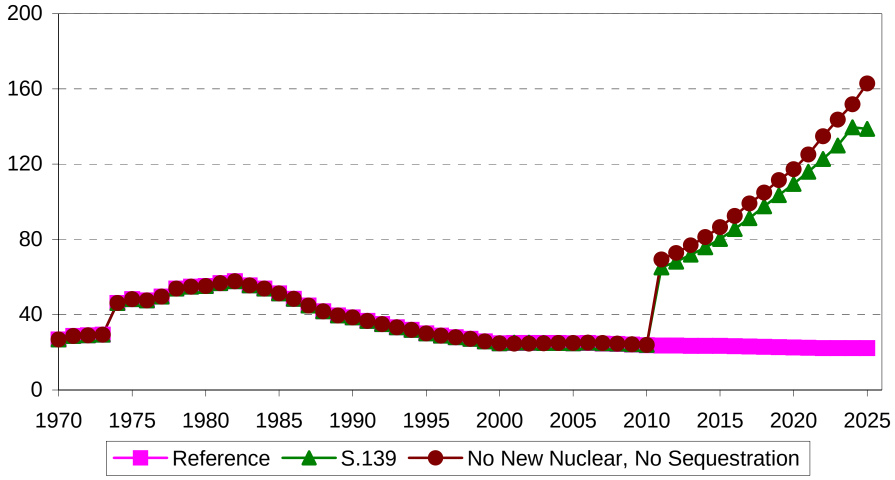
Delivered prices for coal reflect the sum of the minemouth price and transportation cost. The effective delivered price of coal also includes the greenhouse gas allowance cost associated with meeting a greenhouse gas reduction target, because the consumer of the coal must hold sufficient allowances to cover the carbon emissions that result from its combustion. In the S.139 case, the allowance cost exceeds the delivered price, adding $2.02 per million Btu to the effective delivered price of coal to electricity generators in 2010 and $5.62 per million Btu in 2025.

In the reference case, the national average delivered price of coal to electricity generators declines from $25.04 per short ton in 2001 to $22.27 per short ton in 2025. In the S.139 case, the effective delivered price of coal, including the greenhouse gas allowance cost, rises to $65.08 per short ton in 2010 and to $136.11 per short ton in 2025 (Figure 6.19). Excluding the greenhouse gas allowance cost, the delivered price of coal to the electricity sector in the S.139 case is projected to decline to $18.81 per short ton by 2025, 16 percent less than in the reference case.

Coal Industry Employment and Productivity

Between 1978 and 2001, the number of miners employed in the U.S. coal industry fell by 4.9 percent per year, declining from 246,000 to 77,000. The decrease primarily reflected strong growth in labor productivity, which increased at an annual rate of 6.0 percent over the same period. An additional factor

Figure 6.19. Average Effective Delivered Price of Coal to Electricity Generators, Including Greenhouse Gas Allowance Costs, 1970-2025 (2001 dollars per short ton)



Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and ML0NUCSEQ.D050403A.

contributing to the employment decline was the increased output from large surface mines in the Powder River Basin, which require much less labor per ton of output than mines located in the Interior and Appalachian regions.

In the reference case, productivity improvements are assumed to continue but to decline in magnitude over the forecast period. Different rates of improvement are assumed by region and by mine type, surface and underground. On a national basis, labor productivity in the reference case increases on average at a rate of 1.6 percent a year over the entire forecast, declining from an estimated annual rate of 2.5 percent between 2001 and 2010 to 1.1 percent between 2010 and 2025.

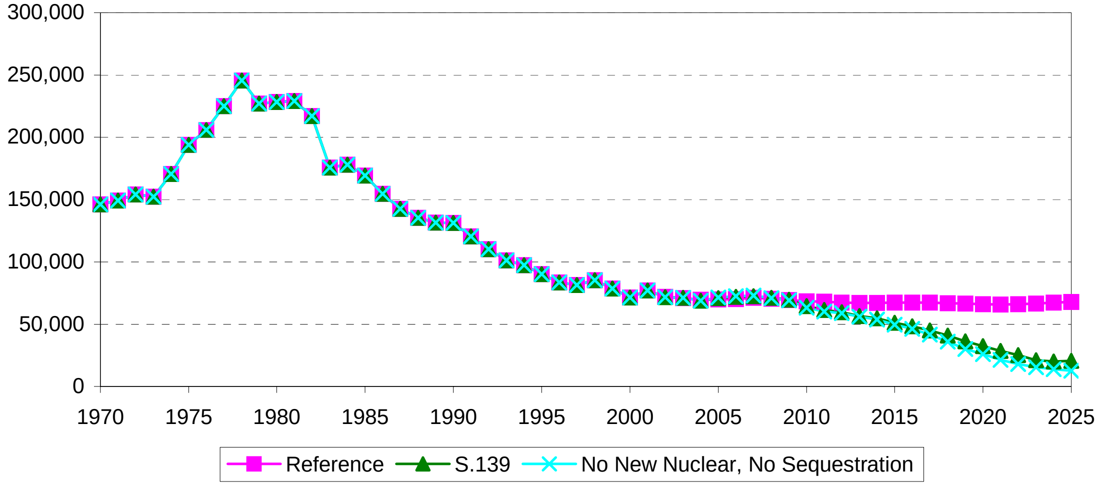
The expectation that the rate of productivity improvements will slow over the forecast horizon, combined with projections of continuing increases in coal production, leads to a relatively stable outlook for U.S. coal mine employment. In the reference case, employment is projected to decline by 1.3 per year between 2001 and 2010 but is expected to stabilize during the later years of the forecast as increases in production outpace expected improvements in productivity. In absolute terms, coal mine employment is projected to decline from 77,000 in 2001 to 68,000 in 2010. After 2010, coal-mining employment declines slightly for several years thereafter but rebounds to 68,000 by 2025 (Figure 6.20).

In the S.139 case, lower levels of coal production in all supply regions relative to the reference case result in lower coal industry employment in all regions. In this carbon reduction scenario, coal mine employment is projected to decline by 5.3 percent a year, from 77,000 in 2001 to 21,000 by 2025.

Alternative Scenarios

Alternative scenarios to the S.139 case were run to assess what impacts on U.S. energy markets would result from using assumptions that differ from those in the S.139 case. Some of the other assumptions that were explored in these alternative cases, and whose impacts on U.S. coal markets are discussed below, include: (1) a case where it is assumed that no advanced fossil-fired generating capacity with

Figure 6.20. U.S. Coal Mine Employment, 1970-2025 (number of jobs)



Sources: **History:** Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and ML0NUCSEQ.D050403A.

sequestration technologies or advanced nuclear will be built; (2) a case that allows up to 50 percent of the greenhouse gas targets to be met by using international offsets, which is more than the S.139 limit of 15 percent in the 2010-2015 period and 10 percent for 2016 and beyond; (3) two cases that include optimistic technology assumptions for the residential, commercial, industrial, and transportation sectors combined with optimistic technology assumptions for new fossil, nuclear, and renewable generating capacity (one with and without the provisions of S.139); and (4) two cases that include less optimistic assumptions about natural gas supply and infrastructure, resulting in projections of higher natural gas prices.

In the alternative scenario assuming no new advanced nuclear and no new advanced fossil-fired generating capacity with carbon sequestration technologies, the outlook for U.S. coal production and consumption is considerably lower than in the S.139 case. In the no new nuclear, no sequestration case, U.S. coal consumption is projected to decline to 352 million tons by 2020 and to 160 million tons by 2025, 25 percent and 48 percent less for those years, respectively, than in the S.139 case. The no new nuclear, no sequestration case leads to the construction of both additional advanced gas-fired generating capacity without sequestration technologies and renewable energy facilities (primarily dedicated biomass plants).

In the alternative scenario that allows covered entities to meet up to 50 percent of their targets with international offsets, U.S. coal production and consumption are projected to be considerably higher than the levels projected in the S.139 case. In the offset 50 case, U.S. coal consumption is projected to decline to 667 million tons by 2020 and to 519 million tons by 2025, 42 percent and 70 percent higher for those years, respectively, than in the S.139 case. Lower greenhouse gas emission allowance prices are the key factor underlying the improved outlook for coal. In 2020, the greenhouse gas allowance price is projected to be $144 per metric ton carbon equivalent, 19 percent less than in the S.139 case; and by 2025 the price is projected to rise to $174 per metric ton carbon equivalent, or 21 percent less than in the S.139 case. Coal-fired generating capacity is projected to decline to 206 gigawatts by 2025, the net result of 5 gigawatts of projected new coal builds less 114 gigawatts of retirements. Because of thermal fatigue and the inefficiencies of starting and stopping units that were designed for baseload operation, an additional improvement in the offset 50 case is the higher average capacity utilization factors projected for coal-fired plants not equipped with carbon sequestration technologies. In the offset 50 case, the capacity factor for this group of coal-fired power plants is projected to decline from 69 percent in 2001 to 52 percent by

2025. In the S.139 case, the average capacity factor for this group of coal plants is projected to decline to 27 percent by 2025.

With the exception of the S.139 high gas price case, the projected decline in coal consumption in the S.139 high technology case is less than in any of the other greenhouse gas reduction scenarios whose assumptions reflect the provisions set forth in S.139. The higher levels of coal consumption in the S.139 high technology case are primarily due to projections of lower greenhouse gas allowance costs than in the other greenhouse gas cases, reducing the effective delivered price of coal inclusive of greenhouse gas costs to end-use consumers in the industrial sector and to electric power producers. The lower greenhouse gas allowance costs in the S.139 high technology case result mostly because of reduced consumption of energy in the end-use sectors. Coal consumption in the S.139 high technology case is projected to decline to 595 million tons in 2020 and to 375 million tons by 2025, 54 percent and 72 percent less, respectively, than projected for those years in the high technology reference case.

Among the greenhouse gas reduction cases whose basic assumptions reflect the provisions set forth in S.139, the S.139 high gas price case results in the lowest overall reduction in coal consumption. The smaller projected decline in coal use in this case is primarily due to improved competitiveness of new coal-fired generating capacity relative to new gas-fired capacity that results because of higher natural gas prices. In the S.139 high gas price case, coal-fired generating capacity is projected to decline from 315 gigawatts in 2001 to 231 gigawatts by 2025, the net result of 81 gigawatts of projected new coal builds (advanced coal-fired capacity equipped with carbon sequestration technologies) less 165 gigawatts of retirements. The projected greenhouse gas allowance prices are similar to other carbon reduction scenarios, rising to $188 per metric ton carbon equivalent by 2020 and to $214 per metric ton carbon equivalent by 2020. Coal consumption in the S.139 high gas price case is projected to decline to 639 million tons in 2025 and to 547 million tons by 2025, 57 percent and 66 percent less, respectively, than projected for those years in the high gas price reference case. In the high gas price reference case, 145 gigawatts of new coal-fired generating capacity is projected to be built. This compares with 81 gigawatts of new coal builds projected in both the reference and S.139 high gas price cases. (For a discussion of the estimated cost and performance characteristics of new generating technologies used by EIA for this study and their relative competitiveness based on projected levels of both fuel and greenhouse gas allowance costs, see the discussion on Electricity Supply in Chapter 5.)

Coal Forecast Comparisons

As indicated by the various greenhouse gas reduction scenarios discussed in this report, there is considerable uncertainty regarding the projected levels of coal consumption. This uncertainty relates to factors such as assumptions about the ways in which greenhouse gas emission allowances are distributed to covered entities, the extent to which covered entities will be allowed to rely on emission allowance offset credits, expectations about technological improvements in the U.S. energy industry, and, perhaps most importantly, the environmental hurdles and the estimated costs associated with the development of fossil-fired generating capacity equipped with carbon capture and sequestration technologies.

By 2020, coal use in the various reduction scenarios evaluated in EIA’s analyses is projected to range from a low of 7.7 quadrillion Btu in the no new nuclear, no sequestration case to a high of 14.4 quadrillion Btu in the offset 50 case, reflecting declines of 65 percent and 35 percent, respectively, from 2001. By 2025, the projected levels of coal consumption are projected to range from a low of 3.7 quadrillion Btu in the no new nuclear, no sequestration case to a high of 11.9 quadrillion Btu in the S.139 high gas price case, reflecting declines of 83 percent and 46 percent, respectively, from 2001.

As an additional point of reference, the Massachusetts Institute of Technology (MIT) Joint Program on the Science and Policy of Global Change recently completed an analysis of S.139 that indicates that the impact on U.S. coal markets will be considerably less severe than projected by EIA. In the MIT analysis, featuring caps on greenhouse gas emissions, banking of emission allowances, but no emission allowance offset credits, U.S. coal consumption is projected to decline to only 19.9 quadrillion Btu by 2020, or 10 percent less than in 2001.[182] In an alternative scenario featuring caps on carbon dioxide emissions alone, banking of emission allowances and access to offset credits (up to 15 percent of covered emissions through 2015 and 10 percent thereafter), MIT projects that U.S. coal consumption will decline to only 20.9 quadrillion Btu by 2020, or 5 percent less than in 2001.[183]

As an added perspective, it is useful to compare the differences in 2020 between the EIA and MIT reference case coal forecasts and their respective greenhouse gas and carbon dioxide reduction scenarios. In EIA's S.139 case, U.S. coal consumption is projected to decline to 10.2 quadrillion Btu by 2020, 63 percent less than the EIA reference case forecast of 27.9 quadrillion Btu, by 2020. In MIT's carbon dioxide emissions reduction case featuring access to offset credits, coal consumption is projected to decline to 20.9 quadrillion Btu by 2020, or 35 percent less than their reference case forecast of 32.2 quadrillion Btu.

Unlike the scenarios featured in EIA's analyses that use a set of marginal abatement cost curves to assign prices to offset credits, the MIT analysis assumes that offset credits will be available at zero cost. The greenhouse gas allowance prices projected in the MIT analyses are comparable to those projected by EIA, but slightly lower. In the MIT scenarios discussed above, allowance price is projected to rise to $158 per metric ton carbon equivalent (2001 dollars) by 2020 in the greenhouse gas cap case with zero offsets, and to $134 per metric ton carbon equivalent by 2020 in the carbon dioxide cap case with access to offsets. This compares with a projected greenhouse gas allowance price of $178 per metric ton carbon equivalent by 2020 in EIA's S.139 case.

Because the EIA analyses of S.139 show much larger increases in natural gas consumption than do the MIT analyses, one possible explanation for the large variation between the EIA and MIT coal forecasts is differences in cost assumptions for new fossil-fuel-fired generating capacity with carbon sequestration technologies (for a discussion of EIA's cost assumptions, see the Chapter 5 discussion of Electricity Supply). EIA's analyses indicate that new natural-gas-fired generating capacity with carbon capture and sequestration technologies will typically be a more economical choice than coal-fired capacity equipped with similar technologies, while MIT's analyses appear to indicate the opposite. In the MIT study, natural gas use is projected to increase by 9 percent between 2000 and 2020 in a greenhouse gas cap case that assumes no offset credits, and to increase by 14 percent over the same period in the carbon dioxide cap case that allows for the percentage of offsets as specified in S.139. In EIA's S.139 case, natural gas consumption is projected to increase by a much more substantial amount, 52 percent, between 2000 and 2020.

Another potential reason for MIT's more robust outlook for U.S. coal consumption is their much smaller projected increase in consumption of petroleum products than is projected in EIA's greenhouse gas reduction scenarios. In MIT's analyses, the relatively small projected increases in petroleum consumption over the forecast horizon would effectively free up greenhouse gas allowances for the electricity sector, making it less difficult for this sector to comply with the caps specified in S.139. In the MIT greenhouse gas cap case with no offsets, petroleum consumption is projected to increase by 5 percent between 2000 and 2020, and in their carbon dioxide cap case with access to offset credits petroleum consumption increases by 8 percent over the same time period. In EIA's S.139 case, consumption of petroleum products is projected to increase by 26 percent between 2000 and 2020.

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[182] S. Palstev, J.M. Reilly, H.D. Jacoby, A.D. Ellerman and K.H. Tay, *Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal*, Report No. 97 (Cambridge, MIT Joint Program on the Science of Global Change, June 2003 [revised: June 17]), Case 5.

[183] S. Palstev, J.M. Reilly, H.D. Jacoby, A.D. Ellerman and K.H. Tay, *Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal*, Report No. 97 (Cambridge, MIT Joint Program on the Science of Global Change, June 2003 [revised: June 17]), Case 7.

7. Assessment of Economic Impacts

Objectives of the Economic Assessment

Because energy resources are used to produce most goods and services, higher energy prices can affect the economy's production potential. Since the energy crisis of the 1970s, economic research has led to a better understanding of the potential adverse economic consequences of rising real energy costs, in terms of both long-run equilibrium costs and short-run adjustment costs. Long-run equilibrium costs are associated with reducing reliance on energy in favor of other factors of production—including labor and capital, which become relatively cheaper as energy costs rise. Short-run adjustment costs can arise when price increases disrupt capital or employment markets.

This chapter assesses possible impacts on the economy associated with attaining the emissions target under alternative scenarios presented earlier in the report and comparing them with a reference case. In evaluating these alternative scenarios, five key questions are posed:

- What would be the long-run cost to the economy?
- With rising energy prices and inflation, what adjustment impacts would the economy face?
- How does the allocation of permits affect the economic outcome?
- What is the role of the Climate Change Credit Corporation in mitigating these economic effects?
- How would the Federal Reserve Board react to higher inflation and unemployment?

Treatment of Permits from a Macroeconomic Perspective

Four basic pollution control policies exist: taxes, subsidies, tradable permits, and command-and-control regulation. S.139 focuses on the establishment of a marketable emission allowance trading system; however, the bill is silent on the allocation of allowances—which will have a significant impact on the energy economy—leaving the decision regarding the allocation to the Secretary of Commerce. To assess the economic impacts, key assumptions were made about the implementation of S.139; the most significant relates to the allocation of the allowance permits and the role of the Climate Change Credit Corporation (hereafter referred to as "the Corporation"), which will be granted a portion of the permits.

The bill sets up a system of marketable permits with a split in the allocation of the permits between a no-cost allocation of permits to business entities and another portion provided to the Corporation, which can sell the permits through an auction. In principle, under a set of conditions, each of these market mechanisms, if implemented independently, will yield the same solution, i.e., will identify the same marginal cost of reducing a pollutant by a given amount. While the policies may achieve the same economically efficient solution, their distributional impacts are considerably different.[184]

In the no-cost allocation to firms, there would be redistribution of income flows among emitters of pollution, in the form of sales and purchases of emission permits. In contrast, with an auction run by the Corporation, there would be a net transfer of income from emitters to the Corporation. The key question at this juncture turns on the use of the funds by the Corporation. If the funds were returned to the emitters through some transfer program, the effect would be the same as in the no-cost allocation scheme, but with the Corporation establishing the distribution mechanism to emitters. Another use of the funds would be to return them to consumers in the form of a lump-sum transfer, compensating consumers for the higher prices paid for energy and non-energy goods and services.

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[184] For a discussion of the relative merits of alternative policy instruments, see Perman, Ma, and McGilvray, "Pollution Control Policy," in *Natural Resource and Environmental Economics* (Addison Wesley Longman, 1996).

The allocation of permits (or redistribution of auctioned revenues) will have differential effects on energy markets and the economy, in terms of both the magnitude and the time profile of the impacts. From a macroeconomic perspective, an auction that transfers funds to consumers in a lump sum would help to maintain their level of overall consumption relative to the no-cost allocation of permits to business. With the transfer, however, total investment would decline relative to the no-cost allocation system. The two effects would tend to counterbalance each other, although not completely. The time profiles of the impacts would differ.

In order to explore the economic implications of different allocation choices for macroeconomic growth, several alternative allocation systems were examined and compared with the reference case,[185] including:

- An allocation that begins with an 80 percent no-cost allocation to firms and a 20 percent allocation to the Corporation in 2010. The share allocated to the Corporation would increase over time to a maximum of 80 percent in 2025. The funds generated from the sale of the permits by the Corporation are recycled back to consumers as a lump-sum transfer after transition assistance and funds for energy-efficient investment are netted out. This methodology is used in the S.139 case.
- A sensitivity case with a fixed 20 percent of the permits granted to the Corporation from 2010 through 2025, with a lump-sum transfer to consumers, with transition assistance and energy-efficient investment funds netted out.
- A sensitivity case with a fixed 80 percent of the permits granted to the Corporation from 2010 through 2025, with a lump-sum transfer to consumers with transition assistance and energy efficient investment funds netted out.

In each of these three cases, the Federal Reserve would seek to balance changes in inflation and the unemployment rate through changes in interest rates. Throughout this chapter, all value concepts are presented in real 1996 dollars, unless otherwise specified.

A Tax Program Versus a Cap and Trade Program with Early Credit Incentives

In order to discuss the differences between a tax and a cap and trade program to control undesirable emissions (pollutants), some background information is needed. If a policy is to be economically efficient, knowledge about both the marginal cost of abatement of the pollutant and the marginal benefit of reducing the pollutant must be known. Equating the two measures derives an economically efficient solution. Rarely is there an explicit representation made of the marginal benefit of reducing the pollutant, however, because of the difficulty of quantification. Most often, a target is specified and the question asked is, “What is the best way to meet the target?” This is referred to as being a cost-effective solution to meet the target. It may not yield the most efficient level of reduction by the best path; rather it identifies the best path to arrive at a predetermined target.

To be efficient, a tax must be imposed on the pollutant directly, not on the output from which it comes or some other measure used as a proxy for the pollutant. Consider a tax applied uniformly across all polluters. Since the tax affects the *price* of the given good or service, the *quantity* of the pollutant will be adjusted; however, the amount by which the quantity will be affected is unknown. In this case, it is not possible to know whether a given tax can result in a specified target.[186]

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[185] EIA used the Global Insight, Inc. (formerly DRI-WEFA) model of the U.S. economy to assess these issues. The Global Insight model is a representation of the U.S. economy with detailed output, price, and financial sectors incorporating both long-term and short-term properties.

[186] See Perman, Ma, and McGilvray, “Pollution Control Policy,” in *Natural Resource and Environmental Economics* (Addison Wesley Longman, 1996).

A Tax Program Versus a Cap and Trade Program with Early Credit Incentives (continued)

With a tradable permit system (often referred to as a cap and trade program), the policy mechanism acts on determining a given *quantity* of adjustment and the value of the tradable permits (which affects the *price* of a given good) needed to achieve the target quantity adjustment. Here the value of the tax, and the ultimate effect on prices are subject to uncertainty.

If the policy maker is certain about the shape of the marginal abatement cost curve, the tax and the cap and trade system will yield equivalent cost-effective solutions. That is, if the policymaker knows how much it will cost to achieve each incremental reduction in a pollutant, the system can be designed so that a tax and a cap and trade system will yield identical results. The primary distinction between the two programs is not associated with economic efficiency (or economic cost-effectiveness) but rather with the distribution effects of the two programs. It is entirely possible that the two will yield equivalent cost-effective solutions to reducing pollution, but the distribution of the impacts can vary considerably, depending on how the permits are allocated. If permits are auctioned, it is equivalent to a tax. If permits are allocated at no cost, the same cost-effective solution is achieved, but there is a redistribution of income among the permit holders and between permit holders and affected non-permit holders. The holders of permits possess a commodity that takes on a value, which can be submitted to the appropriate authority for each unit of pollution emitted or sold to a polluter who has a higher cost of abatement.

The coverage of the policy assumed in the above discussion is the entire economy. If certain segments of the economy are excluded, reducing overall coverage, those units that have the lowest cost abatement profiles may be excluded, making the solution more costly than would otherwise be possible. Another cost is the administration of the program. Monitoring and reporting costs can be significant and, moreover, difficult to quantify. Because a tax program is the easiest to implement, it has a lower administrative cost burden.

Macroeconomic Cost Measures

A number of economic measures are presented later in this chapter. A few key measures are highlighted: potential gross domestic product (GDP), actual GDP, the value of purchased international permits, and the relationship between inflation, unemployment, and interest rates.

Loss in Potential Output of the Economy

The aggregate supply potential of the economy is embodied in a concept identified as “potential GDP.” The estimate of this concept relies on a production function view of the economy that combines factor input growth and improvements in total factor productivity. Factor inputs equal a weighted average of labor, business fixed capital, public infrastructure, and energy. Based on each factor’s historical share of total input costs, the elasticity of potential output with respect to labor is 0.64 (i.e., a 1 percent increase in the labor supply increases potential GDP by 0.64 percent); the business capital elasticity is 0.26; the infrastructure elasticity is 0.02; and the energy elasticity is 0.07. Factor supplies are defined by estimates of the full employment labor force, the full employment capital stock, end-use energy demand, and the stock of infrastructure. The concept of *potential* GDP reflects the trajectory of the long-term growth potential of the economy at full employment; *actual* GDP reflects the trajectory of the actual economy as it adjusts to a long-run path.

Actual GDP and the Adjustment Process

The economy may experience transitional impacts that would result from efforts to reduce U.S. greenhouse gas emissions. The measurement of *actual* output for the economy, or actual GDP, is the key concept used in the examination of changes in the aggregate economy as it adjusts to its long-run path. In addition to internal frictions caused by wage-price interactions and capital stock obsolescence, losses in domestic income may occur as funds are transferred out of the United States to purchase international greenhouse gas allowances. Resources may be less than fully employed, and the economy will move in a cyclical fashion as the initial cause of the disturbance—the increase in energy prices—plays out over time. Shifts in the sectoral composition of the economy would also accompany the adjustment process. Here, a single fiscal policy is assumed to accompany the greenhouse gas mitigation policy—the revenues collected from the domestic permit auction are returned to consumers through personal income tax rebates.

The ultimate impacts of greenhouse gas mitigation policies on the economy will be determined by complex interactions between elements of aggregate supply and demand, in conjunction with monetary and fiscal policy decisions. As such, any discussion of possible transitional impacts on the economy is characterized by uncertainty. The introduction of greenhouse gas emission limits would affect both consumers and businesses. Households would be faced with higher prices for energy and energy-related goods and services, which will have two effects. First, there will be a tendency on the part of households to adjust their spending patterns away from energy-related goods and services. Second, because of lower real disposable income resulting from higher prices for energy, consumers will reduce overall spending and savings. Energy services also represent a key input in the production of goods and services. As energy prices increase, the costs of production rise, placing upward pressure on the nominal prices of all intermediate goods and final goods and services in the economy, with widespread impacts on spending across many markets. The ultimate effect depends on opportunities for substitution away from higher cost energy to other goods and services and the effectiveness of compensatory fiscal and monetary policy.

Purchase of International Permits

The international flow of greenhouse gas permit revenue is considered a change in the purchase of imported services. Funds transferred abroad for purchases of international greenhouse gas emissions permits would, in effect, reduce the amount of potential GDP available for domestic use.

Inflation, Unemployment, and the Role of Monetary Policy

Monetary policy can moderate or intensify the ultimate impacts on the economy; however, trying to predict the response of monetary authorities to large increases in energy prices is a difficult task. The emphasis on controlling inflation relative to concerns about rising unemployment has changed over the past 20 years, and using history as a guide does not remove the large amount of uncertainty about the response of monetary authorities. In addition, the types of financial instruments available have become more numerous and more interdependent, and the task of monitoring the Nation’s money supply has become more complex.

The monetary authorities could concentrate on increased inflation resulting from higher energy prices and choose not to increase the money supply in order to moderate the resulting inflation. In this instance, output and employment losses would be larger than if the money supply were expanded when energy prices increased. Another option would be to allow the money supply to increase in order to remove the unemployment impacts while allowing substantial additional price inflation. This analysis uses neither extreme of these assumptions about the response of the Federal Reserve. The discussion in the following section represents a middle path that the Federal Reserve might follow.

Impacts on the Aggregate Economy

S.139 Case

This section discusses the impacts on the aggregate economy projected in the S.139 case. It focuses on the long-run impact on potential output and the transitional impacts on actual output in the economy. Inflation and unemployment impacts are assessed relative to movements in interest rates in reaction to actions taken by the Federal Reserve Board. The role of international flows of funds to pay for international emissions offsets is also discussed. A single fiscal policy is assumed to accompany the emissions mitigation policy—the revenues collected by the Corporation from the domestic permit auction are returned to consumers, predominantly through a lump-sum transfer to individuals. A provision in the bill also calls for transition assistance, which will be disbursed by the Corporation. The share of the permits allocated to the Corporation changes over time in the S.139 case, rising from a 20 percent allocation in 2010 to 80 percent by 2025. Two sensitivity cases are presented, assuming that the Corporation's share of permits would be constant throughout the forecast period—at 20 percent and 80 percent, respectively.[187]

A. Collection and Distribution of Funds Flowing to the Corporation

Collection of Funds by the Corporation. Because the permits have substantial value under S.139, the establishment of the permit trading system creates a considerable amount of revenue for the Corporation. In the S.139 case, the permit price rises steadily through 2023, then levels off as the amount of banked permits approaches zero and the permit price is determined on a year-by-year basis. Figure 7.1 shows the total amount of revenues in the S.139 case and the growing amount that will flow to the Corporation as the percent allocated to the Corporation grows from 20 percent in 2010 to 80 percent in 2025. In 2010, the aggregate amount of funds totals $116 billion, with $23 billion flowing to the Corporation. By 2025, the aggregate amount of funds has risen to $473 billion, with $378 billion flowing to the Corporation. The large sum of funds, the distribution between grandfathering of the permits and allocating to the Corporation, and the ultimate use of these funds by the Corporation have impacts on the aggregate economy.

Distribution Through Transition Assistance. Under Section 352 of S.139, the Corporation must allocate a percentage of the proceeds it derives from tradable allowances to providing transition assistance to dislocated workers and communities. The percentage specified in S.139 is 20 percent of the Corporation proceeds in 2010, falling by 2 percentage points each year and ending in 2020. The transition assistance may take the form of (1) grants to provide training, adjustment assistance, and employment services to employers and employees, and (2) grants to State and local government to assist communities in attracting new employers or providing other services. The transition assistance portion is removed from the total amount of revenues accruing to the Corporation by the sale of the permits. These are interpreted in the model as, first, non-Medicare transfer payments to persons and, second, grants to State and local governments to be spent on consumption of goods and services. Each receives half of the total transition

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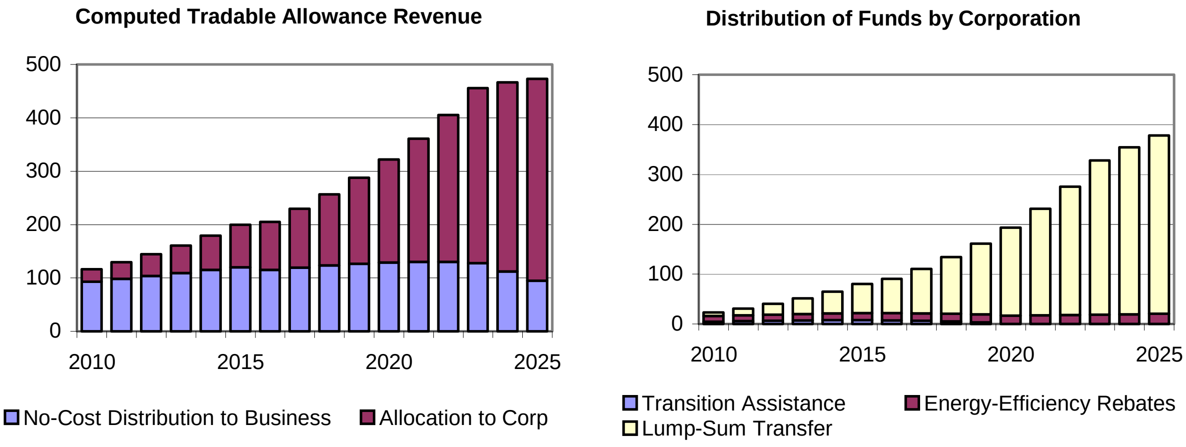
[187] The Corporation is considered to be a quasi-governmental body separate from the Federal Government. To handle the flows of funds to the Corporation and to disperse funds, use is made of tax, expenditure, and transfer levers of the Federal tax system incorporated in the Global Insight Macroeconomic Model. The funds are dealt with in a revenue-neutral manner; i.e., all funds collected are immediately redistributed. This keeps the Federal ledger balanced with respect to receipts and expenditures of the Corporation. However, the Federal surplus/deficit will change due to price and income effects on the economy.

assistance. For the S.139 case, there are three separate trends: the expansion of the revenue base as the percent and going to the Corporation expands from 20 percent to 80 percent; the rise in the permit price, which generates more revenue; and the decreasing share of revenue given to transition assistance. Taking this all into consideration, the nominal amount of transition assistance is about $5 billion in 2010, rising to $8 billion in 2015, and dropping to zero in 2020.

Figure 7.1. Computed Tradable Allowance Revenue and Distribution of Funds by the Corporation in the S.139 Case, 2010-2025 (billion nominal dollars)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Distribution Through Rebates and Subsidies to Consumers. The transition assistance amount is a relatively small percentage of the total amount of revenue collected by the Corporation. The vast majority of the revenues collected by the Corporation remain to be spent or returned in some fashion to the economy. It is assumed that the remaining funds are transferred back to the consumer as a lump-sum transfer—a rebate check. This refund helps to compensate the consumer for the higher energy prices resulting from S.139. Because the Corporation may also subsidize the purchase of increased energy-efficient equipment and appliances to offset some of the energy demand growth in the reference case, the Residential and Commercial submodules of the National Energy Modeling System determine an amount of expenditure that can be expected to be undertaken to upgrade the energy efficiency of the capital stock. From the point of view of the consumer, the amount of compensation is the same, but the split between the actual rebated amount and the subsidy amount is altered. Consumers are induced to purchase a different mix of goods and services than they would have done otherwise.

From the perspective of the consumer, perhaps the most significant feature of the bill is the profile of the impact on disposable income (Figure 7.2). The proportion of the funds being rebated to the consumer grows over time. As a consequence, the consumer sees a rapid recovery in the amount of real disposable income available for spending. From a peak loss of around 0.8 percent in 2016 ($81 billion expressed in 1996 dollars[188]), disposable income rises to marginally above the reference case value by 2025.

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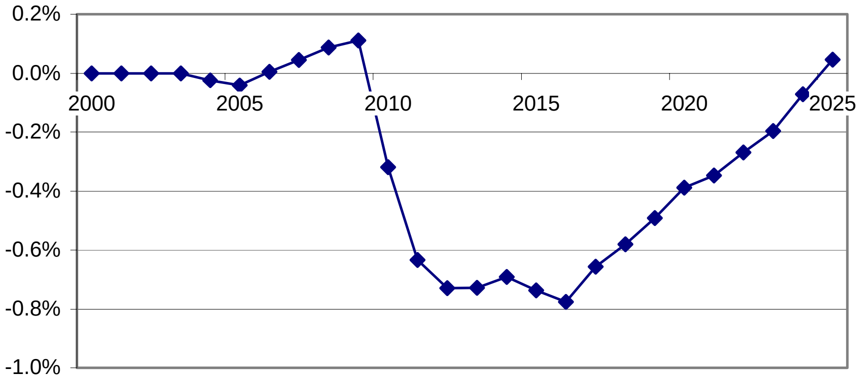
[188] Hereafter, all dollar values, unless stated otherwise, will be expressed in 1996 dollars to conform to National Income and Product Account definitions. Some series will also be expressed in nominal, or current year, dollars, but this will be identified where appropriate.

Figure 7.2. Change in Disposable Income in the S.139 Case Relative to the Reference Case, 2000-2025 (percent change)

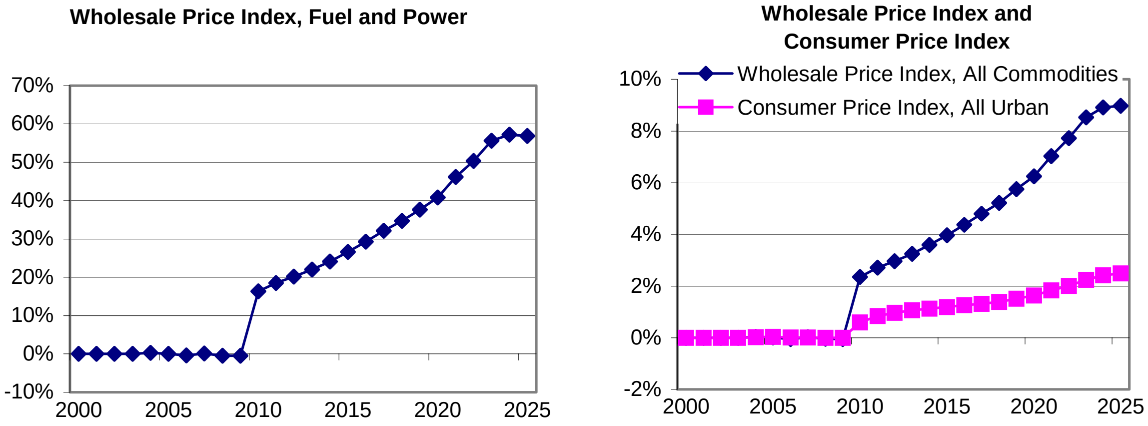


Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

B. Impacts of S.139 on the Aggregate Economy

Higher Prices in the Aggregate Economy. As a direct consequence of the emission permit price, aggregate energy prices in the U.S. economy are expected to rise. One way to measure this effect is to look at the percentage change in the *level* of prices in the economy. The projected energy price, shown as the wholesale price index for fuel and power (Figure 7.3), would also affect downstream prices for all goods and services in the economy. An intermediate measure is the wholesale price index (Figure 7.3), which reflects price impacts on intermediate goods and services. In 2010, the projected increase in the wholesale price index for energy is 16 percent, the increase for producer prices is 2.4 percent, and the increase for final prices for goods and services, as shown by the consumer price index (CPI), is 0.6 percent. By 2020, the three measures rise to 41 percent, 6.3 percent, and 1.6 percent; and by 2025 they rise to 57 percent, 9.0 percent, and 2.5 percent. These figures suggest the following rule of thumb for the

Figure 7.3. Change in Energy, Wholesale and Consumer Prices in the S.139 Case Relative to the Reference Case, 2000-2025 (percent change)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

implementation period: each 10 percent increase in the level of aggregate prices for energy leads to a 1.6 percent increase in producer prices and a 0.5 percent increase in consumer prices.

Impacts on Potential and Actual Output. In the long run, higher energy costs would reduce the use of energy by shifting production toward less energy-intensive sectors, by replacing energy with labor and capital in specific production processes, and by encouraging energy conservation. Although reflecting a more efficient use of higher cost energy, this gradual reduction in energy use would tend to lower the productivity of other factors in the production process. The derivation of the long-run equilibrium path of the economy can be characterized as representing the "potential" output of the economy when all resources—labor, capital, and energy—are fully employed. As such, potential GDP in the Global Insight Model is equivalent to the full employment concept calculated in a number of other models that focus on long-run growth while abstracting from business cycle behavior.

The ultimate impacts of greenhouse mitigation policies on the economy will be determined by complex interactions between elements of aggregate supply and demand, in conjunction with monetary and fiscal policy decisions. As such, cyclical impacts on the economy are bound to be characterized by uncertainty, possibly significant. Raising energy prices and, as a result, downstream prices in the rest of the economy could introduce cyclical behavior in the economy, resulting in employment and output losses in the short run. The measurement of losses in actual output for the economy, or actual GDP, incorporates the transitional cost to the aggregate economy as it adjusts to its long-run path. Resources may be less than fully employed, and the economy may move in a cyclical fashion as the initial cause of the disturbance—the increase in energy prices—plays out over time.

The possible interaction between these impacts is summarized in Figure 7.4, which shows the trends for both *loss of potential GDP* and *loss of actual GDP,* reflecting the macroeconomic *adjustment cost* that may result from the higher prices of the greenhouse gas mitigation policy. It recognizes the possibility that cyclical adjustments may occur in the short run, but that these will play out and converge to potential output as the forecast horizon lengthens.

Actual GDP, which incorporates adjustment costs associated with moving toward a new long-run equilibrium, shows a sharp decline of 0.7 percentage points in 2011 and 2012. Thereafter, the economy begins to rebound from the initial price effects. However, there is a steady negative impact on the long-run supply potential of the economy as all segments adjust to the new pattern of energy use. While the two measures merge by 2025 at a loss of 0.6 percent of actual GDP and 0.5 percent of potential GDP, clearly, the processes of adjustment for both actual and potential output have not fully played out by the end of the forecast period.

Inflation, Unemployment, and the Role of Monetary Policy

In the setting that has been described, higher prices in the economy would place upward pressure on nominal interest rates. The Federal Reserve Board would then seek to balance the adverse effects of higher energy prices on output and employment by making adjustments to the Federal funds rate. The adjustments would be designed to moderate the possible impacts on both inflation and unemployment, and to return the economy toward its long-run growth path.[189]

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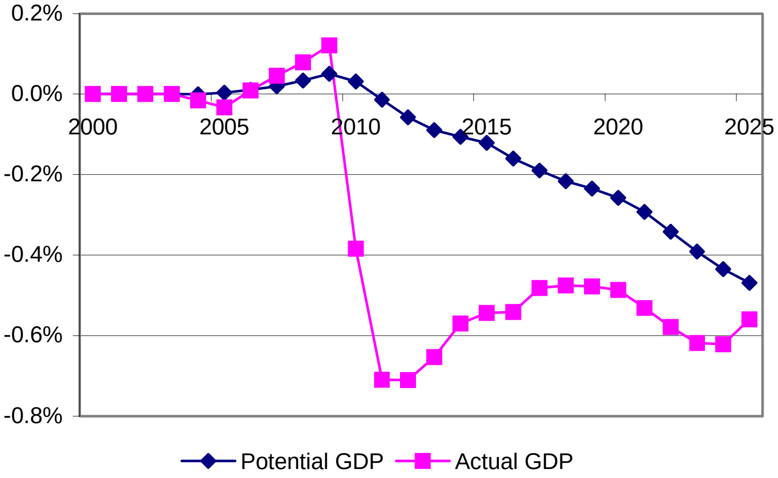
[189] The characterization of monetary policy reactions to inflation and unemployment used in these simulations is based on a Global Insight reaction function that has been estimated to reflect the historical relationship between the Federal funds rate and changes in inflation and unemployment. As such, the reaction function is a reflection of how the Federal Reserve may react to changes in the economy, based on past behavior.

If the rate of inflation increases, but unemployment does not increase, the Federal Reserve may choose to let the nominal interest rate rise in an attempt to cut the rise in inflation. However, if this is accompanied by an increase in the unemployment rate, the Federal Reserve may consider a cut in the rate to stimulate economic expansion and the demand for labor. In essence, there is a balancing act between the two factors—inflation and unemployment—as the initial originating policy initiative has uneven impacts on the two over time.

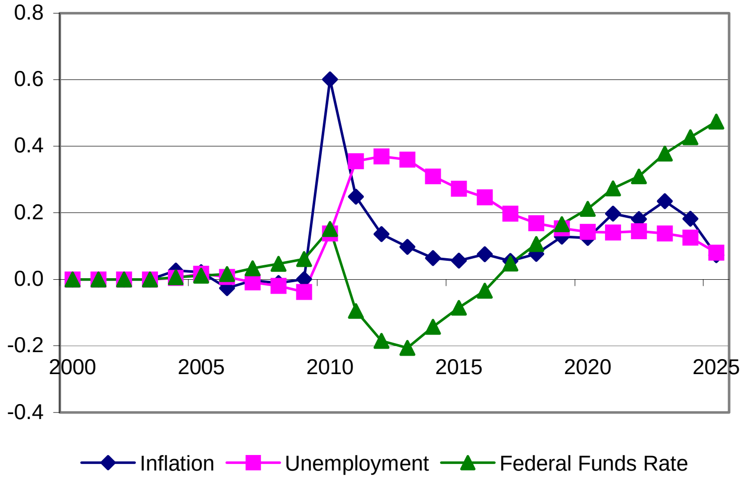
Figure 7.5 shows the interrelationship between the projected inflation, unemployment, and Federal funds rates in S.139. The inflation rate in 2010 jumps from 2.2 percent per year to 2.8 percent per year—a

Figure 7.4. Change in Potential GDP and Actual GDP in the S.139 Case Relative to the Reference Case, 2000-2025 (percent change)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure 7.5. Change in Inflation, Unemployment, and the Federal Funds Rate in the S.139 Case Relative to the Reference Case, 2000-2025 (difference, percentage points)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

difference of 0.6 percentage points—as the provisions of the bill take effect. The price level of the economy continues to rise throughout the forecast period, but the rate of change in the price level—the rate of inflation—decelerates after 2010. After 2017 the inflation rate begins to increase again, but at a slower rate. The rate of inflation always remains above the reference case, keeping continual pressure on the aggregate economy. The unemployment rate increases in response to the rapid increase in inflation. By 2012, the peak impact year, the unemployment rate rises from 4.3 in the reference case to 4.7 percent, a difference of 0.4 percentage points (about 0.6 million jobs). The responses of inflation and unemployment tend not to be symmetric over time. There is a lag between the two effects, with output and employment effects lagging behind price effects. Prices rise in the economy in response to the initial energy price increase and then in response to secondary price effects as the costs of intermediate goods and services rise. Businesses, in response to rising prices and lower aggregate demand, absorb the near-term output loss but eventually reduce their use of labor. The lag from initial price effects to ultimate output and employment losses can be a year or so.

As a result of the differential effects projected for inflation and unemployment during the years from 2010 to 2012, the Federal Reserve is assumed to allow a modest rise in the Federal funds rate in the short term, when concern over inflation outweighs concern over GDP losses and unemployment. After the initial rise in energy prices, the inflation rate approaches the rate projected in the reference case; however, aggregate output is still depressed, and unemployment in the economy remains above the reference case value. During this period, the Federal Reserve reacts by reducing the Federal funds rate, in order to combat the loss in output and employment in the economy. As unemployment falls and prices continue to rise, the Federal Reserve starts increasing the Federal funds rate after 2013. By 2016 the Federal funds rate is back at baseline, but prices are continuing to rise. With unemployment continuing to fall due to demand pressures, mentioned above, the Federal Reserve Board continues to raise the Federal funds rate, which increases all the interest rates, including the rates on Federal Government debt, above baseline values.

Implicit in this discussion about the ability of the Federal Reserve to influence real activity in the economy is the historically observed relationship between the Federal funds rate and real long-term interest rates. While the Federal Reserve can directly influence the nominal Federal funds rate (which is a short-term rate) by increasing or decreasing unborrowed reserves, it is the real long-term rates that influence decisions to save and invest. Figure 7.6 shows the difference from base for the real yield on AA utility bonds and real average yield on U.S. Treasury bonds. As figures 7.5 and 7.6 show, the real long-term rates (Figure 7.6) track closely the Federal funds rate (Figure 7.5) over the forecast period.

Figure 7.7 shows the impacts on actual GDP as well as gross output (value of production) and employment. Gross output declines by 1.1 percent in 2011, rebounds slightly, then declines again as inflation picks up again just before 2020. Employment reaches a peak loss of 0.6 percent in 2012 and by 2025 is almost back to reference case levels. Gross output and employment impacts of S.139 are discussed in more detail later in this chapter.

Composition of Impacts on Actual GDP. Figure 7.8 highlights the relative impacts on components of actual GDP.[190] In the aggregate, actual GDP falls by approximately $93 billion by 2012 (0.7 percent of reference case). However, the impacts are uneven across the components of GDP.

Consumption of goods and services in the economy contributes the most by far to the overall decline, falling by $79 billion (0.9 percent of reference case) in 2012. This is due to the rapid rise in energy prices and the rapid decline in disposable income. Consumption remains down from the reference case as prices

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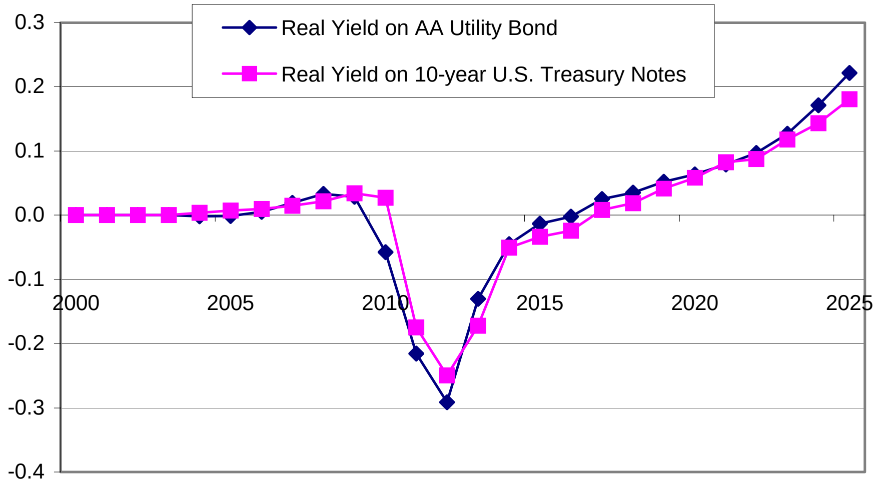
[190] Because of the nature of the chained price indexes adopted in the National Income and Product Accounts, the sum of the components of GDP is not equal to actual GDP in real terms. While the impacts of the real consumption, investment, etc., can be analyzed independently, they do not add up in absolute terms to the loss in actual GDP.

continue to rise, but toward the end of the forecast, consumption begins to recover as inflation begins to stabilize near reference case levels and the amount of disposable income increases. Figure 7.9 shows the rebound in consumption relative to disposable income in percentage terms.

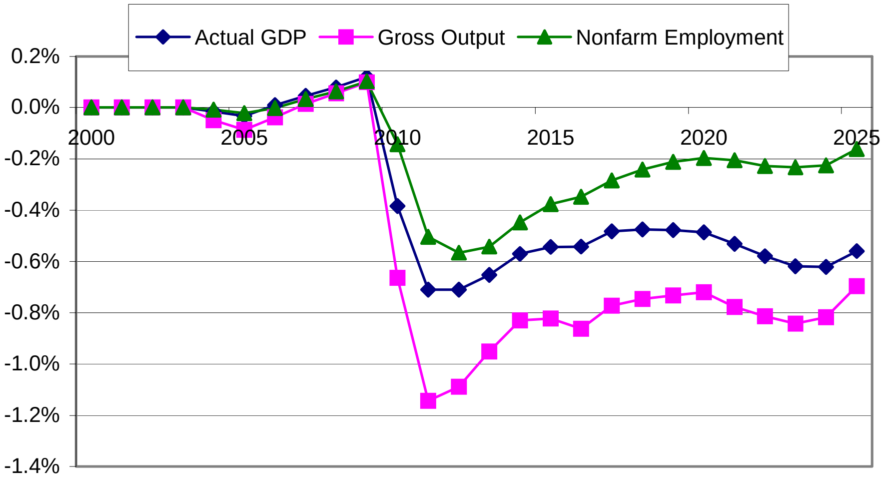
Investment also declines rapidly, reaching a loss of $42 billion (1.6 percent of reference case) in 2011. It recovers early in the period, as the proportion of the funds going to the Corporation remains small. However, as the share remaining in the hands of business declines over time and more funds are shifted to the Corporation, the impact on investment begins to increase again, reaching $49 billion (1.1 percent of reference case) in 2025.

Figure 7.6. Change in Real Long-Term Rates in the S.139 Case Relative to the Reference Case, 2000-2025 (difference, percentage points)



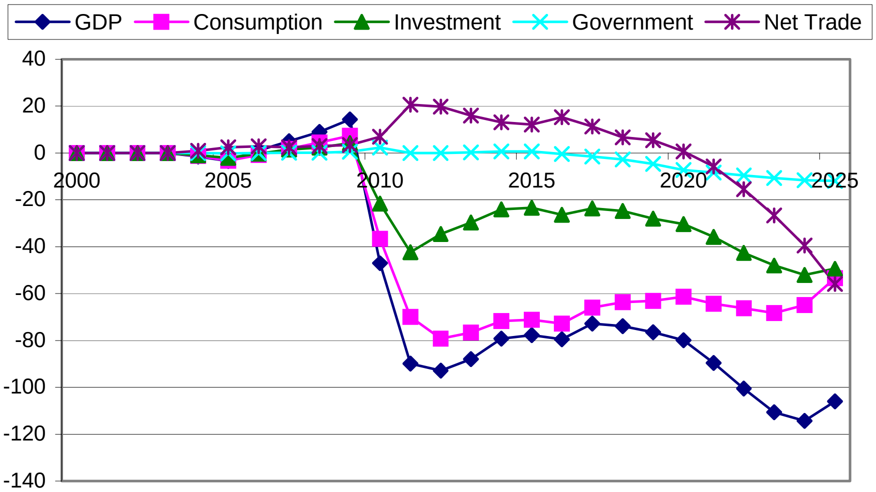
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure 7.7. Change in Actual GDP, Gross Output and Employment in the S.139 Case Relative to the Reference Case, 2000-2025 (percent change)



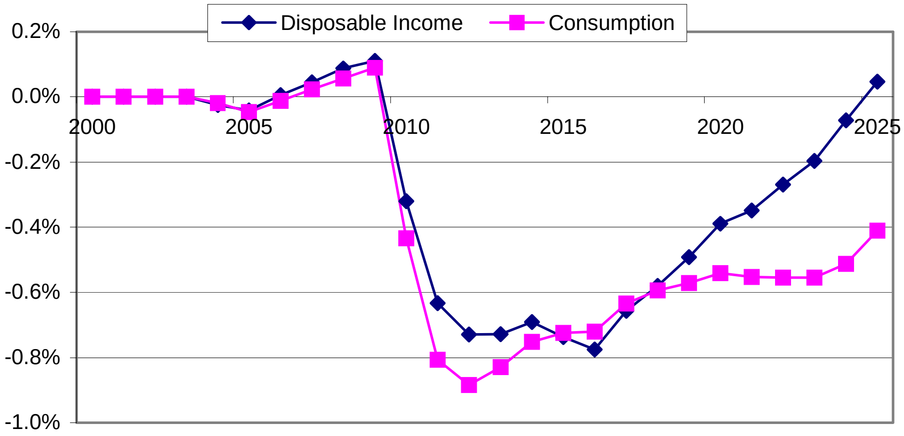
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure 7.8. Change in Composition of Actual GDP in the S.139 Case Relative to the Reference Case, 2000-2025 (differences, billion real 1996 dollars)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

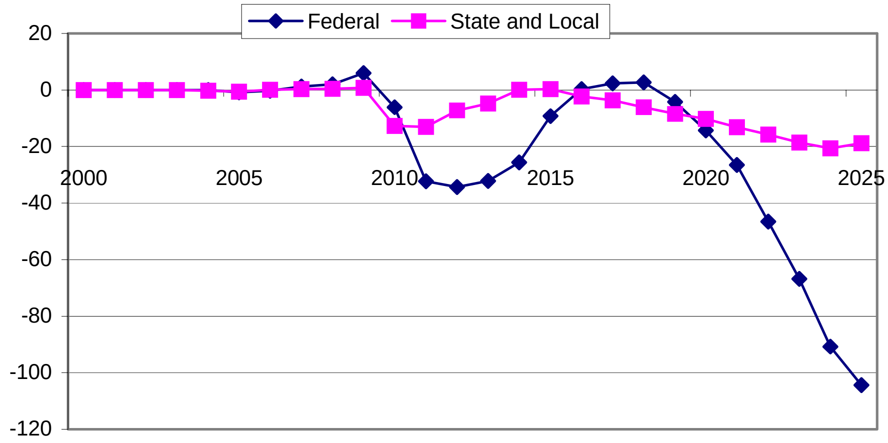
Figure 7.9. Change in Disposable Income and Consumption in the S.139 Case Relative to the Reference Case, 2000-2025 (percent change)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

For the S.139 and the other cases it is assumed that the Federal, and State and local governments do not change their spending and revenue policies, relative to the reference case. However, real government spending and revenues will change due to the presence of spending and revenue raising policies that are linked to the state of the economy as well as price changes. As shown in Figure 7.8, real government expenditures (Federal and State and local) decline gradually over the period due to higher prices. Ultimately the real issue is the decline in the nominal surplus for both (Figure 7.10). The Federal and State and local government surpluses worsen as inflation rises, employment and output decline, and interest rates increase. After the initial worsening, both the Federal and State and local surpluses begin to improve, largely due to the sharp decline in the inflation rate and the improvement in the economy. The Federal surplus declines by $34 billion (nominal) in 2012, improves, and then worsens by approximately $104 billion (nominal) by 2025. The State and local government surplus follows much the same pattern, worsening by $13 billion (nominal) in 2011 and by $21 billion in 2024.

Figure 7.10. Change in Federal and State and Local Surpluses in the S.139 Case Relative to the Reference Case, 2000-2025 (difference, billion nominal dollars)



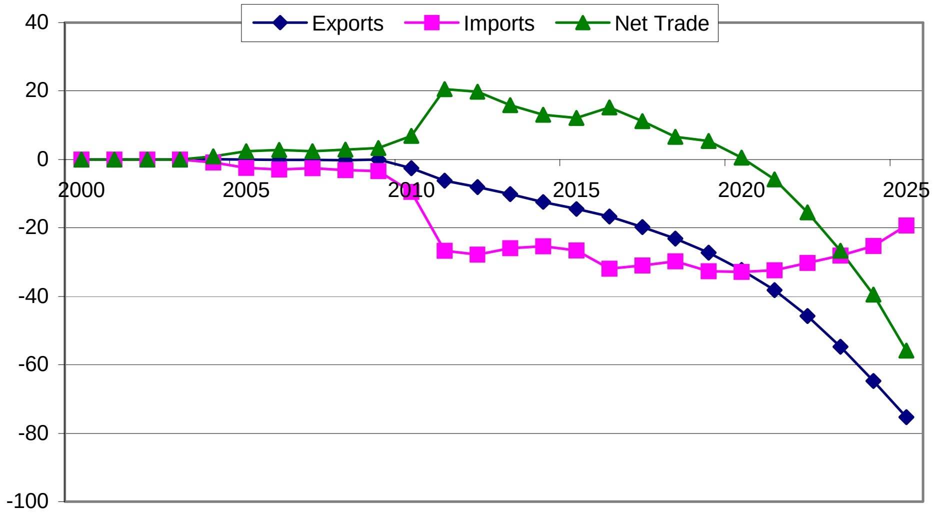
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

The rise in the deficit at the Federal level is, in large part, due to the rise in interest rates and payments on Federal debt. As the discussion of Figure 7.5 mentioned, with the inflation rate continually above reference cases rates, interest rates (and therefore interest payments by the Federal Government on its total debt) increase. This increases the nominal size of the Federal deficit. By 2025 the Federal funds rate is 47 basis point above its baseline value, and the yield on 30-year Treasury bonds is approximately 30 basis points above its baseline value. A 30 basis points increase in interest payments on the nominal Federal debt (which is $13,250 billion in 2025 in the baseline case) amounts to approximately $40 billion and is the principal reason for the increasing size of the Federal nominal deficit.

International trade is also affected by these events. Prices for goods and services within the United States compared to foreign prices drive the results. While S.139 is presumed to be offered in conjunction with expected greenhouse gas initiatives outside the United States, trade impacts of a domestic bill such as S.139 should be examined relative to a reference case assuming foreign programs. In this setting, a rise in U.S. energy prices, feeding through to higher domestic prices, makes U.S. exports less competitive overseas. In the S.139 case, exports decline steadily relative to the reference case to a maximum loss of approximately $75 billion in 2025 (Figure 7.11). Imports are also influenced not only by relative prices but also by the loss in output, employment, and income. Imports decline, reaching a maximum loss of $33 billion, but then begin to increase. Imports of industrial materials and supplies plus services decline the most throughout the period, while imports of foods, feeds and beverages; motor vehicles and parts; and non-automotive consumer goods initially decline, but then recover beyond the baseline by 2025. However, the net trade balance actually improves for most of the forecast as imports decline by more than exports through 2020. After 2020, with imports picking back up and exports declining further, the difference in net trade balance turns negative.

The purchase of international emissions permits is represented as an increase in imports of services. In Phase 1 of the implementation, between 2010 and 2015, a covered entity may satisfy 15 percent of its permit requirements by purchasing allowances from non-covered entities, through sequestration, and from other nations. In the S.139 case, annual purchase of international permits is expected to be just under $5 billion (real 1996 dollars) throughout the Phase 1 period, representing 27 to 31 percent of all offset purchases. In 2016, when the offset allowance is reduced to 10 percent, domestic offsets are adequate to satisfy demand, and international purchases drop to zero.

Figure 7.11. Change in Exports, Imports, and Net Trade in the S.139 Case Relative to the Reference Case, 2000-2025 (difference, billion real 1996 dollars)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

C. Impacts on Output and Employment

This section analyzes the projected impacts of the S.139 case on gross output (or production) and employment. For the manufacturing industries, the value of shipments data collected by the U.S. Bureau of the Census is the basis for measuring the dollar value of output.

Gross Output. In 2001, the service sector accounted for 63 percent of the economy's total output. The manufacturing sector accounted for 28 percent, and the non-manufacturing industries (agriculture, mining and construction), 9 percent. Of the manufacturing output, 27 percent was from energy-intensive industries.[191] In the reference case (Figure 7.12), the service sector is expected to grow at a compound annual growth rate of 3.1 percent for the period 2001-2025, the manufacturing sector at 3.0 percent, and the non-manufacturing sector at 1.4 percent. Energy-intensive industries are projected to grow at a slower pace (1.5 percent) than the non-energy-intensive industries (3.4 percent).

Upon implementation of S.139, the changes in energy prices and the allocation of permit revenue by the Corporation will affect all final demand categories of consumer, investment, and government spending. Demand for domestically produced goods and services will shift, and industries will adjust accordingly.

Figure 7.13 shows the projected changes in output in the S.139 case. All the major sectoral groups decline, but the impacts are uneven. The non-manufacturing sector, which covers mining, is affected the most, followed by the energy-intensive manufacturing industries. In the beginning of the implementation period, the non-energy-intensive industries and the service sector experience a fall in demand because of the surge in prices, but the declines are less than in the other two groups. As a larger portion of the permit revenue is passed to consumers over time, consumer spending improves.

Figure 7.14 shows the average loss in output for the period 2010-2025. The average loss in total output is projected to be about 0.8 percent, slightly higher than the GDP loss of 0.6 percent. Production of the non-

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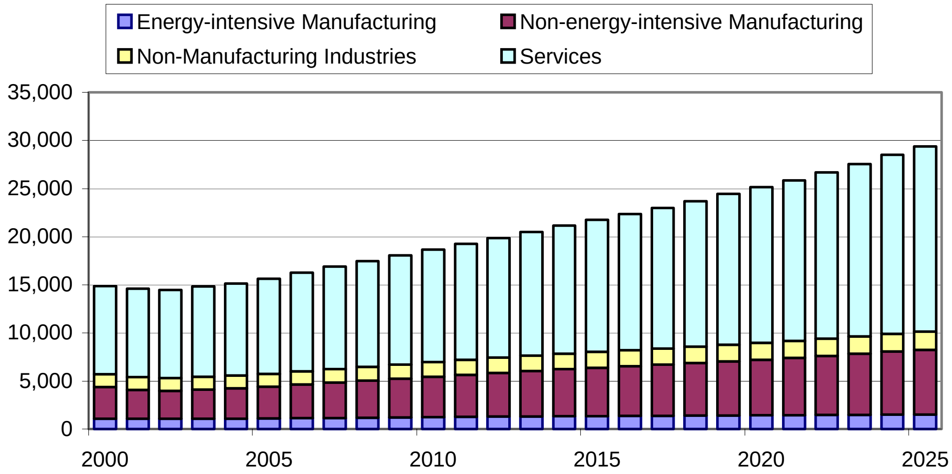
[191] Energy-intensive industries include Food, Paper, Inorganic and Organic Chemicals, Plastic Materials, Agricultural Chemicals, Petroleum Refining, Glass, Cement, Blast Furnace and Basic Steel, and Aluminum.

manufacturing industries (agriculture, mining, and construction) is projected to be reduced by an average of 1.8 percent, energy-intensive manufacturing by an average of 1.2 percent, and other manufacturing by an average of 0.9 percent. The services sector, which comprises two-thirds of the economy and has relatively lower energy intensity, is expected to be reduced by an average of 0.6 percent.

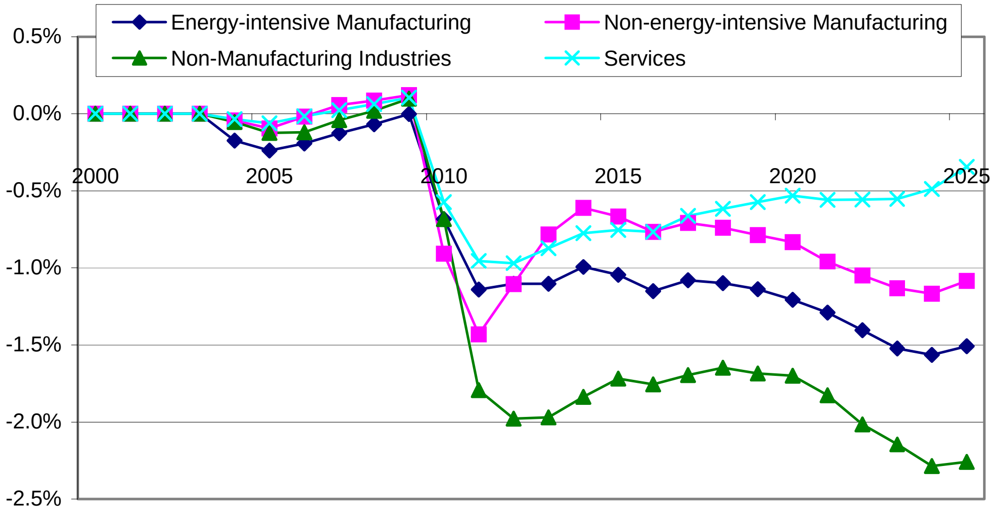
The impact of the S.139 case on detailed sectors is presented in Figure 7.15. The upper part of the graph shows the projected changes in output at the more aggregate level of detail. Mining is expected to register an 8.6 percent loss relative to the reference case for the period 2010-2025. Agriculture and Business and Personal Services will be least affected. The lower part of the graph shows the projected changes for the

Figure 7.12. Gross Output in the Reference Case, 2000-2025 (billion real 1996 dollars)



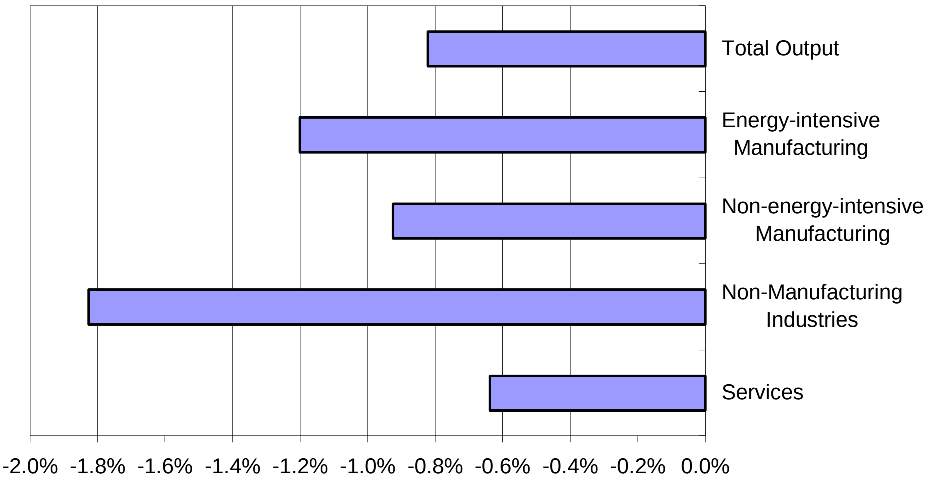
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System run MLBASE.D050303A.

Figure 7.13. Change in Gross Output in the S.139 Case Relative to the Reference Case, 2000-2025 (percent)



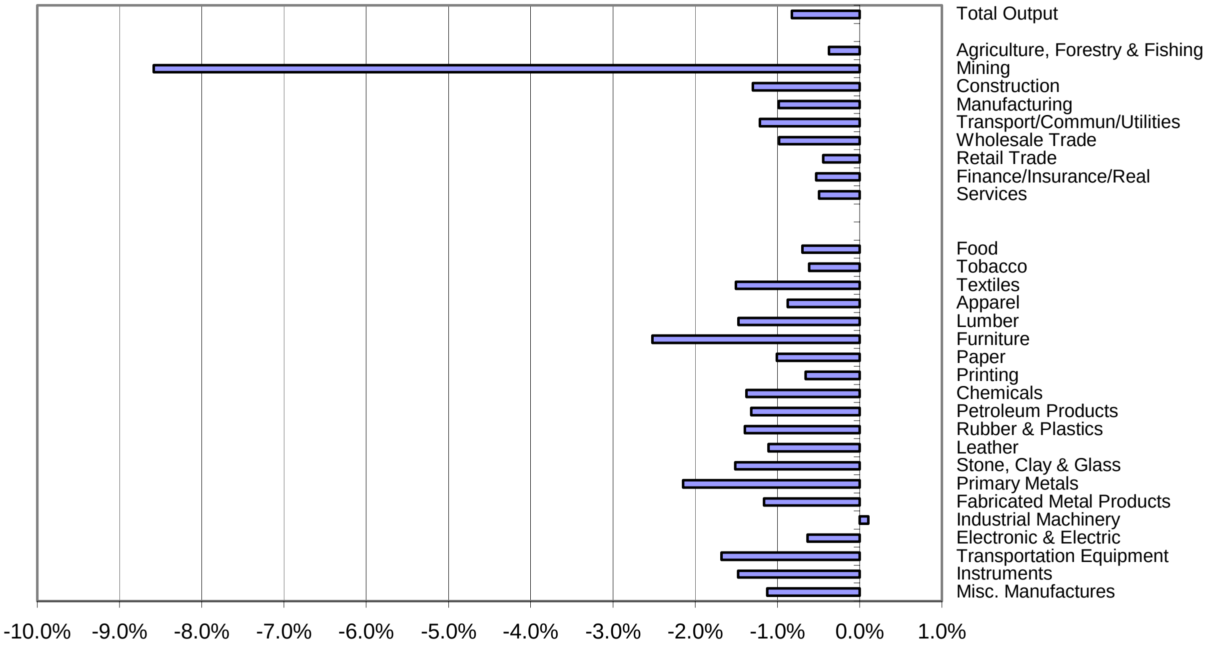
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure 7.14. Average Change in Gross Output in the S.139 Case Relative to the Reference Case, 2010-2025 (percent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Figure 7.15. Average Change in Output by Detailed Sectors in the S.139 Case Relative to the Reference Case, 2010-2025 (percent)



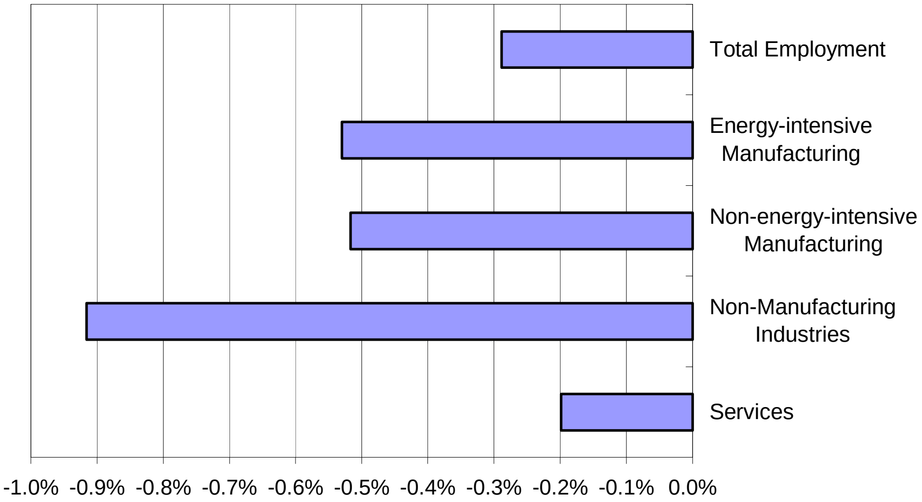
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

manufacturing sectors at the 2-digit Standard Industrial Classification (SIC) level.[192] The impacts vary from a decline of 2.5 percent for furniture to slightly positive for industrial machinery—including computers, the demand for which is expected to increase because their prices are less impacted by increasing energy prices relative to the overall price level.

The differential impacts among industries can be explained by several factors. First, the direct impact of higher energy prices is a reduction in demand for energy products, especially for those with high carbon content. Second, prices for energy-intensive products rise more than prices for non-energy-intensive products and most services, resulting in some substitution effect or change in consumer behavior. Third, demand for some goods and services is not as price-sensitive as others. Fourth, the allocation of permit revenue to consumers increases over time in the S.139 case, which increases the final demand for consumer products and services. Finally, an increase in producer prices changes the relative prices between domestic and foreign goods. Demand for some U.S. goods may fall as they become more expensive, and demand for foreign goods may increase.

Employment. S.139 is projected to have a smaller impact on employment than output. First, there is a portion of employment—managerial and supervisory—that is not engaged in direct production. Second, at least in the short run, the level of direct labor input may be less flexible than the level of production. Also, in the longer run, higher energy prices will induce some substitution from energy to other inputs such as labor and capital. This results in a reduction in labor productivity and a higher labor-to-output ratio. Figure 7.16 shows the average loss in employment for the period 2010-2025 under the S.139 case. The average loss in total employment (including agricultural employment) is projected to be 0.3 percent, or 0.46 million. The loss in non-manufacturing employment is estimated to be 0.9 percent (0.11 million), compared to a 1.8 percent loss in output. Average loss in employment is less in percentage terms for manufacturing (0.5 percent or 0.09 million) and for services (0.2 percent or 0.26 million), corresponding to the smaller impacts on output from these two sectors.

Figure 7.16. Average Change in Employment in the S.139 Case Relative to the Reference Case, 2010-2025 (percent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

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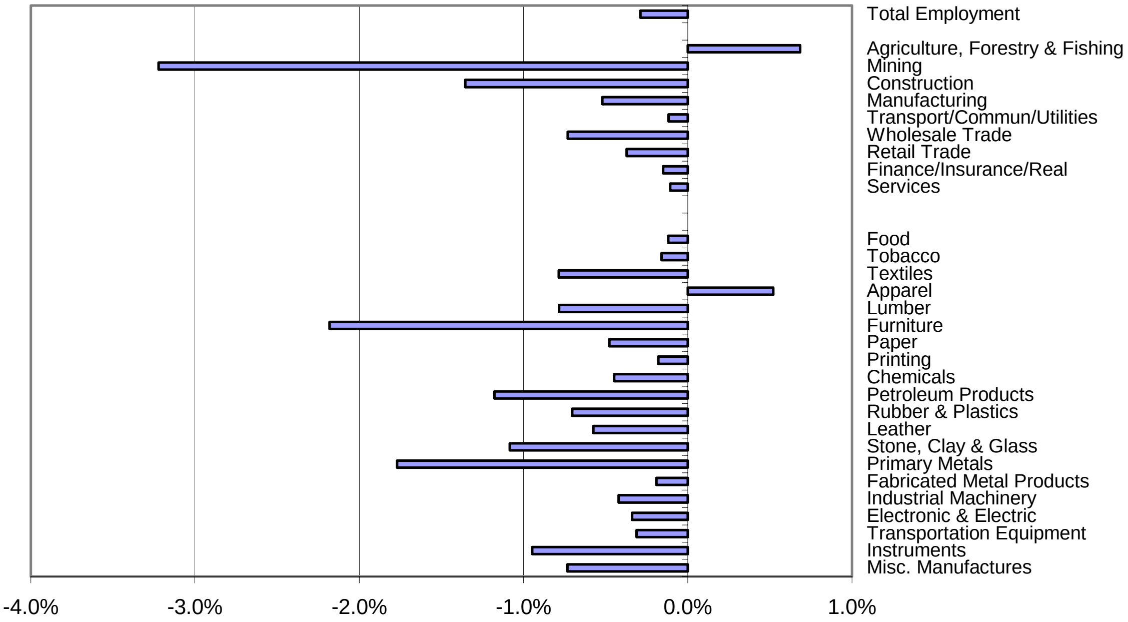
[192] Because of its Global Insight origin, the NEMS macroeconomic analysis relies on SIC industry definitions, as opposed to the North American Industry Classification System (NAICS). The Global Insight model used the SIC definitions.

The impact of the S.139 case on employment at the detailed sectoral level is presented in Figure 7.17. The strongest impact is on the mining sector. The mining sector comprises three subsectors: coal, oil, gas extraction, and other metal and non-metal mining. While the output of coal is projected to decrease by an average of 48 percent from the reference case, output of oil and gas (about three times the dollar value of coal production) is projected to increase by 3 percent. Since the latter is more labor-intensive than the former, the positive impact on employment in the oil and gas industry offsets part of the negative impact on employment in the coal industry. Two sectors—agriculture and apparel—are forecast to have a small positive impact on employment under S.139. The impact on employment can be viewed as the combination of the impacts on output, labor productivity, and the relative price of different productive inputs. The output impacts of the two sectors are negative but small, since both sectors are not very sensitive to energy price changes. The reduction in labor cost relative to the producer price of agricultural products and the reduction in labor productivity in the manufacturing sector have, respectively, much stronger impacts on the two sectors.

Figure 7.17. Average Change in Employment by Detailed Sectors in the S.139 Case Relative to the Reference Case, 2010-2025 (percent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Economic Impacts of Alternative Cases: Allocations of Permits, No Banking, Increased Offset Limits, and High Technology

The discussion above applies to a case in which the allocation of permits to the Corporation rises from 20 percent in 2010 to 80 percent by 2025, or 4 percentage points per year. How does the economic impact of S.139 change if alternative allocation schemes are used? The section below considers two allocation schemes: keeping the percent allocated to the Corporation steady at 20 percent (corp20) and at 80 percent (corp80) from 2010 through 2025. The second section considers a case with no banking of permits allowed. The third section discusses a case that allows up to 50 percent of a covered entity’s emissions to be met by using offsets, and the fourth section deals with high technology.

Comparing Computable General Equilibrium and Macroeconomic Models

To assess the macroeconomic impacts of energy and environmental policies, two types of frameworks are generally employed. While both frameworks model the macroeconomy in a consistent fashion and should provide similar results in the long run, their orientation and objectives are different. Each framework provides relevant insights. In order to fully comprehend the nature of macroeconomic impacts presented in this study, which employs the macroeconomic framework, it is useful to understand the main features of each framework.

Computable General Equilibrium Models. Generally, computable general equilibrium (CGE) models derive demands and supplies from microeconomic optimization theory. (Consumers maximize utility and firms maximize profits.) Given the microeconomic theoretical structure imposed on the demand and supply relationships, the results of these models are easy to understand. Prices adjust rapidly to equate demand to supply and thus all markets, including the labor market, clear. Given this market clearing mechanism of prices, there is full employment of resources in each time period. One can consider these models as representing a microeconomic laboratory where long term simulations of alternative policies can be done in a consistent framework and abstracting from the transitional cost issues. It is this attractive feature that has gained them popularity in climate control discussions. In fact, several have been used to run a number of stylized Kyoto scenarios for the *Energy Journal* (Kyoto Special Issue, 1999). These include: ABARE-GTEM, (Australian Bureau of Agriculture and Resource Economics - Global Trade and Environment Model); AIM (Asian Pacific Integrated Model, National Institute for Environmental Studies, Japan); MS-MRT (Multi Sector – Multi Region Trade Model, Charles River Associates); SGM (Second Generation Model, Batelle Pacific Northwest National Laboratory); MIT-EPPA (Massachusetts Institute of Technology – Emissions Projection and Policy Analysis Model); and WorldScan (Central Planning Bureau/RIVM, Netherlands). The results from these models can be thought of in terms of comparative static exercises. If a policy is instituted that relates to carbon emissions, what will be the new full employment equilibrium? The transitions from one full employment equilibrium to another full employment equilibrium are not charted out in these models, and therefore they are not intended to be used for forecasting the short- to medium-term effects of government policies.

There is generally no role for macroeconomic stabilization policies in these CGE models, because the economy is assumed to be at full employment. Because demands and supplies of goods and services are expressed in terms of relative prices (these are essentially barter models), there is no “medium of exchange” role for money, nominal interest rates, and consequently the central bank. The real interest rate is determined by productivity and thrift in the economy. In most of these models, the government sector is limited in scope and rarely presented in detail. Generally the assumption is made that the government produces a good (public good) that is desired by households and thus enters their utility functions and taxes are the prices they pay for them. The government must balance its budget over the forecast horizon, because forward-looking rational agents (both taxpayers and bondholders) would have it no other way and would adjust their saving and spending behaviors otherwise.

Macroeconomic Models. There is another class of models built around the macroeconomy as accounted by the National Income and Product, Balance of Payments, and Flow of Funds Accounts. These models are used for short- to medium-term forecasting purposes. They have evolved from the short-term Keynesian income-expenditure systems of the 1950s and 1960s, to incorporating the insights of many theoretical approaches to the business cycle: Keynesian, neoclassical, monetarist, supply-side, and rational expectations. As all behavioral relationships in these models are statistically estimated from historical data, they are data intensive and require long time series for all variables modeled. The present-day versions of these models generally incorporate the major properties of the long-term growth models, so that short-run cyclical developments will converge to full employment at long-run equilibrium.

Comparing Computable General Equilibrium and Macroeconomic Models (continued)

Essentially these models are meant for short- to medium-term forecasting, and policy simulations can be run effectively. The adjustment costs of the economy to near-term events and policies and the emergence of disequilibria like labor unemployment and non-optimal use of capital resources are explicitly accounted for. These models often have detailed financial sectors and permit assessment of fiscal and monetary policy measures in reaction to government economic policies. Given that they are based statistically on an observed structure of the economy in the past, all forecasts and policy simulations with these models assume that this structure will prevail in the future. For short-term projections this assumption is plausible, but it becomes increasingly tenuous as the projection period lengthens.

The Macroeconomic Activity Module (MAM) of NEMS, developed by Global Insight, Inc. (formerly DRI-WEFA), is essentially such a macroeconomic model. This model can address transition effects of energy policies and has a more detailed government sector and a well-defined set of fiscal policy levers to address alternative policies related to the collection and redistribution of revenues from a tax. It is regularly used for short- to medium-term forecasting and policy simulations at EIA. Here, we make a distinction between forecasting and policy simulations. By forecasting we mean the most likely outcome in the future (short to medium term) given past behavior, existing policies, and the likely course of exogenous variables. Policy simulation (or simulation) means the likely outcome in the short to medium term as a result of a deliberate change in policy, all else being equal. While the macroeconomic model is useful in providing valuable insights about the likely short- to medium-term direction of changes in the future as a result of energy-related policies and legislation, given the shortcomings noted, the longer-term results should be viewed with caution.

Much of economic decisionmaking is forward looking and is based on expectations of future prices, policies, and the economic environment. Given their empirical orientation, in most macroeconomic models consumer and business expectations of prices, inflation, interest rates, etc., are formulated and statistically estimated as depending upon past experiences (adaptive expectations). In the present context, this largely retrospective approach is not wholly satisfactory to the rational expectations school who would argue that the announcement of the energy legislation would significantly influence expectations of inflation or growth prior to any realized change in prices or spending . Thus, the actual disruptions from a policy, announced well in advance, would be smaller than predicted by the macroeconomic models, because consumers and businesses would already have adjusted their behavior before the policy took effect. Because CGE models are essentially static models where prices always clear markets, the modeling of expectations of prices is less problematic, and they would tend to show smaller impacts. Whether expectations are adaptive or perfect is subject to empirical evaluation, and there is no consensus on this.

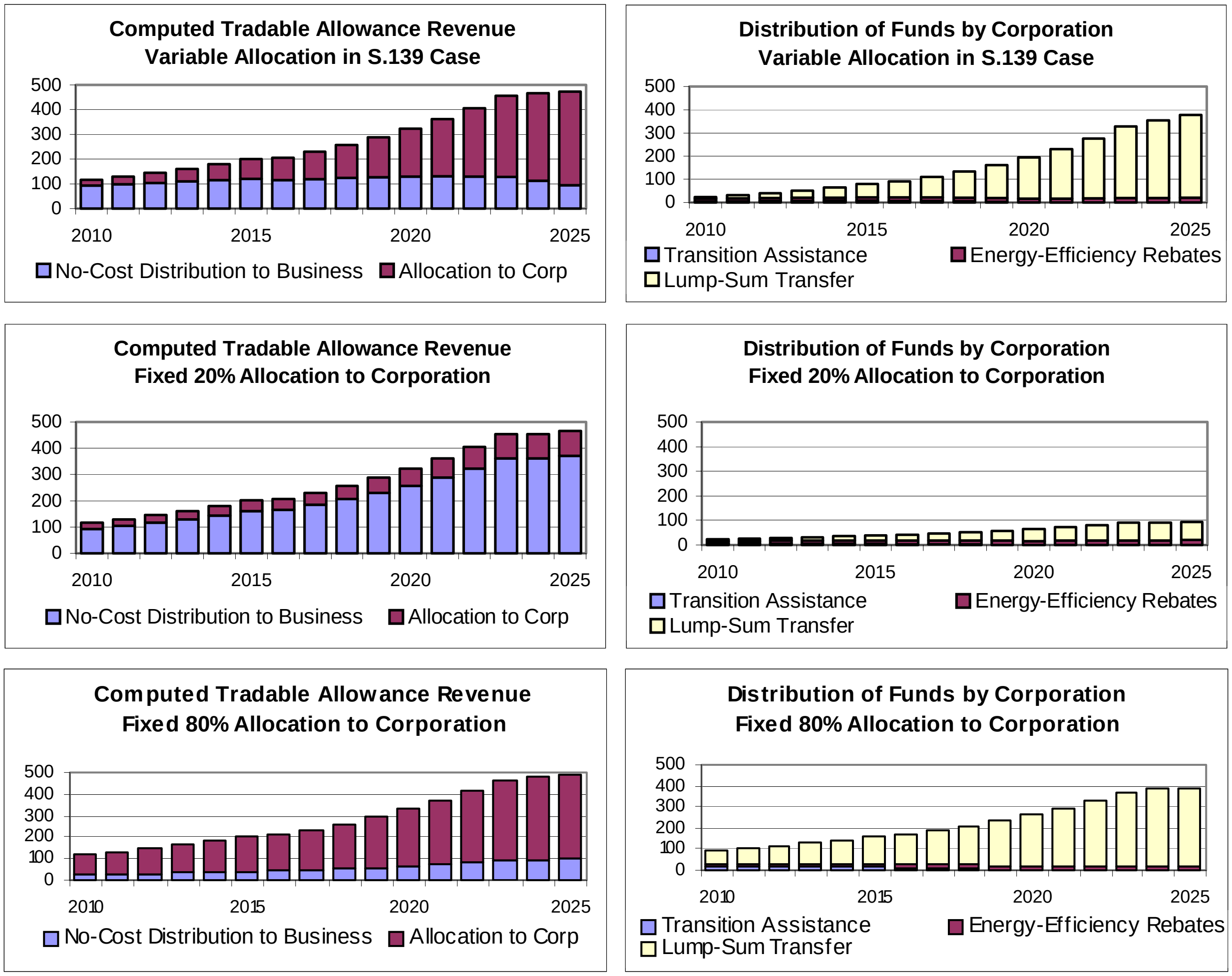
Both macroeconomic models and CGEs have their relative strengths and weaknesses. For studying short- to medium-term impacts of energy, environmental, and other policy changes, macroeconomic models provide insights about the disruption and transition costs involved over time as the economy fully adjusts to them. CGE models provide a useful perspective about the resulting long-run state of the economy.

A. Holding the Allocation Percent Constant

Magnitude and Distribution of Funds. The six charts included in Figure 7.18 show the allocation of the tradable allowance revenue in nominal terms for the S.139 case and the two fixed allocation cases, plus the distribution of these funds. By presenting them side-by-side using the same scale, the differences between the cases can be seen at a glance. Under the S.139 case, the funds allocated to the Corporation rise from $23 billion in 2010 to $378 billion in 2025. Under the corp20 case, the funds again start at $23 billion, but rise only to $93 billion, $285 billion less than in the S.139 case. For the corp80 case, the amount allocated to the Corporation is much higher in the first year, $94 billion as compared to $23 billion in the S.139 case and the corp20 case. But by the last year, the total has risen to $391 billion, slightly higher than that of the S.139 case. This alteration in the allocation of permits has impacts on both the magnitude and time profile of the economic impacts.

Aggregate Impacts on Actual and Potential GDP. The general expectation might well be that, because the S.139 case starts at the beginning of one case (corp20) and ends at the final point of another case (corp80), these two alternative cases would simply bound the S.139 case. As shown below, this is not the case. First, consider how the alternative schemes send funds back to the consumer, both in magnitude and

Figure 7.18. Allocation of Tradable Allowance Revenue in Three Cases, 2010-2025 (billion nominal dollars)



Computed Tradable Allowance Revenue
Variable Allocation in S.139 Case

Distribution of Funds by Corporation
Variable Allocation in S.139 Case

Computed Tradable Allowance Revenue
Fixed 20% Allocation to Corporation

Distribution of Funds by Corporation
Fixed 20% Allocation to Corporation

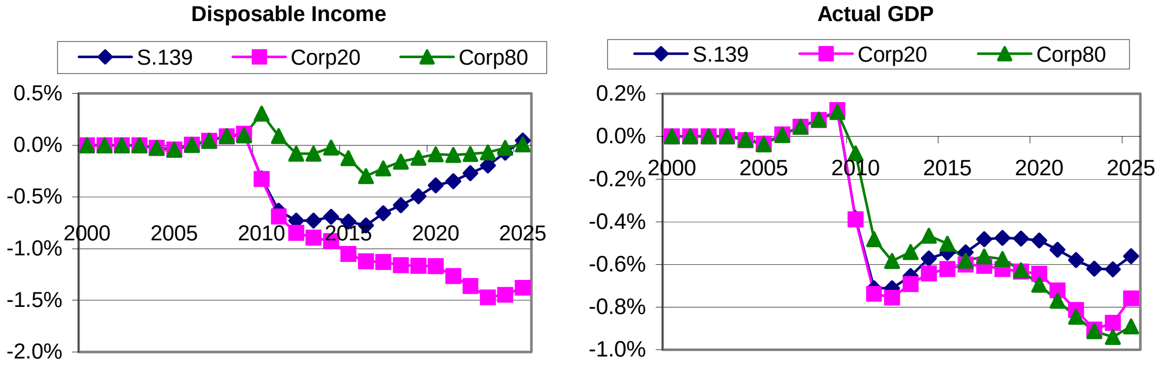
Computed Tradable Allowance Revenue
Fixed 80% Allocation to Corporation

Distribution of Funds by Corporation
Fixed 80% Allocation to Corporation

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC80.D050503A, and ML_CCCC20.D050503A.

trajectory, by looking at the change in disposable income in the three cases. Disposable income includes the transfers to households from the Corporation. The S.139 and corp20 cases are identical until 2010, in that funds retained and thus transferred from the Corporation to households are 20 percent of the total emission revenues in that year. The S.139 case assumes increasing the Corporation intake, on a sliding scale basis, to 80 percent of emission revenues by 2025. The corp80 case starts off in 2010 by retaining and thus transferring 80 percent of total emission revenues to households. The fact that a larger sum is transferred to households in 2010 in the corp80 case relative to the S.139 and corp20 cases accounts for the fact that disposable income is higher, relative to the baseline and the two other cases, even after accounting for price increases. Figure 7.19 shows that the S.139 case follows the corp20 case in the first few years, but then begins to diverge as the S.139 case channels more funds back to the consumer with the ever growing amount of permits allocated to the Corporation. By 2025, disposable income approximately matches the corp80 case. However, actual GDP in the S.139 case recovers faster and by 2025 has the smallest negative effect on actual GDP.

Figure 7.19. Change in Disposable Income and Actual GDP Relative to the Reference Case for Three Cases, 2000-2025 (percent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC80.D050503A, and ML_CCCC20.D050503A.

While the impact on actual GDP focuses on the transition impacts, from a long-run perspective the relationship between the impacts on actual and potential GDP is of primary interest. Figure 7.20 focuses on these two concepts over the forecast period. The S.139 case shows the fastest recovery in actual GDP and approaches potential GDP in the last year of the forecast period. The other two cases remain below potential throughout. Note, however, the relative trajectory of potential GDP in the three cases. The corp20 case actually shows the best outcome for potential GDP, declining to approximately 0.3 percent relative to the reference case level in 2025, as compared to 0.5 percent below for the S.139 case and 0.6 for the corp80 case. Stated another way, although the corp20 case has the largest transition cost, the long-run prospects for this case are actually the most favorable. The corp80 case minimizes the near-term loss in actual GDP but has the weakest long-run outcome. The S.139 case recovers faster toward potential GDP by encouraging investment (aggregate demand and supply) in the earlier years and encouraging consumption (aggregate demand) in the later years. The discussion that follows gives more detail about the composition of these changes. Fundamentally, the differences lie in how the various cases affect consumption and investment, both in the short term and in the long term.[193]

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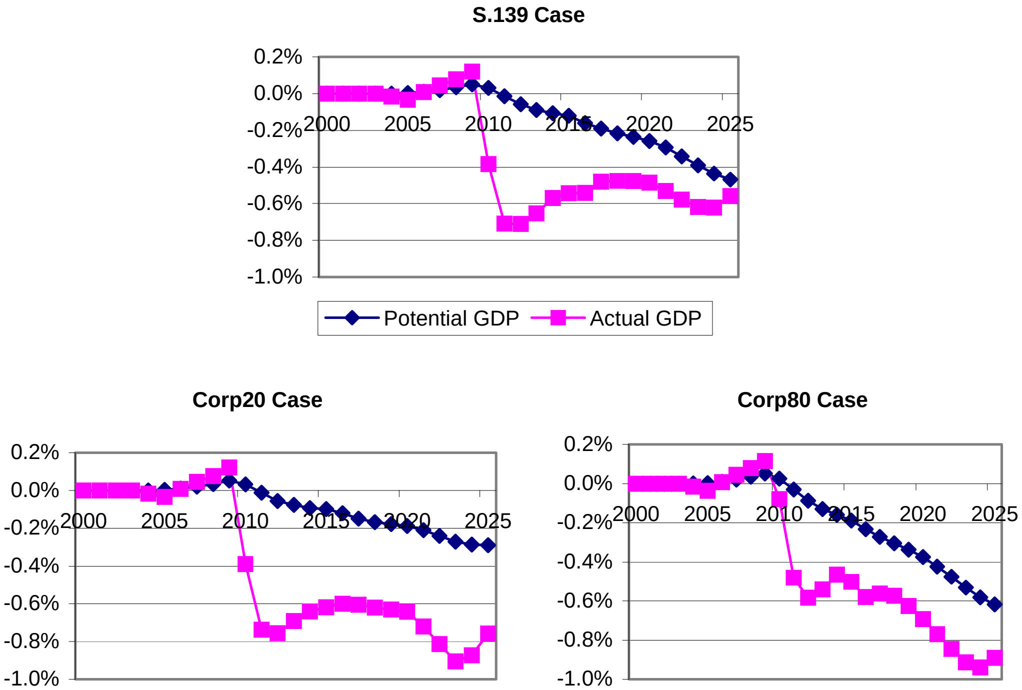
[193] Note: A quick assessment of a 50/50 split allocation would split the difference between the 20/80 and the 80/20 cases.

Figure 7.20. Change in Actual and Potential GDP Relative to the Reference Case for Three Cases, 2000-2025 (percent)



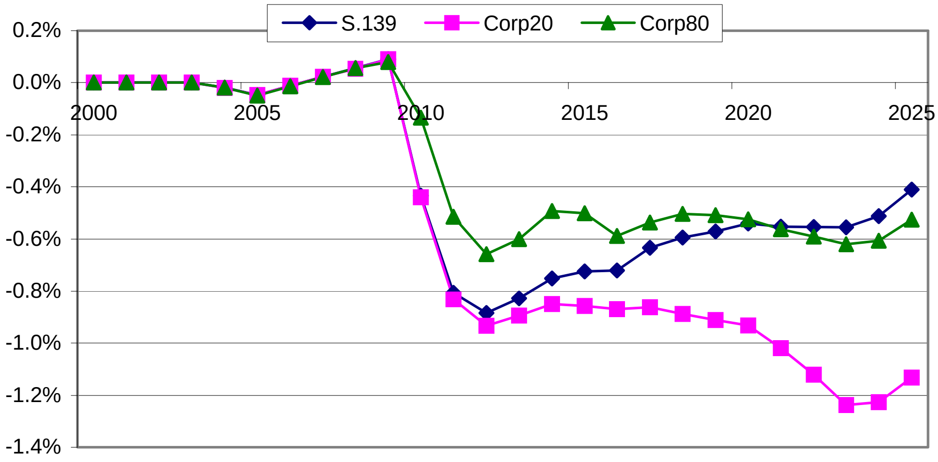
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC80.D050503A, and ML_CCCC20.D050503A.

Consumer Spending. The initial impact on real consumer spending in the S.139 case is similar to that in the corp20 case whereas the impact in the later years resembles the corp80 case. As a higher percentage of the permit revenues is collected and passed by the Corporation to consumers in the S.139 case, consumer spending starts to improve. By 2021, it exceeds that of the corp80 case and continues to trend upward (Figure 7.21). The question here is, why does real consumption in the S.139 case overshoot real consumption in the corp80 case, from 2020 onward, whereas the respective disposable incomes do not and only approximate each other by 2025? The answer is that while disposable income affects consumer behavior, other factors (wealth, consumer confidence, interest rates, etc.) are also important.

This fact cannot be overemphasized since it is the key to explaining the actual GDP profiles for the three cases. One of the most important factors, besides real disposable income, that can alter consumption behavior significantly is expectations about the future. Households base their expectations to a large extent on their past experiences, that is, their best guide to the future is an extrapolation of recent economic conditions and the changes in those conditions. Consumer sentiment about whether this is a “good time to buy” can therefore be influenced by recent levels and changes in employment, income, interest rates, and inflation.

Consider the following sequence of events. As provisions of the bill take effect and energy prices rise, households experience rising inflation and rising unemployment. Clearly these circumstances would not inspire the confidence necessary to lead to greater consumption spending, especially for bigger ticket items. Now consider the impact on consumer confidence as provisions of the three cases play out. In the S.139 case the household finds that it is receiving an ever-increasing transfer from the Corporation and

Figure 7.21. Change in Real Consumer Spending Relative to the Reference Case for Three Cases, 2000-2025 (percent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC80.D050503A, and ML_CCCC20.D050503A.

also notices that the economy is improving. After some time there is therefore a built-in expectation that real disposable income will continue to increase and the economy will continue to improve. In the corp80 case, while the household receives a greater transfer initially, the fact that it stays constant implies that expected disposable income will not rise by as much, and also the economy is not improving as fast as in the S.139 case. In the corp20 case, the consumer receives a similar transfer as in the S.139 case initially, but over time the transfer does not increase by as much as in the other two cases. The economy is not improving as rapidly either. Thus, the S.139 case differs from the other two cases fundamentally because the consumer is seeing a steady improvement in disposable income and other factors over time, which stimulates consumption spending and in turn leads to a faster recovery in the economy than is projected in the other two cases (Figure 7.21).[194]

Investment Spending. Fixed investment consists of residential investment and nonresidential investment. In 2002, residential investment accounted for 29 percent of total investment in nominal terms, and nonresidential investment accounted for 71 percent. Seventy-five percent of the nonresidential investment was in equipment and software.

As shown in Figure 7.22, the change in total investment in the corp80 case is more negative than in the S.139 case, as more emission allowance funds are returned to the consumer. However, the change in the corp20 case tracks closely with that of the S.139 case. To analyze the deviation pattern, two major categories are examined—residential investment and investment in nonresidential equipment.

Impacts on Residential Investment. Although the bill does not cover the residential sector, it is nonetheless affected by income and interest rate changes relative to the reference case. The impact on residential investment in the S.139 case is smaller than those in the corp80 and corp20 cases. In the corp80 case, the nominal mortgage rate is higher (Figure 7.23) than in the S.139 case, dampening the demand for home sales. The rise in the mortgage rate and other interest rates (Figure 7.24) is largely driven by the higher level of prices as reflected by the consumer price index in the corp80 case. In the corp20 case, household disposable income is lower than in the S.139 case, also leading to lower household investment purchases; but interest rates are also lower, helping to support investment purchases. All these factors result in a crossover pattern in the trajectories of residential investment.

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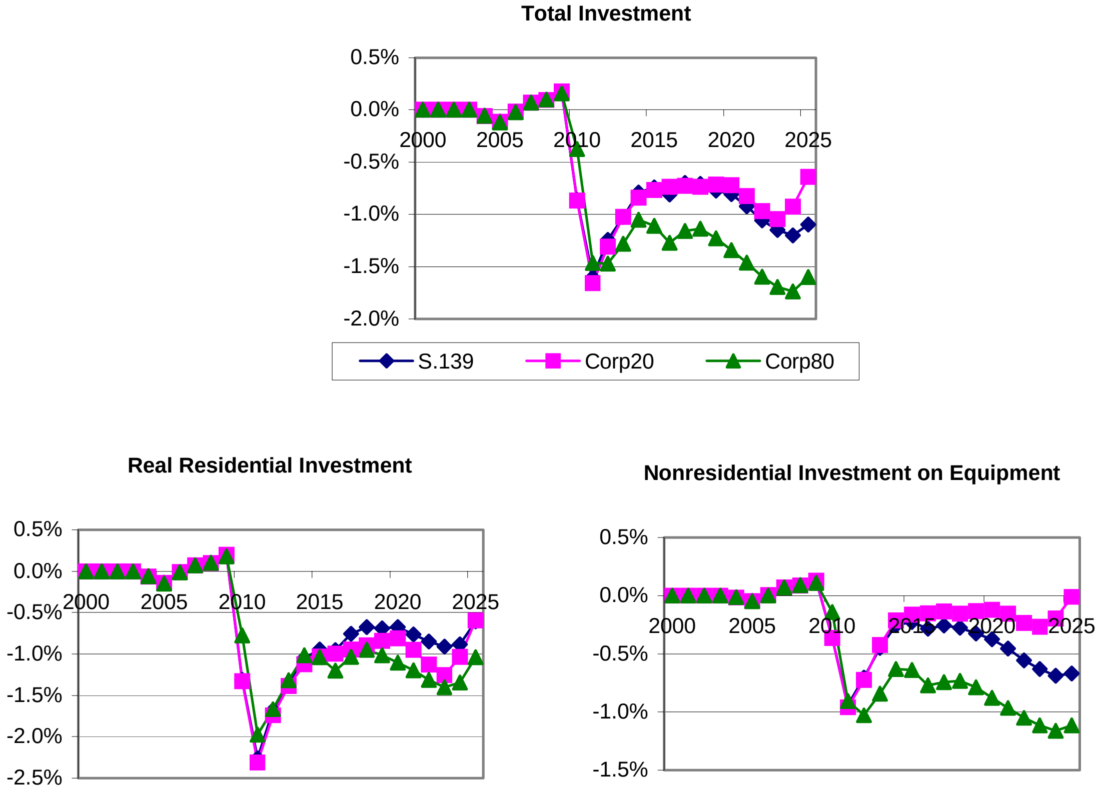
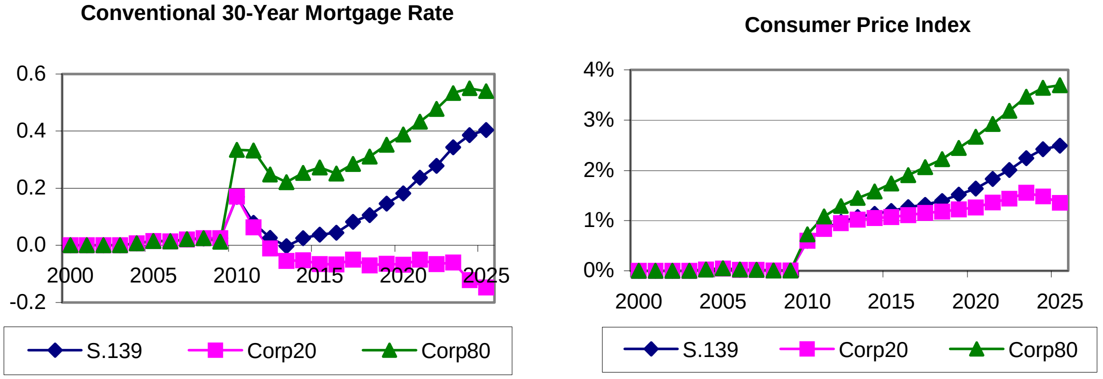
[194] See Energy Information Administration, *Model Documentation Report: Macroeconomic Activity Module (MAM) of the National Energy Modeling System* (February 2003), pp. 5-6.

Figure 7.22. Change in Total Investment, Residential Investment, and Nonresidential Equipment Investment Relative to the Reference Case for Three Cases, 2000-2025 (percent)



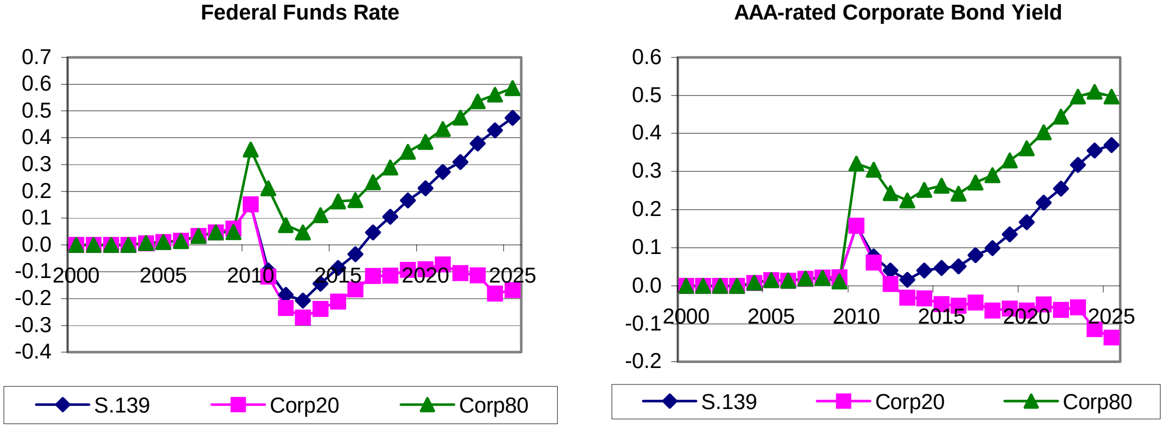
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC80.D050503A, and ML_CCCC20.D050503A.

Figure 7.23. Change in Conventional 30-Year Mortgage Rate (difference, percentage points) and the Consumer Price Index (percent change) Relative to the Reference Case for Three Cases, 2000-2025



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC80.D050503A, and ML_CCCC20.D050503A.

Figure 7.24. Change in the Federal Funds Rate and AAA-Rated Corporate Bond Yield Relative to the Reference Case for Three Cases, 2000-2025 (difference, percentage points)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC80.D050503A, and ML_CCCC20.D050503A.

Impacts on Nonresidential Investment in Equipment. Investment spending on equipment amounts to 53 percent of total investment in nominal terms. The impact of the S.139 case falls between the corp20 and corp80 cases. Investment in equipment depends very much on the cost of capital. In the S.139 case and corp80 case, the Federal Reserve raises the Federal funds rate throughout most of 2010-2025 to balance the unemployment and inflation impacts (Figure 7.24). This affects all interest rates, and hence the cost of financial capital to businesses, and has a dampening effect on investment.

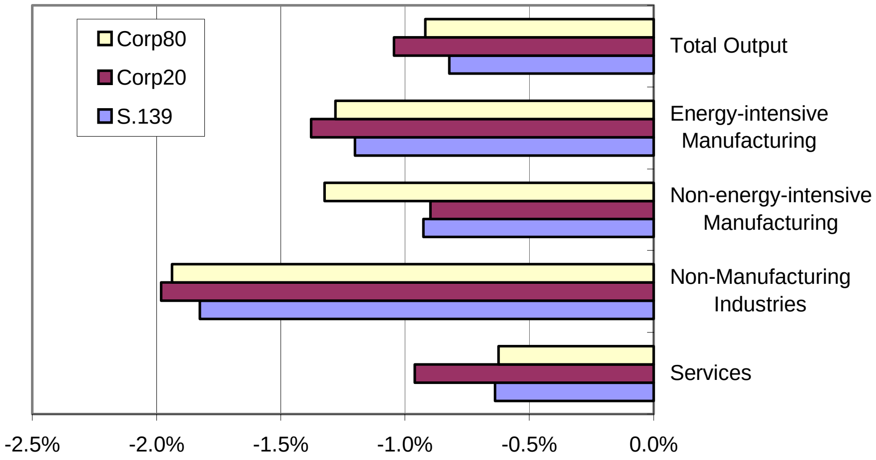
Impacts on Gross Output. Figure 7.25 compares the average loss in gross output for different allocation schemes for the period 2010-2025. The loss in total output reflects the pattern of loss in actual GDP. The S.139 case shows a smaller impact than the corp20 and corp80 cases because of a faster recovery in consumer spending relative to the corp20 case and a lesser impact on investment relative to the corp80 case.

Manufacturing output can be classified into three broad end-use categories: consumer goods, capital goods, and intermediate goods. Production of consumer goods is affected the least in the corp80 case, in which most permit revenue is distributed to consumers. In the S.139 case, it is expected to improve much faster over time because of improving consumer confidence. On the other hand, production of capital goods in the corp80 case has the worst impact because of the weaker investment response, compared with the S.139 case and corp20 case, which have similar impacts. Production of intermediate goods has mixed impacts, depending on the nature of the final goods produced. In the short run, the impact is least in the corp80 case because of the smaller consumption impact. In the longer run, the S.139 case has a faster recovery. The corp20 case is expected to have the worst average impact.

When analyzed by the four categories of output (Figure 7.25), energy-intensive manufacturing output is mostly intermediate goods and therefore has the worst impact in the corp20 case. Non-energy-intensive manufacturing is a mix of capital goods, intermediate goods, and consumer goods. In value terms, this category is dominated by machinery and equipment, which is worse off in the corp80 case. Non-manufacturing industries have the worst impacts over all other categories. The impacts in the S.139 case are slightly better than in the other two cases because of a faster recovery in the construction sector. The service sector serves both consumers and businesses. Consumer services are worse off in the corp20 case, while business services suffer more in the corp80 case. Since the former is more dominant, the corp20 case shows the worst impact on services.

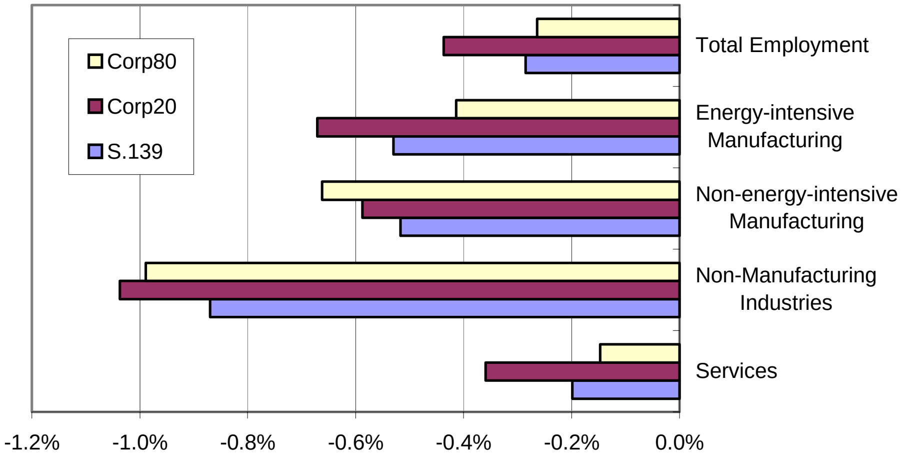
Impact on Employment. The relative impacts on employment do not necessarily follow the relative impacts on output because of changes in other factors like productivity, capacity utilization and relative costs. As shown in Figure 7.26, the impact on employment is less in the corp80 case and more in the corp20 case. Compared with the other allocation schemes, corp80 has less negative impact on consumption but more negative impact on investment. In the long run, this tradeoff is reflected in the potential GDP. The corp80 case has a slower substitution of capital and technology for labor, resulting in a smaller impact on employment. The opposite is true for the corp20 case.

Figure 7.25. Average Change in Gross Output Relative to the Reference Case for Three Cases, 2010-2025 (percent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC80.D050503A, and ML_CCCC20.D050503A.

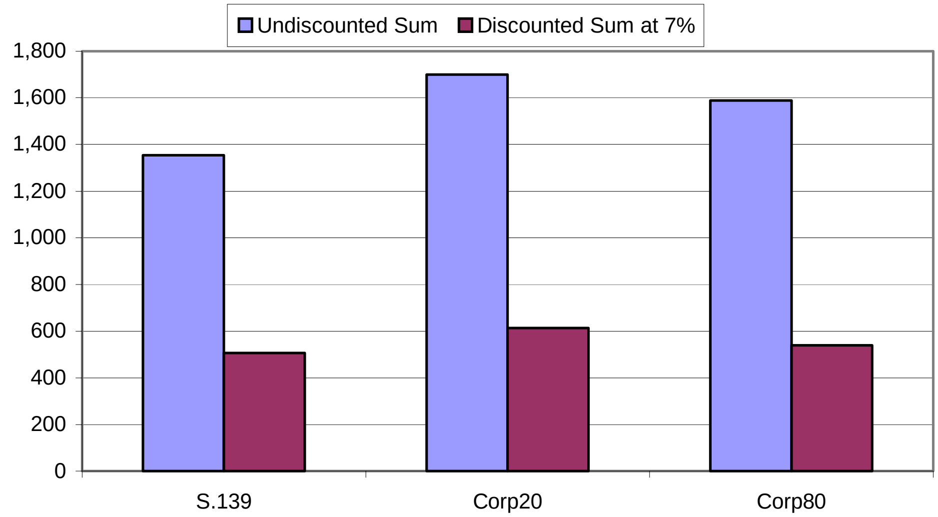
Figure 7.26. Average Change in Employment Relative to the Reference Case for Three Cases, 2010-2025 (percent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC80.D050503A, and ML_CCCC20.D050503A.

Given the different profiles of impacts in the three cases investigated so far—S.139, corp20, and corp80—which one is judged to have the least impact? Figure 7.27 shows two measures of impact covering the entire period from 2004 through 2025. The first shows the undiscounted sum of the impacts on actual GDP and the second calculates a discounted sum of the same stream of actual GDP impacts using a discount rate of 7 percent. Under S.139 the undiscounted sum of the actual GDP loss is $1,354 billion, and the discounted loss is $507 billion (or $1,626 per capita in 1996 prices). Both corp20 and corp80 have undiscounted and discounted actual GDP losses that are higher than in the S.139 case. Also, the corp80 case has slightly smaller aggregate impact than the corp20 case. Given the discussion of these respective cases earlier in this chapter, this result is expected.

Figure 7.27. Loss in Actual GDP, Undiscounted Sum and Discounted Sum at 7 Percent, 2004-2025 (billion 1996 dollars)



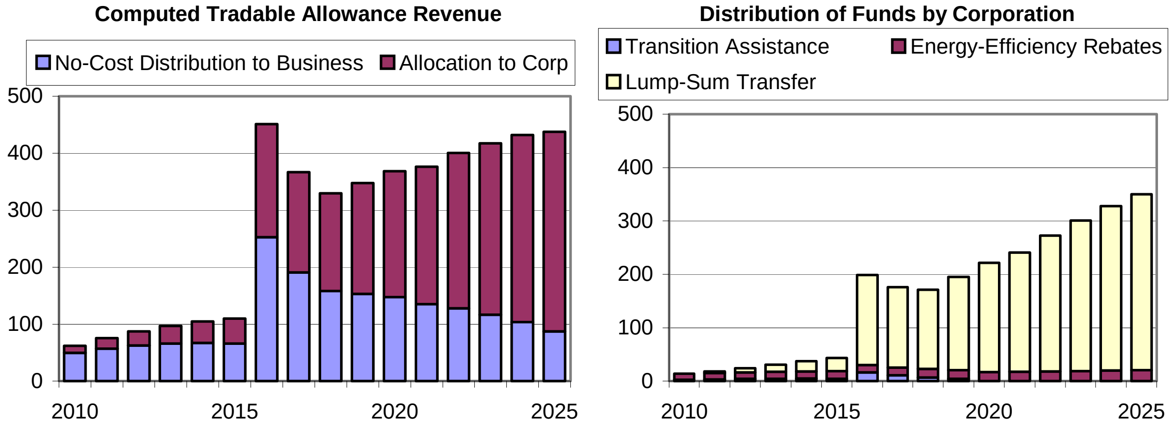
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

B. Economic Impacts of a No Banking Case

In the scenarios discussed up to this point, banking of allowances was permitted in the post-2010 period. The no banking case removes the banking provisions while still maintaining the greenhouse gas targets of S.139. The difference between the no banking case and the S.139 case (with banking) indicates the effectiveness of banking in smoothing the transition effects on the energy system and the aggregate economy. Figure 7.28 shows the computed tradable allowance revenue in nominal terms under the no banking case. The period from 2010 to 2015 shows the small amount of allowance revenues under this case, but they expand dramatically in 2016. (Figure 7.1 shows the smooth profile in the S.139 case.) In the S.139 case, nominal tradable allowance revenue rises steadily from just over $100 billion in 2010 to approximately $200 billion in 2015, and then to just under $500 billion by 2025. However, in the no banking case, nominal allowance revenue remains well under $110 billion from 2010 through 2015, and then jumps dramatically to $451 billion in 2016. After the initial surge, the price of the tradable allowance eases a little but begins to rise again in 2019 when energy demand continues to increase. The allowance revenue varies between $330 billion and $440 billion for the remainder of the forecast period.

Under these conditions, the profile of the distribution of funds to transition assistance, energy-efficient rebates, plus the lump-sum transfer to consumers takes on a very different look. Instead of starting small and rising smoothly over the period, the distribution of funds remains small through 2015, then increases dramatically in 2016 to $200 billion. This sharp difference in the profile of energy prices and the

Figure 7.28. Computed Tradable Allowance Revenue and Distribution of Funds by the Corporation in the No Banking Case, 2010-2025 (billion nominal dollars)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and ML_NOBANK_4.D051203A.

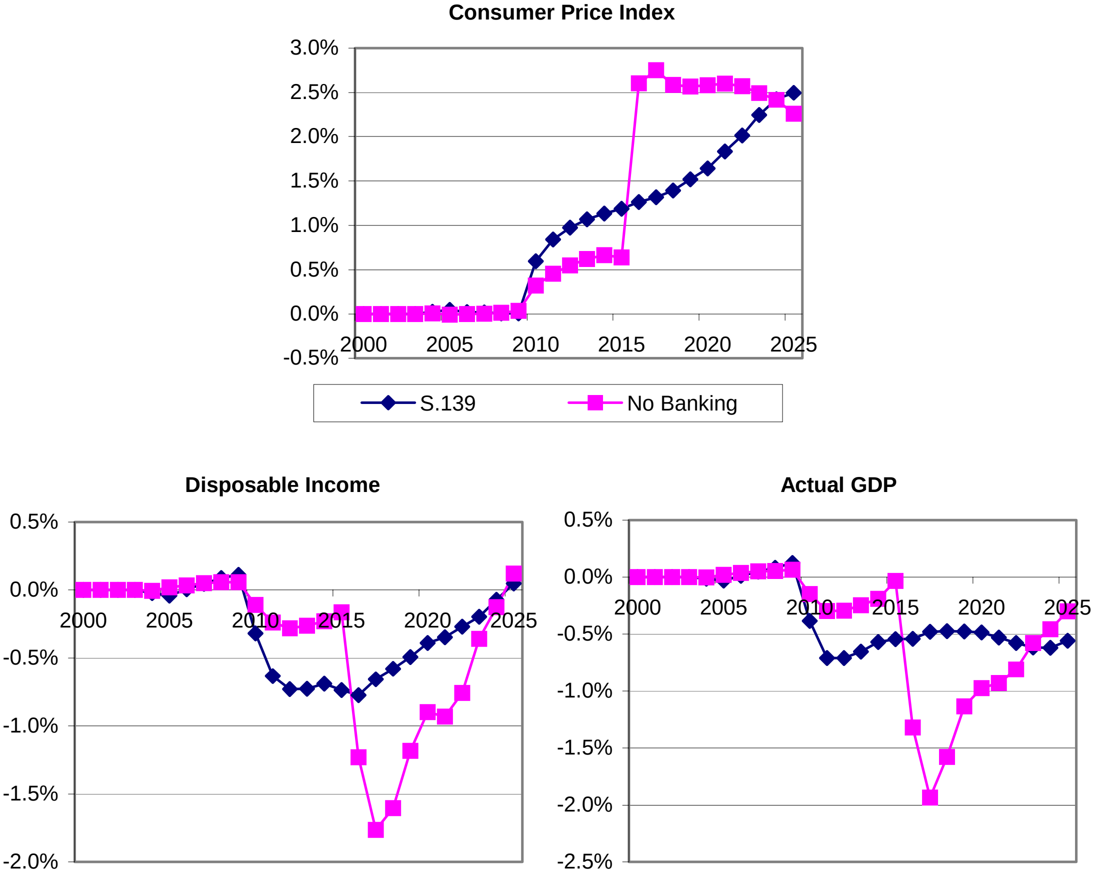
subsequent collection and redistribution of funds is reflected most directly in comparing the impacts on the consumer price index, disposable income, and actual GDP relative to the impacts in the S.139 case (Figure 7.29). Through 2015, disposable income and actual GDP both decline by much less than in the S.139 case. In 2015, the loss in disposable income in the no banking case is 0.2 percent, while in the S.139 case the impact is larger, at 0.7 percent. The impact on actual GDP in the no banking case shows a similar profile, and by 2015 it is almost at reference case levels. However, in 2016 energy prices rise sharply in response to the rise in the allowance price. Actual GDP and disposable income both decline sharply. Both measures reach a peak loss in 2017, with actual GDP 1.9 percent below the reference case level and disposable income 1.8 percent below. Thereafter, both recover sharply. The recovery in both is due to a sharp falloff in energy prices as the allowance price declines, plus the large increases in funds distributed back to consumers and in transition assistance in the post-2015 period.

Again, given the very different impact profiles in the two cases—S.139 and no banking—which one is judged to have the least impact? Clearly, the peak impact is smaller in the S.139 case with banking, but the S.139 case shows a larger impact in the 2010-2015 period. The no banking case has smaller impacts early, but has much larger impacts in subsequent years. Figure 7.30 shows two summary measures of impact covering the entire period from 2004 through 2025. The first shows the undiscounted sum of the impacts on actual GDP and the second calculates a discounted sum of the same stream of actual GDP impacts using a discount rate of 7 percent. Under S.139 the undiscounted sum of the actual GDP loss is $1,354 billion and the discounted loss is $507 billion ($1,626 per capita in 1996 prices). In the no banking case, the undiscounted sum of the actual GDP loss is $1,752 billion, or $398 billion greater than in the S.139 case. The discounted loss in the no banking case is $609 billion ($1,955 per capita in 1996 prices), or $102 billion higher than in the S.139 case. Using these summary measures, plus the time profile of the impacts, the banking provisions of S.139 lessen the aggregate impact on the economy and result in a significantly smoother trajectory of impacts through 2025.

C. Economic Impacts of 50% Offset Case

S.139 specifically allows a covered entity to satisfy 15 percent of its total allowance requirement in 2010-2015 by purchasing allowances from non-covered entities, through sequestration, or from the international allowance market. After 2015, the “offset allowance” is reduced to 10 percent. This section discusses the macroeconomic impacts of the sensitivity case that allows a maximum of 50 percent of the

Figure 7.29. Change in Consumer Prices, Disposable Income and Actual Gross Domestic Product in the No Banking Case Relative to the Reference Case, 2000-2025 (percent)


Consumer Price Index

Disposable Income

Actual GDP

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A MLBILL.D050503A, and ML_NOBANK_4.D051203A.

allowance to be offset for the years 2010 through 2025. In this case, the offset clearing price equates to the emissions price, resulting in a lower allowance price and lower revenue from allowance trading.

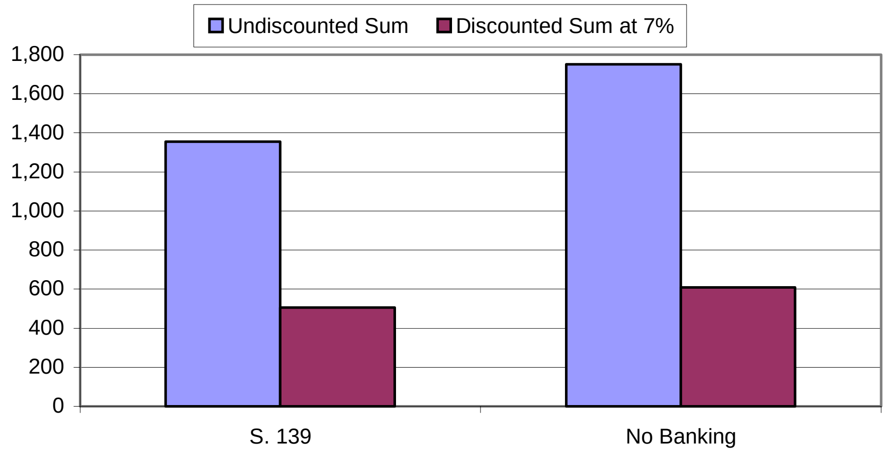
Figure 7.31 shows the computed tradable allowance revenue under the offset50 case. In the period 2010 to 2015, total tradable allowance revenue in nominal terms in the offset50 case is about 23 percent lower than in the S.139 case. However, in the second phase of implementation, when the more stringent emissions requirement results in more offset purchases, nominal tradable allowance revenue grows more slowly than in the S.139 case, reaching $382 billion in 2025. As a result, the distribution of funds to transition assistance, energy-efficient rebates, and the lump-sum transfer to consumers is lower than in the S.139 case.

With a lower emissions price trajectory, the price effect of the offset50 case to the economy is smaller. The first chart in Figure 7.32 compares the changes in consumer price index under the two scenarios. The price impact of the offset50 case is about the same as that of the S.139 case in 2010, and is gradually reduced to half by 2025. This implies that the negative impacts on output and employment are less than in the S.139 case. Figure 7.32 also compares the impacts on actual GDP under the two scenarios. Because the effects on energy prices and demand are smaller in the offset50 case, the impact on economy is expected to be smaller.

As the demand for offset allowance increases significantly in the offset50 case, the purchase of international permits is projected to increase. Figure 7.33 compares the demand for international offsets in the S.139 and offset50 cases. Unlike the S.139 case, demand for international offsets in the offset50 case continues to grow after 2015, reaching $26 billion (in 1996 dollars) by 2025.

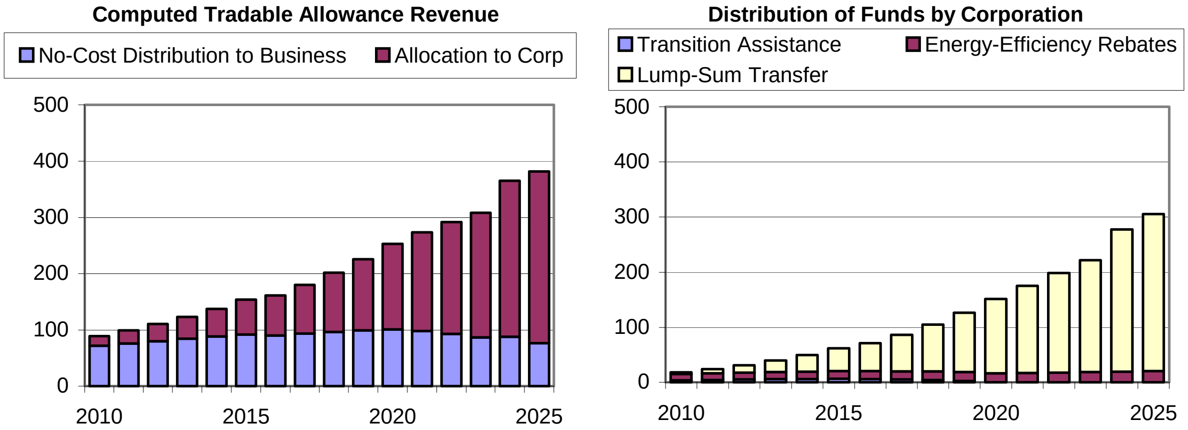
Figure 7.34 provides the undiscounted and discounted (using a 7 percent discount rate) sum of the impacts on actual GDP over the period 2004 through 2025. Under the offset50 case, the undiscounted sum of the actual GDP loss is $1,049 billion, or $305 billion lower than in the S.139 case. The discounted loss for the offset50 case is $399 billion ($1,279 per capita in 1996 dollars), or $108 billion lower than in the S.139 case.

Figure 7.30. Loss in Actual GDP, Undiscounted Sum and Discounted Sum at 7 Percent in the No Banking Case Relative to Reference Case, 2004-2025 (billion 1996 dollars)



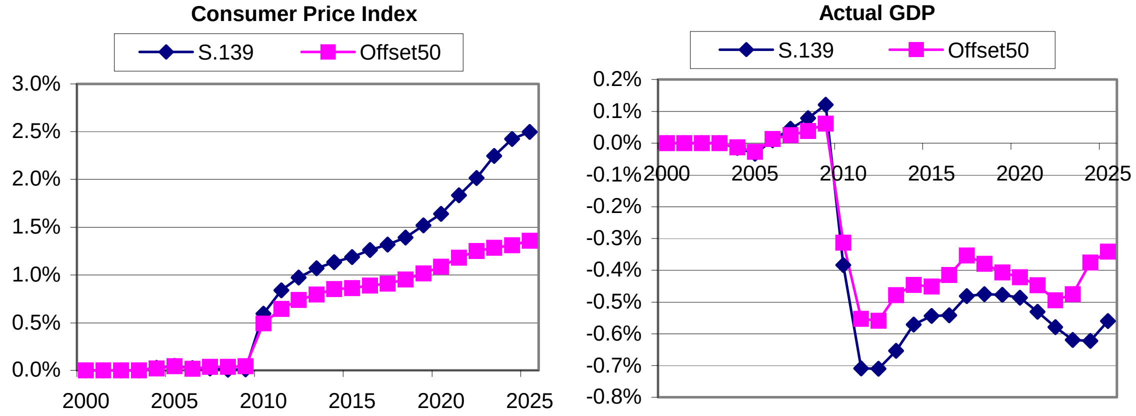
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and ML_NOBANK_4.D051203A.

Figure 7.31. Computed Tradable Allowance Revenue and Distribution of Funds by the Corporation in the Offset50 Case, 2010-2025 (billion nominal dollars)



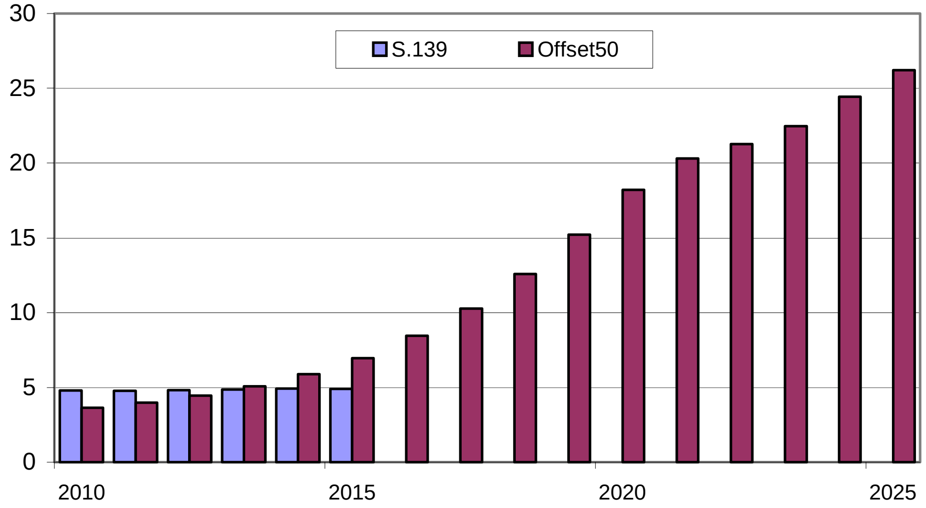
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A and RT2OFFSET.D061103F.

Figure 7.32. Change in Consumer Prices and Actual Gross Domestic Product in the Offset50 Case Relative to the Reference Case, 2000-2025 (percent)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and RT2OFFSET.D061103F.

Figure 7.33. Demand for International Offsets in the S.139 and Offset50 Cases, 2010-2025 (billion 1996 dollars)

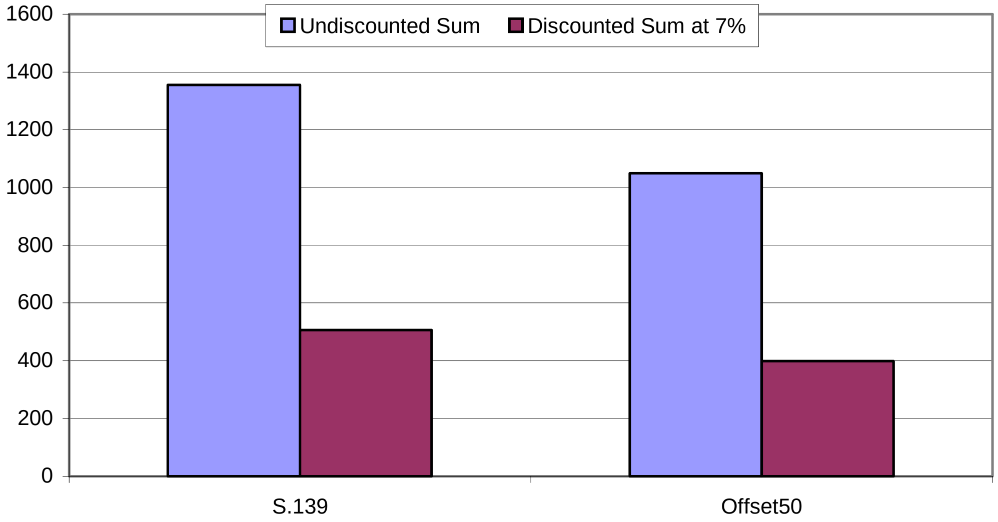


Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and RT2OFFSET.D061103F.

D. Economic Impacts of High Technology Case

The cost and performance of emerging technologies useful in reducing energy use or its greenhouse gas intensity are among the most important factors affecting the evaluation of S.139 impacts. Using the assumptions of the *AEO2003* high technology case for the four end-use sectors and the electric power sector, a high technology reference case and a high technology variation of the S.139 case were prepared. Assumptions in the high technology cases vary by sector but generally include earlier availability, lower costs, and higher efficiencies for advanced technologies than in the reference case.

Figure 7.34. Loss in Actual GDP Undiscounted Sum and Discounted Sum at 7 Percent in the S.139 and Offset50 Cases Relative to the Reference Case, 2004-2025 (billion 1996 dollars)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System, runs MLBASE.D050303A, MLBILL.D050503A, and RT2OFFSET.D061103F.

Table 7.1 provides key results that can be used to show how assumptions about the state of energy-related technology affect the impacts of S.139. Energy-related carbon dioxide emissions in the high technology reference case are 8 percent lower in 2025 than in the standard reference case. The smaller reduction in carbon dioxide emissions needed to comply with S.139 reduces the estimated allowance price in the S.139 high technology case in 2025 by 28 percent relative to its level in the S.139 case. Three sets of comparisons can be used to gauge the economic effects of S.139 under high technology assumptions: (1) the S.139 case relative to the reference case, (2) the S.139 high technology case relative to the high technology reference case, and (3) the S.139 high technology case relative to the reference case.

Table 7.1. Undiscounted and Discounted Sum of Actual GDP Change, 2004-2025 (billion 1996 dollars)

	Undiscounted Sum	Percent Change	Discounted Sum at 7%	Percent Change
1. S.139 minus Reference	-1,354	-0.43%	-507	-0.35%
2. S.139 High Technology minus High Technology Reference...	-1,035	-0.33%	-388	-0.27%
3. S.139 High Technology minus Reference	-971	-0.31%	-369	-0.26%

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, MLBASE_HT.D061703A, and ML_HT.D061703A.

The change in economic performance between the high technology reference case and the S.139 high technology case (row 2 in Table 7.1), implicitly assumes that the enactment of S.139 does not affect the set of available technologies, only what and how much is chosen from that set. Using this comparison, S.139 reduces accumulated actual GDP over the modeled 2004-2025 time frame by $1.035 trillion (0.33 percent). By 2025, when the transition to the S.139 regime is largely complete, the overall size of the economy is reduced by $95 billion (0.50 percent). In contrast, between the S.139 case and the reference case (row 1), the change in cumulative economic impact is $1.354 trillion (0.43 percent). Thus, a high technology economy would lower the economic cost of achieving S.139 by $319 billion and would cut the percentage loss to the economy to 0.1 percent over the 2004-2025 horizon.

Alternatively, economic performance in the S.139 high technology case and the standard reference case can be compared (row 3 in Table 7.1). This comparison implicitly assumes that S.139 is directly responsible for creating technologies with the cost and performance characteristics of EIA's high technology case, which would not be available in its absence. Using this approach, S.139 reduces accumulated actual GDP over the modeled 2004-2025 time frame by $971 billion (0.31 percent). By 2025, when the transition to the S.139 regime is largely complete, the overall size of the economy is reduced by $94 billion (0.50 percent).

Analytical judgment and a recognition of inherent modeling limitations are needed to assess which approach is most likely to reflect the actual impact of "high technology" on the economic assessment of S.139. The major effect that S.139 has on delivered energy prices suggests that it should provide some incentive to research and develop new technologies to increase energy efficiency or reduce greenhouse gas intensity. If so, the first approach (comparison of two high technology cases) could overstate adverse economic impacts.

On the other hand, the third approach (comparison of the S.139 high technology case to the standard reference case) does not consider the cost of researching and developing new technologies. Moreover, NEMS does not explicitly represent the role of non-energy-related research and development (R&D) activities in supporting the baseline scenario of economic growth in its macroeconomic component. Therefore, NEMS cannot represent the macroeconomic impact of diverting R&D effort away from other sectors toward energy-related technologies. Such shifts in R&D effort would erode baseline growth to the extent that scarce R&D resources and technological progress in other areas of the economy were reduced.[195]

The analysis of these effects continues to be an active area of academic research. Based on its reading of the available literature, EIA's view is that the first approach is most likely to provide estimates of economic impacts that are closest to the actual economic effects under a high technology scenario.

A separate issue related to technology is the possibility that one or more technologies superior to those identified in the "high technology" case could become available within the time frame of this analysis. While the high technology case assumptions are optimistic by design, there is always a potential for undiscovered or unanticipated technological developments to occur. The contribution of such technologies within the time frame of this analysis is likely to be limited by delays that often arise in the market penetration of new energy technologies, particularly when the new technologies are not readily compatible with the existing infrastructure.

Summary Tables of Economic Impacts

Tables 7.2, 7.3, 7.4, and 7.5 provide a summary view of the economic impacts associated with the cases presented in this chapter. The economic impacts are presented using a number of different metrics: growth rates, percentage change from the reference case, undiscounted and discounted sum of the change in GDP and disposable income, plus per capita GDP and disposable income changes. These are meant to summarize the rather complex nonlinear relationship between the energy market effects of these policies and the interaction with the overall economy. The tables highlight the key findings of this chapter:

- **There is little or no significant impact on the growth rate of the economy for the long-run horizon of 2001-2025.** Between 2001 and 2025, the growth rates for actual GDP and potential GDP

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[195] This result would hold even with some net increase in total R&D activity.

are virtually identical. The consumer price index is slightly elevated, and the growth rate for disposable income declines in only one case (corp80).

- **Although the growth rate effects are small, the percent change from the reference case in any given year can be larger.** Most of the largest impacts occur near 2012 as the economy is adjusting to the more stringent provisions of the bill. Actual GDP declines between 0.3 and 0.8 percent relative to the reference case in 2012. However, by 2025, the picture has changed. In some of the cases, notably the S.139 case, the economy is recovering and returning toward the reference case. Here, it is helpful to keep the time profile in mind (see Figure 7.20).
- **Actual GDP and potential GDP tend to converge over time.** Actual GDP measures the transition costs associated with the bill, while potential GDP shows the long-run path of the economy. The two begin to merge as the transition costs diminish.
- **While the undiscounted sum of the GDP loss ranges between $1.0 and $1.8 trillion (1996 dollars) and the discounted sum of the GDP loss ranges between $0.4 and $0.6 trillion, these losses represent between 0.3 and 0.6 percent of the total stream of GDP over the 2004-2025 period.**
- **The relative impacts between the S.139 cases and the corp20 and corp80 cases are caused by the alternative methods of passing funds first to the Corporation and then to the consumer.** The S.139 case looks much like the corp20 case early on in the forecast period because the S.139 starts with the same share of revenues going to the Corporation (20 percent). However, as this share shifts toward a maximum of 80 percent in 2025, the S.139 case recovers more rapidly as the amount of funds returned to consumers increases, increasing disposable income and consumption expenditures.
- **The loss in disposable income per capita (discounted) ranges from $100 (corp80) to $2,168 (corp20), with the S.139 case showing a loss of $1,037.** Actual GDP measures the transition costs associated with the bill, while potential GDP shows the long-run path of the economy. The two begin to merge as the transition costs diminish.
- **The S.139 case, with its banking provisions, smoothes the impact on the economy and yields a smaller aggregate loss relative to a case with no banking.** Without the banking provisions, there is a sharp difference in the profile of energy prices and the subsequent collection and redistribution of funds, with the impact on the economy much more uneven over time.
- **If the allowable offset allowance limit is raised, the clearing price for allowances falls and the impact on the economy is reduced.** The undiscounted sum of the actual GDP loss is $305 billion lower in the offset50 case than in the S.139 case.
- **The major effect of S.139 on delivered energy prices suggests that it should provide some incentive to research and develop new technologies to increase energy efficiency or reduce greenhouse gas intensity.** If achieved, a high technology energy economy would lower the cost of achieving S.139.

Uncertainties Associated with Projected Economic Impacts

As is inherent in any medium- to long-term forecast, the projected economic impacts of the S.139 and alternative cases are subject to considerable uncertainty. As will become obvious as the discussion proceeds, providing a quantitative estimate of the level of uncertainty is extremely difficult and would be arbitrary. The standard way in which uncertainty is quantified is by providing summary measures of how

Table 7.2. Summary of Economic Impacts: Undiscounted and Discounted Sum of Change in Actual GDP and Disposable Income, 2004-2025 (billion 1996 dollars)

Analysis Case	Undiscounted Sum	Percent Change From Reference Case	Discounted Sum at 7%	Percent Change from Reference Case
Actual GDP				
S.139	-1,354	-0.4	-507	-0.3
Corp20	-1,698	-0.5	-614	-0.4
Corp80	-1,588	-0.5	-539	-0.4
No Banking	-1,752	-0.6	-609	-0.4
Offset50	-1,049	-0.3	-399	-0.3
High Tech	-971	-0.3	-369	-0.3
High Tech Relative to High Tech Reference	-1,035	-0.3	-388	-0.3
Disposable Income				
S.139	-766	-0.3	-323	-0.3
Corp20	-1,947	-0.9	-676	-0.7
Corp80	-112	-0.1	-31	-0.0
No Banking	-1,090	-0.5	-392	-0.4
Offset50	-694	-0.3	-283	-0.3
High Tech	-445	-0.2	-201	-0.2
High Tech Relative to High Tech Reference	-504	-0.2	-217	-0.2

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC20.D050503A, ML_CCCC80.D050503A, ML_NOBANK_4.D051203A, RT2OFFSET.D061103F, MLBASE_HT.D061703A, and ML_HT.D061703A.

Table 7.3. Summary of Economic Impacts: Undiscounted and Discounted Sum of per Capita Change in Actual GDP and Disposable Income 2004-2025 (1996 dollars)

Analysis Case	Undiscounted Sum		Discounted Sum at 7%	
	Per Capita	Per Capita per Year	Per Capita	Per Capita per Year
Actual GDP				
S.139	-4,346	-198	-1,626	-74
Corp20	-5,450	-248	-1,969	-90
Corp80	-5,096	-232	-1,730	-79
No Banking	-5,622	-256	-1,955	-89
Offset50	-3,367	-153	-1,279	-58
High Tech	-3,117	-142	-1,185	-54
High Tech Relative to High Tech Reference	-3,321	-151	-1,245	-57
Disposable Income				
S.139	-2,459	-112	-1,037	-47
Corp20	-6,250	-284	-2,168	-99
Corp80	-361	-16	-100	-5
No Banking	-3,497	-159	-1,257	-57
Offset50	-2,226	-101	-909	-41
High Tech	-1,428	-65	-646	-29
High Tech Relative to High Tech Reference	-1,616	-73	-697	-32

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC20.D050503A, ML_CCCC80.D050503A, ML_NOBANK_4.D051203A, RT2OFFSET.D061103F, MLBASE_HT.D061703A, and ML_HT.D061703A.

well the macroeconomic framework, which is used for the projections, tracks historical data. Based on these summary measures, a prediction error is computed, which gives an indication of the error to expect in predictions. While the Global Insight suite of models tracks historical data closely, there are four additional sources of uncertainty associated with the economic projections discussed in this chapter.

Statistical Uncertainty. This type of uncertainty arises because of the behavioral nature of the models used. For the reference and alternative cases, the economic projections are based on Global Insight's suite of econometric models. These models are a representation of the U.S. economy, as it has evolved historically, with detailed output, employment, price, and financial sectors. These models, taken together, explain the relationships among more than 1,500 macroeconomic concepts. The behavioral relationships in these models have been estimated statistically employing historical time series data. As is well known in statistics theory, while the parameter estimates of these relationships are unbiased they are subject to statistical error because they are drawn from a sample. In other words, while the parameter estimates provide the best linear unbiased point estimates of the causal effects of explanatory variables, the true effects could be larger or smaller than the ones estimated. Since the macroeconomic cost measures (actual GDP, potential GDP, real disposable income, inflation, unemployment, etc.) are composites of other macroeconomic behavioral variables, the statistical errors associated with these aggregates are also a composite of statistical errors of those behavioral variables. Therefore, the composite statistical errors are hard to quantify and can conceivably build up, resulting in large errors in the projections of composite variables (GDP, etc.). While the statistical errors can be minimized, as has been done in Global Insight's models, they cannot be eliminated. Moreover, because these parameter estimates are invariant across the different cases, this type of uncertainty is not expected to change across them.

Table 7.4. Summary of Economic Impacts: Growth Rates in Actual GDP from 2001 to 2012 (Year of Peak Loss), from 2012 to 2025, and for the Entire Forecast Period from 2001 to 2025

Analysis Case	2001-2012	2012-2025	2001–2025
Annual Growth Rate (percent)			
Reference	3.23	2.88	3.04
S.139	3.17	2.89	3.02
Corp20	3.16	2.88	3.01
Corp80	3.18	2.86	3.00
No Banking	3.21	2.88	3.03
Offset50	3.18	2.90	3.03
High Tech	3.18	2.89	3.02
Difference in Growth Rate from Reference Case (percent)			
S.139	-0.07	-0.01	-0.02
Corp20	-0.07	-0.00	-0.03
Corp80	-0.05	-0.02	-0.04
No Banking	-0.03	-0.00	-0.01
Offset50	-0.05	-0.02	-0.01
High Tech	-0.05	0.00	-0.02
High Tech Relative to High Tech Reference	-0.05	0.00	-0.02

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC20.D050503A, ML_CCCC80.D050503A, ML_NOBANK_4.D051203A, RT2OFFSET.D061103F, MLBASE_HT.D061703A, and ML_HT.D061703A.

Uncertainty of Future Economic Relationships. In contrast to the first type of uncertainty, a more significant source of uncertainty is associated with macroeconomic relationships that have been estimated statistically based on past information but may change in the future because of, or in spite of, the different cases. The U.S. economy is dynamic and continues to evolve over time in response to changes in demographics, tastes and preferences, technologies, economic institutions, and world developments. Assuming that the macroeconomic relationships of the past will continue to hold in the future is more problematic, and the level of uncertainty in projections increases for longer the projection periods.

Table 7.5. Summary of Economic Impacts: Change from Reference Case in Actual GDP, Potential GDP, Consumer Price Index, and Disposable Income (percent)

Analysis Case	2010	2012	2015	2020	2025
Actual GDP					
S.139	-0.4	-0.7	-0.5	-0.5	-0.6
Corp20	-0.4	-0.8	-0.6	-0.6	-0.8
Corp80	-0.1	-0.6	-0.5	-0.7	-0.9
No Banking	-0.1	-0.3	0.0	-1.0	-0.3
Offset50	-0.3	-0.6	-0.5	-0.4	-0.3
High Tech	-0.3	-0.6	-0.4	-0.3	-0.5
High Tech Relative to High Tech Reference	-0.3	-0.6	-0.4	-0.4	-0.5
Potential GDP					
S.139	0.0	-0.1	-0.1	-0.3	-0.5
Corp20	0.0	-0.1	-0.1	-0.2	-0.3
Corp80	0.0	-0.1	-0.2	-0.4	-0.6
No Banking	0.0	0.0	0.0	-0.3	-0.4
Offset50	0.0	-0.1	-0.1	-0.2	-0.3
High Tech	0.0	-0.1	-0.1	-0.2	-0.3
High Tech Relative to High Tech Reference	0.0	-0.1	-0.1	-0.2	-0.3
Consumer Price Index					
S.139	0.6	1.0	1.2	1.6	2.5
Corp20	0.6	0.9	1.1	1.3	1.4
Corp80	0.7	1.3	1.7	2.7	3.7
No Banking	0.3	0.5	0.6	2.6	2.3
Offset50	0.5	0.7	0.9	1.1	1.4
High Tech	0.5	0.7	0.9	1.2	1.9
High Tech Relative to High Tech Reference	0.5	0.7	0.9	1.3	1.9
Disposable Income					
S.139	-0.3	-0.7	-0.7	-0.4	0.0
Corp20	-0.3	-0.8	-1.1	-1.2	-1.4
Corp80	0.3	-0.1	-0.1	-0.1	0.0
No Banking	-0.1	-0.3	-0.2	-0.9	0.1
Offset50	-0.3	-0.6	-0.6	-0.4	-0.0
High Tech	-0.2	-0.5	-0.5	-0.1	0.0
High Tech Relative to High Tech Reference	-0.2	-0.5	-0.5	-0.2	-0.0

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, ML_CCCC20.D050503A, ML_CCCC80.D050503A, ML_NOBANK_4.D051203A, RT2OFFSET.D061103F, MLBASE_HT.D061703A, and ML_HT.D061703A.

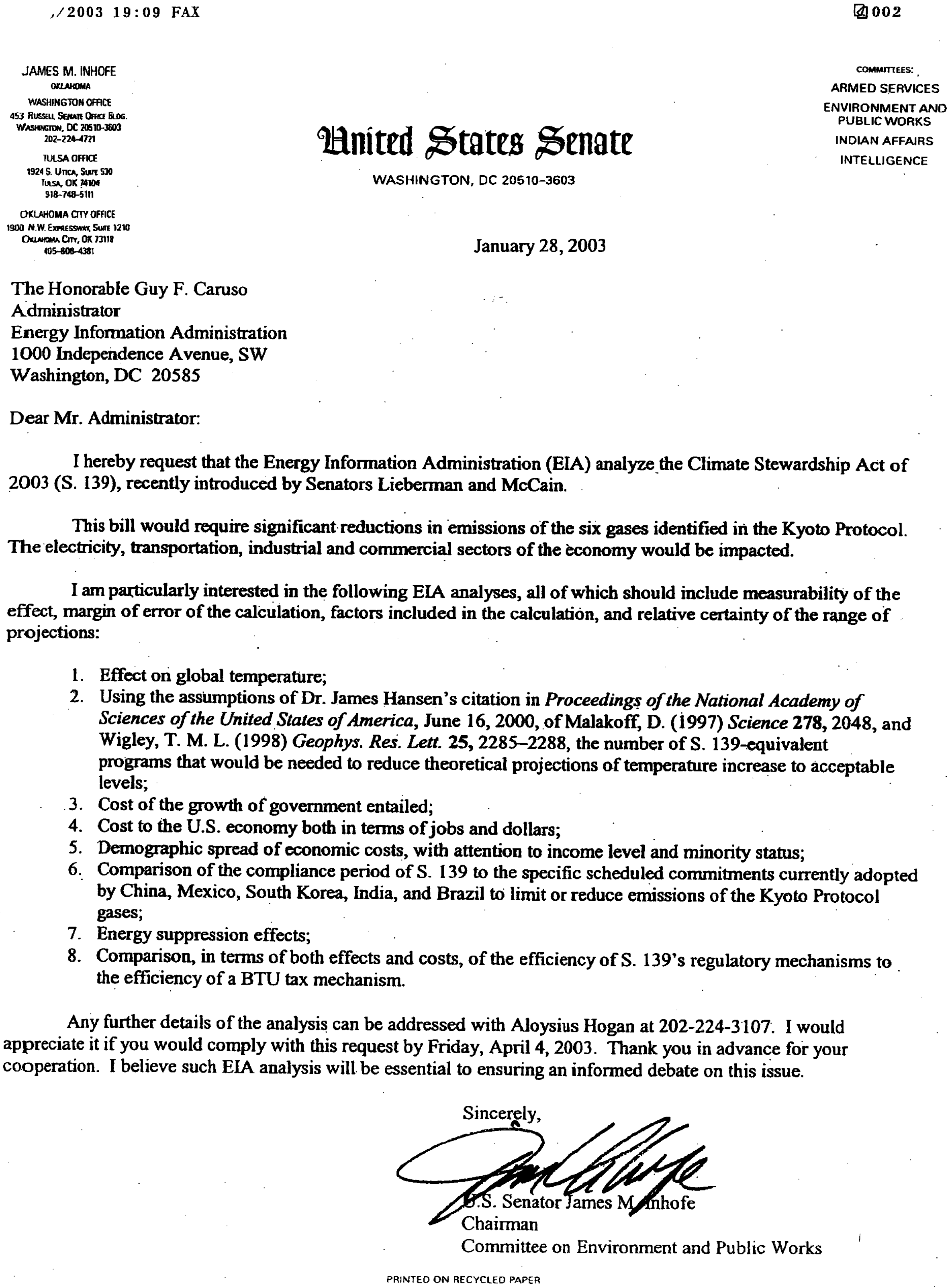
Uncertainty in the Future Evolution of Exogenous Variables. Another source of uncertainty arises because of the assumed evolution of variables not explained within the Global Insight models. Major variables include expected U.S. population growth, foreign economic growth, exchange rates, foreign interest rates, and foreign prices. While it is assumed that the projected values for these variables are the same across all cases, they may not be the same. For example, it is conceivable that exchange rates may change, with implications for U.S. exports and imports, as the Federal Reserve changes the Federal funds rate.

Uncertainty of Policies and Policy Responses. Assumptions have been made about the future evolution of fiscal and monetary policies. It is assumed that monetary policy will be calibrated to balance the risks of unemployment and inflation through changes in the Federal funds rate. This may not occur, because the Federal Reserve may choose to pursue other goals such as exchange rate stability or minimization of unemployment regardless of cost. It is also assumed that there will be no changes in fiscal policy, as the deficit increases or decreases, across the various cases. However, future Congressional actions regarding government taxing and spending are uncertain in the face of changes in the economic environment brought on by the proposed legislation. Alternative assumptions were made about the domestic flow of funds that would result from a system of carbon permits sold by the Corporation and about the international flow of funds that would result from international trading of permits. If the allocations to the Corporation are different and/or a different method is used to redistribute funds to the private sector, the macroeconomic impacts will be altered.

Appendix A

Request Letters and Other Correspondence

Original Request Letter from Senator James M. Inhofe



,/2003 19:09 FAX ☑002

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United States Senate
WASHINGTON, DC 20510-3603

COMMITTEES:
ARMED SERVICES
ENVIRONMENT AND PUBLIC WORKS
INDIAN AFFAIRS
INTELLIGENCE

January 28, 2003

The Honorable Guy F. Caruso
Administrator
Energy Information Administration
1000 Independence Avenue, SW
Washington, DC 20585

Dear Mr. Administrator:

I hereby request that the Energy Information Administration (EIA) analyze the Climate Stewardship Act of 2003 (S. 139), recently introduced by Senators Lieberman and McCain.

This bill would require significant reductions in emissions of the six gases identified in the Kyoto Protocol. The electricity, transportation, industrial and commercial sectors of the economy would be impacted.

I am particularly interested in the following EIA analyses, all of which should include measurability of the effect, margin of error of the calculation, factors included in the calculation, and relative certainty of the range of projections:

1. Effect on global temperature;
2. Using the assumptions of Dr. James Hansen's citation in *Proceedings of the National Academy of Sciences of the United States of America*, June 16, 2000, of Malakoff, D. (1997) *Science* **278**, 2048, and Wigley, T. M. L. (1998) *Geophys. Res. Lett.* **25**, 2285–2288, the number of S. 139-equivalent programs that would be needed to reduce theoretical projections of temperature increase to acceptable levels;
3. Cost of the growth of government entailed;
4. Cost to the U.S. economy both in terms of jobs and dollars;
5. Demographic spread of economic costs, with attention to income level and minority status;
6. Comparison of the compliance period of S. 139 to the specific scheduled commitments currently adopted by China, Mexico, South Korea, India, and Brazil to limit or reduce emissions of the Kyoto Protocol gases;
7. Energy suppression effects;
8. Comparison, in terms of both effects and costs, of the efficiency of S. 139's regulatory mechanisms to the efficiency of a BTU tax mechanism.

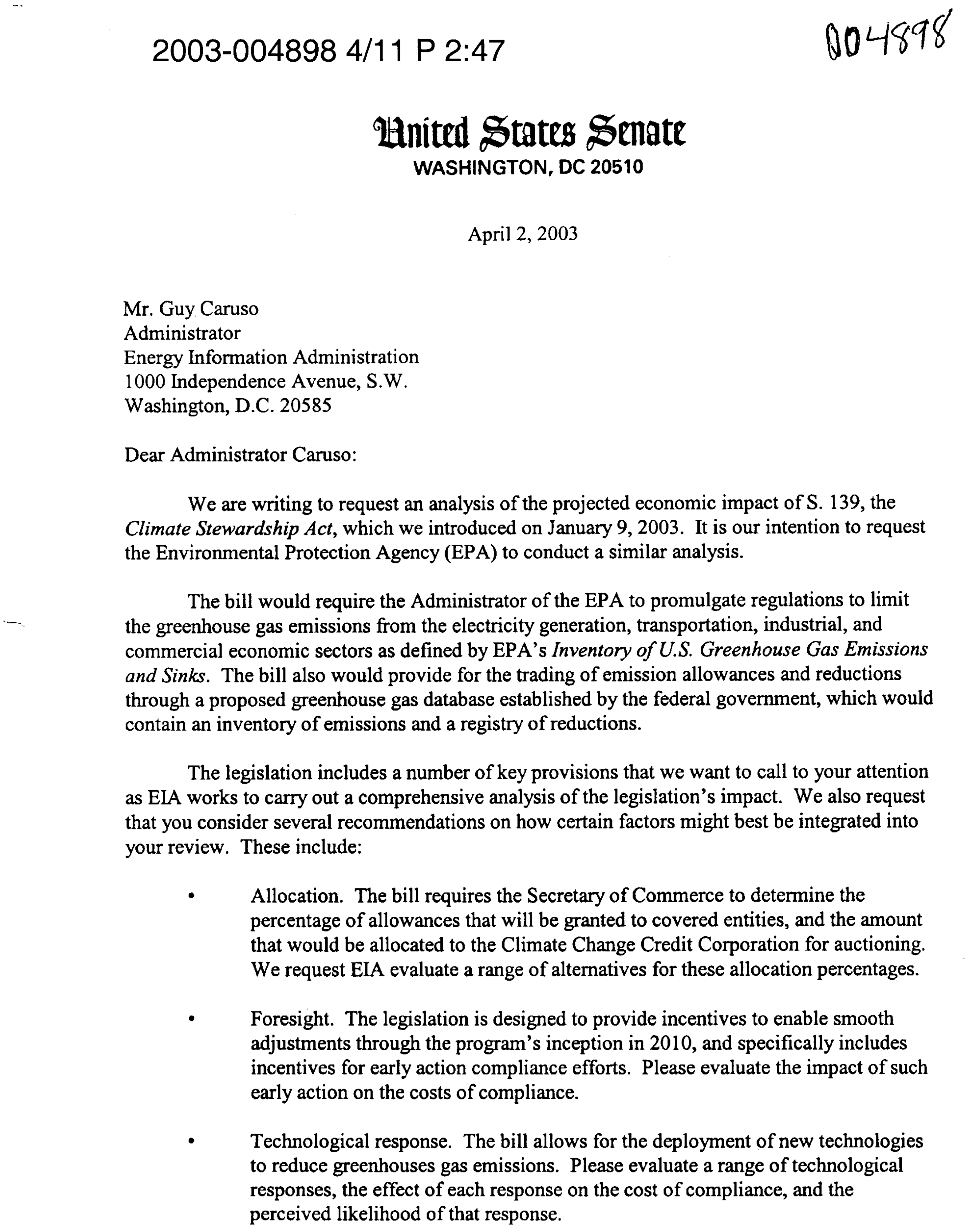
Any further details of the analysis can be addressed with Aloysius Hogan at 202-224-3107. I would appreciate it if you would comply with this request by Friday, April 4, 2003. Thank you in advance for your cooperation. I believe such EIA analysis will be essential to ensuring an informed debate on this issue.

Sincerely,

U.S. Senator James M. Inhofe
Chairman
Committee on Environment and Public Works

PRINTED ON RECYCLED PAPER

Original Request Letter from Senators Joseph I. Lieberman and John McCain



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004898

United States Senate
WASHINGTON, DC 20510

April 2, 2003

Mr. Guy Caruso
Administrator
Energy Information Administration
1000 Independence Avenue, S.W.
Washington, D.C. 20585

Dear Administrator Caruso:

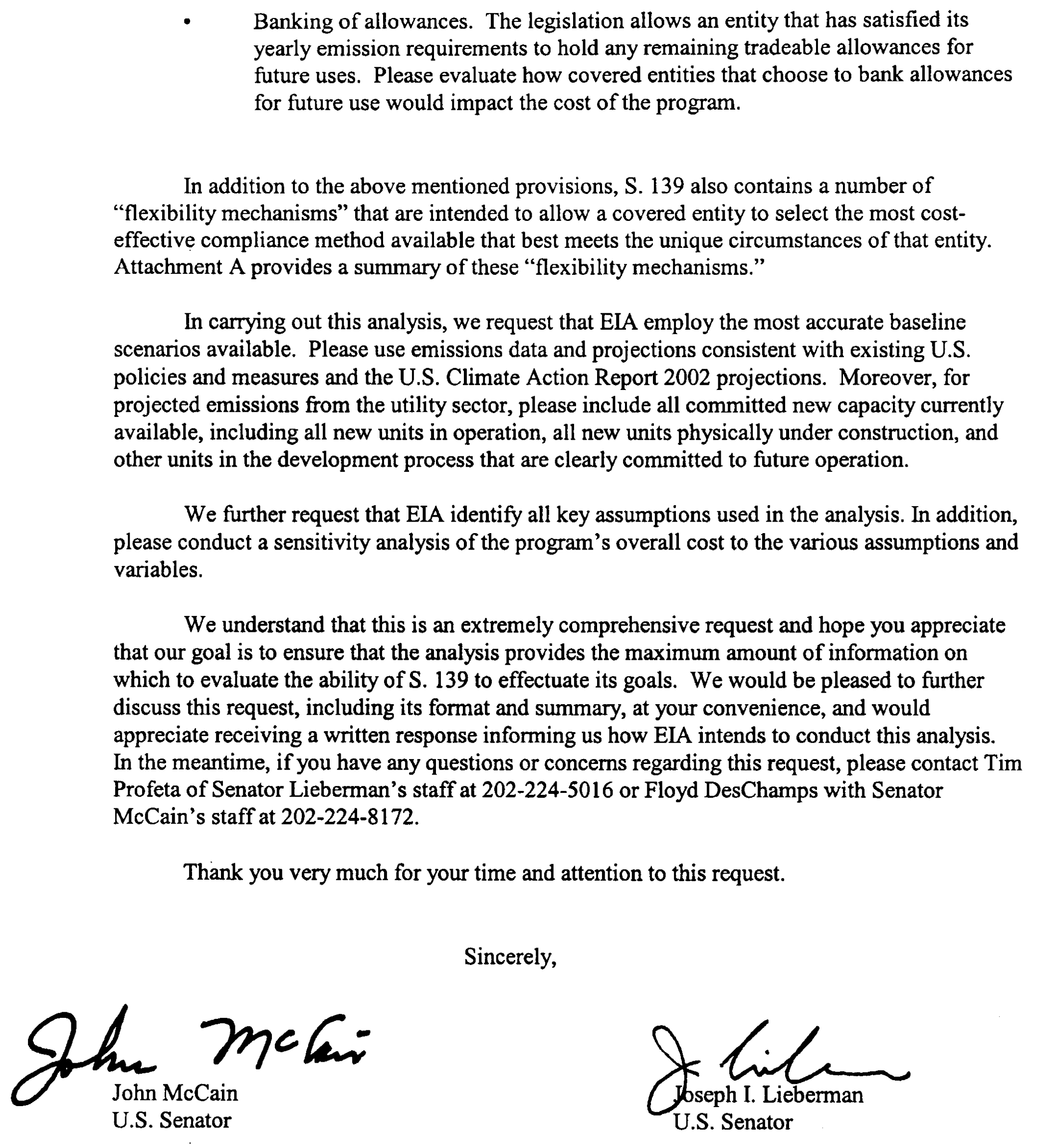
We are writing to request an analysis of the projected economic impact of S. 139, the *Climate Stewardship Act*, which we introduced on January 9, 2003. It is our intention to request the Environmental Protection Agency (EPA) to conduct a similar analysis.

The bill would require the Administrator of the EPA to promulgate regulations to limit the greenhouse gas emissions from the electricity generation, transportation, industrial, and commercial economic sectors as defined by EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. The bill also would provide for the trading of emission allowances and reductions through a proposed greenhouse gas database established by the federal government, which would contain an inventory of emissions and a registry of reductions.

The legislation includes a number of key provisions that we want to call to your attention as EIA works to carry out a comprehensive analysis of the legislation's impact. We also request that you consider several recommendations on how certain factors might best be integrated into your review. These include:

- Allocation. The bill requires the Secretary of Commerce to determine the percentage of allowances that will be granted to covered entities, and the amount that would be allocated to the Climate Change Credit Corporation for auctioning. We request EIA evaluate a range of alternatives for these allocation percentages.
- Foresight. The legislation is designed to provide incentives to enable smooth adjustments through the program's inception in 2010, and specifically includes incentives for early action compliance efforts. Please evaluate the impact of such early action on the costs of compliance.
- Technological response. The bill allows for the deployment of new technologies to reduce greenhouses gas emissions. Please evaluate a range of technological responses, the effect of each response on the cost of compliance, and the perceived likelihood of that response.

Original Request Letter from Senators Joseph I. Lieberman and John McCain (continued)



- Banking of allowances. The legislation allows an entity that has satisfied its yearly emission requirements to hold any remaining tradeable allowances for future uses. Please evaluate how covered entities that choose to bank allowances for future use would impact the cost of the program.

In addition to the above mentioned provisions, S. 139 also contains a number of "flexibility mechanisms" that are intended to allow a covered entity to select the most cost-effective compliance method available that best meets the unique circumstances of that entity. Attachment A provides a summary of these "flexibility mechanisms."

In carrying out this analysis, we request that EIA employ the most accurate baseline scenarios available. Please use emissions data and projections consistent with existing U.S. policies and measures and the U.S. Climate Action Report 2002 projections. Moreover, for projected emissions from the utility sector, please include all committed new capacity currently available, including all new units in operation, all new units physically under construction, and other units in the development process that are clearly committed to future operation.

We further request that EIA identify all key assumptions used in the analysis. In addition, please conduct a sensitivity analysis of the program's overall cost to the various assumptions and variables.

We understand that this is an extremely comprehensive request and hope you appreciate that our goal is to ensure that the analysis provides the maximum amount of information on which to evaluate the ability of S. 139 to effectuate its goals. We would be pleased to further discuss this request, including its format and summary, at your convenience, and would appreciate receiving a written response informing us how EIA intends to conduct this analysis. In the meantime, if you have any questions or concerns regarding this request, please contact Tim Profeta of Senator Lieberman's staff at 202-224-5016 or Floyd DesChamps with Senator McCain's staff at 202-224-8172.

Thank you very much for your time and attention to this request.

Sincerely,

John McCain
John McCain
U.S. Senator

Joseph I. Lieberman
U.S. Senator

Original Request Letter from Senators Joseph I. Lieberman and John McCain (continued)

Attachment A. Flexibility Mechanisms of S.196

The flexibility provisions contained in S. 139 would:

- Allow covered entities to achieve compliance through reductions in non-CO_2 greenhouse gases (CH_4, N_2O, HFCs, PFCs and SF_6). In addition, covered entities may offset their emissions via reductions from non-covered sectors and entities up to the 15% and 10% offset limits for the first and second target periods, respectively. We request that in evaluating the opportunities for compliance through the non-CO_2 gases, EIA bases its findings on fully developed and tested marginal abatement curves, such as those developed by EPA or Energy Modeling Forum at Stanford University.
- Allow unlimited trading among and between sectors.
- Allow covered entities to offset their emissions, up to the 15% and 10% offset limits, by trading with verified inventories in other countries.
- Include an incentive program to encourage automobile manufacturers to increase the fuel economy of autos, as well as offset provisions that will encourage additional demand-side reductions in the electricity sector from non-covered sources.
- Ensure entities engaging in approved geological sequestration projects are not required to turn in allowances for sequestered emissions.
- Allow covered entities to offset their emissions, up to the 15% and 10% offset limits, through biological sequestration achieved through both forestry and agricultural practices.
- Allow covered entities to offset their emissions, up to the 15% and 10% offset limits, by purchasing registered credits from nonparticipating entities.
- Allow covered entities to offset their emissions, up to the 15% and 10% offset limits, by borrowing future reductions up to five years in advance, as long as the future allowances are repaid at a 10 percent interest rate.
- Allow early participants – entities that pledge to reduce their emissions to 1990 levels before 2010 – to raise their use of allowed offsets to 20 percent.

E-Mail from Aloysius Hogan of Senator Inhofe's Committee

(Requesting a Run That Excludes Nuclear and Geologic Sequestration as Options and Delays an Earlier Request To Run a Sensitivity Evaluating a Btu Tax Mechanism)

From: Aloysius_Hogan@epw.senate.gov
[mailto:Aloysius_Hogan@epw.senate.gov]
Sent: Wednesday, April 23, 2003 6:32 PM
To: Mary.hutzler@eia.doe.gov
Subject: Analysis requested by Senator Inhofe

Please perform a model run that excludes nuclear and geologic sequestration which are as of yet not authorized in law and are of indeterminate political acceptability.

In an effort to complete this suite of analyses in a timely fashion, please hold the greenhouse gas tax mechanism/BTU tax mechanism analysis until after the other analyses are complete.

Thank you.

Aloysius Hogan
Chief Counsel
US Senate Environment and Public Works Committee
410 Dirksen Senate
Office Building
Phone: 202-224-6176
Fax: 202-224-5167 E-mail: aloysius_hogan@epw.senate.gov

E-Mail from Floyd Deschamps of Senator Mccain's Staff

(Refining Their Request To Include: Running a Sensitivity That Examines Greater Flexibility in Offsets Than the Current 15 Percent Amount; and Asking EIA To Base Its Non-CO_2 Gas Estimates on Projected Emissions of High-GWP Gases Rather Than Production Levels)

-----Original Message-----
From: DesChamps, Floyd (Commerce)
[mailto:Floyd_DesChamps@commerce.senate.gov]
Sent: Friday, May 02, 2003 3:32 PM
To: mary.hutzler@eia.doe.gov
Cc: Profeta, Tim (Lieberman)
Subject: EIA Analysis of S.139

In our initial memo, we requested EIA to inform our process by conducting a sensitivity analyses. Through this e-mail, we would like to convey specific runs that would be helpful to us. They are:
1) Please include greater flexibility for offsets than the current 15 percent amount (e.g. run 50 percent and full flexibility scenarios); and
2) Regarding non-CO2 gases, please base your estimates on projected emissions of High-GWP gases (not on production levels).

Thanks for your assistance. Please call me with any questions at 22-8172.

E-Mail from Aloysius Hogan of Senator Inhofe's Committee

(Requesting That a Sensitivity Be Run That Includes Higher Natural Gas Prices Based on a More Pessimistic Outlook for Natural Gas Supplies)

-----Original Message-----
From: Hogan, Aloysius (EPW) [mailto:Aloysius_Hogan@epw.senate.gov]
Sent: Thursday, June 05, 2003 6:05 PM
To: mary.hutzler@eia.doe.gov
Subject: Higher gas price analysis

Per our discussion, please include in your analysis of the Lieberman/McCain bill a scenario with higher natural gas prices. Such a scenario could result from Coastal Zone Management Act consistency appeals difficulties in permitting LNG facilities, difficulties in obtaining natural gas in the lower 48 states from Alaska, difficulties associated with Canada's compliance with the Kyoto Protocol, difficulties in developing America's resources on the Outer Continental Shelf, and other possible difficulties.

Please know that time is of the essence, however, with *possible* floor action during the week of June 9. As such, no such analysis should delay the utility of the EIA analysis *in toto* for floor debate.

Aloysius Hogan
Chief Counsel
US Senate Committee on Environment & Public Works
Direct Phone: 202-224-3107
Fax: 202-224-5167

Appendix B

Modifications to the *AEO2003* Reference Case

Introduction

To analyze the Climate Stewardship Act of 2003 (S.139), the Energy Information Administration (EIA) used an updated version of the *Annual Energy Outlook 2003* (*AEO2003*) reference case. The *AEO2003* reference case was updated to incorporate revised expectations about near-term trends in natural gas prices and to reflect recent changes in corporate average fuel economy (CAFE) standards, as discussed in Chapter 2. In addition, Senators McCain and Lieberman explicitly requested that EIA update the projection for electricity generating capacity, taking into account capacity additions made since *AEO2003* was completed (November 2002). The capacity changes are summarized in Chapter 2, and a more in-depth analysis is provided below.

The *AEO2003* reference case was generated using EIA's National Energy Modeling System (NEMS). S.139 proposes a detailed program for greenhouse gas emissions monitoring and control and contains provisions that are either subject to varying interpretation or are intended to be defined after enactment of the bill. Based on EIA's interpretation of S.139, modifications were made in NEMS to allow modeling of its specific provisions. This appendix describes (1) the electric generating capacity updates made in the *AEO2003* reference case, and (2) other key modeling changes that were implemented to address the provisions of S.139 related to greenhouse gases other than carbon dioxide (non-CO_2 gases).

Electric Generating Capacity Updates

Within NEMS, only planned units that are reported as "under construction" are automatically included as being built during the forecast horizon. NEMS forecasts the construction of additional unplanned capacity by type as needed to meet future demand.

For *AEO2003*, the information on planned generating units was based predominantly on 2001 data from company filings on Form EIA-860, "Annual Electric Generator Report," which provides information for both utility and nonutility generators. The EIA-860 data were supplemented by a second data source, the NewGen database developed by Platts Database,[196] which is updated on a monthly basis. The NewGen database was used to update the EIA-860 information for more recent changes in plant operating status.

Based on new information available as of the end of March 2003, planned electric generating capacity was updated for the S.139 analysis. Additional units were represented as planned capacity in the S.139 reference case if they were reported as under construction in the NewGen database and as planned in the EIA-860 inventory.

Table B.1 shows the incremental units represented in the S.139 reference case that were not included in *AEO2003*. About 24 gigawatts of additional planned capacity was reported as being under construction as of March 2003. The additional capacity included about 16 gigawatts of natural-gas-fired combined-cycle plants, 4.6 gigawatts of gas-fired turbines, 2 gigawatts of dual-fired combined-cycle units, and 1.4 gigawatts of dual-fired turbines and internal combustion units, several renewable units, and a relatively small coal-fired unit.[197]

Table B.2 summarizes the total planned capacity included in NEMS for the years 2002-2005 in the S.139 reference case. Total planned capacity in the S.139 reference case is 122 gigawatts, most of it completed in 2002 and 2003. Estimates of total planned capacity, including units under construction and in earlier

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[196] NewGen Data and Analysis, Platts Database (Boulder, CO, March 2003).

[197] The fact that the 24 gigawatts of additional capacity was not included as planned capacity in *AEO2003* does not invalidate the *AEO2003* forecasts, because NEMS projects additional new capacity as needed to meet demand (primarily natural-gas-fired units in the time frame of the forecast).

stages of planning, are much higher. For example, the latest version of NewGen reports 178 gigawatts of new planned capacity between April 2003 and December 2005. However, because 101 gigawatts of units have already been cancelled and because of the likelihood of further cancellations, only planned units that are under construction are included in the reference case.

Table B.1. Incremental Planned Net Summer Capacity Since Completion of *AEO2003** (megawatts)

North American Electric Reliability Council Region	2002	2003	2004	Total
East Central Area Reliability Coordination Agreement	888	1,137	528	2,553
Electric Reliability Council of Texas	371	922		1,293
Mid-Atlantic Area Council	2,221	739	149	3,109
Mid-America Interconnected Network	1,511	150		1,661
Mid-Continent Area Power Pool	302	38	38	378
New York	76	1,038		1,114
New England	703			703
Florida Reliability Coordinating Council	592	543		1,135
Southeastern Electric Reliability Council	637	5,114		5,751
Southwest Power Pool				0
Northwest Power Pool	438		1	438
Rocky Mountain Power Area	298	2,723		3,021
California	454	1,895	479	2,827
Total	**8,490**	**14,299**	**1,195**	**23,984**

*As of March 2003.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report," (2002 preliminary) and NewGen Data and Analysis, Platts Database (Boulder, CO, November 2002).

Table B.2. Total Planned Additions of Net Summer Capacity Included In NEMS Through 2005* (gigawatts)

North American Electric Reliability Council Region	2002	2003	2004	2005	Total
East Central Area Reliability Coordination Agreement	9,606	4,685	994		15,285
Electric Reliability Council of Texas	5,772	2,517	688	121	9,099
Mid-Atlantic Area Council	4,826	3,339	874	48	9,087
Mid-America Interconnected Network	6,012	218			6,230
Mid-Continent Area Power Pool	841	580	110	48	1,578
New York	634	1,569			2,203
New England	3,680	253	0		3,934
Florida Reliability Coordinating Council	4,856	1,805	1,832		8,492
Southeastern Electric Reliability Council	16,462	13,607	519		30,587
Southwest Power Pool	7,158	2,012			9,171
Northwest Power Pool	2,721	953	71	168	3,914
Rocky Mountain Power Area	5,008	6,845	1,112	45	13,008
California	2,722	3,846	1,126	857	8,550
Alaska	752				752
Hawaii	60				60
Total	**71,110**	**42,230**	**7,325**	**1,286**	**121,951**

*As of March 2003.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report," (2002 preliminary) and NewGen Data and Analysis, Platts Database (Boulder, CO, March 2003).

Overview of NEMS Cap and Trade Methodology

Emissions Calculations

The principal source of U.S. greenhouse gas emissions is fossil fuel combustion. These emissions depend on the carbon content of the fuel and the fraction of the fuel consumed in combustion, as reflected in fuel-specific emission factors in NEMS. The emission factors are multiplied by the fuel-specific energy consumption to calculate carbon dioxide emissions. The emission factor for coal is the highest and for natural gas the lowest among the fossil fuels, with petroleum falling about midway between coal and natural gas.

Carbon dioxide emitted by renewable sources is omitted from the emissions calculation. Biogenic carbon dioxide emissions are considered to be balanced by the carbon dioxide sequestration that occurred in its creation, and, by convention, are taken as zero. A portion of the carbon dioxide in nonfuel use of energy, such as for asphalt and petrochemical feedstocks, is assumed to be sequestered in the product and not released to the atmosphere.

While some of the other greenhouse gas emissions are related to energy activities, estimating those emissions based on economic factors is outside the scope of NEMS. As a result, baseline emissions of gases other than energy-related carbon dioxide were obtained from the U.S. Environmental Protection Agency (EPA), along with their marginal abatement cost curves (MACs), to estimate emissions under the provisions of S.139.

To the extent possible, greenhouse gas emissions for covered and noncovered entities were calculated separately. The coverage assumptions and derivation of the emissions caps used in NEMS are discussed in the following sections.

Simulating the Allowance Market

With the cap and trade system envisioned under S.139, a market for emissions allowances arises. Simulating this allowance market is relatively straightforward. The emission allowances required for a given amount of energy-related carbon dioxide can be calculated using the emissions factors and energy consumption. Similarly, the cost of the allowance is added to the price of each fossil fuel in proportion to its carbon emissions, on a dollar per British thermal unit (Btu) basis. While S.139 includes a mechanism to allocate some portion of emissions allowances at no cost to the entity, the tradable nature of allowances implies that the allowance price represents an opportunity cost of emissions. As a result, the allowance price applies to all covered emissions sources, regardless of the initial allocation of allowances.

As the allowance price changes and feeds through to fossil energy prices, the demand for energy changes, as do the corresponding carbon dioxide emissions. For other greenhouse gases, NEMS calculates emissions reductions in covered sectors based on the exogenous marginal abatement cost curves. The emissions abatement at the current market price is subtracted from the baseline emissions to obtain the resulting emissions for the covered sources.

Simulating Alternative Compliance and the Emissions Offset Market

S.139 provides a financial incentive for noncovered entities to obtain credits for their registered reductions in emissions. Noncovered entities can sell allowance credits to covered entities as offsets. However, the bill limits the percentage of allowances that a covered entity may obtain from noncovered entities, from other countries, and from borrowing. The basic limits are 15 percent in Phase I (2010 to 2015) and 10 percent in Phase II. As an incentive for early action, entities may be allowed to satisfy up to 20 percent of their emissions limit from offsets during Phase I, provided they reach their Phase II limit by 2010. All eligible entities are assumed to take advantage of these alternate compliance provisions, and a fraction are assumed to get the early action bonus. For analytical purposes, an effective Phase I limit of 16 percent is assumed,[198] taking into account the extra offset potential available for early action participants.

The alternative compliance provisions of the bill are simulated in NEMS as a separate market for offset credits, interacting with the allowance market. Emissions reduction opportunities from noncovered entities, biological sequestration, and international sources are simulated using MACs, constrained by the overall percentage limits on alternate compliance. Given the constraint, the offset market typically clears at a lower price than the allowance market, suggesting that economical emissions reductions are forgone in the noncovered sectors.

NEMS varies the price of allowances in a goal-directed, iterative process until the covered emissions reach the annual cap as adjusted for the availability of offsets. An allowance price and offset price are determined as the model solves for the energy market equilibrium. A solution is obtained for a single projection year, and then NEMS advances to the next projection year.

Modeling of Allowance Price Expectations

As NEMS solves one year at a time, the results in subsequent years depend in part on prior years' results and the capital stock decisions simulated. Some capital stock decisions in NEMS depend on energy price expectations. When simulating an emissions cap in NEMS, it is assumed that future allowance prices are taken into account for these decisions. The future allowance prices are incorporated in the energy price expectations so that simulated capital decisions reflect the future allowance prices in project costs. NEMS solves for a convergence of the expected path of allowance prices and the realized prices that fulfill the emissions limits.

In a run with converged expectations, the capital stock decisions simulated in NEMS with forward-looking expectations reflect the projected allowance costs. Obviously, this foresight modeling technique does not account for the inevitable decisions that would be made based on over- or under-predictions of expected allowance cost. It represents an optimistic solution for capacity decisions, but one that is internally consistent with the economic factors simulated.

The banking provisions of S.139 provide a mechanism to help prevent losses that might occur on the basis of inaccurate expectations of allowance costs. In particular, decisions based on overestimates of future allowance costs are mitigated by an entity's ability to sell excess emission allowances. While borrowing of allowances is limited by interest penalties, the potential for borrowing provides some protection for underestimating allowance costs as well.

Modeling of the Allowance Banking Provisions

With the allowance banking provisions of S.139, covered entities do not have to meet a particular emissions goal in each year. Instead, they may choose to overcomply and bank allowances for future use. While the banking of allowances is allowed, borrowing of allowances is limited in the bill. An entity may be granted permission to borrow against its own future emission reductions, but only if it shows it has a project underway to achieve those reductions. In addition, borrowed allowances must be returned in excess of those borrowed at a rate of 10 percent per year. The interest penalty and the strict requirements suggest that, in aggregate, borrowing will be minimal.

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[198] The issue of how much of the covered sector market would undertake actions prior to 2010 to meet 1990 greenhouse gas emission levels is debatable. However, assuming that in each sector all of the entities that reduce emissions in 2010 achieve 1990 emissions goals, then that estimate provides an upper bound on the number of entities that could achieve 1990 levels before 2010. For example, using this approach, the electric power sector, the most price-responsive market, yielded a 41 percent participation rate. If the electric power sector were representative of the entire covered entity market, then the percentage offsets allowed in 2010 to 2015 would have been 17 percent (41 percent of the difference between 20 percent offsets and 15 percent offsets). However, the non-electric power markets are much less likely to participate, reducing the calculated market increase for offset purchases to 16 percent.

While banking of allowances is allowed to begin in 2010, the bill provides entities with an incentive for early action emission reductions. Entities that register early action reductions receive a corresponding increase in their allocations of free emissions allowances in Phase I. This provision is implemented such that the total number of allowances issued in Phase I does not change, only their allocation to covered entities.

With allowance banking, the decisions to buy, sell, and hold allowances will depend both on the current and anticipated allowance prices. The allowance price trajectory is assumed to be smoothed through expectations and arbitrage. If allowance prices were expected to grow rapidly in the future, high levels of early reductions and banking (overcompliance) would tend to occur, as the cost of those reductions would be expected to be recoverable in the future. This was the case in the sulfur dioxide trading program under the Clean Air Act Amendments of 1990. However, the buildup of high levels of banked allowances would then tend to lower expectations of prospective carbon prices and moderate banking of allowances.

With perfect banking decisions, the idealized solution is characterized by a price growth at an aggregate discount rate, such that the present value of the expected allowance price is constant. For this analysis, a discount rate equal to the real after-tax cost of capital in the electricity sector was assumed, as the most important capital decisions driving the emissions market are expected to take place in that sector.

The banking provisions are expected to smooth out the potential price spikes that might otherwise occur at the start of Phase I and Phase II. The incentive to bank excess allowances during Phase I is that the Phase II cap (starting in 2016) is more stringent than the Phase I cap. The Phase II cap is based on 1990 emission levels, while the Phase I cap is based on year 2000 emissions. In addition, the Phase II percentage limit on offset purchases is lower, which by itself makes the Phase II cap more difficult to meet. As a result, there is an incentive to build up a bank of allowances during Phase I, and then to deplete the balance gradually in Phase II. Once the bank balance drops to zero, no further incentives to accumulate bank balances exist, and the cost of an allowance will increase no faster than the assumed discount rate.

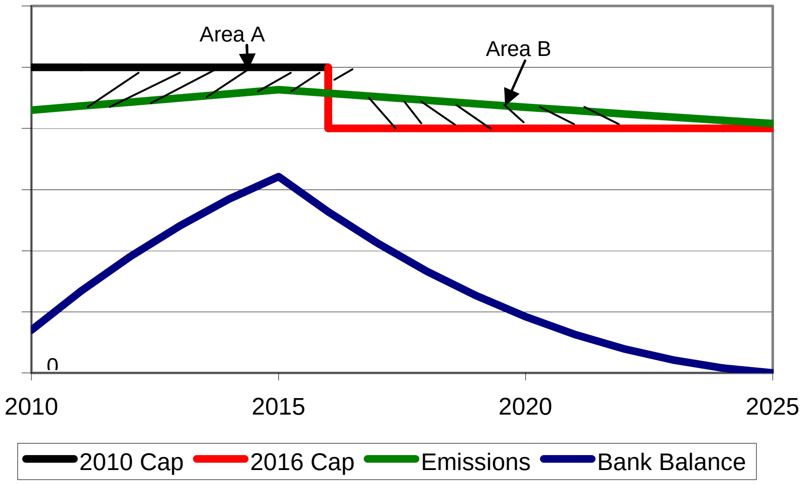
Short-term and long-term factors influence the economics of allowance banking. In the short term, the capital stock is largely fixed. This limits the ability of firms to respond quickly to fluctuations in allowance prices. In the long term, firms may acquire new capital stock to respond to emissions allowance costs. NEMS reflects these factors through explicit simulations of energy-using capital stock investment decisions and by modeling the economic behavior as constrained by available equipment, building structures, and transportation systems. With the relatively smooth price growth associated with allowance banking, firms are able to respond effectively to the long-term emissions reductions without undue disruptions. Without allowance banking, large price changes are more likely to occur as a result of short-term rigidities associated with the fixed capital stock.

In NEMS, the allowance bank balance is assumed to return to zero in some future year, say 2025. The objective of the solution algorithm is to determine the starting allowance price growing at the discount rate, with no annual constraint on emissions during the banking period. The initial price is varied such that the accumulated bank balance in the target year reaches zero. After the target year, emissions are constrained at the Phase II cap (adjusted for offset purchases), and the allowance price needed on a year-by-year basis to meet the cap is determined, subject to a maximum price increase per year equal to the discount rate.

An idealized solution to this procedure is illustrated in Figure B.1, where emissions are plotted along with the emissions caps. The hatched Area A represents the amount of early overcompliance used to build an allowance bank balance. Area B represents the amount of undercompliance and depletion of that bank balance. Areas A and B would be equalized by 2025 (the end of the projection horizon). There is little or no borrowing in aggregate, and the final balance in the target year, 2025, is zero.

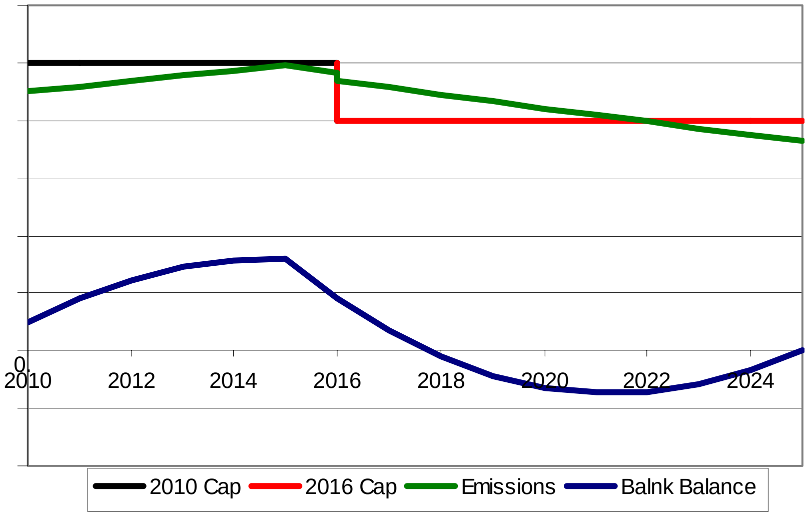
Based on the results in the solution with an assumed target year, the target year for the zero bank balance may be changed. If allowance prices drop significantly after the banking period ends, or borrowing occurs (as shown in Figure B.2), the target year is reassigned to an earlier year and the procedure is repeated. If prices continue to rise faster than the discount rate after the bank balance drops to zero, or if aggregate borrowing occurs in subsequent years, the target year is reassigned to a later year. Consequently, the target year for the end of the allowance banking may differ across the scenarios run for this study. For most scenarios, however, the target year for the end of banking is 2023.

Figure B.1. Illustration of Allowance Banking (emissions)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure B.2. Illustration of Trail Solution With Borrowing—Requires Earlier Target Year (emissions)



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Derivation of Marginal Abatement Cost Curves

Although NEMS is a detailed energy-economy model of United States and uses consumer behavior to develop detailed projections of energy consumption, energy prices, macroeconomic activity, and carbon dioxide emissions, it does not include economic or behavioral models to estimate the other greenhouse gases covered in S.139. *For this study*, a set of exogenous assumptions on projected emissions and MACs was used to analyze S.139.[199] *For the S.139 study*, an exogenous set of curves was incorporated to reflect assumptions about the potential for reductions in other greenhouse gases as a function of allowance prices.

The MACs, along with the associated baseline projections of the emissions, were obtained from the EPA's Office of Air and Radiation. EPA provided EIA with MACs as developed in several recent studies.[200,201,202] At EIA's request, the EPA's business-as-usual (BAU) projections and MACs were extended to 2025. The EPA BAU projections and MACs were used in this analysis because they are the only consistent and relatively complete source for such emission estimates.

While using MACs for emissions of non-CO_2 gases provides a more complete emissions accounting for analyzing S.139, the use of MACs as a proxy for more detailed modeling is an issue. MACs are simplified, reduced-form representations of emissions compliance potential as a function of a single variable, the allowance price. This contrasts with the detailed energy and macroeconomic models in NEMS that simulate behavioral responses, technology choice, and capital stock accounting in great detail. Modeling the determinants of the other greenhouse gases on a similar scale was not feasible.

As an alternative, a relatively simple approach of using exogenous MACs was deemed the best alternative *for this study*. The approach is also justified based on the relative size of the impacts from these other emissions sources in the covered sectors compared to energy-related carbon dioxide. In addition, the potential impact of most of these sources in the noncovered sectors is constrained by the bill's limits on credits from alternative compliance sources. To the extent the MACs misrepresent the cost of reducing emissions from these alternative sources, the primary effect will be on the offset price, with little impact on the overall economic analysis of the bill.

The exogenous MAC curves are treated as four classes:

1. Emissions from non-CO_2 greenhouse gases from domestic covered sectors
2. Emissions of non-CO_2 greenhouse gases from domestic uncovered sectors
3. Carbon Sequestration (agriculture and forestry), domestic
4. International greenhouse gases and sequestration.

The emissions and MACs for category 1 were used to estimate covered emissions under the bill. Within this category, there is no limit on reductions specified in the bill and the allowances for these emissions

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[199] EIA has no plans to develop behavioral models of sequestration or domestic or international marginal abatement curves. Because the estimates of MACs are exogenous to NEMS, highly uncertain, and scenario dependent, use of such curves in future studies will require further review and adjustment.

[200] U.S. Environmental Protection Agency, Office of Air and Radiation, *U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions,* EPA_30-R-99-013 (September 1999), http://www.epa.gov/ghginfo/pdfs/07-complete.pdf; and *Addendum to the U.S. Methane Emissions 1990-2020: Update for Inventories, Projections, and Opportunities for Reductions* ((December 2001), http://www.epa.gov/ghginfo/pdfs/final_addendum2.pdf.

[201] U.S. Environmental Protection Agency, Office of Air and Radiation, *U.S. High GWP Gas Emissions 1990-2010: Inventories, Projections, and Opportunities for Reductions* (June 2001), EPA 000-F-97-000, http://www.epa.gov/ghginfo/pdfs/gwp_gas_emissions_6_01.pdf.

[202] U.S. Environmental Protection Agency, Office of Air and Radiation, *U.S. Adipic Acid and Nitric Acid N_2O Emissions 1990-2020: Inventories, Projections and Opportunities for Reductions* (December 2001), http://www.epa.gov/ghginfo/pdfs/adipic.pdf.

can be considered along with allowances for carbon dioxide emissions as a single market with unlimited trading.

Reductions in a noncovered entity's emissions, potential carbon sequestration, and international emission reductions are included to reflect the bill's alternative compliance provisions. Allowance credits may be obtained from these noncovered entities subject to the restrictions outlined in Chapter 1. The allowance credits from noncovered entities are commonly referred to as offsets. Offsets are capped at 15 percent and 10 percent limits of emissions from covered sectors for Phase I and Phase II, respectively.[203] The price at which offsets sell is also determined within the overall NEMS solution process.

The MACs were adjusted slightly, because the curves reflect abatement options available with negative costs. The availability of abatement options with negative costs suggests that imperfect information, transactions costs, and other factors limiting the adoption of the abatement options are not adequately reflected in the cost curves. The abatement curves were shifted such that the negative portions would become available at $1 per ton carbon equivalent while leaving the rest of the curve unchanged.

Table B.3 presents a summary of the assumed domestic MACs for gases from covered sectors (excluding energy-related CO_2), along with the associated baseline emissions projection for non-CO_2 gases from covered sectors. This table represents the combined response to allowance costs for the high GWP gases, coal-related methane emissions, and a portion of nitrous oxide emissions from adipic and nitric acid production. The price/quantity points on the curve within a year are constructed from the points in the table by linear interpolation. Curves for intervening years are also derived by interpolation.

Table B.3. Domestic Marginal Abatement Costs for Non-CO_2 Covered Gases (reductions in million metric tons carbon equivalent)

Allowance Price (2001 dollars per metric ton carbon equivalent)	2005	2010	2015	2020	2025
			BAU Emissions		
$0	206	233	269	314	373
			Emission Reductions		
$1	11.1	12.2	14.6	17.9	21.3
$10	27.2	30.6	37.5	47.4	60.6
$20	38.2	43.4	54.2	70.0	91.9
$30	39.7	44.9	55.4	70.8	92.8
$40	43.4	49.0	61.1	78.9	103.9
$50	44.9	51.0	63.5	81.9	107.8
$75	47.1	53.4	66.6	86.1	113.5
$100	47.3	53.6	66.7	86.2	113.6
$125	47.8	54.2	67.7	87.5	115.4
$150	49.0	55.7	69.7	90.3	119.3
$175	50.2	57.2	71.6	92.9	123.0
$200	50.3	57.2	71.7	93.0	123.1

Sources: U.S. Environmental Protection Agency, Office of Air and Radiation, *U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions,* EPA_30-R-99-013 (September 1999), http://www.epa.gov/ghginfo/pdfs/07-complete.pdf; *Addendum to the U.S. Methane Emissions 1990-2020: Update for Inventories, Projections, and Opportunities for Reductions* ((December 2001), http://www.epa.gov/ghginfo/pdfs/final_addendum2.pdf; *U.S. High GWP Gas Emissions 1990-2010: Inventories, Projections, and Opportunities for Reductions* (June 2001), EPA 000-F-97-000, http://www.epa.gov/ghginfo/pdfs/gwp_gas_emissions_6_01.pdf; and *U.S. Adipic Acid and Nitric Acid N_2O Emissions 1990-2020: Inventories, Projections and Opportunities for Reductions* (December 2001), http://www.epa.gov/ghginfo/pdfs/adipic.pdf.

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[203] The 15 percent limit is adjusted to 16 percent in this analysis to account for those entities qualifying for a bonus limit of 20 percent for early participation.

The assumed MACs for non-CO_2 emissions in the *noncovered* sectors are presented in Tables B.4 and B.5. Table B.4 includes reduction opportunities in natural gas operations and small landfills. The carbon sequestration MACs (Table B.5 and Figure B.3) are derived from the Forest and Agricultural Sector Optimization Model (FASOM-GHG), in consultation with the EPA.[204,205] Carbon sequestration from biofuel use is not incorporated in the agricultural offset curves in order to avoid double counting of carbon dioxide reductions from the use of biomass energy for power generation, which is already reflected in NEMS.

The quantities from domestic agricultural offsets that are available for reduction at every price in the MAC are adjusted downward by 50 percent, consistent with a previous EPA study for Senators Smith, Voinovich, and Brownback.[206] The pricing and availability of agricultural offsets are deemed to be more uncertain than those for other domestic non-CO_2 offsets because of limited information, an inability to measure or verify the data, and administrative costs.[207] Further, the quantity of offsets from other non-CO_2 gases in the uncovered sector is quite small, as shown in Table B.4. Their adjustment downward by 50 percent would change the demand for these offsets by, at most, 25 million metric tons. The impact on the offset price is expected to be small, based on the remaining offset curves. No impact is expected on the domestic covered entity allowance price because of the limits set on the use of offsets and sequestration in the bill.

Table B.4. Marginal Abatement Costs for Domestic Non-CO_2 Offsets in Noncovered Sectors (reductions in million metric tons carbon equivalent)

Allowance Price (2001 dollars per metric ton carbon equivalent)	2005	2010	2015	2020	2025
	BAU Emissions				
$0	154	155	155	153	151
	Emission Reductions				
$1	14.7	18.6	19.9	21.2	21.2
$10	24.5	24.3	24.3	24.3	24.2
$20	31.3	29.5	29.1	28.6	28.4
$30	38.8	35.9	34.4	32.9	32.8
$40	42.3	40.0	38.1	36.2	36.0
$50	44.9	43.4	41.3	39.2	38.9
$75	49.8	49.9	47.5	45.2	44.9
$100	50.2	50.6	48.4	46.2	45.8
$125	51.2	51.6	49.6	47.5	47.2
$150	51.4	51.8	49.8	47.8	47.5
$175	51.5	51.9	50.0	48.1	47.8
$200	51.6	52.0	50.1	48.3	47.9

Sources: U.S. Environmental Protection Agency, Office of Air and Radiation, *U.S. Methane Emissions 1990-2020: Inventories, Projections, and Opportunities for Reductions,* EPA_30-R-99-013 (September 1999), http://www.epa.gov/ghginfo/pdfs/07-complete.pdf; *Addendum to the U.S. Methane Emissions 1990-2020: Update for Inventories, Projections, and Opportunities for Reductions* ((December 2001), http://www.epa.gov/ghginfo/pdfs/final_addendum2.pdf; *U.S. High GWP Gas Emissions 1990-2010: Inventories, Projections, and Opportunities for Reductions* (June 2001), EPA 000-F-97-000, http://www.epa.gov/ghginfo/pdfs/gwp_gas_emissions_6_01.pdf; and *U.S. Adipic Acid and Nitric Acid N_2O Emissions 1990-2020: Inventories, Projections and Opportunities for Reductions* (December 2001), http://www.epa.gov/ghginfo/pdfs/adipic.pdf.

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[204] D.M. Adams, R.J. Alig, J.M. Callaway, and B.A. McCarl, *The Forest and Agricultural Sector Optimization Model (FASOM): Model Structure and Policy Applications*, USDA Forest Service Report PNW-RP-495 (1996).

[205] B.A. McCarl and U.A Schneider, "Greenhouse Gas Mitigation in U.S. Agriculture and Forestry," *Science Magazine* (December 2001), http://www.sciencemag.org/cgi/content/full/294/5551/2481.

[206] http://www.epa.gov/air/oaq_caa.html.

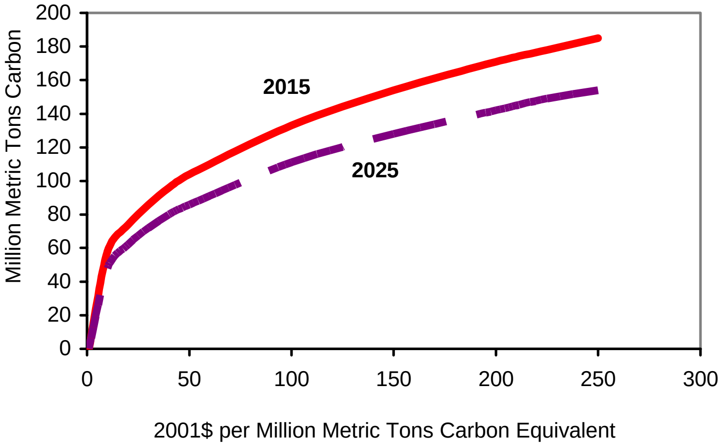
[207] It can be argued that all domestic offsets should be reduced by 50 percent as was done by EPA in its study for Senators Smith, Voinovich, and Brownback. Since the quantities of offsets available from domestic non-agricultural sources are small and prices are sharply rising, this study does not reduce the non-CO_2 abatement quantities.

Table B.5. Marginal Abatement Costs for Carbon Sequestration in Domestic Agriculture and Forestry (reductions in million metric tons carbon equivalent)

Allowance Price (2001 dollars per metric ton carbon equivalent)	2005	2010	2015	2020	2025
$1	0	0	0	0	0
$10	0	57	58	59	48
$20	0	73	74	76	62
$30	0	84	86	88	72
$40	0	94	96	98	80
$50	0	101	104	106	86
$100	0	130	133	136	111
$150	0	151	154	157	128
$200	0	167	171	174	142
$225	0	174	178	182	149
$250	0	181	185	189	154

Notes: The reductions shown are relative to a case with no carbon allowance value. Offset curves exclude biofuels, which are represented endogenously in NEMS.
Source: U.S. Environmental Protection Agency, FASOM Reduced Form Model, excluding biofuels use.

Figure B.3. Agricultural Sequestration Curve



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

S.139 provisions severely limit the sources and quantities of international offsets that qualify for purchase by U.S. entities. The bill asserts that international offsets may only be purchased from countries that have established certified greenhouse gas emission reduction programs.[208] To date, only a portion of the Annex B countries qualify. Further restricting United States access to inexpensive sequestration offsets is the Marrakech Accord which limits the total quantity of sequestration offsets that Annex B (without the U.S.) may register and use to about 70 million metric tons per year.

While the methodology used to develop the international MAC for United States use applies to the entire Annex B group, not counting the United States, information from EPA was only adequate to characterize

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[208] Under S.139, Section 312, Compliance, Part (b)(1)(B), international allowances may be permitted for use if and only if three conditions are simultaneously met, the most important of which is that "… the other nation has adopted enforceable limits on its greenhouse gas emissions which the tradable allowances were issued to implement." The major developing countries of China, Mexico, South Korea, India, and Brazil have no binding obligations to limit or reduce emissions under the UNFCCC or the Kyoto Protocol. Consequently, the only avenue that the United States has to access international allowances is through a subset of Annex B countries that meet the three criteria of S.139.

the MACs for Annex I countries,[209] excluding the United States. (Annex B countries include Annex I countries plus Lithuania, Slovenia, Croatia, and the Ukraine.) However, those excluded from this analysis only account for about 4 percent of Annex B and are unlikely to significantly affect the offset prices from this market. It is possible to try and develop a better estimate for Annex B emissions for the baseline but the problem remains that our study had no known source for non-CO_2 MACs for Lithuania, Slovenia, Croatia and the Ukraine. We expect that had such an estimate been available, it would have lowered the cost of international offsets derived from additional “hot air,” primarily from the Ukraine. Future work by the EPA on developing MACs for all of Annex B would allow a more complete analysis.

The Annex I countries are assumed to adhere to their Kyoto Protocol targets through 2025. The greenhouse gas emission targets of the Kyoto Protocol were used to develop the aggregate emission targets through 2025 for Annex I countries without U.S. participation. Energy Modeling Forum (EMF) 21 assumptions[210] on the availability of non-CO_2 offsets were used to estimate the offset MACs available to Annex I countries without U.S. participation. The Marrakech Accords,[211] also known as the Seventh Conference of the Parties of the United Nations Framework Convention on Climate Change (COP 7 of the UNFCCC), were used to limit the quantity of agricultural/forestry offsets available to this international group to about 70 million metric tons per year, which were assumed to be available at $15 per ton carbon equivalent.[212] Any price at or below $25 per ton carbon equivalent would produce the same international offset curve from Annex I for U.S. use. Pacific Northwest Laboratories provided the MAC and the baseline projection for energy-related carbon dioxide for Annex I countries from its Second Generation Model (SGM).[213] It was assumed that an additional 130 million metric tons of offsets would be available each year from the Clean Development Mechanism (CDM)[214] at $15 per ton carbon. Since the Annex I countries have already demonstrated an interest in “real” greenhouse gas emission control by limiting the use of sequestration/forestry to about 70 million metric tons, a CDM limit of nearly twice the sequestration limit appears to be consistent with the Annex I countries’ determination to reduce greenhouse gas emissions. The difference between the Annex I baseline and the target determines the year-by-year reductions necessary. Subtraction of the reductions from the MAC provides the MAC available for U.S. use.

Recent submissions for CDM credits to the United Nations have been refused, as reported by Reuters.[215] Excerpts from the article include:

> *“Don’t expect miracles,” Hans Jurgen Stehr, chairman of the executive board of the Clean Development Mechanism, told Reuters yesterday [on June 9, 2003] after announcing the results of the study…*
>
> *Twelve projects were presented to the U.N. body. The answer on each occasion was no.*

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[209] Annex I is composed of the 15 European Union countries plus Australia, Bulgaria, Canada, Czech Republic, Estonia, Hungary, Iceland, Japan, Latvia, Liechtenstein, Monaco, New Zealand, Norway, Poland, Romania, Russian Federation, Slovakia, Switzerland, and the United States. The United States is not a participant in the Marrakech Accords, which means that the proposed sequestration limit of 30 million metric tons carbon does not affect U.S. use of sequestration.

[210] The Energy Modeling Forum, sponsored by Stanford University, is a series of periodic seminars and workshops that examine important energy issues. EMF 21 concentrated on non-CO_2 greenhouse gas abatement strategies. See http://www.stanford.edu/group/EMF/group21/index.htm.

[211] http://unfccc.int/resource/docs/cop7/13.pdf

[212] The $15 per ton cost for CDM and sequestration is an assumption of this analysis. There is no good information to estimate such costs. For this analysis, any costs at or below $25 per ton would imply that these reductions would all be taken first and the residual amount of offsets left to the U.S. would remain unchanged. Previous global trading studies by PNNL and EMF suggest that such costs will range between $5 per ton to $25 per ton for Annex I because otherwise, less costly alternative Annex I reductions could be undertaken for the 2008-2020 period.

[213] Communication with Ron Sands, who operates the SGM model for EPA. These curves integrated the EMF 21 offset curves and the SGM baseline and MACs for carbon dioxide.

[214] The CDM allows Annex I countries to take emissions credits for projects that reduce emissions in non-Annex I countries, provided that the projects lead to measurable, long-term benefits.

[215] See http://www.planetark.org/dailynewsstory.cfm/newsid/21123/story.htm

> *The backers of three projects in Brazil, a landfill plant in South Africa, a wind farm in Jamaica and a project in South Korea will, however, be able to resubmit revised applications at the end of June. The backers in each case argued they would reduce the emissions of greenhouse gases such as carbon dioxide.*
>
> *"We have to answer the question: why would this not have happened anyway," said Christine Zumkeller, coordinator of the U.N's cooperative mechanisms programme.*
>
> *A country with many fast-flowing rivers could, for example, argue it is helping the planet by building hydroelectric plants instead of burning fossil fuels, but regulators say that may not be a legitimate argument if the fossil fuel plant was not a viable alternative in the first place.*
>
> *The debate is likely to increase in coming years if the Kyoto Protocol takes effect and if a U.N. climate change summit in Milan in December agrees to give richer nations credits for planting trees that absorb carbon dioxide.*

Since the only participants in these programs are Annex I countries, the uncertainty around the availability of international offsets is assumed to be equivalent to the uncertainty for domestic offsets from sequestration. That is, the remaining quantities of offsets available from participating Annex I countries were reduced by 50 percent. The resulting MAC for international offsets in the main case of this study is shown in Table B.6.

Table B.6. Marginal Abatement Costs for International Offsets (reductions in million metric tons carbon equivalent)

Offset Price (2001 dollars per metric ton carbon equivalent)	2010	2015	2020	2025
$10	0	0	0	0
$15	0	0	0	0
$20	0	0	0	0
$30	13	0	0	0
$40	31	0	0	0
$50	45	3	0	0
$75	81	48	23	3
$100	115	90	71	54
$125	146	129	116	102
$150	170	158	151	138
$175	193	186	183	171
$200	217	214	216	205
$225	263	266	275	265

Source: Communication with Ron Sands, who operates the SGM model for EPA, and adjustments made by EIA as described below.

Annex I Countries' Baseline and MAC Greenhouse Gas Emission Calculations

This section describes the methodology used to derive the baselines and the MAC's *for international offsets*. The Annex I energy-related international carbon emission estimates and the associated MAC for carbon are taken from the SGM model developed by Pacific Northwest Laboratories, as provided by Ron Sands.[216] Although EIA has international energy-related carbon emission projections, EIA does not have associated MACs. The SGM results were used to maintain consistency of the baseline carbon emissions with the appropriate MAC. It is assumed that the SGM definition of Annex I includes Lithuania, Slovenia, Croatia, and Ukraine because, according to documentation provided, Annex I appears to be the sum of OECD, EEU, and FSU, and those four countries would be included in EEU and FSU. This means that the SGM definition of Annex I is actually Annex B. However, EMF21 provides baseline emissions and MAC data for non-CO_2 gases for Annex I countries. In order to derive consistent baseline and MAC

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[216] Ron Sands email to Joseph Beamon dated March 27, 2003.

emission profiles for all greenhouse gas emissions for Annex B, EIA adopted the following methodology. The rates of change of carbon dioxide emissions of the FSU and EE were used as the rates of change for these four countries (Lithuania, Slovenia, Croatia, and Ukraine) and were applied to the most recent historical year emission data to estimate the total greenhouse gas emissions from these countries over the 2000-2025 time frame. The baseline emissions for these four countries, including the SGM projection of U.S. carbon dioxide emissions and MAC, were subtracted from the Annex B greenhouse gas baseline to derive BAU and MAC projections for Annex I excluding the United States.

Baseline carbon dioxide emissions of EEU and FSU countries are projected to decline from 1,319 million metric tons carbon equivalent in 1990 to 1,285 million metric tons carbon equivalent in 2025 according to PNNL's SGM model. The projected annual growth rates for carbon dioxide emissions are calculated in 5-year intervals from these data (Table B.7). For Lithuania and Slovenia only 1990 greenhouse gas emissions data are available from the United Nations (UN),[217] and the derived growth rates are applied to the 1990 emissions. For Croatia and Ukraine, 1990 and 1995 greenhouse gas emissions data are available, and the growth rates are applied beginning in 1995 to estimate the projected greenhouse gas emissions through 2025 (Table B.8). These four countries are estimated to have greenhouse gas emissions of 279 million metric tons carbon equivalent in 1990 and 239 million metric tons carbon equivalent in 2025.

Table B.7. Baseline Carbon Dioxide Emissions for EEU and FSU Countries from SGM (million metric tons carbon equivalent)

Year	Baseline Emissions	Annual growth Rate (percent)
1990	1,319	
1995	894	-7.5
2000	815	-1.8
2005	979	3.7
2010	1,079	2.0
2015	1,167	1.6
2020	1,250	1.4
2025	1,285	0.6

Source: Historical data and projections from Ron Sands, PNNL, obtained using the SGM model.

Table B.8. Baseline Greenhouse Gas Emissions for Lithuania, Slovenia, Croatia, and Ukraine Using SGM Growth Rates (million metric ton carbon equivalent)

Year	Lithuania	Slovenia	Croatia	Ukraine	Total
1990	14	5	9	251	**279**
1995	9	4	6	147	**166**
2000	9	3	5	134	**151**
2005	10	4	7	161	**182**
2010	12	4	7	177	**200**
2015	12	5	8	192	**217**
2020	13	5	9	205	**232**
2025	14	5	9	211	**239**

Source: Historical data from "National Communications From Parties Included in Annex I to the Convention: Report on National Greenhouse Gas Inventory Data from Annex I Parties for 1990 to 2000", United Nations, October 11 2002, FCCC/SB/2002/INF.2, available at http://unfccc.int/program/mis/ghg/index.html (Table 4, page 10). Projections calculated using methodology described in this appendix.

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[217] "National Communications From Parties Included in Annex I to the Convention: Report on National Greenhouse Gas Inventory Data from Annex I Parties for 1990 to 2000", United Nations, October 11 2002, FCCC/SB/2002/INF.2, available at http://unfccc.int/program/mis/ghg/index.html (Table 4, page 10).

In order to derive Annex I greenhouse gas emissions (excluding the United States) that are consistent with the Annex I MACs, the estimated BAU greenhouse gas emissions of these four countries were subtracted from the derived greenhouse gas emissions of Annex I excluding the United States. This calculation underestimates the BAU emissions from the Annex I countries excluding the United States by the quantity of non-CO_2 emissions for 1990, because the non-CO_2 emissions of these four countries are not included.[218] Using the rule of thumb that non-CO_2 emissions typically represent about 15 percent of total greenhouse gas emissions, the underestimate is expected to be about 40 million metric tons carbon equivalent (about 1 percent of Annex I greenhouse gas emissions excluding the United States) and well within the measurement error for 1990 reported data. This level of error was judged to be insignificant within the context of this analysis. With these adjustments, a consistent baseline and MAC were derived for Annex I countries.

The Kyoto Protocol targets for the Annex B countries excluding the United States are specified as percentages in the text of the Kyoto Protocol (Table B.9). These percentages were applied to the 1990 emissions[219] to derive the targets for Annex I countries excluding the United States. Since the Kyoto Protocol specifies that these targets have to be met in the 2008 to 2012 time frame, it is assumed that the targets are met in 2010. It is further assumed that the targets remain constant from 2010 onwards. The difference between the greenhouse gas baseline emissions and the Kyoto target represents the greenhouse gas emissions reductions that would be necessary to meet the Kyoto targets (Table B.10). The baseline emissions for Annex I were developed from SGM and EMF 21 information provided through EPA's contractors (Table B.11).

Table B.9: Kyoto Protocol 2010 National Emissions Targets (percent of 1990 emissions)

Annex B Country	Target	Annex B Country	Target
Australia	108	Lichtenstein	92
Austria	92	Lithuania	92
Belgium	92	Luxembourg	92
Bulgaria	92	Monaco	92
Canada	94	Netherlands	92
Croatia	95	New Zealand	100
Czech Republic	92	Norway	101
Denmark	92	Poland	94
Estonia	92	Portugal	92
Finland	92	Romania	92
France	92	Russian Federation	100
Germany	92	Slovakia	92
Greece	92	Slovenia	92
Hungary	94	Spain	92
Iceland	110	Sweden	92
Ireland	92	Switzerland	92
Italy	92	Ukraine	100
Japan	94	United Kingdom and Northern Ireland	92
Latvia	92	United States	93

Source: "Kyoto Protocol of the United Nations Framework Convention on Climate Change", available at http://unfccc.int/resource/docs/convkp/kpeng.pdf, Annex B, page 23.

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[218] (Annex I + 4 other country) CO_2 + Annex I non-CO_2 - (4 other country CO_2 +non-CO_2) = Annex I total GHG – (4 other country non-CO_2 emissions).

[219] "National Communications From Parties Included in Annex I to the Convention: Report on National Greenhouse Gas Inventory Data from Annex I Parties for 1990 to 2000", October 11, 2002, FCCC/SB/2002/INF.2, available at http://unfccc.int/program/mis/ghg/index.html (Table 4, page 10).

Table B.10. Annex I Countries' Baseline Greenhouse Gas Emissions, Excluding the United States, Historical and Forecast (million metric tons carbon equivalent)

Year	Baseline Emissions	Kyoto Protocol Target	Reductions from Baseline Needed To Meet Kyoto Protocol Target
1990	3,188		
1995	2,906		
2000	2,875		
2005	3,109		
2010	3,299	2,898	401
2015	3,462	2,898	564
2020	3,605	2,898	707
2025	3,688	2,898	790

Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting; Ron Sands, PNL; and The Energy Modeling Forum (EMF), sponsored by Stanford University. EMF is a series of periodic seminars that examine important energy issues. EMF21 concentrated on greenhouse gas abatement strategies. See http://www.stanford.edu/group/EMF/group21/index.htm.

Table B.11. Annex I Countries' Baseline Greenhouse Gas Emissions, Excluding the United States (million metric tons carbon equivalent)

GHG Gas	1990	1995	2000	2005	2010	2015	2020	2025
CO_2 (annex B)..	2,745	2,399	2,386	2,623	2,806	2,957	3,086	3,145
CH_4	472	437	402	405	407	419	431	443
N_2O	216	198	191	204	216	227	242	256
HGWP..	34	39	47	59	71	75	79	82
Lithuania, Slovenia, Croatia, Ukraine........	-279	-166	-151	-182	-200	-217	-232	-239
Total Annex I Baseline.........................	**3,188**	**2,906**	**2,875**	**3,109**	**3,299**	**3,461**	**3,605**	**3,688**

Note: Total greenhouse gas emissions from Annex I, excluding the United States, are the sum of emissions of carbon dioxide (CO_2), methane (CH_4), ntitrous oxide (N_2O), and non-CO_2 gases with high global warming potential (HGWP) minus emissions from Lithuania, Slovenia, Croatia, and the Ukraine. As noted, this sum understates Annex I baseline GHG emissions by the amount of non-CO_2 emissions from the four countries.

Sources: Ron Sands email to Joseph Beamon, March 27, 2003, for Annex I carbon emission projections and marginal abatement cost curves; EMF 21 assumptions for all other gases in Annex I. Note that since we were only interested in greenhouse gas emissions in Annex I excluding the United States, we used SGM results for all countries in Annex I to be consistent.

Detailed Derivation of Marginal Abatement Curves

Data for the carbon dioxide MAC were obtained from SGM model results. Allowance prices were converted from 1990 dollars to 2001 dollars using a factor of 1.26 (Table B.12). The MACs for methane, nitrous oxide, and high-GWP gases were obtained from the EPA/EMF21 IMAC model results using a discount rate of 10 percent and a tax rate of 40 percent (Tables B.13, B.14, and B.15). An aggregated MAC for carbon dioxide, methane, nitrous oxide, and high-GWP gases was derived by summing the amounts at each price (Table B.16). To the aggregate MAC, an amount of 200 million metric tons carbon equivalent was added to represent agriculture and forestry sinks and CDM (70 million metric tons carbon equivalent for agriculture and forestry sinks and 130 million metric tons carbon equivalent for CDM). The 200 million metric tons carbon equivalent was added at $15 per metric ton carbon equivalent.[220] Table

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[220] For purposes of this analysis, any price between $1 per ton and $20 per ton would have made absolutely no difference to the prices and quantities of international offsets offered for sale to the United States. Virtually all estimates *for limited use of international sequestration* fall in that $1 - $20 range. Greater precision was not required for purposes of this study.

B.16 is the summation of Tables B.12 through B.15 with the agriculture and forestry sinks and CDM adjustments.

Using the aggregate MAC, the reductions required to meet Kyoto Protocol targets in each year were subtracted from the MAC to provide an estimate of the offsets that might be available to the U.S. market. The aggregate remaining MAC was then reduced by a factor of 50 percent to represent uncertainties in the available amounts for U.S. offset markets. Table B.17 is the result of adjusting the aggregate MAC for Kyoto Protocol targets and applying the reductions. This exogenously derived MAC was used for this study. Table B.17 implies that the equilibrium price in 2010 for the Annex I countries excluding the United States is expected to be between $20 and $30 per metric ton carbon equivalent in 2010, between $40 and $50 per metric ton in 2015 and between $50 and $75 per metric ton in 2020 and 2025.

Table B.12. Carbon Dioxide Marginal Abatement Costs for Annex I Counties, Excluding the United States (reductions in million metric tons carbon equivalent)

Allowance Price (2001 dollars per metric ton carbon equivalent)	2010	2015	2020	2025
$0	0	0	0	0
$10	44	64	84	95
$15	62	89	117	130
$20	80	115	149	166
$30	114	162	210	232
$40	145	205	265	290
$50	174	244	314	342
$75	236	326	413	447
$100	295	400	499	539
$125	354	474	584	630
$150	400	529	649	696
$175	445	583	711	759
$200	490	637	774	823
$225	535	690	837	887

Source: Ron Sands, PNNL use of the Second Generation Model, provided to EIA staff via email.

Table B.13. Methane Marginal Abatement Costs for Annex I Counties, Excluding the United States (reductions in million metric tons carbon equivalent)

Allowance Price (2001 dollars per metric ton carbon equivalent)	2010	2015	2020	2025
$0	27	27	27	27
$10	42	42	43	43
$15	54	54	55	56
$20	65	66	67	68
$30	78	79	79	80
$40	81	82	83	84
$50	82	83	84	84
$75	90	91	92	94
$100	98	100	101	102
$125	100	102	103	105
$150	102	103	105	106
$175	102	104	106	107
$200	105	107	108	110
$225	148	151	154	157

Source: Energy Modeling Forum, EMF21. The Energy Modeling Forum, sponsored by Stanford University, is a series of periodic seminars that examine important energy issues. EMF21 concentrated on greenhouse gas abatement strategies. See http://www.stanford.edu/group/EMF/group21/index.htm.

Table B.14. Nitrous Oxide Marginal Abatement Costs for Annex I Counties, Excluding the United States (reductions in million metric tons carbon equivalent)

Allowance Price (2001 dollars per metric ton carbon equivalent)	2010	2015	2020	2025
$0	0	0	0	0
$10	19	19	20	20
$15	19	19	20	20
$20	19	19	20	20
$30	19	19	20	20
$40	19	19	20	20
$50	19	19	20	20
$75	19	19	20	20
$100	19	19	20	20
$125	19	19	20	20
$150	19	19	20	20
$175	19	19	20	20
$200	19	19	20	20
$225	19	19	20	20

Source: Energy Modeling Forum, EMF21. The Energy Modeling Forum, sponsored by Stanford University, is a series of periodic seminars that examine important energy issues. EMF21 concentrated on greenhouse gas abatement strategies. See http://www.stanford.edu/group/EMF/group21/index.htm.

Table B.15. Marginal Abatement Costs for Non-CO_2 Gases with High Global Warming Potential for Annex I Counties, Excluding the United States (reductions in million metric tons carbon equivalent)

Allowance Price (2001 dollars per metric ton carbon equivalent)	2010	2015	2020	2025
$0	5	7	9	11
$10	11	12	13	14
$15	13	16	18	21
$20	15	20	24	28
$30	16	21	26	31
$40	17	22	28	33
$50	17	23	28	33
$75	18	23	29	34
$100	18	24	30	36
$125	19	26	33	39
$150	21	28	36	43
$175	21	29	37	45
$200	22	30	38	46
$225	25	35	45	56

Source: Energy Modeling Forum, EMF21. The Energy Modeling Forum, sponsored by Stanford University, is a series of periodic seminars that examine important energy issues. EMF21 concentrated on greenhouse gas abatement strategies. See http://www.stanford.edu/group/EMF/group21/index.htm.

Table B.16. Aggregate Greenhouse Gas Marginal Abatement Costs for Annex I Counties, Excluding the United States and Adjusted for Agriculture and Forestry Sinks and CDM (reductions in million metric tons carbon equivalent)

Allowance Price (2001 dollars per metric ton carbon equivalent)	2010	2015	2020	2025
$0	32	34	36	39
$10	116	137	159	172
$15	348	379	410	427
$20	380	420	460	482
$30	427	481	535	563
$40	462	529	595	627
$50	492	569	645	680
$75	562	660	754	795
$100	630	743	850	898
$125	693	821	940	995
$150	742	880	1,009	1,066
$175	788	935	1,074	1,132
$200	835	992	1,140	1,199
$225	927	1,096	1,256	1,320

Source: Energy Information Administration, Office of Integrated Analysis and Forecadting. The results are the sum of the results from Tables B.11-B.14.

Table B.17. Aggregate Greenhouse Gas Marginal Abatement Costs for Annex I Counties, Excluding the United States and Adjusted for Agriculture and Forestry Sinks, CDM, Kyoto Protocol Targets, and a 50-Percent Reduction Factor (reductions in million metric tons carbon equivalent)

Allowance Price (2001 dollars per metric ton carbon equivalent)	2010	2015	2020	2025
$0	0	0	0	0
$10	0	0	0	0
$15	0	0	0	0
$20	0	0	0	0
$30	13	0	0	0
$40	31	0	0	0
$50	45	3	0	0
$75	81	48	23	3
$100	115	90	71	54
$125	146	129	116	102
$150	170	158	151	138
$175	193	186	183	171
$200	217	214	216	205
$225	263	266	274	265

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, using methodology described above.

Appendix C

Potential Credits for Early Compliance: Assessment of Emissions Reported to EIA’s Voluntary Reporting of Greenhouse Gases Program

Introduction

The purpose of this appendix is to identify some of the difficulties associated with measuring historical greenhouse gas emission reductions and to provide a rough level of the magnitude of the reductions that might be claimed according to the specifications of Section 203 of S.139. Section 203 states that an entity may register greenhouse gas emission reductions achieved after 1990 but before 2010 if it has established a historical baseline. Reductions are to be calculated as changes in direct greenhouse gas emissions relative to historical emission levels after accounting for increases in indirect emissions and/or increases in net carbon sequestration. It is difficult to estimate the amount of potential credits that might be claimed under Section 203, in part because specific rules remain to be developed, and also because it will be difficult to apply and verify the rules retroactively. Careful consideration of greenhouse gas accounting issues will be required, including the operational definition of an entity, greenhouse gas estimation techniques, double reporting of emissions, emissions verification, and the establishment of emissions baselines.

This appendix examines greenhouse gas accounting issues in the context of one potential source of emission reduction credits—the Energy Information Administration (EIA) Voluntary Reporting of Greenhouse Gas Program. The analysis of potential credits for early compliance in this appendix is not part of the analytical efforts reported in the main body of this report and is presented here as a supplement to that modeling effort. EIA's 1605(b) Voluntary Reporting Program would not be the only source of potential credits under S.139. A number of other Government-sponsored voluntary programs and public/private partnerships also promote emission reductions that could qualify for early compliance credits, depending on the availability of data to verify the reductions claimed by program participants.

According to EIA's 1605(b) database, 43 of the 97 entities that have reported entity-level emissions to the program have claimed net reductions in emissions relative to their base years. The 43 reporters that showed net reductions would have generated a total of 868 million metric tons carbon dioxide equivalent in reductions over the period 1991 through 2001. This total includes annual reductions that ranged from a low of 41 million metric tons carbon dioxide equivalent in 1991 to a high of 181 million metric tons in 2001. The analysis described here assumed that emission reductions are cumulative relative to a set base year, normally 1990, so that a reduction relative to the base year that was maintained in future years would continue to be counted each and every year it is maintained (e.g., a 5 ton reduction relative to the base year maintained over 10 years would equal a 50 ton reduction). Emission reductions estimates would be reduced if implementation required emission reductions to be calculated on a year-to-year basis (i.e., total emissions relative to the previous year's emissions). Also, reductions qualifying for early compliance credits could be less than those shown here if reporters were required to establish that the reductions were beyond or "additional to" business-as-usual activities.

Voluntary Reporting of Greenhouse Gases Program: Background and Accounting Issues

Title XVI, Section 1605(b) of the Energy Policy Act of 1992 (EPACT) directed EIA to establish a mechanism for "the voluntary collection and reporting of information on . . . annual reductions of greenhouse gas emissions and carbon fixation achieved through any measures, including fuel switching, forest management practices, tree planting, use of renewable energy, manufacture or use of vehicles with reduced greenhouse gas emissions, appliance efficiency, methane recovery, cogeneration, chlorofluorocarbon capture and replacement, and power plant heat rate improvement . . . ." The legislation further instructed EIA to create forms for the reporting of greenhouse gas emissions and reductions, and to establish a database of the information voluntarily reported under this subsection of EPACT. The reporting Forms EIA-1605 and EIA-1605EZ, "Voluntary Reporting of Greenhouse Gases,"

Key Definitions from S.139 Affecting Potential Credits for Early Compliance

Baseline: The historic greenhouse gas emission level of an entity, as adjusted upward to reflect actual reductions that are verified.

Covered Entity: An entity that owns or controls a source of greenhouse gas emissions in the electric power, industrial, or commercial sector of the U.S. economy that emits over 10,000 metric tons of greenhouse gases per year.

Direct Emissions: Greenhouse gas emissions by an entity from a facility that is owned or controlled by that entity.

Indirect Emissions: Greenhouse gas emissions that are the result of the activities of an entity but are emitted from a facility owned or controlled by another entity and not reported as direct emissions by the entity from which they were emitted.

Sequestration: The capture, long-term separation, isolation, or removal of greenhouse gases from the atmosphere.

were first made available to the public in July 1995, providing a vehicle for voluntary reporting on activities that occurred before and during 1994.

EIA's Voluntary Reporting of Greenhouse Gases Program affords an opportunity for any company, organization, or individual to establish a public record of greenhouse gas emissions, reductions, or sequestration activities in a national database. In the most recent reporting cycle, a total of 228 U.S. companies and other organizations reported to the 1605(b) program that, during 2001, they had undertaken 1,705 projects to reduce or sequester greenhouse gases. Emission reductions reported for 2001 on the long form (Form EIA-1605) included 222 million metric tons carbon dioxide equivalent[221] in direct reductions, 71 million metric tons carbon dioxide equivalent in indirect reductions, and 8 million metric tons carbon dioxide equivalent in reductions from carbon sequestration activities. In addition, 15 million metric tons carbon dioxide equivalent of reductions were reported on the short form (Form EIA-1605EZ), which does not specify whether the reported reductions were direct or indirect. Since 1994, the number of entities reporting to the program has grown by 111 percent, and the number of projects reported has grown by 169 percent. Table C.1 summarizes a number of program reporting indicators over the period from 1994 to 2001.

In accordance with the guidelines developed by the U.S. Department of Energy (DOE) in 1994, the Voluntary Reporting Program allows reporters considerable flexibility in the scope and content of their reports. As a result, companies can report their emissions and reductions in several different ways. This flexibility was built into the guidelines to promote increased participation in voluntary reporting. It can be viewed as a useful attribute in evaluating the design and consequences of any proposed program of credits for early action. The 1605(b) database of real-world emission reduction actions and actors can be used to gain insight into the incentive effects and beneficiaries of various credit for early action and related proposals.

In evaluating any credit for early action approach, a number of pertinent greenhouse gas accounting issues need to be addressed, including the following: (1) what is the appropriate reporting level (entity-level reporting versus project-level reporting); (2) how should ownership issues be handled for direct versus

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[221] Greenhouse gas emissions and reductions are reported to the Voluntary Reporting Program in terms of carbon dioxide equivalent rather than carbon equivalent units, which are used in the other portions of this report. See footnote 38 in Chapter 1.

Table C.1. Reporting Indicators for the Voluntary Reporting of Greenhouse Gases Program, 1994-2001

Indicator	1994	1995	1996	1997	1998	1999	2000	2001
Entities and Projects Reported								
Number of Entities Reporting	108	142	150	162	207	207	236	228
Number of Projects Reported	634	960	1,040	1,288	1,549	1,721	2,089	1,705
Number of Entity-Level Reports Received (Organization- Wide)	40	51	56	60	76	83	109	109
Project-Level Reductions Reported (Million Metric Tons of Carbon Dioxide Equivalent)								
Direct [a]	63	88	90	95	148	155	211	222
Indirect [b]	5	52	53	38	43	57	62	71
Sequestration [c]	1	1	9	10	12	10	9	8
Unspecified [d]	4	6	6	9	19	13	12	15

[a] ”Direct” emission reductions are reductions in releases of greenhouse gases “on site.” For the purpose of completing Form EIA-1605, “on site” is defined as any source owned (wholly or in part) or leased by the reporting entity.

[b] “Indirect” emission reductions are reductions in emissions from sources not owned or leased by the reporting entity but that occur, wholly or in part, as a result of the entity’s activities (for example, an automobile manufacturer’s investment in increased automotive fuel economy can result in decreased emissions from vehicles owned by individuals or managed fleets).

[c] “Sequestration” is the fixation of atmospheric carbon dioxide in a carbon sink through biological or physical processes, such as photosynthesis.

[d] “Unspecified” emission reductions represent quantities reported on Form EIA-1605EZ for which the reporting entity did not specify whether the emission reduction was direct or indirect.

Notes: 2000 data have been revised upward to include 2000 reports that were submitted after the filing deadline. It is expected that the 2001 data will also be revised upward in next year’s report with the inclusion of late 2001 reports. Totals for direct and indirect reductions may not equal sum of components due to independent rounding.

Source: Energy Information Administration, Forms EIA-1605 and EIA-1605EZ.

indirect emissions; (3) against what baseline (historical, business-as-usual, unit of production, etc.) should reductions be calculated; and (4) how should emissions and emission reductions be verified?

S.139 specifies in its provisions on credit for early action that credits would be based on the difference between direct entity-level emissions and a historical emissions baseline, reduced by increases in indirect emissions from the entity’s baseline indirect emissions and increased by carbon sequestration activities. Because almost one-half (109) of the reporters to the Voluntary Reporting Program submit entity-wide reports, including data on indirect emissions and carbon sequestration, the 1605(b) database represents an available resource to evaluate the credit for early action provisions of S.139.

In using the 1605(b) database, two caveats in the areas of “reporting entity” and “verification” should be mentioned. In terms of “reporting entity,” Section 1605(b) mentions only “entities” and “persons” as prospective reporters. Several of the entity-level 1605(b) reports examined for this analysis involved facilities or groups of facilities within a corporation, which might not be considered entities under S.139. In terms of verification, DOE decided not to require verification by an independent third party after considering this issue during the development of the guidelines for the Voluntary Reporting Program. Rather, reporters are required to “self-certify” the accuracy of their reports. EIA reviews each report received for comprehensiveness, arithmetic accuracy, internal consistency, and plausibility and makes suggestions for improving the accuracy and clarity of reports; however, the reporter is ultimately responsible for the accuracy of any report submitted. Meaningful verification of submitted data would require putting in place common baselines and accounting standards that dictate what information should be included in reports and how estimates of greenhouse gas emissions and reductions and carbon sequestration should be calculated. A number of these accounting issues are being addressed under the

President's Climate Change Initiative, which among other things directs DOE to improve the measurement accuracy, data quality, and verfiability of data reported to the Voluntary Reporting Program, with the intent to grant transferable credits for real reductions.

The U.S. Climate Change Initiative and Enhanced Voluntary Reporting of Greenhouse Gases Program

On February 14, 2002, President George W. Bush announced the Administration's Global Climate Change Initiative, which includes new emission intensity reduction goals, incentives for clean technology development, added support for scientific research, expanded collaboration on climate change with foreign governments, and the development of a framework for the enhancement of the Voluntary Reporting of Greenhouse Gases program. Pursuant to the last objective, the Department of Energy is working to improve and expand the 1605(b) Voluntary Reporting of Greenhouse Gases Program. The primary goal is to create a credible and transparent program to report real reductions that support the national greenhouse gas intensity goal of an 18 percent improvement by 2012. In addition, the enhanced 1605(b) Program will allow businesses and individuals to record their reductions and ensure that those reporters are not penalized under a future climate policy. The objective of improving the registry and providing transferable credits for reductions is to help motivate firms to take cost-effective, voluntary actions to reduce greenhouse gas emissions.

On July 8, 2002, the Secretary of Energy, joined by the Secretary of Commerce, the Secretary of Agriculture, and the Administrator of the Environmental Protection Agency, submitted recommendations to the White House that will guide the process over the coming months to improve and expand the Voluntary Reporting Program. Specifically, the Secretaries and Administrator recommended the following improvements to the 1605(b) program:

- Develop fair, objective, and practical methods for reporting baselines, reporting boundaries, calculating real results, and awarding transferable credits for actions that lead to real reductions.
- Standardize widely accepted, transparent accounting methods.
- Support independent verification of registry reports.
- Encourage reporters to report greenhouse gas intensity (emissions per unit of output) as well as emissions or emissions reductions.
- Encourage corporate or entity-wide reporting.
- Provide credits for actions to remove carbon dioxide from the atmosphere (e.g., sequestration activities) as well as for actions to reduce emissions.
- Develop a process for evaluating the extent to which past reductions may qualify for credits.
- Assure that the Voluntary Reporting Program is an effective tool for reaching the 18 percent goal.
- Factor in international strategies as well as State-level efforts.
- Minimize transaction costs for reporters and administrative costs for the Government, where possible, without compromising the foregoing recommendations.

The recommendations highlight the need to create standardized, widely accepted, transparent accounting methods, support independent verification of registry reports, and ensure that companies that make real reductions are awarded credit under a future climate change policy.

To engage the public on these issues, DOE held four regional workshops during November and December 2002. Each workshop addressed the full range of greenhouse gas accounting issues outlined above and how they would relate to an "enhanced" Voluntary Reporting Program. Following the regional workshops, DOE started a process to develop revised guidelines that will meet the intent of the President's Climate Change Initiative. DOE intends to finalize the revised guidelines by the end of calendar year 2003, so that EIA can collect data under the new guidelines in 2004.

Accounting Issues for Voluntary Reporting and Beyond

The Voluntary Reporting Program was designed primarily to serve as a mechanism by which entities could report voluntary actions intended to reduce greenhouse gas emissions and sequester carbon.[222] EIA has the responsibility, among other things, for establishing and maintaining a database of reported greenhouse reductions that also serves as a national registry of reported reductions. While the information in the database may be used by the reporting entity to demonstrate achieved reductions of greenhouse gases, the program was not primarily designed to support credit for early reductions or emissions trading programs. The program guidelines did not attempt to resolve the issues that arise in constructing the required reporting rules that would create a set of comparable, verifiable, auditable emission and reduction reports.

The 1605(b) database provides a mechanism for identifying some of the issues that would have to be resolved in developing an accounting system for quantifying emissions, emission reductions, and sequestration. Such an accounting system may have to answer the following questions:

- Who can report?
- What is a reduction?
- Who owns the reduction?
- Would the reduction have happened anyway?
- How does one verify reports?

A. Who Can Report?

Section 1605(b) of the Energy Policy Act of 1992 mentioned only “entities” and “persons” as prospective reporters. Several overlapping concepts of “who can report” surfaced at the public hearings for the guidelines for the Voluntary Reporting Program, all of which were accommodated. These included:

- **A legal person: i.e., an individual, household, corporation, or trade association**. In this approach, emissions and reductions are calculated and reported for the entire entity.
- **A facility or group of facilities**. Emissions and reductions are calculated as those of a particular facility, defined as a single plant in a specified location, or perhaps even a single stack within a plant. A corporation or legal person acquires responsibility for emissions and reductions through ownership of one or more specified facilities.
- **A “project” or activity**. Reductions are defined by comparing the emissions from some set of sources deemed relevant with an estimate of what emissions would have been if a particular action or bundle of actions had not been undertaken.

B. What is a Reduction?

Perhaps the most intuitive definition of a reduction is one measured against an historical baseline, which represents the use of a “basic reference case.” In this approach, the reduction is defined as the difference between the emissions of an entity or facility in a prior, baseline year, usually 1990, and in the current year. This approach is best suited to reporters whose activities have not appreciably changed since the baseline year. It presents particular problems for firms that have participated in mergers, acquisitions, or divestitures, or have made significant changes in the composition of their business. Startup companies or new facilities that have no history cannot use historical baselines. The historical baseline approach is also

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[222] This discussion of accounting issues is based on testimony given by Jay Hakes, former EIA Administrator, on March 30, 2000, before the Senate Committee on Energy and Natural Resources on Senate Bills S. 882 and S. 1776 and their potential impacts on EIA’s Programs. The full text of the testimony is available on EIA’s web site at http://www.eia.doe.gov/neic/speeches/hrtest3-30-00/testimony3.htm.

not well suited to measuring the reductions achieved by projects, because projects are often entirely new activities with no history.

Alternatively, many reporters define their reductions by comparison with what would have happened in the absence of a specified set of actions. Thus, corporate emissions may have risen, but they are less than they would have been in the absence of corporate action. This approach is called, in the Voluntary Reporting Program, a “modified reference case” or a “hypothetical baseline.” It is important to point out, however, that a hypothetical baseline is a best guess of what would have happened in the absence of a project, and there is no way per se to prove or disprove it. Most of the projects reported to the Voluntary Reporting Program use a hypothetical baseline to calculate emission reductions or sequestration.

The “unit of production” approach is a variant of the fixed historical baseline, where the reporter normalizes baseline emissions to reflect changes in production. If emissions per unit of output have declined, by comparison either with levels in a prior year or with what they would have been in the absence of some actions, then the reporter has a reduction. This approach works reasonably well for organizations that have a well-defined product that is homogeneous across companies and over time: for example, kilowatt-hours generated or sold, tons of steel, or barrels of crude oil. As products increase in complexity, this approach gradually breaks down. Tons of semiconductors, for example, is a meaningless measure of output.

The alternative measures of reductions have their advantages and disadvantages. Basic reference cases are objective and relatively easily verifiable. On the other hand, absolute reductions are often the product of circumstance rather than action, while modified reference cases (which are more difficult to verify) explicitly measure the results of actions. Unit-of-production reference cases are useful only in a limited number of cases, and they can combine some of the disadvantages of both basic and modified reference cases.

C. Who Owns the Reduction?

Two theories of emissions ownership coexist in the Voluntary Reporting Program. The most intuitive, and commonplace, is called “direct emissions” and “direct reductions.” If a reporter owns or uses (e.g., leases) the emission source, that reporter owns the emission as well as any reductions from this source. The advantage of limiting ownership to direct emissions is that it generally prevents multiple ownership of the same emission or reduction. However, this approach excludes many important emission reduction methods, including all activities that tend to reduce electricity consumption, the activities of energy service companies, and the provision of energy-efficient or emission reducing capital goods.

The alternative theory of ownership is based on causation: if an organization causes an emission or reduction, it is responsible for that emission, even if it does not own the emission source. Emissions or reductions from sources not owned by the reporter are referred to as “indirect.” The most important example of an indirect emission is one produced through the consumption of electricity. If entities reduce their consumption of electricity, they cause their electricity supplier to reduce its emissions. This approach permits reporting of any action that has an influence on national emissions. However, the concept of “causing an emission” is inherently more ambiguous than “owning the smoke stack,” and in many cases more than one firm may credibly claim to have helped cause an emission reduction.

EIA requires that reporters using Form EIA-1605 explicitly identify all emissions and reductions as either direct or indirect so that potentially double-counted reductions can be identified.

D. Would the Reduction Have Happened Anyway?

This issue is often discussed in other contexts under the term “additionality.” It has been suggested that many emission reduction projects do not represent “real” reductions because they would have been undertaken “anyway” in the normal course of business. However, creating an operational definition of additionality is difficult, because the “normal course of business” is a hypothetical concept. For the purposes of voluntary reporting—which include publicizing the types of actions that limit national greenhouse gas emissions and providing recognition for the companies that undertake those actions voluntarily—determining the additionality of projects is unnecessary. For the purposes of a credit for early reduction program, however, additionality is an issue that needs to be considered.

E. How Does One Verify Reports?

In general, reports submitted to EIA are judged to be factually accurate. Meaningful verification of the accuracy of 1605(b) reporting would require putting in place common baselines and accounting standards that dictate what information should be included in 1605(b) reports and how estimates of greenhouse gas emissions and reductions and carbon sequestration should be calculated. For example, if the accounting treatment for indirect emissions from electricity purchases is undefined, then a particular set of facts about a reporter could result in two different estimates of emissions: one including electricity purchases and one excluding electricity purchases. A third-party verifier can verify the facts about the reporter but cannot determine whether or not indirect emissions from electricity purchases ought to be included and, consequently, cannot determine whether the total emissions reported are correct or not.

Other Potential Sources of Credits Under S.139

Currently, a broad array of efforts are underway to build corporate awareness about greenhouse gas mitigation and develop comprehensive methods for tracking and reporting corporate greenhouse gas inventories. Included among them are the Pew Center’s Business Environmental Leadership Council, Climate VISION, Climate Leaders, the Environmental Resources Trust (ERT) GHG Registry, the Chicago Climate Exchange, Natural Gas STAR, the Landfill Methane Outreach Program, the Coalbed Methane Outreach Program, the Voluntary Aluminum Industrial Partnership, and the Sulfur Hexafluoride (SF_6) Emissions Reduction Partnership for Electrical Systems. Further, carbon dioxide emissions are reported to the U.S. Environmental Protection Agency (EPA) by utilities required to implement Continuous Emissions Monitoring under the Clean Air Act. Finally, many firms have undertaken emission reduction targets and have achieved emission reductions on a private basis. Some of these initiatives are described below.

- **Climate VISION**, a new voluntary partnership to reduce greenhouse gas emissions launched by DOE on behalf of the Bush Administration, is a public-private partnership to pursue cost-effective initiatives that will reduce the projected growth in U.S. greenhouse gas emissions. The "VISION" in the title stands for “Voluntary Innovative Sector Initiatives: Opportunities Now.” It is administered through DOE’s Office of Policy and International Affairs. A summary of initial industry sector commitments can be found at http://www.energy.gov/HQPress/releases03/febpr/ClimateFactSheet.pdf.
- **Climate Leaders** is a voluntary EPA industry-government partnership that encourages companies to develop long-term comprehensive climate change strategies. Climate Leaders gives companies the opportunity to set corporate-wide greenhouse gas reduction goals and inventory their emissions to measure progress. By reporting inventory data to EPA, partners create a lasting record of their accomplishments. Partners also identify themselves as corporate environmental

leaders and strategically position themselves as climate change policy continues to unfold. A listing of the emission reduction goals adopted by 10 Climate Leaders partners can be found at http://www.epa.gov/climateleaders/goals.html

- The **Pew Center's Business Environmental Leadership Council** (BELC) includes 38 major companies, most in the Fortune 500, that are working together through the Center to educate the public on climate change risks, challenges, and solutions. In addition to agreeing to a Joint Statement of Principles, the corporate members of the BELC serve in an advisory role, offering suggestions and input regarding the Center's activities. The Pew Center provides a searchable database containing case studies of State and local greenhouse gas reduction initiatives at www.pewclimate.org/states/index.cfm.

- The **ERT GHG Registry** and its associated services provide support for the key infrastructure requirements needed for a robust greenhouse gas emissions reductions trading market: defining the commodity that will be exchanged (emissions units), establishing the accounting language and protocols by which market participants will measure and verify their emissions performance, and providing early actors with third-party validation of their emissions performance, including individually serialized records to provide evidence of their accomplishments. As a nonprofit organization, ERT is committed to promoting an emissions trading market that can drive ambitious greenhouse gas reductions at low cost. Summary data on emissions performance of ERT GHG Registry members is available to the public at http://www.ecoregistry.org/. Company-specific data are available only to individual members of the Registry or others they have authorized to view their data.

- The **Chicago Climate Exchange** (CCX) is a voluntary cap and trade program for reducing and trading greenhouse gas emissions. CCX will administer this pilot program for emission sources, farm and forest carbon sinks, offset projects, and liquidity providers in North America. To foster international emissions trading, offset providers in Brazil can also participate. CCX does not provide publicly accessible data on the emissions of its participants.

- The **Natural Gas STAR Program** is a voluntary partnership that encourages companies across the natural gas industry to adopt cost-effective technologies and practices that improve operational efficiency and reduce emissions of methane. Methane, the primary component of natural gas, is a potent greenhouse gas. Natural Gas STAR has three component programs, each of which works with a different sector of the industry: the transmission and distribution program; the producers program; and the gathering and processing program. According to the program's web site, Natural Gas STAR partners have eliminated more than 176 billion cubic feet of methane emissions since 1993. Because the program views the reductions reported as proprietary data, no public database is available.

- The **Landfill Methane Outreach Program** (LMOP) is a voluntary assistance and partnership program that promotes the use of landfill gas as a renewable energy source. By preventing emissions of methane through the development of landfill gas energy projects, LMOP strives to help businesses, States, and communities protect the environment and build a sustainable future. LMOP provides a database of operational, under construction, and planned landfill gas utilization projects at http://www.epa.gov/lmop/projects/lmopdata.xls.

- The **Coalbed Methane Outreach Program** (CMOP) is a voluntary program whose goal is to reduce methane emissions from coal mining activities. Its mission is to promote the profitable recovery and use of coal mine methane. By working cooperatively with coal companies and related industries, CMOP helps to identify and implement methods to use coal mine methane productively. In turn, these actions mitigate climate change, improve mine safety and productivity, and result in financial profits. Since CMOP's inception in 1994, U.S. coal mines have recovered 292 billion cubic feet of gas. The CMOP web site contains summary data on coal mine methane emissions and recovery at http://www.epa.gov/cmop/images/newchart3.gif. CMOP also maintains mine-by-mine data that are not publicly available; however, a large portion of the data (methane emissions from ventilation systems) can be obtained from the Mine Safety and Health Administration.

$ The **Voluntary Aluminum Industrial Partnership** (VAIP) is an innovative prevention program developed jointly by the EPA and the primary aluminum industry. Participating companies work with EPA to improve aluminum production efficiency while reducing emissions of perfluorocarbons, which are potent greenhouse gases that may remain in the atmosphere for thousands of years. According to EPA, between 1990 and 1998, VAIP partners representing 94 percent of U.S. aluminum production capacity reduced perfluorocarbon emissions by 44 percent. There is no readily apparent public database of the partners' emissions improvements.

$ The **SF_6 Emissions Reduction Partnership for Electric Power Systems** works with the electric power industry to pursue technically and economically feasible actions aimed at minimizing SF_6 emissions and reducing the threat of global climate change. SF_6 is a gaseous dielectric used by the electric power industry in circuit breakers, gas-insulated substations, and switchgear. It is a highly potent greenhouse gas. Over a 100-year period, SF_6 is 23,900 times more effective at trapping infrared radiation than an equivalent amount of carbon dioxide. SF_6 is also a very stable chemical, with an atmospheric lifetime of 3,200 years. Thus, a relatively small amount can have an important impact on global climate change. Estimated emission reductions associated with this program can be found in its annual report at http://www.epa.gov/highgwp1/sf6/pdf/eps_program_report_2002.pdf.

Approach and General Trends

In order to produce an estimate of potential credits for early compliance under S.139, EIA examined the emissions and sequestration data reported on Form EIA-1605[223] in light of the requirements contained in S.139 for calculating emission reductions. Section 203 of the bill explicitly focuses on entity-wide reductions and states that the reductions must be calculated by comparing annual emission levels to a historical emission level. Thus, EIA reviewed emissions data reported on an entity-wide basis back to 1990.[224] Because the 1605(b) database is not economy-wide it does not include all the firms that would be eligible for early compliance credits (see box below).

During the 2001 1605(b) reporting cycle, 97 entities reported direct emissions, indirect emissions, and/or achieved carbon sequestration at the entity level (41 electric power producers and 56 entities representing other sectors).[225] Forty-five of the 97 entities reported data for 1990 and were, for the purpose of this analysis, assigned 1990 as the baseline year for comparing annual emission levels (Table C.2). The remaining 52 firms that reported initial data for a year subsequent to 1990 were assigned their first year's emissions levels as a baseline.[226] This appears consistent with Section 203(C)(2)(B)(ii) of S.139, which

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[223] For a detailed description of reported reductions, see Energy Information Administration, *Voluntary Reporting of Greenhouse Gases 2001*, DOE/EIA-0608(2001) (Washington, DC, February 2003), web site www.eia.doe.gov/oiaf/1605/vrrpt/index.html.

[224] Because 1990 was a recession year, it may not be indicative of the success or failure of a reporting firm's action.

[225] Only data submitted during the most recent reporting cycle (2001) were examined. In most cases, reporters submit data on all previous years during each subsequent reporting cycle. As a result, earlier estimates of emissions are often superseded by an entity's most recent report. However, because some entities did not report during the 2001 reporting cycle after having reported during earlier cycles, their emissions and reductions were not captured in this analysis.

[226] Two firms that reported emissions data only for 2001 were excluded from this analysis, because no changes from a previous year's baseline could be ascertained.

seems to apply to entity-wide reductions achieved relative to the year preceding the first year data are submitted.

Emission levels for the 45 entities assigned a 1990 baseline rose by an aggregate 242 million metric tons carbon dioxide equivalent between 1991 and 2001. However, the results show a discernible trend over time. Until 1996, emissions were nearly unchanged or below 1990 levels. For example, 1992 emission levels were 39 million metric tons carbon dioxide equivalent lower than 1990 levels. Emissions then increased to levels well above 1990 levels, peaking at 96 million metric tons carbon dioxide equivalent above 1990 levels in 1998. In 2001, emissions were once again 26 million metric tons carbon dioxide equivalent below 1990 levels. This trend correlates with economic growth trends and general national emission trends. Emissions growth was centered in the electric power sector. The 14 firms that reported 1990 data and were not electric power producers showed an aggregate decline of 224 million metric tons carbon dioxide equivalent from 1990 levels and were below 1990 emission levels for all years from 1991 through 2001.

Table C.2. Entities Reporting to the Voluntary Reporting Program, 2001

Entity-Type	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Total Number of Entities Reporting Changes in Entity-Level Emissions in 2001											
Against 1990 Baseline											
Electric Power	27	27	28	29	30	31	32	31	32	31	31
Other Sectors	9	10	11	11	11	11	12	13	14	14	14
Subtotal	*36*	*37*	*39*	*40*	*41*	*42*	*44*	*44*	*46*	*45*	*45*
Against Post-1990 Baseline											
Electric Power	0	5	6	6	7	7	8	8	7	9	10
Other Sectors	0	7	7	7	8	12	15	18	22	29	42
Subtotal	*0*	*12*	*13*	*13*	*15*	*19*	*23*	*26*	*29*	*38*	*52*
Total	**38**	**49**	**52**	**53**	**56**	**61**	**67**	**70**	**75**	**83**	**97**
Number of Entities Showing Increases in Net Emissions											
Against 1990 Baseline											
Electric Power	8	11	16	19	19	18	20	20	23	22	22
Other Sectors	2	3	6	4	3	4	4	4	4	4	4
Subtotal	*10*	*14*	*22*	*23*	*22*	*22*	*24*	*24*	*27*	*26*	*26*
Against Post-1990 Baseline											
Electric Power	0	1	1	3	3	3	3	3	4	6	4
Other Sectors	0	5	5	4	6	9	13	10	14	19	24
Subtotal	*0*	*6*	*6*	*7*	*9*	*12*	*16*	*13*	*18*	*25*	*28*
Total	**10**	**20**	**28**	**30**	**31**	**34**	**40**	**37**	**45**	**51**	**54**
Number of Entities Showing Decreases in Net Emissions											
Against 1990 Baseline											
Electric Power	19	16	12	10	11	13	12	11	9	9	9
Other Sectors	7	7	5	7	8	7	8	9	10	10	10
Subtotal	*26*	*23*	*17*	*17*	*19*	*20*	*20*	*20*	*19*	*19*	*19*
Against Post-1990 Baseline											
Electric Power	2	4	5	3	4	4	5	5	3	3	6
Other Sectors	0	2	2	3	2	3	2	8	8	10	18
Subtotal	*2*	*6*	*7*	*6*	*6*	*7*	*7*	*13*	*11*	*13*	*24*
Total	**28**	**29**	**24**	**23**	**25**	**27**	**27**	**33**	**30**	**32**	**43**

Source: Energy Information Administration, Voluntary Reporting of Greenhouse Gases Public Use Database (May 2003), Form EIA-1605.

The 52 firms that reported initial data for a year subsequent to 1990 showed similar results against their assigned baselines. The 10 electric power producers showed an aggregate increase of 51 million metric tons carbon dioxide equivalent against their baseline emission levels between 1992 and 2001, and other entities showed an aggregate decrease of 15 million metric tons carbon dioxide equivalent against their baseline emission levels between 1992 and 2001.

Entities Potentially Eligible for Early Compliance Credits Under S.139

Entities covered under S.139 include those that own or control a source of greenhouse gas emissions in the electric power, industrial, or commercial sectors that emits over 10,000 metric tons carbon dioxide equivalent per year. Additionally, an entity that imports or produces petroleum products for use in transportation that will emit more than 10,000 metric tons carbon dioxide equivalent is also covered. Determining the number of entities that would be eligible for early credits under S.139 is not a straightforward matter. An earlier analysis has estimated the number of facilities that produce more than 10,000 metric tons of greenhouse gases per year,[227] but it was conducted on a facility level. Allocating facilities to corporate entities is not a simple undertaking. Further, only those entities achieving reductions in direct emissions or increases in sequestration relative to a historical level after accounting for increases in indirect emissions would be eligible. Absent a comprehensive national reporting system, it is impossible to determine the full inventory of entities that have achieved or will be able to achieve such reductions against their baselines.

Based on existing data some broad suppositions can be made about potential entities covered under the early credit provisions of S.139 on a sector-by-sector basis, as follows:

- *Electric Power*. There are approximately 3,100 electric utilities and 2,100 nonutility power producers in the United States. The 100 largest owners of electricity generation capacity in the United States collectively own more than 1,900 power plants, which produce about 90 percent of carbon dioxide emissions in the power generation sector.[228] A total of 4,636 facilities report carbon dioxide emissions under the Clean Air Act Amendments of 1990. Of that total, 1,633 report more than 10,000 metric tons of annual emissions. In the aggregate, those 1,633 facilities represent 99.9 percent of all carbon dioxide emissions from power plants.[229] Thus, it can be assumed that nearly all entities from the electric power sector covered by S.139 would be among the 100 largest owners.
- *Petroleum Refining*. Petroleum refiners produce petroleum products for use in transportation that will emit more than 10,000 metric tons of greenhouse gases when combusted. There are 153 petroleum refineries in the United States, of which 144 are operating. There are 44 entities that own more than 10,000 barrels of daily capacity within these refineries.[230] This would imply that up to 44 entities would be covered by the reporting requirements of S.139 and potentially eligible for credit for early compliance. Output at U.S. refineries has increased steadily over the last 15 years, despite a 25 percent decline in the total number of refineries. Early reductions would be difficult to achieve if that trend continues. Further, nearly all the large refiners are part of large integrated oil companies that maintain a much broader emissions portfolio.

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[227] Tristam O. West and Naomi Pena, “Determining Thresholds for Mandatory Reporting of Greenhouse Gas Emissions,” *Environmental Science and Technology*, Vol. 37, No. 6 (2003), pp. 1057-1060.

[228] Natural Resources Defense Council, *Benchmarking Air Emissions of the 100 Largest Electric Generation Owners in the U.S.* (2000).

[229] Tristam O. West and Naomi Pena, “Determining Thresholds for Mandatory Reporting of Greenhouse Gas Emissions,” *Environmental Science and Technology*, Vol. 37, No. 6 (2003), pp. 1057-1060.

[230] Energy Information Administration, *Petroleum Supply Annual 2002, Volume 1*, DOE/EIA-0340(02)/1 (Washington, DC, June 2003), Table 40.

Entities Potentially Eligible for Early Compliance Credits Under S.139 (continued)

- *Manufacturing*. It has been estimated that some 7,777 manufacturing facilities have carbon dioxide equivalent emissions in excess of 10,000 metric tons annually.[231] It is impossible to allocate these emissions to a specific number of entities without data on emissions and facility ownership in the manufacturing sector.

- *Commercial*. It is unlikely that commercial buildings will surpass the 10,000 metric ton threshold limit. Some commercial buildings, however, could be captured in the entity-level inventories of manufacturers, petroleum refiners, or electric power producers that have significant point sources of emissions. It is difficult to determine the level of participation by large-scale commercial entities with many buildings or retail outlets.

Quantification of Reductions from Early Compliance

Because S.139 specifically offers the opportunity to register emission reductions achieved after 1990, the remainder of this appendix focuses only on those entities showing net emission reductions against their assigned baseline years, in accordance with the guidelines outlined in S.139. After comparing annual reported emissions data to a 1990 baseline, or the first year of data reported by a participant in the 1605(b) program, EIA generated tables of annual changes in greenhouse gas emissions relative to the base year by reporting entity (Tables C.3 and C.4).

For the purposes of S.139, and as outlined in Tables C.3 and C.4, “changes in greenhouse gas emissions” are equal to the sum of: (1) changes in direct emissions; (2) carbon sequestration (recorded as a negative number because sequestration denotes an activity where carbon is taken from the atmosphere and sequestered in a carbon sink); and (3) increases in indirect emissions (set to zero if indirect emissions are not increasing). All the data shown in Tables C.3 and C.4 are evaluated relative to the base year. Positive numbers denote emissions increases, and negative numbers denote emissions reductions.

Magnitude of Emission Reductions

Forty-three of the 97 entities reporting direct emissions, indirect emissions, or sequestration at the entity level showed net reductions in emissions relative to the base year after adding in increases in carbon sequestration and any increases in indirect emissions. The 43 reporters that showed net reductions of direct emissions after accounting for increases in net sequestration and increases in indirect emissions would have generated a total of 868 million metric tons carbon dioxide equivalent in reductions over the period 1991 through 2001 (Table C.4). This total includes annual reductions that ranged from a low of 41 million metric tons carbon dioxide equivalent in 1991 to a high of 181 million metric tons in 2001.[232] Of the 868 million metric tons carbon dioxide equivalent reduced over the 11-year period, 58 million metric tons (6.7 percent) is attributable to increases in sequestration. Overall reductions in direct emissions

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[231] Tristam O. West and Naomi Pena, “Determining Thresholds for Mandatory Reporting of Greenhouse Gas Emissions,” *Environmental Science and Technology*, Vol. 37, No. 6 (2003), pp. 1057-1060.

[232] The large increase in 2001 totals, roughly 90 million metric tons carbon dioxide equivalent higher than the next highest year (1996), is attributable to a large decrease in emissions from Southern Company (explained later in this appendix).

Table C.3. Reported Changes in Emissions Relative to 1990 Levels (million metric tons carbon dioxide equivalent)

Reduction Category	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Totals
Sum (Net) of All Changes in Emissions Reported by 2001 Entity-Level Reporters[a]												
Electric Power Providers												
Change in Direct Emissions	-29.79	-40.21	-5.06	-3.35	-1.99	2.54	43.68	87.36	82.98	88.01	-25.62	**198.57**
Sequestration	-0.55	-0.08	-0.31	-0.41	-1.14	-1.15	-1.99	-2.21	-2.23	-1.63	-1.74	**-13.44**
Subtotal	*-30.34*	*-40.29*	*-5.36*	*-3.76*	*-3.12*	*1.39*	*41.69*	*85.15*	*80.75*	*86.38*	*-27.36*	***185.13***
Increases in Indirect Emissions	4.00	4.39	10.78	12.26	16.28	27.19	57.19	36.44	35.76	40.60	36.02	**280.91**
Net Total Change—Electric Power Sector	**-26.34**	**-35.90**	**5.41**	**8.50**	**13.15**	**28.58**	**98.88**	**121.59**	**116.52**	**126.99**	**8.66**	**466.04**
Reporters from Other Sectors												
Change in Direct Emissions	-3.72	-3.03	-6.98	-20.50	-19.87	-23.21	-24.84	-25.89	-31.63	-32.94	-35.76	**-228.36**
Sequestration	*	*	*	*	*	*	*	*	*	*	*	**-0.02**
Subtotal	*-3.72*	*-3.03*	*-6.98*	*-20.50*	*-19.87*	*-23.21*	*-24.84*	*-25.89*	*-31.63*	*-32.95*	*-35.76*	***-228.38***
Increases in Indirect Emissions	0.06	0.04	0.03	2.00	0.09	0.26	0.31	0.15	0.16	0.33	0.72	**4.16**
Net Total Change—Other Sectors	**-3.66**	**-2.99**	**-6.95**	**-18.50**	**-19.78**	**-22.95**	**-24.52**	**-25.74**	**-31.47**	**-32.61**	**-35.04**	**-224.22**
Reporters from All Sectors												
Change in Direct Emissions	-33.51	-43.24	-12.04	-23.85	-21.86	-20.66	18.85	61.47	51.35	55.07	-61.38	**-29.79**
Sequestration	-0.55	-0.08	-0.31	-0.41	-1.14	-1.15	-1.99	-2.21	-2.23	-1.63	-1.74	**-13.46**
Subtotal	*-34.06*	*-43.32*	*-12.35*	*-24.26*	*-22.99*	*-21.81*	*16.86*	*59.26*	*49.13*	*53.44*	*-63.12*	***-43.25***
Increases in Indirect Emissions	4.06	4.42	10.81	14.26	16.37	27.45	57.50	36.58	35.93	40.94	36.74	**285.07**
Net Total Change—All Sectors	**-30.00**	**-38.90**	**-1.54**	**-10.00**	**-6.62**	**5.64**	**74.36**	**95.85**	**85.05**	**94.37**	**-26.38**	**241.82**
Changes in Emissions Reported by Entities with Increases in Net Emissions Relative to 1990 Levels												
Electric Power Providers												
Change in Direct Emissions	7.56	10.87	37.67	45.34	54.19	63.20	94.19	116.38	109.21	127.43	113.18	**779.22**
Sequestration	*	1.53	-0.01	0.00	-0.55	-0.58	-1.41	-1.52	-1.64	-1.20	-1.15	**-6.53**
Subtotal	*7.56*	*12.40*	*37.66*	*45.34*	*53.65*	*62.61*	*92.78*	*114.86*	*107.57*	*126.22*	*112.03*	***772.68***
Increases in Indirect Emissions	2.44	1.64	6.86	8.84	11.47	22.21	52.47	36.27	33.26	37.97	32.47	**245.89**
Net Total Change—Electric Power Sector	**10.00**	**12.44**	**44.34**	**54.15**	**65.08**	**84.80**	**145.22**	**151.10**	**140.79**	**164.16**	**144.50**	**1,016.58**
Reporters from Other Sectors												
Change in Direct Emissions	0.82	1.33	1.43	1.21	1.53	1.74	1.63	1.63	2.42	3.33	3.29	**20.38**
Sequestration	*	*	*	*	*	*	*	*	*	*	*	*****
Subtotal	*0.82*	*1.33*	*1.43*	*1.21*	*1.53*	*1.74*	*1.63*	*1.64*	*2.42*	*3.33*	*3.29*	***20.38***
Increases in Indirect Emissions	0.00	0.04	0.01	1.93	0.01	0.01	0.01	0.01	0.01	0.02	0.02	**2.06**
Net Total Change—Other Sectors	**0.82**	**1.37**	**1.44**	**3.15**	**1.54**	**1.75**	**1.64**	**1.65**	**2.43**	**3.35**	**3.30**	**22.44**
Reporters from All Sectors												
Change in Direct Emissions	8.37	12.20	39.11	46.55	55.72	64.94	95.83	118.01	111.63	130.76	116.46	**799.59**
Sequestration	*	1.53	-0.01	0.00	-0.55	-0.58	-1.41	-1.52	-1.64	-1.20	-1.15	**-6.53**
Subtotal	*8.37*	*13.73*	*39.10*	*46.55*	*55.18*	*64.35*	*94.42*	*116.50*	*109.99*	*129.56*	*115.32*	***793.06***
Increases in Indirect Emissions	2.44	1.68	6.86	10.78	11.47	22.22	52.48	36.28	33.27	37.99	32.48	**247.95**
Net Total Change—All Sectors	**10.82**	**13.81**	**45.78**	**57.30**	**66.63**	**86.55**	**146.86**	**152.74**	**143.23**	**167.51**	**147.80**	**1,039.02**

Table C.3. Reported Changes in Emissions Relative to 1990 Levels (continued)

Reduction Category	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Totals
Changes in Emissions Reported by Entities with Decreases in Net Emissions Relative to 1990 Levels												
Electric Power Providers												
Change in Direct Emissions	-37.34	-51.08	-42.73	-48.69	-56.18	-60.65	-50.51	-29.02	-26.23	-39.41	-138.80	**-580.65**
Sequestration	-0.55	-1.61	-0.30	-0.40	-0.59	-0.57	-0.58	-0.69	-0.59	-0.43	-0.60	**-6.90**
Subtotal	*-37.90*	*-52.69*	*-43.03*	*-49.10*	*-56.77*	*-61.22*	*-51.09*	*-29.71*	*-26.82*	*-39.84*	*-139.39*	***-587.55***
Increases in Indirect Emissions	1.56	2.75	3.92	3.41	4.81	4.98	4.72	0.17	2.51	2.63	3.56	**35.02**
Net Total Change—Electric Power Sector	**-36.33**	**-48.34**	**-38.93**	**-45.66**	**-51.93**	**-56.22**	**-46.33**	**-29.51**	**-24.28**	**-37.18**	**-135.84**	**-550.54**
Reporters from Other Sectors												
Change in Direct Emissions	-4.54	-4.36	-8.42	-21.71	-21.41	-24.95	-26.47	-27.52	-34.05	-36.28	-39.04	**-248.74**
Sequestration	*	*	*	*	*	*	*	*	*	*	*	**-0.02**
Subtotal	*-4.54*	*-4.36*	*-8.42*	*-21.71*	*-21.41*	*-24.95*	*-26.47*	*-27.52*	*-34.05*	*-36.28*	*-39.05*	***-248.76***
Increases in Indirect Emissions	0.06	0.00	0.03	0.07	0.09	0.25	0.30	0.14	0.15	0.32	0.71	**2.10**
Net Total Change—Other Sectors	**-4.48**	**-4.36**	**-8.39**	**-21.64**	**-21.32**	**-24.70**	**-26.17**	**-27.39**	**-33.90**	**-35.96**	**-38.34**	**-246.65**
Reporters from All Sectors												
Change in Direct Emissions	-41.88	-55.45	-51.15	-70.40	-77.58	-85.60	-76.98	-56.54	-60.27	-75.69	-177.84	**-829.39**
Sequestration	-0.55	-1.61	-0.30	-0.40	-0.59	-0.57	-0.58	-0.70	-0.59	-0.43	-0.60	**-6.92**
Subtotal	*-42.44*	*-57.05*	*-51.45*	*-70.81*	*-78.17*	*-86.17*	*-77.56*	*-57.23*	*-60.87*	*-76.12*	*-178.44*	***-836.31***
Increases in Indirect Emissions	1.62	2.75	3.95	3.48	4.90	5.23	5.03	0.31	2.65	2.95	4.26	**37.12**
Net Total Change—All Sectors	**-40.81**	**-52.71**	**-47.32**	**-67.30**	**-73.25**	**-80.91**	**-72.50**	**-56.90**	**-58.18**	**-73.14**	**-174.18**	**-797.20**

[a] Positive values indicate increases in emission; negative values indicate sequestration or decreases in emissions.

*Less than 0.005 million metric tons carbon dioxide equivalent.

Source: Energy Information Administration, Voluntary Reporting of Greenhouse Gases Public Use Database (May 2003), Form EIA-1605.

Table C.4. Reported Changes in Emissions Relative to “First Year Reported” Levels (million metric tons carbon dioxide equivalent)

Reduction Category	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Totals
Sum (Net) of All Changes in Emissions Reported by 2001 Entity-Level Reporters[a]												
Electric Power Providers												
Change in Direct Emissions	-29.79	-40.76	-3.48	-0.52	4.31	9.91	51.89	106.18	100.31	109.19	-16.98	**290.27**
Sequestration	-0.55	-1.64	-6.02	-6.12	-6.85	-6.86	-7.70	-7.93	-7.94	-7.34	-7.46	**-66.41**
Subtotal	*-30.34*	*-42.40*	*-9.49*	*-6.63*	*-2.54*	*3.05*	*44.19*	*98.26*	*92.37*	*101.84*	*-24.43*	***223.86***
Increases in Indirect Emissions	4.00	4.39	11.39	13.07	17.54	28.48	58.53	38.23	37.50	41.99	37.63	**292.75**
Net Total Change—Electric Power Sector	**-26.34**	**-38.01**	**1.89**	**6.44**	**15.00**	**31.53**	**102.71**	**136.49**	**129.87**	**143.83**	**13.20**	**516.61**
Reporters from Other Sectors												
Change in Direct Emissions	-3.72	-2.83	-6.72	-20.95	-19.38	-26.26	-35.73	-35.33	-26.29	-31.72	-37.77	**-246.71**
Sequestration	*	*	*	*	*	*	*	*	*	*	*	**-0.02**
Subtotal	*-3.72*	*-2.83*	*-6.72*	*-20.95*	*-19.38*	*-26.27*	*-35.73*	*-35.33*	*-26.30*	*-31.72*	*-37.77*	***-246.73***
Increases in Indirect Emissions	0.06	0.07	0.07	2.04	0.14	0.54	0.62	0.54	0.73	1.08	1.13	**7.02**
Net Total Change—Other Sectors	**-3.66**	**-2.77**	**-6.65**	**-18.91**	**-19.25**	**-25.73**	**-35.11**	**-34.79**	**-25.56**	**-30.64**	**-36.64**	**-239.71**
Reporters from All Sectors												
Change in Direct Emissions	-33.51	-43.60	-10.19	-21.47	-15.08	-16.35	16.16	70.85	74.01	77.47	-54.74	**43.56**
Sequestration	-0.55	-1.64	-6.02	-6.12	-6.85	-6.86	-7.70	-7.93	-7.94	-7.34	-7.46	**-66.43**
Subtotal	*-34.06*	*-45.23*	*-16.21*	*-27.59*	*-21.92*	*-23.22*	*8.46*	*62.93*	*66.07*	*70.13*	*-62.20*	***-22.87***
Increases in Indirect Emissions	4.06	4.45	11.46	15.11	17.68	29.02	59.14	38.78	38.24	43.07	38.76	**299.78**
Net Total Change—All Sectors	**-30.00**	**-40.78**	**-4.75**	**-12.47**	**-4.25**	**5.80**	**67.60**	**101.70**	**104.31**	**113.19**	**-23.44**	**276.91**
Changes in Emissions Reported by Entities with Increases in Net Emissions Relative to First Year Levels												
Electric Power Providers												
Change in Direct Emissions	7.56	10.96	38.25	46.97	59.13	69.57	101.32	133.85	123.75	147.57	120.98	**859.90**
Sequestration	*	0.00	-0.01	-0.03	-0.58	-0.62	-1.45	-1.55	-1.67	-1.24	-1.15	**-8.29**
Subtotal	*7.56*	*10.96*	*38.23*	*46.94*	*58.55*	*68.95*	*99.88*	*132.29*	*122.08*	*146.34*	*119.83*	***851.60***
Increases in Indirect Emissions	2.44	1.64	6.86	8.84	11.47	22.22	52.48	36.27	34.69	37.98	32.79	**247.68**
Net Total Change—Electric Power Sector	**10.00**	**12.53**	**45.09**	**55.74**	**69.99**	**91.14**	**152.32**	**168.54**	**156.74**	**184.28**	**152.62**	**1,098.99**
Reporters from Other Sectors												
Change in Direct Emissions	0.82	1.66	2.02	1.91	2.21	3.82	3.60	3.61	8.72	7.80	4.57	**40.71**
Sequestration	*	*	*	*	*	*	*	*	*	*	*	*****
Subtotal	*0.82*	*1.66*	*2.02*	*1.91*	*2.21*	*3.82*	*3.60*	*3.61*	*8.72*	*7.78*	*4.57*	***40.69***
Increases in Indirect Emissions	0.00	0.07	0.04	1.97	0.05	0.27	0.31	0.37	0.56	0.72	0.41	**4.77**
Net Total Change—Other Sectors	**0.82**	**1.72**	**2.06**	**3.88**	**2.25**	**4.09**	**3.91**	**4.01**	**9.31**	**8.54**	**4.98**	**45.59**
Reporters from All Sectors												
Change in Direct Emissions	8.37	12.62	40.26	48.88	61.33	73.38	104.92	137.45	132.47	155.37	125.54	**900.61**
Sequestration	*	0.00	-0.01	-0.03	-0.58	-0.62	-1.45	-1.55	-1.67	-1.24	-1.15	**-8.29**
Subtotal	*8.37*	*12.62*	*40.25*	*48.85*	*60.76*	*72.77*	*103.48*	*135.90*	*130.80*	*154.12*	*124.39*	***892.29***
Increases in Indirect Emissions	2.44	1.71	6.90	10.82	11.51	22.49	52.78	36.64	35.25	38.70	33.20	**252.45**
Net Total Change—All Sectors	**10.82**	**14.25**	**47.15**	**59.63**	**72.24**	**95.23**	**156.24**	**172.55**	**166.04**	**192.82**	**157.60**	**1,144.58**

Table C.4. Reported Changes in Emissions Relative to “First Year Reported” Levels (continued)

Reduction Category	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Totals
Changes in Emissions Reported by Entities with Decreases in Net Emissions Relative to First Year Levels												
Electric Power Providers												
Change in Direct Emissions	-37.34	-51.72	-41.72	-47.49	-54.82	-59.66	-49.43	-27.66	-23.44	-38.38	-137.95	**-569.63**
Sequestration	-0.55	-1.63	-6.01	-6.08	-6.27	-6.25	-6.26	-6.37	-6.27	-6.11	-6.31	**-58.11**
Subtotal	*-37.90*	*-53.36*	*-47.73*	*-53.57*	*-61.09*	*-65.90*	*-55.69*	*-34.04*	*-29.71*	*-44.49*	*-144.26*	***-627.74***
Increases in Indirect Emissions	1.56	2.75	4.53	4.23	6.07	6.26	6.05	1.96	2.81	4.01	4.84	**45.08**
Net Total Change—Electric Power Sector	**-36.34**	**-50.54**	**-43.20**	**-49.31**	**-54.99**	**-59.61**	**-49.61**	**-32.05**	**-26.87**	**-40.45**	**-139.42**	**-582.38**
Reporters from Other Sectors												
Change in Direct Emissions	-4.54	-4.49	-8.73	-22.86	-21.59	-30.08	-39.33	-38.94	-35.01	-39.51	-42.33	**-287.42**
Sequestration	*	*	*	*	*	*	*	*	*	*	*	**-0.02**
Subtotal	*-4.54*	*-4.49*	*-8.73*	*-22.86*	*-21.59*	*-30.08*	*-39.33*	*-38.94*	*-35.02*	*-39.51*	*-42.34*	***-287.42***
Increases in Indirect Emissions	0.06	0.00	0.03	0.07	0.09	0.27	0.31	0.17	0.18	0.36	0.72	**2.26**
Net Total Change—Other Sectors	**-4.48**	**-4.49**	**-8.71**	**-22.80**	**-21.50**	**-29.82**	**-39.02**	**-38.80**	**-34.87**	**-39.18**	**-41.62**	**-285.29**
Reporters from All Sectors												
Change in Direct Emissions	-41.88	-56.21	-50.46	-70.35	-76.41	-89.74	-88.76	-66.60	-58.46	-77.90	-180.29	**-857.05**
Sequestration	-0.55	-1.63	-6.01	-6.08	-6.27	-6.25	-6.26	-6.38	-6.27	-6.11	-6.31	**-58.13**
Subtotal	*-42.44*	*-57.85*	*-56.46*	*-76.43*	*-82.68*	*-95.99*	*-95.02*	*-72.97*	*-64.73*	*-83.99*	*-186.59*	***-915.16***
Increases in Indirect Emissions	1.62	2.75	4.56	4.30	6.16	6.53	6.36	2.13	2.99	4.38	5.56	**47.33**
Net Total Change—All Sectors	**-40.81**	**-55.03**	**-51.90**	**-72.10**	**-76.49**	**-89.43**	**-88.64**	**-70.85**	**-61.74**	**-79.63**	**-181.04**	**-867.67**

[a] Positive values indicate increases in emission; negative values indicate sequestration or decreases in emissions.

[b] First Year Reported is defined as 1990 or the first post-1990 year for which emissions data were reported.

*Less than 0.005 million metric tons carbon dioxide equivalent.

Source: Energy Information Administration, Voluntary Reporting of Greenhouse Gases Public Use Database (May 2003), Form EIA-1605.

would have been 44 million metric tons carbon dioxide equivalent (5.3 percent) higher if they had not been offset by increases in indirect emissions.

Of the 43 reporters showing net emission reductions in one or more years between 1991 and 2001, 19 showed emissions data for a 1990 base year and 24 used a subsequent year as their initial base year. Nine of the 15 electric power producers showing net decreases in emissions provided data for a 1990 base year (Table C.2). A preponderance of reductions (797 million metric tons carbon dioxide equivalent or 91.9 percent) was generated against a 1990 base year, with 70 million metric tons carbon dioxide equivalent (8.1 percent) generated against a subsequent baseline year (Tables C.3 and C.4). Of that 70 million metric tons carbon dioxide equivalent, 39 million metric tons was attributable to 18 entities from industries other than electric power production.

Distribution of Emission Reductions

Electric power producers represented 67 percent of the 868 million metric tons carbon dioxide equivalent in reductions generated from 1991 through 2001. This share did not remain consistent over time however. In 1994, 1995, and 1996, electric power producers showed 68, 72, and 67 percent of all reductions, respectively, as compared with only 45, 44, and 51 percent of reductions in 1998, 1999, and 2000.[233] While reductions from other sectors grew between 1996 and 2000, reductions from the electricity sector declined (Table C.4). This was partially a reporting-related phenomenon, in that 17 of 28 reporters showing reductions outside the electric power sector had a base year of 1996 or later, while all but 6 electric power producers used a 1990 baseline.

Together, 7 entities generated 74 percent of all emission reductions from 1991 through 2001. The largest was FirstEnergy Corporation of Akron, Ohio, with 187 million metric tons carbon dioxide equivalent in reductions, or 21.6 percent of all reductions generated between 1991 and 2001. FirstEnergy's share of overall reductions ranged from 10.3 percent in 1998 to 51.1 percent in 1991.[234] Next, Consol Coal Company showed 121 million metric tons carbon dioxide equivalent in reductions, or 14.0 percent of the overall total. Consol's share of overall reductions ranged from a high of 27.9 percent in 1999 to a low of 10.4 percent in 2001. Consol did not report emissions for 1991 through 1993. Together, 5 other entities—Southern Company (12.3), Jim Walters Resources (8.6 percent), Niagara Mohawk (6.7 percent), KeySpan (5.6 percent), and the AES companies (5.2 percent)—were responsible for an additional 38.2 percent of total reductions.

Characterization of Emission Reductions

Because a small group of entities represents a large share of total emission reductions that could be registered under S.139, the nature of those entities and their emission reductions are described below. The discussion below also highlights a number of accounting issues germane to greenhouse gas accounting in a flexible system such as the Voluntary Reporting Program.

FirstEnergy. The seven electric utility operating companies held by FirstEnergy[235] have a combined generating capacity of 13,000 megawatts and serve 4.3 million customers across Ohio, Pennsylvania, and New Jersey. FirstEnergy also holds interest in 7,700 oil and gas wells and owns some 5,000 miles of gas pipeline. FirstEnergy reported direct emissions from eight power plants owned by Ohio Edison and its

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[233] This share jumps to 77 percent in 2001 if the very large reductions accruing to Southern Company in that year are included.

[234] FirstEnergy's share of total annual reductions was 7.9 percent in 2001, due in part to the very large reductions accruing to Southern Company.

[235] Ohio Edison, Cleveland Electric Illuminating Company, Toledo Edison, Pennsylvania Power, Pennsylvania Electric, Metropolitan Edison, and Jersey Central Power & Light.

subsidiary Penn Power, as well as fossil plants owned by the Cleveland Electric Illuminating Company and Toledo Edison. FirstEnergy's direct stationary combustion emissions peaked at 51.2 million metric tons carbon dioxide equivalent in 1990 and have been lower in every subsequent year by as much as 22.2 million metric tons carbon dioxide equivalent, or 43.4 percent (reported for 1995). FirstEnergy has embarked on a comprehensive emissions mitigation program that has included heat rate improvements, fuel switching, transmission and distribution improvements, and a host of demand-side management measures. Capacity improvements at three nuclear generating facilities (Perry, Davis-Besse, and Beaver Valley) are likely to have had the biggest effects on overall emission levels. Other large emission changes may be attributable to the evolving nature of the holding company's assets, which cannot be traced using the existing data.

CONSOL Coal Group. CONSOL Coal Group has 22 coal mining complexes in the United States, 20 of which are underground mines. CONSOL reports direct emissions of methane associated with mine ventilation systems, degasification wells, inactive mines, and post-mining sources. CONSOL reduced its emissions significantly through alterations in mining techniques, the capture and sale of methane from degasification wells, and the internal use of coalbed methane as a fuel. Post-1993 emissions data are increased for the acquisition of Island Creek Coal Company in 1993, Rochester and Pittsburgh Coal in 1998, and AEP's mining operations in mid-2001. If the baseline were restated, emission reductions would increase accordingly. Because the emissions reduced are methane, the benefit in carbon dioxide equivalent is 23 times that of carbon dioxide reductions (due to the greater heat trapping capacity of methane).

Southern Company. As the owner of five electric utilities in the Southeast, Southern Company operates over 36,000 megawatts of capacity. It has more than 26,000 employees and generated $1.3 billion in net income for 2002. Ninety-one percent (97 million metric tons carbon dioxide equivalent) of Southern Company's reductions from its 1990 baseline accrued in 2001. This large single-year change in emission rates does not appear to represent an "actual" change in emissions as envisaged under S.139 but rather the exclusion of a large portion of the company's coal-fired fleet from emissions reported for 2001. Southern Company chose to discontinue reporting on these emission sources, because it had removed emission reduction projects at the plants from the scope of its voluntary report.[236]

Jim Walters Resources. As the owner-operator of three underground coal mines in Tuscaloosa County, Alabama, Jim Walters has a productive capacity of approximately 7 million short tons of coal annually. Jim Walters reported direct methane emissions from ventilation systems at these coal mines. Emissions peaked in 1990 at 662,119 metric tons methane and have declined steadily to 238,821 metric tons methane in 2001. About half of this decrease can be traced to the application of improved methane control techniques, including horizontal drilling, gobwell,[237] and standard well degasification systems. The source of the remainder is undetermined. Because the emissions reduced are methane, the benefit in carbon dioxide equivalent is 23 times that of carbon dioxide reductions.

Niagara Mohawk. A subsidiary of National Grid USA, Niagara Mohawk provides electric service to approximately 1.5 million customers in upstate New York. Niagara Mohawk's direct emissions from stationary combustion peaked at 15.2 million metric tons carbon dioxide equivalent in 1990. This number declined rapidly and steadily to 0.1 million metric tons carbon dioxide equivalent in 2001. The reductions were partially offset by increased indirect emissions from power purchases, which grew from 3.6 million metric tons carbon dioxide equivalent in 1990 to 7.2 million metric tons in 2001. Nearly all the remaining

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[236] Although "entity-level" reporting normally denotes reporting emissions for an entire organization, the General Program Guidelines (Section GG-4.3) allow entity-level reporting for individual plants or sets of plants. For purposes of reporting entity-level information for S.139, Southern Company would need to revise its entity-level emissions baseline so that the plants included in the base year matched plants included in subsequent years.

[237] A gob is a zone of rubble created when the roof of a coal mine collapses behind the mining operations.

reductions prior to 1999 can be attributed to increased generation at the Nine Mile Point nuclear generation plant. The remaining reductions after 1998 are attributable to Niagara Mohawk's divestiture of fossil-fueled generating facilities.

AES. AES owns and operates 158 power generation facilities in the United States and worldwide, with 55,000 megawatts of electric generation capacity. AES does not report emissions for all of its U.S. plants but rather for a set of four, each presented as an individual entity. Nearly all of AES's reductions are the result of increases in sequestration activities undertaken overseas to offset emissions from each of the plants.[238]

KeySpan. KeySpan was formed in 1998 as the result of the merger of KeySpan Energy, the parent company of Brooklyn Union Gas, and portions of Long Island Lighting Company (LILCO), including LILCO generating assets. KeySpan is the largest distributor of natural gas in the Northeast and the largest investor-owned utility in New York State. KeySpan's total electric power system requirements increased somewhat from its 1990 levels. However, the company was able to reduce its direct emission levels by moving away from oil- and gas-fired generation at LILCO plants to generation from the Nine Mile Point nuclear power plant and, to a greater extent, outside power purchases. It appears possible that KeySpan does not capture all the carbon dioxide emissions associated with outside power purchases in its voluntary report. If it did report all its indirect emissions, KeySpan's overall reductions between 1990 and 2001 could be smaller.

Summary of Findings

In aggregate, total net greenhouse gas emissions reported by the 97 entities that reported direct emissions, indirect emissions, or sequestration at the entity level to the Voluntary Reporting Program increased by 241.8 to 276.9 million metric tons carbon dioxide equivalent between 1990 and 2001.[239] The net increase includes a total increase of 1,039.0 to 1,144.6 million metric tons carbon dioxide equivalent for the 54 companies reporting increased entity-level emissions and a total decrease of 797.2 to 867.7 million metric tons carbon dioxide equivalent for 43 companies reporting decreased entity-level emissions. The dichotomy between companies reporting increases and those reporting decreases illustrates how it is possible for entities to qualify for credits for early action in the face of increases in total emissions. To put these reductions in perspective, total reported reductions by only 97 entities out of thousands of possible emitting entities represent from 1.1 to 1.2 percent of total U.S. greenhouse gas emissions (72,568 million metric tons carbon dioxide equivalent) during the 1991 to 2001 time period.[240]

The characterization of emission reductions above also serves to highlight some of the important greenhouse gas accounting issues that must be considered in implementing a program of credits for early compliance. The operational definition of an entity would have important ramifications for early action credits. How aggregated or subaggregated an entity could become could be the difference between qualifying for credits and not pursuing such action. Additionally, how a firm's actual emissions and reductions are calculated would also come in to play, particularly where activities and emissions sources do not always have a straightforward or certain calculation methodology (unlike fossil fuel combustion, for example). The issue of direct and indirect emissions would also have to be addressed. The bill requires

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[238] As mentioned above, the General Program Guidelines (Section GG-4.3) allow entity-level reporting for individual plants or sets of plants. Thus, AES, would, for the purposes of reporting entity-level information for S.139, need to revise its entity-level emissions baseline so that the plants included in the base year matched plants included in subsequent years.

[239] The lower bound number in all the ranges in this section is the total for all Voluntary Reporting Program entity-level reporters for which a 1990 base year could be used. The upper bound number is the total for all Voluntary Reporting Program entity-level reporters whose base year was between 1990 and 2000.

[240] Reporters to the Voluntary Reporting Program self-certify their reports. EIA does not certify the correctness of this information.

that indirect emissions must come into consideration if they are not reported by another entity. Safeguards would need to be put in place to ensure that all indirect emissions were properly reported. Implementation of the credit for early compliance would also require consideration of the issue of verification. Namely, how can it be determined that past and current emission levels reported by individual firms are accurate?

Table D1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Production							
Crude Oil and Lease Condensate	12.29	11.94	11.92	11.50	11.45	11.23	11.15
Natural Gas Plant Liquids	2.65	3.12	3.21	3.53	3.75	3.70	3.84
Dry Natural Gas	19.97	22.11	22.81	25.52	27.33	27.08	28.06
Coal	23.97	25.69	22.57	27.83	10.46	29.61	6.82
Nuclear Power	8.03	8.25	8.37	8.28	9.75	8.28	12.39
Renewable Energy[1]	5.32	7.30	9.03	8.31	14.68	8.77	16.22
Other[2]	0.57	0.85	0.82	0.79	0.62	0.80	0.59
Total	**72.80**	**79.26**	**78.73**	**85.76**	**78.04**	**89.47**	**79.06**
Imports							
Crude Oil[3]	20.26	25.09	24.88	27.63	26.92	28.62	27.72
Petroleum Products[4]	5.04	6.32	5.73	11.72	8.82	14.79	10.43
Natural Gas	4.18	5.43	5.53	7.41	9.37	8.44	11.48
Other Imports[5]	0.71	0.92	0.81	0.95	0.94	0.93	0.79
Total	**30.19**	**37.76**	**36.94**	**47.71**	**46.05**	**52.78**	**50.42**
Exports							
Petroleum[6]	2.01	2.25	2.21	2.38	2.29	2.43	2.32
Natural Gas	0.37	0.56	0.57	0.38	0.37	0.37	0.36
Coal	1.27	0.86	0.84	0.74	0.76	0.62	0.61
Total	**3.64**	**3.67**	**3.61**	**3.50**	**3.42**	**3.42**	**3.29**
Discrepancy[7]	**2.06**	**0.22**	**0.39**	**0.23**	**0.18**	**0.20**	**0.22**
Consumption							
Petroleum Products[8]	38.46	44.45	43.74	52.15	48.65	56.11	50.76
Natural Gas	23.26	27.35	28.12	32.95	36.69	35.55	39.54
Coal	22.02	25.47	22.00	27.88	10.23	29.86	6.74
Nuclear Power	8.03	8.25	8.37	8.28	9.75	8.28	12.39
Renewable Energy[1]	5.32	7.30	9.03	8.31	14.68	8.77	16.22
Other[9]	0.21	0.31	0.43	0.17	0.50	0.06	0.32
Total	**97.29**	**113.13**	**111.67**	**129.74**	**120.50**	**138.63**	**125.97**
Net Imports - Petroleum	**23.29**	**29.16**	**28.40**	**36.97**	**33.45**	**40.98**	**35.83**
Prices (2001 dollars per unit)							
World Oil Price (dollars per barrel)[10]	22.01	23.99	23.77	25.48	24.15	26.57	24.58
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.12	3.39	3.51	3.70	3.97	3.95	4.36
Coal Minemouth Price (dollars per ton)	17.59	15.06	15.84	14.34	15.27	14.39	13.67
Average Electricity Price (cents per kilowatthour)	7.3	6.4	7.0	6.7	8.8	6.7	9.8

[1] Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table D18 for selected nonmarketed residential and commercial renewable energy.

[2] Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.

[3] Includes imports of crude oil for the Strategic Petroleum Reserve.

[4] Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.

[5] Includes coal, coal coke (net), and electricity (net).

[6] Includes crude oil and petroleum products.

[7] Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.

[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.

[9] Includes net electricity imports, methanol, and liquid hydrogen.

[10] Average refiner acquisition cost for imported crude oil.

[11] Represents lower 48 onshore and offshore supplies.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Energy Consumption							
Residential							
Distillate Fuel	0.91	0.91	0.91	0.84	0.84	0.81	0.81
Kerosene	0.10	0.08	0.08	0.06	0.06	0.06	0.06
Liquefied Petroleum Gas	0.50	0.47	0.47	0.46	0.47	0.46	0.47
Petroleum Subtotal	1.50	1.46	1.46	1.36	1.37	1.33	1.33
Natural Gas	4.94	5.63	5.62	6.10	5.96	6.38	6.20
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.41	0.41	0.41	0.40	0.40	0.40
Electricity	4.10	4.93	4.88	5.60	5.05	5.95	5.11
Delivered Energy	**10.94**	**12.45**	**12.38**	**13.48**	**12.80**	**14.08**	**13.06**
Electricity Related Losses	9.15	10.37	10.11	11.03	9.29	11.42	9.26
Total	**20.08**	**22.82**	**22.50**	**24.51**	**22.09**	**25.50**	**22.32**
Commercial							
Distillate Fuel	0.46	0.51	0.51	0.52	0.54	0.52	0.56
Residual Fuel	0.09	0.04	0.04	0.05	0.05	0.05	0.05
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.09	0.09	0.10
Motor Gasoline[2]	0.05	0.03	0.03	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.71	0.70	0.70	0.72	0.75	0.72	0.76
Natural Gas	3.33	3.74	3.74	4.23	4.27	4.50	4.97
Coal	0.09	0.10	0.10	0.10	0.11	0.11	0.11
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.08	5.01	4.97	6.17	5.66	6.79	5.97
Delivered Energy	**8.32**	**9.65**	**9.60**	**11.33**	**10.89**	**12.23**	**11.92**
Electricity Related Losses	9.12	10.53	10.30	12.16	10.42	13.02	10.82
Total	**17.44**	**20.19**	**19.90**	**23.50**	**21.31**	**25.25**	**22.74**
Industrial[4]							
Distillate Fuel	1.13	1.21	1.20	1.36	1.30	1.44	1.36
Liquefied Petroleum Gas	2.10	2.55	2.54	3.06	2.99	3.28	3.14
Petrochemical Feedstock	1.14	1.44	1.41	1.70	1.53	1.82	1.57
Residual Fuel	0.23	0.19	0.18	0.20	0.17	0.20	0.17
Motor Gasoline[2]	0.15	0.17	0.17	0.18	0.18	0.19	0.19
Other Petroleum[5]	4.03	4.27	4.18	4.46	4.09	4.57	4.12
Petroleum Subtotal	8.79	9.82	9.67	10.96	10.26	11.50	10.55
Natural Gas	7.74	9.06	9.16	10.39	10.36	11.23	11.09
Lease and Plant Fuel[6]	1.20	1.37	1.40	1.60	1.70	1.73	1.77
Natural Gas Subtotal	8.94	10.43	10.56	11.98	12.06	12.96	12.86
Metallurgical Coal	0.72	0.66	0.65	0.55	0.47	0.50	0.39
Steam Coal	1.42	1.46	1.33	1.51	1.28	1.54	1.26
Net Coal Coke Imports	0.03	0.11	0.11	0.16	0.18	0.18	0.21
Coal Subtotal	2.16	2.23	2.09	2.22	1.93	2.22	1.87
Renewable Energy[7]	1.82	2.22	2.21	2.77	2.74	3.05	3.02
Electricity	3.39	3.97	3.89	4.65	4.41	5.01	4.66
Delivered Energy	**25.10**	**28.67**	**28.41**	**32.58**	**31.40**	**34.75**	**32.96**
Electricity Related Losses	7.57	8.35	8.06	9.17	8.12	9.61	8.45
Total	**32.67**	**37.02**	**36.47**	**41.75**	**39.53**	**44.36**	**41.40**

Table D2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Transportation							
Distillate Fuel[8]	5.44	7.09	7.01	8.68	8.30	9.55	8.98
Jet Fuel[9]	3.43	3.93	3.91	5.09	5.01	5.67	5.56
Motor Gasoline[2]	16.26	19.81	19.58	23.57	21.55	25.48	22.10
Residual Fuel	0.84	0.83	0.83	0.85	0.85	0.87	0.86
Liquefied Petroleum Gas	0.02	0.05	0.05	0.07	0.08	0.09	0.09
Other Petroleum[10]	0.24	0.26	0.26	0.30	0.30	0.32	0.32
Petroleum Subtotal	26.22	31.98	31.64	38.57	36.09	41.98	37.91
Pipeline Fuel Natural Gas	0.63	0.78	0.81	0.94	1.05	1.03	1.11
Compressed Natural Gas	0.01	0.06	0.06	0.10	0.09	0.11	0.10
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.07	0.09	0.09	0.12	0.12	0.14	0.13
Delivered Energy	**26.94**	**32.91**	**32.61**	**39.73**	**37.36**	**43.26**	**39.25**
Electricity Related Losses	0.17	0.20	0.19	0.24	0.22	0.27	0.24
Total	**27.10**	**33.10**	**32.80**	**39.98**	**37.58**	**43.53**	**39.50**
Delivered Energy Consumption for All Sectors							
Distillate Fuel	7.94	9.74	9.64	11.40	10.99	12.32	11.71
Kerosene	0.15	0.12	0.12	0.11	0.11	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.91	5.09	5.01	5.67	5.56
Liquefied Petroleum Gas	2.70	3.16	3.16	3.69	3.63	3.92	3.78
Motor Gasoline[2]	16.46	20.01	19.78	23.79	21.77	25.71	22.33
Petrochemical Feedstock	1.14	1.44	1.41	1.70	1.53	1.82	1.57
Residual Fuel	1.15	1.06	1.05	1.10	1.07	1.12	1.08
Other Petroleum[12]	4.24	4.51	4.41	4.74	4.36	4.87	4.42
Petroleum Subtotal	37.21	43.97	43.48	51.61	48.47	55.53	50.55
Natural Gas	16.02	18.49	18.57	20.82	20.68	22.23	22.36
Lease and Plant Fuel Plant[6]	1.20	1.37	1.40	1.60	1.70	1.73	1.77
Pipeline Natural Gas	0.63	0.78	0.81	0.94	1.05	1.03	1.11
Natural Gas Subtotal	17.86	20.64	20.78	23.35	23.43	24.98	25.23
Metallurgical Coal	0.72	0.66	0.65	0.55	0.47	0.50	0.39
Steam Coal	1.53	1.56	1.44	1.63	1.40	1.66	1.39
Net Coal Coke Imports	0.03	0.11	0.11	0.16	0.18	0.18	0.21
Coal Subtotal	2.27	2.34	2.20	2.34	2.05	2.34	1.99
Renewable Energy[13]	2.31	2.74	2.72	3.28	3.26	3.57	3.53
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.65	14.00	13.82	16.54	15.24	17.90	15.87
Delivered Energy	**71.29**	**83.68**	**83.01**	**97.13**	**92.45**	**104.32**	**97.19**
Electricity Related Losses	26.00	29.45	28.66	32.61	28.05	34.32	28.78
Total	**97.29**	**113.13**	**111.67**	**129.74**	**120.50**	**138.63**	**125.97**
Electric Power[14]							
Distillate Fuel	0.17	0.09	0.07	0.13	0.05	0.18	0.06
Residual Fuel	1.08	0.39	0.19	0.41	0.14	0.40	0.14
Petroleum Subtotal	1.25	0.48	0.26	0.54	0.19	0.58	0.21
Natural Gas	5.40	6.71	7.33	9.60	13.25	10.56	14.30
Steam Coal	19.75	23.13	19.79	25.54	8.18	27.52	4.74
Nuclear Power	8.03	8.25	8.37	8.28	9.75	8.28	12.39
Renewable Energy[15]	3.01	4.57	6.30	5.02	11.42	5.21	12.69
Electricity Imports	0.21	0.31	0.43	0.17	0.50	0.06	0.32
Total	**37.65**	**43.45**	**42.48**	**49.15**	**43.29**	**52.21**	**44.65**

Table D2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Total Energy Consumption							
Distillate Fuel	8.10	9.83	9.71	11.53	11.04	12.50	11.77
Kerosene	0.15	0.12	0.12	0.11	0.11	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.91	5.09	5.01	5.67	5.56
Liquefied Petroleum Gas	2.70	3.16	3.16	3.69	3.63	3.92	3.78
Motor Gasoline[2]	16.46	20.01	19.78	23.79	21.77	25.71	22.33
Petrochemical Feedstock	1.14	1.44	1.41	1.70	1.53	1.82	1.57
Residual Fuel	2.23	1.45	1.24	1.51	1.20	1.52	1.22
Other Petroleum[12]	4.24	4.51	4.41	4.74	4.36	4.87	4.42
Petroleum Subtotal	38.46	44.45	43.74	52.15	48.65	56.11	50.76
Natural Gas	21.42	25.20	25.91	30.42	33.94	32.79	36.67
Lease and Plant Fuel[6]	1.20	1.37	1.40	1.60	1.70	1.73	1.77
Pipeline Natural Gas	0.63	0.78	0.81	0.94	1.05	1.03	1.11
Natural Gas Subtotal	23.26	27.35	28.12	32.95	36.69	35.55	39.54
Metallurgical Coal	0.72	0.66	0.65	0.55	0.47	0.50	0.39
Steam Coal	21.28	24.70	21.24	27.17	9.58	29.18	6.13
Net Coal Coke Imports	0.03	0.11	0.11	0.16	0.18	0.18	0.21
Coal Subtotal	22.02	25.47	22.00	27.88	10.23	29.86	6.74
Nuclear Power	8.03	8.25	8.37	8.28	9.75	8.28	12.39
Renewable Energy[16]	5.32	7.30	9.03	8.31	14.68	8.77	16.22
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.21	0.31	0.43	0.17	0.50	0.06	0.32
Total	**97.29**	**113.13**	**111.67**	**129.74**	**120.50**	**138.63**	**125.97**
Energy Use and Related Statistics							
Delivered Energy Use	71.29	83.68	83.01	97.13	92.45	104.32	97.19
Total Energy Use	97.29	113.13	111.67	129.74	120.50	138.63	125.97
Population (millions)	278.18	300.24	300.24	325.32	325.32	338.24	338.24
Gross Domestic Product (billion 1996 dollars)	9215	12258	12211	16444	16364	18916	18810
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1558.6	1802.2	1710.1	2077.7	1568.5	2234.4	1482.2

[1] Includes wood used for residential heating. See Table D18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.

[2] Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.

[3] Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table D18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.

[4] Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.

[5] Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.

[6] Represents natural gas used in the field gathering and processing plant machinery.

[7] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.

[8] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.

[9] Includes only kerosene type.

[10] Includes aviation gasoline and lubricants.

[11] E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).

[12] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.

[13] Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

[14] Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[15] Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.

[16] Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.

Sources: 2001 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 population and gross domestic product: Global Insight macroeconomic model CTL0802. 2001 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D3. Delivered Energy Prices by Sector and Source
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Residential	**15.81**	**13.97**	**14.62**	**14.62**	**17.37**	**14.89**	**18.74**
Primary Energy[1]	9.73	8.07	8.11	8.33	8.48	8.57	8.88
Petroleum Products[2]	10.85	10.02	9.88	10.91	10.32	11.21	10.79
Distillate Fuel	8.99	7.99	7.95	8.70	8.23	8.93	8.58
Liquefied Petroleum Gas	14.84	14.35	13.97	15.28	14.44	15.52	14.96
Natural Gas	9.41	7.57	7.67	7.77	8.07	8.04	8.48
Electricity	25.37	22.48	24.10	23.03	30.32	23.09	33.29
Commercial	**15.50**	**13.45**	**14.35**	**14.58**	**17.78**	**15.00**	**19.27**
Primary Energy[1]	7.81	6.43	6.50	6.78	6.93	7.05	7.33
Petroleum Products[2]	7.27	6.78	6.70	7.51	6.96	7.81	7.28
Distillate Fuel	6.40	5.67	5.63	6.45	5.96	6.75	6.30
Residual Fuel	3.46	4.01	3.93	4.23	3.96	4.39	4.02
Natural Gas	8.09	6.49	6.59	6.79	7.07	7.07	7.48
Electricity	23.28	19.81	21.51	20.98	27.61	21.25	30.97
Industrial[3]	**7.11**	**6.39**	**6.61**	**7.01**	**7.80**	**7.25**	**8.45**
Primary Energy	5.83	5.18	5.16	5.74	5.65	5.99	5.97
Petroleum Products[2]	7.72	7.07	6.93	7.85	7.40	8.13	7.68
Distillate Fuel	6.55	5.75	5.71	6.74	6.18	7.19	6.53
Liquefied Petroleum Gas	12.34	9.93	9.58	10.85	10.14	11.13	10.60
Residual Fuel	3.28	3.71	3.66	3.94	3.70	4.10	3.77
Natural Gas[4]	4.87	4.00	4.11	4.39	4.68	4.63	5.07
Metallurgical Coal	1.69	1.50	1.51	1.39	1.40	1.34	1.34
Steam Coal	1.46	1.39	1.38	1.31	1.14	1.30	1.04
Electricity	14.13	12.82	14.34	13.37	18.65	13.48	20.86
Transportation	**10.28**	**10.22**	**11.73**	**10.37**	**13.27**	**10.82**	**14.17**
Primary Energy	10.25	10.19	11.70	10.35	13.24	10.79	14.12
Petroleum Products[2]	10.25	10.20	11.71	10.35	13.25	10.80	14.14
Distillate Fuel[5]	10.05	10.19	11.71	10.27	13.17	10.64	14.37
Jet Fuel[6]	6.20	5.66	7.10	6.34	9.26	6.72	10.35
Motor Gasoline[7]	11.57	11.45	12.98	11.55	14.52	12.07	15.31
Residual Fuel	3.90	3.56	5.19	3.78	7.36	3.94	8.32
Liquefied Petroleum Gas[8]	16.93	15.55	16.35	16.06	18.30	15.99	19.15
Natural Gas[9]	7.65	7.19	7.25	7.75	7.72	8.09	8.08
Electricity	21.87	19.10	20.82	18.45	24.39	17.90	26.05
Average End-Use Energy	**10.75**	**9.97**	**10.87**	**10.47**	**12.73**	**10.82**	**13.71**
Primary Energy	8.52	8.07	8.82	8.46	9.90	8.84	10.52
Electricity	21.34	18.76	20.40	19.52	25.89	19.66	28.70
Electric Power[10]							
Fossil Fuel Average	2.14	1.82	1.97	2.04	3.36	2.13	4.13
Petroleum Products	4.73	4.28	4.49	4.72	5.02	5.04	5.18
Distillate Fuel	6.20	5.13	5.01	5.94	5.39	6.16	5.64
Residual Fuel	4.50	4.08	4.29	4.33	4.88	4.55	4.98
Natural Gas	4.78	3.88	4.07	4.35	4.79	4.64	5.19
Steam Coal	1.25	1.17	1.16	1.12	0.99	1.11	0.90

Table D3. Delivered Energy Prices by Sector and Source (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Average Price to All Users[11]							
Petroleum Products[2]	9.54	9.46	11.91	9.81	14.92	10.22	16.37
Distillate Fuel	9.16	9.15	10.25	9.52	11.58	9.90	12.64
Jet Fuel	6.20	5.66	7.10	6.34	9.26	6.72	10.35
Liquefied Petroleum Gas	12.85	10.75	10.43	11.58	10.93	11.81	11.40
Motor Gasoline[7]	11.57	11.45	12.97	11.55	14.49	12.07	15.27
Residual Fuel	4.11	3.73	4.79	3.96	6.42	4.14	7.12
Natural Gas	6.40	5.15	5.24	5.40	5.63	5.64	6.03
Coal	1.26	1.18	1.17	1.13	1.02	1.12	0.94
Electricity	21.34	18.76	20.40	19.52	25.89	19.66	28.70
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)							
Residential	166.77	168.16	175.14	191.19	215.33	203.68	237.11
Commercial	127.30	128.40	136.28	163.77	191.81	181.88	227.72
Industrial	135.32	137.86	141.86	172.27	185.88	190.69	212.44
Transportation	270.41	328.32	372.90	402.37	481.84	456.80	540.27
Total Non-Renewable Expenditures	699.80	762.73	826.18	929.60	1074.86	1033.06	1217.53
Transportation Renewable Expenditures	0.01	0.05	0.05	0.10	0.11	0.13	0.15
Total Expenditures	**699.81**	**762.78**	**826.23**	**929.70**	**1074.97**	**1033.19**	**1217.69**

[1] Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3] Includes combined heat and power, which produces electricity and other useful thermal energy.
[4] Excludes use for lease and plant fuel.
[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6] Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7] Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8] Includes Federal and State taxes while excluding county and local taxes.
[9] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[10] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[11] Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D4. Greenhouse Gas Allowance Cost by End-Use Sector and Source

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Commercial							
Petroleum Products[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residual Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[3]							
Petroleum Products[2]	0.00	0.00	0.94	0.00	2.15	0.00	2.66
Distillate Fuel	0.00	0.00	1.56	0.00	3.52	0.00	4.36
Liquefied Petroleum Gas	0.00	0.00	1.35	0.00	3.05	0.00	3.77
Residual Fuel	0.00	0.00	1.68	0.00	3.80	0.00	4.70
Natural Gas[4]	0.00	0.00	1.11	0.00	2.52	0.00	3.12
Metallurgical Coal	0.00	0.00	2.00	0.00	4.51	0.00	5.58
Steam Coal	0.00	0.00	2.00	0.00	4.53	0.00	5.60
Electric Power[5]							
Fossil Fuel Average	0.00	0.00	1.78	0.00	3.32	0.00	3.80
Petroleum Products	0.00	0.00	1.65	0.00	3.72	0.00	4.60
Distillate Fuel	0.00	0.00	1.56	0.00	3.52	0.00	4.36
Residual Fuel	0.00	0.00	1.68	0.00	3.80	0.00	4.70
Natural Gas	0.00	0.00	1.14	0.00	2.57	0.00	3.18
Steam Coal	0.00	0.00	2.02	0.00	4.54	0.00	5.62
Average Allowance Cost to All Users[6]							
Petroleum Products[2]	0.00	0.00	0.22	0.00	0.48	0.00	0.59
Distillate Fuel	0.00	0.00	0.20	0.00	0.43	0.00	0.53
Jet Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquefied Petroleum Gas	0.00	0.00	1.09	0.00	2.51	0.00	3.13
Motor Gasoline	0.00	0.00	0.01	0.00	0.03	0.00	0.04
Residual Fuel	0.00	0.00	0.50	0.00	0.98	0.00	1.21
Natural Gas	0.00	0.00	0.72	0.00	1.78	0.00	2.19
Coal	0.00	0.00	2.00	0.00	4.48	0.00	5.50

[1] Weighted average allowance cost includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3] Includes combined heat and power, which produces electricity and other useful thermal energy.
[4] Excludes use for lease and plant fuel.
[5] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[6] Weighted averages of allowance costs are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2001 are model results and may differ slightly from official EIA data reports.
Projections: EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D5. Energy Prices by Sector and Source with Greenhouse Gas Allowance Cost
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Residential	**15.81**	**13.97**	**14.62**	**14.62**	**17.37**	**14.89**	**18.74**
Primary Energy[1]	9.73	8.07	8.11	8.33	8.48	8.57	8.88
Petroleum Products[2]	10.85	10.02	9.88	10.91	10.32	11.21	10.79
Distillate Fuel	8.99	7.99	7.95	8.70	8.23	8.93	8.58
Liquefied Petroleum Gas	14.84	14.35	13.97	15.28	14.44	15.52	14.96
Natural Gas	9.41	7.57	7.67	7.77	8.07	8.04	8.48
Electricity	25.37	22.48	24.10	23.03	30.32	23.09	33.29
Commercial	**15.50**	**13.45**	**14.35**	**14.58**	**17.78**	**15.00**	**19.27**
Primary Energy[1]	7.81	6.43	6.50	6.78	6.93	7.05	7.33
Petroleum Products[2]	7.27	6.78	6.70	7.51	6.96	7.81	7.28
Distillate Fuel	6.40	5.67	5.63	6.45	5.96	6.75	6.30
Residual Fuel	3.46	4.01	3.93	4.23	3.96	4.39	4.02
Natural Gas	8.09	6.49	6.59	6.79	7.07	7.07	7.48
Electricity	23.28	19.81	21.51	20.98	27.61	21.25	30.97
Industrial[3]	**7.11**	**6.39**	**7.55**	**7.01**	**9.89**	**7.25**	**11.03**
Primary Energy	5.83	5.18	6.28	5.74	8.16	5.99	9.06
Petroleum Products[2]	7.72	7.07	7.87	7.85	9.55	8.13	10.34
Distillate Fuel	6.55	5.75	7.27	6.74	9.70	7.19	10.89
Liquefied Petroleum Gas	12.34	9.93	10.93	10.85	13.19	11.13	14.38
Residual Fuel	3.28	3.71	5.34	3.94	7.49	4.10	8.46
Natural Gas[4]	4.87	4.00	5.23	4.39	7.20	4.63	8.19
Metallurgical Coal	1.69	1.50	3.50	1.39	5.91	1.34	6.92
Steam Coal	1.46	1.39	3.38	1.31	5.67	1.30	6.64
Electricity	14.13	12.82	14.34	13.37	18.65	13.48	20.86
Transportation	**10.28**	**10.22**	**11.73**	**10.37**	**13.28**	**10.82**	**14.17**
Primary Energy	10.25	10.19	11.70	10.35	13.24	10.79	14.13
Petroleum Products[2]	10.25	10.20	11.71	10.35	13.25	10.80	14.14
Distillate Fuel[5]	10.05	10.19	11.71	10.27	13.17	10.64	14.37
Jet Fuel[6]	6.20	5.66	7.10	6.34	9.26	6.72	10.35
Motor Gasoline[7]	11.57	11.45	12.98	11.55	14.52	12.07	15.31
Residual Fuel	3.90	3.56	5.19	3.78	7.36	3.94	8.32
Liquefied Petroleum Gas[8]	16.93	15.55	16.35	16.06	18.30	15.99	19.15
Natural Gas[9]	7.65	7.19	8.38	7.75	10.29	8.09	11.26
Electricity	21.87	19.10	20.82	18.45	24.39	17.90	26.05
Average End-Use Energy	**10.75**	**9.97**	**11.17**	**10.47**	**13.38**	**10.82**	**14.50**
Primary Energy	8.52	8.07	9.18	8.46	10.70	8.84	11.49
Electricity	21.34	18.76	20.40	19.52	25.89	19.66	28.70
Electric Power[10]							
Fossil Fuel Average	2.14	1.82	3.75	2.04	6.68	2.13	7.93
Petroleum Products	4.73	4.28	6.13	4.72	8.74	5.04	9.77
Distillate Fuel	6.20	5.13	6.57	5.94	8.91	6.16	9.99
Residual Fuel	4.50	4.08	5.97	4.33	8.68	4.55	9.68
Natural Gas	4.78	3.88	5.20	4.35	7.36	4.64	8.37
Steam Coal	1.25	1.17	3.17	1.12	5.53	1.11	6.53

Table D5. Energy Prices by Sector and Source with Greenhouse Gas Allowance Cost (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Average Price to All Users[11]							
Petroleum Products[2]	9.54	9.46	10.76	9.81	12.34	10.22	13.20
Distillate Fuel	9.16	9.15	10.45	9.52	12.01	9.90	13.17
Jet Fuel	6.20	5.66	7.10	6.34	9.26	6.72	10.35
Liquefied Petroleum Gas	12.85	10.75	11.51	11.58	13.44	11.81	14.52
Motor Gasoline[7]	11.57	11.45	12.98	11.55	14.52	12.07	15.31
Residual Fuel	4.11	3.73	5.29	3.96	7.39	4.14	8.33
Natural Gas	6.40	5.15	5.96	5.40	7.41	5.64	8.22
Coal	1.26	1.18	3.18	1.13	5.50	1.12	6.44
Electricity	21.34	18.76	20.40	19.52	25.89	19.66	28.70
Non-Renewable Energy and Allowance Expenditures by Sector (billion 2001 dollars)							
Residential	166.77	168.16	175.14	191.19	215.33	203.68	237.11
Commercial	127.30	128.40	136.28	163.77	191.81	181.88	227.72
Industrial	135.32	137.86	162.27	172.27	235.92	190.69	277.18
Transportation	270.41	328.32	372.97	402.37	482.08	456.80	540.60
Total Non-Renewable Expenditures	699.80	762.73	846.66	929.60	1125.14	1033.06	1282.60
Transportation Renewable Expenditures	0.01	0.05	0.05	0.10	0.12	0.13	0.16
Total Expenditures	**699.81**	**762.78**	**846.72**	**929.70**	**1125.26**	**1033.19**	**1282.76**

[1] Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3] Includes combined heat and power, which produces electricity and other useful thermal energy.
[4] Excludes use for lease and plant fuel.
[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6] Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7] Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8] Includes Federal and State taxes while excluding county and local taxes.
[9] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[10] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[11] Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D6. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Key Indicators							
Households (millions)							
Single-Family	77.50	86.16	86.14	94.13	93.99	97.63	97.43
Multifamily	22.19	24.15	24.13	27.09	26.99	28.82	28.71
Mobile Homes	6.57	7.11	7.10	7.86	7.86	8.11	8.11
Total	**106.27**	**117.42**	**117.37**	**129.08**	**128.83**	**134.55**	**134.25**
Average House Square Footage	**1685**	**1740**	**1740**	**1782**	**1782**	**1798**	**1798**
Energy Intensity							
(million Btu per household)							
Delivered Energy Consumption	102.9	106.0	105.5	104.4	99.3	104.6	97.3
Total Energy Consumption	189.0	194.3	191.7	189.9	171.4	189.5	166.3
(thousand Btu per square foot)							
Delivered Energy Consumption	61.1	60.9	60.7	58.6	55.7	58.2	54.1
Total Energy Consumption	112.2	111.7	110.2	106.6	96.2	105.4	92.5
Delivered Energy Consumption by Fuel							
Electricity							
Space Heating	0.39	0.46	0.46	0.50	0.46	0.52	0.45
Space Cooling	0.52	0.60	0.60	0.65	0.59	0.69	0.59
Water Heating	0.45	0.47	0.46	0.44	0.38	0.44	0.33
Refrigeration	0.42	0.34	0.34	0.32	0.32	0.33	0.33
Cooking	0.10	0.11	0.11	0.12	0.12	0.13	0.13
Clothes Dryers	0.22	0.25	0.24	0.27	0.25	0.28	0.25
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.93	0.91	1.03	0.81	1.07	0.74
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers[1]	0.02	0.02	0.02	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.20	0.19	0.25	0.24	0.27	0.24
Personal Computers	0.06	0.08	0.08	0.10	0.10	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.10	0.09	0.11	0.10
Other Uses[2]	0.83	1.26	1.25	1.66	1.54	1.87	1.69
Delivered Energy	**4.10**	**4.93**	**4.88**	**5.60**	**5.05**	**5.95**	**5.11**
Natural Gas							
Space Heating	3.13	3.70	3.69	4.10	3.97	4.30	4.11
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.48	1.55	1.55	1.59	1.58	1.65	1.62
Cooking	0.20	0.23	0.23	0.25	0.25	0.26	0.26
Clothes Dryers	0.06	0.08	0.08	0.10	0.10	0.10	0.10
Other Uses[3]	0.06	0.07	0.07	0.07	0.07	0.08	0.11
Delivered Energy	**4.94**	**5.63**	**5.62**	**6.10**	**5.96**	**6.38**	**6.20**
Distillate							
Space Heating	0.74	0.76	0.76	0.71	0.71	0.69	0.69
Water Heating	0.16	0.14	0.14	0.12	0.12	0.11	0.11
Other Uses[4]	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.91**	**0.91**	**0.91**	**0.84**	**0.84**	**0.81**	**0.81**
Liquefied Petroleum Gas							
Space Heating	0.26	0.25	0.25	0.24	0.24	0.24	0.24
Water Heating	0.09	0.07	0.07	0.06	0.06	0.06	0.06
Cooking	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Other Uses[3]	0.12	0.13	0.13	0.14	0.14	0.14	0.14
Delivered Energy	**0.50**	**0.47**	**0.47**	**0.46**	**0.47**	**0.46**	**0.47**
Marketed Renewables (wood)[5]	0.39	0.41	0.41	0.41	0.40	0.40	0.40
Other Fuels[6]	0.11	0.09	0.09	0.08	0.08	0.07	0.07

Table D6. Residential Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Delivered Energy Consumption by End-Use							
Space Heating	5.01	5.68	5.66	6.04	5.86	6.22	5.96
Space Cooling	0.52	0.60	0.60	0.65	0.59	0.69	0.59
Water Heating	2.19	2.24	2.23	2.21	2.14	2.26	2.13
Refrigeration	0.42	0.34	0.34	0.32	0.32	0.33	0.33
Cooking	0.33	0.36	0.36	0.39	0.39	0.40	0.40
Clothes Dryers	0.28	0.33	0.33	0.36	0.34	0.38	0.35
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.93	0.91	1.03	0.81	1.07	0.74
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers	0.02	0.02	0.02	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.20	0.19	0.25	0.24	0.27	0.24
Personal Computers	0.06	0.08	0.08	0.10	0.10	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.10	0.09	0.11	0.10
Other Uses[7]	1.01	1.46	1.45	1.87	1.76	2.09	1.94
Delivered Energy	**10.94**	**12.45**	**12.38**	**13.48**	**12.80**	**14.08**	**13.06**
Electricity Related Losses	**9.15**	**10.37**	**10.11**	**11.03**	**9.29**	**11.42**	**9.26**
Total Energy Consumption by End-Use							
Space Heating	5.89	6.64	6.61	7.03	6.70	7.22	6.78
Space Cooling	1.68	1.86	1.83	1.94	1.68	2.00	1.67
Water Heating	3.20	3.23	3.20	3.08	2.84	3.10	2.74
Refrigeration	1.36	1.06	1.05	0.96	0.91	0.97	0.93
Cooking	0.55	0.59	0.59	0.63	0.61	0.65	0.63
Clothes Dryers	0.78	0.85	0.84	0.89	0.80	0.91	0.81
Freezers	0.36	0.28	0.27	0.26	0.25	0.27	0.25
Lighting	2.40	2.90	2.81	3.06	2.31	3.12	2.09
Clothes Washers	0.10	0.10	0.10	0.09	0.08	0.08	0.08
Dishwashers	0.07	0.07	0.07	0.08	0.08	0.08	0.08
Color Televisions	0.43	0.61	0.60	0.75	0.67	0.78	0.68
Personal Computers	0.19	0.25	0.25	0.31	0.29	0.33	0.32
Furnace Fans	0.23	0.27	0.26	0.30	0.27	0.31	0.27
Other Uses[7]	2.86	4.10	4.03	5.14	4.59	5.67	4.99
Total	**20.08**	**22.82**	**22.50**	**24.51**	**22.09**	**25.50**	**22.32**
Non-Marketed Renewables							
Geothermal[8]	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar[9]	0.03	0.03	0.03	0.04	0.04	0.04	0.04
Total	**0.03**	**0.04**	**0.04**	**0.05**	**0.05**	**0.06**	**0.06**

[1] Does not include electric water heating portion of load.

[2] Includes small electric devices, heating elements, and motors.

[3] Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).

[4] Includes such appliances as swimming pool and hot tub heaters.

[5] Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.

[6] Includes kerosene and coal.

[7] Includes all other uses listed above.

[8] Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.

[9] Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D7. Commercial Sector Key Indicators and Consumption

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Key Indicators							
Total Floorspace (billion square feet)							
Surviving	66.6	79.0	79.0	91.2	90.8	97.4	97.1
New Additions	3.6	3.0	3.0	3.4	3.4	3.4	3.4
Total	**70.2**	**82.0**	**82.0**	**94.6**	**94.2**	**100.8**	**100.6**
Energy Consumption Intensity (thousand Btu per square foot)							
Delivered Energy Consumption	118.4	117.8	117.1	119.8	115.6	121.3	118.6
Electricity Related Losses	129.9	128.5	125.6	128.5	110.6	129.1	107.6
Total Energy Consumption	248.3	246.2	242.7	248.3	226.1	250.4	226.2
Delivered Energy Consumption by Fuel							
Purchased Electricity							
Space Heating[1]	0.14	0.16	0.15	0.15	0.14	0.15	0.13
Space Cooling[1]	0.43	0.43	0.42	0.45	0.41	0.46	0.40
Water Heating[1]	0.15	0.16	0.15	0.16	0.14	0.15	0.13
Ventilation	0.17	0.18	0.18	0.19	0.17	0.19	0.16
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.02
Lighting	1.02	1.21	1.18	1.30	0.99	1.33	0.88
Refrigeration	0.21	0.24	0.24	0.26	0.24	0.27	0.23
Office Equipment (PC)	0.16	0.24	0.24	0.32	0.31	0.36	0.34
Office Equipment (non-PC)	0.31	0.47	0.47	0.75	0.72	0.92	0.87
Other Uses[2]	1.46	1.90	1.90	2.57	2.51	2.92	2.80
Delivered Energy	**4.08**	**5.01**	**4.97**	**6.17**	**5.66**	**6.79**	**5.97**
Natural Gas							
Space Heating[1]	1.32	1.53	1.53	1.65	1.58	1.71	1.56
Space Cooling[1]	0.01	0.02	0.02	0.03	0.03	0.04	0.03
Water Heating[1]	0.57	0.69	0.69	0.81	0.77	0.86	0.78
Cooking	0.25	0.30	0.30	0.35	0.33	0.37	0.35
Other Uses[3]	1.17	1.20	1.20	1.39	1.57	1.52	2.25
Delivered Energy	**3.33**	**3.74**	**3.74**	**4.23**	**4.27**	**4.50**	**4.97**
Distillate							
Space Heating[1]	0.17	0.24	0.23	0.25	0.27	0.25	0.28
Water Heating[1]	0.07	0.08	0.08	0.08	0.08	0.08	0.08
Other Uses[4]	0.22	0.20	0.20	0.20	0.20	0.20	0.20
Delivered Energy	**0.46**	**0.51**	**0.51**	**0.52**	**0.54**	**0.52**	**0.56**
Other Fuels[5]	**0.34**	**0.29**	**0.29**	**0.30**	**0.31**	**0.31**	**0.32**
Marketed Renewable Fuels							
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Energy	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Delivered Energy Consumption by End-Use							
Space Heating[1]	1.63	1.92	1.92	2.05	1.98	2.11	1.97
Space Cooling[1]	0.44	0.45	0.44	0.48	0.44	0.50	0.43
Water Heating[1]	0.79	0.92	0.92	1.04	0.99	1.09	0.99
Ventilation	0.17	0.18	0.18	0.19	0.17	0.19	0.16
Cooking	0.29	0.33	0.33	0.38	0.36	0.40	0.37
Lighting	1.02	1.21	1.18	1.30	0.99	1.33	0.88
Refrigeration	0.21	0.24	0.24	0.26	0.24	0.27	0.23
Office Equipment (PC)	0.16	0.24	0.24	0.32	0.31	0.36	0.34
Office Equipment (non-PC)	0.31	0.47	0.47	0.75	0.72	0.92	0.87
Other Uses[6]	3.30	3.69	3.69	4.56	4.69	5.05	5.68
Delivered Energy	**8.32**	**9.65**	**9.60**	**11.33**	**10.89**	**12.23**	**11.92**

Table D7. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Electricity Related Losses	**9.12**	**10.53**	**10.30**	**12.16**	**10.42**	**13.02**	**10.82**
Total Energy Consumption by End-Use							
Space Heating[1]	1.95	2.25	2.24	2.36	2.24	2.40	2.20
Space Cooling[1]	1.39	1.34	1.32	1.38	1.21	1.39	1.15
Water Heating[1]	1.12	1.25	1.24	1.35	1.25	1.39	1.23
Ventilation	0.55	0.56	0.55	0.56	0.48	0.57	0.45
Cooking	0.37	0.40	0.40	0.44	0.41	0.45	0.41
Lighting	3.31	3.74	3.62	3.86	2.80	3.88	2.48
Refrigeration	0.69	0.74	0.73	0.77	0.68	0.78	0.66
Office Equipment (PC)	0.52	0.75	0.74	0.95	0.88	1.05	0.96
Office Equipment (non-PC)	0.99	1.45	1.43	2.21	2.06	2.69	2.45
Other Uses[6]	6.56	7.70	7.63	9.62	9.31	10.65	10.76
Total	**17.44**	**20.19**	**19.90**	**23.50**	**21.31**	**25.25**	**22.74**
Non-Marketed Renewable Fuels							
Solar[7]	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

[1] Includes fuel consumption for district services.

[2] Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.

[3] Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.

[4] Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.

[5] Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.

[6] Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.

[7] Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.

Btu = British thermal unit.

PC = Personal computer.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D8. Industrial Sector Key Indicators and Consumption

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Key Indicators							
Value of Shipments (billion 1996 dollars)							
Manufacturing	4079	5466	5420	7226	7160	8258	8162
Nonmanufacturing	1346	1510	1500	1744	1714	1870	1828
Total	**5425**	**6977**	**6920**	**8969**	**8874**	**10128**	**9990**
Energy Prices (2001 dollars per million Btu)							
Electricity	14.13	12.82	14.34	13.37	18.65	13.48	20.86
Natural Gas	4.87	4.00	5.23	4.39	7.20	4.63	8.19
Steam Coal	1.46	1.39	3.38	1.31	5.67	1.30	6.64
Residual Oil	3.28	3.71	5.34	3.94	7.49	4.10	8.46
Distillate Oil	6.55	5.75	7.27	6.74	9.70	7.19	10.89
Liquefied Petroleum Gas	12.34	9.93	10.93	10.85	13.19	11.13	14.38
Motor Gasoline	11.57	11.40	12.94	11.52	14.49	12.05	15.28
Metallurgical Coal	1.69	1.50	3.50	1.39	5.91	1.34	6.92
Energy Consumption[1]							
Purchased Electricity	3.39	3.97	3.89	4.65	4.41	5.01	4.66
Natural Gas	7.74	9.06	9.16	10.39	10.36	11.23	11.09
Lease and Plant Fuel[2]	1.20	1.37	1.40	1.60	1.70	1.73	1.77
Natural Gas Subtotal	8.94	10.43	10.56	11.98	12.06	12.96	12.86
Steam Coal	1.42	1.46	1.33	1.51	1.28	1.54	1.26
Metallurgical Coal and Coke[3]	0.74	0.77	0.76	0.71	0.65	0.68	0.60
Residual Fuel	0.23	0.19	0.18	0.20	0.17	0.20	0.17
Distillate	1.13	1.21	1.20	1.36	1.30	1.44	1.36
Liquefied Petroleum Gas	2.10	2.55	2.54	3.06	2.99	3.28	3.14
Petrochemical Feedstocks	1.14	1.44	1.41	1.70	1.53	1.82	1.57
Other Petroleum[4]	4.18	4.44	4.34	4.64	4.27	4.76	4.32
Renewables[5]	1.82	2.22	2.21	2.77	2.74	3.05	3.02
Delivered Energy	**25.10**	**28.67**	**28.41**	**32.58**	**31.40**	**34.75**	**32.96**
Electricity Related Losses	7.57	8.35	8.06	9.17	8.12	9.61	8.45
Total	**32.67**	**37.02**	**36.47**	**41.75**	**39.53**	**44.36**	**41.40**
Energy Consumption per dollar of Shipments[1] (thousand Btu per 1996 dollars)							
Purchased Electricity	0.63	0.57	0.56	0.52	0.50	0.49	0.47
Natural Gas	1.43	1.30	1.32	1.16	1.17	1.11	1.11
Lease and Plant Fuel[2]	0.22	0.20	0.20	0.18	0.19	0.17	0.18
Natural Gas Subtotal	1.65	1.49	1.53	1.34	1.36	1.28	1.29
Steam Coal	0.26	0.21	0.19	0.17	0.14	0.15	0.13
Metallurgical Coal and Coke[3]	0.14	0.11	0.11	0.08	0.07	0.07	0.06
Residual Fuel	0.04	0.03	0.03	0.02	0.02	0.02	0.02
Distillate	0.21	0.17	0.17	0.15	0.15	0.14	0.14
Liquefied Petroleum Gas	0.39	0.37	0.37	0.34	0.34	0.32	0.31
Petrochemical Feedstocks	0.21	0.21	0.20	0.19	0.17	0.18	0.16
Other Petroleum[4]	0.77	0.64	0.63	0.52	0.48	0.47	0.43
Renewables[5]	0.33	0.32	0.32	0.31	0.31	0.30	0.30
Delivered Energy	**4.63**	**4.11**	**4.11**	**3.63**	**3.54**	**3.43**	**3.30**
Electricity Related Losses	1.40	1.20	1.16	1.02	0.92	0.95	0.85
Total	**6.02**	**5.31**	**5.27**	**4.65**	**4.45**	**4.38**	**4.14**

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[1] Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2] Represents natural gas used in the field gathering and processing plant machinery.
[3] Includes net coal coke imports.
[4] Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 coal prices are based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 consumption values based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 shipments: Global Insight macroeconomic model CTL0802. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D9. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Key Indicators							
Level of Travel (billions)							
Light-Duty Vehicles <8,500 pounds (VMT)	2409	3006	2975	3752	3547	4133	3795
Commercial Light Trucks (VMT)[1]	66	84	83	107	104	120	115
Freight Trucks >10,000 pounds (VMT)	206	265	263	339	335	382	377
Air (seat miles available)	1109	1356	1348	1944	1928	2258	2231
Rail (ton miles traveled)	1448	1691	1579	2003	1467	2173	1486
Domestic Shipping (ton miles traveled)	788	882	869	1012	950	1088	992
Energy Efficiency Indicators							
New Light-Duty Vehicle (miles per gallon)[2]	24.1	25.1	25.3	26.0	28.1	26.4	29.0
New Car (miles per gallon)[2]	28.1	28.5	28.8	29.7	32.6	30.1	32.9
New Light Truck (miles per gallon)[2]	20.7	22.3	22.5	23.1	24.6	23.5	25.8
Light-Duty Fleet (miles per gallon)[3]	19.8	19.6	19.6	20.3	20.9	20.5	21.8
New Commercial Light Truck (MPG)[1]	13.8	14.7	14.8	15.2	16.3	15.5	17.1
Stock Commercial Light Truck (MPG)[1]	13.7	14.3	14.3	14.9	15.4	15.2	16.2
Aircraft Efficiency (seat miles per gallon)	51.2	54.3	54.3	58.6	59.1	60.7	61.2
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.3	6.4	6.5	6.6
Rail Efficiency (ton miles per thousand Btu)	2.8	3.1	3.1	3.4	3.4	3.6	3.6
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.3	2.4	2.4	2.4	2.4
Energy Use by Mode (quadrillion Btu)							
Light-Duty Vehicles	15.28	18.88	18.86	22.76	20.99	24.71	21.55
Commercial Light Trucks[1]	0.60	0.73	0.73	0.89	0.84	0.98	0.89
Freight Trucks[4]	4.68	5.92	5.88	7.11	6.94	7.81	7.55
Air[5]	3.47	3.98	3.96	5.15	5.07	5.73	5.63
Rail[6]	0.63	0.68	0.65	0.75	0.59	0.78	0.59
Marine[7]	1.45	1.49	1.49	1.59	1.56	1.64	1.60
Pipeline Fuel	0.63	0.78	0.81	0.94	1.05	1.03	1.11
Lubricants	0.19	0.22	0.21	0.26	0.26	0.28	0.28
Total	**26.94**	**32.68**	**32.58**	**39.45**	**37.30**	**42.96**	**39.19**
Energy Use by Mode (million barrels per day oil equivalent)							
Light-Duty Vehicles	8.05	9.93	9.96	11.96	11.07	12.98	11.36
Commercial Light Trucks[1]	0.32	0.39	0.38	0.47	0.45	0.52	0.47
Freight Trucks	2.05	2.61	2.59	3.16	3.09	3.49	3.37
Railroad	0.24	0.26	0.24	0.28	0.20	0.28	0.19
Domestic Shipping	0.16	0.17	0.17	0.20	0.18	0.21	0.19
International Shipping	0.34	0.33	0.33	0.34	0.34	0.34	0.34
Air[5]	1.44	1.65	1.64	2.19	2.15	2.45	2.40
Military Use	0.30	0.34	0.34	0.38	0.38	0.40	0.40
Bus Transportation	0.12	0.13	0.13	0.13	0.13	0.13	0.13
Rail Transportation[6]	0.05	0.06	0.06	0.08	0.08	0.08	0.08
Recreational Boats	0.16	0.18	0.18	0.19	0.19	0.20	0.20
Lubricants	0.09	0.10	0.10	0.12	0.12	0.13	0.13
Pipeline Fuel	0.32	0.39	0.41	0.47	0.53	0.52	0.56
Total	**13.64**	**16.54**	**16.54**	**19.97**	**18.90**	**21.74**	**19.83**

[1] Commercial trucks 8,500 to 10,000 pounds.
[2] Environmental Protection Agency rated miles per gallon.
[3] Combined car and light truck "on-the-road" estimate.
[4] Includes energy use by buses and military distillate consumption.
[5] Includes jet fuel and aviation gasoline.
[6] Includes passenger rail.
[7] Includes military residual fuel use and recreational boats.

Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001); Federal Highway Administration, *Highway Statistics 2000* (Washington, DC, November 2001); Oak Ridge National Laboratory, Transportation Energy Data Book: *Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey" EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA,*State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2001/2000* (Washington, DC, 2001); EIA, *Fuel Oil and Kerosene Sales 2001*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/historical/foks.html; and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D10. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Generation by Fuel Type							
Electric Power Sector[1]							
Power Only[2]							
Coal	1848	2237	1927	2512	836	2747	526
Petroleum	113	40	19	47	11	52	13
Natural Gas[3]	411	671	811	1143	1745	1314	1889
Nuclear Power	769	790	801	793	934	793	1186
Pumped Storage/Other	-9	-1	-1	-1	-1	-1	-1
Renewable Sources[4]	258	394	517	414	991	423	1122
Distributed Generation (Natural Gas)	0	1	5	5	13	8	13
Non-Utility Generation for Own Use	-21	-24	-26	-24	-26	-24	-25
Total	**3370**	**4107**	**4053**	**4889**	**4503**	**5312**	**4725**
Combined Heat and Power[5]							
Coal	33	33	30	33	16	33	10
Petroleum	7	4	3	3	3	3	3
Natural Gas	124	171	161	156	131	149	115
Renewable Sources	5	4	4	4	4	4	4
Non-Utility Generation for Own Use	-9	-18	-18	-18	-17	-18	-16
Total	**162**	**193**	**181**	**178**	**138**	**171**	**116**
Net Available to the Grid	**3532**	**4301**	**4234**	**5067**	**4641**	**5483**	**4841**
End-Use Sector Generation							
Combined Heat and Power[6]							
Coal	23	23	23	23	23	23	23
Petroleum	6	6	6	6	6	6	6
Natural Gas	84	105	122	142	201	174	328
Other Gaseous Fuels[7]	6	7	7	7	7	8	7
Renewable Sources[4]	31	40	39	51	50	56	55
Other[8]	11	11	11	11	11	11	11
Total	**160**	**192**	**209**	**240**	**298**	**278**	**431**
Other End-Use Generators[9]	4	5	5	6	6	6	7
Generation for Own Use	-138	-154	-173	-183	-241	-207	-328
Total Sales to the Grid	**27**	**43**	**41**	**63**	**63**	**78**	**110**
Net Imports	**20**	**30**	**41**	**16**	**48**	**6**	**31**
Electricity Sales by Sector							
Residential	1201	1445	1429	1640	1479	1745	1498
Commercial	1197	1468	1455	1808	1659	1990	1750
Industrial	994	1164	1139	1364	1293	1469	1366
Transportation	22	27	27	36	35	42	39
Total	**3414**	**4104**	**4050**	**4848**	**4467**	**5246**	**4653**
End-Use Prices[10] **(2001 cents per kilowatthour)**							
Residential	8.7	7.7	8.2	7.9	10.3	7.9	11.4
Commercial	7.9	6.8	7.3	7.2	9.4	7.2	10.6
Industrial	4.8	4.4	4.9	4.6	6.4	4.6	7.1
Transportation	7.5	6.5	7.1	6.3	8.3	6.1	8.9
All Sectors Average	**7.3**	**6.4**	**7.0**	**6.7**	**8.8**	**6.7**	**9.8**
Prices by Service Category[10] **(2001 cents per kilowatthour)**							
Generation	4.7	3.9	4.4	4.2	6.1	4.2	7.1
Transmission	0.5	0.6	0.6	0.6	0.7	0.6	0.8
Distribution	2.0	2.0	2.0	1.9	2.0	1.9	2.0

Table D10. Electricity Supply, Disposition, Prices, and Emissions (Continued)

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Emissions							
Sulfur Dioxide (million tons)	10.63	9.69	9.84	8.95	5.87	8.95	1.93
Nitrogen Oxide (million tons)	4.75	3.90	3.50	4.02	1.48	4.08	0.67
Mercury (tons)	53.52	53.60	48.66	54.05	19.07	54.82	7.18

[1] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes plants that only produce electricity.

[3] Includes electricity generation from fuel cells.

[4] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.

[5] Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).

[6] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[7] Other gaseous fuels include refinery and still gas.

[8] Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.

[9] Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[10] Prices represent average revenue per kilowatthour.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Source: 2001 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and supporting databases. 2001 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2001 prices: EIA, National Energy Modeling System run MLBILL.D050503A. **Projections**: EIA, AEO2003 National Energy Modeling System run MLBASE.D050303A and MLBILL.D050503A.

Table D11. Electricity Generating Capacity

(Gigawatts)

Net Summer Capacity[1]	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Electric Power Sector[2]							
Power Only[3]							
Coal Steam	305.3	310.6	289.0	343.9	209.3	376.0	139.9
Other Fossil Steam[4]	133.8	77.9	80.7	71.9	64.8	71.1	53.0
Combined Cycle	43.2	148.4	175.9	233.0	319.1	278.1	374.1
Combustion Turbine/Diesel	97.6	126.4	123.2	148.0	121.4	164.3	118.2
Nuclear Power[5]	98.2	98.7	100.3	99.0	117.2	99.0	149.2
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.2	0.2	0.2	0.2
Renewable Sources[6]	90.4	97.2	129.0	101.0	225.0	102.6	245.6
Distributed Generation[7]	0.0	1.7	1.7	11.7	4.9	17.7	5.0
Total	**788.3**	**881.2**	**920.2**	**1029.0**	**1082.2**	**1129.3**	**1105.4**
Combined Heat and Power[8]							
Coal Steam	5.2	4.7	4.4	4.7	3.3	4.7	2.6
Other Fossil Steam[4]	1.2	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	22.6	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	4.6	5.3	5.3	5.3	5.3	5.3	5.3
Renewable Sources[6]	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**33.7**	**44.3**	**44.0**	**44.3**	**42.9**	**44.3**	**42.2**
Total Electric Power Industry	**822.0**	**925.6**	**964.2**	**1073.4**	**1125.1**	**1173.7**	**1147.6**
Cumulative Planned Additions[9]							
Coal Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	83.1	83.1	83.1	83.1	83.1	83.1
Combustion Turbine/Diesel	0.0	31.5	31.5	31.5	31.5	31.5	31.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.1	0.2	0.2	0.2	0.2
Renewable Sources[6]	0.0	4.9	4.9	6.5	6.5	6.6	6.6
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**120.0**	**120.0**	**121.7**	**121.7**	**121.8**	**121.8**
Cumulative Unplanned Additions[9]							
Coal Steam	0.0	12.3	0.0	47.5	12.2	80.7	37.7
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	32.0	59.7	116.7	203.0	161.8	259.6
Combustion Turbine/Diesel	0.0	9.0	3.7	33.7	3.7	52.3	3.7
Nuclear Power	0.0	0.0	0.0	0.0	16.5	0.0	48.5
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	1.5	33.3	3.8	127.8	5.2	148.2
Distributed Generation[7]	0.0	1.7	1.7	11.7	4.9	17.7	5.0
Total	**0.0**	**56.5**	**98.4**	**213.3**	**368.1**	**317.8**	**502.8**
Cumulative Total Additions	**0.0**	**176.6**	**218.4**	**334.9**	**489.8**	**439.5**	**624.6**
Cumulative Retirements[10]							
Coal Steam	0.0	7.6	17.2	9.4	110.2	10.5	205.8
Other Fossil Steam[4]	0.0	54.4	51.6	60.4	67.5	61.2	79.3
Combined Cycle	0.0	0.7	0.9	0.7	0.9	0.7	2.6
Combustion Turbine/Diesel	0.0	11.2	9.1	14.3	10.9	16.7	14.2
Nuclear Power	0.0	2.4	0.8	3.4	1.8	3.4	1.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**76.5**	**79.7**	**88.3**	**191.4**	**92.6**	**303.8**

Table D11. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
End-Use Sector							
Combined Heat and Power[11]							
Coal	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Petroleum	0.9	1.0	1.0	1.0	1.0	1.0	1.0
Natural Gas	14.6	17.0	19.4	22.1	30.1	26.4	48.7
Other Gaseous Fuels	2.1	2.2	2.2	2.2	2.2	2.3	2.2
Renewable Sources[6]	4.7	6.2	6.2	8.1	8.0	9.0	8.9
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.8**	**31.8**	**34.2**	**38.8**	**46.7**	**44.2**	**66.2**
Other End-Use Generators[12]							
Renewable Sources[13]	1.1	1.5	1.5	1.7	1.9	2.0	2.2
Cumulative Additions[9]							
Combined Heat and Power[11]	0.0	4.1	6.4	11.1	19.0	16.6	38.5
Other End-Use Generators[12]	0.0	0.4	0.4	0.6	0.7	0.9	1.1

[1] Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.

[2] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[3] Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.

[4] Includes oil-, gas-, and dual-fired capability.

[5] Nuclear capacity reflects operating capacity of existing units, including 4.3 gigawatts of uprates through 2025.

[6] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.

[7] Primarily peak-load capacity fueled by natural gas

[8] Includes combined heat and power plants whose primary business is to sell electricity and heat to the public(i.e., those that report NAICS code 22).

[9] Cumulative additions after December 31, 2001.

[10] Cumulative total retirements after December 31, 2001.

[11] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[12] Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[13] See Table D17 for more detail.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model estimates and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with capability for electric utility generators.

Source: 2001 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D12. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Crude Oil							
Domestic Crude Production[1]	5.80	5.64	5.63	5.43	5.41	5.30	5.27
Alaska	0.97	0.64	0.64	1.23	1.23	1.17	1.17
Lower 48 States	4.84	5.00	4.99	4.20	4.18	4.13	4.09
Net Imports	9.31	11.49	11.40	12.67	12.35	13.14	12.72
Gross Imports	9.33	11.56	11.46	12.73	12.40	13.18	12.77
Exports	0.02	0.06	0.06	0.05	0.05	0.05	0.05
Other Crude Supply[2]	0.02	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.13**	**17.13**	**17.03**	**18.10**	**17.76**	**18.44**	**17.99**
Natural Gas Plant Liquids	**1.87**	**2.20**	**2.27**	**2.48**	**2.63**	**2.59**	**2.69**
Other Inputs[3]	**0.30**	**0.44**	**0.43**	**0.44**	**0.36**	**0.44**	**0.35**
Refinery Processing Gain[4]	**0.90**	**0.91**	**0.89**	**0.96**	**0.94**	**0.96**	**0.93**
Net Product Imports[5]	**1.59**	**2.17**	**1.89**	**4.88**	**3.42**	**6.48**	**4.22**
Gross Refined Product Imports[6]	2.08	2.55	2.32	4.89	3.40	6.51	4.26
Unfinished Oil Imports	0.38	0.63	0.55	1.07	1.06	1.08	1.01
Ether Imports	0.08	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.95	1.00	0.98	1.08	1.03	1.11	1.05
Total Primary Supply[7]	**19.80**	**22.86**	**22.52**	**26.86**	**25.10**	**28.90**	**26.17**
Refined Petroleum Products Supplied							
Motor Gasoline[8]	8.67	10.54	10.42	12.53	11.47	13.55	11.76
Jet Fuel[9]	1.66	1.90	1.89	2.46	2.42	2.74	2.69
Distillate Fuel[10]	3.81	4.62	4.57	5.42	5.19	5.88	5.54
Residual Fuel	0.97	0.63	0.54	0.66	0.52	0.66	0.53
Other[11]	4.58	5.18	5.12	5.80	5.50	6.09	5.66
Total	**19.69**	**22.87**	**22.53**	**26.87**	**25.11**	**28.92**	**26.18**
Refined Petroleum Products Supplied							
Residential and Commercial	1.21	1.18	1.18	1.14	1.16	1.13	1.15
Industrial[12]	4.67	5.28	5.21	5.96	5.62	6.28	5.79
Transportation	13.27	16.19	16.02	19.53	18.25	21.25	19.14
Electric Power[13]	0.55	0.21	0.12	0.24	0.08	0.26	0.09
Total	**19.69**	**22.87**	**22.53**	**26.87**	**25.11**	**28.92**	**26.18**
Discrepancy[14]	**0.10**	**-0.02**	**-0.02**	**-0.02**	**-0.01**	**-0.02**	**-0.01**
World Oil Price (2001 dollars per barrel)[15]	**22.01**	**23.99**	**23.77**	**25.48**	**24.15**	**26.57**	**24.58**
Import Share of Product Supplied	**0.55**	**0.60**	**0.59**	**0.65**	**0.63**	**0.68**	**0.65**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2001 dollars)	**89.20**	**122.23**	**117.95**	**172.92**	**144.08**	**205.85**	**158.78**
Domestic Refinery Distillation Capacity[16]	**16.8**	**18.7**	**18.7**	**19.5**	**19.1**	**19.8**	**19.3**
Capacity Utilization Rate (percent)	**93.0**	**93.1**	**92.8**	**94.6**	**94.5**	**94.6**	**94.6**

[1] Includes lease condensate.

[2] Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.

[3] Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.

[4] Represents volumetric gain in refinery distillation and cracking processes.

[5] Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.

[6] Includes other hydrocarbons, alcohols, and blending components.

[7] Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.

[8] Includes ethanol and ethers blended into gasoline.

[9] Includes only kerosene type.

[10] Includes distillate and kerosene.

[11] Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.

[12] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[13] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[14] Balancing item. Includes unaccounted for supply, losses, and gains.

[15] Average refiner acquisition cost for imported crude oil.

[16] End-of-year capacity.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). Other 2001 data: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D13. Petroleum Product Prices

(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
World Oil Price (2001 dollars per barrel)	**22.01**	**23.99**	**23.77**	**25.48**	**24.15**	**26.57**	**24.58**
Delivered Sector Product Prices							
Residential							
Distillate Fuel	124.6	110.9	110.3	120.7	114.2	123.8	119.0
Liquefied Petroleum Gas	127.3	123.1	119.8	131.1	123.9	133.1	128.3
Commercial							
Distillate Fuel	88.7	78.6	78.0	89.5	82.6	93.7	87.3
Residual Fuel	51.8	60.1	58.9	63.3	59.3	65.7	60.2
Residual Fuel (2001 dollars per barrel)	21.75	25.24	24.73	26.57	24.92	27.58	25.30
Industrial[1]							
Distillate Fuel	90.8	79.7	79.2	93.4	85.7	99.7	90.6
Liquefied Petroleum Gas	105.9	85.2	82.2	93.1	87.0	95.4	91.0
Residual Fuel	49.1	55.6	54.7	58.9	55.4	61.4	56.4
Residual Fuel (2001 dollars per barrel)	20.61	23.35	22.99	24.75	23.26	25.77	23.67
Transportation							
Diesel Fuel (distillate)[2]	139.4	141.4	162.4	142.4	182.6	147.5	199.3
Jet Fuel[3]	83.7	76.3	95.9	85.6	125.0	90.7	139.7
Motor Gasoline[4]	143.3	141.8	160.8	143.1	179.9	149.4	189.6
Liquid Petroleum Gas	145.2	133.4	140.3	137.8	157.0	137.1	164.3
Residual Fuel	58.4	53.4	77.8	56.6	110.1	59.0	124.5
Residual Fuel (2001 dollars per barrel)	24.52	22.41	32.66	23.76	46.25	24.80	52.31
Electric Power[5]							
Distillate Fuel	86.0	71.2	69.5	82.4	74.7	85.4	78.2
Residual Fuel	67.4	61.0	64.2	64.8	73.1	68.1	74.6
Residual Fuel (2001 dollars per barrel)	28.30	25.63	26.98	27.23	30.71	28.60	31.31
Refined Petroleum Product Prices[6]							
Distillate Fuel	127.0	127.0	142.1	132.0	160.6	137.3	175.3
Jet Fuel[3]	83.7	76.3	95.9	85.6	125.0	90.7	139.7
Liquefied Petroleum Gas	110.3	92.2	89.4	99.3	93.8	101.3	97.8
Motor Gasoline[4]	143.4	141.8	160.6	143.1	179.4	149.4	189.1
Residual Fuel	61.5	55.9	71.7	59.3	96.1	61.9	106.5
Residual Fuel (2001 dollars per barrel)	25.85	23.48	30.13	24.92	40.35	26.02	44.75
Average	**123.6**	**122.0**	**137.0**	**125.7**	**154.1**	**131.1**	**164.3**
Greenhouse Gas Allowance Cost							
Commercial							
Distillate Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residual Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residual Fuel (2001 dollars per barrel)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[1]							
Distillate Fuel	0.0	0.0	21.6	0.0	48.9	0.0	60.5
Liquefied Petroleum Gas	0.0	0.0	11.6	0.0	26.1	0.0	32.4
Residual Fuel	0.0	0.0	25.1	0.0	56.8	0.0	70.3
Residual Fuel (2001 dollars per barrel)	0.00	0.00	10.55	0.00	23.86	0.00	29.53
Electric Power[5]							
Distillate Fuel	0.0	0.0	21.6	0.0	48.9	0.0	60.5
Residual Fuel	0.0	0.0	25.1	0.0	56.8	0.0	70.3
Residual Fuel (2001 dollars per barrel)	0.00	0.00	10.55	0.00	23.86	0.00	29.53

Table D13. Petroleum Product Prices (Continued)

(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Delivered Sector Product Prices with Greenhouse Gas Allowance Cost							
Commercial							
Distillate Fuel	88.7	78.6	78.0	89.5	82.6	93.7	87.3
Residual Fuel	51.8	60.1	58.9	63.3	59.3	65.7	60.2
Residual Fuel (2001 dollars per barrel)	21.75	25.24	24.73	26.57	24.92	27.58	25.30
Industrial[1]							
Distillate Fuel	90.8	79.7	100.8	93.4	134.6	99.7	151.0
Liquefied Petroleum Gas	105.9	85.2	93.8	93.1	113.1	95.4	123.3
Residual Fuel	49.1	55.6	79.9	58.9	112.2	61.4	126.7
Residual Fuel (2001 dollars per barrel)	20.61	23.35	33.55	24.75	47.12	25.77	53.20
Electric Power[5]							
Distillate Fuel	86.0	71.2	91.1	82.4	123.6	85.4	138.6
Residual Fuel	67.4	61.0	89.4	64.8	129.9	68.1	144.9
Residual Fuel (2001 dollars per barrel)	28.30	25.63	37.53	27.23	54.57	28.60	60.84

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[1] Includes combined heat and power, which produces electricity and other useful thermal energy.

[2] Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur. Includes Federal and State taxes while excluding county and local taxes.

[3] Kerosene-type jet fuel.

[4] Sales weighted-average price for all grades. Includes Federal, State and local taxes.

[5] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[6] Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources:. 2001 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A: "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2001 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2001 world oil price: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections**: EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D14. Natural Gas Supply and Disposition

(Trillion Cubic Feet per Year)

Supply and Disposition	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Production							
Dry Gas Production[1]	19.45	21.53	22.21	24.85	26.61	26.36	27.32
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.73**	**4.76**	**4.85**	**6.88**	**8.80**	**7.90**	**10.87**
Canada	3.61	4.16	4.20	5.14	5.44	5.21	5.61
Mexico	-0.13	-0.20	-0.21	-0.02	0.16	0.29	0.66
Liquefied Natural Gas	0.26	0.80	0.86	1.76	3.21	2.40	4.60
Total Supply	**23.26**	**26.39**	**27.15**	**31.83**	**35.51**	**34.36**	**38.29**
Consumption by Sector							
Residential	4.81	5.48	5.47	5.93	5.80	6.21	6.03
Commercial	3.24	3.64	3.63	4.12	4.16	4.38	4.84
Industrial[3]	7.53	8.81	8.91	10.10	10.08	10.93	10.79
Electric Power[4]	5.30	6.58	7.20	9.42	13.00	10.37	14.03
Transportation[5]	0.01	0.06	0.06	0.10	0.09	0.11	0.10
Pipeline Fuel	0.61	0.76	0.79	0.91	1.02	1.00	1.08
Lease and Plant Fuel[6]	1.17	1.33	1.36	1.56	1.66	1.68	1.72
Total	**22.67**	**26.66**	**27.42**	**32.14**	**35.80**	**34.67**	**38.59**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.59**	**-0.28**	**-0.26**	**-0.31**	**-0.30**	**-0.31**	**-0.30**

[1] Marketed production (wet) minus extraction losses.

[2] Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

[3] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as vehicle fuel.

[6] Represents natural gas used in the field gathering and processing plant machinery.

[7] Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2001 values include net storage injections.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D15. Natural Gas Prices, Margins, and Revenue

(2001 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Source Price							
Average Lower 48 Wellhead Price[1]	4.12	3.39	3.51	3.70	3.97	3.95	4.36
Average Import Price	4.43	3.40	3.46	3.88	4.17	4.19	4.65
Average[2]	**4.17**	**3.39**	**3.50**	**3.74**	**4.02**	**4.01**	**4.45**
Delivered Prices							
Residential	9.68	7.79	7.89	7.99	8.30	8.26	8.72
Commercial	8.32	6.67	6.78	6.98	7.27	7.26	7.69
Industrial[3]	5.01	4.11	4.23	4.51	4.81	4.76	5.21
Electric Power[4]	4.87	3.95	4.14	4.44	4.88	4.73	5.29
Transportation[5]	7.87	7.39	7.45	7.97	7.94	8.32	8.30
Average[6]	**6.57**	**5.28**	**5.38**	**5.55**	**5.78**	**5.80**	**6.19**
Transmission & Distribution Margins[7]							
Residential	5.50	4.39	4.39	4.25	4.27	4.25	4.28
Commercial	4.14	3.28	3.28	3.24	3.24	3.25	3.24
Industrial[3]	0.83	0.72	0.73	0.77	0.79	0.75	0.77
Electric Power[4]	0.70	0.56	0.65	0.70	0.86	0.72	0.84
Transportation[5]	3.69	4.00	3.95	4.23	3.92	4.31	3.86
Average[6]	**2.40**	**1.89**	**1.88**	**1.81**	**1.76**	**1.79**	**1.75**
Transmission & Distribution Revenue (billion 2001 dollars)							
Residential	26.45	24.08	24.00	25.22	24.78	26.39	25.78
Commercial	13.42	11.94	11.91	13.33	13.48	14.25	15.68
Industrial[3]	6.28	6.36	6.49	7.82	7.94	8.23	8.27
Electric Power[4]	3.69	3.70	4.64	6.57	11.18	7.42	11.80
Transportation[5]	0.04	0.23	0.22	0.41	0.36	0.47	0.39
Total	**49.88**	**46.31**	**47.27**	**53.36**	**57.74**	**56.76**	**61.91**
Greenhouse Gas Allowance Cost							
Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[3]	0.00	0.00	1.15	0.00	2.59	0.00	3.21
Electric Power[4]	0.00	0.00	1.16	0.00	2.62	0.00	3.24
Transportation[5]	0.00	0.00	1.17	0.00	2.64	0.00	3.27
Average[6]	**0.00**	**0.00**	**0.74**	**0.00**	**1.83**	**0.00**	**2.25**
Delivered Prices with Greenhouse Gas Allowance Cost							
Residential	9.68	7.79	7.89	7.99	8.30	8.26	8.72
Commercial	8.32	6.67	6.78	6.98	7.27	7.26	7.69
Industrial[3]	5.01	4.11	5.37	4.51	7.40	4.76	8.42
Electric Power[4]	4.87	3.95	5.30	4.44	7.50	4.73	8.53
Transportation[5]	7.87	7.39	8.62	7.97	10.58	8.32	11.57
Average[6]	**6.57**	**5.28**	**6.12**	**5.55**	**7.61**	**5.80**	**8.44**

[1] Represents lower 48 onshore and offshore supplies.

[2] Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.

[3] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.

[6] Weighted average allowance cost. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.

[7] Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 electric generators delivered price: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1998*. 2001 residential, commercial, and transportation delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D16. Oil and Gas Supply

Production and Supply	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Crude Oil							
Lower 48 Average Wellhead Price[1] (2001 dollars per barrel)	**22.91**	**23.89**	**23.56**	**24.98**	**23.65**	**26.22**	**24.11**
Production (million barrels per day)[2]							
U.S. Total	**5.80**	**5.64**	**5.63**	**5.43**	**5.41**	**5.30**	**5.27**
Lower 48 Onshore	3.13	2.47	2.47	2.06	2.05	1.92	1.90
Lower 48 Offshore	1.71	2.52	2.52	2.14	2.13	2.22	2.19
Alaska	0.97	0.64	0.64	1.23	1.23	1.17	1.17
Lower 48 End of Year Reserves (billion barrels)[2]	**19.48**	**17.72**	**17.70**	**15.39**	**15.34**	**15.04**	**14.92**
Natural Gas							
Lower 48 Average Wellhead Price[1] (2001 dollars per thousand cubic feet)	**4.12**	**3.39**	**3.51**	**3.70**	**3.97**	**3.95**	**4.36**
Dry Production (trillion cubic feet)[3]							
U.S. Total	**19.45**	**21.54**	**22.21**	**24.86**	**26.61**	**26.37**	**27.32**
Lower 48 Onshore	13.72	15.57	16.17	17.96	18.65	17.77	18.72
Associated-Dissolved[4]	1.77	1.37	1.36	1.19	1.19	1.13	1.13
Non-Associated	11.94	14.20	14.81	16.77	17.46	16.64	17.59
Conventional	6.54	7.04	7.32	7.15	7.37	7.04	7.13
Unconventional	5.40	7.16	7.49	9.61	10.09	9.60	10.46
Lower 48 Offshore	5.30	5.49	5.56	5.43	5.58	5.74	5.77
Associated-Dissolved[4]	1.08	0.96	0.96	0.80	0.79	0.82	0.81
Non-Associated	4.22	4.53	4.60	4.63	4.78	4.93	4.96
Alaska	0.43	0.48	0.48	1.47	2.39	2.85	2.84
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**174.04**	**186.42**	**185.39**	**194.24**	**195.87**	**190.10**	**192.41**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Total Lower 48 Wells (thousands)	**33.94**	**25.73**	**25.75**	**26.21**	**27.25**	**27.53**	**29.30**

[1] Represents lower 48 onshore and offshore supplies.
[2] Includes lease condensate.
[3] Marketed production (wet) minus extraction losses.
[4] Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5] Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2001 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting.
Projections: EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D17. Coal Supply, Disposition, and Prices

(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Production[1]							
Appalachia	443	420	415	416	212	433	145
Interior	147	161	153	151	88	159	42
West	548	669	513	801	185	865	128
East of the Mississippi	539	527	518	529	286	554	182
West of the Mississippi	599	723	563	839	199	902	132
Total	**1138**	**1250**	**1081**	**1367**	**485**	**1456**	**315**
Net Imports							
Imports	19	20	11	25	11	28	10
Exports	49	33	33	29	29	24	24
Total	**-30**	**-14**	**-22**	**-4**	**-19**	**3**	**-13**
Total Supply[2]	**1109**	**1236**	**1060**	**1363**	**466**	**1460**	**301**
Consumption by Sector							
Residential and Commercial	4	5	5	5	5	5	6
Industrial[3]	63	67	61	70	59	71	58
of which: Coal to Liquids	0	0	0	0	0	0	0
Coke Plants	26	24	24	20	17	18	14
Electric Power[4]	957	1146	966	1274	390	1371	227
Total	**1050**	**1242**	**1055**	**1369**	**471**	**1466**	**306**
Discrepancy and Stock Change[5]	**58**	**-6**	**4**	**-6**	**-6**	**-6**	**-4**
Average Minemouth Price							
(2001 dollars per short ton)	17.59	15.06	15.84	14.34	15.27	14.39	13.67
(2001 dollars per million Btu)	0.83	0.73	0.76	0.70	0.71	0.71	0.63
Delivered Prices (2001 dollars per short ton)[6]							
Industrial	32.82	30.11	30.10	28.45	24.86	28.04	22.55
Coke Plants	46.42	41.27	41.37	38.08	38.31	36.67	36.64
Electric Power							
(2001 dollars per short ton)	25.06	23.63	23.76	22.44	20.83	22.27	18.81
(2001 dollars per million Btu)	1.25	1.17	1.16	1.12	0.99	1.11	0.90
Average	**26.06**	**24.33**	**24.53**	**22.98**	**21.98**	**22.74**	**20.39**
Exports[7]	36.97	32.68	32.41	30.94	28.76	30.36	27.46
Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]							
Industrial	0.00	0.00	43.59	0.00	98.28	0.00	121.42
Coke Plants	0.00	0.00	54.74	0.00	123.76	0.00	153.14
Electric Power							
(2001 dollars per short ton)	0.00	0.00	41.32	0.00	95.21	0.00	117.30
(2001 dollars per million Btu)	0.00	0.00	2.02	0.00	4.54	0.00	5.62
Average	**0.00**	**0.00**	**41.76**	**0.00**	**96.65**	**0.00**	**119.82**
Delivered Prices with Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]							
Industrial	32.82	30.11	73.69	28.45	123.14	28.04	143.97
Coke Plants	46.42	41.27	96.11	38.08	162.07	36.67	189.79
Electric Power							
(2001 dollars per short ton)	25.06	23.63	65.08	22.44	116.04	22.27	136.11
(2001 dollars per million Btu)	1.25	1.17	3.17	1.12	5.53	1.11	6.53
Average	**26.06**	**24.33**	**66.29**	**22.98**	**118.63**	**22.74**	**140.21**

[1] Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.1 million tons in 2000 and 10.6 million tons in 2001.

[2] Production plus net imports and net storage withdrawals.

[3] Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

[4] Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[5] Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.

[6] Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.

[7] F.a.s. price at U.S. port of exit.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D18. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Electric Power Sector[1]							
Net Summer Capacity							
Conventional Hydropower	78.10	78.66	78.66	78.65	78.65	78.65	78.65
Geothermal[2]	2.83	3.81	6.68	5.19	10.06	5.77	10.55
Municipal Solid Waste[3]	3.25	4.08	4.84	4.41	5.17	4.42	5.19
Wood and Other Biomass[4]	1.80	2.09	3.96	2.20	48.03	2.33	67.38
Solar Thermal	0.33	0.44	0.44	0.48	0.48	0.50	0.50
Solar Photovoltaic[5]	0.02	0.10	0.10	0.27	0.27	0.36	0.36
Wind	4.29	8.24	34.53	10.05	82.60	10.81	83.22
Total	**90.62**	**97.42**	**129.20**	**101.24**	**225.26**	**102.83**	**245.84**
Generation (billion kilowatthours)							
Conventional Hydropower	213.82	300.90	300.89	300.07	299.92	300.36	300.10
Geothermal[2]	13.81	22.04	44.61	33.43	73.14	38.12	77.22
Municipal Solid Waste[3]	19.55	29.20	35.17	31.67	37.63	31.81	37.83
Wood and Other Biomass[4]	9.38	21.47	27.11	22.06	304.95	22.82	429.32
Dedicated Plants	7.66	12.47	19.52	13.22	304.95	14.09	429.32
Cofiring	1.72	9.00	7.59	8.84	0.00	8.73	0.00
Solar Thermal	0.49	0.77	0.77	0.90	0.90	0.97	0.97
Solar Photovoltaic[5]	0.00	0.24	0.24	0.66	0.66	0.88	0.88
Wind	5.78	22.91	112.46	29.20	277.70	32.03	280.10
Total	**262.85**	**397.53**	**521.25**	**417.98**	**994.90**	**427.00**	**1126.43**
End- Use Sector							
Net Summer Capacity							
Combined Heat and Power[6]							
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Biomass	4.41	5.93	5.89	7.79	7.67	8.74	8.60
Total	**4.69**	**6.21**	**6.17**	**8.07**	**7.95**	**9.03**	**8.88**
Other End-Use Generators[7]							
Conventional Hydropower[8]	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.38	0.38	0.61	0.76	0.94	1.15
Total	**1.12**	**1.47**	**1.47**	**1.71**	**1.85**	**2.04**	**2.25**
Generation (billion kilowatthours)							
Combined Heat and Power[6]							
Municipal Solid Waste	2.46	2.15	2.15	2.15	2.15	2.15	2.15
Biomass	28.67	37.53	37.31	48.39	47.72	53.98	53.13
Total	**31.13**	**39.68**	**39.46**	**50.54**	**49.87**	**56.13**	**55.28**
Other End-Use Generators[7]							
Conventional Hydropower[8]	4.23	4.23	4.23	4.23	4.23	4.23	4.23
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.82	0.82	1.32	1.61	1.99	2.42
Total	**4.25**	**5.05**	**5.05**	**5.55**	**5.85**	**6.23**	**6.66**

[1] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes hydrothermal resources only (hot water and steam).

[3] Includes landfill gas.

[4] Includes projections for energy crops after 2010.

[5] Does not include off-grid photovoltaics (PV). See Annual Energy Review 2001 Table 10.6 for estimates of 1989-2000 PV shipments, including exports, for both grid-connected and off-grid applications.

[6] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[7] Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[8] Represents own-use industrial hydroelectric power.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2003. Net summer capacity is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.

Sources: 2001 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2001 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D19. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Marketed Renewable Energy[2]							
Residential	**0.39**	**0.41**	**0.41**	**0.41**	**0.40**	**0.40**	**0.40**
Wood	0.39	0.41	0.41	0.41	0.40	0.40	0.40
Commercial	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Industrial[3]	**1.82**	**2.22**	**2.21**	**2.77**	**2.74**	**3.05**	**3.02**
Conventional Hydroelectric	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.77	2.17	2.16	2.72	2.69	3.00	2.97
Transportation	**0.15**	**0.26**	**0.26**	**0.31**	**0.28**	**0.33**	**0.29**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Ethanol used in Gasoline Blending	0.15	0.26	0.26	0.30	0.28	0.33	0.28
Electric Power[5]	**3.01**	**4.57**	**6.30**	**5.02**	**11.42**	**5.21**	**12.69**
Conventional Hydroelectric	2.16	3.09	3.09	3.07	3.07	3.07	3.07
Geothermal	0.29	0.57	1.30	0.93	2.23	1.07	2.36
Municipal Solid Waste[6]	0.31	0.40	0.48	0.43	0.51	0.43	0.51
Biomass	0.15	0.26	0.31	0.27	2.78	0.28	3.89
Dedicated Plants	0.12	0.14	0.21	0.15	2.78	0.16	3.89
Cofiring	0.03	0.12	0.09	0.12	0.00	0.12	0.00
Solar Thermal	0.01	0.01	0.01	0.02	0.02	0.02	0.02
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.08	0.24	1.12	0.30	2.82	0.33	2.84
Total Marketed Renewable Energy	**5.46**	**7.56**	**9.28**	**8.61**	**14.95**	**9.10**	**16.50**
Sources of Ethanol							
From Corn	0.15	0.26	0.26	0.28	0.26	0.28	0.24
From Cellulose	0.00	0.00	0.00	0.02	0.02	0.05	0.05
Total	**0.15**	**0.26**	**0.26**	**0.31**	**0.28**	**0.33**	**0.29**
Non-Marketed Renewable Energy[7] **Selected Consumption**							
Residential	**0.03**	**0.04**	**0.04**	**0.05**	**0.05**	**0.06**	**0.06**
Solar Hot Water Heating	0.03	0.03	0.03	0.04	0.04	0.04	0.04
Geothermal Heat Pumps	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.01	0.01

[1] Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.

[2] Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table D8.

[3] Includes all electricity production by industrial and other combined heat and power for the grid and for own use.

[4] Excludes motor gasoline component of E85.

[5] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[6] Includes landfill gas.

[7] Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 electric generators: EIA, Form EIA-860: "Annual Electric Generator Report" (preliminary). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D20. Greenhouse Gas Emissions and Allowance Cost
(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Carbon Dioxide Emissions							
Residential							
Petroleum	27.2	27.6	27.6	25.7	25.8	25.0	25.0
Natural Gas	71.1	81.1	81.0	87.9	85.8	91.9	89.3
Coal	0.3	0.4	0.4	0.4	0.4	0.3	0.3
Total	**98.7**	**109.1**	**109.0**	**113.9**	**112.0**	**117.2**	**114.7**
Commercial							
Petroleum	14.0	13.7	13.7	14.1	14.5	14.1	14.8
Natural Gas	48.0	53.9	53.8	60.9	61.5	64.8	71.6
Coal	2.3	2.4	2.5	2.7	2.8	2.8	2.9
Total	**64.3**	**70.0**	**69.9**	**77.7**	**78.8**	**81.7**	**89.3**
Industrial[1]							
Petroleum	97.9	97.9	96.0	105.5	99.1	109.1	101.1
Natural Gas[2]	123.4	147.7	149.8	169.4	171.0	183.3	182.4
Coal	52.1	56.5	53.1	56.2	48.9	56.2	47.3
Total	**273.4**	**302.1**	**298.9**	**331.2**	**319.0**	**348.6**	**330.8**
Transportation							
Petroleum[3]	501.4	611.5	605.1	737.5	690.4	802.8	725.3
Natural Gas[4]	9.2	12.0	12.5	14.9	16.4	16.4	17.4
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**510.6**	**623.6**	**617.6**	**752.5**	**706.8**	**819.2**	**742.7**
Total Carbon Dioxide Emissions by Delivered Fuel							
Petroleum[3]	640.5	750.8	742.5	882.8	829.8	950.9	866.2
Natural Gas	251.7	294.7	297.0	333.1	334.8	356.4	360.7
Coal	54.7	59.3	55.9	59.3	52.0	59.4	50.5
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**947.0**	**1104.8**	**1095.4**	**1275.2**	**1216.6**	**1366.7**	**1277.4**
Electric Power[6]							
Petroleum	27.5	10.1	5.4	11.3	3.9	12.0	3.9
Natural Gas	77.7	96.6	105.0	138.2	158.0	152.1	132.6
Coal	506.4	590.8	504.4	653.0	190.0	703.6	68.3
Total	**611.6**	**697.4**	**614.8**	**802.5**	**351.9**	**867.8**	**204.8**
Total Carbon Dioxide Emissions by Primary Fuel[7]							
Petroleum[3]	668.0	760.8	747.9	894.1	833.7	962.9	870.2
Natural Gas	329.4	391.3	402.0	471.3	492.8	508.5	493.3
Coal	561.1	650.1	560.3	712.2	242.0	763.0	118.8
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1558.6**	**1802.2**	**1710.1**	**2077.7**	**1568.5**	**2234.4**	**1482.2**
Non-Energy Related Carbon Dioxide Emissions	**36.3**	**39.5**	**39.5**	**43.9**	**43.9**	**46.2**	**46.2**
Total Carbon Dioxide Emissions	**1594.9**	**1841.7**	**1749.7**	**2121.6**	**1612.4**	**2280.6**	**1528.4**
Other Greenhouse Gas Emissions	**332.9**	**388.3**	**286.4**	**466.6**	**339.5**	**525.0**	**362.9**
Methane	175.2	177.6	115.2	174.3	126.4	172.2	120.0
Nitrous Oxide	118.9	126.5	121.0	137.3	131.4	143.4	137.2
High Global Warming Potential Gases	38.8	84.2	50.2	155.0	81.8	209.4	105.8
Total Greenhouse Gas Emissions	**1927.8**	**2230.1**	**2036.1**	**2588.2**	**1951.9**	**2805.6**	**1891.4**

Table D20. Greenhouse Gas Emissions and Allowance Cost (Continued)

(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
Greenhouse Gas Emission Cap Compliance							
Covered Emissions							
Energy-Related Carbon Dioxide	1378.2	1605.0	1513.1	1866.0	1357.5	2014.2	1256.9
Other Greenhouse Gases	75.2	123.5	70.1	195.7	102.8	250.7	127.6
Offsets Purchased	0.0	0.0	234.7	0.0	126.1	0.0	125.6
Non-Covered Greenhouse Gas Offsets	0.0	0.0	48.5	0.0	34.3	0.0	39.0
U.S. Sequestration Offsets	0.0	0.0	112.8	0.0	91.8	0.0	86.5
International Offsets	0.0	0.0	73.4	0.0	0.0	0.0	0.1
Covered Emissions less Offsets	1453.4	1728.5	1348.5	2061.6	1334.2	2264.9	1258.9
Covered Emissions Coal	N/A	N/A	1465.1	N/A	1257.9	N/A	1257.9
Allowance Bank Activity	0.0	0.0	116.5	0.0	-76.3	0.0	-1.0
Cumulative Bank Balance	0.0	0.0	116.5	0.0	98.9	0.0	7.3
Allowance Cost (2001 dollars per ton)							
Emissions Allowance Cost	0.00	0.00	78.89	0.00	178.36	0.00	220.71
Offset Price	0.00	0.00	71.49	0.00	34.84	0.00	51.73

[1] Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes lease and plant fuel.

[3] This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons carbon equivalent of carbon dioxide annually.

[4] Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

[5] Includes methanol and liquid hydrogen.

[6] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.

[7] Emissions from electric power generators are distributed to the primary fuels.

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table D21. Macroeconomic Indicators

(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2001	Projections					
		2010		2020		2025	
		Reference	S. 139 Case	Reference	S. 139 Case	Reference	S. 139 Case
GDP Chain-Type Price Index (1996=1.000)	**1.094**	**1.313**	**1.321**	**1.708**	**1.735**	**1.981**	**2.028**
Potential Gross Domestic Product	**9456**	**12454**	**12458**	**16772**	**16729**	**19240**	**19150**
Real Gross Domestic Product	**9215**	**12258**	**12211**	**16444**	**16364**	**18916**	**18810**
Real Consumption	6377	8412	8375	11346	11284	13008	12954
Real Investment	1575	2499	2478	3755	3724	4496	4447
Real Government Spending	1640	1895	1897	2211	2204	2429	2417
Real Exports	1076	1784	1781	3361	3329	4696	4621
Real Imports	1492	2302	2292	4060	4027	5395	5376
Real Disposable Personal Income	**6748**	**8635**	**8607**	**11693**	**11648**	**13425**	**13432**
Federal Funds Rate (percent)	**3.89**	**5.48**	**5.63**	**6.37**	**6.58**	**6.49**	**6.97**
AA Utility Bond Rate (percent)							
Nominal	7.57	7.22	7.38	9.00	9.17	9.61	9.99
Real	5.60	5.26	5.20	6.12	6.18	6.54	6.76
Energy Intensity (thousand Btu per 1996 dollar of GDP)							
Delivered Energy	7.74	6.83	6.80	5.91	5.65	5.52	5.17
Total Energy	10.56	9.24	9.15	7.89	7.37	7.33	6.70
Consumer Price Index (1982-84=1.00)	**1.77**	**2.19**	**2.20**	**2.93**	**2.97**	**3.47**	**3.55**
Unemployment Rate (percent)	**4.79**	**4.42**	**4.55**	**5.88**	**6.03**	**5.77**	**5.85**
Housing Starts (millions)	**1.80**	**2.18**	**2.12**	**1.93**	**1.92**	**2.01**	**2.01**
Single-Family	1.27	1.34	1.31	1.12	1.11	1.12	1.11
Multifamily	0.33	0.47	0.45	0.49	0.49	0.57	0.57
Mobile Home Shipments	0.19	0.37	0.36	0.32	0.33	0.33	0.33
Commercial Floorspace, Total (billion square feet)	**70.2**	**82.0**	**82.0**	**94.6**	**94.2**	**100.8**	**100.6**
Value of Shipments (billion 1996 dollars)							
Total Industrial	5425	6977	6920	8969	8874	10128	9990
Nonmanufacturing	1346	1510	1500	1744	1714	1870	1828
Manufacturing	4079	5466	5420	7226	7160	8258	8162
Energy-Intensive Manufacturing	1086	1264	1255	1451	1434	1538	1515
Non-Energy-Intensive Manufacturing	2993	4203	4164	5774	5726	6720	6647
United Sales of Light-Duty Vehicles (millions)	**17.11**	**18.29**	**17.87**	**20.02**	**20.06**	**20.00**	**20.15**
Population (millions)							
Population with Armed Forces Overseas	278.2	300.2	300.2	325.3	325.3	338.2	338.2
Population (aged 16 and over)	215.4	236.6	236.6	256.5	256.5	266.6	266.6
Employment, Non-Agriculture	131.7	147.3	147.1	159.1	158.8	165.8	165.5
Employment, Manufacturing	17.5	17.7	17.7	17.8	17.7	18.5	18.4
Labor Force	141.8	156.5	156.5	169.8	169.6	177.4	177.3

GDP = Gross domestic product.

Btu = British thermal unit.

Sources: 2001: Global Insight macroeconomic model CTL0802. **Projections:** Energy Information Administration, AEO2003 National Energy Modeling System runs MLBASE.D050303A and MLBILL.D050503A.

Table E1. Total Energy Supply and Disposition Summary

(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Production										
Crude Oil and Lease Condensate	12.29	11.92	11.93	11.92	11.45	11.46	11.46	11.15	11.11	11.15
Natural Gas Plant Liquids	2.65	3.21	3.20	3.19	3.75	3.74	3.70	3.84	3.84	3.84
Dry Natural Gas	19.97	22.81	22.72	22.63	27.33	27.21	26.96	28.06	28.05	28.05
Coal	23.97	22.57	22.51	22.37	10.46	10.71	10.39	6.82	7.55	6.62
Nuclear Power	8.03	8.37	8.37	8.37	9.75	9.74	9.80	12.39	12.39	12.43
Renewable Energy[1]	5.32	9.03	9.00	9.03	14.68	14.74	14.75	16.22	16.07	16.30
Other[2]	0.57	0.82	0.83	0.85	0.62	0.61	0.62	0.59	0.58	0.59
Total	**72.80**	**78.73**	**78.56**	**78.35**	**78.04**	**78.21**	**77.68**	**79.06**	**79.59**	**78.98**
Imports										
Crude Oil[3]	20.26	24.88	24.87	24.88	26.92	26.88	26.85	27.72	27.77	27.71
Petroleum Products[4]	5.04	5.73	5.77	5.89	8.82	8.82	8.91	10.43	10.36	10.32
Natural Gas	4.18	5.53	5.59	5.60	9.37	9.38	9.38	11.48	11.41	11.40
Other Imports[5]	0.71	0.81	0.81	0.81	0.94	0.95	0.96	0.79	0.80	0.81
Total	**30.19**	**36.94**	**37.03**	**37.19**	**46.05**	**46.03**	**46.10**	**50.42**	**50.34**	**50.24**
Exports										
Petroleum[6]	2.01	2.21	2.21	2.22	2.29	2.29	2.30	2.32	2.31	2.32
Natural Gas	0.37	0.57	0.57	0.57	0.37	0.38	0.38	0.36	0.37	0.37
Coal	1.27	0.84	0.83	0.83	0.76	0.76	0.80	0.61	0.62	0.62
Total	**3.64**	**3.61**	**3.61**	**3.62**	**3.42**	**3.43**	**3.47**	**3.29**	**3.29**	**3.30**
Discrepancy[7]	**2.06**	**0.39**	**0.28**	**0.11**	**0.18**	**0.13**	**-0.01**	**0.22**	**0.25**	**0.19**
Consumption										
Petroleum Products[8]	38.46	43.74	43.75	43.87	48.65	48.59	48.61	50.76	50.72	50.65
Natural Gas	23.26	28.12	28.10	28.03	36.69	36.58	36.31	39.54	39.46	39.44
Coal	22.02	22.00	22.05	22.08	10.23	10.52	10.34	6.74	7.44	6.56
Nuclear Power	8.03	8.37	8.37	8.37	9.75	9.74	9.80	12.39	12.39	12.43
Renewable Energy[1]	5.32	9.03	9.00	9.03	14.68	14.74	14.75	16.22	16.07	16.30
Other[9]	0.21	0.43	0.43	0.43	0.50	0.51	0.52	0.32	0.32	0.35
Total	**97.29**	**111.67**	**111.70**	**111.80**	**120.50**	**120.68**	**120.32**	**125.97**	**126.40**	**125.73**
Net Imports - Petroleum	**23.29**	**28.40**	**28.42**	**28.55**	**33.45**	**33.40**	**33.47**	**35.83**	**35.83**	**35.71**
Prices (2001 dollars per unit)										
World Oil Price (dollars per barrel)[10]	22.01	23.77	23.76	23.81	24.15	24.14	24.18	24.58	24.59	24.57
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.12	3.51	3.47	3.43	3.97	3.96	3.90	4.36	4.35	4.38
Coal Minemouth Price (dollars per ton)	17.59	15.84	15.91	15.90	15.27	15.41	15.50	13.67	13.98	13.74
Average Electricity Price (cents per kilowatthour)	7.3	7.0	7.0	7.2	8.8	8.4	9.0	9.8	9.0	9.8

[1] Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table E18 for selected nonmarketed residential and commercial renewable energy.

[2] Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.

[3] Includes imports of crude oil for the Strategic Petroleum Reserve.

[4] Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.

[5] Includes coal, coal coke (net), and electricity (net).

[6] Includes crude oil and petroleum products.

[7] Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.

[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.

[9] Includes net electricity imports, methanol, and liquid hydrogen.

[10] Average refiner acquisition cost for imported crude oil.

[11] Represents lower 48 onshore and offshore supplies.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Energy Consumption										
Residential										
Distillate Fuel	0.91	0.91	0.91	0.91	0.84	0.84	0.84	0.81	0.81	0.81
Kerosene	0.10	0.08	0.08	0.08	0.06	0.06	0.06	0.06	0.06	0.06
Liquefied Petroleum Gas	0.50	0.47	0.47	0.47	0.47	0.46	0.46	0.47	0.47	0.47
Petroleum Subtotal	1.50	1.46	1.46	1.46	1.37	1.37	1.37	1.33	1.33	1.33
Natural Gas	4.94	5.62	5.62	5.62	5.96	5.96	5.97	6.20	6.20	6.22
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.41	0.41	0.41	0.40	0.40	0.40	0.40	0.40	0.40
Electricity	4.10	4.88	4.88	4.85	5.05	5.13	4.99	5.11	5.30	5.09
Delivered Energy	**10.94**	**12.38**	**12.38**	**12.35**	**12.80**	**12.88**	**12.74**	**13.06**	**13.24**	**13.05**
Electricity Related Losses	9.15	10.11	10.11	10.07	9.29	9.42	9.25	9.26	9.53	9.24
Total	**20.08**	**22.50**	**22.50**	**22.43**	**22.09**	**22.30**	**21.99**	**22.32**	**22.77**	**22.29**
Commercial										
Distillate Fuel	0.46	0.51	0.51	0.51	0.54	0.54	0.54	0.56	0.55	0.55
Residual Fuel	0.09	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.09	0.10
Motor Gasoline[2]	0.05	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.71	0.70	0.70	0.70	0.75	0.74	0.74	0.76	0.76	0.76
Natural Gas	3.33	3.74	3.74	3.74	4.27	4.22	4.34	4.97	4.82	5.07
Coal	0.09	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.11	0.11
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.08	4.97	4.97	4.95	5.66	5.71	5.63	5.97	6.05	5.95
Delivered Energy	**8.32**	**9.60**	**9.60**	**9.59**	**10.89**	**10.89**	**10.92**	**11.92**	**11.84**	**11.99**
Electricity Related Losses	9.12	10.30	10.30	10.28	10.42	10.48	10.44	10.82	10.88	10.81
Total	**17.44**	**19.90**	**19.90**	**19.87**	**21.31**	**21.36**	**21.37**	**22.74**	**22.72**	**22.80**
Industrial[4]										
Distillate Fuel	1.13	1.20	1.20	1.20	1.30	1.30	1.29	1.36	1.36	1.36
Liquefied Petroleum Gas	2.10	2.54	2.55	2.56	2.99	3.01	2.99	3.14	3.17	3.14
Petrochemical Feedstock	1.14	1.41	1.41	1.41	1.53	1.53	1.52	1.57	1.58	1.56
Residual Fuel	0.23	0.18	0.18	0.18	0.17	0.17	0.17	0.17	0.17	0.17
Motor Gasoline[2]	0.15	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19	0.19
Other Petroleum[5]	4.03	4.18	4.19	4.20	4.09	4.11	4.08	4.12	4.15	4.11
Petroleum Subtotal	8.79	9.67	9.69	9.71	10.26	10.30	10.23	10.55	10.62	10.52
Natural Gas	7.74	9.16	9.11	9.20	10.36	10.17	10.40	11.09	10.81	11.11
Lease and Plant Fuel[6]	1.20	1.40	1.40	1.39	1.70	1.70	1.69	1.77	1.77	1.77
Natural Gas Subtotal	8.94	10.56	10.51	10.60	12.06	11.87	12.08	12.86	12.58	12.88
Metallurgical Coal	0.72	0.65	0.65	0.65	0.47	0.47	0.47	0.39	0.39	0.39
Steam Coal	1.42	1.33	1.34	1.34	1.28	1.28	1.27	1.26	1.27	1.25
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.18	0.18	0.18	0.21	0.21	0.20
Coal Subtotal	2.16	2.09	2.09	2.10	1.93	1.93	1.92	1.87	1.87	1.85
Renewable Energy[7]	1.82	2.21	2.21	2.22	2.74	2.74	2.74	3.02	3.01	3.01
Electricity	3.39	3.89	3.90	3.89	4.41	4.48	4.36	4.66	4.80	4.60
Delivered Energy	**25.10**	**28.41**	**28.40**	**28.52**	**31.40**	**31.32**	**31.32**	**32.96**	**32.88**	**32.86**
Electricity Related Losses	7.57	8.06	8.10	8.09	8.12	8.23	8.09	8.45	8.63	8.36
Total	**32.67**	**36.47**	**36.50**	**36.61**	**39.53**	**39.55**	**39.41**	**41.40**	**41.51**	**41.22**

Table E2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Transportation										
Distillate Fuel[8]	5.44	7.01	7.01	7.04	8.30	8.29	8.28	8.98	8.97	8.95
Jet Fuel[9]	3.43	3.91	3.91	3.91	5.01	5.02	5.01	5.56	5.57	5.55
Motor Gasoline[2]	16.26	19.58	19.58	19.65	21.55	21.46	21.58	22.10	22.01	22.08
Residual Fuel	0.84	0.83	0.83	0.83	0.85	0.85	0.85	0.86	0.86	0.86
Liquefied Petroleum Gas	0.02	0.05	0.05	0.05	0.08	0.08	0.08	0.09	0.08	0.09
Other Petroleum[10]	0.24	0.26	0.26	0.26	0.30	0.30	0.30	0.32	0.32	0.32
Petroleum Subtotal	26.22	31.64	31.65	31.74	36.09	35.99	36.09	37.91	37.81	37.84
Pipeline Fuel Natural Gas	0.63	0.81	0.81	0.80	1.05	1.04	1.03	1.11	1.10	1.10
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.09	0.09	0.09	0.10	0.10	0.10
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.07	0.09	0.09	0.09	0.12	0.12	0.12	0.13	0.13	0.13
Delivered Energy	**26.94**	**32.61**	**32.60**	**32.70**	**37.36**	**37.25**	**37.33**	**39.25**	**39.16**	**39.18**
Electricity Related Losses	0.17	0.19	0.19	0.19	0.22	0.22	0.22	0.24	0.24	0.24
Total	**27.10**	**32.80**	**32.80**	**32.90**	**37.58**	**37.47**	**37.55**	**39.50**	**39.40**	**39.42**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.94	9.64	9.64	9.67	10.99	10.97	10.96	11.71	11.69	11.67
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.91	3.91	3.91	5.01	5.02	5.01	5.56	5.57	5.55
Liquefied Petroleum Gas	2.70	3.16	3.17	3.17	3.63	3.65	3.62	3.78	3.81	3.79
Motor Gasoline[2]	16.46	19.78	19.78	19.85	21.77	21.68	21.79	22.33	22.24	22.31
Petrochemical Feedstock	1.14	1.41	1.41	1.41	1.53	1.53	1.52	1.57	1.58	1.56
Residual Fuel	1.15	1.05	1.05	1.05	1.07	1.07	1.07	1.08	1.08	1.08
Other Petroleum[12]	4.24	4.41	4.42	4.43	4.36	4.39	4.36	4.42	4.44	4.40
Petroleum Subtotal	37.21	43.48	43.50	43.62	48.47	48.40	48.43	50.55	50.51	50.45
Natural Gas	16.02	18.57	18.53	18.62	20.68	20.45	20.80	22.36	21.92	22.49
Lease and Plant Fuel Plant[6]	1.20	1.40	1.40	1.39	1.70	1.70	1.69	1.77	1.77	1.77
Pipeline Natural Gas	0.63	0.81	0.81	0.80	1.05	1.04	1.03	1.11	1.10	1.10
Natural Gas Subtotal	17.86	20.78	20.73	20.82	23.43	23.19	23.51	25.23	24.79	25.36
Metallurgical Coal	0.72	0.65	0.65	0.65	0.47	0.47	0.47	0.39	0.39	0.39
Steam Coal	1.53	1.44	1.45	1.45	1.40	1.40	1.39	1.39	1.39	1.38
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.18	0.18	0.18	0.21	0.21	0.20
Coal Subtotal	2.27	2.20	2.20	2.21	2.05	2.05	2.04	1.99	2.00	1.97
Renewable Energy[13]	2.31	2.72	2.72	2.73	3.26	3.25	3.25	3.53	3.53	3.52
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.65	13.82	13.84	13.78	15.24	15.44	15.09	15.87	16.28	15.77
Delivered Energy	**71.29**	**83.01**	**83.00**	**83.16**	**92.45**	**92.34**	**92.32**	**97.19**	**97.11**	**97.08**
Electricity Related Losses	26.00	28.66	28.70	28.64	28.05	28.34	28.00	28.78	29.28	28.65
Total	**97.29**	**111.67**	**111.70**	**111.80**	**120.50**	**120.68**	**120.32**	**125.97**	**126.40**	**125.73**
Electric Power[14]										
Distillate Fuel	0.17	0.07	0.07	0.07	0.05	0.05	0.05	0.06	0.06	0.06
Residual Fuel	1.08	0.19	0.18	0.18	0.14	0.14	0.14	0.14	0.15	0.15
Petroleum Subtotal	1.25	0.26	0.25	0.25	0.19	0.19	0.18	0.21	0.21	0.20
Natural Gas	5.40	7.33	7.37	7.21	13.25	13.38	12.79	14.30	14.66	14.07
Steam Coal	19.75	19.79	19.85	19.87	8.18	8.47	8.30	4.74	5.44	4.59
Nuclear Power	8.03	8.37	8.37	8.37	9.75	9.74	9.80	12.39	12.39	12.43
Renewable Energy[15]	3.01	6.30	6.28	6.30	11.42	11.49	11.50	12.69	12.55	12.78
Electricity Imports	0.21	0.43	0.43	0.43	0.50	0.51	0.52	0.32	0.32	0.35
Total	**37.65**	**42.48**	**42.54**	**42.42**	**43.29**	**43.79**	**43.09**	**44.65**	**45.56**	**44.42**

Table E2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Total Energy Consumption										
Distillate Fuel	8.10	9.71	9.71	9.74	11.04	11.02	11.01	11.77	11.75	11.72
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.91	3.91	3.91	5.01	5.02	5.01	5.56	5.57	5.55
Liquefied Petroleum Gas	2.70	3.16	3.17	3.17	3.63	3.65	3.62	3.78	3.81	3.79
Motor Gasoline[2]	16.46	19.78	19.78	19.85	21.77	21.68	21.79	22.33	22.24	22.31
Petrochemical Feedstock	1.14	1.41	1.41	1.41	1.53	1.53	1.52	1.57	1.58	1.56
Residual Fuel	2.23	1.24	1.23	1.23	1.20	1.21	1.20	1.22	1.22	1.22
Other Petroleum[12]	4.24	4.41	4.42	4.43	4.36	4.39	4.36	4.42	4.44	4.40
Petroleum Subtotal	38.46	43.74	43.75	43.87	48.65	48.59	48.61	50.76	50.72	50.65
Natural Gas	21.42	25.91	25.90	25.83	33.94	33.83	33.59	36.67	36.59	36.57
Lease and Plant Fuel[6]	1.20	1.40	1.40	1.39	1.70	1.70	1.69	1.77	1.77	1.77
Pipeline Natural Gas	0.63	0.81	0.81	0.80	1.05	1.04	1.03	1.11	1.10	1.10
Natural Gas Subtotal	23.26	28.12	28.10	28.03	36.69	36.58	36.31	39.54	39.46	39.44
Metallurgical Coal	0.72	0.65	0.65	0.65	0.47	0.47	0.47	0.39	0.39	0.39
Steam Coal	21.28	21.24	21.29	21.31	9.58	9.87	9.69	6.13	6.83	5.96
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.18	0.18	0.18	0.21	0.21	0.20
Coal Subtotal	22.02	22.00	22.05	22.08	10.23	10.52	10.34	6.74	7.44	6.56
Nuclear Power	8.03	8.37	8.37	8.37	9.75	9.74	9.80	12.39	12.39	12.43
Renewable Energy[16]	5.32	9.03	9.00	9.03	14.68	14.74	14.75	16.22	16.07	16.30
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.21	0.43	0.43	0.43	0.50	0.51	0.52	0.32	0.32	0.35
Total	**97.29**	**111.67**	**111.70**	**111.80**	**120.50**	**120.68**	**120.32**	**125.97**	**126.40**	**125.73**
Energy Use and Related Statistics										
Delivered Energy Use	71.29	83.01	83.00	83.16	92.45	92.34	92.32	97.19	97.11	97.08
Total Energy Use	97.29	111.67	111.70	111.80	120.50	120.68	120.32	125.97	126.40	125.73
Population (millions)	278.18	300.24	300.24	300.24	325.32	325.32	325.32	338.24	338.24	338.24
Gross Domestic Product (billion 1996 dollars)	9215	12211	12210	12248	16364	16338	16330	18810	18773	18748
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1558.6	1710.1	1711.2	1712.8	1568.5	1569.6	1573.7	1482.2	1478.2	1483.9

[1] Includes wood used for residential heating. See Table E18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.

[2] Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.

[3] Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table E18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.

[4] Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.

[5] Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.

[6] Represents natural gas used in the field gathering and processing plant machinery.

[7] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.

[8] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.

[9] Includes only kerosene type.

[10] Includes aviation gasoline and lubricants.

[11] E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).

[12] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.

[13] Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

[14] Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[15] Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.

[16] Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.

Sources: 2001 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 population and gross domestic product: Global Insight macroeconomic model CTL0802. 2001 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E3. Delivered Energy Prices by Sector and Source
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Residential	**15.81**	**14.62**	**14.62**	**15.00**	**17.37**	**16.87**	**17.60**	**18.74**	**17.79**	**18.73**
Primary Energy[1]	9.73	8.11	8.09	8.09	8.48	8.49	8.45	8.88	8.84	8.88
Petroleum Products[2]	10.85	9.88	9.88	9.97	10.32	10.46	10.46	10.79	10.77	10.78
Distillate Fuel	8.99	7.95	7.95	7.97	8.23	8.25	8.24	8.58	8.58	8.58
Liquefied Petroleum Gas	14.84	13.97	14.00	14.22	14.44	14.86	14.86	14.96	14.91	14.96
Natural Gas	9.41	7.67	7.64	7.62	8.07	8.05	8.00	8.48	8.44	8.48
Electricity	25.37	24.10	24.12	25.14	30.32	28.86	31.08	33.29	30.52	33.37
Commercial	**15.50**	**14.35**	**14.33**	**14.74**	**17.78**	**17.22**	**18.00**	**19.27**	**18.33**	**19.17**
Primary Energy[1]	7.81	6.50	6.47	6.46	6.93	6.93	6.88	7.33	7.30	7.33
Petroleum Products[2]	7.27	6.70	6.70	6.74	6.96	7.01	7.02	7.28	7.27	7.28
Distillate Fuel	6.40	5.63	5.62	5.65	5.96	5.97	5.97	6.30	6.30	6.30
Residual Fuel	3.46	3.93	3.93	3.94	3.96	3.96	3.97	4.02	4.03	4.02
Natural Gas	8.09	6.59	6.56	6.53	7.07	7.05	6.99	7.48	7.45	7.47
Electricity	23.28	21.51	21.51	22.32	27.61	26.37	28.27	30.97	28.71	31.00
Industrial[3]	**7.11**	**6.61**	**6.61**	**6.70**	**7.80**	**7.78**	**7.87**	**8.45**	**8.28**	**8.44**
Primary Energy	5.83	5.16	5.16	5.18	5.65	5.74	5.69	5.97	5.96	5.97
Petroleum Products[2]	7.72	6.93	6.93	7.02	7.40	7.55	7.56	7.68	7.64	7.68
Distillate Fuel	6.55	5.71	5.70	5.73	6.18	6.18	6.19	6.53	6.53	6.53
Liquefied Petroleum Gas	12.34	9.58	9.60	9.82	10.14	10.55	10.54	10.60	10.53	10.60
Residual Fuel	3.28	3.66	3.65	3.66	3.70	3.70	3.70	3.77	3.77	3.76
Natural Gas[4]	4.87	4.11	4.08	4.05	4.68	4.68	4.60	5.07	5.06	5.06
Metallurgical Coal	1.69	1.51	1.51	1.51	1.40	1.39	1.40	1.34	1.33	1.34
Steam Coal	1.46	1.38	1.38	1.38	1.14	1.16	1.15	1.04	1.07	1.04
Electricity	14.13	14.34	14.34	14.87	18.65	17.89	19.05	20.86	19.42	20.96
Transportation	**10.28**	**11.73**	**11.72**	**11.72**	**13.27**	**13.20**	**13.28**	**14.17**	**14.12**	**14.20**
Primary Energy	10.25	11.70	11.70	11.70	13.24	13.16	13.24	14.12	14.08	14.16
Petroleum Products[2]	10.25	11.71	11.70	11.70	13.25	13.18	13.26	14.14	14.10	14.17
Distillate Fuel[5]	10.05	11.71	11.70	11.70	13.17	13.20	13.16	14.37	14.38	14.38
Jet Fuel[6]	6.20	7.10	7.11	7.13	9.26	9.27	9.29	10.35	10.33	10.41
Motor Gasoline[7]	11.57	12.98	12.98	12.96	14.52	14.39	14.52	15.31	15.24	15.35
Residual Fuel	3.90	5.19	5.20	5.22	7.36	7.36	7.39	8.32	8.30	8.41
Liquefied Petroleum Gas[8]	16.93	16.35	16.38	16.59	18.30	18.69	18.65	19.15	18.93	19.20
Natural Gas[9]	7.65	7.25	7.21	7.19	7.72	7.72	7.65	8.08	8.06	8.07
Electricity	21.87	20.82	20.82	21.58	24.39	23.41	24.90	26.05	24.25	26.10
Average End-Use Energy	**10.75**	**10.87**	**10.87**	**11.00**	**12.73**	**12.55**	**12.81**	**13.71**	**13.39**	**13.71**
Primary Energy	8.52	8.82	8.81	8.81	9.90	9.90	9.91	10.52	10.50	10.53
Electricity	21.34	20.40	20.40	21.20	25.89	24.71	26.51	28.70	26.52	28.79
Electric Power[10]										
Fossil Fuel Average	2.14	1.97	1.96	1.94	3.36	3.34	3.27	4.13	4.03	4.13
Petroleum Products	4.73	4.49	4.52	4.53	5.02	5.00	5.02	5.18	5.17	5.16
Distillate Fuel	6.20	5.01	5.01	5.03	5.39	5.39	5.40	5.64	5.65	5.66
Residual Fuel	4.50	4.29	4.34	4.34	4.88	4.86	4.89	4.98	4.98	4.96
Natural Gas	4.78	4.07	4.03	4.00	4.79	4.79	4.71	5.19	5.16	5.17
Steam Coal	1.25	1.16	1.16	1.16	0.99	1.00	0.99	0.90	0.92	0.90

Table E3. Delivered Energy Prices by Sector and Source (Continued)
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Average Price to All Users[11]										
Petroleum Products[2]	9.54	10.54	10.53	10.56	11.85	11.83	11.90	12.61	12.56	12.64
Distillate Fuel	9.16	10.25	10.23	10.25	11.58	11.60	11.58	12.64	12.65	12.65
Jet Fuel	6.20	7.10	7.11	7.13	9.26	9.27	9.29	10.35	10.33	10.41
Liquefied Petroleum Gas	12.85	10.43	10.44	10.66	10.93	11.33	11.33	11.40	11.31	11.39
Motor Gasoline[7]	11.57	12.97	12.96	12.95	14.49	14.36	14.49	15.27	15.20	15.30
Residual Fuel	4.11	4.79	4.80	4.82	6.42	6.41	6.45	7.12	7.09	7.18
Natural Gas	6.40	5.24	5.21	5.18	5.63	5.62	5.57	6.03	6.00	6.03
Coal	1.26	1.17	1.18	1.18	1.02	1.02	1.02	0.94	0.95	0.93
Electricity	21.34	20.40	20.40	21.20	25.89	24.71	26.51	28.70	26.52	28.79
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)										
Residential	166.77	175.14	175.03	179.25	215.33	210.47	217.13	237.11	228.35	236.80
Commercial	127.30	136.28	136.16	139.72	191.81	185.64	194.80	227.72	215.09	227.91
Industrial	135.32	141.86	141.89	144.57	185.88	184.68	187.08	212.44	207.35	211.47
Transportation	270.41	372.90	372.75	373.94	481.84	477.68	482.04	540.27	537.03	540.61
Total Non-Renewable Expenditures	699.80	826.18	825.83	837.48	1074.86	1058.47	1081.05	1217.53	1187.82	1216.78
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.11	0.11	0.11	0.15	0.15	0.15
Total Expenditures	**699.81**	**826.23**	**825.88**	**837.53**	**1074.97**	**1058.58**	**1081.16**	**1217.69**	**1187.97**	**1216.94**

[1] Weighted average price includes fuels below as well as coal.

[2] This quantity is the weighted average for all petroleum products, not just those listed below.

[3] Includes combined heat and power, which produces electricity and other useful thermal energy.

[4] Excludes use for lease and plant fuel.

[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.

[6] Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.

[7] Sales weighted-average price for all grades. Includes Federal, State and local taxes.

[8] Includes Federal and State taxes while excluding county and local taxes.

[9] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.

[10] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

[11] Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.

Btu = British thermal unit.

Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E4. Greenhouse Gas Allowance Cost by End-Use Sector and Source
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Commercial										
Petroleum Products[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residual Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[3]										
Petroleum Products[2]	0.00	0.94	0.95	0.95	2.15	2.16	2.17	2.66	2.65	2.71
Distillate Fuel	0.00	1.56	1.56	1.57	3.52	3.53	3.55	4.36	4.33	4.44
Liquefied Petroleum Gas	0.00	1.35	1.35	1.36	3.05	3.06	3.07	3.77	3.75	3.84
Residual Fuel	0.00	1.68	1.68	1.69	3.80	3.81	3.83	4.70	4.67	4.79
Natural Gas[4]	0.00	1.11	1.12	1.12	2.52	2.53	2.54	3.12	3.10	3.18
Metallurgical Coal	0.00	2.00	2.00	2.01	4.51	4.52	4.55	5.58	5.55	5.69
Steam Coal	0.00	2.00	2.01	2.02	4.53	4.54	4.56	5.60	5.57	5.71
Electric Power[5]										
Fossil Fuel Average	0.00	1.78	1.78	1.79	3.32	3.34	3.37	3.80	3.83	3.86
Petroleum Products	0.00	1.65	1.65	1.66	3.72	3.74	3.76	4.60	4.57	4.69
Distillate Fuel	0.00	1.56	1.56	1.57	3.52	3.53	3.55	4.36	4.33	4.44
Residual Fuel	0.00	1.68	1.68	1.69	3.80	3.81	3.83	4.70	4.67	4.79
Natural Gas	0.00	1.14	1.14	1.15	2.57	2.57	2.59	3.18	3.16	3.24
Steam Coal	0.00	2.02	2.02	2.03	4.54	4.55	4.58	5.62	5.59	5.73
Average Allowance Cost to All Users[6]										
Petroleum Products[2]	0.00	0.22	0.22	0.23	0.48	0.49	0.48	0.59	0.59	0.60
Distillate Fuel	0.00	0.20	0.20	0.21	0.43	0.43	0.43	0.53	0.52	0.54
Jet Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquefied Petroleum Gas	0.00	1.09	1.09	1.10	2.51	2.52	2.54	3.13	3.12	3.19
Motor Gasoline	0.00	0.01	0.01	0.01	0.03	0.03	0.03	0.04	0.04	0.04
Residual Fuel	0.00	0.50	0.49	0.49	0.98	0.99	0.98	1.21	1.22	1.24
Natural Gas	0.00	0.72	0.72	0.72	1.78	1.79	1.78	2.19	2.19	2.22
Coal	0.00	2.00	2.01	2.02	4.48	4.49	4.52	5.50	5.48	5.60

[1] Weighted average allowance cost includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3] Includes combined heat and power, which produces electricity and other useful thermal energy.
[4] Excludes use for lease and plant fuel.
[5] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[6] Weighted averages of allowance costs are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Projections: EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E5. Energy Prices by Sector and Source with Greenhouse Gas Allowance Cost
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Residential	**15.81**	**14.62**	**14.62**	**15.00**	**17.37**	**16.87**	**17.60**	**18.74**	**17.79**	**18.73**
Primary Energy[1]	9.73	8.11	8.09	8.09	8.48	8.49	8.45	8.88	8.84	8.88
Petroleum Products[2]	10.85	9.88	9.88	9.97	10.32	10.46	10.46	10.79	10.77	10.78
Distillate Fuel	8.99	7.95	7.95	7.97	8.23	8.25	8.24	8.58	8.58	8.58
Liquefied Petroleum Gas	14.84	13.97	14.00	14.22	14.44	14.86	14.86	14.96	14.91	14.96
Natural Gas	9.41	7.67	7.64	7.62	8.07	8.05	8.00	8.48	8.44	8.48
Electricity	25.37	24.10	24.12	25.14	30.32	28.86	31.08	33.29	30.52	33.37
Commercial	**15.50**	**14.35**	**14.33**	**14.74**	**17.78**	**17.22**	**18.00**	**19.27**	**18.33**	**19.17**
Primary Energy[1]	7.81	6.50	6.47	6.46	6.93	6.93	6.88	7.33	7.30	7.33
Petroleum Products[2]	7.27	6.70	6.70	6.74	6.96	7.01	7.02	7.28	7.27	7.28
Distillate Fuel	6.40	5.63	5.62	5.65	5.96	5.97	5.97	6.30	6.30	6.30
Residual Fuel	3.46	3.93	3.93	3.94	3.96	3.96	3.97	4.02	4.03	4.02
Natural Gas	8.09	6.59	6.56	6.53	7.07	7.05	6.99	7.48	7.45	7.47
Electricity	23.28	21.51	21.51	22.32	27.61	26.37	28.27	30.97	28.71	31.00
Industrial[3]	**7.11**	**7.55**	**7.55**	**7.65**	**9.89**	**9.87**	**9.99**	**11.03**	**10.82**	**11.07**
Primary Energy	5.83	6.28	6.28	6.31	8.16	8.26	8.22	9.06	9.04	9.11
Petroleum Products[2]	7.72	7.87	7.88	7.97	9.55	9.72	9.73	10.34	10.30	10.39
Distillate Fuel	6.55	7.27	7.27	7.30	9.70	9.71	9.74	10.89	10.87	10.97
Liquefied Petroleum Gas	12.34	10.93	10.95	11.18	13.19	13.60	13.61	14.38	14.28	14.44
Residual Fuel	3.28	5.34	5.34	5.35	7.49	7.50	7.53	8.46	8.44	8.55
Natural Gas[4]	4.87	5.23	5.20	5.18	7.20	7.21	7.15	8.19	8.16	8.24
Metallurgical Coal	1.69	3.50	3.51	3.52	5.91	5.91	5.95	6.92	6.88	7.03
Steam Coal	1.46	3.38	3.39	3.40	5.67	5.69	5.71	6.64	6.64	6.75
Electricity	14.13	14.34	14.34	14.87	18.65	17.89	19.05	20.86	19.42	20.96
Transportation	**10.28**	**11.73**	**11.73**	**11.73**	**13.28**	**13.20**	**13.29**	**14.17**	**14.12**	**14.21**
Primary Energy	10.25	11.70	11.70	11.70	13.24	13.17	13.25	14.13	14.09	14.17
Petroleum Products[2]	10.25	11.71	11.70	11.70	13.25	13.18	13.26	14.14	14.10	14.17
Distillate Fuel[5]	10.05	11.71	11.70	11.70	13.17	13.20	13.16	14.37	14.38	14.38
Jet Fuel[6]	6.20	7.10	7.11	7.13	9.26	9.27	9.29	10.35	10.33	10.41
Motor Gasoline[7]	11.57	12.98	12.98	12.96	14.52	14.39	14.52	15.31	15.24	15.35
Residual Fuel	3.90	5.19	5.20	5.22	7.36	7.36	7.39	8.32	8.30	8.41
Liquefied Petroleum Gas[8]	16.93	16.35	16.38	16.59	18.30	18.69	18.65	19.15	18.93	19.20
Natural Gas[9]	7.65	8.38	8.35	8.33	10.29	10.29	10.24	11.26	11.22	11.31
Electricity	21.87	20.82	20.82	21.58	24.39	23.41	24.90	26.05	24.25	26.10
Average End-Use Energy	**10.75**	**11.17**	**11.17**	**11.30**	**13.38**	**13.20**	**13.47**	**14.50**	**14.17**	**14.52**
Primary Energy	8.52	9.18	9.17	9.18	10.70	10.69	10.71	11.49	11.46	11.51
Electricity	21.34	20.40	20.40	21.20	25.89	24.71	26.51	28.70	26.52	28.79
Electric Power[10]										
Fossil Fuel Average	2.14	3.75	3.74	3.74	6.68	6.68	6.64	7.93	7.85	7.99
Petroleum Products	4.73	6.13	6.17	6.19	8.74	8.73	8.78	9.77	9.74	9.85
Distillate Fuel	6.20	6.57	6.57	6.60	8.91	8.92	8.95	9.99	9.98	10.10
Residual Fuel	4.50	5.97	6.02	6.03	8.68	8.67	8.72	9.68	9.65	9.75
Natural Gas	4.78	5.20	5.17	5.14	7.36	7.37	7.30	8.37	8.32	8.41
Steam Coal	1.25	3.17	3.18	3.19	5.53	5.55	5.57	6.53	6.51	6.62

Table E5. Energy Prices by Sector and Source with Greenhouse Gas Allowance Cost (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Average Price to All Users[11]										
Petroleum Products[2]	9.54	10.76	10.76	10.78	12.34	12.32	12.39	13.20	13.15	13.24
Distillate Fuel	9.16	10.45	10.44	10.46	12.01	12.03	12.01	13.17	13.18	13.18
Jet Fuel	6.20	7.10	7.11	7.13	9.26	9.27	9.29	10.35	10.33	10.41
Liquefied Petroleum Gas	12.85	11.51	11.53	11.76	13.44	13.86	13.86	14.52	14.43	14.58
Motor Gasoline[7]	11.57	12.98	12.98	12.96	14.52	14.39	14.52	15.31	15.24	15.34
Residual Fuel	4.11	5.29	5.29	5.31	7.39	7.40	7.43	8.33	8.31	8.41
Natural Gas	6.40	5.96	5.92	5.90	7.41	7.41	7.35	8.22	8.19	8.25
Coal	1.26	3.18	3.19	3.20	5.50	5.52	5.53	6.44	6.44	6.53
Electricity	21.34	20.40	20.40	21.20	25.89	24.71	26.51	28.70	26.52	28.79
Non-Renewable Energy and Allowance Expenditures by Sector (billion 2001 dollars)										
Residential	166.77	175.14	175.03	179.25	215.33	210.47	217.13	237.11	228.35	236.80
Commercial	127.30	136.28	136.16	139.72	191.81	185.64	194.80	227.72	215.09	227.91
Industrial	135.32	162.27	162.33	165.25	235.92	234.52	237.52	277.18	271.11	277.35
Transportation	270.41	372.97	372.82	374.01	482.08	477.93	482.28	540.60	537.35	540.94
Total Non-Renewable Expenditures	699.80	846.66	846.34	858.22	1125.14	1108.55	1131.73	1282.60	1251.90	1283.00
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.12	0.11	0.12	0.16	0.16	0.16
Total Expenditures	**699.81**	**846.72**	**846.39**	**858.28**	**1125.26**	**1108.67**	**1131.84**	**1282.76**	**1252.05**	**1283.15**

[1] Weighted average price includes fuels below as well as coal.

[2] This quantity is the weighted average for all petroleum products, not just those listed below.

[3] Includes combined heat and power, which produces electricity and other useful thermal energy.

[4] Excludes use for lease and plant fuel.

[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.

[6] Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.

[7] Sales weighted-average price for all grades. Includes Federal, State and local taxes.

[8] Includes Federal and State taxes while excluding county and local taxes.

[9] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.

[10] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

[11] Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.

Btu = British thermal unit.

Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E6. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Key Indicators										
Households (millions)										
Single-Family	77.50	86.14	86.14	86.14	93.99	93.99	93.95	97.43	97.45	97.36
Multifamily	22.19	24.13	24.13	24.14	26.99	26.98	26.98	28.71	28.69	28.68
Mobile Homes	6.57	7.10	7.10	7.10	7.86	7.86	7.85	8.11	8.12	8.11
Total	**106.27**	**117.37**	**117.37**	**117.38**	**128.83**	**128.83**	**128.77**	**134.25**	**134.26**	**134.14**
Average House Square Footage	**1685**	**1740**	**1740**	**1739**	**1782**	**1782**	**1782**	**1798**	**1798**	**1798**
Energy Intensity										
(million Btu per household)										
Delivered Energy Consumption	102.9	105.5	105.5	105.2	99.3	100.0	98.9	97.3	98.6	97.3
Total Energy Consumption	189.0	191.7	191.7	191.1	171.4	173.1	170.8	166.3	169.6	166.2
(thousand Btu per square foot)										
Delivered Energy Consumption	61.1	60.7	60.6	60.5	55.7	56.1	55.5	54.1	54.8	54.1
Total Energy Consumption	112.2	110.2	110.2	109.8	96.2	97.2	95.9	92.5	94.3	92.4
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.39	0.46	0.46	0.45	0.46	0.46	0.45	0.45	0.46	0.45
Space Cooling	0.52	0.60	0.60	0.59	0.59	0.60	0.59	0.59	0.61	0.59
Water Heating	0.45	0.46	0.46	0.46	0.38	0.39	0.37	0.33	0.35	0.33
Refrigeration	0.42	0.34	0.34	0.34	0.32	0.32	0.32	0.33	0.33	0.33
Cooking	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.13
Clothes Dryers	0.22	0.24	0.24	0.24	0.25	0.25	0.25	0.25	0.26	0.25
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.91	0.91	0.90	0.81	0.85	0.79	0.74	0.82	0.74
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers[1]	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.19	0.19	0.19	0.24	0.24	0.23	0.24	0.25	0.24
Personal Computers	0.06	0.08	0.08	0.08	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10
Other Uses[2]	0.83	1.25	1.25	1.24	1.54	1.56	1.53	1.69	1.73	1.68
Delivered Energy	**4.10**	**4.88**	**4.88**	**4.85**	**5.05**	**5.13**	**4.99**	**5.11**	**5.30**	**5.09**
Natural Gas										
Space Heating	3.13	3.69	3.69	3.69	3.97	3.97	3.97	4.11	4.12	4.12
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.48	1.55	1.55	1.55	1.58	1.58	1.58	1.62	1.63	1.63
Cooking	0.20	0.23	0.23	0.23	0.25	0.25	0.25	0.26	0.26	0.26
Clothes Dryers	0.06	0.08	0.08	0.08	0.10	0.10	0.10	0.10	0.10	0.10
Other Uses[3]	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.11	0.08	0.11
Delivered Energy	**4.94**	**5.62**	**5.62**	**5.62**	**5.96**	**5.96**	**5.97**	**6.20**	**6.20**	**6.22**
Distillate										
Space Heating	0.74	0.76	0.76	0.76	0.71	0.71	0.71	0.69	0.69	0.69
Water Heating	0.16	0.14	0.14	0.14	0.12	0.12	0.12	0.11	0.11	0.11
Other Uses[4]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.91**	**0.91**	**0.91**	**0.91**	**0.84**	**0.84**	**0.84**	**0.81**	**0.81**	**0.81**
Liquefied Petroleum Gas										
Space Heating	0.26	0.25	0.25	0.25	0.24	0.24	0.24	0.24	0.24	0.24
Water Heating	0.09	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06
Cooking	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Other Uses[3]	0.12	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14
Delivered Energy	**0.50**	**0.47**	**0.47**	**0.47**	**0.47**	**0.46**	**0.46**	**0.47**	**0.47**	**0.47**
Marketed Renewables (wood)[5]	0.39	0.41	0.41	0.41	0.40	0.40	0.40	0.40	0.40	0.40
Other Fuels[6]	0.11	0.09	0.09	0.09	0.08	0.08	0.08	0.07	0.07	0.07

Table E6. Residential Sector Key Indicators and End-Use Consumption (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Delivered Energy Consumption by End-Use										
Space Heating	5.01	5.66	5.66	5.66	5.86	5.87	5.86	5.96	5.99	5.97
Space Cooling	0.52	0.60	0.60	0.59	0.59	0.60	0.59	0.59	0.61	0.59
Water Heating	2.19	2.23	2.23	2.23	2.14	2.15	2.14	2.13	2.16	2.13
Refrigeration	0.42	0.34	0.34	0.34	0.32	0.32	0.32	0.33	0.33	0.33
Cooking	0.33	0.36	0.36	0.36	0.39	0.39	0.39	0.40	0.40	0.40
Clothes Dryers	0.28	0.33	0.33	0.33	0.34	0.35	0.34	0.35	0.36	0.35
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.91	0.91	0.90	0.81	0.85	0.79	0.74	0.82	0.74
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.19	0.19	0.19	0.24	0.24	0.23	0.24	0.25	0.24
Personal Computers	0.06	0.08	0.08	0.08	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10
Other Uses[7]	1.01	1.45	1.45	1.44	1.76	1.77	1.75	1.94	1.96	1.94
Delivered Energy	**10.94**	**12.38**	**12.38**	**12.35**	**12.80**	**12.88**	**12.74**	**13.06**	**13.24**	**13.05**
Electricity Related Losses	**9.15**	**10.11**	**10.11**	**10.07**	**9.29**	**9.42**	**9.25**	**9.26**	**9.53**	**9.24**
Total Energy Consumption by End-Use										
Space Heating	5.89	6.61	6.61	6.60	6.70	6.72	6.69	6.78	6.82	6.78
Space Cooling	1.68	1.83	1.83	1.82	1.68	1.70	1.67	1.67	1.71	1.67
Water Heating	3.20	3.20	3.20	3.19	2.84	2.86	2.83	2.74	2.79	2.72
Refrigeration	1.36	1.05	1.05	1.05	0.91	0.91	0.92	0.93	0.92	0.93
Cooking	0.55	0.59	0.59	0.59	0.61	0.61	0.62	0.63	0.63	0.63
Clothes Dryers	0.78	0.84	0.84	0.83	0.80	0.81	0.80	0.81	0.82	0.81
Freezers	0.36	0.27	0.27	0.27	0.25	0.25	0.25	0.25	0.25	0.25
Lighting	2.40	2.81	2.81	2.77	2.31	2.42	2.25	2.09	2.31	2.07
Clothes Washers	0.10	0.10	0.10	0.10	0.08	0.08	0.08	0.08	0.08	0.08
Dishwashers	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08
Color Televisions	0.43	0.60	0.60	0.59	0.67	0.68	0.67	0.68	0.70	0.68
Personal Computers	0.19	0.25	0.25	0.25	0.29	0.29	0.29	0.32	0.32	0.32
Furnace Fans	0.23	0.26	0.26	0.26	0.27	0.27	0.27	0.27	0.28	0.27
Other Uses[7]	2.86	4.03	4.03	4.01	4.59	4.63	4.58	4.99	5.07	4.99
Total	**20.08**	**22.50**	**22.50**	**22.43**	**22.09**	**22.30**	**21.99**	**22.32**	**22.77**	**22.29**
Non-Marketed Renewables										
Geothermal[8]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar[9]	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Total	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**

[1] Does not include electric water heating portion of load.

[2] Includes small electric devices, heating elements, and motors.

[3] Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).

[4] Includes such appliances as swimming pool and hot tub heaters.

[5] Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.

[6] Includes kerosene and coal.

[7] Includes all other uses listed above.

[8] Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.

[9] Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E7. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Key Indicators										
Total Floorspace (billion square feet)										
Surviving	66.6	79.0	79.0	79.0	90.8	90.6	91.1	97.1	96.5	97.4
New Additions	3.6	3.0	3.0	3.0	3.4	3.4	3.4	3.4	3.3	3.4
Total	**70.2**	**82.0**	**82.0**	**82.0**	**94.2**	**94.0**	**94.5**	**100.6**	**99.8**	**100.7**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	118.4	117.1	117.1	116.9	115.6	115.8	115.6	118.6	118.6	119.1
Electricity Related Losses	129.9	125.6	125.6	125.4	110.6	111.5	110.4	107.6	109.0	107.3
Total Energy Consumption	248.3	242.7	242.8	242.3	226.1	227.3	226.0	226.2	227.5	226.3
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating[1]	0.14	0.15	0.15	0.15	0.14	0.14	0.14	0.13	0.13	0.13
Space Cooling[1]	0.43	0.42	0.42	0.42	0.41	0.42	0.41	0.40	0.41	0.39
Water Heating[1]	0.15	0.15	0.15	0.15	0.14	0.14	0.14	0.13	0.14	0.13
Ventilation	0.17	0.18	0.18	0.18	0.17	0.17	0.17	0.16	0.17	0.16
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.02
Lighting	1.02	1.18	1.18	1.17	0.99	1.02	0.97	0.88	0.92	0.87
Refrigeration	0.21	0.24	0.24	0.24	0.24	0.24	0.24	0.23	0.24	0.23
Office Equipment (PC)	0.16	0.24	0.24	0.24	0.31	0.31	0.31	0.34	0.34	0.34
Office Equipment (non-PC)	0.31	0.47	0.47	0.47	0.72	0.73	0.72	0.87	0.87	0.87
Other Uses[2]	1.46	1.90	1.90	1.90	2.51	2.51	2.51	2.80	2.81	2.80
Delivered Energy	**4.08**	**4.97**	**4.97**	**4.95**	**5.66**	**5.71**	**5.63**	**5.97**	**6.05**	**5.95**
Natural Gas										
Space Heating[1]	1.32	1.53	1.53	1.53	1.58	1.58	1.58	1.56	1.57	1.56
Space Cooling[1]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Water Heating[1]	0.57	0.69	0.69	0.69	0.77	0.77	0.77	0.78	0.79	0.78
Cooking	0.25	0.30	0.30	0.30	0.33	0.33	0.34	0.35	0.35	0.35
Other Uses[3]	1.17	1.20	1.20	1.20	1.57	1.52	1.63	2.25	2.09	2.35
Delivered Energy	**3.33**	**3.74**	**3.74**	**3.74**	**4.27**	**4.22**	**4.34**	**4.97**	**4.82**	**5.07**
Distillate										
Space Heating[1]	0.17	0.23	0.23	0.23	0.27	0.26	0.26	0.28	0.27	0.27
Water Heating[1]	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Other Uses[4]	0.22	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Delivered Energy	**0.46**	**0.51**	**0.51**	**0.51**	**0.54**	**0.54**	**0.54**	**0.56**	**0.55**	**0.55**
Other Fuels[5]	**0.34**	**0.29**	**0.29**	**0.29**	**0.31**	**0.31**	**0.31**	**0.32**	**0.31**	**0.32**
Marketed Renewable Fuels										
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Energy	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Delivered Energy Consumption by End-Use										
Space Heating[1]	1.63	1.92	1.92	1.92	1.98	1.98	1.98	1.97	1.97	1.96
Space Cooling[1]	0.44	0.44	0.44	0.44	0.44	0.45	0.44	0.43	0.44	0.42
Water Heating[1]	0.79	0.92	0.92	0.92	0.99	0.99	0.99	0.99	1.00	0.99
Ventilation	0.17	0.18	0.18	0.18	0.17	0.17	0.17	0.16	0.17	0.16
Cooking	0.29	0.33	0.33	0.33	0.36	0.36	0.36	0.37	0.37	0.37
Lighting	1.02	1.18	1.18	1.17	0.99	1.02	0.97	0.88	0.92	0.87
Refrigeration	0.21	0.24	0.24	0.24	0.24	0.24	0.24	0.23	0.24	0.23
Office Equipment (PC)	0.16	0.24	0.24	0.24	0.31	0.31	0.31	0.34	0.34	0.34
Office Equipment (non-PC)	0.31	0.47	0.47	0.47	0.72	0.73	0.72	0.87	0.87	0.87
Other Uses[6]	3.30	3.69	3.69	3.69	4.69	4.64	4.75	5.68	5.52	5.78
Delivered Energy	**8.32**	**9.60**	**9.60**	**9.59**	**10.89**	**10.89**	**10.92**	**11.92**	**11.84**	**11.99**

Table E7. Commercial Sector Key Indicators and Consumption (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Electricity Related Losses	**9.12**	**10.30**	**10.30**	**10.28**	**10.42**	**10.48**	**10.44**	**10.82**	**10.88**	**10.81**
Total Energy Consumption by End-Use										
Space Heating[1]	1.95	2.24	2.24	2.23	2.24	2.24	2.23	2.20	2.21	2.19
Space Cooling[1]	1.39	1.32	1.32	1.32	1.21	1.22	1.20	1.15	1.17	1.14
Water Heating[1]	1.12	1.24	1.24	1.24	1.25	1.26	1.25	1.23	1.25	1.23
Ventilation	0.55	0.55	0.55	0.55	0.48	0.48	0.47	0.45	0.46	0.45
Cooking	0.37	0.40	0.40	0.40	0.41	0.41	0.41	0.41	0.41	0.42
Lighting	3.31	3.62	3.62	3.59	2.80	2.88	2.76	2.48	2.58	2.46
Refrigeration	0.69	0.73	0.73	0.73	0.68	0.68	0.68	0.66	0.66	0.65
Office Equipment (PC)	0.52	0.74	0.74	0.74	0.88	0.88	0.89	0.96	0.96	0.95
Office Equipment (non-PC)	0.99	1.43	1.43	1.44	2.06	2.06	2.06	2.45	2.45	2.44
Other Uses[6]	6.56	7.63	7.63	7.64	9.31	9.25	9.41	10.76	10.57	10.87
Total	**17.44**	**19.90**	**19.90**	**19.87**	**21.31**	**21.36**	**21.37**	**22.74**	**22.72**	**22.80**
Non-Marketed Renewable Fuels										
Solar[7]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

[1] Includes fuel consumption for district services.

[2] Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.

[3] Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.

[4] Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.

[5] Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.

[6] Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.

[7] Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.

Btu = British thermal unit.

PC = Personal computer.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E8. Industrial Sector Key Indicators and Consumption

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Key Indicators										
Value of Shipments (billion 1996 dollars)										
Manufacturing	4079	5420	5420	5445	7160	7158	7123	8162	8182	8104
Nonmanufacturing	1346	1500	1501	1505	1714	1710	1708	1828	1825	1821
Total	**5425**	**6920**	**6920**	**6950**	**8874**	**8868**	**8831**	**9990**	**10007**	**9924**
Energy Prices (2001 dollars per million Btu)										
Electricity	14.13	14.34	14.34	14.87	18.65	17.89	19.05	20.86	19.42	20.96
Natural Gas	4.87	5.23	5.20	5.18	7.20	7.21	7.15	8.19	8.16	8.24
Steam Coal	1.46	3.38	3.39	3.40	5.67	5.69	5.71	6.64	6.64	6.75
Residual Oil	3.28	5.34	5.34	5.35	7.49	7.50	7.53	8.46	8.44	8.55
Distillate Oil	6.55	7.27	7.27	7.30	9.70	9.71	9.74	10.89	10.87	10.97
Liquefied Petroleum Gas	12.34	10.93	10.95	11.18	13.19	13.60	13.61	14.38	14.28	14.44
Motor Gasoline	11.57	12.94	12.93	12.92	14.49	14.35	14.49	15.28	15.21	15.31
Metallurgical Coal	1.69	3.50	3.51	3.52	5.91	5.91	5.95	6.92	6.88	7.03
Energy Consumption[1]										
Purchased Electricity	3.39	3.89	3.90	3.89	4.41	4.48	4.36	4.66	4.80	4.60
Natural Gas	7.74	9.16	9.11	9.20	10.36	10.17	10.40	11.09	10.81	11.11
Lease and Plant Fuel[2]	1.20	1.40	1.40	1.39	1.70	1.70	1.69	1.77	1.77	1.77
Natural Gas Subtotal	8.94	10.56	10.51	10.60	12.06	11.87	12.08	12.86	12.58	12.88
Steam Coal	1.42	1.33	1.34	1.34	1.28	1.28	1.27	1.26	1.27	1.25
Metallurgical Coal and Coke[3]	0.74	0.76	0.76	0.76	0.65	0.65	0.65	0.60	0.61	0.60
Residual Fuel	0.23	0.18	0.18	0.18	0.17	0.17	0.17	0.17	0.17	0.17
Distillate	1.13	1.20	1.20	1.20	1.30	1.30	1.29	1.36	1.36	1.36
Liquefied Petroleum Gas	2.10	2.54	2.55	2.56	2.99	3.01	2.99	3.14	3.17	3.14
Petrochemical Feedstocks	1.14	1.41	1.41	1.41	1.53	1.53	1.52	1.57	1.58	1.56
Other Petroleum[4]	4.18	4.34	4.35	4.36	4.27	4.29	4.26	4.32	4.34	4.30
Renewables[5]	1.82	2.21	2.21	2.22	2.74	2.74	2.74	3.02	3.01	3.01
Delivered Energy	**25.10**	**28.41**	**28.40**	**28.52**	**31.40**	**31.32**	**31.32**	**32.96**	**32.88**	**32.86**
Electricity Related Losses	7.57	8.06	8.10	8.09	8.12	8.23	8.09	8.45	8.63	8.36
Total	**32.67**	**36.47**	**36.50**	**36.61**	**39.53**	**39.55**	**39.41**	**41.40**	**41.51**	**41.22**
Energy Consumption per dollar of Shipments[1] **(thousand Btu per 1996 dollars)**										
Purchased Electricity	0.63	0.56	0.56	0.56	0.50	0.51	0.49	0.47	0.48	0.46
Natural Gas	1.43	1.32	1.32	1.32	1.17	1.15	1.18	1.11	1.08	1.12
Lease and Plant Fuel[2]	0.22	0.20	0.20	0.20	0.19	0.19	0.19	0.18	0.18	0.18
Natural Gas Subtotal	1.65	1.53	1.52	1.52	1.36	1.34	1.37	1.29	1.26	1.30
Steam Coal	0.26	0.19	0.19	0.19	0.14	0.14	0.14	0.13	0.13	0.13
Metallurgical Coal and Coke[3]	0.14	0.11	0.11	0.11	0.07	0.07	0.07	0.06	0.06	0.06
Residual Fuel	0.04	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Distillate	0.21	0.17	0.17	0.17	0.15	0.15	0.15	0.14	0.14	0.14
Liquefied Petroleum Gas	0.39	0.37	0.37	0.37	0.34	0.34	0.34	0.31	0.32	0.32
Petrochemical Feedstocks	0.21	0.20	0.20	0.20	0.17	0.17	0.17	0.16	0.16	0.16
Other Petroleum[4]	0.77	0.63	0.63	0.63	0.48	0.48	0.48	0.43	0.43	0.43
Renewables[5]	0.33	0.32	0.32	0.32	0.31	0.31	0.31	0.30	0.30	0.30
Delivered Energy	**4.63**	**4.11**	**4.10**	**4.10**	**3.54**	**3.53**	**3.55**	**3.30**	**3.29**	**3.31**
Electricity Related Losses	1.40	1.16	1.17	1.16	0.92	0.93	0.92	0.85	0.86	0.84
Total	**6.02**	**5.27**	**5.28**	**5.27**	**4.45**	**4.46**	**4.46**	**4.14**	**4.15**	**4.15**

[1] Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Represents natural gas used in the field gathering and processing plant machinery.

[3] Includes net coal coke imports.

[4] Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.

[5] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 coal prices are based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 consumption values based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **2001** shipments: Global Insight macroeconomic model CTL0802. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E9. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 pounds (VMT)	2409	2975	2975	2985	3547	3532	3551	3795	3778	3794
Commercial Light Trucks (VMT)[1]	66	83	83	83	104	104	104	115	115	115
Freight Trucks >10,000 pounds (VMT)	206	263	263	264	335	335	334	377	376	375
Air (seat miles available)	1109	1348	1348	1351	1928	1929	1925	2231	2236	2224
Rail (ton miles traveled)	1448	1579	1577	1577	1467	1471	1461	1486	1500	1474
Domestic Shipping (ton miles traveled)	788	869	870	873	950	947	947	992	991	993
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	24.1	25.3	25.3	25.3	28.1	28.1	28.1	29.0	29.0	29.1
New Car (miles per gallon)[2]	28.1	28.8	28.8	28.7	32.6	32.6	32.6	32.9	32.9	32.9
New Light Truck (miles per gallon)[2]	20.7	22.5	22.5	22.5	24.6	24.6	24.7	25.8	25.8	25.8
Light-Duty Fleet (miles per gallon)[3]	19.8	19.6	19.6	19.6	20.9	20.9	20.9	21.8	21.8	21.8
New Commercial Light Truck (MPG)[1]	13.8	14.8	14.8	14.8	16.3	16.3	16.3	17.1	17.1	17.1
Stock Commercial Light Truck (MPG)[1]	13.7	14.3	14.3	14.3	15.4	15.4	15.4	16.2	16.2	16.2
Aircraft Efficiency (seat miles per gallon)	51.2	54.3	54.3	54.3	59.1	59.1	59.1	61.2	61.2	61.2
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.0	6.4	6.4	6.4	6.6	6.6	6.6
Rail Efficiency (ton miles per thousand Btu)	2.8	3.1	3.1	3.1	3.4	3.4	3.4	3.6	3.6	3.6
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	15.28	18.86	18.86	18.93	20.99	20.90	21.02	21.55	21.46	21.54
Commercial Light Trucks[1]	0.60	0.73	0.73	0.73	0.84	0.84	0.84	0.89	0.89	0.89
Freight Trucks[4]	4.68	5.88	5.88	5.90	6.94	6.93	6.92	7.55	7.54	7.51
Air[5]	3.47	3.96	3.96	3.96	5.07	5.07	5.06	5.63	5.64	5.61
Rail[6]	0.63	0.65	0.65	0.65	0.59	0.59	0.59	0.59	0.59	0.58
Marine[7]	1.45	1.49	1.49	1.49	1.56	1.56	1.56	1.60	1.60	1.60
Pipeline Fuel	0.63	0.81	0.81	0.80	1.05	1.04	1.03	1.11	1.10	1.10
Lubricants	0.19	0.21	0.21	0.22	0.26	0.26	0.26	0.28	0.27	0.27
Total	**26.94**	**32.58**	**32.58**	**32.68**	**37.30**	**37.19**	**37.27**	**39.19**	**39.09**	**39.11**
Energy Use by Mode (million barrels per day oil equivalent)										
Light-Duty Vehicles	8.05	9.96	9.96	10.00	11.07	11.02	11.09	11.36	11.31	11.36
Commercial Light Trucks[1]	0.32	0.38	0.38	0.38	0.45	0.44	0.44	0.47	0.47	0.47
Freight Trucks	2.05	2.59	2.59	2.60	3.09	3.08	3.08	3.37	3.37	3.35
Railroad	0.24	0.24	0.24	0.24	0.20	0.20	0.20	0.19	0.20	0.19
Domestic Shipping	0.16	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19	0.19
International Shipping	0.34	0.33	0.33	0.33	0.34	0.34	0.34	0.34	0.34	0.34
Air[5]	1.44	1.64	1.64	1.64	2.15	2.15	2.15	2.40	2.40	2.39
Military Use	0.30	0.34	0.34	0.34	0.38	0.38	0.38	0.40	0.40	0.40
Bus Transportation	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Rail Transportation[6]	0.05	0.06	0.06	0.06	0.08	0.08	0.08	0.08	0.08	0.08
Recreational Boats	0.16	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20
Lubricants	0.09	0.10	0.10	0.10	0.12	0.12	0.12	0.13	0.13	0.13
Pipeline Fuel	0.32	0.41	0.41	0.41	0.53	0.53	0.52	0.56	0.56	0.56
Total	**13.64**	**16.54**	**16.54**	**16.59**	**18.90**	**18.85**	**18.89**	**19.83**	**19.78**	**19.79**

[1] Commercial trucks 8,500 to 10,000 pounds.
[2] Environmental Protection Agency rated miles per gallon.
[3] Combined car and light truck "on-the-road" estimate.
[4] Includes energy use by buses and military distillate consumption.
[5] Includes jet fuel and aviation gasoline.
[6] Includes passenger rail.
[7] Includes military residual fuel use and recreational boats.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001); Federal Highway Administration, *Highway Statistics 2000* (Washington, DC, November 2001); Oak Ridge National Laboratory, Transportation Energy Data Book: *Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey" EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA,*State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2001/2000* (Washington, DC, 2001); EIA, *Fuel Oil and Kerosene Sales 2001*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/historical/foks.html; and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E10. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Generation by Fuel Type										
Electric Power Sector[1]										
Power Only[2]										
Coal	1848	1927	1931	1934	836	871	848	526	617	508
Petroleum	113	19	19	19	11	12	11	13	13	13
Natural Gas[3]	411	811	819	797	1745	1763	1661	1889	1939	1850
Nuclear Power	769	801	801	801	934	933	938	1186	1186	1190
Pumped Storage/Other	-9	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[4]	258	517	515	516	991	1004	1006	1122	1119	1134
Distributed Generation (Natural Gas)	0	5	4	5	13	14	13	13	14	13
Non-Utility Generation for Own Use	-21	-26	-27	-27	-26	-26	-26	-25	-25	-25
Total	**3370**	**4053**	**4062**	**4044**	**4503**	**4570**	**4449**	**4725**	**4861**	**4683**
Combined Heat and Power[5]										
Coal	33	30	30	29	16	16	16	10	10	9
Petroleum	7	3	3	3	3	3	3	3	3	3
Natural Gas	124	161	160	159	131	133	136	115	117	120
Renewable Sources	5	4	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-9	-18	-18	-18	-17	-17	-17	-16	-16	-16
Total	**162**	**181**	**179**	**178**	**138**	**140**	**142**	**116**	**117**	**120**
Net Available to the Grid	**3532**	**4234**	**4241**	**4222**	**4641**	**4709**	**4591**	**4841**	**4978**	**4803**
End-Use Sector Generation										
Combined Heat and Power[6]										
Coal	23	23	23	23	23	23	23	23	23	23
Petroleum	6	6	6	6	6	6	6	6	6	7
Natural Gas	84	122	115	123	201	170	217	328	262	351
Other Gaseous Fuels[7]	6	7	7	7	7	7	7	7	7	7
Renewable Sources[4]	31	39	39	40	50	50	50	55	55	55
Other[8]	11	11	11	11	11	11	11	11	11	11
Total	**160**	**209**	**202**	**210**	**298**	**268**	**314**	**431**	**365**	**454**
Other End-Use Generators[9]	4	5	5	5	6	6	6	7	7	7
Generation for Own Use	-138	-173	-168	-174	-241	-218	-252	-328	-280	-343
Total Sales to the Grid	**27**	**41**	**39**	**41**	**63**	**55**	**68**	**110**	**91**	**118**
Net Imports	**20**	**41**	**41**	**41**	**48**	**49**	**50**	**31**	**31**	**34**
Electricity Sales by Sector										
Residential	1201	1429	1429	1420	1479	1505	1462	1498	1553	1491
Commercial	1197	1455	1455	1450	1659	1673	1649	1750	1772	1743
Industrial	994	1139	1144	1141	1293	1313	1277	1366	1406	1349
Transportation	22	27	27	27	35	35	35	39	39	39
Total	**3414**	**4050**	**4056**	**4039**	**4467**	**4525**	**4423**	**4653**	**4770**	**4621**
End-Use Prices[10] (2001 cents per kilowatthour)										
Residential	8.7	8.2	8.2	8.6	10.3	9.8	10.6	11.4	10.4	11.4
Commercial	7.9	7.3	7.3	7.6	9.4	9.0	9.6	10.6	9.8	10.6
Industrial	4.8	4.9	4.9	5.1	6.4	6.1	6.5	7.1	6.6	7.2
Transportation	7.5	7.1	7.1	7.4	8.3	8.0	8.5	8.9	8.3	8.9
All Sectors Average	**7.3**	**7.0**	**7.0**	**7.2**	**8.8**	**8.4**	**9.0**	**9.8**	**9.0**	**9.8**
Prices by Service Category[10] (2001 cents per kilowatthour)										
Generation	4.7	4.4	4.4	4.7	6.1	5.8	6.4	7.1	6.4	7.1
Transmission	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8
Distribution	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	1.9	2.0

Table E10. Electricity Supply, Disposition, Prices, and Emissions (Continued)

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Emissions										
Sulfur Dioxide (million tons)	10.63	9.84	9.86	9.80	5.87	5.90	6.05	1.93	1.92	2.05
Nitrogen Oxide (million tons)	4.75	3.50	3.52	3.52	1.48	1.49	1.51	0.67	0.66	0.65
Mercury (tons)	53.52	48.66	48.48	48.16	19.07	19.30	18.97	7.18	7.21	6.85

[1] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes plants that only produce electricity.

[3] Includes electricity generation from fuel cells.

[4] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.

[5] Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).

[6] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[7] Other gaseous fuels include refinery and still gas.

[8] Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.

[9] Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[10] Prices represent average revenue per kilowatthour.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Source: 2001 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and supporting databases. 2001 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2001 prices: EIA, National Energy Modeling System run MLBILL.D050503A. **Projections**: EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E11. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Electric Power Sector[2]										
Power Only[3]										
Coal Steam	305.3	289.0	288.3	288.2	209.3	210.3	211.1	139.9	155.2	136.1
Other Fossil Steam[4]	133.8	80.7	80.6	81.0	64.8	66.9	62.1	53.0	54.0	55.3
Combined Cycle	43.2	175.9	177.0	176.1	319.1	320.3	302.5	374.1	380.6	363.3
Combustion Turbine/Diesel	97.6	123.2	123.7	123.5	121.4	121.3	120.8	118.2	118.6	118.4
Nuclear Power[5]	98.2	100.3	100.3	100.3	117.2	117.2	117.7	149.2	149.2	149.7
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	90.4	129.0	128.4	128.6	225.0	226.4	230.7	245.6	243.6	248.9
Distributed Generation[7]	0.0	1.7	1.6	1.7	4.9	4.8	4.5	5.0	4.9	4.6
Total	**788.3**	**920.2**	**920.4**	**919.9**	**1082.2**	**1087.8**	**1070.0**	**1105.4**	**1126.7**	**1096.8**
Combined Heat and Power[8]										
Coal Steam	5.2	4.4	4.5	4.4	3.3	3.3	3.3	2.6	2.6	2.6
Other Fossil Steam[4]	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	22.6	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	4.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Renewable Sources[6]	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**33.7**	**44.0**	**44.1**	**44.0**	**42.9**	**42.9**	**42.9**	**42.2**	**42.2**	**42.2**
Total Electric Power Industry	**822.0**	**964.2**	**964.5**	**963.9**	**1125.1**	**1130.7**	**1112.9**	**1147.6**	**1168.9**	**1139.0**
Cumulative Planned Additions[9]										
Coal Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1
Combustion Turbine/Diesel	0.0	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	0.0	4.9	4.9	4.9	6.5	6.5	6.5	6.6	6.6	6.6
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**120.0**	**120.0**	**120.0**	**121.7**	**121.7**	**121.7**	**121.8**	**121.8**	**121.8**
Cumulative Unplanned Additions[9]										
Coal Steam	0.0	0.0	0.0	0.0	12.2	16.1	11.1	37.7	50.6	35.5
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	59.7	60.7	59.8	203.0	204.0	186.2	259.6	265.7	248.7
Combustion Turbine/Diesel	0.0	3.7	3.9	3.6	3.7	3.9	3.6	3.7	3.9	3.6
Nuclear Power	0.0	0.0	0.0	0.0	16.5	16.5	17.0	48.5	48.5	49.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	33.3	32.8	32.9	127.8	129.2	133.4	148.2	146.3	151.6
Distributed Generation[7]	0.0	1.7	1.6	1.7	4.9	4.8	4.5	5.0	4.9	4.6
Total	**0.0**	**98.4**	**98.9**	**98.0**	**368.1**	**374.5**	**355.9**	**502.8**	**519.9**	**493.0**
Cumulative Total Additions	**0.0**	**218.4**	**218.9**	**218.0**	**489.8**	**496.1**	**477.6**	**624.6**	**641.7**	**614.8**
Cumulative Retirements[10]										
Coal Steam	0.0	17.2	17.7	17.9	110.2	113.1	107.3	205.8	203.4	207.4
Other Fossil Steam[4]	0.0	51.6	51.7	51.3	67.5	65.4	70.2	79.3	78.3	77.0
Combined Cycle	0.0	0.9	0.7	0.7	0.9	0.7	0.7	2.6	2.1	2.4
Combustion Turbine/Diesel	0.0	9.1	8.8	8.7	10.9	11.1	11.4	14.2	13.9	13.8
Nuclear Power	0.0	0.8	0.8	0.8	1.8	1.8	1.8	1.8	1.8	1.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**79.7**	**79.9**	**79.5**	**191.4**	**192.2**	**191.5**	**303.8**	**299.6**	**302.5**

Table E11. Electricity Generating Capacity (Continued)

(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
End-Use Sector										
Combined Heat and Power[11]										
Coal	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Petroleum	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1
Natural Gas	14.6	19.4	18.4	19.4	30.1	26.0	32.4	48.7	39.0	52.0
Other Gaseous Fuels	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Renewable Sources[6]	4.7	6.2	6.2	6.2	8.0	7.9	7.9	8.9	8.9	8.8
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.8**	**34.2**	**33.2**	**34.2**	**46.7**	**42.6**	**49.0**	**66.2**	**56.5**	**69.5**
Other End-Use Generators[12]										
Renewable Sources[13]	1.1	1.5	1.5	1.5	1.9	1.8	1.9	2.2	2.2	2.3
Cumulative Additions[9]										
Combined Heat and Power[11]	0.0	6.4	5.5	6.5	19.0	14.9	21.2	38.5	28.8	41.8
Other End-Use Generators[12]	0.0	0.4	0.4	0.4	0.7	0.7	0.8	1.1	1.1	1.2

[1] Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.

[2] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[3] Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.

[4] Includes oil-, gas-, and dual-fired capability.

[5] Nuclear capacity reflects operating capacity of existing units, including 4.3 gigawatts of uprates through 2025.

[6] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.

[7] Primarily peak-load capacity fueled by natural gas

[8] Includes combined heat and power plants whose primary business is to sell electricity and heat to the public(i.e., those that report NAICS code 22).

[9] Cumulative additions after December 31, 2001.

[10] Cumulative total retirements after December 31, 2001.

[11] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[12] Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[13] See Table E17 for more detail.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model estimates and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with capability for electric utility generators.

Source: 2001 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E12. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Crude Oil										
Domestic Crude Production[1]	5.80	5.63	5.63	5.63	5.41	5.41	5.41	5.27	5.25	5.27
Alaska	0.97	0.64	0.64	0.64	1.23	1.23	1.23	1.17	1.17	1.17
Lower 48 States	4.84	4.99	4.99	4.99	4.18	4.18	4.18	4.09	4.08	4.09
Net Imports	9.31	11.40	11.39	11.40	12.35	12.33	12.31	12.72	12.74	12.72
Gross Imports	9.33	11.46	11.45	11.46	12.40	12.38	12.37	12.77	12.79	12.76
Exports	0.02	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.05
Other Crude Supply[2]	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.13**	**17.03**	**17.03**	**17.03**	**17.76**	**17.74**	**17.73**	**17.99**	**17.99**	**17.98**
Natural Gas Plant Liquids	**1.87**	**2.27**	**2.26**	**2.25**	**2.63**	**2.62**	**2.59**	**2.69**	**2.68**	**2.68**
Other Inputs[3]	**0.30**	**0.43**	**0.43**	**0.44**	**0.36**	**0.35**	**0.36**	**0.35**	**0.34**	**0.35**
Refinery Processing Gain[4]	**0.90**	**0.89**	**0.89**	**0.90**	**0.94**	**0.94**	**0.94**	**0.93**	**0.94**	**0.94**
Net Product Imports[5]	**1.59**	**1.89**	**1.91**	**1.97**	**3.42**	**3.42**	**3.47**	**4.22**	**4.20**	**4.17**
Gross Refined Product Imports[6]	2.08	2.32	2.32	2.37	3.40	3.40	3.45	4.26	4.24	4.22
Unfinished Oil Imports	0.38	0.55	0.58	0.59	1.06	1.06	1.06	1.01	1.01	1.01
Ether Imports	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.95	0.98	0.98	0.99	1.03	1.03	1.04	1.05	1.05	1.05
Total Primary Supply[7]	**19.80**	**22.52**	**22.53**	**22.59**	**25.10**	**25.07**	**25.08**	**26.17**	**26.16**	**26.12**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.67	10.42	10.42	10.45	11.47	11.42	11.48	11.76	11.71	11.75
Jet Fuel[9]	1.66	1.89	1.89	1.89	2.42	2.42	2.42	2.69	2.69	2.68
Distillate Fuel[10]	3.81	4.57	4.57	4.58	5.19	5.18	5.18	5.54	5.53	5.51
Residual Fuel	0.97	0.54	0.54	0.54	0.52	0.53	0.52	0.53	0.53	0.53
Other[11]	4.58	5.12	5.13	5.14	5.50	5.53	5.49	5.66	5.70	5.65
Total	**19.69**	**22.53**	**22.54**	**22.61**	**25.11**	**25.08**	**25.09**	**26.18**	**26.16**	**26.13**
Refined Petroleum Products Supplied										
Residential and Commercial	1.21	1.18	1.18	1.18	1.16	1.16	1.16	1.15	1.15	1.15
Industrial[12]	4.67	5.21	5.22	5.23	5.62	5.64	5.60	5.79	5.83	5.78
Transportation	13.27	16.02	16.03	16.08	18.25	18.19	18.25	19.14	19.09	19.11
Electric Power[13]	0.55	0.12	0.11	0.11	0.08	0.08	0.08	0.09	0.09	0.09
Total	**19.69**	**22.53**	**22.54**	**22.61**	**25.11**	**25.08**	**25.09**	**26.18**	**26.16**	**26.13**
Discrepancy[14]	**0.10**	**-0.02**	**-0.02**	**-0.02**	**-0.01**	**-0.01**	**-0.01**	**-0.01**	**-0.01**	**-0.00**
World Oil Price (2001 dollars per barrel)[15]	**22.01**	**23.77**	**23.76**	**23.81**	**24.15**	**24.14**	**24.18**	**24.58**	**24.59**	**24.57**
Import Share of Product Supplied	**0.55**	**0.59**	**0.59**	**0.59**	**0.63**	**0.63**	**0.63**	**0.65**	**0.65**	**0.65**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2001 dollars)	**89.20**	**117.95**	**118.01**	**118.81**	**144.08**	**143.64**	**144.26**	**158.78**	**158.68**	**158.03**
Domestic Refinery Distillation Capacity[16]	**16.8**	**18.7**	**18.7**	**18.7**	**19.1**	**19.1**	**19.1**	**19.3**	**19.3**	**19.3**
Capacity Utilization Rate (percent)	**93.0**	**92.8**	**92.8**	**92.8**	**94.5**	**94.5**	**94.4**	**94.6**	**94.6**	**94.6**

[1] Includes lease condensate.

[2] Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.

[3] Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.

[4] Represents volumetric gain in refinery distillation and cracking processes.

[5] Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.

[6] Includes other hydrocarbons, alcohols, and blending components.

[7] Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.

[8] Includes ethanol and ethers blended into gasoline.

[9] Includes only kerosene type.

[10] Includes distillate and kerosene.

[11] Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.

[12] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[13] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[14] Balancing item. Includes unaccounted for supply, losses, and gains.

[15] Average refiner acquisition cost for imported crude oil.

[16] End-of-year capacity.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). Other 2001 data: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E13. Petroleum Product Prices
(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
World Oil Price (2001 dollars per barrel)	**22.01**	**23.77**	**23.76**	**23.81**	**24.15**	**24.14**	**24.18**	**24.58**	**24.59**	**24.57**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	124.6	110.3	110.2	110.5	114.2	114.4	114.3	119.0	119.0	119.0
Liquefied Petroleum Gas	127.3	119.8	120.1	122.0	123.9	127.5	127.4	128.3	127.9	128.3
Commercial										
Distillate Fuel	88.7	78.0	78.0	78.3	82.6	82.8	82.8	87.3	87.4	87.3
Residual Fuel	51.8	58.9	58.8	59.0	59.3	59.3	59.4	60.2	60.3	60.2
Residual Fuel (2001 dollars per barrel)	21.75	24.73	24.71	24.76	24.92	24.91	24.94	25.30	25.31	25.29
Industrial[1]										
Distillate Fuel	90.8	79.2	79.1	79.4	85.7	85.8	85.9	90.6	90.6	90.6
Liquefied Petroleum Gas	105.9	82.2	82.3	84.2	87.0	90.5	90.4	91.0	90.3	90.9
Residual Fuel	49.1	54.7	54.7	54.8	55.4	55.4	55.4	56.4	56.4	56.3
Residual Fuel (2001 dollars per barrel)	20.61	22.99	22.97	23.02	23.26	23.25	23.28	23.67	23.69	23.66
Transportation										
Diesel Fuel (distillate)[2]	139.4	162.4	162.2	162.3	182.6	183.1	182.5	199.3	199.5	199.4
Jet Fuel[3]	83.7	95.9	95.9	96.3	125.0	125.1	125.4	139.7	139.5	140.5
Motor Gasoline[4]	143.3	160.8	160.8	160.6	179.9	178.2	179.9	189.6	188.8	190.1
Liquid Petroleum Gas	145.2	140.3	140.5	142.3	157.0	160.4	160.0	164.3	162.4	164.7
Residual Fuel	58.4	77.8	77.8	78.1	110.1	110.2	110.6	124.5	124.2	125.9
Residual Fuel (2001 dollars per barrel)	24.52	32.66	32.67	32.79	46.25	46.30	46.47	52.31	52.15	52.86
Electric Power[5]										
Distillate Fuel	86.0	69.5	69.4	69.7	74.7	74.7	74.8	78.2	78.3	78.5
Residual Fuel	67.4	64.2	64.9	65.0	73.1	72.8	73.2	74.6	74.5	74.2
Residual Fuel (2001 dollars per barrel)	28.30	26.98	27.27	27.30	30.71	30.58	30.75	31.31	31.29	31.18
Refined Petroleum Product Prices[6]										
Distillate Fuel	127.0	142.1	141.9	142.2	160.6	160.9	160.6	175.3	175.5	175.4
Jet Fuel[3]	83.7	95.9	95.9	96.3	125.0	125.1	125.4	139.7	139.5	140.5
Liquefied Petroleum Gas	110.3	89.4	89.6	91.5	93.8	97.2	97.2	97.8	97.0	97.7
Motor Gasoline[4]	143.4	160.6	160.6	160.4	179.4	177.8	179.4	189.1	188.3	189.5
Residual Fuel	61.5	71.7	71.9	72.1	96.1	96.0	96.5	106.5	106.2	107.4
Residual Fuel (2001 dollars per barrel)	25.85	30.13	30.20	30.29	40.35	40.32	40.54	44.75	44.59	45.12
Average	**123.6**	**137.0**	**136.9**	**137.2**	**154.1**	**153.7**	**154.6**	**164.3**	**163.6**	**164.6**
Greenhouse Gas Allowance Cost										
Commercial										
Distillate Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residual Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residual Fuel (2001 dollars per barrel)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[1]										
Distillate Fuel	0.0	21.6	21.7	21.8	48.9	49.0	49.3	60.5	60.1	61.6
Liquefied Petroleum Gas	0.0	11.6	11.6	11.7	26.1	26.2	26.4	32.4	32.2	33.0
Residual Fuel	0.0	25.1	25.2	25.3	56.8	57.0	57.3	70.3	69.9	71.6
Residual Fuel (2001 dollars per barrel)	0.00	10.55	10.58	10.64	23.86	23.92	24.06	29.53	29.36	30.09
Electric Power[5]										
Distillate Fuel	0.0	21.6	21.7	21.8	48.9	49.0	49.3	60.5	60.1	61.6
Residual Fuel	0.0	25.1	25.2	25.3	56.8	57.0	57.3	70.3	69.9	71.6
Residual Fuel (2001 dollars per barrel)	0.00	10.55	10.58	10.64	23.86	23.92	24.06	29.53	29.36	30.09

Table E13. Petroleum Product Prices (Continued)
(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Delivered Sector Product Prices with Greenhouse Gas Allowance Cost										
Commercial										
Distillate Fuel	88.7	78.0	78.0	78.3	82.6	82.8	82.8	87.3	87.4	87.3
Residual Fuel	51.8	58.9	58.8	59.0	59.3	59.3	59.4	60.2	60.3	60.2
Residual Fuel (2001 dollars per barrel)	21.75	24.73	24.71	24.76	24.92	24.91	24.94	25.30	25.31	25.29
Industrial[1]										
Distillate Fuel	90.8	100.8	100.8	101.2	134.6	134.7	135.1	151.0	150.7	152.2
Liquefied Petroleum Gas	105.9	93.8	93.9	95.9	113.1	116.7	116.8	123.3	122.5	123.9
Residual Fuel	49.1	79.9	79.9	80.2	112.2	112.3	112.7	126.7	126.3	128.0
Residual Fuel (2001 dollars per barrel)	20.61	33.55	33.55	33.67	47.12	47.18	47.34	53.20	53.05	53.75
Electric Power[5]										
Distillate Fuel	86.0	91.1	91.1	91.5	123.6	123.7	124.1	138.6	138.4	140.1
Residual Fuel	67.4	89.4	90.1	90.3	129.9	129.8	130.5	144.9	144.4	145.9
Residual Fuel (2001 dollars per barrel)	28.30	37.53	37.85	37.94	54.57	54.51	54.81	60.84	60.65	61.27

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[1] Includes combined heat and power, which produces electricity and other useful thermal energy.

[2] Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur. Includes Federal and State taxes while excluding county and local taxes.

[3] Kerosene-type jet fuel.

[4] Sales weighted-average price for all grades. Includes Federal, State and local taxes.

[5] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[6] Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources:. 2001 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A: "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2001 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2001 world oil price: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections**: EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E14. Natural Gas Supply and Disposition

(Trillion Cubic Feet per Year)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Production										
Dry Gas Production[1]	19.45	22.21	22.12	22.04	26.61	26.50	26.25	27.32	27.31	27.31
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.73**	**4.85**	**4.91**	**4.92**	**8.80**	**8.81**	**8.80**	**10.87**	**10.80**	**10.79**
Canada	3.61	4.20	4.18	4.18	5.44	5.44	5.38	5.61	5.58	5.54
Mexico	-0.13	-0.21	-0.21	-0.20	0.16	0.14	0.14	0.66	0.64	0.64
Liquefied Natural Gas	0.26	0.86	0.93	0.94	3.21	3.22	3.28	4.60	4.58	4.61
Total Supply	**23.26**	**27.15**	**27.13**	**27.05**	**35.51**	**35.40**	**35.15**	**38.29**	**38.21**	**38.19**
Consumption by Sector										
Residential	4.81	5.47	5.47	5.47	5.80	5.80	5.81	6.03	6.03	6.05
Commercial	3.24	3.63	3.63	3.63	4.16	4.11	4.22	4.84	4.69	4.94
Industrial[3]	7.53	8.91	8.86	8.95	10.08	9.90	10.11	10.79	10.51	10.80
Electric Power[4]	5.30	7.20	7.23	7.08	13.00	13.13	12.56	14.03	14.38	13.81
Transportation[5]	0.01	0.06	0.06	0.06	0.09	0.09	0.09	0.10	0.10	0.10
Pipeline Fuel	0.61	0.79	0.78	0.78	1.02	1.02	1.00	1.08	1.07	1.07
Lease and Plant Fuel[6]	1.17	1.36	1.36	1.36	1.66	1.65	1.64	1.72	1.72	1.72
Total	**22.67**	**27.42**	**27.40**	**27.33**	**35.80**	**35.70**	**35.43**	**38.59**	**38.51**	**38.49**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.59**	**-0.26**	**-0.28**	**-0.28**	**-0.30**	**-0.30**	**-0.28**	**-0.30**	**-0.30**	**-0.30**

[1] Marketed production (wet) minus extraction losses.

[2] Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

[3] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as vehicle fuel.

[6] Represents natural gas used in the field gathering and processing plant machinery.

[7] Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2001 values include net storage injections.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E15. Natural Gas Prices, Margins, and Revenue
(2001 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Source Price										
Average Lower 48 Wellhead Price[1]	4.12	3.51	3.47	3.43	3.97	3.96	3.90	4.36	4.35	4.38
Average Import Price	4.43	3.46	3.45	3.45	4.17	4.17	4.12	4.65	4.60	4.62
Average[2]	**4.17**	**3.50**	**3.47**	**3.44**	**4.02**	**4.02**	**3.96**	**4.45**	**4.42**	**4.45**
Delivered Prices										
Residential	9.68	7.89	7.85	7.83	8.30	8.28	8.23	8.72	8.68	8.72
Commercial	8.32	6.78	6.74	6.72	7.27	7.25	7.19	7.69	7.66	7.68
Industrial[3]	5.01	4.23	4.20	4.17	4.81	4.82	4.73	5.21	5.20	5.20
Electric Power[4]	4.87	4.14	4.11	4.08	4.88	4.88	4.80	5.29	5.26	5.27
Transportation[5]	7.87	7.45	7.42	7.39	7.94	7.93	7.86	8.30	8.29	8.30
Average[6]	**6.57**	**5.38**	**5.35**	**5.32**	**5.78**	**5.78**	**5.72**	**6.19**	**6.16**	**6.19**
Transmission & Distribution Margins[7]										
Residential	5.50	4.39	4.39	4.39	4.27	4.26	4.27	4.28	4.26	4.28
Commercial	4.14	3.28	3.28	3.28	3.24	3.23	3.23	3.24	3.23	3.24
Industrial[3]	0.83	0.73	0.73	0.73	0.79	0.80	0.78	0.77	0.78	0.76
Electric Power[4]	0.70	0.65	0.64	0.64	0.86	0.87	0.85	0.84	0.84	0.83
Transportation[5]	3.69	3.95	3.95	3.95	3.92	3.92	3.91	3.86	3.86	3.85
Average[6]	**2.40**	**1.88**	**1.88**	**1.88**	**1.76**	**1.76**	**1.76**	**1.75**	**1.74**	**1.75**
Transmission & Distribution Revenue (billion 2001 dollars)										
Residential	26.45	24.00	23.98	24.02	24.78	24.69	24.81	25.78	25.66	25.86
Commercial	13.42	11.91	11.90	11.92	13.48	13.28	13.66	15.68	15.16	15.97
Industrial[3]	6.28	6.49	6.48	6.53	7.94	7.90	7.86	8.27	8.18	8.17
Electric Power[4]	3.69	4.64	4.65	4.52	11.18	11.38	10.63	11.80	12.05	11.43
Transportation[5]	0.04	0.22	0.22	0.23	0.36	0.36	0.36	0.39	0.39	0.38
Total	**49.88**	**47.27**	**47.24**	**47.22**	**57.74**	**57.60**	**57.31**	**61.91**	**61.43**	**61.82**
Greenhouse Gas Allowance Cost										
Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[3]	0.00	1.15	1.15	1.16	2.59	2.60	2.61	3.21	3.19	3.27
Electric Power[4]	0.00	1.16	1.16	1.17	2.62	2.62	2.64	3.24	3.22	3.30
Transportation[5]	0.00	1.17	1.17	1.18	2.64	2.65	2.66	3.27	3.25	3.33
Average[6]	**0.00**	**0.74**	**0.74**	**0.74**	**1.83**	**1.83**	**1.83**	**2.25**	**2.25**	**2.28**
Delivered Prices with Greenhouse Gas Allowance Cost										
Residential	9.68	7.89	7.85	7.83	8.30	8.28	8.23	8.72	8.68	8.72
Commercial	8.32	6.78	6.74	6.72	7.27	7.25	7.19	7.69	7.66	7.68
Industrial[3]	5.01	5.37	5.35	5.32	7.40	7.41	7.35	8.42	8.39	8.47
Electric Power[4]	4.87	5.30	5.27	5.24	7.50	7.51	7.44	8.53	8.48	8.57
Transportation[5]	7.87	8.62	8.59	8.56	10.58	10.58	10.53	11.57	11.53	11.63
Average[6]	**6.57**	**6.12**	**6.08**	**6.06**	**7.61**	**7.61**	**7.55**	**8.44**	**8.41**	**8.47**

[1] Represents lower 48 onshore and offshore supplies.

[2] Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.

[3] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.

[6] Weighted average allowance cost. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.

[7] Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 electric generators delivered price: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1998*. 2001 residential, commercial, and transportation delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E16. Oil and Gas Supply

Production and Supply	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Crude Oil										
Lower 48 Average Wellhead Price[1] (2001 dollars per barrel)	**22.91**	**23.56**	**23.52**	**23.60**	**23.65**	**23.62**	**23.64**	**24.11**	**24.09**	**24.10**
Production (million barrels per day)[2]										
U.S. Total	**5.80**	**5.63**	**5.63**	**5.63**	**5.41**	**5.41**	**5.41**	**5.27**	**5.25**	**5.27**
Lower 48 Onshore	3.13	2.47	2.47	2.47	2.05	2.05	2.05	1.90	1.90	1.90
Lower 48 Offshore	1.71	2.52	2.52	2.52	2.13	2.13	2.13	2.19	2.18	2.20
Alaska	0.97	0.64	0.64	0.64	1.23	1.23	1.23	1.17	1.17	1.17
Lower 48 End of Year Reserves (billion barrels)[2]	**19.48**	**17.70**	**17.71**	**17.70**	**15.34**	**15.35**	**15.35**	**14.92**	**14.88**	**14.92**
Natural Gas										
Lower 48 Average Wellhead Price[1] (2001 dollars per thousand cubic feet)	**4.12**	**3.51**	**3.47**	**3.43**	**3.97**	**3.96**	**3.90**	**4.36**	**4.35**	**4.38**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**19.45**	**22.21**	**22.12**	**22.04**	**26.61**	**26.50**	**26.25**	**27.32**	**27.32**	**27.31**
Lower 48 Onshore	13.72	16.17	16.09	16.01	18.65	18.53	18.31	18.72	18.68	18.69
Associated-Dissolved[4]	1.77	1.36	1.36	1.36	1.19	1.19	1.19	1.13	1.13	1.13
Non-Associated	11.94	14.81	14.72	14.65	17.46	17.34	17.12	17.59	17.56	17.56
Conventional	6.54	7.32	7.24	7.18	7.37	7.35	7.27	7.13	7.12	7.19
Unconventional	5.40	7.49	7.48	7.47	10.09	9.99	9.85	10.46	10.43	10.38
Lower 48 Offshore	5.30	5.56	5.56	5.55	5.58	5.58	5.56	5.77	5.79	5.79
Associated-Dissolved[4]	1.08	0.96	0.96	0.96	0.79	0.79	0.80	0.81	0.80	0.81
Non-Associated	4.22	4.60	4.60	4.59	4.78	4.79	4.76	4.96	4.99	4.98
Alaska	0.43	0.48	0.48	0.48	2.39	2.39	2.39	2.84	2.84	2.84
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**174.04**	**185.39**	**185.32**	**185.32**	**195.87**	**195.15**	**194.65**	**192.41**	**191.65**	**191.39**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Total Lower 48 Wells (thousands)	**33.94**	**25.75**	**25.67**	**25.51**	**27.25**	**27.28**	**27.12**	**29.30**	**29.19**	**29.23**

[1] Represents lower 48 onshore and offshore supplies.
[2] Includes lease condensate.
[3] Marketed production (wet) minus extraction losses.
[4] Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5] Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2001 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E17. Coal Supply, Disposition, and Prices

(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Production[1]										
Appalachia	443	415	413	411	212	217	214	145	168	143
Interior	147	153	156	154	88	90	88	42	45	42
West	548	513	509	506	185	188	179	128	136	119
East of the Mississippi	539	518	519	516	286	292	287	182	208	181
West of the Mississippi	599	563	559	555	199	204	193	132	140	124
Total	**1138**	**1081**	**1078**	**1071**	**485**	**496**	**480**	**315**	**348**	**304**
Net Imports										
Imports	19	11	11	11	11	11	11	10	10	10
Exports	49	33	33	32	29	29	31	24	24	24
Total	**-30**	**-22**	**-22**	**-22**	**-19**	**-19**	**-20**	**-13**	**-14**	**-13**
Total Supply[2]	**1109**	**1060**	**1056**	**1049**	**466**	**477**	**460**	**301**	**335**	**291**
Consumption by Sector										
Residential and Commercial	4	5	5	5	5	5	5	6	6	6
Industrial[3]	63	61	61	61	59	59	59	58	58	58
of which: Coal to Liquids	0	0	0	0	0	0	0	0	0	0
Coke Plants	26	24	24	24	17	17	17	14	14	14
Electric Power[4]	957	966	968	969	390	403	395	227	260	219
Total	**1050**	**1055**	**1058**	**1059**	**471**	**484**	**476**	**306**	**338**	**297**
Discrepancy and Stock Change[5]	**58**	**4**	**-1**	**-9**	**-6**	**-8**	**-16**	**-4**	**-3**	**-6**
Average Minemouth Price										
(2001 dollars per short ton)	17.59	15.84	15.91	15.90	15.27	15.41	15.50	13.67	13.98	13.74
(2001 dollars per million Btu)	0.83	0.76	0.76	0.76	0.71	0.71	0.72	0.63	0.65	0.63
Delivered Prices (2001 dollars per short ton)[6]										
Industrial	32.82	30.10	30.15	30.13	24.86	25.08	24.93	22.55	23.15	22.50
Coke Plants	46.42	41.37	41.34	41.45	38.31	38.14	38.34	36.64	36.54	36.63
Electric Power										
(2001 dollars per short ton)	25.06	23.76	23.78	23.77	20.83	21.06	20.88	18.81	19.29	18.76
(2001 dollars per million Btu)	1.25	1.16	1.16	1.16	0.99	1.00	0.99	0.90	0.92	0.90
Average	**26.06**	**24.53**	**24.55**	**24.54**	**21.98**	**22.16**	**22.02**	**20.39**	**20.71**	**20.38**
Exports[7]	36.97	32.41	32.41	32.47	28.76	28.76	28.54	27.46	27.64	27.48
Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]										
Industrial	0.00	43.59	43.71	43.96	98.28	98.54	99.11	121.42	120.72	123.76
Coke Plants	0.00	54.74	54.88	55.19	123.76	124.08	124.79	153.14	152.27	156.06
Electric Power										
(2001 dollars per short ton)	0.00	41.32	41.44	41.68	95.21	95.66	96.23	117.30	117.13	120.00
(2001 dollars per million Btu)	0.00	2.02	2.02	2.03	4.54	4.55	4.58	5.62	5.59	5.73
Average	**0.00**	**41.76**	**41.87**	**42.12**	**96.65**	**97.03**	**97.63**	**119.82**	**119.28**	**122.53**
Delivered Prices with Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]										
Industrial	32.82	73.69	73.86	74.09	123.14	123.62	124.04	143.97	143.87	146.26
Coke Plants	46.42	96.11	96.22	96.65	162.07	162.22	163.13	189.79	188.82	192.68
Electric Power										
(2001 dollars per short ton)	25.06	65.08	65.22	65.46	116.04	116.71	117.11	136.11	136.42	138.76
(2001 dollars per million Btu)	1.25	3.17	3.18	3.19	5.53	5.55	5.57	6.53	6.51	6.62
Average	**26.06**	**66.29**	**66.42**	**66.66**	**118.63**	**119.19**	**119.65**	**140.21**	**140.00**	**142.91**

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[1] Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.1 million tons in 2000 and 10.6 million tons in 2001.

[2] Production plus net imports and net storage withdrawals.

[3] Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

[4] Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[5] Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.

[6] Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.

[7] F.a.s. price at U.S. port of exit.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E18. Renewable Energy Generating Capacity and Generation

(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Electric Power Sector[1]										
Net Summer Capacity										
Conventional Hydropower	78.10	78.66	78.66	78.66	78.65	78.65	78.65	78.65	78.65	78.65
Geothermal[2]	2.83	6.68	6.68	6.69	10.06	9.84	9.82	10.55	9.97	10.34
Municipal Solid Waste[3]	3.25	4.84	4.84	4.84	5.17	5.17	5.17	5.19	5.19	5.19
Wood and Other Biomass[4]	1.80	3.96	4.01	3.98	48.03	50.56	52.89	67.38	66.71	65.53
Solar Thermal	0.33	0.44	0.44	0.44	0.48	0.48	0.48	0.50	0.50	0.50
Solar Photovoltaic[5]	0.02	0.10	0.10	0.10	0.27	0.27	0.27	0.36	0.36	0.36
Wind	4.29	34.53	33.97	34.10	82.60	81.72	83.62	83.22	82.49	88.63
Total	**90.62**	**129.20**	**128.68**	**128.81**	**225.26**	**226.69**	**230.90**	**245.84**	**243.86**	**249.20**
Generation (billion kilowatthours)										
Conventional Hydropower	213.82	300.89	300.89	300.88	299.92	299.95	299.89	300.10	300.15	300.09
Geothermal[2]	13.81	44.61	44.61	44.72	73.14	71.50	71.29	77.22	72.75	75.71
Municipal Solid Waste[3]	19.55	35.17	35.17	35.17	37.63	37.64	37.63	37.83	37.83	37.82
Wood and Other Biomass[4]	9.38	27.11	27.14	27.02	304.95	322.64	319.87	429.32	432.22	423.70
Dedicated Plants	7.66	19.52	19.68	19.58	304.95	322.64	319.87	429.32	432.22	423.70
Cofiring	1.72	7.59	7.46	7.44	0.00	0.00	0.00	0.00	0.00	0.00
Solar Thermal	0.49	0.77	0.77	0.77	0.90	0.90	0.90	0.97	0.97	0.97
Solar Photovoltaic[5]	0.00	0.24	0.24	0.24	0.66	0.66	0.66	0.88	0.88	0.88
Wind	5.78	112.46	110.30	111.41	277.70	275.12	279.51	280.10	277.97	299.00
Total	**262.85**	**521.25**	**519.13**	**520.22**	**994.90**	**1008.40**	**1009.75**	**1126.43**	**1122.77**	**1138.18**
End- Use Sector										
Net Summer Capacity										
Combined Heat and Power[6]										
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Biomass	4.41	5.89	5.89	5.91	7.67	7.65	7.65	8.60	8.58	8.56
Total	**4.69**	**6.17**	**6.17**	**6.20**	**7.95**	**7.94**	**7.93**	**8.88**	**8.86**	**8.84**
Other End-Use Generators[7]										
Conventional Hydropower[8]	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.38	0.38	0.38	0.76	0.72	0.78	1.15	1.10	1.18
Total	**1.12**	**1.47**	**1.47**	**1.47**	**1.85**	**1.82**	**1.87**	**2.25**	**2.19**	**2.27**
Generation (billion kilowatthours)										
Combined Heat and Power[6]										
Municipal Solid Waste	2.46	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15
Biomass	28.67	37.31	37.31	37.46	47.72	47.61	47.59	53.13	53.01	52.91
Total	**31.13**	**39.46**	**39.46**	**39.61**	**49.87**	**49.76**	**49.74**	**55.28**	**55.16**	**55.06**
Other End-Use Generators[7]										
Conventional Hydropower[8]	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.82	0.82	0.82	1.61	1.55	1.66	2.42	2.30	2.48
Total	**4.25**	**5.05**	**5.05**	**5.05**	**5.85**	**5.78**	**5.90**	**6.66**	**6.54**	**6.72**

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[1] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes hydrothermal resources only (hot water and steam).

[3] Includes landfill gas.

[4] Includes projections for energy crops after 2010.

[5] Does not include off-grid photovoltaics (PV). See Annual Energy Review 2001 Table 10.6 for estimates of 1989-2000 PV shipments, including exports, for both grid-connected and off-grid applications.

[6] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[7] Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[8] Represents own-use industrial hydroelectric power.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2003. Net summer capacity is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.

Sources: 2001 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2001 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E19. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Marketed Renewable Energy[2]										
Residential	**0.39**	**0.41**	**0.41**	**0.41**	**0.40**	**0.40**	**0.40**	**0.40**	**0.40**	**0.40**
Wood	0.39	0.41	0.41	0.41	0.40	0.40	0.40	0.40	0.40	0.40
Commercial	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Industrial[3]	**1.82**	**2.21**	**2.21**	**2.22**	**2.74**	**2.74**	**2.74**	**3.02**	**3.01**	**3.01**
Conventional Hydroelectric	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.77	2.16	2.16	2.17	2.69	2.69	2.69	2.97	2.96	2.96
Transportation	**0.15**	**0.26**	**0.26**	**0.26**	**0.28**	**0.28**	**0.28**	**0.29**	**0.29**	**0.29**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Ethanol used in Gasoline Blending	0.15	0.26	0.26	0.26	0.28	0.28	0.28	0.28	0.28	0.28
Electric Power[5]	**3.01**	**6.30**	**6.28**	**6.30**	**11.42**	**11.49**	**11.50**	**12.69**	**12.55**	**12.78**
Conventional Hydroelectric	2.16	3.09	3.09	3.09	3.07	3.07	3.07	3.07	3.07	3.07
Geothermal	0.29	1.30	1.30	1.31	2.23	2.17	2.16	2.36	2.21	2.30
Municipal Solid Waste[6]	0.31	0.48	0.48	0.48	0.51	0.51	0.51	0.51	0.51	0.51
Biomass	0.15	0.31	0.31	0.31	2.78	2.94	2.91	3.89	3.91	3.84
Dedicated Plants	0.12	0.21	0.22	0.22	2.78	2.94	2.91	3.89	3.91	3.84
Cofiring	0.03	0.09	0.09	0.09	0.00	0.00	0.00	0.00	0.00	0.00
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.08	1.12	1.09	1.11	2.82	2.79	2.84	2.84	2.82	3.04
Total Marketed Renewable Energy	**5.46**	**9.28**	**9.26**	**9.28**	**14.95**	**15.02**	**15.03**	**16.50**	**16.35**	**16.58**
Sources of Ethanol										
From Corn	0.15	0.26	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24
From Cellulose	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.05	0.05	0.05
Total	**0.15**	**0.26**	**0.26**	**0.26**	**0.28**	**0.28**	**0.28**	**0.29**	**0.29**	**0.29**
Non-Marketed Renewable Energy[7] **Selected Consumption**										
Residential	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**
Solar Hot Water Heating	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Geothermal Heat Pumps	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01

[1] Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.

[2] Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table E8.

[3] Includes all electricity production by industrial and other combined heat and power for the grid and for own use.

[4] Excludes motor gasoline component of E85.

[5] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[6] Includes landfill gas.

[7] Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 electric generators: EIA, Form EIA-860: "Annual Electric Generator Report" (preliminary). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E20. Greenhouse Gas Emissions and Allowance Cost
(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Carbon Dioxide Emissions										
Residential										
Petroleum	27.2	27.6	27.6	27.6	25.8	25.8	25.8	25.0	25.0	25.0
Natural Gas	71.1	81.0	81.0	81.0	85.8	85.8	86.0	89.3	89.2	89.5
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3
Total	**98.7**	**109.0**	**109.0**	**108.9**	**112.0**	**112.0**	**112.1**	**114.7**	**114.6**	**114.9**
Commercial										
Petroleum	14.0	13.7	13.7	13.7	14.5	14.5	14.5	14.8	14.7	14.8
Natural Gas	48.0	53.8	53.8	53.8	61.5	60.8	62.5	71.6	69.4	73.1
Coal	2.3	2.5	2.5	2.5	2.8	2.8	2.8	2.9	2.9	2.9
Total	**64.3**	**69.9**	**69.9**	**69.9**	**78.8**	**78.0**	**79.8**	**89.3**	**87.0**	**90.7**
Industrial[1]										
Petroleum	97.9	96.0	96.4	96.5	99.1	99.6	98.7	101.1	101.7	100.8
Natural Gas[2]	123.4	149.8	148.9	150.1	171.0	168.2	171.3	182.4	178.3	182.6
Coal	52.1	53.1	53.1	53.3	48.9	49.0	48.6	47.3	47.5	46.9
Total	**273.4**	**298.9**	**298.3**	**299.8**	**319.0**	**316.8**	**318.6**	**330.8**	**327.5**	**330.3**
Transportation										
Petroleum[3]	501.4	605.1	605.2	607.1	690.4	688.3	690.2	725.3	723.4	724.0
Natural Gas[4]	9.2	12.5	12.4	12.4	16.4	16.4	16.1	17.4	17.4	17.3
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**510.6**	**617.6**	**617.6**	**619.5**	**706.8**	**704.7**	**706.3**	**742.7**	**740.8**	**741.3**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	640.5	742.5	742.8	744.8	829.8	828.2	829.1	866.2	864.8	864.5
Natural Gas	251.7	297.0	296.1	297.2	334.8	331.2	335.9	360.7	354.3	362.5
Coal	54.7	55.9	55.9	56.1	52.0	52.1	51.7	50.5	50.7	50.1
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**947.0**	**1095.4**	**1094.8**	**1098.2**	**1216.6**	**1211.6**	**1216.8**	**1277.4**	**1269.9**	**1277.2**
Electric Power[6]										
Petroleum	27.5	5.4	5.3	5.3	3.9	4.0	3.9	3.9	4.0	3.9
Natural Gas	77.7	105.0	105.5	103.2	158.0	161.9	162.4	132.6	136.0	135.8
Coal	506.4	504.4	505.6	506.2	190.0	192.1	190.7	68.3	68.4	66.9
Total	**611.6**	**614.8**	**616.4**	**614.6**	**351.9**	**358.0**	**357.0**	**204.8**	**208.3**	**206.7**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	668.0	747.9	748.1	750.1	833.7	832.2	833.0	870.2	868.8	868.5
Natural Gas	329.4	402.0	401.6	400.4	492.8	493.1	498.3	493.3	490.3	498.4
Coal	561.1	560.3	561.6	562.3	242.0	244.2	242.5	118.8	119.1	117.0
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1558.6**	**1710.1**	**1711.2**	**1712.8**	**1568.5**	**1569.6**	**1573.7**	**1482.2**	**1478.2**	**1483.9**
Non-Energy Related Carbon Dioxide Emissions	**36.3**	**39.5**	**39.5**	**39.5**	**43.9**	**43.9**	**43.9**	**46.2**	**46.2**	**46.2**
Total Carbon Dioxide Emissions	**1594.9**	**1749.7**	**1750.8**	**1752.3**	**1612.4**	**1613.5**	**1617.6**	**1528.4**	**1524.4**	**1530.1**
Other Greenhouse Gas Emissions	**332.9**	**286.4**	**286.5**	**286.4**	**339.5**	**339.5**	**339.6**	**362.9**	**363.0**	**362.9**
Methane	175.2	115.2	115.2	115.2	126.4	126.4	126.5	120.0	120.0	120.0
Nitrous Oxide	118.9	121.0	121.0	121.0	131.4	131.4	131.4	137.2	137.2	137.2
High Global Warming Potential Gases	38.8	50.2	50.2	50.2	81.8	81.7	81.7	105.8	105.8	105.8
Total Greenhouse Gas Emissions	**1927.8**	**2036.1**	**2037.3**	**2038.8**	**1951.9**	**1952.9**	**1957.2**	**1891.4**	**1887.4**	**1893.0**

Table E20. Greenhouse Gas Emissions and Allowance Cost (Continued)

(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
Greenhouse Gas Emission Cap Compliance										
Covered Emissions										
Energy-Related Carbon Dioxide	1378.2	1513.1	1514.2	1515.8	1357.5	1359.5	1361.7	1256.9	1255.3	1257.0
Other Greenhouse Gases	75.2	70.1	70.1	70.1	102.8	102.8	102.7	127.6	127.6	127.6
Offsets Purchased	0.0	234.7	234.5	234.7	126.1	126.2	125.6	125.6	125.4	125.7
Non-Covered Greenhouse Gas Offsets	0.0	48.5	48.5	48.5	34.3	34.3	34.1	39.0	39.0	39.1
U.S. Sequestration Offsets	0.0	112.8	112.7	112.8	91.8	91.9	91.4	86.5	86.4	86.6
International Offsets	0.0	73.4	73.2	73.4	0.0	0.0	0.0	0.1	0.0	0.1
Covered Emissions less Offsets	1453.4	1348.5	1349.9	1351.2	1334.2	1336.0	1338.9	1258.9	1257.6	1258.9
Covered Emissions Coal	N/A	1465.1	1465.1	1465.1	1257.9	1257.9	1257.9	1257.9	1257.9	1257.9
Allowance Bank Activity	0.0	116.5	115.2	113.8	-76.3	-78.1	-81.0	-1.0	0.3	-1.0
Cumulative Bank Balance	0.0	116.5	115.2	113.8	98.9	106.1	94.0	7.3	6.7	-1.1
Allowance Cost (2001 dollars per ton)										
Emissions Allowance Cost	0.00	78.89	79.09	79.54	178.36	178.82	179.85	220.71	219.45	224.90
Offset Price	0.00	71.49	71.36	71.47	34.84	34.93	34.42	51.73	51.43	51.83

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[1] Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes lease and plant fuel.

[3] This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons carbon equivalent of carbon dioxide annually.

[4] Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

[5] Includes methanol and liquid hydrogen.

[6] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.

[7] Emissions from electric power generators are distributed to the primary fuels.

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table E21. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2001	Projections								
		2010			2020			2025		
		S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction	S. 139 Case	20% Auction	80% Auction
GDP Chain-Type Price Index (1996=1.000)	1.094	1.321	1.321	1.323	1.735	1.728	1.753	2.028	2.006	2.053
Potential Gross Domestic Product	9456	12458	12458	12457	16729	16740	16709	19150	19185	19121
Real Gross Domestic Product	9215	12211	12210	12248	16364	16338	16330	18810	18773	18748
Real Consumption	6377	8375	8375	8401	11284	11240	11286	12954	12860	12939
Real Investment	1575	2478	2477	2490	3724	3728	3704	4447	4467	4424
Real Government Spending	1640	1897	1897	1906	2204	2205	2204	2417	2420	2418
Real Exports	1076	1781	1781	1780	3329	3335	3310	4621	4646	4586
Real Imports	1492	2292	2292	2302	4027	4007	4038	5376	5329	5393
Real Disposable Personal Income	6748	8607	8607	8661	11648	11557	11683	13432	13240	13427
Federal Funds Rate (percent)	3.89	5.63	5.63	5.84	6.58	6.28	6.75	6.97	6.32	7.08
AA Utility Bond Rate (percent)										
Nominal	7.57	7.38	7.38	7.53	9.17	8.93	9.37	9.99	9.47	10.12
Real	5.60	5.20	5.20	5.32	6.18	6.01	6.28	6.76	6.43	6.88
Energy Intensity (thousand Btu per 1996 dollar of GDP)										
Delivered Energy	7.74	6.80	6.80	6.80	5.65	5.66	5.66	5.17	5.18	5.18
Total Energy	10.56	9.15	9.15	9.13	7.37	7.39	7.37	6.70	6.74	6.71
Consumer Price Index (1982-84=1.00)	1.77	2.20	2.20	2.20	2.97	2.96	3.00	3.55	3.51	3.59
Unemployment Rate (percent)	4.79	4.55	4.56	4.43	6.03	6.15	6.07	5.85	6.08	5.96
Housing Starts (millions)	1.80	2.12	2.12	2.13	1.92	1.92	1.91	2.01	2.02	2.00
Single-Family	1.27	1.31	1.31	1.31	1.11	1.11	1.10	1.11	1.12	1.10
Multifamily	0.33	0.45	0.45	0.45	0.49	0.48	0.48	0.57	0.57	0.57
Mobile Home Shipments	0.19	0.36	0.36	0.37	0.33	0.33	0.33	0.33	0.33	0.33
Commercial Floorspace, Total (billion square feet)	70.2	82.0	82.0	82.0	94.2	94.0	94.5	100.6	99.8	100.7
Value of Shipments (billion 1996 dollars)										
Total Industrial	5425	6920	6920	6950	8874	8868	8831	9990	10007	9924
Nonmanufacturing	1346	1500	1501	1505	1714	1710	1708	1828	1825	1821
Manufacturing	4079	5420	5420	5445	7160	7158	7123	8162	8182	8104
Energy-Intensive Manufacturing	1086	1255	1255	1261	1434	1430	1430	1515	1511	1510
Non-Energy-Intensive Manufacturing	2993	4164	4164	4185	5726	5727	5693	6647	6671	6594
United Sales of Light-Duty Vehicles	17.11	17.87	17.86	18.14	20.06	20.01	19.93	20.15	20.15	19.93
Population (millions)										
Population with Armed Forces Overseas	278.2	300.2	300.2	300.2	325.3	325.3	325.3	338.2	338.2	338.2
Population (aged 16 and over)	215.4	236.6	236.6	236.6	256.5	256.5	256.5	266.6	266.6	266.6
Employment, Non-Agriculture	131.7	147.1	147.0	147.4	158.8	158.5	158.7	165.5	165.0	165.3
Employment, Manufacturing	17.5	17.7	17.7	17.7	17.7	17.7	17.7	18.4	18.4	18.3
Labor Force	141.8	156.5	156.5	156.5	169.6	169.6	169.6	177.3	177.1	177.2

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2001: Global Insight macroeconomic model CTL0802. **Projections:** Energy Information Administration, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_CCCC20.D050503A, and ML_CCCC80.D050503A.

Table F1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Production										
Crude Oil and Lease Condensate	12.29	11.94	11.94	11.91	11.50	11.49	11.38	11.23	11.17	10.82
Natural Gas Plant Liquids	2.65	3.12	3.08	3.09	3.53	3.32	3.49	3.70	3.49	3.70
Dry Natural Gas	19.97	22.11	21.84	21.94	25.52	23.80	25.00	27.08	25.41	26.98
Coal	23.97	25.69	25.10	22.84	27.83	26.00	13.38	29.61	26.77	8.10
Nuclear Power	8.03	8.25	8.17	8.37	8.28	8.14	9.52	8.28	8.05	11.76
Renewable Energy[1]	5.32	7.30	7.71	9.03	8.31	9.53	14.34	8.77	10.28	15.60
Other[2]	0.57	0.85	0.84	0.84	0.79	0.77	0.70	0.80	0.78	0.61
Total	**72.80**	**79.26**	**78.67**	**78.02**	**85.76**	**83.06**	**77.81**	**89.47**	**85.94**	**77.56**
Imports										
Crude Oil[3]	20.26	25.09	24.92	24.78	27.63	27.26	27.06	28.62	28.18	27.86
Petroleum Products[4]	5.04	6.32	5.89	5.51	11.72	10.07	7.76	14.79	12.64	9.36
Natural Gas	4.18	5.43	4.99	5.08	7.41	6.55	7.70	8.44	6.91	9.45
Other Imports[5]	0.71	0.92	0.86	0.79	0.95	0.89	0.84	0.93	0.88	0.58
Total	**30.19**	**37.76**	**36.65**	**36.16**	**47.71**	**44.77**	**43.35**	**52.78**	**48.61**	**47.25**
Exports										
Petroleum[6]	2.01	2.25	2.23	2.21	2.38	2.32	2.28	2.43	2.35	2.29
Natural Gas	0.37	0.56	0.57	0.57	0.38	0.42	0.39	0.37	0.36	0.36
Coal	1.27	0.86	0.87	0.86	0.74	0.71	0.70	0.62	0.71	0.64
Total	**3.64**	**3.67**	**3.67**	**3.65**	**3.50**	**3.45**	**3.37**	**3.42**	**3.42**	**3.28**
Discrepancy[7]	**2.06**	**0.22**	**0.22**	**0.13**	**0.23**	**0.25**	**0.53**	**0.20**	**0.23**	**0.22**
Consumption										
Petroleum Products[8]	38.46	44.45	43.82	43.30	52.15	49.95	47.45	56.11	53.29	49.41
Natural Gas	23.26	27.35	26.62	26.82	32.95	30.33	32.70	35.55	32.35	36.44
Coal	22.02	25.47	24.85	22.47	27.88	26.05	12.85	29.86	26.89	8.00
Nuclear Power	8.03	8.25	8.17	8.37	8.28	8.14	9.52	8.28	8.05	11.76
Renewable Energy[1]	5.32	7.30	7.71	9.03	8.31	9.53	14.35	8.77	10.28	15.60
Other[9]	0.21	0.31	0.27	0.41	0.17	0.13	0.39	0.06	0.05	0.11
Total	**97.29**	**113.13**	**111.44**	**110.39**	**129.74**	**124.13**	**117.26**	**138.63**	**130.90**	**121.31**
Net Imports - Petroleum	**23.29**	**29.16**	**28.58**	**28.08**	**36.97**	**35.01**	**32.54**	**40.98**	**38.47**	**34.93**
Prices (2001 dollars per unit)										
World Oil Price (dollars per barrel)[10]	22.01	23.99	23.99	23.59	25.48	25.48	23.68	26.57	26.57	23.94
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.12	3.39	3.28	3.33	3.70	3.56	3.83	3.95	3.51	4.09
Coal Minemouth Price (dollars per ton)	17.59	15.06	15.09	15.68	14.34	14.20	15.51	14.39	14.05	13.29
Average Electricity Price (cents per kilowatthour)	7.3	6.4	6.3	6.7	6.7	6.3	7.9	6.7	6.3	8.6

[1] Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table F18 for selected nonmarketed residential and commercial renewable energy.

[2] Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.

[3] Includes imports of crude oil for the Strategic Petroleum Reserve.

[4] Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.

[5] Includes coal, coal coke (net), and electricity (net).

[6] Includes crude oil and petroleum products.

[7] Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.

[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.

[9] Includes net electricity imports, methanol, and liquid hydrogen.

[10] Average refiner acquisition cost for imported crude oil.

[11] Represents lower 48 onshore and offshore supplies.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Energy Consumption										
Residential										
Distillate Fuel	0.91	0.91	0.91	0.91	0.84	0.82	0.83	0.81	0.78	0.80
Kerosene	0.10	0.08	0.08	0.08	0.06	0.06	0.06	0.06	0.05	0.06
Liquefied Petroleum Gas	0.50	0.47	0.47	0.47	0.46	0.45	0.46	0.46	0.45	0.45
Petroleum Subtotal	1.50	1.46	1.45	1.45	1.36	1.34	1.35	1.33	1.29	1.31
Natural Gas	4.94	5.63	5.63	5.61	6.10	6.05	5.95	6.38	6.29	6.18
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.41	0.40	0.40	0.41	0.39	0.39	0.40	0.39	0.39
Electricity	4.10	4.93	4.84	4.79	5.60	5.35	4.92	5.95	5.67	4.97
Delivered Energy	**10.94**	**12.45**	**12.33**	**12.28**	**13.48**	**13.14**	**12.63**	**14.08**	**13.66**	**12.86**
Electricity Related Losses	9.15	10.37	10.20	10.08	11.03	10.31	9.16	11.42	10.36	8.82
Total	**20.08**	**22.82**	**22.53**	**22.36**	**24.51**	**23.45**	**21.78**	**25.50**	**24.02**	**21.69**
Commercial										
Distillate Fuel	0.46	0.51	0.51	0.51	0.52	0.51	0.53	0.52	0.50	0.54
Residual Fuel	0.09	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.10
Motor Gasoline[2]	0.05	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.71	0.70	0.70	0.70	0.72	0.71	0.73	0.72	0.71	0.74
Natural Gas	3.33	3.74	3.74	3.74	4.23	4.24	4.25	4.50	4.52	4.94
Coal	0.09	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.08	5.01	4.94	4.89	6.17	6.02	5.58	6.79	6.56	5.83
Delivered Energy	**8.32**	**9.65**	**9.58**	**9.52**	**11.33**	**11.18**	**10.77**	**12.23**	**12.00**	**11.73**
Electricity Related Losses	9.12	10.53	10.41	10.28	12.16	11.60	10.39	13.02	11.98	10.35
Total	**17.44**	**20.19**	**19.99**	**19.80**	**23.50**	**22.78**	**21.16**	**25.25**	**23.98**	**22.08**
Industrial[4]										
Distillate Fuel	1.13	1.21	1.20	1.19	1.36	1.31	1.26	1.44	1.38	1.31
Liquefied Petroleum Gas	2.10	2.55	2.53	2.52	3.06	3.00	2.96	3.28	3.22	3.14
Petrochemical Feedstock	1.14	1.44	1.43	1.40	1.70	1.68	1.53	1.82	1.80	1.57
Residual Fuel	0.23	0.19	0.18	0.17	0.20	0.18	0.16	0.20	0.18	0.16
Motor Gasoline[2]	0.15	0.17	0.16	0.16	0.18	0.18	0.18	0.19	0.19	0.19
Other Petroleum[5]	4.03	4.27	4.23	4.17	4.46	4.32	4.11	4.57	4.44	4.08
Petroleum Subtotal	8.79	9.82	9.73	9.62	10.96	10.67	10.21	11.50	11.21	10.46
Natural Gas	7.74	9.06	8.76	8.86	10.39	9.58	9.45	11.23	10.14	9.86
Lease and Plant Fuel[6]	1.20	1.37	1.36	1.36	1.60	1.49	1.55	1.73	1.63	1.71
Natural Gas Subtotal	8.94	10.43	10.12	10.22	11.98	11.07	10.99	12.96	11.77	11.57
Metallurgical Coal	0.72	0.66	0.59	0.57	0.55	0.42	0.27	0.50	0.35	0.21
Steam Coal	1.42	1.46	1.43	1.34	1.51	1.45	1.25	1.54	1.45	1.23
Net Coal Coke Imports	0.03	0.11	0.10	0.10	0.16	0.13	0.19	0.18	0.14	0.22
Coal Subtotal	2.16	2.23	2.11	2.00	2.22	1.99	1.71	2.22	1.95	1.66
Renewable Energy[7]	1.82	2.22	2.35	2.34	2.77	3.17	3.14	3.05	3.64	3.59
Electricity	3.39	3.97	3.85	3.75	4.65	4.39	4.17	5.01	4.69	4.35
Delivered Energy	**25.10**	**28.67**	**28.15**	**27.94**	**32.58**	**31.29**	**30.21**	**34.75**	**33.25**	**31.62**
Electricity Related Losses	7.57	8.35	8.11	7.89	9.17	8.47	7.76	9.61	8.56	7.72
Total	**32.67**	**37.02**	**36.27**	**35.83**	**41.75**	**39.76**	**37.97**	**44.36**	**41.81**	**39.34**

Table F2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Transportation										
Distillate Fuel[8]	5.44	7.09	7.05	6.93	8.68	8.52	7.98	9.55	9.34	8.55
Jet Fuel[9]	3.43	3.93	3.89	3.87	5.09	4.87	4.73	5.67	5.31	5.10
Motor Gasoline[2]	16.26	19.81	19.46	19.34	23.57	22.23	21.06	25.48	23.76	21.79
Residual Fuel	0.84	0.83	0.83	0.82	0.85	0.84	0.84	0.87	0.85	0.84
Liquefied Petroleum Gas	0.02	0.05	0.05	0.05	0.07	0.07	0.07	0.09	0.08	0.08
Other Petroleum[10]	0.24	0.26	0.26	0.26	0.30	0.30	0.30	0.32	0.32	0.32
Petroleum Subtotal	26.22	31.98	31.53	31.28	38.57	36.83	34.98	41.98	39.66	36.68
Pipeline Fuel Natural Gas	0.63	0.78	0.77	0.77	0.94	0.85	0.92	1.03	0.95	1.05
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.10	0.07	0.07	0.11	0.07	0.06
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.00	0.03	0.03
Electricity	0.07	0.09	0.09	0.09	0.12	0.12	0.12	0.14	0.13	0.13
Delivered Energy	**26.94**	**32.91**	**32.45**	**32.21**	**39.73**	**37.90**	**36.11**	**43.26**	**40.84**	**37.96**
Electricity Related Losses	0.17	0.20	0.20	0.20	0.24	0.23	0.22	0.27	0.25	0.24
Total	**27.10**	**33.10**	**32.65**	**32.41**	**39.98**	**38.13**	**36.33**	**43.53**	**41.09**	**38.19**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.94	9.74	9.66	9.54	11.40	11.17	10.61	12.32	12.01	11.20
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.89	3.87	5.09	4.87	4.73	5.67	5.31	5.10
Liquefied Petroleum Gas	2.70	3.16	3.13	3.13	3.69	3.61	3.58	3.92	3.84	3.77
Motor Gasoline[2]	16.46	20.01	19.66	19.54	23.79	22.44	21.27	25.71	23.98	22.01
Petrochemical Feedstock	1.14	1.44	1.43	1.40	1.70	1.68	1.53	1.82	1.80	1.57
Residual Fuel	1.15	1.06	1.05	1.04	1.10	1.07	1.05	1.12	1.08	1.06
Other Petroleum[12]	4.24	4.51	4.47	4.40	4.74	4.60	4.39	4.87	4.73	4.37
Petroleum Subtotal	37.21	43.97	43.40	43.05	51.61	49.55	47.27	55.53	52.86	49.19
Natural Gas	16.02	18.49	18.19	18.27	20.82	19.95	19.72	22.23	21.02	21.04
Lease and Plant Fuel Plant[6]	1.20	1.37	1.36	1.36	1.60	1.49	1.55	1.73	1.63	1.71
Pipeline Natural Gas	0.63	0.78	0.77	0.77	0.94	0.85	0.92	1.03	0.95	1.05
Natural Gas Subtotal	17.86	20.64	20.31	20.40	23.35	22.29	22.18	24.98	23.60	23.80
Metallurgical Coal	0.72	0.66	0.59	0.57	0.55	0.42	0.27	0.50	0.35	0.21
Steam Coal	1.53	1.56	1.54	1.44	1.63	1.56	1.37	1.66	1.57	1.36
Net Coal Coke Imports	0.03	0.11	0.10	0.10	0.16	0.13	0.19	0.18	0.14	0.22
Coal Subtotal	2.27	2.34	2.22	2.11	2.34	2.11	1.83	2.34	2.07	1.78
Renewable Energy[13]	2.31	2.74	2.86	2.85	3.28	3.68	3.65	3.57	4.14	4.10
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.00	0.03	0.03
Electricity	11.65	14.00	13.72	13.53	16.54	15.87	14.78	17.90	17.05	15.29
Delivered Energy	**71.29**	**83.68**	**82.51**	**81.94**	**97.13**	**93.52**	**89.72**	**104.32**	**99.76**	**94.19**
Electricity Related Losses	26.00	29.45	28.93	28.45	32.61	30.60	27.53	34.32	31.14	27.12
Total	**97.29**	**113.13**	**111.44**	**110.39**	**129.74**	**124.13**	**117.26**	**138.63**	**130.90**	**121.31**
Electric Power[14]										
Distillate Fuel	0.17	0.09	0.09	0.07	0.13	0.08	0.05	0.18	0.11	0.08
Residual Fuel	1.08	0.39	0.33	0.18	0.41	0.32	0.13	0.40	0.32	0.14
Petroleum Subtotal	1.25	0.48	0.42	0.25	0.54	0.40	0.19	0.58	0.42	0.22
Natural Gas	5.40	6.71	6.31	6.41	9.60	8.01	10.49	10.56	8.71	12.60
Steam Coal	19.75	23.13	22.63	20.36	25.54	23.94	11.02	27.52	24.82	6.22
Nuclear Power	8.03	8.25	8.17	8.37	8.28	8.14	9.52	8.28	8.05	11.76
Renewable Energy[15]	3.01	4.57	4.85	6.18	5.02	5.85	10.70	5.21	6.14	11.51
Electricity Imports	0.21	0.31	0.27	0.41	0.17	0.13	0.39	0.06	0.05	0.11
Total	**37.65**	**43.45**	**42.64**	**41.98**	**49.15**	**46.48**	**42.31**	**52.21**	**48.19**	**42.41**

Table F2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Total Energy Consumption										
Distillate Fuel	8.10	9.83	9.75	9.61	11.53	11.25	10.66	12.50	12.11	11.28
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.89	3.87	5.09	4.87	4.73	5.67	5.31	5.10
Liquefied Petroleum Gas	2.70	3.16	3.13	3.13	3.69	3.61	3.58	3.92	3.84	3.77
Motor Gasoline[2]	16.46	20.01	19.66	19.54	23.79	22.44	21.27	25.71	23.98	22.01
Petrochemical Feedstock	1.14	1.44	1.43	1.40	1.70	1.68	1.53	1.82	1.80	1.57
Residual Fuel	2.23	1.45	1.38	1.22	1.51	1.39	1.18	1.52	1.40	1.20
Other Petroleum[12]	4.24	4.51	4.47	4.40	4.74	4.60	4.39	4.87	4.73	4.37
Petroleum Subtotal	38.46	44.45	43.82	43.30	52.15	49.95	47.45	56.11	53.29	49.41
Natural Gas	21.42	25.20	24.49	24.68	30.42	27.98	30.23	32.79	29.77	33.68
Lease and Plant Fuel[6]	1.20	1.37	1.36	1.36	1.60	1.49	1.55	1.73	1.63	1.71
Pipeline Natural Gas	0.63	0.78	0.77	0.77	0.94	0.85	0.92	1.03	0.95	1.05
Natural Gas Subtotal	23.26	27.35	26.62	26.82	32.95	30.33	32.70	35.55	32.35	36.44
Metallurgical Coal	0.72	0.66	0.59	0.57	0.55	0.42	0.27	0.50	0.35	0.21
Steam Coal	21.28	24.70	24.16	21.80	27.17	25.50	12.39	29.18	26.39	7.57
Net Coal Coke Imports	0.03	0.11	0.10	0.10	0.16	0.13	0.19	0.18	0.14	0.22
Coal Subtotal	22.02	25.47	24.85	22.47	27.88	26.05	12.85	29.86	26.89	8.00
Nuclear Power	8.03	8.25	8.17	8.37	8.28	8.14	9.52	8.28	8.05	11.76
Renewable Energy[16]	5.32	7.30	7.71	9.03	8.31	9.53	14.35	8.77	10.28	15.60
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.00	0.03	0.03
Electricity Imports	0.21	0.31	0.27	0.41	0.17	0.13	0.39	0.06	0.05	0.11
Total	**97.29**	**113.13**	**111.44**	**110.39**	**129.74**	**124.13**	**117.26**	**138.63**	**130.90**	**121.31**
Energy Use and Related Statistics										
Delivered Energy Use	71.29	83.68	82.51	81.94	97.13	93.52	89.72	104.32	99.76	94.19
Total Energy Use	97.29	113.13	111.44	110.39	129.74	124.13	117.26	138.63	130.90	121.31
Population (millions)	278.18	300.24	300.24	300.24	325.32	325.32	325.32	338.24	338.24	338.24
Gross Domestic Product (billion 1996 dollars)	9215	12258	12257	12220	16444	16459	16398	18916	18917	18823
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1558.6	1802.2	1764.4	1695.9	2077.7	1952.6	1576.2	2234.4	2060.1	1476.5

[1] Includes wood used for residential heating. See Table F18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.

[2] Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.

[3] Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table F18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.

[4] Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.

[5] Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.

[6] Represents natural gas used in the field gathering and processing plant machinery.

[7] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.

[8] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.

[9] Includes only kerosene type.

[10] Includes aviation gasoline and lubricants.

[11] E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).

[12] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.

[13] Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

[14] Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[15] Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.

[16] Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.

Sources: 2001 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 population and gross domestic product: Global Insight macroeconomic model CTL0802. 2001 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F3. Delivered Energy Prices by Sector and Source

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Residential	**15.81**	**13.97**	**13.74**	**14.17**	**14.62**	**13.99**	**15.98**	**14.89**	**13.92**	**16.88**
Primary Energy[1]	9.73	8.07	7.98	8.00	8.33	8.16	8.32	8.57	8.17	8.59
Petroleum Products[2]	10.85	10.02	10.00	9.89	10.91	10.74	10.19	11.21	11.12	10.43
Distillate Fuel	8.99	7.99	7.97	7.88	8.70	8.44	7.94	8.93	8.87	8.12
Liquefied Petroleum Gas	14.84	14.35	14.32	14.18	15.28	15.31	14.71	15.52	15.39	14.87
Natural Gas	9.41	7.57	7.48	7.52	7.77	7.60	7.91	8.04	7.57	8.21
Electricity	25.37	22.48	22.17	23.30	23.03	22.08	27.39	23.09	21.63	29.40
Commercial	**15.50**	**13.45**	**13.16**	**13.82**	**14.58**	**13.79**	**16.13**	**15.00**	**13.85**	**16.99**
Primary Energy[1]	7.81	6.43	6.35	6.37	6.78	6.60	6.76	7.05	6.65	7.04
Petroleum Products[2]	7.27	6.78	6.77	6.67	7.51	7.32	6.74	7.81	7.70	6.94
Distillate Fuel	6.40	5.67	5.65	5.56	6.45	6.18	5.65	6.75	6.63	5.86
Residual Fuel	3.46	4.01	4.01	3.90	4.23	4.22	3.89	4.39	4.37	3.93
Natural Gas	8.09	6.49	6.39	6.43	6.79	6.61	6.90	7.07	6.61	7.19
Electricity	23.28	19.81	19.42	20.72	20.98	19.83	24.68	21.25	19.72	26.89
Industrial[3]	**7.11**	**6.39**	**6.31**	**6.44**	**7.01**	**6.80**	**7.39**	**7.25**	**6.95**	**7.85**
Primary Energy	5.83	5.18	5.15	5.12	5.74	5.68	5.63	5.99	5.85	5.85
Petroleum Products[2]	7.72	7.07	7.05	6.95	7.85	7.77	7.33	8.13	8.07	7.54
Distillate Fuel	6.55	5.75	5.74	5.64	6.74	6.40	5.82	7.19	6.91	6.09
Liquefied Petroleum Gas	12.34	9.93	9.90	9.77	10.85	10.86	10.32	11.13	11.11	10.55
Residual Fuel	3.28	3.71	3.71	3.63	3.94	3.92	3.62	4.10	4.09	3.66
Natural Gas[4]	4.87	4.00	3.89	3.93	4.39	4.20	4.50	4.63	4.22	4.76
Metallurgical Coal	1.69	1.50	1.49	1.49	1.39	1.36	1.34	1.34	1.30	1.29
Steam Coal	1.46	1.39	1.38	1.38	1.31	1.29	1.19	1.30	1.26	1.05
Electricity	14.13	12.82	12.51	13.63	13.37	12.43	16.37	13.48	12.38	17.85
Transportation	**10.28**	**10.22**	**10.18**	**11.25**	**10.37**	**10.23**	**12.02**	**10.82**	**10.43**	**12.78**
Primary Energy	10.25	10.19	10.15	11.23	10.35	10.20	11.98	10.79	10.40	12.74
Petroleum Products[2]	10.25	10.20	10.15	11.23	10.35	10.21	11.99	10.80	10.41	12.75
Distillate Fuel[5]	10.05	10.19	10.21	11.31	10.27	9.91	12.07	10.64	10.29	12.75
Jet Fuel[6]	6.20	5.66	5.64	6.67	6.34	6.06	8.10	6.72	6.44	8.78
Motor Gasoline[7]	11.57	11.45	11.38	12.48	11.55	11.53	13.14	12.07	11.64	13.98
Residual Fuel	3.90	3.56	3.56	4.74	3.78	3.78	6.31	3.94	3.95	6.89
Liquefied Petroleum Gas[8]	16.93	15.55	15.42	16.24	16.06	16.13	17.82	15.99	15.83	18.32
Natural Gas[9]	7.65	7.19	7.10	7.12	7.75	7.60	7.65	8.09	7.65	7.89
Electricity	21.87	19.10	19.05	20.28	18.45	19.07	23.59	17.90	18.83	25.26
Average End-Use Energy	**10.75**	**9.97**	**9.87**	**10.51**	**10.47**	**10.19**	**11.72**	**10.82**	**10.33**	**12.45**
Primary Energy	8.52	8.07	8.03	8.55	8.46	8.34	9.24	8.84	8.53	9.76
Electricity	21.34	18.76	18.45	19.66	19.52	18.53	23.23	19.66	18.33	25.12
Electric Power[10]										
Fossil Fuel Average	2.14	1.82	1.77	1.83	2.04	1.89	2.75	2.13	1.92	3.55
Petroleum Products	4.73	4.28	4.33	4.50	4.72	4.72	4.90	5.04	5.05	5.05
Distillate Fuel	6.20	5.13	5.12	4.94	5.94	5.77	5.10	6.16	6.13	5.37
Residual Fuel	4.50	4.08	4.11	4.33	4.33	4.46	4.82	4.55	4.68	4.87
Natural Gas	4.78	3.88	3.76	3.84	4.35	4.12	4.54	4.64	4.16	4.83
Steam Coal	1.25	1.17	1.17	1.16	1.12	1.10	1.01	1.11	1.08	0.91

Table F3. Delivered Energy Prices by Sector and Source (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Average Price to All Users[11]										
Petroleum Products[2]	9.54	9.46	9.43	10.20	9.81	9.68	10.89	10.22	9.92	11.51
Distillate Fuel	9.16	9.15	9.17	9.93	9.52	9.19	10.65	9.90	9.62	11.27
Jet Fuel	6.20	5.66	5.64	6.67	6.34	6.06	8.10	6.72	6.44	8.78
Liquefied Petroleum Gas	12.85	10.75	10.72	10.61	11.58	11.59	11.09	11.81	11.77	11.29
Motor Gasoline[7]	11.57	11.45	11.38	12.46	11.55	11.53	13.11	12.07	11.64	13.95
Residual Fuel	4.11	3.73	3.73	4.49	3.96	3.97	5.67	4.14	4.14	6.10
Natural Gas	6.40	5.15	5.07	5.11	5.40	5.29	5.53	5.64	5.29	5.78
Coal	1.26	1.18	1.18	1.17	1.13	1.11	1.03	1.12	1.09	0.94
Electricity	21.34	18.76	18.45	19.66	19.52	18.53	23.23	19.66	18.33	25.12
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)										
Residential	166.77	168.16	163.87	168.33	191.19	178.40	195.47	203.68	184.73	210.64
Commercial	127.30	128.40	124.62	130.09	163.77	152.67	172.06	181.88	164.76	197.64
Industrial	135.32	137.86	132.25	134.49	172.27	156.71	164.96	190.69	169.36	182.11
Transportation	270.41	328.32	322.36	353.70	402.37	378.93	422.99	456.80	416.20	471.76
Total Non-Renewable Expenditures	699.80	762.73	743.09	786.61	929.60	866.71	955.48	1033.06	935.06	1062.15
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.10	0.10	0.10	0.13	0.12	0.14
Total Expenditures	**699.81**	**762.78**	**743.14**	**786.66**	**929.70**	**866.80**	**955.58**	**1033.19**	**935.18**	**1062.29**

[1] Weighted average price includes fuels below as well as coal.

[2] This quantity is the weighted average for all petroleum products, not just those listed below.

[3] Includes combined heat and power, which produces electricity and other useful thermal energy.

[4] Excludes use for lease and plant fuel.

[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.

[6] Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.

[7] Sales weighted-average price for all grades. Includes Federal, State and local taxes.

[8] Includes Federal and State taxes while excluding county and local taxes.

[9] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.

[10] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

[11] Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.

Btu = British thermal unit.

Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F4. Greenhouse Gas Allowance Cost by End-Use Sector and Source

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Commercial										
Petroleum Products[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residual Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[3]										
Petroleum Products[2]	0.00	0.00	0.00	0.70	0.00	0.00	1.59	0.00	0.00	1.91
Distillate Fuel	0.00	0.00	0.00	1.16	0.00	0.00	2.62	0.00	0.00	3.13
Liquefied Petroleum Gas	0.00	0.00	0.00	1.00	0.00	0.00	2.27	0.00	0.00	2.71
Residual Fuel	0.00	0.00	0.00	1.25	0.00	0.00	2.83	0.00	0.00	3.37
Natural Gas[4]	0.00	0.00	0.00	0.83	0.00	0.00	1.87	0.00	0.00	2.24
Metallurgical Coal	0.00	0.00	0.00	1.49	0.00	0.00	3.36	0.00	0.00	4.01
Steam Coal	0.00	0.00	0.00	1.49	0.00	0.00	3.37	0.00	0.00	4.02
Electric Power[5]										
Fossil Fuel Average	0.00	0.00	0.00	1.34	0.00	0.00	2.67	0.00	0.00	2.87
Petroleum Products	0.00	0.00	0.00	1.22	0.00	0.00	2.77	0.00	0.00	3.28
Distillate Fuel	0.00	0.00	0.00	1.16	0.00	0.00	2.62	0.00	0.00	3.13
Residual Fuel	0.00	0.00	0.00	1.25	0.00	0.00	2.83	0.00	0.00	3.37
Natural Gas	0.00	0.00	0.00	0.85	0.00	0.00	1.91	0.00	0.00	2.28
Steam Coal	0.00	0.00	0.00	1.50	0.00	0.00	3.38	0.00	0.00	4.04
Average Allowance Cost to All Users[6]										
Petroleum Products[2]	0.00	0.00	0.00	0.17	0.00	0.00	0.36	0.00	0.00	0.43
Distillate Fuel	0.00	0.00	0.00	0.15	0.00	0.00	0.32	0.00	0.00	0.39
Jet Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquefied Petroleum Gas	0.00	0.00	0.00	0.81	0.00	0.00	1.88	0.00	0.00	2.26
Motor Gasoline	0.00	0.00	0.00	0.01	0.00	0.00	0.02	0.00	0.00	0.03
Residual Fuel	0.00	0.00	0.00	0.36	0.00	0.00	0.71	0.00	0.00	0.85
Natural Gas	0.00	0.00	0.00	0.52	0.00	0.00	1.26	0.00	0.00	1.52
Coal	0.00	0.00	0.00	1.49	0.00	0.00	3.35	0.00	0.00	3.97

[1] Weighted average allowance cost includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3] Includes combined heat and power, which produces electricity and other useful thermal energy.
[4] Excludes use for lease and plant fuel.
[5] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[6] Weighted averages of allowance costs are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Projections: EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F5. Energy Prices by Sector and Source with Greenhouse Gas Allowance Cost
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Residential	**15.81**	**13.97**	**13.74**	**14.17**	**14.62**	**13.99**	**15.98**	**14.89**	**13.92**	**16.88**
Primary Energy[1]	9.73	8.07	7.98	8.00	8.33	8.16	8.32	8.57	8.17	8.59
Petroleum Products[2]	10.85	10.02	10.00	9.89	10.91	10.74	10.19	11.21	11.12	10.43
Distillate Fuel	8.99	7.99	7.97	7.88	8.70	8.44	7.94	8.93	8.87	8.12
Liquefied Petroleum Gas	14.84	14.35	14.32	14.18	15.28	15.31	14.71	15.52	15.39	14.87
Natural Gas	9.41	7.57	7.48	7.52	7.77	7.60	7.91	8.04	7.57	8.21
Electricity	25.37	22.48	22.17	23.30	23.03	22.08	27.39	23.09	21.63	29.40
Commercial	**15.50**	**13.45**	**13.16**	**13.82**	**14.58**	**13.79**	**16.13**	**15.00**	**13.85**	**16.99**
Primary Energy[1]	7.81	6.43	6.35	6.37	6.78	6.60	6.76	7.05	6.65	7.04
Petroleum Products[2]	7.27	6.78	6.77	6.67	7.51	7.32	6.74	7.81	7.70	6.94
Distillate Fuel	6.40	5.67	5.65	5.56	6.45	6.18	5.65	6.75	6.63	5.86
Residual Fuel	3.46	4.01	4.01	3.90	4.23	4.22	3.89	4.39	4.37	3.93
Natural Gas	8.09	6.49	6.39	6.43	6.79	6.61	6.90	7.07	6.61	7.19
Electricity	23.28	19.81	19.42	20.72	20.98	19.83	24.68	21.25	19.72	26.89
Industrial[3]	**7.11**	**6.39**	**6.31**	**7.14**	**7.01**	**6.80**	**8.94**	**7.25**	**6.95**	**9.68**
Primary Energy	5.83	5.18	5.15	5.95	5.74	5.68	7.47	5.99	5.85	8.05
Petroleum Products[2]	7.72	7.07	7.05	7.65	7.85	7.77	8.92	8.13	8.07	9.45
Distillate Fuel	6.55	5.75	5.74	6.80	6.74	6.40	8.45	7.19	6.91	9.22
Liquefied Petroleum Gas	12.34	9.93	9.90	10.77	10.85	10.86	12.59	11.13	11.11	13.26
Residual Fuel	3.28	3.71	3.71	4.88	3.94	3.92	6.45	4.10	4.09	7.04
Natural Gas[4]	4.87	4.00	3.89	4.76	4.39	4.20	6.37	4.63	4.22	6.99
Metallurgical Coal	1.69	1.50	1.49	2.98	1.39	1.36	4.70	1.34	1.30	5.30
Steam Coal	1.46	1.39	1.38	2.87	1.31	1.29	4.56	1.30	1.26	5.08
Electricity	14.13	12.82	12.51	13.63	13.37	12.43	16.37	13.48	12.38	17.85
Transportation	**10.28**	**10.22**	**10.18**	**11.26**	**10.37**	**10.23**	**12.03**	**10.82**	**10.43**	**12.79**
Primary Energy	10.25	10.19	10.15	11.23	10.35	10.20	11.99	10.79	10.40	12.74
Petroleum Products[2]	10.25	10.20	10.15	11.23	10.35	10.21	11.99	10.80	10.41	12.75
Distillate Fuel[5]	10.05	10.19	10.21	11.31	10.27	9.91	12.07	10.64	10.29	12.75
Jet Fuel[6]	6.20	5.66	5.64	6.67	6.34	6.06	8.10	6.72	6.44	8.78
Motor Gasoline[7]	11.57	11.45	11.38	12.48	11.55	11.53	13.14	12.07	11.64	13.98
Residual Fuel	3.90	3.56	3.56	4.74	3.78	3.78	6.31	3.94	3.95	6.89
Liquefied Petroleum Gas[8]	16.93	15.55	15.42	16.24	16.06	16.13	17.82	15.99	15.83	18.32
Natural Gas[9]	7.65	7.19	7.10	7.97	7.75	7.60	9.57	8.09	7.65	10.17
Electricity	21.87	19.10	19.05	20.28	18.45	19.07	23.59	17.90	18.83	25.26
Average End-Use Energy	**10.75**	**9.97**	**9.87**	**10.73**	**10.47**	**10.19**	**12.19**	**10.82**	**10.33**	**13.01**
Primary Energy	8.52	8.07	8.03	8.82	8.46	8.34	9.82	8.84	8.53	10.43
Electricity	21.34	18.76	18.45	19.66	19.52	18.53	23.23	19.66	18.33	25.12
Electric Power[10]										
Fossil Fuel Average	2.14	1.82	1.77	3.17	2.04	1.89	5.42	2.13	1.92	6.42
Petroleum Products	4.73	4.28	4.33	5.73	4.72	4.72	7.67	5.04	5.05	8.34
Distillate Fuel	6.20	5.13	5.12	6.10	5.94	5.77	7.72	6.16	6.13	8.50
Residual Fuel	4.50	4.08	4.11	5.58	4.33	4.46	7.65	4.55	4.68	8.24
Natural Gas	4.78	3.88	3.76	4.69	4.35	4.12	6.45	4.64	4.16	7.11
Steam Coal	1.25	1.17	1.17	2.66	1.12	1.10	4.39	1.11	1.08	4.96

Table F5. Energy Prices by Sector and Source with Greenhouse Gas Allowance Cost (Continued)
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Average Price to All Users[11]										
Petroleum Products[2]	9.54	9.46	9.43	10.36	9.81	9.68	11.25	10.22	9.92	11.94
Distillate Fuel	9.16	9.15	9.17	10.09	9.52	9.19	10.98	9.90	9.62	11.65
Jet Fuel	6.20	5.66	5.64	6.67	6.34	6.06	8.10	6.72	6.44	8.78
Liquefied Petroleum Gas	12.85	10.75	10.72	11.42	11.58	11.59	12.97	11.81	11.77	13.55
Motor Gasoline[7]	11.57	11.45	11.38	12.47	11.55	11.53	13.13	12.07	11.64	13.98
Residual Fuel	4.11	3.73	3.73	4.85	3.96	3.97	6.38	4.14	4.14	6.95
Natural Gas	6.40	5.15	5.07	5.63	5.40	5.29	6.78	5.64	5.29	7.30
Coal	1.26	1.18	1.18	2.67	1.13	1.11	4.38	1.12	1.09	4.91
Electricity	21.34	18.76	18.45	19.66	19.52	18.53	23.23	19.66	18.33	25.12
Non-Renewable Energy and Allowance Expenditures by Sector (billion 2001 dollars)										
Residential	166.77	168.16	163.87	168.33	191.19	178.40	195.47	203.68	184.73	210.64
Commercial	127.30	128.40	124.62	130.09	163.77	152.67	172.06	181.88	164.76	197.64
Industrial	135.32	137.86	132.25	149.27	172.27	156.71	199.57	190.69	169.36	224.80
Transportation	270.41	328.32	322.36	353.75	402.37	378.93	423.17	456.80	416.20	471.99
Total Non-Renewable Expenditures	699.80	762.73	743.09	801.44	929.60	866.71	990.27	1033.06	935.06	1105.06
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.10	0.10	0.10	0.13	0.12	0.14
Total Expenditures	**699.81**	**762.78**	**743.14**	**801.49**	**929.70**	**866.80**	**990.37**	**1033.19**	**935.18**	**1105.21**

[1] Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3] Includes combined heat and power, which produces electricity and other useful thermal energy.
[4] Excludes use for lease and plant fuel.
[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6] Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7] Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8] Includes Federal and State taxes while excluding county and local taxes.
[9] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[10] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[11] Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F6. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Key Indicators										
Households (millions)										
Single-Family	77.50	86.16	86.17	86.15	94.13	94.17	94.04	97.63	97.69	97.49
Multifamily	22.19	24.15	24.15	24.14	27.09	27.11	27.03	28.82	28.85	28.75
Mobile Homes	6.57	7.11	7.11	7.10	7.86	7.86	7.86	8.11	8.10	8.11
Total	**106.27**	**117.42**	**117.43**	**117.39**	**129.08**	**129.14**	**128.92**	**134.55**	**134.64**	**134.34**
Average House Square Footage	**1685**	**1740**	**1740**	**1740**	**1782**	**1782**	**1782**	**1798**	**1798**	**1798**
Energy Intensity										
(million Btu per household)										
Delivered Energy Consumption	102.9	106.0	105.0	104.6	104.4	101.8	97.9	104.6	101.4	95.8
Total Energy Consumption	189.0	194.3	191.9	190.5	189.9	181.6	169.0	189.5	178.4	161.4
(thousand Btu per square foot)										
Delivered Energy Consumption	61.1	60.9	60.4	60.1	58.6	57.1	55.0	58.2	56.4	53.3
Total Energy Consumption	112.2	111.7	110.3	109.5	106.6	101.9	94.8	105.4	99.2	89.8
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.39	0.46	0.46	0.45	0.50	0.49	0.46	0.52	0.50	0.45
Space Cooling	0.52	0.60	0.60	0.59	0.65	0.63	0.58	0.69	0.66	0.58
Water Heating	0.45	0.47	0.47	0.46	0.44	0.44	0.39	0.44	0.44	0.35
Refrigeration	0.42	0.34	0.34	0.34	0.32	0.32	0.32	0.33	0.33	0.32
Cooking	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.13
Clothes Dryers	0.22	0.25	0.25	0.25	0.27	0.27	0.25	0.28	0.28	0.26
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.93	0.88	0.86	1.03	0.86	0.69	1.07	0.88	0.63
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers[1]	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.20	0.20	0.19	0.25	0.26	0.24	0.27	0.27	0.25
Personal Computers	0.06	0.08	0.08	0.08	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.10
Other Uses[2]	0.83	1.26	1.23	1.22	1.66	1.61	1.52	1.87	1.82	1.65
Delivered Energy	**4.10**	**4.93**	**4.84**	**4.79**	**5.60**	**5.35**	**4.92**	**5.95**	**5.67**	**4.97**
Natural Gas										
Space Heating	3.13	3.70	3.69	3.68	4.10	4.02	3.94	4.30	4.18	4.05
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.48	1.55	1.56	1.56	1.59	1.61	1.60	1.65	1.68	1.64
Cooking	0.20	0.23	0.23	0.23	0.25	0.25	0.25	0.26	0.26	0.26
Clothes Dryers	0.06	0.08	0.08	0.08	0.10	0.10	0.10	0.10	0.10	0.10
Other Uses[3]	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.14
Delivered Energy	**4.94**	**5.63**	**5.63**	**5.61**	**6.10**	**6.05**	**5.95**	**6.38**	**6.29**	**6.18**
Distillate										
Space Heating	0.74	0.76	0.76	0.76	0.71	0.70	0.70	0.69	0.66	0.68
Water Heating	0.16	0.14	0.14	0.14	0.12	0.12	0.12	0.11	0.11	0.12
Other Uses[4]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.91**	**0.91**	**0.91**	**0.91**	**0.84**	**0.82**	**0.83**	**0.81**	**0.78**	**0.80**
Liquefied Petroleum Gas										
Space Heating	0.26	0.25	0.25	0.25	0.24	0.23	0.24	0.24	0.23	0.23
Water Heating	0.09	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06
Cooking	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Other Uses[3]	0.12	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14
Delivered Energy	**0.50**	**0.47**	**0.47**	**0.47**	**0.46**	**0.45**	**0.46**	**0.46**	**0.45**	**0.45**
Marketed Renewables (wood)[5]	0.39	0.41	0.40	0.40	0.41	0.39	0.39	0.40	0.39	0.39
Other Fuels[6]	0.11	0.09	0.09	0.09	0.08	0.08	0.08	0.07	0.07	0.07

Table F6. Residential Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Delivered Energy Consumption by										
Space Heating	5.01	5.68	5.64	5.63	6.04	5.91	5.80	6.22	6.03	5.86
Space Cooling	0.52	0.60	0.60	0.59	0.65	0.63	0.58	0.69	0.66	0.58
Water Heating	2.19	2.24	2.25	2.24	2.21	2.23	2.17	2.26	2.29	2.16
Refrigeration	0.42	0.34	0.34	0.34	0.32	0.32	0.32	0.33	0.33	0.32
Cooking	0.33	0.36	0.36	0.36	0.39	0.39	0.39	0.40	0.40	0.40
Clothes Dryers	0.28	0.33	0.33	0.33	0.36	0.37	0.35	0.38	0.38	0.36
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.93	0.88	0.86	1.03	0.86	0.69	1.07	0.88	0.63
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.20	0.20	0.19	0.25	0.26	0.24	0.27	0.27	0.25
Personal Computers	0.06	0.08	0.08	0.08	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.10
Other Uses[7]	1.01	1.46	1.43	1.42	1.87	1.83	1.73	2.09	2.04	1.94
Delivered Energy	**10.94**	**12.45**	**12.33**	**12.28**	**13.48**	**13.14**	**12.63**	**14.08**	**13.66**	**12.86**
Electricity Related Losses	**9.15**	**10.37**	**10.20**	**10.08**	**11.03**	**10.31**	**9.16**	**11.42**	**10.36**	**8.82**
Total Energy Consumption by End-Use										
Space Heating	5.89	6.64	6.60	6.58	7.03	6.86	6.65	7.22	6.94	6.65
Space Cooling	1.68	1.86	1.86	1.84	1.94	1.86	1.67	2.00	1.87	1.61
Water Heating	3.20	3.23	3.24	3.22	3.08	3.08	2.90	3.10	3.09	2.78
Refrigeration	1.36	1.06	1.06	1.06	0.96	0.94	0.92	0.97	0.92	0.89
Cooking	0.55	0.59	0.59	0.59	0.63	0.63	0.62	0.65	0.64	0.63
Clothes Dryers	0.78	0.85	0.85	0.85	0.89	0.88	0.83	0.91	0.90	0.82
Freezers	0.36	0.28	0.28	0.28	0.26	0.26	0.25	0.27	0.26	0.25
Lighting	2.40	2.90	2.72	2.66	3.06	2.51	1.97	3.12	2.49	1.74
Clothes Washers	0.10	0.10	0.10	0.10	0.09	0.08	0.08	0.08	0.08	0.08
Dishwashers	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08
Color Televisions	0.43	0.61	0.61	0.60	0.75	0.75	0.69	0.78	0.77	0.69
Personal Computers	0.19	0.25	0.24	0.24	0.31	0.29	0.29	0.33	0.31	0.30
Furnace Fans	0.23	0.27	0.27	0.27	0.30	0.30	0.27	0.31	0.31	0.28
Other Uses[7]	2.86	4.10	4.04	4.00	5.14	4.93	4.56	5.67	5.37	4.87
Total	**20.08**	**22.82**	**22.53**	**22.36**	**24.51**	**23.45**	**21.78**	**25.50**	**24.02**	**21.69**
Non-Marketed Renewables										
Geothermal[8]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar[9]	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.05	0.05
Total	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**

[1] Does not include electric water heating portion of load.
[2] Includes small electric devices, heating elements, and motors.
[3] Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4] Includes such appliances as swimming pool and hot tub heaters.
[5] Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.
[6] Includes kerosene and coal.
[7] Includes all other uses listed above.
[8] Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9] Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F7. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Key Indicators										
Total Floorspace (billion square feet)										
Surviving	66.6	79.0	79.0	79.0	91.2	91.2	91.0	97.4	97.5	97.3
New Additions	3.6	3.0	3.0	3.0	3.4	3.4	3.4	3.4	3.4	3.4
Total	**70.2**	**82.0**	**82.0**	**82.0**	**94.6**	**94.6**	**94.4**	**100.8**	**100.9**	**100.7**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	118.4	117.8	116.8	116.1	119.8	118.1	114.1	121.3	119.0	116.5
Electricity Related Losses	129.9	128.5	127.0	125.3	128.5	122.6	110.1	129.1	118.7	102.7
Total Energy Consumption	248.3	246.2	243.8	241.4	248.3	240.7	224.3	250.4	237.7	219.2
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating[1]	0.14	0.16	0.16	0.15	0.15	0.15	0.14	0.15	0.15	0.13
Space Cooling[1]	0.43	0.43	0.43	0.42	0.45	0.45	0.42	0.46	0.46	0.40
Water Heating[1]	0.15	0.16	0.16	0.15	0.16	0.16	0.15	0.15	0.16	0.14
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.17	0.19	0.20	0.16
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02
Lighting	1.02	1.21	1.19	1.16	1.30	1.29	1.01	1.33	1.32	0.91
Refrigeration	0.21	0.24	0.24	0.24	0.26	0.26	0.24	0.27	0.27	0.24
Office Equipment (PC)	0.16	0.24	0.22	0.22	0.32	0.32	0.31	0.36	0.36	0.34
Office Equipment (non-PC)	0.31	0.47	0.46	0.46	0.75	0.73	0.71	0.92	0.89	0.85
Other Uses[2]	1.46	1.90	1.87	1.87	2.57	2.44	2.39	2.92	2.73	2.64
Delivered Energy	**4.08**	**5.01**	**4.94**	**4.89**	**6.17**	**6.02**	**5.58**	**6.79**	**6.56**	**5.83**
Natural Gas										
Space Heating[1]	1.32	1.53	1.52	1.52	1.65	1.65	1.58	1.71	1.71	1.57
Space Cooling[1]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.03
Water Heating[1]	0.57	0.69	0.69	0.69	0.81	0.82	0.78	0.86	0.88	0.80
Cooking	0.25	0.30	0.30	0.30	0.35	0.35	0.34	0.37	0.37	0.35
Other Uses[3]	1.17	1.20	1.20	1.20	1.39	1.39	1.52	1.52	1.52	2.18
Delivered Energy	**3.33**	**3.74**	**3.74**	**3.74**	**4.23**	**4.24**	**4.25**	**4.50**	**4.52**	**4.94**
Distillate										
Space Heating[1]	0.17	0.24	0.23	0.23	0.25	0.24	0.25	0.25	0.23	0.25
Water Heating[1]	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Other Uses[4]	0.22	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Delivered Energy	**0.46**	**0.51**	**0.51**	**0.51**	**0.52**	**0.51**	**0.53**	**0.52**	**0.50**	**0.54**
Other Fuels[5]	**0.34**	**0.29**	**0.29**	**0.29**	**0.30**	**0.30**	**0.31**	**0.31**	**0.31**	**0.32**
Marketed Renewable Fuels										
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Energy	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Delivered Energy Consumption by End-Use										
Space Heating[1]	1.63	1.92	1.91	1.90	2.05	2.04	1.97	2.11	2.10	1.96
Space Cooling[1]	0.44	0.45	0.45	0.44	0.48	0.48	0.45	0.50	0.50	0.44
Water Heating[1]	0.79	0.92	0.93	0.92	1.04	1.06	1.01	1.09	1.11	1.02
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.17	0.19	0.20	0.16
Cooking	0.29	0.33	0.34	0.33	0.38	0.38	0.37	0.40	0.40	0.38
Lighting	1.02	1.21	1.19	1.16	1.30	1.29	1.01	1.33	1.32	0.91
Refrigeration	0.21	0.24	0.24	0.24	0.26	0.26	0.24	0.27	0.27	0.24
Office Equipment (PC)	0.16	0.24	0.22	0.22	0.32	0.32	0.31	0.36	0.36	0.34
Office Equipment (non-PC)	0.31	0.47	0.46	0.46	0.75	0.73	0.71	0.92	0.89	0.85
Other Uses[6]	3.30	3.69	3.66	3.66	4.56	4.44	4.53	5.05	4.86	5.45
Delivered Energy	**8.32**	**9.65**	**9.58**	**9.52**	**11.33**	**11.18**	**10.77**	**12.23**	**12.00**	**11.73**

Table F7. Commercial Sector Key Indicators and Consumption (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Electricity Related Losses	**9.12**	**10.53**	**10.41**	**10.28**	**12.16**	**11.60**	**10.39**	**13.02**	**11.98**	**10.35**
Total Energy Consumption by End-Use										
Space Heating[1]	1.95	2.25	2.23	2.22	2.36	2.33	2.23	2.40	2.37	2.19
Space Cooling[1]	1.39	1.34	1.35	1.33	1.38	1.34	1.23	1.39	1.33	1.15
Water Heating[1]	1.12	1.25	1.26	1.25	1.35	1.36	1.28	1.39	1.40	1.26
Ventilation	0.55	0.56	0.56	0.55	0.56	0.56	0.48	0.57	0.56	0.45
Cooking	0.37	0.40	0.41	0.40	0.44	0.44	0.42	0.45	0.46	0.42
Lighting	3.31	3.74	3.71	3.60	3.86	3.79	2.90	3.88	3.72	2.52
Refrigeration	0.69	0.74	0.74	0.73	0.77	0.76	0.69	0.78	0.76	0.65
Office Equipment (PC)	0.52	0.75	0.69	0.69	0.95	0.93	0.89	1.05	1.02	0.95
Office Equipment (non-PC)	0.99	1.45	1.44	1.43	2.21	2.13	2.04	2.69	2.53	2.36
Other Uses[6]	6.56	7.70	7.61	7.59	9.62	9.13	8.99	10.65	9.84	10.12
Total	**17.44**	**20.19**	**19.99**	**19.80**	**23.50**	**22.78**	**21.16**	**25.25**	**23.98**	**22.08**
Non-Marketed Renewable Fuels										
Solar[7]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

[1] Includes fuel consumption for district services.

[2] Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.

[3] Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.

[4] Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.

[5] Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.

[6] Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.

[7] Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.

Btu = British thermal unit.

PC = Personal computer.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F8. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Key Indicators										
Value of Shipments (billion 1996 dollars)										
Manufacturing	4079	5466	5464	5428	7226	7231	7177	8258	8253	8159
Nonmanufacturing	1346	1510	1509	1499	1744	1740	1715	1870	1863	1829
Total	**5425**	**6977**	**6973**	**6927**	**8969**	**8972**	**8892**	**10128**	**10115**	**9988**
Energy Prices (2001 dollars per million Btu)										
Electricity	14.13	12.82	12.51	13.63	13.37	12.43	16.37	13.48	12.38	17.85
Natural Gas	4.87	4.00	3.89	4.76	4.39	4.20	6.37	4.63	4.22	6.99
Steam Coal	1.46	1.39	1.38	2.87	1.31	1.29	4.56	1.30	1.26	5.08
Residual Oil	3.28	3.71	3.71	4.88	3.94	3.92	6.45	4.10	4.09	7.04
Distillate Oil	6.55	5.75	5.74	6.80	6.74	6.40	8.45	7.19	6.91	9.22
Liquefied Petroleum Gas	12.34	9.93	9.90	10.77	10.85	10.86	12.59	11.13	11.11	13.26
Motor Gasoline	11.57	11.40	11.33	12.43	11.52	11.51	13.08	12.05	11.62	13.95
Metallurgical Coal	1.69	1.50	1.49	2.98	1.39	1.36	4.70	1.34	1.30	5.30
Energy Consumption[1]										
Purchased Electricity	3.39	3.97	3.85	3.75	4.65	4.39	4.17	5.01	4.69	4.35
Natural Gas	7.74	9.06	8.76	8.86	10.39	9.58	9.45	11.23	10.14	9.86
Lease and Plant Fuel[2]	1.20	1.37	1.36	1.36	1.60	1.49	1.55	1.73	1.63	1.71
Natural Gas Subtotal	8.94	10.43	10.12	10.22	11.98	11.07	10.99	12.96	11.77	11.57
Steam Coal	1.42	1.46	1.43	1.34	1.51	1.45	1.25	1.54	1.45	1.23
Metallurgical Coal and Coke[3]	0.74	0.77	0.69	0.67	0.71	0.55	0.46	0.68	0.49	0.43
Residual Fuel	0.23	0.19	0.18	0.17	0.20	0.18	0.16	0.20	0.18	0.16
Distillate	1.13	1.21	1.20	1.19	1.36	1.31	1.26	1.44	1.38	1.31
Liquefied Petroleum Gas	2.10	2.55	2.53	2.52	3.06	3.00	2.96	3.28	3.22	3.14
Petrochemical Feedstocks	1.14	1.44	1.43	1.40	1.70	1.68	1.53	1.82	1.80	1.57
Other Petroleum[4]	4.18	4.44	4.40	4.33	4.64	4.50	4.29	4.76	4.63	4.27
Renewables[5]	1.82	2.22	2.35	2.34	2.77	3.17	3.14	3.05	3.64	3.59
Delivered Energy	**25.10**	**28.67**	**28.15**	**27.94**	**32.58**	**31.29**	**30.21**	**34.75**	**33.25**	**31.62**
Electricity Related Losses	7.57	8.35	8.11	7.89	9.17	8.47	7.76	9.61	8.56	7.72
Total	**32.67**	**37.02**	**36.27**	**35.83**	**41.75**	**39.76**	**37.97**	**44.36**	**41.81**	**39.34**
Energy Consumption per dollar of Shipments[1] (thousand Btu per 1996 dollars)										
Purchased Electricity	0.83	0.7262	0.7041	0.54	0.6439	0.6073	0.47	0.607	0.5678	0.44
Natural Gas	1.89	1.6573	1.6031	1.28	1.4376	1.3247	1.06	1.3604	1.2283	0.99
Lease and Plant Fuel[2]	0.29	0.2507	0.2482	0.20	0.221	0.2062	0.17	0.2093	0.198	0.17
Natural Gas Subtotal	2.19	1.908	1.8512	1.48	1.6586	1.531	1.24	1.5696	1.4263	1.16
Steam Coal	0.34	0.2662	0.2609	0.19	0.209	0.2	0.14	0.1863	0.1761	0.12
Metallurgical Coal and Coke[3]	0.18	0.1412	0.1259	0.10	0.098	0.076	0.05	0.082	0.06	0.04
Residual Fuel	0.06	0.034	0.033	0.03	0.027	0.025	0.02	0.024	0.022	0.02
Distillate	0.27	0.222	0.2193	0.17	0.1878	0.1813	0.14	0.1747	0.1672	0.13
Liquefied Petroleum Gas	0.51	0.4667	0.4625	0.36	0.4239	0.4142	0.33	0.3968	0.3904	0.31
Petrochemical Feedstocks	0.27	0.2626	0.261	0.20	0.2348	0.2318	0.17	0.2204	0.2181	0.16
Other Petroleum[4]	1.02	0.8121	0.8043	0.63	0.6426	0.6228	0.48	0.5769	0.5605	0.43
Renewables[5]	0.44	0.4062	0.4296	0.34	0.3832	0.4387	0.35	0.3693	0.441	0.36
Delivered Energy	**6.15**	**5.2452**	**5.152**	**4.03**	**4.5088**	**4.3276**	**3.40**	**4.2074**	**4.0288**	**3.17**
Electricity Related Losses	1.85	1.5274	1.4849	1.14	1.2693	1.1709	0.87	1.1637	1.0371	0.77
Total	**8.01**	**6.7726**	**6.637**	**5.17**	**5.7781**	**5.4985**	**4.27**	**5.3712**	**5.0659**	**3.94**

[1] Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2] Represents natural gas used in the field gathering and processing plant machinery.
[3] Includes net coal coke imports.
[4] Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 coal prices are based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 consumption values based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **2001** shipments: Global Insight macroeconomic model CTL0802. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F9. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 pounds (VMT)	2409	3006	3010	2996	3752	3764	3710	4133	4151	4020
Commercial Light Trucks (VMT)[1]	66	84	84	83	107	107	106	120	120	118
Freight Trucks >10,000 pounds (VMT)	206	265	265	263	339	339	336	382	383	377
Air (seat miles available)	1109	1356	1357	1353	1944	1947	1932	2258	2262	2237
Rail (ton miles traveled)	1448	1691	1672	1591	2003	1949	1548	2173	2091	1527
Domestic Shipping (ton miles traveled)	788	882	877	866	1012	991	943	1088	1065	987
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	24.1	25.1	26.5	26.9	26.0	28.5	30.6	26.4	29.0	31.1
New Car (miles per gallon)[2]	28.1	28.5	30.7	31.3	29.7	32.5	34.5	30.1	32.9	34.9
New Light Truck (miles per gallon)[2]	20.7	22.3	23.3	23.4	23.1	25.3	27.5	23.5	25.9	28.0
Light-Duty Fleet (miles per gallon)[3]	19.8	19.6	20.0	20.1	20.3	21.6	22.5	20.5	22.2	23.5
New Commercial Light Truck (MPG)[1]	13.8	14.7	15.5	15.6	15.2	16.8	18.4	15.5	17.2	18.7
Stock Commercial Light Truck (MPG)[1]	13.7	14.3	14.5	14.5	14.9	16.1	16.9	15.2	16.7	17.9
Aircraft Efficiency (seat miles per gallon)	51.2	54.3	55.0	55.1	58.6	61.7	63.3	60.7	65.4	67.7
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.1	6.3	6.3	6.6	6.5	6.5	6.9
Rail Efficiency (ton miles per thousand Btu)	2.8	3.1	3.2	3.2	3.4	3.8	3.8	3.6	4.1	4.1
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.4	2.4	2.4	2.5	2.5	2.4	2.6	2.6
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	15.28	18.88	18.52	18.61	22.76	21.41	20.46	24.71	22.95	21.19
Commercial Light Trucks[1]	0.60	0.73	0.72	0.72	0.89	0.84	0.79	0.98	0.90	0.82
Freight Trucks[4]	4.68	5.92	5.92	5.83	7.11	7.13	6.74	7.81	7.84	7.28
Air[5]	3.47	3.98	3.94	3.92	5.15	4.93	4.79	5.73	5.37	5.16
Rail[6]	0.63	0.68	0.66	0.64	0.75	0.70	0.59	0.78	0.71	0.57
Marine[7]	1.45	1.49	1.48	1.48	1.59	1.56	1.54	1.64	1.60	1.57
Pipeline Fuel	0.63	0.78	0.77	0.77	0.94	0.85	0.92	1.03	0.95	1.05
Lubricants	0.19	0.22	0.22	0.22	0.26	0.26	0.26	0.28	0.28	0.27
Total	**26.94**	**32.68**	**32.23**	**32.18**	**39.45**	**37.66**	**36.07**	**42.96**	**40.61**	**37.92**
Energy Use by Mode (million barrels per day oil equivalent)										
Light-Duty Vehicles	8.05	9.93	9.74	9.83	11.96	11.25	10.79	12.98	12.06	11.18
Commercial Light Trucks[1]	0.32	0.39	0.38	0.38	0.47	0.44	0.41	0.52	0.48	0.43
Freight Trucks	2.05	2.61	2.61	2.57	3.16	3.17	2.99	3.49	3.50	3.25
Railroad	0.24	0.26	0.24	0.23	0.28	0.24	0.19	0.28	0.24	0.18
Domestic Shipping	0.16	0.17	0.17	0.17	0.20	0.18	0.17	0.21	0.19	0.18
International Shipping	0.34	0.33	0.33	0.33	0.34	0.34	0.34	0.34	0.34	0.34
Air[5]	1.44	1.65	1.63	1.62	2.19	2.08	2.01	2.45	2.28	2.18
Military Use	0.30	0.34	0.34	0.34	0.38	0.38	0.38	0.40	0.40	0.40
Bus Transportation	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.14	0.13
Rail Transportation[6]	0.05	0.06	0.07	0.07	0.08	0.09	0.08	0.08	0.10	0.09
Recreational Boats	0.16	0.18	0.18	0.18	0.19	0.20	0.19	0.20	0.20	0.20
Lubricants	0.09	0.10	0.10	0.10	0.12	0.12	0.12	0.13	0.13	0.13
Pipeline Fuel	0.32	0.39	0.39	0.39	0.47	0.43	0.46	0.52	0.48	0.53
Total	**13.64**	**16.54**	**16.31**	**16.34**	**19.97**	**19.04**	**18.28**	**21.74**	**20.53**	**19.20**

[1] Commercial trucks 8,500 to 10,000 pounds.
[2] Environmental Protection Agency rated miles per gallon.
[3] Combined car and light truck "on-the-road" estimate.
[4] Includes energy use by buses and military distillate consumption.
[5] Includes jet fuel and aviation gasoline.
[6] Includes passenger rail.
[7] Includes military residual fuel use and recreational boats.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001); Federal Highway Administration, *Highway Statistics 2000* (Washington, DC, November 2001); Oak Ridge National Laboratory, Transportation Energy Data Book: *Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey" EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA, *State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2001/2000* (Washington, DC, 2001); EIA, *Fuel Oil and Kerosene Sales 2001*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/historical/foks.html; and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F10. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Generation by Fuel Type										
Electric Power Sector[1]										
Power Only[2]										
Coal	1848	2237	2192	1977	2512	2394	1108	2747	2559	660
Petroleum	113	40	35	18	47	32	11	52	36	16
Natural Gas[3]	411	671	637	705	1143	1077	1513	1314	1272	1856
Nuclear Power	769	790	783	801	793	779	912	793	771	1126
Pumped Storage/Other	-9	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[4]	258	394	404	493	414	445	866	423	459	938
Distributed Generation (Natural Gas)	0	1	1	1	5	2	2	8	4	2
Non-Utility Generation for Own Use	-21	-24	-24	-27	-24	-24	-26	-24	-23	-25
Total	**3370**	**4107**	**4026**	**3969**	**4889**	**4705**	**4384**	**5312**	**5076**	**4572**
Combined Heat and Power[5]										
Coal	33	33	33	30	33	33	19	33	33	13
Petroleum	7	4	3	3	3	3	3	3	3	3
Natural Gas	124	171	165	154	156	135	114	149	124	105
Renewable Sources	5	4	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-9	-18	-18	-18	-18	-18	-17	-18	-18	-16
Total	**162**	**193**	**188**	**174**	**178**	**158**	**123**	**171**	**147**	**109**
Net Available to the Grid	**3532**	**4301**	**4214**	**4143**	**5067**	**4863**	**4507**	**5483**	**5222**	**4681**
End-Use Sector Generation										
Combined Heat and Power[6]										
Coal	23	23	23	23	23	23	23	23	23	23
Petroleum	6	6	6	6	6	6	6	6	6	6
Natural Gas	84	105	108	128	142	134	185	174	153	294
Other Gaseous Fuels[7]	6	7	7	7	7	7	7	8	7	7
Renewable Sources[4]	31	40	43	43	51	65	64	56	79	77
Other[8]	11	11	11	11	11	11	11	11	11	11
Total	**160**	**192**	**199**	**219**	**240**	**247**	**296**	**278**	**280**	**420**
Other End-Use Generators[9]	4	5	5	5	6	6	7	6	7	9
Generation for Own Use	-138	-154	-158	-180	-183	-187	-240	-207	-208	-320
Total Sales to the Grid	**27**	**43**	**46**	**44**	**63**	**67**	**63**	**78**	**79**	**108**
Net Imports	**20**	**30**	**26**	**40**	**16**	**13**	**38**	**6**	**5**	**11**
Electricity Sales by Sector										
Residential	1201	1445	1418	1405	1640	1567	1441	1745	1662	1458
Commercial	1197	1468	1447	1432	1808	1763	1635	1990	1922	1709
Industrial	994	1164	1128	1100	1364	1287	1221	1469	1373	1275
Transportation	22	27	28	28	36	35	35	42	39	39
Total	**3414**	**4104**	**4020**	**3965**	**4848**	**4652**	**4331**	**5246**	**4997**	**4481**
End-Use Prices[10] (2001 cents per kilowatthour)										
Residential	8.7	7.7	7.6	7.9	7.9	7.5	9.3	7.9	7.4	10.0
Commercial	7.9	6.8	6.6	7.1	7.2	6.8	8.4	7.2	6.7	9.2
Industrial	4.8	4.4	4.3	4.6	4.6	4.2	5.6	4.6	4.2	6.1
Transportation	7.5	6.5	6.5	6.9	6.3	6.5	8.0	6.1	6.4	8.6
All Sectors Average	**7.3**	**6.4**	**6.3**	**6.7**	**6.7**	**6.3**	**7.9**	**6.7**	**6.3**	**8.6**
Prices by Service Category[10] (2001 cents per kilowatthour)										
Generation	4.7	3.9	3.8	4.1	4.2	3.8	5.2	4.2	3.7	5.9
Transmission	0.5	0.6	0.6	0.6	0.6	0.6	0.7	0.6	0.6	0.8
Distribution	2.0	2.0	2.0	2.0	1.9	1.9	2.0	1.9	1.9	2.0

Table F10. Electricity Supply, Disposition, Prices, and Emissions (Continued)

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Emissions										
Sulfur Dioxide (million tons)	10.63	9.69	9.67	9.89	8.95	8.95	8.84	8.95	8.95	4.16
Nitrogen Oxide (million tons)	4.75	3.90	3.83	3.60	4.02	3.83	2.00	4.08	3.81	1.09
Mercury (tons)	53.52	53.60	53.19	49.53	54.05	53.21	27.95	54.82	53.58	13.33

[1] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes plants that only produce electricity.

[3] Includes electricity generation from fuel cells.

[4] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.

[5] Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).

[6] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[7] Other gaseous fuels include refinery and still gas.

[8] Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.

[9] Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[10] Prices represent average revenue per kilowatthour.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Source: 2001 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and supporting databases. 2001 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2001 prices: EIA, National Energy Modeling System run MLBILL.D050503A. **Projections**: EIA, AEO2003 National Energy Modeling System run MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F11. Electricity Generating Capacity

(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Electric Power Sector[2]										
Power Only[3]										
Coal Steam	305.3	310.6	307.0	286.7	343.9	331.9	222.7	376.0	354.7	174.3
Other Fossil Steam[4]	133.8	77.9	76.0	76.9	71.9	67.1	57.6	71.1	64.1	53.6
Combined Cycle	43.2	148.4	145.5	167.1	233.0	247.9	305.6	278.1	298.8	377.4
Combustion Turbine/Diesel	97.6	126.4	121.8	120.1	148.0	121.4	114.9	164.3	128.5	113.8
Nuclear Power[5]	98.2	98.7	97.7	100.3	99.0	97.0	114.8	99.0	95.9	141.5
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	90.4	97.2	98.9	120.2	101.0	105.9	196.5	102.6	108.6	207.5
Distributed Generation[7]	0.0	1.7	1.2	0.9	11.7	4.5	1.8	17.7	8.1	2.1
Total	**788.3**	**881.2**	**868.5**	**892.6**	**1029.0**	**996.3**	**1034.6**	**1129.3**	**1079.3**	**1090.7**
Combined Heat and Power[8]										
Coal Steam	5.2	4.7	4.7	4.4	4.7	4.7	3.4	4.7	4.7	2.7
Other Fossil Steam[4]	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	22.6	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	4.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Renewable Sources[6]	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**33.7**	**44.3**	**44.3**	**44.0**	**44.3**	**44.3**	**43.0**	**44.3**	**44.3**	**42.3**
Total Electric Power Industry	**822.0**	**925.6**	**912.8**	**936.6**	**1073.4**	**1040.6**	**1077.6**	**1173.7**	**1123.6**	**1132.9**
Cumulative Planned Additions[9]										
Coal Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1
Combustion Turbine/Diesel	0.0	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	0.0	4.9	4.9	4.9	6.5	6.5	6.5	6.6	6.6	6.6
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**120.0**	**120.0**	**120.0**	**121.7**	**121.7**	**121.7**	**121.8**	**121.8**	**121.8**
Cumulative Unplanned Additions[9]										
Coal Steam	0.0	12.3	8.7	0.0	47.5	36.3	5.2	80.7	60.2	17.5
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	32.0	30.1	51.0	116.7	132.6	189.7	161.8	183.5	261.7
Combustion Turbine/Diesel	0.0	9.0	3.5	0.6	33.7	9.3	0.6	52.3	17.2	0.6
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	14.2	0.0	0.0	40.9
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	1.5	3.2	24.5	3.8	8.6	99.3	5.2	11.3	110.2
Distributed Generation[7]	0.0	1.7	1.2	0.9	11.7	4.5	1.8	17.7	8.1	2.1
Total	**0.0**	**56.5**	**46.8**	**77.0**	**213.3**	**191.3**	**310.8**	**317.8**	**280.2**	**433.0**
Cumulative Total Additions	**0.0**	**176.6**	**166.8**	**197.0**	**334.9**	**313.0**	**432.5**	**439.5**	**402.0**	**554.8**
Cumulative Retirements[10]										
Coal Steam	0.0	7.6	7.6	19.5	9.4	10.2	89.6	10.5	11.3	151.2
Other Fossil Steam[4]	0.0	54.4	56.3	55.4	60.4	65.2	74.6	61.2	68.2	78.7
Combined Cycle	0.0	0.7	1.7	0.9	0.7	1.7	1.2	0.7	1.7	1.4
Combustion Turbine/Diesel	0.0	11.2	10.3	9.1	14.3	16.4	14.2	16.7	17.3	15.4
Nuclear Power	0.0	2.4	3.4	0.8	3.4	5.4	1.8	3.4	6.5	1.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**76.5**	**79.5**	**85.8**	**88.3**	**99.1**	**181.6**	**92.6**	**105.2**	**248.6**

Table F11. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
End-Use Sector										
Combined Heat and Power[11]										
Coal	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Petroleum	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Natural Gas	14.6	17.0	17.4	20.2	22.1	21.1	28.1	26.4	23.6	45.0
Other Gaseous Fuels	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.2	2.2
Renewable Sources[6]	4.7	6.2	6.8	6.8	8.1	10.6	10.4	9.0	12.9	12.7
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.8**	**31.8**	**32.8**	**35.7**	**38.8**	**40.2**	**47.1**	**44.2**	**45.2**	**66.4**
Other End-Use Generators[12]										
Renewable Sources[13]	1.1	1.5	1.5	1.5	1.7	2.0	2.2	2.0	2.6	3.3
Cumulative Additions[9]										
Combined Heat and Power[11]	0.0	4.1	5.2	8.0	11.1	12.6	19.4	16.6	17.7	38.7
Other End-Use Generators[12]	0.0	0.4	0.4	0.4	0.6	0.9	1.1	0.9	1.5	2.2

[1] Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.

[2] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[3] Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.

[4] Includes oil-, gas-, and dual-fired capability.

[5] Nuclear capacity reflects operating capacity of existing units, including 4.3 gigawatts of uprates through 2025.

[6] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.

[7] Primarily peak-load capacity fueled by natural gas

[8] Includes combined heat and power plants whose primary business is to sell electricity and heat to the public(i.e., those that report NAICS code 22).

[9] Cumulative additions after December 31, 2001.

[10] Cumulative total retirements after December 31, 2001.

[11] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[12] Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[13] See Table F17 for more detail.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model estimates and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with capability for electric utility generators.

Source: 2001 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F12. Petroleum Supply and Disposition Balance

(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Crude Oil										
Domestic Crude Production[1]	5.80	5.64	5.64	5.63	5.43	5.43	5.37	5.30	5.27	5.11
Alaska	0.97	0.64	0.64	0.64	1.23	1.23	1.23	1.17	1.17	1.17
Lower 48 States	4.84	5.00	5.00	4.99	4.20	4.20	4.14	4.13	4.10	3.94
Net Imports	9.31	11.49	11.41	11.35	12.67	12.50	12.41	13.14	12.93	12.79
Gross Imports	9.33	11.56	11.48	11.41	12.73	12.56	12.46	13.18	12.98	12.83
Exports	0.02	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.05	0.04
Other Crude Supply[2]	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.13**	**17.13**	**17.05**	**16.98**	**18.10**	**17.93**	**17.79**	**18.44**	**18.21**	**17.90**
Natural Gas Plant Liquids	**1.87**	**2.20**	**2.17**	**2.18**	**2.48**	**2.34**	**2.46**	**2.59**	**2.44**	**2.59**
Other Inputs[3]	**0.30**	**0.44**	**0.44**	**0.44**	**0.44**	**0.42**	**0.39**	**0.44**	**0.43**	**0.36**
Refinery Processing Gain[4]	**0.90**	**0.91**	**0.90**	**0.90**	**0.96**	**0.95**	**0.94**	**0.96**	**0.94**	**0.93**
Net Product Imports[5]	**1.59**	**2.17**	**1.97**	**1.79**	**4.88**	**4.08**	**2.91**	**6.48**	**5.44**	**3.72**
Gross Refined Product Imports[6]	2.08	2.55	2.38	2.24	4.89	4.04	3.04	6.51	5.47	3.73
Unfinished Oil Imports	0.38	0.63	0.59	0.54	1.07	1.09	0.90	1.08	1.04	1.05
Ether Imports	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.95	1.00	0.99	0.99	1.08	1.05	1.03	1.11	1.07	1.05
Total Primary Supply[7]	**19.80**	**22.86**	**22.54**	**22.29**	**26.86**	**25.73**	**24.49**	**28.90**	**27.46**	**25.51**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.67	10.54	10.35	10.29	12.53	11.82	11.20	13.55	12.63	11.60
Jet Fuel[9]	1.66	1.90	1.88	1.87	2.46	2.35	2.29	2.74	2.57	2.46
Distillate Fuel[10]	3.81	4.62	4.59	4.52	5.42	5.29	5.02	5.88	5.70	5.31
Residual Fuel	0.97	0.63	0.60	0.53	0.66	0.61	0.52	0.66	0.61	0.52
Other[11]	4.58	5.18	5.14	5.09	5.80	5.67	5.48	6.09	5.96	5.63
Total	**19.69**	**22.87**	**22.55**	**22.30**	**26.87**	**25.74**	**24.50**	**28.92**	**27.47**	**25.52**
Refined Petroleum Products Supplied										
Residential and Commercial	1.21	1.18	1.17	1.18	1.14	1.12	1.14	1.13	1.10	1.13
Industrial[12]	4.67	5.28	5.23	5.18	5.96	5.81	5.59	6.28	6.13	5.75
Transportation	13.27	16.19	15.96	15.84	19.53	18.63	17.69	21.25	20.06	18.54
Electric Power[13]	0.55	0.21	0.19	0.11	0.24	0.18	0.08	0.26	0.19	0.10
Total	**19.69**	**22.87**	**22.55**	**22.30**	**26.87**	**25.74**	**24.50**	**28.92**	**27.47**	**25.52**
Discrepancy[14]	**0.10**	**-0.02**	**-0.01**	**-0.02**	**-0.02**	**-0.02**	**-0.01**	**-0.02**	**-0.01**	**-0.01**
World Oil Price (2001 dollars per barrel)[15]	**22.01**	**23.99**	**23.99**	**23.59**	**25.48**	**25.48**	**23.68**	**26.57**	**26.57**	**23.94**
Import Share of Product Supplied	**0.55**	**0.60**	**0.59**	**0.59**	**0.65**	**0.64**	**0.63**	**0.68**	**0.67**	**0.65**
Net Expenditures for Imported Crude Oil & Petroleum Products (billion 2001 dollars)	**89.20**	**122.23**	**119.49**	**115.54**	**172.92**	**161.13**	**136.47**	**205.85**	**189.24**	**150.03**
Domestic Refinery Distillation Capacity[16]	**16.8**	**18.7**	**18.7**	**18.7**	**19.5**	**19.3**	**19.1**	**19.8**	**19.6**	**19.3**
Capacity Utilization Rate (percent)	**93.0**	**93.1**	**92.9**	**92.6**	**94.6**	**94.6**	**94.6**	**94.6**	**94.5**	**94.6**

[1] Includes lease condensate.

[2] Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.

[3] Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.

[4] Represents volumetric gain in refinery distillation and cracking processes.

[5] Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.

[6] Includes other hydrocarbons, alcohols, and blending components.

[7] Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.

[8] Includes ethanol and ethers blended into gasoline.

[9] Includes only kerosene type.

[10] Includes distillate and kerosene.

[11] Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.

[12] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[13] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[14] Balancing item. Includes unaccounted for supply, losses, and gains.

[15] Average refiner acquisition cost for imported crude oil.

[16] End-of-year capacity.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). Other 2001 data: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F13. Petroleum Product Prices

(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
World Oil Price (2001 dollars per barrel)	**22.01**	**23.99**	**23.99**	**23.59**	**25.48**	**25.48**	**23.68**	**26.57**	**26.57**	**23.94**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	124.6	110.9	110.6	109.2	120.7	117.1	110.1	123.8	123.1	112.6
Liquefied Petroleum Gas	127.3	123.1	122.9	121.7	131.1	131.3	126.2	133.1	132.0	127.6
Commercial										
Distillate Fuel	88.7	78.6	78.4	77.1	89.5	85.7	78.3	93.7	91.9	81.2
Residual Fuel	51.8	60.1	60.0	58.4	63.3	63.1	58.2	65.7	65.5	58.8
Residual Fuel (2001 dollars per barrel)	21.75	25.24	25.20	24.54	26.57	26.50	24.45	27.58	27.50	24.68
Industrial[1]										
Distillate Fuel	90.8	79.7	79.6	78.2	93.4	88.8	80.8	99.7	95.8	84.5
Liquefied Petroleum Gas	105.9	85.2	84.9	83.8	93.1	93.2	88.6	95.4	95.3	90.5
Residual Fuel	49.1	55.6	55.5	54.3	58.9	58.7	54.2	61.4	61.2	54.8
Residual Fuel (2001 dollars per barrel)	20.61	23.35	23.30	22.80	24.75	24.67	22.78	25.77	25.70	23.03
Transportation										
Diesel Fuel (distillate)[2]	139.4	141.4	141.7	156.8	142.4	137.4	167.4	147.5	142.7	176.9
Jet Fuel[3]	83.7	76.3	76.1	90.0	85.6	81.9	109.4	90.7	87.0	118.6
Motor Gasoline[4]	143.3	141.8	141.0	154.5	143.1	142.8	162.7	149.4	144.2	173.2
Liquid Petroleum Gas	145.2	133.4	132.3	139.3	137.8	138.4	152.8	137.1	135.8	157.1
Residual Fuel	58.4	53.4	53.3	70.9	56.6	56.6	94.5	59.0	59.1	103.2
Residual Fuel (2001 dollars per barrel)	24.52	22.41	22.40	29.79	23.76	23.77	39.68	24.80	24.80	43.35
Electric Power[5]										
Distillate Fuel	86.0	71.2	71.0	68.5	82.4	80.0	70.7	85.4	85.0	74.5
Residual Fuel	67.4	61.0	61.6	64.7	64.8	66.8	72.1	68.1	70.0	72.9
Residual Fuel (2001 dollars per barrel)	28.30	25.63	25.86	27.19	27.23	28.04	30.30	28.60	29.40	30.61
Refined Petroleum Product Prices[6]										
Distillate Fuel	127.0	127.0	127.2	137.8	132.0	127.5	147.7	137.3	133.5	156.2
Jet Fuel[3]	83.7	76.3	76.1	90.0	85.6	81.9	109.4	90.7	87.0	118.6
Liquefied Petroleum Gas	110.3	92.2	92.0	91.0	99.3	99.4	95.1	101.3	100.9	96.8
Motor Gasoline[4]	143.4	141.8	141.0	154.4	143.1	142.8	162.4	149.4	144.2	172.8
Residual Fuel	61.5	55.9	55.8	67.2	59.3	59.4	84.9	61.9	62.0	91.3
Residual Fuel (2001 dollars per barrel)	25.85	23.48	23.43	28.23	24.92	24.96	35.66	26.02	26.05	38.33
Average	**123.6**	**122.0**	**121.6**	**132.3**	**125.7**	**124.1**	**141.0**	**131.1**	**127.0**	**149.2**
Greenhouse Gas Allowance Cost										
Commercial										
Distillate Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residual Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residual Fuel (2001 dollars per barrel)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[1]										
Distillate Fuel	0.0	0.0	0.0	16.1	0.0	0.0	36.4	0.0	0.0	43.4
Liquefied Petroleum Gas	0.0	0.0	0.0	8.6	0.0	0.0	19.5	0.0	0.0	23.2
Residual Fuel	0.0	0.0	0.0	18.7	0.0	0.0	42.3	0.0	0.0	50.5
Residual Fuel (2001 dollars per barrel)	0.00	0.00	0.00	7.86	0.00	0.00	17.77	0.00	0.00	21.20
Electric Power[5]										
Distillate Fuel	0.0	0.0	0.0	16.1	0.0	0.0	36.4	0.0	0.0	43.4
Residual Fuel	0.0	0.0	0.0	18.7	0.0	0.0	42.3	0.0	0.0	50.5
Residual Fuel (2001 dollars per barrel)	0.00	0.00	0.00	7.86	0.00	0.00	17.77	0.00	0.00	21.20

Table F13. Petroleum Product Prices (Continued)

(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Delivered Sector Product Prices with Greenhouse Gas Allowance Cost										
Commercial										
Distillate Fuel	88.7	78.6	78.4	77.1	89.5	85.7	78.3	93.7	91.9	81.2
Residual Fuel	51.8	60.1	60.0	58.4	63.3	63.1	58.2	65.7	65.5	58.8
Residual Fuel (2001 dollars per barrel)	21.75	25.24	25.20	24.54	26.57	26.50	24.45	27.58	27.50	24.68
Industrial[1]										
Distillate Fuel	90.8	79.7	79.6	94.3	93.4	88.8	117.2	99.7	95.8	127.9
Liquefied Petroleum Gas	105.9	85.2	84.9	92.4	93.1	93.2	108.0	95.4	95.3	113.7
Residual Fuel	49.1	55.6	55.5	73.0	58.9	58.7	96.6	61.4	61.2	105.3
Residual Fuel (2001 dollars per barrel)	20.61	23.35	23.30	30.66	24.75	24.67	40.55	25.77	25.70	44.24
Electric Power[5]										
Distillate Fuel	86.0	71.2	71.0	84.6	82.4	80.0	107.0	85.4	85.0	117.9
Residual Fuel	67.4	61.0	61.6	83.5	64.8	66.8	114.4	68.1	70.0	123.4
Residual Fuel (2001 dollars per barrel)	28.30	25.63	25.86	35.05	27.23	28.04	48.07	28.60	29.40	51.82

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[1] Includes combined heat and power, which produces electricity and other useful thermal energy.

[2] Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur. Includes Federal and State taxes while excluding county and local taxes.

[3] Kerosene-type jet fuel.

[4] Sales weighted-average price for all grades. Includes Federal, State and local taxes.

[5] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[6] Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources:. 2001 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A: "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2001 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2001 world oil price: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections**: EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F14. Natural Gas Supply and Disposition

(Trillion Cubic Feet per Year)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Production										
Dry Gas Production[1]	19.45	21.53	21.26	21.37	24.85	23.18	24.34	26.36	24.74	26.27
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.73**	**4.76**	**4.31**	**4.40**	**6.88**	**6.00**	**7.14**	**7.90**	**6.40**	**8.89**
Canada	3.61	4.16	4.00	3.95	5.14	4.92	5.36	5.21	4.90	5.42
Mexico	-0.13	-0.20	-0.21	-0.21	-0.02	-0.06	-0.03	0.29	0.04	0.29
Liquefied Natural Gas	0.26	0.80	0.52	0.66	1.76	1.13	1.81	2.40	1.46	3.18
Total Supply	**23.26**	**26.39**	**25.67**	**25.86**	**31.83**	**29.27**	**31.58**	**34.36**	**31.25**	**35.25**
Consumption by Sector										
Residential	4.81	5.48	5.47	5.46	5.93	5.89	5.79	6.21	6.12	6.01
Commercial	3.24	3.64	3.64	3.63	4.12	4.13	4.14	4.38	4.40	4.81
Industrial[3]	7.53	8.81	8.52	8.62	10.10	9.32	9.19	10.93	9.86	9.59
Electric Power[4]	5.30	6.58	6.19	6.29	9.42	7.86	10.30	10.37	8.55	12.36
Transportation[5]	0.01	0.06	0.06	0.06	0.10	0.09	0.09	0.11	0.10	0.10
Pipeline Fuel	0.61	0.76	0.75	0.75	0.91	0.83	0.89	1.00	0.92	1.02
Lease and Plant Fuel[6]	1.17	1.33	1.32	1.32	1.56	1.45	1.50	1.68	1.59	1.67
Total	**22.67**	**26.66**	**25.95**	**26.14**	**32.14**	**29.57**	**31.90**	**34.67**	**31.55**	**35.55**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.59**	**-0.28**	**-0.28**	**-0.28**	**-0.31**	**-0.30**	**-0.32**	**-0.31**	**-0.30**	**-0.30**

[1] Marketed production (wet) minus extraction losses.

[2] Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

[3] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as vehicle fuel.

[6] Represents natural gas used in the field gathering and processing plant machinery.

[7] Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2001 values include net storage injections.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F15. Natural Gas Prices, Margins, and Revenue
(2001 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Source Price										
Average Lower 48 Wellhead Price[1]	4.12	3.39	3.28	3.33	3.70	3.56	3.83	3.95	3.51	4.09
Average Import Price	4.43	3.40	3.32	3.34	3.88	3.65	3.96	4.19	3.80	4.26
Average[2]	**4.17**	**3.39**	**3.29**	**3.33**	**3.74**	**3.58**	**3.86**	**4.01**	**3.58**	**4.13**
Delivered Prices										
Residential	9.68	7.79	7.69	7.73	7.99	7.81	8.13	8.26	7.78	8.44
Commercial	8.32	6.67	6.57	6.61	6.98	6.79	7.09	7.26	6.79	7.39
Industrial[3]	5.01	4.11	4.00	4.04	4.51	4.32	4.62	4.76	4.34	4.89
Electric Power[4]	4.87	3.95	3.83	3.91	4.44	4.20	4.62	4.73	4.24	4.92
Transportation[5]	7.87	7.39	7.30	7.32	7.97	7.81	7.87	8.32	7.87	8.11
Average[6]	**6.57**	**5.28**	**5.21**	**5.25**	**5.55**	**5.43**	**5.68**	**5.80**	**5.43**	**5.94**
Transmission & Distribution Margins[7]										
Residential	5.50	4.39	4.40	4.40	4.25	4.24	4.27	4.25	4.21	4.31
Commercial	4.14	3.28	3.28	3.28	3.24	3.21	3.23	3.25	3.22	3.26
Industrial[3]	0.83	0.72	0.72	0.71	0.77	0.74	0.76	0.75	0.76	0.75
Electric Power[4]	0.70	0.56	0.54	0.58	0.70	0.62	0.77	0.72	0.67	0.78
Transportation[5]	3.69	4.00	4.02	3.99	4.23	4.24	4.01	4.31	4.29	3.97
Average[6]	**2.40**	**1.89**	**1.92**	**1.92**	**1.81**	**1.86**	**1.82**	**1.79**	**1.85**	**1.81**
Transmission & Distribution Revenue (billion 2001 dollars)										
Residential	26.45	24.08	24.10	24.05	25.22	24.94	24.72	26.39	25.77	25.90
Commercial	13.42	11.94	11.96	11.93	13.33	13.26	13.39	14.25	14.15	15.66
Industrial[3]	6.28	6.36	6.09	6.12	7.82	6.92	7.02	8.23	7.49	7.24
Electric Power[4]	3.69	3.70	3.37	3.66	6.57	4.89	7.89	7.42	5.69	9.70
Transportation[5]	0.04	0.23	0.23	0.22	0.41	0.40	0.36	0.47	0.45	0.39
Total	**49.88**	**46.31**	**45.75**	**45.98**	**53.36**	**50.41**	**53.37**	**56.76**	**53.55**	**58.89**
Greenhouse Gas Allowance Cost										
Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[3]	0.00	0.00	0.00	0.85	0.00	0.00	1.93	0.00	0.00	2.30
Electric Power[4]	0.00	0.00	0.00	0.86	0.00	0.00	1.95	0.00	0.00	2.33
Transportation[5]	0.00	0.00	0.00	0.87	0.00	0.00	1.97	0.00	0.00	2.35
Average[6]	**0.00**	**0.00**	**0.00**	**0.53**	**0.00**	**0.00**	**1.29**	**0.00**	**0.00**	**1.56**
Delivered Prices with Greenhouse Gas Allowance Cost										
Residential	9.68	7.79	7.69	7.73	7.99	7.81	8.13	8.26	7.78	8.44
Commercial	8.32	6.67	6.57	6.61	6.98	6.79	7.09	7.26	6.79	7.39
Industrial[3]	5.01	4.11	4.00	4.89	4.51	4.32	6.55	4.76	4.34	7.19
Electric Power[4]	4.87	3.95	3.83	4.77	4.44	4.20	6.57	4.73	4.24	7.24
Transportation[5]	7.87	7.39	7.30	8.19	7.97	7.81	9.83	8.32	7.87	10.45
Average[6]	**6.57**	**5.28**	**5.21**	**5.78**	**5.55**	**5.43**	**6.97**	**5.80**	**5.43**	**7.50**

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[1] Represents lower 48 onshore and offshore supplies.

[2] Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.

[3] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.

[6] Weighted average allowance cost. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.

[7] Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 electric generators delivered price: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1998*. 2001 residential, commercial, and transportation delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F16. Oil and Gas Supply

Production and Supply	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Crude Oil										
Lower 48 Average Wellhead Price[1]										
(2001 dollars per barrel)	22.91	23.89	23.88	23.41	24.98	24.96	23.07	26.22	26.17	23.55
Production (million barrels per day)[2]										
U.S. Total	5.80	5.64	5.64	5.63	5.43	5.43	5.37	5.30	5.27	5.11
Lower 48 Onshore	3.13	2.47	2.47	2.47	2.06	2.06	2.04	1.92	1.91	1.89
Lower 48 Offshore	1.71	2.52	2.52	2.52	2.14	2.14	2.10	2.22	2.19	2.05
Alaska	0.97	0.64	0.64	0.64	1.23	1.23	1.23	1.17	1.17	1.17
Lower 48 End of Year Reserves (billion barrels)[2]	19.48	17.72	17.72	17.69	15.39	15.40	15.19	15.04	14.98	14.53
Natural Gas										
Lower 48 Average Wellhead Price[1]										
(2001 dollars per thousand cubic feet)	4.12	3.39	3.28	3.33	3.70	3.56	3.83	3.95	3.51	4.09
Dry Production (trillion cubic feet)[3]										
U.S. Total	19.45	21.54	21.26	21.37	24.86	23.18	24.34	26.37	24.75	26.27
Lower 48 Onshore	13.72	15.57	15.36	15.45	17.96	17.24	18.32	17.77	16.74	18.04
Associated-Dissolved[4]	1.77	1.37	1.37	1.36	1.19	1.19	1.19	1.13	1.13	1.12
Non-Associated	11.94	14.20	13.99	14.09	16.77	16.05	17.13	16.64	15.61	16.91
Conventional	6.54	7.04	7.00	7.07	7.15	7.12	7.28	7.04	6.72	7.04
Unconventional	5.40	7.16	6.99	7.01	9.61	8.93	9.85	9.60	8.89	9.88
Lower 48 Offshore	5.30	5.49	5.43	5.44	5.43	5.40	5.49	5.74	5.59	5.61
Associated-Dissolved[4]	1.08	0.96	0.95	0.95	0.80	0.80	0.78	0.82	0.81	0.76
Non-Associated	4.22	4.53	4.48	4.49	4.63	4.60	4.70	4.93	4.78	4.85
Alaska	0.43	0.48	0.47	0.47	1.47	0.54	0.54	2.85	2.42	2.63
Lower 48 End of Year Dry Reserves[3]										
(trillion cubic feet)	174.04	186.42	185.56	184.54	194.24	196.09	193.77	190.10	192.76	190.79
Supplemental Gas Supplies (trillion cubic feet)[5]	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Total Lower 48 Wells (thousands)	33.94	25.73	24.95	24.72	26.21	25.78	27.00	27.53	26.30	27.99

[1] Represents lower 48 onshore and offshore supplies.
[2] Includes lease condensate.
[3] Marketed production (wet) minus extraction losses.
[4] Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5] Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2001 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F17. Coal Supply, Disposition, and Prices

(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Production[1]										
Appalachia	443	420	419	411	416	397	262	433	396	145
Interior	147	161	165	159	151	160	116	159	169	63
West	548	669	637	528	801	721	246	865	754	176
East of the Mississippi	539	527	526	518	529	512	357	554	521	200
West of the Mississippi	599	723	695	580	839	765	266	902	798	184
Total	**1138**	**1250**	**1221**	**1098**	**1367**	**1277**	**623**	**1456**	**1319**	**384**
Net Imports										
Imports	19	20	20	11	25	25	11	28	28	10
Exports	49	33	34	34	29	27	27	24	28	25
Total	**-30**	**-14**	**-14**	**-23**	**-4**	**-2**	**-17**	**3**	**0**	**-14**
Total Supply[2]	**1109**	**1236**	**1207**	**1075**	**1363**	**1275**	**607**	**1460**	**1319**	**370**
Consumption by Sector										
Residential and Commercial	4	5	5	5	5	5	5	5	5	6
Industrial[3]	63	67	66	61	70	67	58	71	67	57
of which: Coal to Liquids	0	0	0	0	0	0	0	0	0	0
Coke Plants	26	24	21	21	20	15	10	18	13	8
Electric Power[4]	957	1146	1120	996	1274	1193	522	1371	1240	305
Total	**1050**	**1242**	**1212**	**1083**	**1369**	**1281**	**595**	**1466**	**1325**	**375**
Discrepancy and Stock Change[5]	**58**	**-6**	**-5**	**-8**	**-6**	**-6**	**12**	**-6**	**-6**	**-5**
Average Minemouth Price										
(2001 dollars per short ton)	17.59	15.06	15.09	15.68	14.34	14.20	15.51	14.39	14.05	13.29
(2001 dollars per million Btu)	0.83	0.73	0.73	0.75	0.70	0.70	0.72	0.71	0.69	0.63
Delivered Prices (2001 dollars per short ton)[6]										
Industrial	32.82	30.11	30.01	30.03	28.45	27.97	25.84	28.04	27.32	22.81
Coke Plants	46.42	41.27	40.91	40.98	38.08	37.28	36.66	36.67	35.73	35.27
Electric Power										
(2001 dollars per short ton)	25.06	23.63	23.60	23.66	22.44	22.05	21.39	22.27	21.68	18.61
(2001 dollars per million Btu)	1.25	1.17	1.17	1.16	1.12	1.10	1.01	1.11	1.08	0.91
Average	**26.06**	**24.33**	**24.26**	**24.36**	**22.98**	**22.54**	**22.08**	**22.74**	**22.10**	**19.61**
Exports[7]	36.97	32.68	32.46	32.38	30.94	30.36	28.90	30.36	29.23	27.03
Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]										
Industrial	0.00	0.00	0.00	32.45	0.00	0.00	73.13	0.00	0.00	87.05
Coke Plants	0.00	0.00	0.00	40.76	0.00	0.00	92.16	0.00	0.00	109.97
Electric Power										
(2001 dollars per short ton)	0.00	0.00	0.00	30.69	0.00	0.00	71.35	0.00	0.00	82.56
(2001 dollars per million Btu)	0.00	0.00	0.00	1.50	0.00	0.00	3.38	0.00	0.00	4.04
Average	**0.00**	**0.00**	**0.00**	**30.98**	**0.00**	**0.00**	**71.87**	**0.00**	**0.00**	**83.83**
Delivered Prices with Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]										
Industrial	32.82	30.11	30.01	62.48	28.45	27.97	98.97	28.04	27.32	109.86
Coke Plants	46.42	41.27	40.91	81.74	38.08	37.28	128.81	36.67	35.73	145.24
Electric Power										
(2001 dollars per short ton)	25.06	23.63	23.60	54.35	22.44	22.05	92.74	22.27	21.68	101.17
(2001 dollars per million Btu)	1.25	1.17	1.17	2.66	1.12	1.10	4.39	1.11	1.08	4.96
Average	**26.06**	**24.33**	**24.26**	**55.34**	**22.98**	**22.54**	**93.96**	**22.74**	**22.10**	**103.44**

[1] Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.1 million tons in 2000 and 10.6 million tons in 2001.

[2] Production plus net imports and net storage withdrawals.

[3] Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

[4] Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[5] Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.

[6] Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.

[7] F.a.s. price at U.S. port of exit.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F18. Renewable Energy Generating Capacity and Generation

(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Electric Power Sector[1]										
Net Summer Capacity										
Conventional Hydropower	78.10	78.66	78.66	78.66	78.65	78.65	78.65	78.65	78.65	78.65
Geothermal[2]	2.83	3.81	4.82	7.15	5.19	8.11	11.83	5.77	8.91	12.53
Municipal Solid Waste[3]	3.25	4.08	4.03	4.71	4.41	4.36	5.16	4.42	4.36	5.16
Wood and Other Biomass[4]	1.80	2.09	2.09	4.20	2.20	2.20	29.70	2.33	2.20	39.76
Solar Thermal	0.33	0.44	0.44	0.44	0.48	0.48	0.60	0.50	0.50	0.66
Solar Photovoltaic[5]	0.02	0.10	0.10	0.10	0.27	0.27	0.27	0.36	0.36	0.36
Wind	4.29	8.24	9.03	25.21	10.05	12.06	70.58	10.81	13.89	70.67
Total	**90.62**	**97.42**	**99.16**	**120.47**	**101.24**	**106.12**	**196.79**	**102.83**	**108.87**	**207.80**
Generation (billion kilowatthours)										
Conventional Hydropower	213.82	300.90	300.85	300.84	300.07	299.95	299.83	300.36	300.21	299.99
Geothermal[2]	13.81	22.04	29.95	48.33	33.43	57.16	87.09	38.12	63.75	92.66
Municipal Solid Waste[3]	19.55	29.20	28.79	34.20	31.67	31.24	37.54	31.81	31.34	37.63
Wood and Other Biomass[4]	9.38	21.47	21.47	29.35	22.06	21.98	190.49	22.82	21.77	256.47
Dedicated Plants	7.66	12.47	12.44	20.50	13.22	13.14	190.49	14.09	13.08	256.47
Cofiring	1.72	9.00	9.03	8.85	8.84	8.84	0.00	8.73	8.69	0.00
Solar Thermal	0.49	0.77	0.86	0.86	0.90	1.08	1.93	0.97	1.21	2.30
Solar Photovoltaic[5]	0.00	0.24	0.24	0.24	0.66	0.66	0.66	0.88	0.88	0.88
Wind	5.78	22.91	25.76	83.57	29.20	36.92	252.05	32.03	44.06	252.48
Total	**262.85**	**397.53**	**407.93**	**497.39**	**417.98**	**448.99**	**869.60**	**427.00**	**463.23**	**942.42**
End- Use Sector										
Net Summer Capacity										
Combined Heat and Power[6]										
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Biomass	4.41	5.93	6.57	6.53	7.79	10.27	10.11	8.74	12.67	12.40
Total	**4.69**	**6.21**	**6.85**	**6.81**	**8.07**	**10.56**	**10.39**	**9.03**	**12.95**	**12.68**
Other End-Use Generators[7]										
Conventional Hydropower[8]	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.38	0.39	0.40	0.61	0.92	1.09	0.94	1.49	2.19
Total	**1.12**	**1.47**	**1.49**	**1.49**	**1.71**	**2.01**	**2.19**	**2.04**	**2.58**	**3.29**
Generation (billion kilowatthours)										
Combined Heat and Power[6]										
Municipal Solid Waste	2.46	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15
Biomass	28.67	37.53	41.27	41.03	48.39	62.90	61.95	53.98	76.87	75.33
Total	**31.13**	**39.68**	**43.42**	**43.18**	**50.54**	**65.05**	**64.10**	**56.13**	**79.03**	**77.48**
Other End-Use Generators[7]										
Conventional Hydropower[8]	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.82	0.85	0.85	1.32	1.95	2.31	1.99	3.13	4.58
Total	**4.25**	**5.05**	**5.08**	**5.09**	**5.55**	**6.18**	**6.54**	**6.23**	**7.37**	**8.81**

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[1] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes hydrothermal resources only (hot water and steam).

[3] Includes landfill gas.

[4] Includes projections for energy crops after 2010.

[5] Does not include off-grid photovoltaics (PV). See Annual Energy Review 2001 Table 10.6 for estimates of 1989-2000 PV shipments, including exports, for both grid-connected and off-grid applications.

[6] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[7] Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[8] Represents own-use industrial hydroelectric power.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2003. Net summer capacity is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.

Sources: 2001 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2001 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F19. Renewable Energy Consumption by Sector and Source[1]

(Quadrillion Btu per Year)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Marketed Renewable Energy[2]										
Residential	**0.39**	**0.41**	**0.40**	**0.40**	**0.41**	**0.39**	**0.39**	**0.40**	**0.39**	**0.39**
Wood	0.39	0.41	0.40	0.40	0.41	0.39	0.39	0.40	0.39	0.39
Commercial	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Industrial[3]	**1.82**	**2.22**	**2.35**	**2.34**	**2.77**	**3.17**	**3.14**	**3.05**	**3.64**	**3.59**
Conventional Hydroelectric	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.77	2.17	2.30	2.29	2.72	3.12	3.09	3.00	3.59	3.54
Transportation	**0.15**	**0.26**	**0.26**	**0.25**	**0.31**	**0.29**	**0.28**	**0.33**	**0.31**	**0.30**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Ethanol used in Gasoline Blending	0.15	0.26	0.25	0.25	0.30	0.29	0.27	0.33	0.31	0.30
Electric Power[5]	**3.01**	**4.57**	**4.85**	**6.18**	**5.02**	**5.85**	**10.70**	**5.21**	**6.14**	**11.51**
Conventional Hydroelectric	2.16	3.09	3.09	3.09	3.07	3.07	3.07	3.07	3.07	3.07
Geothermal	0.29	0.57	0.83	1.43	0.93	1.68	2.74	1.07	1.89	2.95
Municipal Solid Waste[6]	0.31	0.40	0.39	0.47	0.43	0.43	0.51	0.43	0.43	0.51
Biomass	0.15	0.26	0.27	0.33	0.27	0.27	1.76	0.28	0.27	2.35
Dedicated Plants	0.12	0.14	0.14	0.22	0.15	0.15	1.76	0.16	0.15	2.35
Cofiring	0.03	0.12	0.13	0.11	0.12	0.12	0.00	0.12	0.12	0.00
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	0.03	0.02	0.02	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.08	0.24	0.26	0.86	0.30	0.38	2.59	0.33	0.45	2.60
Total Marketed Renewable Energy	**5.46**	**7.56**	**7.96**	**9.28**	**8.61**	**9.82**	**14.62**	**9.10**	**10.58**	**15.90**
Sources of Ethanol										
From Corn	0.15	0.26	0.24	0.24	0.28	0.24	0.23	0.28	0.21	0.20
From Cellulose	0.00	0.00	0.01	0.01	0.02	0.05	0.05	0.05	0.10	0.10
Total	**0.15**	**0.26**	**0.26**	**0.25**	**0.31**	**0.29**	**0.28**	**0.33**	**0.31**	**0.30**
Non-Marketed Renewable Energy[7] **Selected Consumption**										
Residential	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**
Solar Hot Water Heating	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Geothermal Heat Pumps	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01

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[1] Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.

[2] Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table F8.

[3] Includes all electricity production by industrial and other combined heat and power for the grid and for own use.

[4] Excludes motor gasoline component of E85.

[5] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[6] Includes landfill gas.

[7] Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 electric generators: EIA, Form EIA-860: "Annual Electric Generator Report" (preliminary). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runsMLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F20. Greenhouse Gas Emissions and Allowance Cost
(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Carbon Dioxide Emissions										
Residential										
Petroleum	27.2	27.6	27.4	27.4	25.7	25.2	25.5	25.0	24.2	24.6
Natural Gas	71.1	81.1	81.0	80.9	87.9	87.1	85.7	91.9	90.6	89.0
Coal	0.3	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3
Total	**98.7**	**109.1**	**108.8**	**108.7**	**113.9**	**112.7**	**111.5**	**117.2**	**115.2**	**114.0**
Commercial										
Petroleum	14.0	13.7	13.5	13.6	14.1	13.8	14.2	14.1	13.7	14.5
Natural Gas	48.0	53.9	53.9	53.8	60.9	61.1	61.3	64.8	65.1	71.2
Coal	2.3	2.4	2.4	2.5	2.7	2.7	2.7	2.8	2.8	2.9
Total	**64.3**	**70.0**	**69.9**	**69.8**	**77.7**	**77.6**	**78.2**	**81.7**	**81.7**	**88.5**
Industrial[1]										
Petroleum	97.9	97.9	96.8	95.6	105.5	101.8	97.9	109.1	105.2	99.2
Natural Gas[2]	123.4	147.7	143.2	144.7	169.4	156.5	155.5	183.3	166.4	163.8
Coal	52.1	56.5	53.6	50.8	56.2	50.5	43.3	56.2	49.3	42.1
Total	**273.4**	**302.1**	**293.6**	**291.2**	**331.2**	**308.7**	**296.7**	**348.6**	**320.9**	**305.1**
Transportation										
Petroleum[3]	501.4	611.5	603.0	598.1	737.5	704.5	668.9	802.8	758.6	701.2
Natural Gas[4]	9.2	12.0	11.9	12.0	14.9	13.7	14.5	16.4	15.2	16.5
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**510.6**	**623.6**	**614.9**	**610.1**	**752.5**	**718.2**	**683.4**	**819.2**	**773.8**	**717.8**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	640.5	750.8	740.7	734.8	882.8	845.3	806.5	950.9	901.8	839.6
Natural Gas	251.7	294.7	290.0	291.3	333.1	318.3	317.0	356.4	337.3	340.5
Coal	54.7	59.3	56.4	53.6	59.3	53.6	46.4	59.4	52.5	45.3
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**947.0**	**1104.8**	**1087.1**	**1079.7**	**1275.2**	**1217.2**	**1169.9**	**1366.7**	**1291.6**	**1225.3**
Electric Power[6]										
Petroleum	27.5	10.1	8.8	5.2	11.3	8.4	3.9	12.0	8.8	3.9
Natural Gas	77.7	96.6	90.8	91.9	138.2	115.4	124.2	152.1	125.4	110.7
Coal	506.4	590.8	577.7	519.0	653.0	611.6	278.2	703.6	634.2	136.6
Total	**611.6**	**697.4**	**677.3**	**616.1**	**802.5**	**735.4**	**406.3**	**867.8**	**768.5**	**251.2**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	668.0	760.8	749.5	739.9	894.1	853.7	810.4	962.9	910.6	843.5
Natural Gas	329.4	391.3	380.8	383.2	471.3	433.7	441.2	508.5	462.8	451.1
Coal	561.1	650.1	634.1	572.7	712.2	665.2	324.6	763.0	686.7	181.9
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1558.6**	**1802.2**	**1764.4**	**1695.9**	**2077.7**	**1952.6**	**1576.2**	**2234.4**	**2060.1**	**1476.5**
Non-Energy Related Carbon Dioxide Emissions	**36.3**	**39.5**	**39.5**	**39.5**	**43.9**	**43.9**	**43.9**	**46.2**	**46.2**	**46.2**
Total Carbon Dioxide Emissions	**1594.9**	**1841.7**	**1804.0**	**1735.4**	**2121.6**	**1996.5**	**1620.1**	**2280.6**	**2106.3**	**1522.7**
Other Greenhouse Gas Emissions	**332.9**	**388.3**	**388.3**	**291.3**	**466.6**	**466.6**	**344.6**	**525.0**	**525.0**	**365.9**
Methane	175.2	177.6	177.6	118.8	174.3	174.3	126.8	172.2	172.2	120.1
Nitrous Oxide	118.9	126.5	126.5	121.0	137.3	137.3	131.4	143.4	143.4	137.2
High Global Warming Potential Gases	38.8	84.2	84.2	51.5	155.0	155.0	86.4	209.4	209.4	108.6
Total Greenhouse Gas Emissions	**1927.8**	**2230.1**	**2192.3**	**2026.7**	**2588.2**	**2463.2**	**1964.6**	**2805.6**	**2631.3**	**1888.6**

Table F20. Greenhouse Gas Emissions and Allowance Cost (Continued)
(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
Greenhouse Gas Emission Cap Compliance										
Covered Emissions										
Energy-Related Carbon Dioxide	1378.2	1605.0	1567.8	1499.4	1866.0	1742.6	1366.8	2014.2	1842.3	1253.3
Other Greenhouse Gases	75.2	123.5	123.5	71.8	195.7	195.7	107.7	250.7	250.7	130.6
Offsets Purchased	0.0	0.0	0.0	206.8	0.0	0.0	125.3	0.0	0.0	125.8
Non-Covered Greenhouse Gas Offsets	0.0	0.0	0.0	45.3	0.0	0.0	34.1	0.0	0.0	39.1
U.S. Sequestration Offsets	0.0	0.0	0.0	105.7	0.0	0.0	91.2	0.0	0.0	86.7
International Offsets	0.0	0.0	0.0	55.8	0.0	0.0	0.0	0.0	0.0	0.1
Covered Emissions less Offsets	1453.4	1728.5	1691.3	1364.5	2061.6	1938.3	1349.1	2264.9	2093.0	1258.1
Covered Emissions Coal	N/A	N/A	N/A	1465.1	N/A	N/A	1257.9	N/A	N/A	1257.9
Allowance Bank Activity	0.0	0.0	0.0	100.6	0.0	0.0	-91.2	0.0	0.0	-0.2
Cumulative Bank Balance	0.0	0.0	0.0	100.6	0.0	0.0	132.4	0.0	0.0	5.5
Allowance Cost (2001 dollars per ton)										
Emissions Allowance Cost	0.00	0.00	0.00	58.74	0.00	0.00	132.82	0.00	0.00	158.49
Offset Price	0.00	0.00	0.00	58.74	0.00	0.00	34.24	0.00	0.00	52.00

[1] Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes lease and plant fuel.

[3] This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons carbon equivalent of carbon dioxide annually.

[4] Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

[5] Includes methanol and liquid hydrogen.

[6] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.

[7] Emissions from electric power generators are distributed to the primary fuels.

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table F21. Macroeconomic Indicators

(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2001	Projections								
		2010			2020			2025		
		Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology	Reference	High Technology	S. 139 with High Technology
GDP Chain-Type Price Index (1996=1.000)	**1.094**	**1.313**	**1.313**	**1.320**	**1.708**	**1.707**	**1.729**	**1.981**	**1.981**	**2.019**
Potential Gross Domestic Product	**9456**	**12454**	**12454**	**12455**	**16772**	**16776**	**16740**	**19240**	**19243**	**19181**
Real Gross Domestic Product	**9215**	**12258**	**12257**	**12220**	**16444**	**16459**	**16398**	**18916**	**18917**	**18823**
Real Consumption	6377	8412	8412	8383	11346	11355	11313	13008	13010	12968
Real Investment	1575	2499	2499	2482	3755	3760	3739	4496	4494	4453
Real Government Spending	1640	1895	1895	1896	2211	2212	2207	2429	2429	2420
Real Exports	1076	1784	1784	1781	3361	3362	3331	4696	4696	4630
Real Imports	1492	2302	2302	2294	4060	4060	4041	5395	5395	5396
Real Disposable Personal Income	**6748**	**8635**	**8634**	**8614**	**11693**	**11705**	**11678**	**13425**	**13429**	**13426**
Federal Funds Rate (percent)	**3.89**	**5.48**	**5.48**	**5.58**	**6.37**	**6.41**	**6.57**	**6.49**	**6.51**	**6.82**
AA Utility Bond Rate (percent)										
Nominal	7.57	7.22	7.22	7.34	9.00	9.02	9.15	9.61	9.62	9.89
Real	5.60	5.26	5.26	5.21	6.12	6.15	6.20	6.54	6.54	6.68
Energy Intensity (thousand Btu per 1996 dollar of GDP)										
Delivered Energy	7.74	6.83	6.74	6.71	5.91	5.69	5.48	5.52	5.28	5.01
Total Energy	10.56	9.24	9.10	9.04	7.89	7.55	7.16	7.33	6.92	6.45
Consumer Price Index (1982-84=1.00)	**1.77**	**2.19**	**2.19**	**2.20**	**2.93**	**2.92**	**2.96**	**3.47**	**3.47**	**3.53**
Unemployment Rate (percent)	**4.79**	**4.42**	**4.42**	**4.53**	**5.88**	**5.85**	**5.95**	**5.77**	**5.77**	**5.87**
Housing Starts (millions)	**1.80**	**2.18**	**2.18**	**2.14**	**1.93**	**1.93**	**1.93**	**2.01**	**2.01**	**2.00**
Single-Family	1.27	1.34	1.34	1.32	1.12	1.12	1.11	1.12	1.12	1.11
Multifamily	0.33	0.47	0.47	0.45	0.49	0.49	0.49	0.57	0.56	0.56
Mobile Home Shipments	0.19	0.37	0.37	0.37	0.32	0.32	0.33	0.33	0.33	0.33
Commercial Floorspace, Total (billion square feet)	**70.2**	**82.0**	**82.0**	**82.0**	**94.6**	**94.6**	**94.4**	**100.8**	**100.9**	**100.7**
Value of Shipments (billion 1996 dollars)										
Total Industrial	5425	6977	6973	6927	8969	8972	8892	10128	10115	9988
Nonmanufacturing	1346	1510	1509	1499	1744	1740	1715	1870	1863	1829
Manufacturing	4079	5466	5464	5428	7226	7231	7177	8258	8253	8159
Energy-Intensive Manufacturing	1086	1264	1262	1256	1451	1450	1436	1538	1534	1515
Non-Energy-Intensive Manufacturing	2993	4203	4202	4173	5774	5781	5741	6720	6718	6644
United Sales of Light-Duty Vehicles	**17.11**	**18.29**	**18.28**	**17.98**	**20.02**	**20.08**	**20.14**	**20.00**	**19.98**	**19.96**
Population (millions)										
Population with Armed Forces Overseas	278.2	300.2	300.2	300.2	325.3	325.3	325.3	338.2	338.2	338.2
Population (aged 16 and over)	215.4	236.6	236.6	236.6	256.5	256.5	256.5	266.6	266.6	266.6
Employment, Non-Agriculture	131.7	147.3	147.2	147.1	159.1	159.2	159.0	165.8	165.8	165.5
Employment, Manufacturing	17.5	17.7	17.7	17.7	17.8	17.8	17.8	18.5	18.5	18.4
Labor Force	141.8	156.5	156.5	156.5	169.8	169.8	169.7	177.4	177.4	177.3

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2001: Global Insight macroeconomic model CTL0802. **Projections:** Energy Information Administration, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HT.D052003C, and ML_HT.D050503A.

Table G1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Production							
Crude Oil and Lease Condensate	12.29	11.92	11.92	11.45	11.47	11.15	11.16
Natural Gas Plant Liquids	2.65	3.21	3.21	3.75	3.74	3.84	3.92
Dry Natural Gas	19.97	22.81	22.74	27.33	27.23	28.06	28.63
Coal	23.97	22.57	22.01	10.46	8.04	6.82	3.90
Nuclear Power	8.03	8.37	8.37	9.75	8.40	12.39	8.40
Renewable Energy[1]	5.32	9.03	9.21	14.68	17.08	16.22	19.56
Other[2]	0.57	0.82	0.82	0.62	0.58	0.59	0.45
Total	**72.80**	**78.73**	**78.27**	**78.04**	**76.54**	**79.06**	**76.01**
Imports							
Crude Oil[3]	20.26	24.88	24.88	26.92	26.87	27.72	27.57
Petroleum Products[4]	5.04	5.73	5.63	8.82	8.54	10.43	10.10
Natural Gas	4.18	5.53	5.62	9.37	9.87	11.48	11.96
Other Imports[5]	0.71	0.81	0.81	0.94	1.00	0.79	0.92
Total	**30.19**	**36.94**	**36.94**	**46.05**	**46.27**	**50.42**	**50.54**
Exports							
Petroleum[6]	2.01	2.21	2.22	2.29	2.29	2.32	2.30
Natural Gas	0.37	0.57	0.56	0.37	0.36	0.36	0.35
Coal	1.27	0.84	0.84	0.76	0.80	0.61	0.68
Total	**3.64**	**3.61**	**3.62**	**3.42**	**3.45**	**3.29**	**3.34**
Discrepancy[7]	**2.06**	**0.39**	**0.07**	**0.18**	**0.25**	**0.22**	**0.31**
Consumption							
Petroleum Products[8]	38.46	43.74	43.63	48.65	48.28	50.76	50.17
Natural Gas	23.26	28.12	28.16	36.69	37.08	39.54	40.59
Coal	22.02	22.00	21.73	10.23	7.71	6.74	3.73
Nuclear Power	8.03	8.37	8.37	9.75	8.40	12.39	8.40
Renewable Energy[1]	5.32	9.03	9.21	14.68	17.08	16.22	19.56
Other[9]	0.21	0.43	0.43	0.50	0.55	0.32	0.45
Total	**97.29**	**111.67**	**111.53**	**120.50**	**119.10**	**125.97**	**122.90**
Net Imports - Petroleum	**23.29**	**28.40**	**28.29**	**33.45**	**33.12**	**35.83**	**35.36**
Prices (2001 dollars per unit)							
World Oil Price (dollars per barrel)[10]	22.01	23.77	23.75	24.15	24.05	24.58	24.18
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.12	3.51	3.49	3.97	3.99	4.36	4.70
Coal Minemouth Price (dollars per ton)	17.59	15.84	15.83	15.27	14.86	13.67	13.40
Average Electricity Price (cents per kilowatthour)	7.3	7.0	7.0	8.8	9.1	9.8	10.7

[1] Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table G18 for selected nonmarketed residential and commercial renewable energy.

[2] Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.

[3] Includes imports of crude oil for the Strategic Petroleum Reserve.

[4] Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.

[5] Includes coal, coal coke (net), and electricity (net).

[6] Includes crude oil and petroleum products.

[7] Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.

[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.

[9] Includes net electricity imports, methanol, and liquid hydrogen.

[10] Average refiner acquisition cost for imported crude oil.

[11] Represents lower 48 onshore and offshore supplies.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Energy Consumption							
Residential							
Distillate Fuel	0.91	0.91	0.91	0.84	0.84	0.81	0.81
Kerosene	0.10	0.08	0.08	0.06	0.06	0.06	0.06
Liquefied Petroleum Gas	0.50	0.47	0.47	0.47	0.47	0.47	0.47
Petroleum Subtotal	1.50	1.46	1.46	1.37	1.38	1.33	1.34
Natural Gas	4.94	5.62	5.62	5.96	5.96	6.20	6.20
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.41	0.41	0.40	0.40	0.40	0.40
Electricity	4.10	4.88	4.87	5.05	4.98	5.11	4.97
Delivered Energy	**10.94**	**12.38**	**12.37**	**12.80**	**12.73**	**13.06**	**12.92**
Electricity Related Losses	9.15	10.11	10.11	9.29	8.96	9.26	8.56
Total	**20.08**	**22.50**	**22.48**	**22.09**	**21.69**	**22.32**	**21.48**
Commercial							
Distillate Fuel	0.46	0.51	0.51	0.54	0.55	0.56	0.57
Residual Fuel	0.09	0.04	0.04	0.05	0.05	0.05	0.05
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.09	0.10	0.10
Motor Gasoline[2]	0.05	0.03	0.03	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.71	0.70	0.70	0.75	0.75	0.76	0.78
Natural Gas	3.33	3.74	3.73	4.27	4.32	4.97	5.13
Coal	0.09	0.10	0.10	0.11	0.11	0.11	0.11
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.08	4.97	4.96	5.66	5.60	5.97	5.86
Delivered Energy	**8.32**	**9.60**	**9.60**	**10.89**	**10.89**	**11.92**	**11.99**
Electricity Related Losses	9.12	10.30	10.30	10.42	10.07	10.82	10.10
Total	**17.44**	**19.90**	**19.90**	**21.31**	**20.96**	**22.74**	**22.08**
Industrial[4]							
Distillate Fuel	1.13	1.20	1.20	1.30	1.29	1.36	1.36
Liquefied Petroleum Gas	2.10	2.54	2.53	2.99	3.00	3.14	3.49
Petrochemical Feedstock	1.14	1.41	1.41	1.53	1.52	1.57	1.56
Residual Fuel	0.23	0.18	0.18	0.17	0.17	0.17	0.17
Motor Gasoline[2]	0.15	0.17	0.17	0.18	0.18	0.19	0.19
Other Petroleum[5]	4.03	4.18	4.16	4.09	4.05	4.12	3.96
Petroleum Subtotal	8.79	9.67	9.64	10.26	10.21	10.55	10.72
Natural Gas	7.74	9.16	9.18	10.36	10.39	11.09	10.65
Lease and Plant Fuel[6]	1.20	1.40	1.40	1.70	1.70	1.77	1.79
Natural Gas Subtotal	8.94	10.56	10.58	12.06	12.09	12.86	12.44
Metallurgical Coal	0.72	0.65	0.65	0.47	0.47	0.39	0.39
Steam Coal	1.42	1.33	1.32	1.28	1.26	1.26	1.20
Net Coal Coke Imports	0.03	0.11	0.11	0.18	0.18	0.21	0.21
Coal Subtotal	2.16	2.09	2.08	1.93	1.90	1.87	1.80
Renewable Energy[7]	1.82	2.21	2.21	2.74	2.74	3.02	3.02
Electricity	3.39	3.89	3.87	4.41	4.39	4.66	4.64
Delivered Energy	**25.10**	**28.41**	**28.38**	**31.40**	**31.33**	**32.96**	**32.63**
Electricity Related Losses	7.57	8.06	8.04	8.12	7.89	8.45	8.00
Total	**32.67**	**36.47**	**36.42**	**39.53**	**39.22**	**41.40**	**40.62**

Table G2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Transportation							
Distillate Fuel[8]	5.44	7.01	7.00	8.30	8.26	8.98	8.89
Jet Fuel[9]	3.43	3.91	3.90	5.01	5.01	5.56	5.56
Motor Gasoline[2]	16.26	19.58	19.53	21.55	21.25	22.10	21.41
Residual Fuel	0.84	0.83	0.83	0.85	0.85	0.86	0.86
Liquefied Petroleum Gas	0.02	0.05	0.05	0.08	0.08	0.09	0.08
Other Petroleum[10]	0.24	0.26	0.26	0.30	0.30	0.32	0.32
Petroleum Subtotal	26.22	31.64	31.57	36.09	35.75	37.91	37.11
Pipeline Fuel Natural Gas	0.63	0.81	0.81	1.05	1.05	1.11	1.14
Compressed Natural Gas	0.01	0.06	0.06	0.09	0.09	0.10	0.09
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Electricity	0.07	0.09	0.09	0.12	0.12	0.13	0.13
Delivered Energy	**26.94**	**32.61**	**32.53**	**37.36**	**37.01**	**39.25**	**38.49**
Electricity Related Losses	0.17	0.19	0.19	0.22	0.21	0.24	0.23
Total	**27.10**	**32.80**	**32.72**	**37.58**	**37.23**	**39.50**	**38.72**
Delivered Energy Consumption for All Sectors							
Distillate Fuel	7.94	9.64	9.62	10.99	10.95	11.71	11.64
Kerosene	0.15	0.12	0.12	0.11	0.11	0.10	0.10
Jet Fuel[9]	3.43	3.91	3.90	5.01	5.01	5.56	5.56
Liquefied Petroleum Gas	2.70	3.16	3.15	3.63	3.63	3.78	4.13
Motor Gasoline[2]	16.46	19.78	19.73	21.77	21.47	22.33	21.63
Petrochemical Feedstock	1.14	1.41	1.41	1.53	1.52	1.57	1.56
Residual Fuel	1.15	1.05	1.05	1.07	1.06	1.08	1.07
Other Petroleum[12]	4.24	4.41	4.40	4.36	4.33	4.42	4.25
Petroleum Subtotal	37.21	43.48	43.38	48.47	48.09	50.55	49.95
Natural Gas	16.02	18.57	18.59	20.68	20.76	22.36	22.07
Lease and Plant Fuel Plant[6]	1.20	1.40	1.40	1.70	1.70	1.77	1.79
Pipeline Natural Gas	0.63	0.81	0.81	1.05	1.05	1.11	1.14
Natural Gas Subtotal	17.86	20.78	20.79	23.43	23.50	25.23	25.00
Metallurgical Coal	0.72	0.65	0.65	0.47	0.47	0.39	0.39
Steam Coal	1.53	1.44	1.43	1.40	1.38	1.39	1.33
Net Coal Coke Imports	0.03	0.11	0.11	0.18	0.18	0.21	0.21
Coal Subtotal	2.27	2.20	2.19	2.05	2.03	1.99	1.93
Renewable Energy[13]	2.31	2.72	2.72	3.26	3.26	3.53	3.53
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Electricity	11.65	13.82	13.80	15.24	15.10	15.87	15.60
Delivered Energy	**71.29**	**83.01**	**82.88**	**92.45**	**91.97**	**97.19**	**96.03**
Electricity Related Losses	26.00	28.66	28.65	28.05	27.13	28.78	26.88
Total	**97.29**	**111.67**	**111.53**	**120.50**	**119.10**	**125.97**	**122.90**
Electric Power[14]							
Distillate Fuel	0.17	0.07	0.07	0.05	0.05	0.06	0.07
Residual Fuel	1.08	0.19	0.18	0.14	0.14	0.14	0.15
Petroleum Subtotal	1.25	0.26	0.26	0.19	0.19	0.21	0.22
Natural Gas	5.40	7.33	7.36	13.25	13.58	14.30	15.58
Steam Coal	19.75	19.79	19.55	8.18	5.69	4.74	1.80
Nuclear Power	8.03	8.37	8.37	9.75	8.40	12.39	8.40
Renewable Energy[15]	3.01	6.30	6.49	11.42	13.82	12.69	16.03
Electricity Imports	0.21	0.43	0.43	0.50	0.55	0.32	0.45
Total	**37.65**	**42.48**	**42.45**	**43.29**	**42.23**	**44.65**	**42.48**

Table G2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Total Energy Consumption							
Distillate Fuel	8.10	9.71	9.69	11.04	11.00	11.77	11.71
Kerosene	0.15	0.12	0.12	0.11	0.11	0.10	0.10
Jet Fuel[9]	3.43	3.91	3.90	5.01	5.01	5.56	5.56
Liquefied Petroleum Gas	2.70	3.16	3.15	3.63	3.63	3.78	4.13
Motor Gasoline[2]	16.46	19.78	19.73	21.77	21.47	22.33	21.63
Petrochemical Feedstock	1.14	1.41	1.41	1.53	1.52	1.57	1.56
Residual Fuel	2.23	1.24	1.23	1.20	1.21	1.22	1.23
Other Petroleum[12]	4.24	4.41	4.40	4.36	4.33	4.42	4.25
Petroleum Subtotal	38.46	43.74	43.63	48.65	48.28	50.76	50.17
Natural Gas	21.42	25.91	25.95	33.94	34.34	36.67	37.66
Lease and Plant Fuel[6]	1.20	1.40	1.40	1.70	1.70	1.77	1.79
Pipeline Natural Gas	0.63	0.81	0.81	1.05	1.05	1.11	1.14
Natural Gas Subtotal	23.26	28.12	28.16	36.69	37.08	39.54	40.59
Metallurgical Coal	0.72	0.65	0.65	0.47	0.47	0.39	0.39
Steam Coal	21.28	21.24	20.98	9.58	7.06	6.13	3.12
Net Coal Coke Imports	0.03	0.11	0.11	0.18	0.18	0.21	0.21
Coal Subtotal	22.02	22.00	21.73	10.23	7.71	6.74	3.73
Nuclear Power	8.03	8.37	8.37	9.75	8.40	12.39	8.40
Renewable Energy[16]	5.32	9.03	9.21	14.68	17.08	16.22	19.56
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Electricity Imports	0.21	0.43	0.43	0.50	0.55	0.32	0.45
Total	**97.29**	**111.67**	**111.53**	**120.50**	**119.10**	**125.97**	**122.90**
Energy Use and Related Statistics							
Delivered Energy Use	71.29	83.01	82.88	92.45	91.97	97.19	96.03
Total Energy Use	97.29	111.67	111.53	120.50	119.10	125.97	122.90
Population (millions)	278.18	300.24	300.24	325.32	325.32	338.24	338.24
Gross Domestic Product (billion 1996 dollars)	9215	12211	12203	16364	16370	18810	18821
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1558.6	1710.1	1702.7	1568.5	1553.0	1482.2	1533.9

[1] Includes wood used for residential heating. See Table G18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.

[2] Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.

[3] Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table G18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.

[4] Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.

[5] Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.

[6] Represents natural gas used in the field gathering and processing plant machinery.

[7] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.

[8] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.

[9] Includes only kerosene type.

[10] Includes aviation gasoline and lubricants.

[11] E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).

[12] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.

[13] Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

[14] Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[15] Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.

[16] Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.

Sources: 2001 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 population and gross domestic product: Global Insight macroeconomic model CTL0802. 2001 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G3. Delivered Energy Prices by Sector and Source

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Residential	**15.81**	**14.62**	**14.73**	**17.37**	**17.66**	**18.74**	**19.78**
Primary Energy[1]	9.73	8.11	8.11	8.48	8.46	8.88	9.09
Petroleum Products[2]	10.85	9.88	9.94	10.32	10.24	10.79	10.59
Distillate Fuel	8.99	7.95	7.95	8.23	8.14	8.58	8.38
Liquefied Petroleum Gas	14.84	13.97	14.20	14.44	14.40	14.96	14.79
Natural Gas	9.41	7.67	7.65	8.07	8.06	8.48	8.78
Electricity	25.37	24.10	24.37	30.32	31.24	33.29	36.03
Commercial	**15.50**	**14.35**	**14.46**	**17.78**	**18.15**	**19.27**	**20.49**
Primary Energy[1]	7.81	6.50	6.49	6.93	6.91	7.33	7.56
Petroleum Products[2]	7.27	6.70	6.72	6.96	6.87	7.28	7.06
Distillate Fuel	6.40	5.63	5.62	5.96	5.87	6.30	6.10
Residual Fuel	3.46	3.93	3.93	3.96	3.95	4.02	3.96
Natural Gas	8.09	6.59	6.57	7.07	7.06	7.48	7.78
Electricity	23.28	21.51	21.73	27.61	28.54	30.97	33.77
Industrial[3]	**7.11**	**6.61**	**6.66**	**7.80**	**7.87**	**8.45**	**9.02**
Primary Energy	5.83	5.16	5.19	5.65	5.63	5.97	6.16
Petroleum Products[2]	7.72	6.93	7.00	7.40	7.34	7.68	7.65
Distillate Fuel	6.55	5.71	5.70	6.18	6.09	6.53	6.34
Liquefied Petroleum Gas	12.34	9.58	9.80	10.14	10.09	10.60	10.46
Residual Fuel	3.28	3.66	3.65	3.70	3.68	3.77	3.71
Natural Gas[4]	4.87	4.11	4.09	4.68	4.68	5.07	5.42
Metallurgical Coal	1.69	1.51	1.51	1.40	1.40	1.34	1.33
Steam Coal	1.46	1.38	1.38	1.14	1.10	1.04	0.96
Electricity	14.13	14.34	14.56	18.65	19.30	20.86	23.19
Transportation	**10.28**	**11.73**	**11.88**	**13.27**	**13.46**	**14.17**	**15.29**
Primary Energy	10.25	11.70	11.86	13.24	13.42	14.12	15.24
Petroleum Products[2]	10.25	11.71	11.87	13.25	13.43	14.14	15.26
Distillate Fuel[5]	10.05	11.71	11.90	13.17	13.48	14.37	15.80
Jet Fuel[6]	6.20	7.10	7.26	9.26	9.56	10.35	11.63
Motor Gasoline[7]	11.57	12.98	13.13	14.52	14.64	15.31	16.29
Residual Fuel	3.90	5.19	5.37	7.36	7.74	8.32	9.87
Liquefied Petroleum Gas[8]	16.93	16.35	16.69	18.30	18.56	19.15	20.18
Natural Gas[9]	7.65	7.25	7.20	7.72	7.69	8.08	8.39
Electricity	21.87	20.82	21.08	24.39	25.14	26.05	28.48
Average End-Use Energy	**10.75**	**10.87**	**10.98**	**12.73**	**12.91**	**13.71**	**14.67**
Primary Energy	8.52	8.82	8.90	9.90	9.97	10.52	11.16
Electricity	21.34	20.40	20.64	25.89	26.72	28.70	31.30
Electric Power[10]							
Fossil Fuel Average	2.14	1.97	1.97	3.36	3.69	4.13	5.09
Petroleum Products	4.73	4.49	4.52	5.02	4.94	5.18	5.05
Distillate Fuel	6.20	5.01	5.00	5.39	5.30	5.64	5.52
Residual Fuel	4.50	4.29	4.33	4.88	4.82	4.98	4.84
Natural Gas	4.78	4.07	4.05	4.79	4.81	5.19	5.58
Steam Coal	1.25	1.16	1.16	0.99	0.97	0.90	0.84

Table G3. Delivered Energy Prices by Sector and Source (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Average Price to All Users[11]							
Petroleum Products[2]	9.54	10.54	10.67	11.85	11.97	12.61	13.38
Distillate Fuel	9.16	10.25	10.38	11.58	11.79	12.64	13.65
Jet Fuel	6.20	7.10	7.26	9.26	9.56	10.35	11.63
Liquefied Petroleum Gas	12.85	10.43	10.65	10.93	10.89	11.40	11.21
Motor Gasoline[7]	11.57	12.97	13.11	14.49	14.60	15.27	16.23
Residual Fuel	4.11	4.79	4.92	6.42	6.68	7.12	8.16
Natural Gas	6.40	5.24	5.22	5.63	5.63	6.03	6.37
Coal	1.26	1.17	1.17	1.02	1.00	0.94	0.89
Electricity	21.34	20.40	20.64	25.89	26.72	28.70	31.30
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)							
Residential	166.77	175.14	176.22	215.33	217.83	237.11	247.65
Commercial	127.30	136.28	137.25	191.81	195.72	227.72	243.40
Industrial	135.32	141.86	142.86	185.88	187.75	212.44	225.88
Transportation	270.41	372.90	376.95	481.84	483.97	540.27	570.97
Total Non-Renewable Expenditures	699.80	826.18	833.29	1074.86	1085.26	1217.53	1287.91
Transportation Renewable Expenditures	0.01	0.05	0.05	0.11	0.11	0.15	0.16
Total Expenditures	**699.81**	**826.23**	**833.34**	**1074.97**	**1085.37**	**1217.69**	**1288.07**

[1] Weighted average price includes fuels below as well as coal.

[2] This quantity is the weighted average for all petroleum products, not just those listed below.

[3] Includes combined heat and power, which produces electricity and other useful thermal energy.

[4] Excludes use for lease and plant fuel.

[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.

[6] Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.

[7] Sales weighted-average price for all grades. Includes Federal, State and local taxes.

[8] Includes Federal and State taxes while excluding county and local taxes.

[9] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.

[10] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

[11] Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.

Btu = British thermal unit.

Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G4. Greenhouse Gas Allowance Cost by End-Use Sector and Source

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Commercial							
Petroleum Products[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residual Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[3]							
Petroleum Products[2]	0.00	0.94	1.04	2.15	2.38	2.66	3.63
Distillate Fuel	0.00	1.56	1.72	3.52	3.90	4.36	5.86
Liquefied Petroleum Gas	0.00	1.35	1.49	3.05	3.37	3.77	5.07
Residual Fuel	0.00	1.68	1.86	3.80	4.20	4.70	6.31
Natural Gas[4]	0.00	1.11	1.23	2.52	2.79	3.12	4.19
Metallurgical Coal	0.00	2.00	2.21	4.51	4.99	5.58	7.50
Steam Coal	0.00	2.00	2.21	4.53	5.01	5.60	7.53
Electric Power[5]							
Fossil Fuel Average	0.00	1.78	1.96	3.32	3.49	3.80	4.63
Petroleum Products	0.00	1.65	1.82	3.72	4.12	4.60	6.17
Distillate Fuel	0.00	1.56	1.72	3.52	3.90	4.36	5.86
Residual Fuel	0.00	1.68	1.86	3.80	4.20	4.70	6.31
Natural Gas	0.00	1.14	1.26	2.57	2.84	3.18	4.27
Steam Coal	0.00	2.02	2.23	4.54	5.02	5.62	7.53
Average Allowance Cost to All Users[6]							
Petroleum Products[2]	0.00	0.22	0.25	0.48	0.53	0.59	0.83
Distillate Fuel	0.00	0.20	0.23	0.43	0.48	0.53	0.72
Jet Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquefied Petroleum Gas	0.00	1.09	1.20	2.51	2.78	3.13	4.28
Motor Gasoline	0.00	0.01	0.01	0.03	0.03	0.04	0.05
Residual Fuel	0.00	0.50	0.54	0.98	1.09	1.21	1.65
Natural Gas	0.00	0.72	0.80	1.78	1.97	2.19	2.96
Coal	0.00	2.00	2.22	4.48	4.93	5.50	7.23

[1] Weighted average allowance cost includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3] Includes combined heat and power, which produces electricity and other useful thermal energy.
[4] Excludes use for lease and plant fuel.
[5] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[6] Weighted averages of allowance cost are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Projections: EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G5. Energy Prices by Sector and Source with Greenhouse Gas Allowance Cost

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Residential	**15.81**	**14.62**	**14.73**	**17.37**	**17.66**	**18.74**	**19.78**
Primary Energy[1]	9.73	8.11	8.11	8.48	8.46	8.88	9.09
Petroleum Products[2]	10.85	9.88	9.94	10.32	10.24	10.79	10.59
Distillate Fuel	8.99	7.95	7.95	8.23	8.14	8.58	8.38
Liquefied Petroleum Gas	14.84	13.97	14.20	14.44	14.40	14.96	14.79
Natural Gas	9.41	7.67	7.65	8.07	8.06	8.48	8.78
Electricity	25.37	24.10	24.37	30.32	31.24	33.29	36.03
Commercial	**15.50**	**14.35**	**14.46**	**17.78**	**18.15**	**19.27**	**20.49**
Primary Energy[1]	7.81	6.50	6.49	6.93	6.91	7.33	7.56
Petroleum Products[2]	7.27	6.70	6.72	6.96	6.87	7.28	7.06
Distillate Fuel	6.40	5.63	5.62	5.96	5.87	6.30	6.10
Residual Fuel	3.46	3.93	3.93	3.96	3.95	4.02	3.96
Natural Gas	8.09	6.59	6.57	7.07	7.06	7.48	7.78
Electricity	23.28	21.51	21.73	27.61	28.54	30.97	33.77
Industrial[3]	**7.11**	**7.55**	**7.70**	**9.89**	**10.19**	**11.03**	**12.48**
Primary Energy	5.83	6.28	6.43	8.16	8.40	9.06	10.32
Petroleum Products[2]	7.72	7.87	8.04	9.55	9.71	10.34	11.28
Distillate Fuel	6.55	7.27	7.43	9.70	9.99	10.89	12.20
Liquefied Petroleum Gas	12.34	10.93	11.29	13.19	13.46	14.38	15.53
Residual Fuel	3.28	5.34	5.51	7.49	7.88	8.46	10.02
Natural Gas[4]	4.87	5.23	5.33	7.20	7.47	8.19	9.61
Metallurgical Coal	1.69	3.50	3.72	5.91	6.39	6.92	8.84
Steam Coal	1.46	3.38	3.60	5.67	6.10	6.64	8.48
Electricity	14.13	14.34	14.56	18.65	19.30	20.86	23.19
Transportation	**10.28**	**11.73**	**11.89**	**13.28**	**13.47**	**14.17**	**15.30**
Primary Energy	10.25	11.70	11.86	13.24	13.43	14.13	15.25
Petroleum Products[2]	10.25	11.71	11.87	13.25	13.43	14.14	15.26
Distillate Fuel[5]	10.05	11.71	11.90	13.17	13.48	14.37	15.80
Jet Fuel[6]	6.20	7.10	7.26	9.26	9.56	10.35	11.63
Motor Gasoline[7]	11.57	12.98	13.13	14.52	14.64	15.31	16.29
Residual Fuel	3.90	5.19	5.37	7.36	7.74	8.32	9.87
Liquefied Petroleum Gas[8]	16.93	16.35	16.69	18.30	18.56	19.15	20.18
Natural Gas[9]	7.65	8.38	8.46	10.29	10.53	11.26	12.66
Electricity	21.87	20.82	21.08	24.39	25.14	26.05	28.48
Average End-Use Energy	**10.75**	**11.17**	**11.31**	**13.38**	**13.64**	**14.50**	**15.75**
Primary Energy	8.52	9.18	9.30	10.70	10.85	11.49	12.46
Electricity	21.34	20.40	20.64	25.89	26.72	28.70	31.30
Electric Power[10]							
Fossil Fuel Average	2.14	3.75	3.93	6.68	7.18	7.93	9.72
Petroleum Products	4.73	6.13	6.34	8.74	9.06	9.77	11.22
Distillate Fuel	6.20	6.57	6.73	8.91	9.20	9.99	11.38
Residual Fuel	4.50	5.97	6.19	8.68	9.02	9.68	11.15
Natural Gas	4.78	5.20	5.31	7.36	7.65	8.37	9.85
Steam Coal	1.25	3.17	3.39	5.53	5.98	6.53	8.37

Table G5. Energy Prices by Sector and Source with Greenhouse Gas Allowance Cost (Continued)
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Average Price to All Users[11]							
Petroleum Products[2]	9.54	10.76	10.92	12.34	12.50	13.20	14.20
Distillate Fuel	9.16	10.45	10.60	12.01	12.26	13.17	14.37
Jet Fuel	6.20	7.10	7.26	9.26	9.56	10.35	11.63
Liquefied Petroleum Gas	12.85	11.51	11.85	13.44	13.67	14.52	15.48
Motor Gasoline[7]	11.57	12.98	13.13	14.52	14.63	15.31	16.28
Residual Fuel	4.11	5.29	5.46	7.39	7.76	8.33	9.82
Natural Gas	6.40	5.96	6.01	7.41	7.60	8.22	9.33
Coal	1.26	3.18	3.39	5.50	5.92	6.44	8.12
Electricity	21.34	20.40	20.64	25.89	26.72	28.70	31.30
Non-Renewable Energy and Allowance Expenditures by Sector (billion 2001 dollars)							
Residential	166.77	175.14	176.22	215.33	217.83	237.11	247.65
Commercial	127.30	136.28	137.25	191.81	195.72	227.72	243.40
Industrial	135.32	162.27	165.40	235.92	242.98	277.18	312.88
Transportation	270.41	372.97	377.02	482.08	484.24	540.60	571.41
Total Non-Renewable Expenditures	699.80	846.66	855.90	1125.14	1140.76	1282.60	1375.34
Transportation Renewable Expenditures	0.01	0.05	0.05	0.12	0.12	0.16	0.17
Total Expenditures	**699.81**	**846.72**	**855.96**	**1125.26**	**1140.88**	**1282.76**	**1375.51**

[1] Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3] Includes combined heat and power, which produces electricity and other useful thermal energy.
[4] Excludes use for lease and plant fuel.
[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6] Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7] Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8] Includes Federal and State taxes while excluding county and local taxes.
[9] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[10] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[11] Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G6. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Key Indicators							
Households (millions)							
Single-Family	77.50	86.14	86.13	93.99	93.97	97.43	97.41
Multifamily	22.19	24.13	24.13	26.99	26.98	28.71	28.70
Mobile Homes	6.57	7.10	7.10	7.86	7.86	8.11	8.11
Total	**106.27**	**117.37**	**117.36**	**128.83**	**128.81**	**134.25**	**134.23**
Average House Square Footage	**1685**	**1740**	**1740**	**1782**	**1782**	**1798**	**1798**
Energy Intensity							
(million Btu per household)							
Delivered Energy Consumption	102.9	105.5	105.4	99.3	98.9	97.3	96.3
Total Energy Consumption	189.0	191.7	191.6	171.4	168.4	166.3	160.0
(thousand Btu per square foot)							
Delivered Energy Consumption	61.1	60.7	60.6	55.7	55.5	54.1	53.5
Total Energy Consumption	112.2	110.2	110.1	96.2	94.5	92.5	89.0
Delivered Energy Consumption by Fuel							
Electricity							
Space Heating	0.39	0.46	0.46	0.46	0.45	0.45	0.44
Space Cooling	0.52	0.60	0.60	0.59	0.59	0.59	0.58
Water Heating	0.45	0.46	0.46	0.38	0.37	0.33	0.32
Refrigeration	0.42	0.34	0.34	0.32	0.32	0.33	0.33
Cooking	0.10	0.11	0.11	0.12	0.12	0.13	0.13
Clothes Dryers	0.22	0.24	0.24	0.25	0.25	0.25	0.25
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.91	0.91	0.81	0.78	0.74	0.68
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers[1]	0.02	0.02	0.02	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.19	0.19	0.24	0.23	0.24	0.24
Personal Computers	0.06	0.08	0.08	0.10	0.10	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.09	0.09	0.10	0.10
Other Uses[2]	0.83	1.25	1.24	1.54	1.53	1.69	1.65
Delivered Energy	**4.10**	**4.88**	**4.87**	**5.05**	**4.98**	**5.11**	**4.97**
Natural Gas							
Space Heating	3.13	3.69	3.69	3.97	3.96	4.11	4.10
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.48	1.55	1.55	1.58	1.58	1.62	1.61
Cooking	0.20	0.23	0.23	0.25	0.25	0.26	0.26
Clothes Dryers	0.06	0.08	0.08	0.10	0.10	0.10	0.10
Other Uses[3]	0.06	0.07	0.07	0.07	0.07	0.11	0.14
Delivered Energy	**4.94**	**5.62**	**5.62**	**5.96**	**5.96**	**6.20**	**6.20**
Distillate							
Space Heating	0.74	0.76	0.76	0.71	0.72	0.69	0.69
Water Heating	0.16	0.14	0.14	0.12	0.12	0.11	0.12
Other Uses[4]	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.91**	**0.91**	**0.91**	**0.84**	**0.84**	**0.81**	**0.81**
Liquefied Petroleum Gas							
Space Heating	0.26	0.25	0.25	0.24	0.24	0.24	0.24
Water Heating	0.09	0.07	0.07	0.06	0.06	0.06	0.06
Cooking	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Other Uses[3]	0.12	0.13	0.13	0.14	0.14	0.14	0.14
Delivered Energy	**0.50**	**0.47**	**0.47**	**0.47**	**0.47**	**0.47**	**0.47**
Marketed Renewables (wood)[5]	0.39	0.41	0.41	0.40	0.40	0.40	0.40
Other Fuels[6]	0.11	0.09	0.09	0.08	0.08	0.07	0.07

Table G6. Residential Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Delivered Energy Consumption by End-Use							
Space Heating	5.01	5.66	5.66	5.86	5.86	5.96	5.94
Space Cooling	0.52	0.60	0.60	0.59	0.59	0.59	0.58
Water Heating	2.19	2.23	2.23	2.14	2.14	2.13	2.11
Refrigeration	0.42	0.34	0.34	0.32	0.32	0.33	0.33
Cooking	0.33	0.36	0.36	0.39	0.39	0.40	0.40
Clothes Dryers	0.28	0.33	0.33	0.34	0.34	0.35	0.35
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.91	0.91	0.81	0.78	0.74	0.68
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers	0.02	0.02	0.02	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.19	0.19	0.24	0.23	0.24	0.24
Personal Computers	0.06	0.08	0.08	0.10	0.10	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.09	0.09	0.10	0.10
Other Uses[7]	1.01	1.45	1.44	1.76	1.74	1.94	1.93
Delivered Energy	**10.94**	**12.38**	**12.37**	**12.80**	**12.73**	**13.06**	**12.92**
Electricity Related Losses	**9.15**	**10.11**	**10.11**	**9.29**	**8.96**	**9.26**	**8.56**
Total Energy Consumption by End-Use							
Space Heating	5.89	6.61	6.60	6.70	6.67	6.78	6.70
Space Cooling	1.68	1.83	1.83	1.68	1.64	1.67	1.59
Water Heating	3.20	3.20	3.19	2.84	2.81	2.74	2.66
Refrigeration	1.36	1.05	1.05	0.91	0.90	0.93	0.90
Cooking	0.55	0.59	0.59	0.61	0.61	0.63	0.62
Clothes Dryers	0.78	0.84	0.84	0.80	0.78	0.81	0.78
Freezers	0.36	0.27	0.27	0.25	0.24	0.25	0.25
Lighting	2.40	2.81	2.80	2.31	2.19	2.09	1.84
Clothes Washers	0.10	0.10	0.10	0.08	0.08	0.08	0.08
Dishwashers	0.07	0.07	0.07	0.08	0.08	0.08	0.08
Color Televisions	0.43	0.60	0.60	0.67	0.66	0.68	0.65
Personal Computers	0.19	0.25	0.25	0.29	0.29	0.32	0.31
Furnace Fans	0.23	0.26	0.26	0.27	0.26	0.27	0.26
Other Uses[7]	2.86	4.03	4.03	4.59	4.49	4.99	4.77
Total	**20.08**	**22.50**	**22.48**	**22.09**	**21.69**	**22.32**	**21.48**
Non-Marketed Renewables							
Geothermal[8]	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar[9]	0.03	0.03	0.03	0.04	0.04	0.04	0.04
Total	**0.03**	**0.04**	**0.04**	**0.05**	**0.05**	**0.06**	**0.06**

[1] Does not include electric water heating portion of load.
[2] Includes small electric devices, heating elements, and motors.
[3] Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4] Includes such appliances as swimming pool and hot tub heaters.
[5] Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.
[6] Includes kerosene and coal.
[7] Includes all other uses listed above.
[8] Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9] Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G7. Commercial Sector Key Indicators and Consumption

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration and New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Key Indicators							
Total Floorspace (billion square feet)							
Surviving	66.6	79.0	79.0	90.8	90.8	97.1	97.2
New Additions	3.6	3.0	3.0	3.4	3.4	3.4	3.4
Total	**70.2**	**82.0**	**82.0**	**94.2**	**94.2**	**100.6**	**100.6**
Energy Consumption Intensity (thousand Btu per square foot)							
Delivered Energy Consumption	118.4	117.1	117.1	115.6	115.6	118.6	119.1
Electricity Related Losses	129.9	125.6	125.7	110.6	106.9	107.6	100.3
Total Energy Consumption	248.3	242.7	242.7	226.1	222.5	226.2	219.5
Delivered Energy Consumption by Fuel							
Purchased Electricity							
Space Heating[1]	0.14	0.15	0.15	0.14	0.14	0.13	0.13
Space Cooling[1]	0.43	0.42	0.42	0.41	0.41	0.40	0.38
Water Heating[1]	0.15	0.15	0.15	0.14	0.14	0.13	0.13
Ventilation	0.17	0.18	0.18	0.17	0.17	0.16	0.16
Cooking	0.03	0.03	0.03	0.03	0.03	0.02	0.02
Lighting	1.02	1.18	1.17	0.99	0.96	0.88	0.84
Refrigeration	0.21	0.24	0.24	0.24	0.24	0.23	0.23
Office Equipment (PC)	0.16	0.24	0.24	0.31	0.31	0.34	0.34
Office Equipment (non-PC)	0.31	0.47	0.47	0.72	0.72	0.87	0.86
Other Uses[2]	1.46	1.90	1.90	2.51	2.50	2.80	2.78
Delivered Energy	**4.08**	**4.97**	**4.96**	**5.66**	**5.60**	**5.97**	**5.86**
Natural Gas							
Space Heating[1]	1.32	1.53	1.53	1.58	1.57	1.56	1.53
Space Cooling[1]	0.01	0.02	0.02	0.03	0.03	0.03	0.03
Water Heating[1]	0.57	0.69	0.69	0.77	0.76	0.78	0.77
Cooking	0.25	0.30	0.30	0.33	0.33	0.35	0.35
Other Uses[3]	1.17	1.20	1.20	1.57	1.63	2.25	2.46
Delivered Energy	**3.33**	**3.74**	**3.73**	**4.27**	**4.32**	**4.97**	**5.13**
Distillate							
Space Heating[1]	0.17	0.23	0.23	0.27	0.27	0.28	0.28
Water Heating[1]	0.07	0.08	0.08	0.08	0.08	0.08	0.08
Other Uses[4]	0.22	0.20	0.20	0.20	0.20	0.20	0.21
Delivered Energy	**0.46**	**0.51**	**0.51**	**0.54**	**0.55**	**0.56**	**0.57**
Other Fuels[5]	**0.34**	**0.29**	**0.29**	**0.31**	**0.31**	**0.32**	**0.32**
Marketed Renewable Fuels							
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Energy	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Delivered Energy Consumption by End-Use							
Space Heating[1]	1.63	1.92	1.92	1.98	1.97	1.97	1.94
Space Cooling[1]	0.44	0.44	0.44	0.44	0.44	0.43	0.41
Water Heating[1]	0.79	0.92	0.92	0.99	0.98	0.99	0.98
Ventilation	0.17	0.18	0.18	0.17	0.17	0.16	0.16
Cooking	0.29	0.33	0.33	0.36	0.36	0.37	0.37
Lighting	1.02	1.18	1.17	0.99	0.96	0.88	0.84
Refrigeration	0.21	0.24	0.24	0.24	0.24	0.23	0.23
Office Equipment (PC)	0.16	0.24	0.24	0.31	0.31	0.34	0.34
Office Equipment (non-PC)	0.31	0.47	0.47	0.72	0.72	0.87	0.86
Other Uses[6]	3.30	3.69	3.69	4.69	4.74	5.68	5.87
Delivered Energy	**8.32**	**9.60**	**9.60**	**10.89**	**10.89**	**11.92**	**11.99**

Table G7. Commercial Sector Key Indicators and Consumption (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Electricity Related Losses	**9.12**	**10.30**	**10.30**	**10.42**	**10.07**	**10.82**	**10.10**
Total Energy Consumption by End-Use							
Space Heating[1]	1.95	2.24	2.23	2.24	2.22	2.20	2.15
Space Cooling[1]	1.39	1.32	1.32	1.21	1.17	1.15	1.07
Water Heating[1]	1.12	1.24	1.24	1.25	1.24	1.23	1.20
Ventilation	0.55	0.55	0.55	0.48	0.46	0.45	0.42
Cooking	0.37	0.40	0.40	0.41	0.41	0.41	0.41
Lighting	3.31	3.62	3.61	2.80	2.68	2.48	2.29
Refrigeration	0.69	0.73	0.73	0.68	0.66	0.66	0.62
Office Equipment (PC)	0.52	0.74	0.74	0.88	0.86	0.96	0.91
Office Equipment (non-PC)	0.99	1.43	1.44	2.06	2.02	2.45	2.34
Other Uses[6]	6.56	7.63	7.63	9.31	9.23	10.76	10.66
Total	**17.44**	**19.90**	**19.90**	**21.31**	**20.96**	**22.74**	**22.08**
Non-Marketed Renewable Fuels							
Solar[7]	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

[1] Includes fuel consumption for district services.

[2] Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.

[3] Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.

[4] Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.

[5] Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.

[6] Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.

[7] Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.

Btu = British thermal unit.

PC = Personal computer.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G8. Industrial Sector Key Indicators and Consumption

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Key Indicators							
Value of Shipments (billion 1996 dollars)							
Manufacturing	4079	5420	5412	7160	7156	8162	8152
Nonmanufacturing	1346	1500	1499	1714	1713	1828	1827
Total	**5425**	**6920**	**6912**	**8874**	**8869**	**9990**	**9979**
Energy Prices (2001 dollars per million Btu)							
Electricity	14.13	14.34	14.56	18.65	19.30	20.86	23.19
Natural Gas	4.87	5.23	5.33	7.20	7.47	8.19	9.61
Steam Coal	1.46	3.38	3.60	5.67	6.10	6.64	8.48
Residual Oil	3.28	5.34	5.51	7.49	7.88	8.46	10.02
Distillate Oil	6.55	7.27	7.43	9.70	9.99	10.89	12.20
Liquefied Petroleum Gas	12.34	10.93	11.29	13.19	13.46	14.38	15.53
Motor Gasoline	11.57	12.94	13.09	14.49	14.60	15.28	16.24
Metallurgical Coal	1.69	3.50	3.72	5.91	6.39	6.92	8.84
Energy Consumption[1]							
Purchased Electricity	3.39	3.89	3.87	4.41	4.39	4.66	4.64
Natural Gas	7.74	9.16	9.18	10.36	10.39	11.09	10.65
Lease and Plant Fuel[2]	1.20	1.40	1.40	1.70	1.70	1.77	1.79
Natural Gas Subtotal	8.94	10.56	10.58	12.06	12.09	12.86	12.44
Steam Coal	1.42	1.33	1.32	1.28	1.26	1.26	1.20
Metallurgical Coal and Coke[3]	0.74	0.76	0.76	0.65	0.65	0.60	0.60
Residual Fuel	0.23	0.18	0.18	0.17	0.17	0.17	0.17
Distillate	1.13	1.20	1.20	1.30	1.29	1.36	1.36
Liquefied Petroleum Gas	2.10	2.54	2.53	2.99	3.00	3.14	3.49
Petrochemical Feedstocks	1.14	1.41	1.41	1.53	1.52	1.57	1.56
Other Petroleum[4]	4.18	4.34	4.33	4.27	4.23	4.32	4.15
Renewables[5]	1.82	2.21	2.21	2.74	2.74	3.02	3.02
Delivered Energy	**25.10**	**28.41**	**28.38**	**31.40**	**31.33**	**32.96**	**32.63**
Electricity Related Losses	7.57	8.06	8.04	8.12	7.89	8.45	8.00
Total	**32.67**	**36.47**	**36.42**	**39.53**	**39.22**	**41.40**	**40.62**
Energy Consumption per dollar of Shipments[1] **(thousand Btu per 1996 dollars)**							
Purchased Electricity	0.63	0.56	0.56	0.50	0.49	0.47	0.47
Natural Gas	1.43	1.32	1.33	1.17	1.17	1.11	1.07
Lease and Plant Fuel[2]	0.22	0.20	0.20	0.19	0.19	0.18	0.18
Natural Gas Subtotal	1.65	1.53	1.53	1.36	1.36	1.29	1.25
Steam Coal	0.26	0.19	0.19	0.14	0.14	0.13	0.12
Metallurgical Coal and Coke[3]	0.14	0.11	0.11	0.07	0.07	0.06	0.06
Residual Fuel	0.04	0.03	0.03	0.02	0.02	0.02	0.02
Distillate	0.21	0.17	0.17	0.15	0.15	0.14	0.14
Liquefied Petroleum Gas	0.39	0.37	0.37	0.34	0.34	0.31	0.35
Petrochemical Feedstocks	0.21	0.20	0.20	0.17	0.17	0.16	0.16
Other Petroleum[4]	0.77	0.63	0.63	0.48	0.48	0.43	0.42
Renewables[5]	0.33	0.32	0.32	0.31	0.31	0.30	0.30
Delivered Energy	**4.63**	**4.11**	**4.11**	**3.54**	**3.53**	**3.30**	**3.27**
Electricity Related Losses	1.40	1.16	1.16	0.92	0.89	0.85	0.80
Total	**6.02**	**5.27**	**5.27**	**4.45**	**4.42**	**4.14**	**4.07**

[1] Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2] Represents natural gas used in the field gathering and processing plant machinery.
[3] Includes net coal coke imports.
[4] Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 coal prices are based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 consumption values based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 shipments: Global Insight macroeconomic model CTL0802. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G9. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Key Indicators							
Level of Travel (billions)							
Light-Duty Vehicles <8,500 pounds (VMT)	2409	2975	2966	3547	3516	3795	3708
Commercial Light Trucks (VMT)[1]	66	83	83	104	104	115	115
Freight Trucks >10,000 pounds (VMT)	206	263	263	335	335	377	377
Air (seat miles available)	1109	1348	1344	1928	1927	2231	2226
Rail (ton miles traveled)	1448	1579	1563	1467	1401	1486	1406
Domestic Shipping (ton miles traveled)	788	869	868	950	941	992	986
Energy Efficiency Indicators							
New Light-Duty Vehicle (miles per gallon)[2]	24.1	25.3	25.3	28.1	28.5	29.0	29.6
New Car (miles per gallon)[2]	28.1	28.8	28.8	32.6	33.0	32.9	33.4
New Light Truck (miles per gallon)[2]	20.7	22.5	22.5	24.6	25.0	25.8	26.2
Light-Duty Fleet (miles per gallon)[3]	19.8	19.6	19.6	20.9	21.1	21.8	22.0
New Commercial Light Truck (MPG)[1]	13.8	14.8	14.9	16.3	16.5	17.1	17.4
Stock Commercial Light Truck (MPG)[1]	13.7	14.3	14.3	15.4	15.5	16.2	16.4
Aircraft Efficiency (seat miles per gallon)	51.2	54.3	54.3	59.1	59.1	61.2	61.2
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.4	6.4	6.6	6.6
Rail Efficiency (ton miles per thousand Btu)	2.8	3.1	3.1	3.4	3.4	3.6	3.6
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.3	2.4	2.4	2.4	2.4
Energy Use by Mode (quadrillion Btu)							
Light-Duty Vehicles	15.28	18.86	18.81	20.99	20.68	21.55	20.83
Commercial Light Trucks[1]	0.60	0.73	0.73	0.84	0.84	0.89	0.87
Freight Trucks[4]	4.68	5.88	5.87	6.94	6.93	7.55	7.53
Air[5]	3.47	3.96	3.95	5.07	5.07	5.63	5.62
Rail[6]	0.63	0.65	0.64	0.59	0.57	0.59	0.56
Marine[7]	1.45	1.49	1.49	1.56	1.56	1.60	1.60
Pipeline Fuel	0.63	0.81	0.81	1.05	1.05	1.11	1.14
Lubricants	0.19	0.21	0.21	0.26	0.26	0.28	0.28
Total	**26.94**	**32.58**	**32.50**	**37.30**	**36.96**	**39.19**	**38.43**
Energy Use by Mode (million barrels per day oil equivalent)							
Light-Duty Vehicles	8.05	9.96	9.93	11.07	10.91	11.36	10.98
Commercial Light Trucks[1]	0.32	0.38	0.38	0.45	0.44	0.47	0.46
Freight Trucks	2.05	2.59	2.59	3.09	3.08	3.37	3.36
Railroad	0.24	0.24	0.24	0.20	0.19	0.19	0.18
Domestic Shipping	0.16	0.17	0.17	0.18	0.18	0.19	0.19
International Shipping	0.34	0.33	0.33	0.34	0.34	0.34	0.34
Air[5]	1.44	1.64	1.64	2.15	2.15	2.40	2.40
Military Use	0.30	0.34	0.34	0.38	0.38	0.40	0.40
Bus Transportation	0.12	0.13	0.13	0.13	0.13	0.13	0.13
Rail Transportation[6]	0.05	0.06	0.06	0.08	0.08	0.08	0.08
Recreational Boats	0.16	0.18	0.18	0.19	0.19	0.20	0.20
Lubricants	0.09	0.10	0.10	0.12	0.12	0.13	0.13
Pipeline Fuel	0.32	0.41	0.41	0.53	0.53	0.56	0.58
Total	**13.64**	**16.54**	**16.50**	**18.90**	**18.72**	**19.83**	**19.43**

[1] Commercial trucks 8,500 to 10,000 pounds.
[2] Environmental Protection Agency rated miles per gallon.
[3] Combined car and light truck "on-the-road" estimate.
[4] Includes energy use by buses and military distillate consumption.
[5] Includes jet fuel and aviation gasoline.
[6] Includes passenger rail.
[7] Includes military residual fuel use and recreational boats.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001); Federal Highway Administration, *Highway Statistics 2000* (Washington, DC, November 2001); Oak Ridge National Laboratory, Transportation Energy Data Book: *Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey" EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA,*State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2001/2000* (Washington, DC, 2001); EIA, *Fuel Oil and Kerosene Sales 2001*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/historical/foks.html; and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G10. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Generation by Fuel Type							
Electric Power Sector[1]							
Power Only[2]							
Coal	1848	1927	1905	836	569	526	174
Petroleum	113	19	19	11	12	13	15
Natural Gas[3]	411	811	815	1745	1821	1889	2117
Nuclear Power	769	801	801	934	804	1186	804
Pumped Storage/Other	-9	-1	-1	-1	-1	-1	-1
Renewable Sources[4]	258	517	527	991	1252	1122	1498
Distributed Generation (Natural Gas)	0	5	6	13	15	13	16
Non-Utility Generation for Own Use	-21	-26	-27	-26	-26	-25	-26
Total	**3370**	**4053**	**4046**	**4503**	**4445**	**4725**	**4598**
Combined Heat and Power[5]							
Coal	33	30	29	16	15	10	8
Petroleum	7	3	3	3	3	3	3
Natural Gas	124	161	162	131	141	115	147
Renewable Sources	5	4	4	4	4	4	4
Non-Utility Generation for Own Use	-9	-18	-18	-17	-16	-16	-16
Total	**162**	**181**	**181**	**138**	**147**	**116**	**146**
Net Available to the Grid	**3532**	**4234**	**4227**	**4641**	**4592**	**4841**	**4744**
End-Use Sector Generation							
Combined Heat and Power[6]							
Coal	23	23	23	23	23	23	23
Petroleum	6	6	6	6	6	6	7
Natural Gas	84	122	124	201	211	328	359
Other Gaseous Fuels[7]	6	7	7	7	7	7	7
Renewable Sources[4]	31	39	39	50	50	55	55
Other[8]	11	11	11	11	11	11	11
Total	**160**	**209**	**211**	**298**	**308**	**431**	**463**
Other End-Use Generators[9]	4	5	5	6	6	7	7
Generation for Own Use	-138	-173	-174	-241	-247	-328	-345
Total Sales to the Grid	**27**	**41**	**41**	**63**	**67**	**110**	**125**
Net Imports	**20**	**41**	**42**	**48**	**54**	**31**	**44**
Electricity Sales by Sector							
Residential	1201	1429	1427	1479	1461	1498	1456
Commercial	1197	1455	1454	1659	1642	1750	1718
Industrial	994	1139	1135	1293	1286	1366	1361
Transportation	22	27	27	35	35	39	39
Total	**3414**	**4050**	**4044**	**4467**	**4424**	**4653**	**4573**
End-Use Prices[10] (2001 cents per kilowatthour)							
Residential	8.7	8.2	8.3	10.3	10.7	11.4	12.3
Commercial	7.9	7.3	7.4	9.4	9.7	10.6	11.5
Industrial	4.8	4.9	5.0	6.4	6.6	7.1	7.9
Transportation	7.5	7.1	7.2	8.3	8.6	8.9	9.7
All Sectors Average	**7.3**	**7.0**	**7.0**	**8.8**	**9.1**	**9.8**	**10.7**
Prices by Service Category[10] (2001 cents per kilowatthour)							
Generation	4.7	4.4	4.5	6.1	6.4	7.1	8.0
Transmission	0.5	0.6	0.6	0.7	0.8	0.8	0.8
Distribution	2.0	2.0	2.0	2.0	2.0	2.0	2.0

Table G10. Electricity Supply, Disposition, Prices, and Emissions (Continued)

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Emissions							
Sulfur Dioxide (million tons)	10.63	9.84	9.56	5.87	4.64	1.93	1.63
Nitrogen Oxide (million tons)	4.75	3.50	3.46	1.48	1.21	0.67	0.57
Mercury (tons)	53.52	48.66	47.36	19.07	15.44	7.18	4.61

[1] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes plants that only produce electricity.

[3] Includes electricity generation from fuel cells.

[4] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.

[5] Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).

[6] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[7] Other gaseous fuels include refinery and still gas.

[8] Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.

[9] Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[10] Prices represent average revenue per kilowatthour.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Source: 2001 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and supporting databases. 2001 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2001 prices: EIA, National Energy Modeling System run MLBILL.D050503A. **Projections**: EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G11. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Electric Power Sector[2]							
Power Only[3]							
Coal Steam	305.3	289.0	288.9	209.3	182.9	139.9	106.2
Other Fossil Steam[4]	133.8	80.7	85.8	64.8	66.6	53.0	53.4
Combined Cycle	43.2	175.9	176.6	319.1	318.3	374.1	365.0
Combustion Turbine/Diesel	97.6	123.2	121.4	121.4	119.9	118.2	120.9
Nuclear Power[5]	98.2	100.3	100.3	117.2	100.7	149.2	100.7
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.2	0.2	0.2	0.2
Renewable Sources[6]	90.4	129.0	131.9	225.0	271.8	245.6	303.0
Distributed Generation[7]	0.0	1.7	2.0	4.9	4.3	5.0	6.3
Total	**788.3**	**920.2**	**927.4**	**1082.2**	**1085.0**	**1105.4**	**1076.0**
Combined Heat and Power[8]							
Coal Steam	5.2	4.4	4.3	3.3	3.0	2.6	3.0
Other Fossil Steam[4]	1.2	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	22.6	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	4.6	5.3	5.3	5.3	5.3	5.3	5.3
Renewable Sources[6]	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**33.7**	**44.0**	**43.9**	**42.9**	**42.6**	**42.2**	**42.6**
Total Electric Power Industry	**822.0**	**964.2**	**971.3**	**1125.1**	**1127.6**	**1147.6**	**1118.5**
Cumulative Planned Additions[9]							
Coal Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	83.1	83.1	83.1	83.1	83.1	83.1
Combustion Turbine/Diesel	0.0	31.5	31.5	31.5	31.5	31.5	31.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.1	0.2	0.2	0.2	0.2
Renewable Sources[6]	0.0	4.9	4.9	6.5	6.5	6.6	6.6
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**120.0**	**120.0**	**121.7**	**121.7**	**121.8**	**121.8**
Cumulative Unplanned Additions[9]							
Coal Steam	0.0	0.0	0.0	12.2	0.0	37.7	0.0
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	59.7	60.2	203.0	201.8	259.6	248.9
Combustion Turbine/Diesel	0.0	3.7	1.8	3.7	1.8	3.7	3.5
Nuclear Power	0.0	0.0	0.0	16.5	0.0	48.5	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	33.3	36.3	127.8	174.5	148.2	205.7
Distributed Generation[7]	0.0	1.7	2.0	4.9	4.3	5.0	6.3
Total	**0.0**	**98.4**	**100.3**	**368.1**	**382.6**	**502.8**	**464.3**
Cumulative Total Additions	**0.0**	**218.4**	**220.3**	**489.8**	**504.2**	**624.6**	**586.1**
Cumulative Retirements[10]							
Coal Steam	0.0	17.2	17.3	110.2	124.6	205.8	201.4
Other Fossil Steam[4]	0.0	51.6	46.5	67.5	65.7	79.3	78.9
Combined Cycle	0.0	0.9	0.6	0.9	0.6	2.6	0.9
Combustion Turbine/Diesel	0.0	9.1	9.1	10.9	10.6	14.2	11.2
Nuclear Power	0.0	0.8	0.8	1.8	1.8	1.8	1.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**79.7**	**74.4**	**191.4**	**203.4**	**303.8**	**294.3**

Table G11. Electricity Generating Capacity (Continued)

(Gigawatts)

Net Summer Capacity[1]	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
End-Use Sector							
Combined Heat and Power[11]							
Coal	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Petroleum	0.9	1.0	1.0	1.0	1.0	1.0	1.1
Natural Gas	14.6	19.4	19.6	30.1	31.6	48.7	53.9
Other Gaseous Fuels	2.1	2.2	2.2	2.2	2.2	2.2	2.2
Renewable Sources[6]	4.7	6.2	6.2	8.0	7.9	8.9	8.9
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.8**	**34.2**	**34.3**	**46.7**	**48.2**	**66.2**	**71.5**
Other End-Use Generators[12]							
Renewable Sources[13]	1.1	1.5	1.5	1.9	1.9	2.2	2.3
Cumulative Additions[9]							
Combined Heat and Power[11]	0.0	6.4	6.6	19.0	20.4	38.5	43.7
Other End-Use Generators[12]	0.0	0.4	0.4	0.7	0.8	1.1	1.2

[1] Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.

[2] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[3] Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.

[4] Includes oil-, gas-, and dual-fired capability.

[5] Nuclear capacity reflects operating capacity of existing units, including 4.3 gigawatts of uprates through 2025.

[6] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.

[7] Primarily peak-load capacity fueled by natural gas

[8] Includes combined heat and power plants whose primary business is to sell electricity and heat to the public(i.e., those that report NAICS code 22).

[9] Cumulative additions after December 31, 2001.

[10] Cumulative total retirements after December 31, 2001.

[11] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[12] Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[13] See Table G17 for more detail.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model estimates and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with capability for electric utility generators.

Source: 2001 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G12. Petroleum Supply and Disposition Balance

(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Crude Oil							
Domestic Crude Production[1]	5.80	5.63	5.63	5.41	5.42	5.27	5.27
Alaska	0.97	0.64	0.64	1.23	1.23	1.17	1.17
Lower 48 States	4.84	4.99	4.99	4.18	4.19	4.09	4.10
Net Imports	9.31	11.40	11.40	12.35	12.32	12.72	12.65
Gross Imports	9.33	11.46	11.46	12.40	12.38	12.77	12.70
Exports	0.02	0.06	0.06	0.05	0.05	0.05	0.05
Other Crude Supply[2]	0.02	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.13**	**17.03**	**17.03**	**17.76**	**17.74**	**17.99**	**17.92**
Natural Gas Plant Liquids	**1.87**	**2.27**	**2.26**	**2.63**	**2.62**	**2.69**	**2.74**
Other Inputs[3]	**0.30**	**0.43**	**0.43**	**0.36**	**0.34**	**0.35**	**0.28**
Refinery Processing Gain[4]	**0.90**	**0.89**	**0.90**	**0.94**	**0.93**	**0.93**	**0.92**
Net Product Imports[5]	**1.59**	**1.89**	**1.85**	**3.42**	**3.28**	**4.22**	**4.09**
Gross Refined Product Imports[6]	2.08	2.32	2.31	3.40	3.25	4.26	4.13
Unfinished Oil Imports	0.38	0.55	0.53	1.06	1.06	1.01	1.01
Ether Imports	0.08	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.95	0.98	0.99	1.03	1.03	1.05	1.05
Total Primary Supply[7]	**19.80**	**22.52**	**22.46**	**25.10**	**24.91**	**26.17**	**25.96**
Refined Petroleum Products Supplied							
Motor Gasoline[8]	8.67	10.42	10.39	11.47	11.31	11.76	11.39
Jet Fuel[9]	1.66	1.89	1.88	2.42	2.42	2.69	2.69
Distillate Fuel[10]	3.81	4.57	4.56	5.19	5.17	5.54	5.51
Residual Fuel	0.97	0.54	0.54	0.52	0.53	0.53	0.53
Other[11]	4.58	5.12	5.11	5.50	5.49	5.66	5.84
Total	**19.69**	**22.53**	**22.48**	**25.11**	**24.92**	**26.18**	**25.97**
Refined Petroleum Products Supplied							
Residential and Commercial	1.21	1.18	1.18	1.16	1.16	1.15	1.16
Industrial[12]	4.67	5.21	5.20	5.62	5.59	5.79	5.98
Transportation	13.27	16.02	15.98	18.25	18.07	19.14	18.73
Electric Power[13]	0.55	0.12	0.11	0.08	0.09	0.09	0.10
Total	**19.69**	**22.53**	**22.48**	**25.11**	**24.92**	**26.18**	**25.97**
Discrepancy[14]	**0.10**	**-0.02**	**-0.02**	**-0.01**	**-0.01**	**-0.01**	**-0.00**
World Oil Price (2001 dollars per barrel)[15]	**22.01**	**23.77**	**23.75**	**24.15**	**24.05**	**24.58**	**24.18**
Import Share of Product Supplied	**0.55**	**0.59**	**0.59**	**0.63**	**0.63**	**0.65**	**0.64**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2001 dollars)	**89.20**	**117.95**	**117.34**	**144.08**	**141.55**	**158.78**	**153.19**
Domestic Refinery Distillation Capacity[16]	**16.8**	**18.7**	**18.7**	**19.1**	**19.1**	**19.3**	**19.3**
Capacity Utilization Rate (percent)	**93.0**	**92.8**	**92.8**	**94.5**	**94.5**	**94.6**	**94.4**

[1] Includes lease condensate.

[2] Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.

[3] Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.

[4] Represents volumetric gain in refinery distillation and cracking processes.

[5] Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.

[6] Includes other hydrocarbons, alcohols, and blending components.

[7] Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.

[8] Includes ethanol and ethers blended into gasoline.

[9] Includes only kerosene type.

[10] Includes distillate and kerosene.

[11] Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.

[12] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[13] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[14] Balancing item. Includes unaccounted for supply, losses, and gains.

[15] Average refiner acquisition cost for imported crude oil.

[16] End-of-year capacity.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). Other 2001 data: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G13. Petroleum Product Prices
(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
World Oil Price (2001 dollars per barrel)	**22.01**	**23.77**	**23.75**	**24.15**	**24.05**	**24.58**	**24.18**
Delivered Sector Product Prices							
Residential							
Distillate Fuel	124.6	110.3	110.2	114.2	112.9	119.0	116.3
Liquefied Petroleum Gas	127.3	119.8	121.8	123.9	123.5	128.3	126.9
Commercial							
Distillate Fuel	88.7	78.0	78.0	82.6	81.4	87.3	84.6
Residual Fuel	51.8	58.9	58.8	59.3	59.1	60.2	59.3
Residual Fuel (2001 dollars per barrel)	21.75	24.73	24.70	24.92	24.82	25.30	24.90
Industrial[1]							
Distillate Fuel	90.8	79.2	79.1	85.7	84.5	90.6	87.9
Liquefied Petroleum Gas	105.9	82.2	84.1	87.0	86.6	91.0	89.8
Residual Fuel	49.1	54.7	54.7	55.4	55.2	56.4	55.5
Residual Fuel (2001 dollars per barrel)	20.61	22.99	22.96	23.26	23.17	23.67	23.29
Transportation							
Diesel Fuel (distillate)[2]	139.4	162.4	165.0	182.6	187.0	199.3	219.2
Jet Fuel[3]	83.7	95.9	98.1	125.0	129.0	139.7	157.1
Motor Gasoline[4]	143.3	160.8	162.6	179.9	181.3	189.6	201.7
Liquid Petroleum Gas	145.2	140.3	143.2	157.0	159.3	164.3	173.1
Residual Fuel	58.4	77.8	80.4	110.1	115.9	124.5	147.8
Residual Fuel (2001 dollars per barrel)	24.52	32.66	33.75	46.25	48.67	52.31	62.06
Electric Power[5]							
Distillate Fuel	86.0	69.5	69.4	74.7	73.5	78.2	76.5
Residual Fuel	67.4	64.2	64.8	73.1	72.2	74.6	72.4
Residual Fuel (2001 dollars per barrel)	28.30	26.98	27.23	30.71	30.31	31.31	30.42
Refined Petroleum Product Prices[6]							
Distillate Fuel	127.0	142.1	143.9	160.6	163.4	175.3	189.4
Jet Fuel[3]	83.7	95.9	98.1	125.0	129.0	139.7	157.1
Liquefied Petroleum Gas	110.3	89.4	91.4	93.8	93.4	97.8	96.1
Motor Gasoline[4]	143.4	160.6	162.4	179.4	180.8	189.1	201.0
Residual Fuel	61.5	71.7	73.6	96.1	99.9	106.5	122.2
Residual Fuel (2001 dollars per barrel)	25.85	30.13	30.92	40.35	41.97	44.75	51.33
Average	**123.6**	**137.0**	**138.7**	**154.1**	**155.7**	**164.3**	**174.0**
Greenhouse Gas Allowance Cost							
Commercial							
Distillate Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residual Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residual Fuel (2001 dollars per barrel)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[1]							
Distillate Fuel	0.0	21.6	23.9	48.9	54.0	60.5	81.2
Liquefied Petroleum Gas	0.0	11.6	12.8	26.1	28.9	32.4	43.5
Residual Fuel	0.0	25.1	27.8	56.8	62.8	70.3	94.5
Residual Fuel (2001 dollars per barrel)	0.00	10.55	11.67	23.86	26.39	29.53	39.68
Electric Power[5]							
Distillate Fuel	0.0	21.6	23.9	48.9	54.0	60.5	81.2
Residual Fuel	0.0	25.1	27.8	56.8	62.8	70.3	94.5
Residual Fuel (2001 dollars per barrel)	0.00	10.55	11.67	23.86	26.39	29.53	39.68

Table G13. Petroleum Product Prices (Continued)

(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Delivered Sector Product Prices with Greenhouse Gas Allowance Cost							
Commercial							
Distillate Fuel	88.7	78.0	78.0	82.6	81.4	87.3	84.6
Residual Fuel	51.8	58.9	58.8	59.3	59.1	60.2	59.3
Residual Fuel (2001 dollars per barrel)	21.75	24.73	24.70	24.92	24.82	25.30	24.90
Industrial[1]							
Distillate Fuel	90.8	100.8	103.0	134.6	138.5	151.0	169.2
Liquefied Petroleum Gas	105.9	93.8	96.9	113.1	115.5	123.3	133.2
Residual Fuel	49.1	79.9	82.4	112.2	118.0	126.7	149.9
Residual Fuel (2001 dollars per barrel)	20.61	33.55	34.63	47.12	49.55	53.20	62.97
Electric Power[5]							
Distillate Fuel	86.0	91.1	93.3	123.6	127.6	138.6	157.8
Residual Fuel	67.4	89.4	92.6	129.9	135.0	144.9	166.9
Residual Fuel (2001 dollars per barrel)	28.30	37.53	38.90	54.57	56.69	60.84	70.09

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[1] Includes combined heat and power, which produces electricity and other useful thermal energy.

[2] Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur. Includes Federal and State taxes while excluding county and local taxes.

[3] Kerosene-type jet fuel.

[4] Sales weighted-average price for all grades. Includes Federal, State and local taxes.

[5] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[6] Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources:. 2001 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A: “Refiners’/Gas Plant Operators’ Monthly Petroleum Product Sales Report.” 2001 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2001 world oil price: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections**: EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G14. Natural Gas Supply and Disposition

(Trillion Cubic Feet per Year)

Supply and Disposition	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Production							
Dry Gas Production[1]	19.45	22.21	22.14	26.61	26.51	27.32	27.87
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.73**	**4.85**	**4.94**	**8.80**	**9.29**	**10.87**	**11.35**
Canada	3.61	4.20	4.18	5.44	5.39	5.61	5.61
Mexico	-0.13	-0.21	-0.20	0.16	0.26	0.66	0.69
Liquefied Natural Gas	0.26	0.86	0.96	3.21	3.64	4.60	5.05
Total Supply	**23.26**	**27.15**	**27.18**	**35.51**	**35.90**	**38.29**	**39.32**
Consumption by Sector							
Residential	4.81	5.47	5.47	5.80	5.80	6.03	6.03
Commercial	3.24	3.63	3.63	4.16	4.20	4.84	4.99
Industrial[3]	7.53	8.91	8.93	10.08	10.11	10.79	10.36
Electric Power[4]	5.30	7.20	7.23	13.00	13.33	14.03	15.29
Transportation[5]	0.01	0.06	0.06	0.09	0.09	0.10	0.10
Pipeline Fuel	0.61	0.79	0.79	1.02	1.02	1.08	1.11
Lease and Plant Fuel[6]	1.17	1.36	1.36	1.66	1.65	1.72	1.75
Total	**22.67**	**27.42**	**27.46**	**35.80**	**36.19**	**38.59**	**39.62**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.59**	**-0.26**	**-0.28**	**-0.30**	**-0.29**	**-0.30**	**-0.30**

[1] Marketed production (wet) minus extraction losses.

[2] Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

[3] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as vehicle fuel.

[6] Represents natural gas used in the field gathering and processing plant machinery.

[7] Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2001 values include net storage injections.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G15. Natural Gas Prices, Margins, and Revenue

(2001 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Source Price							
Average Lower 48 Wellhead Price[1]	4.12	3.51	3.49	3.97	3.99	4.36	4.70
Average Import Price	4.43	3.46	3.46	4.17	4.15	4.65	4.91
Average[2]	**4.17**	**3.50**	**3.48**	**4.02**	**4.03**	**4.45**	**4.76**
Delivered Prices							
Residential	9.68	7.89	7.87	8.30	8.29	8.72	9.03
Commercial	8.32	6.78	6.76	7.27	7.26	7.69	7.99
Industrial[3]	5.01	4.23	4.21	4.81	4.81	5.21	5.57
Electric Power[4]	4.87	4.14	4.13	4.88	4.90	5.29	5.69
Transportation[5]	7.87	7.45	7.41	7.94	7.91	8.30	8.62
Average[6]	**6.57**	**5.38**	**5.36**	**5.78**	**5.78**	**6.19**	**6.54**
Transmission & Distribution Margins[7]							
Residential	5.50	4.39	4.38	4.27	4.25	4.28	4.27
Commercial	4.14	3.28	3.27	3.24	3.22	3.24	3.23
Industrial[3]	0.83	0.73	0.73	0.79	0.78	0.77	0.81
Electric Power[4]	0.70	0.65	0.65	0.86	0.87	0.84	0.93
Transportation[5]	3.69	3.95	3.92	3.92	3.87	3.86	3.86
Average[6]	**2.40**	**1.88**	**1.88**	**1.76**	**1.74**	**1.75**	**1.78**
Transmission & Distribution Revenue (billion 2001 dollars)							
Residential	26.45	24.00	23.97	24.78	24.66	25.78	25.75
Commercial	13.42	11.91	11.90	13.48	13.55	15.68	16.14
Industrial[3]	6.28	6.49	6.49	7.94	7.86	8.27	8.40
Electric Power[4]	3.69	4.64	4.67	11.18	11.55	11.80	14.18
Transportation[5]	0.04	0.22	0.22	0.36	0.35	0.39	0.38
Total	**49.88**	**47.27**	**47.25**	**57.74**	**57.97**	**61.91**	**64.85**
Greenhouse Gas Allowance Cost							
Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[3]	0.00	1.15	1.27	2.59	2.87	3.21	4.31
Electric Power[4]	0.00	1.16	1.28	2.62	2.89	3.24	4.35
Transportation[5]	0.00	1.17	1.29	2.64	2.92	3.27	4.39
Average[6]	**0.00**	**0.74**	**0.82**	**1.83**	**2.03**	**2.25**	**3.04**
Delivered Prices with Greenhouse Gas Allowance Cost							
Residential	9.68	7.89	7.87	8.30	8.29	8.72	9.03
Commercial	8.32	6.78	6.76	7.27	7.26	7.69	7.99
Industrial[3]	5.01	5.37	5.48	7.40	7.68	8.42	9.88
Electric Power[4]	4.87	5.30	5.41	7.50	7.79	8.53	10.04
Transportation[5]	7.87	8.62	8.70	10.58	10.83	11.57	13.01
Average[6]	**6.57**	**6.12**	**6.17**	**7.61**	**7.81**	**8.44**	**9.58**

[1] Represents lower 48 onshore and offshore supplies.

[2] Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.

[3] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.

[6] Weighted average allowance cost. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.

[7] Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 electric generators delivered price: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1998*. 2001 residential, commercial, and transportation delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G16. Oil and Gas Supply

Production and Supply	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Crude Oil							
Lower 48 Average Wellhead Price[1] (2001 dollars per barrel)	**22.91**	**23.56**	**23.48**	**23.65**	**23.54**	**24.11**	**23.60**
Production (million barrels per day)[2]							
U.S. Total	**5.80**	**5.63**	**5.63**	**5.41**	**5.42**	**5.27**	**5.27**
Lower 48 Onshore	3.13	2.47	2.47	2.05	2.05	1.90	1.90
Lower 48 Offshore	1.71	2.52	2.52	2.13	2.14	2.19	2.20
Alaska	0.97	0.64	0.64	1.23	1.23	1.17	1.17
Lower 48 End of Year Reserves (billion barrels)[2]	**19.48**	**17.70**	**17.70**	**15.34**	**15.36**	**14.92**	**14.93**
Natural Gas							
Lower 48 Average Wellhead Price[1] (2001 dollars per thousand cubic feet)	**4.12**	**3.51**	**3.49**	**3.97**	**3.99**	**4.36**	**4.70**
Dry Production (trillion cubic feet)[3]							
U.S. Total	**19.45**	**22.21**	**22.14**	**26.61**	**26.51**	**27.32**	**27.88**
Lower 48 Onshore	13.72	16.17	16.13	18.65	18.54	18.72	19.42
Associated-Dissolved[4]	1.77	1.36	1.36	1.19	1.19	1.13	1.13
Non-Associated	11.94	14.81	14.77	17.46	17.35	17.59	18.29
Conventional	6.54	7.32	7.26	7.37	7.35	7.13	7.44
Unconventional	5.40	7.49	7.51	10.09	10.00	10.46	10.85
Lower 48 Offshore	5.30	5.56	5.53	5.58	5.59	5.77	5.62
Associated-Dissolved[4]	1.08	0.96	0.96	0.79	0.80	0.81	0.81
Non-Associated	4.22	4.60	4.57	4.78	4.79	4.96	4.80
Alaska	0.43	0.48	0.48	2.39	2.39	2.84	2.84
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**174.04**	**185.39**	**185.28**	**195.87**	**195.78**	**192.41**	**191.97**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Total Lower 48 Wells (thousands)	**33.94**	**25.75**	**25.55**	**27.25**	**27.24**	**29.30**	**29.86**

[1] Represents lower 48 onshore and offshore supplies.
[2] Includes lease condensate.
[3] Marketed production (wet) minus extraction losses.
[4] Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5] Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2001 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting.
Projections: EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G17. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Production[1]							
Appalachia	443	415	402	212	173	145	95
Interior	147	153	157	88	69	42	24
West	548	513	497	185	128	128	54
East of the Mississippi	539	518	506	286	231	182	115
West of the Mississippi	599	563	549	199	139	132	58
Total	**1138**	**1081**	**1055**	**485**	**370**	**315**	**173**
Net Imports							
Imports	19	11	11	11	11	10	10
Exports	49	33	33	29	31	24	26
Total	**-30**	**-22**	**-22**	**-19**	**-20**	**-13**	**-16**
Total Supply[2]	**1109**	**1060**	**1034**	**466**	**350**	**301**	**157**
Consumption by Sector							
Residential and Commercial	4	5	5	5	5	6	6
Industrial[3]	63	61	61	59	58	58	55
of which: Coal to Liquids	0	0	0	0	0	0	0
Coke Plants	26	24	24	17	17	14	14
Electric Power[4]	957	966	955	390	272	227	85
Total	**1050**	**1055**	**1044**	**471**	**352**	**306**	**160**
Discrepancy and Stock Change[5]	**58**	**4**	**-10**	**-6**	**-3**	**-4**	**-3**
Average Minemouth Price							
(2001 dollars per short ton)	17.59	15.84	15.83	15.27	14.86	13.67	13.40
(2001 dollars per million Btu)	0.83	0.76	0.76	0.71	0.68	0.63	0.60
Delivered Prices (2001 dollars per short ton)[6]							
Industrial	32.82	30.10	30.09	24.86	23.86	22.55	20.79
Coke Plants	46.42	41.37	41.38	38.31	38.35	36.64	36.57
Electric Power							
(2001 dollars per short ton)	25.06	23.76	23.66	20.83	20.24	18.81	17.68
(2001 dollars per million Btu)	1.25	1.16	1.16	0.99	0.97	0.90	0.84
Average	**26.06**	**24.53**	**24.44**	**21.98**	**21.73**	**20.39**	**20.54**
Exports[7]	36.97	32.41	32.40	28.76	27.86	27.46	25.57
Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]							
Industrial	0.00	43.59	48.22	98.28	108.68	121.42	163.43
Coke Plants	0.00	54.74	60.53	123.76	136.85	153.14	205.78
Electric Power							
(2001 dollars per short ton)	0.00	41.32	45.63	95.21	104.88	117.30	159.37
(2001 dollars per million Btu)	0.00	2.02	2.23	4.54	5.02	5.62	7.53
Average	**0.00**	**41.76**	**46.12**	**96.65**	**107.09**	**119.82**	**165.11**
Delivered Prices with Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]							
Industrial	32.82	73.69	78.31	123.14	132.54	143.97	184.22
Coke Plants	46.42	96.11	101.91	162.07	175.21	189.79	242.35
Electric Power							
(2001 dollars per short ton)	25.06	65.08	69.29	116.04	125.12	136.11	177.05
(2001 dollars per million Btu)	1.25	3.17	3.39	5.53	5.98	6.53	8.37
Average	**26.06**	**66.29**	**70.56**	**118.63**	**128.82**	**140.21**	**185.65**

[1] Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.1 million tons in 2000 and 10.6 million tons in 2001.

[2] Production plus net imports and net storage withdrawals.

[3] Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

[4] Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[5] Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.

[6] Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.

[7] F.a.s. price at U.S. port of exit.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G18. Renewable Energy Generating Capacity and Generation

(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Electric Power Sector[1]							
Net Summer Capacity							
Conventional Hydropower	78.10	78.66	78.66	78.65	78.65	78.65	78.73
Geothermal[2]	2.83	6.68	6.93	10.06	10.21	10.55	10.21
Municipal Solid Waste[3]	3.25	4.84	4.84	5.17	5.17	5.19	5.19
Wood and Other Biomass[4]	1.80	3.96	3.15	48.03	90.73	67.38	120.58
Solar Thermal	0.33	0.44	0.44	0.48	0.48	0.50	0.50
Solar Photovoltaic[5]	0.02	0.10	0.10	0.27	0.27	0.36	0.36
Wind	4.29	34.53	38.07	82.60	86.53	83.22	87.73
Total	**90.62**	**129.20**	**132.19**	**225.26**	**272.03**	**245.84**	**303.29**
Generation (billion kilowatthours)							
Conventional Hydropower	213.82	300.89	300.88	299.92	299.89	300.10	300.34
Geothermal[2]	13.81	44.61	46.60	73.14	74.59	77.22	74.89
Municipal Solid Waste[3]	19.55	35.17	35.18	37.63	37.63	37.83	37.82
Wood and Other Biomass[4]	9.38	27.11	22.91	304.95	547.30	429.32	788.65
Dedicated Plants	7.66	19.52	16.27	304.95	547.30	429.32	788.65
Cofiring	1.72	7.59	6.64	0.00	0.00	0.00	0.00
Solar Thermal	0.49	0.77	0.77	0.90	0.90	0.97	0.97
Solar Photovoltaic[5]	0.00	0.24	0.24	0.66	0.66	0.88	0.88
Wind	5.78	112.46	124.27	277.70	294.56	280.10	298.70
Total	**262.85**	**521.25**	**530.86**	**994.90**	**1255.52**	**1126.43**	**1502.26**
End- Use Sector							
Net Summer Capacity							
Combined Heat and Power[6]							
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Biomass	4.41	5.89	5.88	7.67	7.66	8.60	8.59
Total	**4.69**	**6.17**	**6.17**	**7.95**	**7.94**	**8.88**	**8.87**
Other End-Use Generators[7]							
Conventional Hydropower[8]	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.38	0.38	0.76	0.78	1.15	1.23
Total	**1.12**	**1.47**	**1.47**	**1.85**	**1.87**	**2.25**	**2.32**
Generation (billion kilowatthours)							
Combined Heat and Power[6]							
Municipal Solid Waste	2.46	2.15	2.15	2.15	2.15	2.15	2.15
Biomass	28.67	37.31	37.27	47.72	47.66	53.13	53.09
Total	**31.13**	**39.46**	**39.43**	**49.87**	**49.81**	**55.28**	**55.24**
Other End-Use Generators[7]							
Conventional Hydropower[8]	4.23	4.23	4.23	4.23	4.23	4.23	4.23
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.82	0.82	1.61	1.65	2.42	2.59
Total	**4.25**	**5.05**	**5.05**	**5.85**	**5.89**	**6.66**	**6.83**

[1] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes hydrothermal resources only (hot water and steam).

[3] Includes landfill gas.

[4] Includes projections for energy crops after 2010.

[5] Does not include off-grid photovoltaics (PV). See Annual Energy Review 2001 Table 10.6 for estimates of 1989-2000 PV shipments, including exports, for both grid-connected and off-grid applications.

[6] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[7] Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[8] Represents own-use industrial hydroelectric power.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2003. Net summer capacity is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.

Sources: 2001 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2001 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G19. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Marketed Renewable Energy[2]							
Residential	**0.39**	**0.41**	**0.41**	**0.40**	**0.40**	**0.40**	**0.40**
Wood	0.39	0.41	0.41	0.40	0.40	0.40	0.40
Commercial	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Industrial[3]	**1.82**	**2.21**	**2.21**	**2.74**	**2.74**	**3.02**	**3.02**
Conventional Hydroelectric	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.77	2.16	2.16	2.69	2.69	2.97	2.97
Transportation	**0.15**	**0.26**	**0.26**	**0.28**	**0.28**	**0.29**	**0.28**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.01	0.01
Ethanol used in Gasoline Blending	0.15	0.26	0.25	0.28	0.27	0.28	0.28
Electric Power[5]	**3.01**	**6.30**	**6.49**	**11.42**	**13.82**	**12.69**	**16.03**
Conventional Hydroelectric	2.16	3.09	3.09	3.07	3.07	3.07	3.08
Geothermal	0.29	1.30	1.37	2.23	2.26	2.36	2.27
Municipal Solid Waste[6]	0.31	0.48	0.48	0.51	0.51	0.51	0.51
Biomass	0.15	0.31	0.27	2.78	4.94	3.89	7.09
Dedicated Plants	0.12	0.21	0.18	2.78	4.94	3.89	7.09
Cofiring	0.03	0.09	0.09	0.00	0.00	0.00	0.00
Solar Thermal	0.01	0.01	0.01	0.02	0.02	0.02	0.02
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.08	1.12	1.28	2.82	3.03	2.84	3.07
Total Marketed Renewable Energy	**5.46**	**9.28**	**9.47**	**14.95**	**17.35**	**16.50**	**19.84**
Sources of Ethanol							
From Corn	0.15	0.26	0.25	0.26	0.26	0.24	0.25
From Cellulose	0.00	0.00	0.00	0.02	0.02	0.05	0.03
Total	**0.15**	**0.26**	**0.26**	**0.28**	**0.28**	**0.29**	**0.28**
Non-Marketed Renewable Energy[7]							
Selected Consumption							
Residential	**0.03**	**0.04**	**0.04**	**0.05**	**0.05**	**0.06**	**0.06**
Solar Hot Water Heating	0.03	0.03	0.03	0.04	0.04	0.04	0.04
Geothermal Heat Pumps	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.01	0.01

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[1] Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.

[2] Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table G8.

[3] Includes all electricity production by industrial and other combined heat and power for the grid and for own use.

[4] Excludes motor gasoline component of E85.

[5] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[6] Includes landfill gas.

[7] Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 electric generators: EIA, Form EIA-860: "Annual Electric Generator Report" (preliminary). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G20. Greenhouse Gas Emissions and Allowance Cost

(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear	S. 139 Case	No Geologic Sequestration/ No New Nuclear
Carbon Dioxide Emissions							
Residential							
Petroleum	27.2	27.6	27.6	25.8	25.9	25.0	25.2
Natural Gas	71.1	81.0	80.9	85.8	85.8	89.3	89.3
Coal	0.3	0.4	0.4	0.4	0.4	0.3	0.3
Total	**98.7**	**109.0**	**108.9**	**112.0**	**112.1**	**114.7**	**114.8**
Commercial							
Petroleum	14.0	13.7	13.7	14.5	14.6	14.8	15.1
Natural Gas	48.0	53.8	53.8	61.5	62.2	71.6	73.9
Coal	2.3	2.5	2.5	2.8	2.8	2.9	2.9
Total	**64.3**	**69.9**	**69.9**	**78.8**	**79.6**	**89.3**	**91.9**
Industrial[1]							
Petroleum	97.9	96.0	95.9	99.1	98.4	101.1	104.3
Natural Gas[2]	123.4	149.8	149.8	171.0	171.4	182.4	176.4
Coal	52.1	53.1	52.7	48.9	48.3	47.3	45.7
Total	**273.4**	**298.9**	**298.4**	**319.0**	**318.0**	**330.8**	**326.3**
Transportation							
Petroleum[3]	501.4	605.1	603.7	690.4	683.8	725.3	710.2
Natural Gas[4]	9.2	12.5	12.5	16.4	16.4	17.4	17.8
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**510.6**	**617.6**	**616.1**	**706.8**	**700.2**	**742.7**	**728.0**
Total Carbon Dioxide Emissions by Delivered Fuel							
Petroleum[3]	640.5	742.5	740.9	829.8	822.7	866.2	854.8
Natural Gas	251.7	297.0	297.0	334.8	335.8	360.7	357.4
Coal	54.7	55.9	55.5	52.0	51.4	50.5	48.9
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**947.0**	**1095.4**	**1093.4**	**1216.6**	**1209.9**	**1277.4**	**1261.1**
Electric Power[6]							
Petroleum	27.5	5.4	5.3	3.9	4.0	3.9	4.6
Natural Gas	77.7	105.0	106.0	158.0	195.6	132.6	224.3
Coal	506.4	504.4	498.0	190.0	143.5	68.3	43.9
Total	**611.6**	**614.8**	**609.4**	**351.9**	**343.1**	**204.8**	**272.9**
Total Carbon Dioxide Emissions by Primary Fuel[7]							
Petroleum[3]	668.0	747.9	746.2	833.7	826.7	870.2	859.4
Natural Gas	329.4	402.0	403.0	492.8	531.4	493.3	581.7
Coal	561.1	560.3	553.6	242.0	194.9	118.8	92.8
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1558.6**	**1710.1**	**1702.7**	**1568.5**	**1553.0**	**1482.2**	**1533.9**
Non-Energy Related Carbon Dioxide Emissions	**36.3**	**39.5**	**39.5**	**43.9**	**43.9**	**46.2**	**46.2**
Total Carbon Dioxide Emissions	**1594.9**	**1749.7**	**1742.3**	**1612.4**	**1596.9**	**1528.4**	**1580.1**
Other Greenhouse Gas Emissions	**332.9**	**286.4**	**286.4**	**339.5**	**339.4**	**362.9**	**362.8**
Methane	175.2	115.2	115.1	126.4	126.4	120.0	119.9
Nitrous Oxide	118.9	121.0	121.0	131.4	131.4	137.2	137.2
High Global Warming Potential Gases	38.8	50.2	50.2	81.8	81.7	105.8	105.8
Total Greenhouse Gas Emissions	**1964.1**	**2075.7**	**2068.2**	**1995.8**	**1980.3**	**1937.6**	**1989.2**

Table G20. Greenhouse Gas Emissions and Allowance Cost (Continued)

(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration and New Nuclear	S. 139 Case	No Geologic Sequestration and New Nuclear	S. 139 Case	No Geologic Sequestration and New Nuclear
Greenhouse Gas Emission Cap Compliance							
Covered Emissions							
Energy-Related Carbon Dioxide	1378.2	1513.1	1505.8	1357.5	1341.2	1256.9	1305.8
Other Greenhouse Gases	75.2	70.1	70.1	102.8	102.7	127.6	127.6
Offsets Purchased	0.0	234.7	234.9	126.1	125.9	125.6	125.9
Non-Covered Greenhouse Gas Offsets	0.0	48.5	48.6	34.3	34.2	39.0	39.1
U.S. Sequestration Offsets	0.0	112.8	112.9	91.8	91.6	86.5	86.7
International Offsets	0.0	73.4	73.5	0.0	0.0	0.1	0.1
Covered Emissions less Offsets	1453.4	1348.5	1341.0	1334.2	1318.0	1258.9	1307.5
Covered Emissions Coal	N/A	1465.1	1465.1	1257.9	1257.9	1257.9	1257.9
Allowance Bank Activity	0.0	116.5	124.1	-76.3	-60.1	-1.0	-49.6
Cumulative Bank Balance	0.0	116.5	124.1	98.9	214.6	7.3	-5.0
Allowance Cost (2001 dollars per ton)							
Emissions Allowance Cost	0.00	78.89	87.23	178.36	197.23	220.71	296.57
Offset Price	0.00	71.49	71.56	34.84	34.67	51.73	52.13

[1] Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes lease and plant fuel.

[3] This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons carbon equivalent of carbon dioxide annually.

[4] Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

[5] Includes methanol and liquid hydrogen.

[6] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.

[7] Emissions from electric power generators are distributed to the primary fuels.

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table G21. Macroeconomic Indicators

(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration and New Nuclear	S. 139 Case	No Geologic Sequestration and New Nuclear	S. 139 Case	No Geologic Sequestration and New Nuclear
GDP Chain-Type Price Index (1996=1.000)	**1.094**	**1.321**	**1.322**	**1.735**	**1.736**	**2.028**	**2.034**
Potential Gross Domestic Product	9456	12458	12459	16729	16732	19150	19154
Real Gross Domestic Product	**9215**	**12211**	**12203**	**16364**	**16370**	**18810**	**18821**
Real Consumption	6377	8375	8370	11284	11285	12954	12963
Real Investment	1575	2478	2474	3724	3724	4447	4442
Real Government Spending	1640	1897	1897	2204	2204	2417	2416
Real Exports	1076	1781	1781	3329	3326	4621	4617
Real Imports	1492	2292	2291	4027	4017	5376	5367
Real Disposable Personal Income	**6748**	**8607**	**8602**	**11648**	**11651**	**13432**	**13463**
Federal Funds Rate (percent)	**3.89**	**5.63**	**5.64**	**6.58**	**6.61**	**6.97**	**7.16**
AA Utility Bond Rate (percent)							
Nominal	7.57	7.38	7.39	9.17	9.18	9.99	10.13
Real	5.60	5.20	5.19	6.18	6.20	6.76	6.83
Energy Intensity (thousand Btu per 1996 dollar of GDP)							
Delivered Energy	7.74	6.80	6.80	5.65	5.62	5.17	5.11
Total Energy	10.56	9.15	9.14	7.37	7.28	6.70	6.53
Consumer Price Index (1982-84=1.00)	**1.77**	**2.20**	**2.20**	**2.97**	**2.98**	**3.55**	**3.56**
Unemployment Rate (percent)	**4.79**	**4.55**	**4.57**	**6.03**	**6.02**	**5.85**	**5.82**
Housing Starts (millions)	**1.80**	**2.12**	**2.11**	**1.92**	**1.93**	**2.01**	**2.00**
Single-Family	1.27	1.31	1.31	1.11	1.11	1.11	1.10
Multifamily	0.33	0.45	0.44	0.49	0.49	0.57	0.56
Mobile Home Shipments	0.19	0.36	0.36	0.33	0.33	0.33	0.33
Commercial Floorspace, Total (billion square feet)	**70.2**	**82.0**	**82.0**	**94.2**	**94.2**	**100.6**	**100.6**
Value of Shipments (billion 1996 dollars)							
Total Industrial	5425	6920	6912	8874	8869	9990	9979
Nonmanufacturing	1346	1500	1499	1714	1713	1828	1827
Manufacturing	4079	5420	5412	7160	7156	8162	8152
Energy-Intensive Manufacturing	1086	1255	1254	1434	1433	1515	1514
Non-Energy-Intensive Manufacturing	2993	4164	4158	5726	5724	6647	6639
Unit Sales of Light-Duty Vehicles (millions)	**17.11**	**17.87**	**17.80**	**20.06**	**20.13**	**20.15**	**20.14**
Population (millions)							
Population with Armed Forces Overseas	278.2	300.2	300.2	325.3	325.3	338.2	338.2
Population (aged 16 and over)	215.4	236.6	236.6	256.5	256.5	266.6	266.6
Employment, Non-Agriculture	131.7	147.1	147.0	158.8	158.9	165.5	165.7
Employment, Manufacturing	17.5	17.7	17.7	17.7	17.7	18.4	18.4
Labor Force	141.8	156.5	156.5	169.6	169.6	177.3	177.3

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2001: Global Insight macroeconomic model CTL0802. **Projections:** Energy Information Administration, AEO2003 National Energy Modeling System runs MLBILL.D050503A and ML0NUCSEQ.D050403A.

Table H1. Total Energy Supply and Disposition Summary

(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Production										
Crude Oil and Lease Condensate	12.29	11.92	11.93	11.93	11.45	11.42	11.46	11.15	10.99	11.12
Natural Gas Plant Liquids	2.65	3.21	3.13	3.19	3.75	3.69	3.74	3.84	3.73	3.82
Dry Natural Gas	19.97	22.81	22.17	22.62	27.33	26.86	27.25	28.06	27.26	27.91
Coal	23.97	22.57	24.04	22.41	10.46	7.77	10.81	6.82	7.47	7.31
Nuclear Power	8.03	8.37	8.37	8.37	9.75	10.35	9.75	12.39	14.28	12.39
Renewable Energy[1]	5.32	9.03	8.90	8.87	14.68	16.95	14.59	16.22	17.40	15.98
Other[2]	0.57	0.82	0.84	0.83	0.62	0.60	0.61	0.59	0.60	0.59
Total	**72.80**	**78.73**	**79.38**	**78.22**	**78.04**	**77.64**	**78.21**	**79.06**	**81.73**	**79.12**
Imports										
Crude Oil[3]	20.26	24.88	24.94	24.86	26.92	27.01	26.88	27.72	27.95	27.74
Petroleum Products[4]	5.04	5.73	6.07	5.73	8.82	8.49	8.82	10.43	10.68	10.39
Natural Gas	4.18	5.53	5.39	5.63	9.37	9.10	9.13	11.48	10.00	11.03
Other Imports[5]	0.71	0.81	0.80	0.81	0.94	0.98	0.94	0.79	0.66	0.76
Total	**30.19**	**36.94**	**37.20**	**37.03**	**46.05**	**45.58**	**45.76**	**50.42**	**49.28**	**49.91**
Exports										
Petroleum[6]	2.01	2.21	2.24	2.21	2.29	2.31	2.29	2.32	2.33	2.30
Natural Gas	0.37	0.57	0.57	0.57	0.37	0.36	0.37	0.36	0.35	0.36
Coal	1.27	0.84	0.84	0.83	0.76	0.74	0.76	0.61	0.60	0.61
Total	**3.64**	**3.61**	**3.64**	**3.61**	**3.42**	**3.41**	**3.43**	**3.29**	**3.28**	**3.28**
Discrepancy[7]	**2.06**	**0.39**	**0.24**	**0.10**	**0.18**	**0.01**	**0.25**	**0.22**	**0.44**	**0.31**
Consumption										
Petroleum Products[8]	38.46	43.74	44.02	43.70	48.65	48.31	48.61	50.76	50.99	50.70
Natural Gas	23.26	28.12	27.36	28.05	36.69	35.96	36.37	39.54	37.30	38.94
Coal	22.02	22.00	23.65	22.13	10.23	7.69	10.49	6.74	7.14	7.15
Nuclear Power	8.03	8.37	8.37	8.37	9.75	10.35	9.75	12.39	14.28	12.39
Renewable Energy[1]	5.32	9.03	8.90	8.87	14.68	16.95	14.59	16.22	17.40	15.98
Other[9]	0.21	0.43	0.41	0.43	0.50	0.55	0.49	0.32	0.19	0.29
Total	**97.29**	**111.67**	**112.70**	**111.54**	**120.50**	**119.80**	**120.30**	**125.97**	**127.29**	**125.45**
Net Imports - Petroleum	**23.29**	**28.40**	**28.78**	**28.38**	**33.45**	**33.19**	**33.40**	**35.83**	**36.30**	**35.83**
Prices (2001 dollars per unit)										
World Oil Price (dollars per barrel)[10]	22.01	23.77	23.86	23.75	24.15	23.75	24.14	24.58	24.55	24.54
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.12	3.51	3.42	3.45	3.97	3.85	3.98	4.36	4.09	4.29
Coal Minemouth Price (dollars per ton)	17.59	15.84	14.99	15.90	15.27	15.22	15.26	13.67	13.60	14.11
Average Electricity Price (cents per kilowatthour)	7.3	7.0	6.7	7.0	8.8	9.1	8.9	9.8	9.5	9.8

[1] Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table H18 for selected nonmarketed residential and commercial renewable energy.

[2] Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.

[3] Includes imports of crude oil for the Strategic Petroleum Reserve.

[4] Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.

[5] Includes coal, coal coke (net), and electricity (net).

[6] Includes crude oil and petroleum products.

[7] Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.

[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.

[9] Includes net electricity imports, methanol, and liquid hydrogen.

[10] Average refiner acquisition cost for imported crude oil.

[11] Represents lower 48 onshore and offshore supplies.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H2. Energy Consumption by Sector and Source

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Energy Consumption										
Residential										
Distillate Fuel	0.91	0.91	0.91	0.91	0.84	0.84	0.84	0.81	0.81	0.81
Kerosene	0.10	0.08	0.08	0.08	0.06	0.06	0.06	0.06	0.06	0.06
Liquefied Petroleum Gas	0.50	0.47	0.47	0.47	0.47	0.46	0.46	0.47	0.46	0.47
Petroleum Subtotal	1.50	1.46	1.46	1.46	1.37	1.37	1.37	1.33	1.33	1.33
Natural Gas	4.94	5.62	5.62	5.62	5.96	5.97	5.96	6.20	6.33	6.21
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.41	0.41	0.41	0.40	0.40	0.40	0.40	0.40	0.40
Electricity	4.10	4.88	4.90	4.88	5.05	4.97	5.04	5.11	5.16	5.12
Delivered Energy	**10.94**	**12.38**	**12.41**	**12.38**	**12.80**	**12.73**	**12.80**	**13.06**	**13.22**	**13.07**
Electricity Related Losses	9.15	10.11	10.37	10.11	9.29	9.23	9.23	9.26	9.55	9.16
Total	**20.08**	**22.50**	**22.78**	**22.49**	**22.09**	**21.96**	**22.03**	**22.32**	**22.78**	**22.23**
Commercial										
Distillate Fuel	0.46	0.51	0.51	0.49	0.54	0.55	0.46	0.56	0.55	0.44
Residual Fuel	0.09	0.04	0.04	0.03	0.05	0.05	0.04	0.05	0.05	0.04
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.09
Motor Gasoline[2]	0.05	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.71	0.70	0.70	0.67	0.75	0.75	0.65	0.76	0.75	0.63
Natural Gas	3.33	3.74	3.74	3.66	4.27	4.44	3.86	4.97	5.27	4.07
Coal	0.09	0.10	0.09	0.06	0.11	0.11	0.08	0.11	0.11	0.07
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.08	4.97	4.98	4.98	5.66	5.55	5.84	5.97	5.92	6.25
Delivered Energy	**8.32**	**9.60**	**9.62**	**9.47**	**10.89**	**10.95**	**10.52**	**11.92**	**12.16**	**11.13**
Electricity Related Losses	9.12	10.30	10.54	10.32	10.42	10.30	10.68	10.82	10.96	11.18
Total	**17.44**	**19.90**	**20.16**	**19.79**	**21.31**	**21.26**	**21.21**	**22.74**	**23.12**	**22.31**
Industrial[4]										
Distillate Fuel	1.13	1.20	1.20	1.20	1.30	1.28	1.30	1.36	1.36	1.36
Liquefied Petroleum Gas	2.10	2.54	2.54	2.55	2.99	2.99	3.00	3.14	3.15	3.15
Petrochemical Feedstock	1.14	1.41	1.42	1.41	1.53	1.52	1.52	1.57	1.58	1.57
Residual Fuel	0.23	0.18	0.18	0.18	0.17	0.17	0.17	0.17	0.17	0.17
Motor Gasoline[2]	0.15	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19	0.19
Other Petroleum[5]	4.03	4.18	4.21	4.17	4.09	4.12	4.10	4.12	4.20	4.13
Petroleum Subtotal	8.79	9.67	9.72	9.67	10.26	10.26	10.28	10.55	10.65	10.57
Natural Gas	7.74	9.16	9.19	9.17	10.36	10.42	10.37	11.09	11.33	11.16
Lease and Plant Fuel[6]	1.20	1.40	1.37	1.39	1.70	1.68	1.70	1.77	1.73	1.76
Natural Gas Subtotal	8.94	10.56	10.57	10.57	12.06	12.10	12.07	12.86	13.06	12.92
Metallurgical Coal	0.72	0.65	0.66	0.65	0.47	0.48	0.47	0.39	0.40	0.39
Steam Coal	1.42	1.33	1.40	1.34	1.28	1.23	1.28	1.26	1.24	1.26
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.18	0.17	0.18	0.21	0.21	0.21
Coal Subtotal	2.16	2.09	2.16	2.09	1.93	1.88	1.93	1.87	1.85	1.86
Renewable Energy[7]	1.82	2.21	2.21	2.21	2.74	2.72	2.74	3.02	3.03	3.02
Electricity	3.39	3.89	3.89	3.88	4.41	4.34	4.40	4.66	4.62	4.65
Delivered Energy	**25.10**	**28.41**	**28.55**	**28.42**	**31.40**	**31.31**	**31.41**	**32.96**	**33.21**	**33.03**
Electricity Related Losses	7.57	8.06	8.22	8.05	8.12	8.06	8.05	8.45	8.56	8.32
Total	**32.67**	**36.47**	**36.78**	**36.47**	**39.53**	**39.37**	**39.46**	**41.40**	**41.76**	**41.35**

Table H2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Transportation										
Distillate Fuel[8]	5.44	7.01	7.05	7.01	8.30	8.22	8.30	8.98	8.99	9.00
Jet Fuel[9]	3.43	3.91	3.92	3.91	5.01	5.01	5.01	5.56	5.57	5.56
Motor Gasoline[2]	16.26	19.58	19.74	19.58	21.55	21.31	21.58	22.10	22.26	22.15
Residual Fuel	0.84	0.83	0.83	0.83	0.85	0.84	0.85	0.86	0.86	0.86
Liquefied Petroleum Gas	0.02	0.05	0.05	0.05	0.08	0.07	0.08	0.09	0.08	0.09
Other Petroleum[10]	0.24	0.26	0.26	0.26	0.30	0.30	0.30	0.32	0.32	0.32
Petroleum Subtotal	26.22	31.64	31.86	31.64	36.09	35.75	36.13	37.91	38.07	37.98
Pipeline Fuel Natural Gas	0.63	0.81	0.78	0.80	1.05	1.02	1.04	1.11	1.06	1.09
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.09	0.09	0.09	0.10	0.10	0.10
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00
Electricity	0.07	0.09	0.09	0.09	0.12	0.12	0.12	0.13	0.13	0.13
Delivered Energy	**26.94**	**32.61**	**32.79**	**32.60**	**37.36**	**36.99**	**37.38**	**39.25**	**39.38**	**39.31**
Electricity Related Losses	0.17	0.19	0.20	0.19	0.22	0.22	0.22	0.24	0.25	0.24
Total	**27.10**	**32.80**	**32.99**	**32.79**	**37.58**	**37.21**	**37.60**	**39.50**	**39.63**	**39.55**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.94	9.64	9.68	9.62	10.99	10.89	10.91	11.71	11.70	11.61
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.91	3.92	3.91	5.01	5.01	5.01	5.56	5.57	5.56
Liquefied Petroleum Gas	2.70	3.16	3.16	3.16	3.63	3.62	3.63	3.78	3.80	3.80
Motor Gasoline[2]	16.46	19.78	19.94	19.78	21.77	21.52	21.80	22.33	22.49	22.38
Petrochemical Feedstock	1.14	1.41	1.42	1.41	1.53	1.52	1.52	1.57	1.58	1.57
Residual Fuel	1.15	1.05	1.05	1.03	1.07	1.06	1.06	1.08	1.07	1.06
Other Petroleum[12]	4.24	4.41	4.45	4.41	4.36	4.39	4.38	4.42	4.49	4.42
Petroleum Subtotal	37.21	43.48	43.74	43.44	48.47	48.13	48.42	50.55	50.80	50.51
Natural Gas	16.02	18.57	18.62	18.51	20.68	20.93	20.28	22.36	23.02	21.54
Lease and Plant Fuel Plant[6]	1.20	1.40	1.37	1.39	1.70	1.68	1.70	1.77	1.73	1.76
Pipeline Natural Gas	0.63	0.81	0.78	0.80	1.05	1.02	1.04	1.11	1.06	1.09
Natural Gas Subtotal	17.86	20.78	20.77	20.71	23.43	23.64	23.02	25.23	25.82	24.39
Metallurgical Coal	0.72	0.65	0.66	0.65	0.47	0.48	0.47	0.39	0.40	0.39
Steam Coal	1.53	1.44	1.51	1.41	1.40	1.35	1.37	1.39	1.37	1.34
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.18	0.17	0.18	0.21	0.21	0.21
Coal Subtotal	2.27	2.20	2.27	2.16	2.05	2.00	2.02	1.99	1.98	1.95
Renewable Energy[13]	2.31	2.72	2.73	2.72	3.26	3.24	3.26	3.53	3.54	3.54
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00
Electricity	11.65	13.82	13.86	13.83	15.24	14.98	15.40	15.87	15.82	16.15
Delivered Energy	**71.29**	**83.01**	**83.38**	**82.87**	**92.45**	**91.98**	**92.12**	**97.19**	**97.97**	**96.54**
Electricity Related Losses	26.00	28.66	29.33	28.67	28.05	27.82	28.18	28.78	29.32	28.90
Total	**97.29**	**111.67**	**112.70**	**111.54**	**120.50**	**119.80**	**120.30**	**125.97**	**127.29**	**125.45**
Electric Power[14]										
Distillate Fuel	0.17	0.07	0.07	0.07	0.05	0.05	0.05	0.06	0.04	0.04
Residual Fuel	1.08	0.19	0.20	0.19	0.14	0.13	0.14	0.14	0.14	0.15
Petroleum Subtotal	1.25	0.26	0.27	0.26	0.19	0.18	0.19	0.21	0.19	0.19
Natural Gas	5.40	7.33	6.59	7.34	13.25	12.32	13.34	14.30	11.47	14.54
Steam Coal	19.75	19.79	21.37	19.96	8.18	5.69	8.47	4.74	5.16	5.20
Nuclear Power	8.03	8.37	8.37	8.37	9.75	10.35	9.75	12.39	14.28	12.39
Renewable Energy[15]	3.01	6.30	6.17	6.15	11.42	13.71	11.34	12.69	13.86	12.45
Electricity Imports	0.21	0.43	0.41	0.43	0.50	0.55	0.49	0.32	0.19	0.29
Total	**37.65**	**42.48**	**43.19**	**42.50**	**43.29**	**42.80**	**43.58**	**44.65**	**45.15**	**45.05**

Table H2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Total Energy Consumption										
Distillate Fuel	8.10	9.71	9.76	9.69	11.04	10.94	10.96	11.77	11.74	11.66
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.91	3.92	3.91	5.01	5.01	5.01	5.56	5.57	5.56
Liquefied Petroleum Gas	2.70	3.16	3.16	3.16	3.63	3.62	3.63	3.78	3.80	3.80
Motor Gasoline[2]	16.46	19.78	19.94	19.78	21.77	21.52	21.80	22.33	22.49	22.38
Petrochemical Feedstock	1.14	1.41	1.42	1.41	1.53	1.52	1.52	1.57	1.58	1.57
Residual Fuel	2.23	1.24	1.25	1.22	1.20	1.19	1.19	1.22	1.22	1.21
Other Petroleum[12]	4.24	4.41	4.45	4.41	4.36	4.39	4.38	4.42	4.49	4.42
Petroleum Subtotal	38.46	43.74	44.02	43.70	48.65	48.31	48.61	50.76	50.99	50.70
Natural Gas	21.42	25.91	25.21	25.85	33.94	33.26	33.63	36.67	34.50	36.09
Lease and Plant Fuel[6]	1.20	1.40	1.37	1.39	1.70	1.68	1.70	1.77	1.73	1.76
Pipeline Natural Gas	0.63	0.81	0.78	0.80	1.05	1.02	1.04	1.11	1.06	1.09
Natural Gas Subtotal	23.26	28.12	27.36	28.05	36.69	35.96	36.37	39.54	37.30	38.94
Metallurgical Coal	0.72	0.65	0.66	0.65	0.47	0.48	0.47	0.39	0.40	0.39
Steam Coal	21.28	21.24	22.88	21.37	9.58	7.04	9.84	6.13	6.53	6.54
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.18	0.17	0.18	0.21	0.21	0.21
Coal Subtotal	22.02	22.00	23.65	22.13	10.23	7.69	10.49	6.74	7.14	7.15
Nuclear Power	8.03	8.37	8.37	8.37	9.75	10.35	9.75	12.39	14.28	12.39
Renewable Energy[16]	5.32	9.03	8.90	8.87	14.68	16.95	14.59	16.22	17.40	15.98
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00
Electricity Imports	0.21	0.43	0.41	0.43	0.50	0.55	0.49	0.32	0.19	0.29
Total	**97.29**	**111.67**	**112.70**	**111.54**	**120.50**	**119.80**	**120.30**	**125.97**	**127.29**	**125.45**
Energy Use and Related Statistics										
Delivered Energy Use	71.29	83.01	83.38	82.87	92.45	91.98	92.12	97.19	97.97	96.54
Total Energy Use	97.29	111.67	112.70	111.54	120.50	119.80	120.30	125.97	127.29	125.45
Population (millions)	278.18	300.24	300.24	300.24	325.32	325.32	325.32	338.24	338.24	338.24
Gross Domestic Product (billion 1996 dollars)	9215	12211	12239	12208	16364	16283	16368	18810	18860	18838
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1558.6	1710.1	1747.4	1711.4	1568.5	1494.3	1562.9	1482.2	1485.4	1457.9

[1] Includes wood used for residential heating. See Table H18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.

[2] Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.

[3] Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table H18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.

[4] Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.

[5] Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.

[6] Represents natural gas used in the field gathering and processing plant machinery.

[7] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.

[8] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.

[9] Includes only kerosene type.

[10] Includes aviation gasoline and lubricants.

[11] E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).

[12] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.

[13] Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

[14] Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[15] Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.

[16] Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.

Sources: 2001 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 population and gross domestic product: Global Insight macroeconomic model CTL0802. 2001 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H3. Delivered Energy Prices by Sector and Source

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Residential	**15.81**	**14.62**	**14.26**	**14.60**	**17.37**	**17.46**	**17.40**	**18.74**	**18.06**	**18.69**
Primary Energy[1]	9.73	8.11	8.08	8.08	8.48	8.30	8.49	8.88	8.53	8.77
Petroleum Products[2]	10.85	9.88	9.98	9.93	10.32	10.42	10.36	10.79	10.76	10.75
Distillate Fuel	8.99	7.95	7.96	7.95	8.23	8.23	8.20	8.58	8.58	8.57
Liquefied Petroleum Gas	14.84	13.97	14.28	14.14	14.44	14.80	14.64	14.96	14.89	14.88
Natural Gas	9.41	7.67	7.60	7.62	8.07	7.83	8.07	8.48	8.08	8.37
Electricity	25.37	24.10	23.20	24.09	30.32	31.01	30.39	33.29	32.23	33.34
Commercial	**15.50**	**14.35**	**13.86**	**14.49**	**17.78**	**17.87**	**18.56**	**19.27**	**18.28**	**20.72**
Primary Energy[1]	7.81	6.50	6.44	6.52	6.93	6.73	7.01	7.33	6.99	7.32
Petroleum Products[2]	7.27	6.70	6.74	6.78	6.96	6.92	7.13	7.28	7.26	7.47
Distillate Fuel	6.40	5.63	5.63	5.62	5.96	5.91	5.94	6.30	6.30	6.30
Residual Fuel	3.46	3.93	3.95	3.94	3.96	3.90	3.97	4.02	4.02	4.03
Natural Gas	8.09	6.59	6.51	6.55	7.07	6.83	7.10	7.48	7.07	7.41
Electricity	23.28	21.51	20.62	21.50	27.61	28.52	27.62	30.97	29.99	30.95
Industrial[3]	**7.11**	**6.61**	**6.46**	**6.61**	**7.80**	**7.81**	**7.82**	**8.45**	**8.10**	**8.38**
Primary Energy	5.83	5.16	5.16	5.16	5.65	5.59	5.69	5.97	5.76	5.90
Petroleum Products[2]	7.72	6.93	7.04	6.98	7.40	7.49	7.46	7.68	7.65	7.63
Distillate Fuel	6.55	5.71	5.72	5.71	6.18	6.08	6.15	6.53	6.53	6.52
Liquefied Petroleum Gas	12.34	9.58	9.87	9.74	10.14	10.46	10.32	10.60	10.50	10.50
Residual Fuel	3.28	3.66	3.67	3.65	3.70	3.64	3.70	3.77	3.76	3.76
Natural Gas[4]	4.87	4.11	4.02	4.06	4.68	4.45	4.69	5.07	4.66	4.97
Metallurgical Coal	1.69	1.51	1.51	1.50	1.40	1.40	1.39	1.34	1.33	1.34
Steam Coal	1.46	1.38	1.38	1.38	1.14	1.10	1.15	1.04	1.06	1.07
Electricity	14.13	14.34	13.49	14.34	18.65	19.27	18.67	20.86	20.07	20.83
Transportation	**10.28**	**11.73**	**10.99**	**11.72**	**13.27**	**13.34**	**13.25**	**14.17**	**13.78**	**14.18**
Primary Energy	10.25	11.70	10.97	11.70	13.24	13.30	13.22	14.12	13.74	14.14
Petroleum Products[2]	10.25	11.71	10.97	11.71	13.25	13.32	13.23	14.14	13.75	14.15
Distillate Fuel[5]	10.05	11.71	10.95	11.72	13.17	13.54	13.15	14.37	14.10	14.34
Jet Fuel[6]	6.20	7.10	6.38	7.10	9.26	9.63	9.23	10.35	10.04	10.35
Motor Gasoline[7]	11.57	12.98	12.24	12.97	14.52	14.40	14.50	15.31	14.85	15.34
Residual Fuel	3.90	5.19	4.38	5.18	7.36	7.79	7.34	8.32	7.97	8.32
Liquefied Petroleum Gas[8]	16.93	16.35	16.08	16.50	18.30	19.10	18.43	19.15	18.63	18.90
Natural Gas[9]	7.65	7.25	7.21	7.24	7.72	7.48	8.02	8.08	7.70	8.38
Electricity	21.87	20.82	19.92	20.80	24.39	24.97	24.41	26.05	25.19	25.97
Average End-Use Energy	**10.75**	**10.87**	**10.40**	**10.87**	**12.73**	**12.78**	**12.80**	**13.71**	**13.22**	**13.81**
Primary Energy	8.52	8.82	8.44	8.82	9.90	9.86	9.93	10.52	10.17	10.54
Electricity	21.34	20.40	19.53	20.40	25.89	26.64	25.94	28.70	27.78	28.75
Electric Power[10]										
Fossil Fuel Average	2.14	1.97	1.85	1.95	3.36	3.44	3.34	4.13	3.55	4.01
Petroleum Products	4.73	4.49	4.48	4.50	5.02	4.97	5.02	5.18	5.15	5.12
Distillate Fuel	6.20	5.01	5.02	5.01	5.39	5.29	5.36	5.64	5.70	5.66
Residual Fuel	4.50	4.29	4.27	4.31	4.88	4.85	4.90	4.98	4.98	4.96
Natural Gas	4.78	4.07	3.94	4.02	4.79	4.56	4.81	5.19	4.72	5.09
Steam Coal	1.25	1.16	1.17	1.16	0.99	0.97	1.00	0.90	0.88	0.92

Table H3. Delivered Energy Prices by Sector and Source (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Average Price to All Users[11]										
Petroleum Products[2]	9.54	10.54	10.03	10.55	11.85	11.92	11.86	12.61	12.32	12.63
Distillate Fuel	9.16	10.25	9.70	10.26	11.58	11.84	11.60	12.64	12.45	12.69
Jet Fuel	6.20	7.10	6.38	7.10	9.26	9.63	9.23	10.35	10.04	10.35
Liquefied Petroleum Gas	12.85	10.43	10.70	10.58	10.93	11.25	11.11	11.40	11.28	11.29
Motor Gasoline[7]	11.57	12.97	12.24	12.96	14.49	14.36	14.46	15.27	14.81	15.30
Residual Fuel	4.11	4.79	4.25	4.80	6.42	6.73	6.43	7.12	6.88	7.15
Natural Gas	6.40	5.24	5.17	5.18	5.63	5.42	5.62	6.03	5.68	5.89
Coal	1.26	1.17	1.19	1.17	1.02	1.00	1.02	0.94	0.92	0.95
Electricity	21.34	20.40	19.53	20.40	25.89	26.64	25.94	28.70	27.78	28.75
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)										
Residential	166.77	175.14	171.12	174.87	215.33	215.24	215.66	237.11	231.56	236.88
Commercial	127.30	136.28	131.88	135.62	191.81	193.88	193.35	227.72	220.35	228.34
Industrial	135.32	141.86	139.17	141.86	185.88	185.70	186.49	212.44	205.09	211.17
Transportation	270.41	372.90	351.82	372.75	481.84	479.75	481.53	540.27	527.74	541.72
Total Non-Renewable Expenditures	699.80	826.18	793.98	825.10	1074.86	1074.57	1077.03	1217.53	1184.73	1218.11
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.11	0.11	0.11	0.15	0.15	0.15
Total Expenditures	**699.81**	**826.23**	**794.03**	**825.15**	**1074.97**	**1074.68**	**1077.15**	**1217.69**	**1184.88**	**1218.27**

[1] Weighted average price includes fuels below as well as coal.

[2] This quantity is the weighted average for all petroleum products, not just those listed below.

[3] Includes combined heat and power, which produces electricity and other useful thermal energy.

[4] Excludes use for lease and plant fuel.

[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.

[6] Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.

[7] Sales weighted-average price for all grades. Includes Federal, State and local taxes.

[8] Includes Federal and State taxes while excluding county and local taxes.

[9] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.

[10] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

[11] Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.

Btu = British thermal unit.

Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H4. Greenhouse Gas Allowance Cost by End-Use Sector and Source

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Commercial										
Petroleum Products[2]	0.00	0.00	0.00	1.53	0.00	0.00	3.45	0.00	0.00	4.29
Distillate Fuel	0.00	0.00	0.00	1.55	0.00	0.00	3.51	0.00	0.00	4.37
Residual Fuel	0.00	0.00	0.00	1.67	0.00	0.00	3.78	0.00	0.00	4.71
Natural Gas	0.00	0.00	0.00	1.13	0.00	0.00	2.56	0.00	0.00	3.19
Industrial[3]										
Petroleum Products[2]	0.00	0.94	0.48	0.94	2.15	2.43	2.14	2.66	2.46	2.67
Distillate Fuel	0.00	1.56	0.79	1.55	3.52	3.99	3.51	4.36	4.04	4.37
Liquefied Petroleum Gas	0.00	1.35	0.68	1.34	3.05	3.45	3.04	3.77	3.49	3.78
Residual Fuel	0.00	1.68	0.85	1.67	3.80	4.29	3.78	4.70	4.35	4.71
Natural Gas[4]	0.00	1.11	0.57	1.11	2.52	2.85	2.51	3.12	2.89	3.13
Metallurgical Coal	0.00	2.00	1.01	1.99	4.51	5.10	4.49	5.58	5.17	5.60
Steam Coal	0.00	2.00	1.02	1.99	4.53	5.12	4.51	5.60	5.19	5.62
Electric Power[5]										
Fossil Fuel Average	0.00	1.78	0.92	1.77	3.32	3.61	3.32	3.80	3.66	3.84
Petroleum Products	0.00	1.65	0.83	1.64	3.72	4.21	3.71	4.60	4.28	4.63
Distillate Fuel	0.00	1.56	0.79	1.55	3.52	3.99	3.51	4.36	4.04	4.37
Residual Fuel	0.00	1.68	0.85	1.67	3.80	4.29	3.78	4.70	4.35	4.71
Natural Gas	0.00	1.14	0.58	1.13	2.57	2.91	2.56	3.18	2.94	3.19
Steam Coal	0.00	2.02	1.02	2.01	4.54	5.13	4.52	5.62	5.22	5.64
Average Allowance Cost to All Users[6]										
Petroleum Products[2]	0.00	0.22	0.11	0.25	0.48	0.55	0.53	0.59	0.54	0.64
Distillate Fuel	0.00	0.20	0.10	0.28	0.43	0.48	0.58	0.53	0.48	0.69
Jet Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquefied Petroleum Gas	0.00	1.09	0.55	1.12	2.51	2.85	2.58	3.13	2.90	3.23
Motor Gasoline	0.00	0.01	0.01	0.02	0.03	0.03	0.03	0.04	0.03	0.04
Residual Fuel	0.00	0.50	0.26	0.54	0.98	1.08	1.10	1.21	1.11	1.37
Natural Gas	0.00	0.72	0.36	0.88	1.78	1.98	2.09	2.19	1.94	2.62
Coal	0.00	2.00	1.02	2.01	4.48	5.04	4.51	5.50	5.11	5.62

[1] Weighted average allowance cost includes fuels below as well as coal.

[2] This quantity is the weighted average for all petroleum products, not just those listed below.

[3] Includes combined heat and power, which produces electricity and other useful thermal energy.

[4] Excludes use for lease and plant fuel.

[5] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

[6] Weighted averages of allowance cost are derived from the prices shown in each sector and the corresponding sectoral consumption.

Btu = British thermal unit.

Projections: EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H5. Energy Prices by Sector and Source with Greenhouse Gas Allowance Cost

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Residential	**15.81**	**14.62**	**14.26**	**14.60**	**17.37**	**17.46**	**17.40**	**18.74**	**18.06**	**18.69**
Primary Energy[1]	9.73	8.11	8.08	8.08	8.48	8.30	8.49	8.88	8.53	8.77
Petroleum Products[2]	10.85	9.88	9.98	9.93	10.32	10.42	10.36	10.79	10.76	10.75
Distillate Fuel	8.99	7.95	7.96	7.95	8.23	8.23	8.20	8.58	8.58	8.57
Liquefied Petroleum Gas	14.84	13.97	14.28	14.14	14.44	14.80	14.64	14.96	14.89	14.88
Natural Gas	9.41	7.67	7.60	7.62	8.07	7.83	8.07	8.48	8.08	8.37
Electricity	25.37	24.10	23.20	24.09	30.32	31.01	30.39	33.29	32.23	33.34
Commercial	**15.50**	**14.35**	**13.86**	**15.05**	**17.78**	**17.87**	**19.75**	**19.27**	**18.28**	**22.18**
Primary Energy[1]	7.81	6.50	6.44	7.72	6.93	6.73	9.73	7.33	6.99	10.69
Petroleum Products[2]	7.27	6.70	6.74	8.31	6.96	6.92	10.58	7.28	7.26	11.77
Distillate Fuel	6.40	5.63	5.63	7.18	5.96	5.91	9.45	6.30	6.30	10.67
Residual Fuel	3.46	3.93	3.95	5.61	3.96	3.90	7.75	4.02	4.02	8.74
Natural Gas	8.09	6.59	6.51	7.68	7.07	6.83	9.66	7.48	7.07	10.60
Electricity	23.28	21.51	20.62	21.50	27.61	28.52	27.62	30.97	29.99	30.95
Industrial[3]	**7.11**	**7.55**	**6.94**	**7.55**	**9.89**	**10.18**	**9.91**	**11.03**	**10.49**	**10.96**
Primary Energy	5.83	6.28	5.73	6.28	8.16	8.42	8.19	9.06	8.62	9.00
Petroleum Products[2]	7.72	7.87	7.51	7.92	9.55	9.92	9.60	10.34	10.11	10.30
Distillate Fuel	6.55	7.27	6.51	7.26	9.70	10.06	9.66	10.89	10.57	10.89
Liquefied Petroleum Gas	12.34	10.93	10.55	11.08	13.19	13.91	13.36	14.38	14.00	14.28
Residual Fuel	3.28	5.34	4.52	5.32	7.49	7.93	7.48	8.46	8.11	8.47
Natural Gas[4]	4.87	5.23	4.59	5.17	7.20	7.30	7.20	8.19	7.55	8.10
Metallurgical Coal	1.69	3.50	2.52	3.49	5.91	6.50	5.89	6.92	6.51	6.94
Steam Coal	1.46	3.38	2.39	3.38	5.67	6.22	5.66	6.64	6.25	6.68
Electricity	14.13	14.34	13.49	14.34	18.65	19.27	18.67	20.86	20.07	20.83
Transportation	**10.28**	**11.73**	**10.99**	**11.73**	**13.28**	**13.35**	**13.26**	**14.17**	**13.78**	**14.19**
Primary Energy	10.25	11.70	10.97	11.70	13.24	13.31	13.22	14.13	13.74	14.14
Petroleum Products[2]	10.25	11.71	10.97	11.71	13.25	13.32	13.23	14.14	13.75	14.15
Distillate Fuel[5]	10.05	11.71	10.95	11.72	13.17	13.54	13.15	14.37	14.10	14.34
Jet Fuel[6]	6.20	7.10	6.38	7.10	9.26	9.63	9.23	10.35	10.04	10.35
Motor Gasoline[7]	11.57	12.98	12.24	12.97	14.52	14.40	14.50	15.31	14.85	15.34
Residual Fuel	3.90	5.19	4.38	5.18	7.36	7.79	7.34	8.32	7.97	8.32
Liquefied Petroleum Gas[8]	16.93	16.35	16.08	16.50	18.30	19.10	18.43	19.15	18.63	18.90
Natural Gas[9]	7.65	8.38	7.79	8.38	10.29	10.38	10.58	11.26	10.64	11.56
Electricity	21.87	20.82	19.92	20.80	24.39	24.97	24.41	26.05	25.19	25.97
Average End-Use Energy	**10.75**	**11.17**	**10.56**	**11.24**	**13.38**	**13.53**	**13.60**	**14.50**	**13.96**	**14.79**
Primary Energy	8.52	9.18	8.63	9.26	10.70	10.75	10.90	11.49	11.07	11.74
Electricity	21.34	20.40	19.53	20.40	25.89	26.64	25.94	28.70	27.78	28.75
Electric Power[10]										
Fossil Fuel Average	2.14	3.75	2.77	3.72	6.68	7.05	6.66	7.93	7.20	7.85
Petroleum Products	4.73	6.13	5.31	6.14	8.74	9.18	8.73	9.77	9.43	9.76
Distillate Fuel	6.20	6.57	5.81	6.56	8.91	9.28	8.87	9.99	9.74	10.03
Residual Fuel	4.50	5.97	5.12	5.98	8.68	9.15	8.68	9.68	9.33	9.67
Natural Gas	4.78	5.20	4.51	5.15	7.36	7.47	7.36	8.37	7.66	8.28
Steam Coal	1.25	3.17	2.20	3.17	5.53	6.09	5.52	6.53	6.10	6.55

Table H5. Energy Prices by Sector and Source with Greenhouse Gas Allowance Cost (Continued)
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Average Price to All Users[11]										
Petroleum Products[2]	9.54	10.76	10.15	10.80	12.34	12.46	12.39	13.20	12.86	13.27
Distillate Fuel	9.16	10.45	9.80	10.55	12.01	12.32	12.18	13.17	12.93	13.38
Jet Fuel	6.20	7.10	6.38	7.10	9.26	9.63	9.23	10.35	10.04	10.35
Liquefied Petroleum Gas	12.85	11.51	11.25	11.70	13.44	14.10	13.69	14.52	14.18	14.52
Motor Gasoline[7]	11.57	12.98	12.24	12.97	14.52	14.39	14.50	15.31	14.84	15.34
Residual Fuel	4.11	5.29	4.51	5.34	7.39	7.81	7.53	8.33	7.99	8.52
Natural Gas	6.40	5.96	5.53	6.06	7.41	7.40	7.71	8.22	7.62	8.51
Coal	1.26	3.18	2.20	3.18	5.50	6.03	5.53	6.44	6.04	6.57
Electricity	21.34	20.40	19.53	20.40	25.89	26.64	25.94	28.70	27.78	28.75
Non-Renewable Energy and Allowance Expenditures by Sector (billion 2001 dollars)										
Residential	166.77	175.14	171.12	174.87	215.33	215.24	215.66	237.11	231.56	236.88
Commercial	127.30	136.28	131.88	140.89	191.81	193.88	205.79	227.72	220.35	244.44
Industrial	135.32	162.27	149.62	162.21	235.92	242.18	236.39	277.18	265.80	276.34
Transportation	270.41	372.97	351.85	372.82	482.08	480.02	481.77	540.60	528.04	542.05
Total Non-Renewable Expenditures	699.80	846.66	804.47	850.78	1125.14	1131.32	1139.61	1282.60	1245.75	1299.72
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.12	0.11	0.12	0.16	0.16	0.16
Total Expenditures	**699.81**	**846.72**	**804.52**	**850.84**	**1125.26**	**1131.44**	**1139.73**	**1282.76**	**1245.90**	**1299.88**

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[1] Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3] Includes combined heat and power, which produces electricity and other useful thermal energy.
[4] Excludes use for lease and plant fuel.
[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6] Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7] Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8] Includes Federal and State taxes while excluding county and local taxes.
[9] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[10] E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[10] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[11] Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H6. Residential Sector Key Indicators and End-Use Consumption

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Key Indicators										
Households (millions)										
Single-Family	77.50	86.14	86.15	86.13	93.99	93.95	93.98	97.43	97.42	97.42
Multifamily	22.19	24.13	24.14	24.13	26.99	26.92	26.98	28.71	28.70	28.71
Mobile Homes	6.57	7.10	7.10	7.10	7.86	7.85	7.86	8.11	8.12	8.12
Total	**106.27**	**117.37**	**117.39**	**117.37**	**128.83**	**128.72**	**128.82**	**134.25**	**134.23**	**134.25**
Average House Square Footage	**1685**	**1740**	**1740**	**1740**	**1782**	**1782**	**1782**	**1798**	**1798**	**1798**
Energy Intensity										
(million Btu per household)										
Delivered Energy Consumption	102.9	105.5	105.7	105.5	99.3	98.9	99.3	97.3	98.5	97.4
Total Energy Consumption	189.0	191.7	194.1	191.7	171.4	170.6	171.0	166.3	169.7	165.6
(thousand Btu per square foot)										
Delivered Energy Consumption	61.1	60.7	60.8	60.7	55.7	55.5	55.8	54.1	54.8	54.2
Total Energy Consumption	112.2	110.2	111.6	110.2	96.2	95.8	96.0	92.5	94.4	92.1
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.39	0.46	0.46	0.46	0.46	0.45	0.46	0.45	0.45	0.45
Space Cooling	0.52	0.60	0.60	0.60	0.59	0.58	0.59	0.59	0.60	0.59
Water Heating	0.45	0.46	0.47	0.46	0.38	0.37	0.38	0.33	0.33	0.33
Refrigeration	0.42	0.34	0.34	0.34	0.32	0.32	0.32	0.33	0.33	0.33
Cooking	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.13
Clothes Dryers	0.22	0.24	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.91	0.92	0.91	0.81	0.78	0.81	0.74	0.77	0.74
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers[1]	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.19	0.19	0.19	0.24	0.23	0.24	0.24	0.25	0.24
Personal Computers	0.06	0.08	0.08	0.08	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10
Other Uses[2]	0.83	1.25	1.25	1.25	1.54	1.53	1.54	1.69	1.69	1.69
Delivered Energy	**4.10**	**4.88**	**4.90**	**4.88**	**5.05**	**4.97**	**5.04**	**5.11**	**5.16**	**5.12**
Natural Gas										
Space Heating	3.13	3.69	3.70	3.69	3.97	3.97	3.97	4.11	4.19	4.14
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.48	1.55	1.55	1.55	1.58	1.58	1.58	1.62	1.65	1.64
Cooking	0.20	0.23	0.23	0.23	0.25	0.25	0.25	0.26	0.26	0.26
Clothes Dryers	0.06	0.08	0.08	0.08	0.10	0.10	0.10	0.10	0.10	0.10
Other Uses[3]	0.06	0.07	0.07	0.07	0.07	0.08	0.07	0.11	0.13	0.08
Delivered Energy	**4.94**	**5.62**	**5.62**	**5.62**	**5.96**	**5.97**	**5.96**	**6.20**	**6.33**	**6.21**
Distillate										
Space Heating	0.74	0.76	0.76	0.76	0.71	0.71	0.71	0.69	0.69	0.69
Water Heating	0.16	0.14	0.14	0.14	0.12	0.12	0.12	0.11	0.11	0.11
Other Uses[4]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.91**	**0.91**	**0.91**	**0.91**	**0.84**	**0.84**	**0.84**	**0.81**	**0.81**	**0.81**
Liquefied Petroleum Gas										
Space Heating	0.26	0.25	0.25	0.25	0.24	0.24	0.24	0.24	0.24	0.24
Water Heating	0.09	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06
Cooking	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Other Uses[3]	0.12	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14
Delivered Energy	**0.50**	**0.47**	**0.47**	**0.47**	**0.47**	**0.46**	**0.46**	**0.47**	**0.46**	**0.47**
Marketed Renewables (wood)[5]	0.39	0.41	0.41	0.41	0.40	0.40	0.40	0.40	0.40	0.40
Other Fuels[6]	0.11	0.09	0.09	0.09	0.08	0.08	0.08	0.07	0.07	0.07

Table H6. Residential Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Delivered Energy Consumption by End-Use										
Space Heating	5.01	5.66	5.67	5.66	5.86	5.85	5.86	5.96	6.05	5.99
Space Cooling	0.52	0.60	0.60	0.60	0.59	0.58	0.59	0.59	0.60	0.59
Water Heating	2.19	2.23	2.24	2.23	2.14	2.14	2.14	2.13	2.15	2.15
Refrigeration	0.42	0.34	0.34	0.34	0.32	0.32	0.32	0.33	0.33	0.33
Cooking	0.33	0.36	0.36	0.36	0.39	0.39	0.39	0.40	0.40	0.40
Clothes Dryers	0.28	0.33	0.33	0.33	0.34	0.34	0.34	0.35	0.36	0.35
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.91	0.92	0.91	0.81	0.78	0.81	0.74	0.77	0.74
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.19	0.19	0.19	0.24	0.23	0.24	0.24	0.25	0.24
Personal Computers	0.06	0.08	0.08	0.08	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10
Other Uses[7]	1.01	1.45	1.45	1.45	1.76	1.74	1.75	1.94	1.96	1.92
Delivered Energy	**10.94**	**12.38**	**12.41**	**12.38**	**12.80**	**12.73**	**12.80**	**13.06**	**13.22**	**13.07**
Electricity Related Losses	**9.15**	**10.11**	**10.37**	**10.11**	**9.29**	**9.23**	**9.23**	**9.26**	**9.55**	**9.16**
Total Energy Consumption by End-Use										
Space Heating	5.89	6.61	6.63	6.61	6.70	6.69	6.70	6.78	6.89	6.79
Space Cooling	1.68	1.83	1.86	1.83	1.68	1.67	1.67	1.67	1.71	1.66
Water Heating	3.20	3.20	3.22	3.19	2.84	2.82	2.84	2.74	2.77	2.74
Refrigeration	1.36	1.05	1.06	1.05	0.91	0.92	0.91	0.93	0.94	0.92
Cooking	0.55	0.59	0.59	0.59	0.61	0.62	0.61	0.63	0.64	0.63
Clothes Dryers	0.78	0.84	0.85	0.84	0.80	0.80	0.80	0.81	0.83	0.80
Freezers	0.36	0.27	0.28	0.27	0.25	0.25	0.25	0.25	0.26	0.25
Lighting	2.40	2.81	2.88	2.81	2.31	2.24	2.30	2.09	2.20	2.07
Clothes Washers	0.10	0.10	0.10	0.10	0.08	0.08	0.08	0.08	0.08	0.08
Dishwashers	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08
Color Televisions	0.43	0.60	0.61	0.60	0.67	0.67	0.67	0.68	0.70	0.68
Personal Computers	0.19	0.25	0.25	0.25	0.29	0.29	0.29	0.32	0.32	0.32
Furnace Fans	0.23	0.26	0.27	0.26	0.27	0.27	0.26	0.27	0.28	0.27
Other Uses[7]	2.86	4.03	4.10	4.03	4.59	4.58	4.57	4.99	5.10	4.95
Total	**20.08**	**22.50**	**22.78**	**22.49**	**22.09**	**21.96**	**22.03**	**22.32**	**22.78**	**22.23**
Non-Marketed Renewables										
Geothermal[8]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar[9]	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Total	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**

[1] Does not include electric water heating portion of load.
[2] Includes small electric devices, heating elements, and motors.
[3] Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4] Includes such appliances as swimming pool and hot tub heaters.
[5] Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.
[6] Includes kerosene and coal.
[7] Includes all other uses listed above.
[8] Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9] Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H7. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Key Indicators										
Total Floorspace (billion square feet)										
Surviving	66.6	79.0	79.0	79.0	90.8	90.7	90.8	97.1	96.9	97.1
New Additions	3.6	3.0	3.0	3.0	3.4	3.3	3.4	3.4	3.5	3.4
Total	**70.2**	**82.0**	**82.0**	**82.0**	**94.2**	**94.0**	**94.2**	**100.6**	**100.3**	**100.6**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	118.4	117.1	117.3	115.5	115.6	116.5	111.7	118.6	121.2	110.6
Electricity Related Losses	129.9	125.6	128.5	125.9	110.6	109.6	113.4	107.6	109.3	111.2
Total Energy Consumption	248.3	242.7	245.8	241.3	226.1	226.1	225.1	226.2	230.4	221.8
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating[1]	0.14	0.15	0.15	0.15	0.14	0.14	0.14	0.13	0.13	0.13
Space Cooling[1]	0.43	0.42	0.42	0.42	0.41	0.40	0.42	0.40	0.39	0.42
Water Heating[1]	0.15	0.15	0.15	0.15	0.14	0.14	0.14	0.13	0.13	0.14
Ventilation	0.17	0.18	0.18	0.18	0.17	0.16	0.17	0.16	0.16	0.17
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.03
Lighting	1.02	1.18	1.19	1.19	0.99	0.94	1.12	0.88	0.87	1.01
Refrigeration	0.21	0.24	0.24	0.24	0.24	0.23	0.25	0.23	0.23	0.25
Office Equipment (PC)	0.16	0.24	0.24	0.24	0.31	0.31	0.31	0.34	0.34	0.35
Office Equipment (non-PC)	0.31	0.47	0.47	0.47	0.72	0.71	0.73	0.87	0.86	0.90
Other Uses[2]	1.46	1.90	1.90	1.90	2.51	2.49	2.52	2.80	2.79	2.85
Delivered Energy	**4.08**	**4.97**	**4.98**	**4.98**	**5.66**	**5.55**	**5.84**	**5.97**	**5.92**	**6.25**
Natural Gas										
Space Heating[1]	1.32	1.53	1.53	1.50	1.58	1.56	1.51	1.56	1.58	1.53
Space Cooling[1]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Water Heating[1]	0.57	0.69	0.69	0.68	0.77	0.76	0.73	0.78	0.79	0.75
Cooking	0.25	0.30	0.30	0.29	0.33	0.33	0.31	0.35	0.35	0.32
Other Uses[3]	1.17	1.20	1.20	1.17	1.57	1.76	1.28	2.25	2.52	1.43
Delivered Energy	**3.33**	**3.74**	**3.74**	**3.66**	**4.27**	**4.44**	**3.86**	**4.97**	**5.27**	**4.07**
Distillate										
Space Heating[1]	0.17	0.23	0.24	0.23	0.27	0.26	0.22	0.28	0.26	0.20
Water Heating[1]	0.07	0.08	0.08	0.07	0.08	0.08	0.07	0.08	0.08	0.07
Other Uses[4]	0.22	0.20	0.20	0.19	0.20	0.20	0.18	0.20	0.20	0.17
Delivered Energy	**0.46**	**0.51**	**0.51**	**0.49**	**0.54**	**0.55**	**0.46**	**0.56**	**0.55**	**0.44**
Other Fuels[5]	**0.34**	**0.29**	**0.28**	**0.23**	**0.31**	**0.31**	**0.26**	**0.32**	**0.32**	**0.26**
Marketed Renewable Fuels										
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Energy	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Delivered Energy Consumption by End-Use										
Space Heating[1]	1.63	1.92	1.92	1.88	1.98	1.96	1.87	1.97	1.97	1.87
Space Cooling[1]	0.44	0.44	0.44	0.44	0.44	0.43	0.45	0.43	0.42	0.45
Water Heating[1]	0.79	0.92	0.92	0.91	0.99	0.98	0.94	0.99	1.00	0.96
Ventilation	0.17	0.18	0.18	0.18	0.17	0.16	0.17	0.16	0.16	0.17
Cooking	0.29	0.33	0.33	0.33	0.36	0.36	0.34	0.37	0.38	0.35
Lighting	1.02	1.18	1.19	1.19	0.99	0.94	1.12	0.88	0.87	1.01
Refrigeration	0.21	0.24	0.24	0.24	0.24	0.23	0.25	0.23	0.23	0.25
Office Equipment (PC)	0.16	0.24	0.24	0.24	0.31	0.31	0.31	0.34	0.34	0.35
Office Equipment (non-PC)	0.31	0.47	0.47	0.47	0.72	0.71	0.73	0.87	0.86	0.90
Other Uses[6]	3.30	3.69	3.69	3.60	4.69	4.86	4.34	5.68	5.93	4.82
Delivered Energy	**8.32**	**9.60**	**9.62**	**9.47**	**10.89**	**10.95**	**10.52**	**11.92**	**12.16**	**11.13**

Table H7. Commercial Sector Key Indicators and Consumption (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Electricity Related Losses	**9.12**	**10.30**	**10.54**	**10.32**	**10.42**	**10.30**	**10.68**	**10.82**	**10.96**	**11.18**
Total Energy Consumption by End-Use										
Space Heating[1]	1.95	2.24	2.25	2.20	2.24	2.22	2.12	2.20	2.21	2.11
Space Cooling[1]	1.39	1.32	1.34	1.32	1.21	1.18	1.23	1.15	1.15	1.20
Water Heating[1]	1.12	1.24	1.25	1.23	1.25	1.24	1.21	1.23	1.24	1.20
Ventilation	0.55	0.55	0.56	0.55	0.48	0.47	0.49	0.45	0.45	0.47
Cooking	0.37	0.40	0.40	0.40	0.41	0.41	0.39	0.41	0.42	0.40
Lighting	3.31	3.62	3.69	3.65	2.80	2.68	3.16	2.48	2.49	2.81
Refrigeration	0.69	0.73	0.74	0.73	0.68	0.67	0.70	0.66	0.66	0.70
Office Equipment (PC)	0.52	0.74	0.75	0.74	0.88	0.88	0.89	0.96	0.96	0.98
Office Equipment (non-PC)	0.99	1.43	1.46	1.43	2.06	2.04	2.07	2.45	2.45	2.51
Other Uses[6]	6.56	7.63	7.71	7.54	9.31	9.48	8.96	10.76	11.09	9.93
Total	**17.44**	**19.90**	**20.16**	**19.79**	**21.31**	**21.26**	**21.21**	**22.74**	**23.12**	**22.31**
Non-Marketed Renewable Fuels										
Solar[7]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

[1] Includes fuel consumption for district services.

[2] Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.

[3] Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.

[4] Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.

[5] Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.

[6] Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.

[7] Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.

Btu = British thermal unit.

PC = Personal computer.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H8. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Key Indicators										
Value of Shipments (billion 1996 dollars)										
Manufacturing	4079	5420	5444	5418	7160	7131	7157	8162	8176	8176
Nonmanufacturing	1346	1500	1504	1500	1714	1691	1715	1828	1842	1830
Total	**5425**	**6920**	**6949**	**6918**	**8874**	**8823**	**8872**	**9990**	**10018**	**10006**
Energy Prices (2001 dollars per million Btu)										
Electricity	14.13	14.34	13.49	14.34	18.65	19.27	18.67	20.86	20.07	20.83
Natural Gas	4.87	5.23	4.59	5.17	7.20	7.30	7.20	8.19	7.55	8.10
Steam Coal	1.46	3.38	2.39	3.38	5.67	6.22	5.66	6.64	6.25	6.68
Residual Oil	3.28	5.34	4.52	5.32	7.49	7.93	7.48	8.46	8.11	8.47
Distillate Oil	6.55	7.27	6.51	7.26	9.70	10.06	9.66	10.89	10.57	10.89
Liquefied Petroleum Gas	12.34	10.93	10.55	11.08	13.19	13.91	13.36	14.38	14.00	14.28
Motor Gasoline	11.57	12.94	12.20	12.93	14.49	14.34	14.46	15.28	14.80	15.31
Metallurgical Coal	1.69	3.50	2.52	3.49	5.91	6.50	5.89	6.92	6.51	6.94
Energy Consumption[1]										
Purchased Electricity	3.39	3.89	3.89	3.88	4.41	4.34	4.40	4.66	4.62	4.65
Natural Gas	7.74	9.16	9.19	9.17	10.36	10.42	10.37	11.09	11.33	11.16
Lease and Plant Fuel[2]	1.20	1.40	1.37	1.39	1.70	1.68	1.70	1.77	1.73	1.76
Natural Gas Subtotal	8.94	10.56	10.57	10.57	12.06	12.10	12.07	12.86	13.06	12.92
Steam Coal	1.42	1.33	1.40	1.34	1.28	1.23	1.28	1.26	1.24	1.26
Metallurgical Coal and Coke[3]	0.74	0.76	0.77	0.76	0.65	0.65	0.65	0.60	0.61	0.61
Residual Fuel	0.23	0.18	0.18	0.18	0.17	0.17	0.17	0.17	0.17	0.17
Distillate	1.13	1.20	1.20	1.20	1.30	1.28	1.30	1.36	1.36	1.36
Liquefied Petroleum Gas	2.10	2.54	2.54	2.55	2.99	2.99	3.00	3.14	3.15	3.15
Petrochemical Feedstocks	1.14	1.41	1.42	1.41	1.53	1.52	1.52	1.57	1.58	1.57
Other Petroleum[4]	4.18	4.34	4.38	4.34	4.27	4.30	4.29	4.32	4.39	4.32
Renewables[5]	1.82	2.21	2.21	2.21	2.74	2.72	2.74	3.02	3.03	3.02
Delivered Energy	**25.10**	**28.41**	**28.55**	**28.42**	**31.40**	**31.31**	**31.41**	**32.96**	**33.21**	**33.03**
Electricity Related Losses	7.57	8.06	8.22	8.05	8.12	8.06	8.05	8.45	8.56	8.32
Total	**32.67**	**36.47**	**36.78**	**36.47**	**39.53**	**39.37**	**39.46**	**41.40**	**41.76**	**41.35**
Energy Consumption per dollar of Shipments[1] (thousand Btu per 1996 dollars)										
Purchased Electricity	0.63	0.56	0.56	0.56	0.50	0.49	0.50	0.47	0.46	0.46
Natural Gas	1.43	1.32	1.32	1.33	1.17	1.18	1.17	1.11	1.13	1.12
Lease and Plant Fuel[2]	0.22	0.20	0.20	0.20	0.19	0.19	0.19	0.18	0.17	0.18
Natural Gas Subtotal	1.65	1.53	1.52	1.53	1.36	1.37	1.36	1.29	1.30	1.29
Steam Coal	0.26	0.19	0.20	0.19	0.14	0.14	0.14	0.13	0.12	0.13
Metallurgical Coal and Coke[3]	0.14	0.11	0.11	0.11	0.07	0.07	0.07	0.06	0.06	0.06
Residual Fuel	0.04	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Distillate	0.21	0.17	0.17	0.17	0.15	0.15	0.15	0.14	0.14	0.14
Liquefied Petroleum Gas	0.39	0.37	0.37	0.37	0.34	0.34	0.34	0.31	0.31	0.32
Petrochemical Feedstocks	0.21	0.20	0.20	0.20	0.17	0.17	0.17	0.16	0.16	0.16
Other Petroleum[4]	0.77	0.63	0.63	0.63	0.48	0.49	0.48	0.43	0.44	0.43
Renewables[5]	0.33	0.32	0.32	0.32	0.31	0.31	0.31	0.30	0.30	0.30
Delivered Energy	**4.63**	**4.11**	**4.11**	**4.11**	**3.54**	**3.55**	**3.54**	**3.30**	**3.31**	**3.30**
Electricity Related Losses	1.40	1.16	1.18	1.16	0.92	0.91	0.91	0.85	0.85	0.83
Total	**6.02**	**5.27**	**5.29**	**5.27**	**4.45**	**4.46**	**4.45**	**4.14**	**4.17**	**4.13**

[1] Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2] Represents natural gas used in the field gathering and processing plant machinery.
[3] Includes net coal coke imports.
[4] Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 coal prices are based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 consumption values based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **2001** shipments: Global Insight macroeconomic model CTL0802. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H9. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 pounds (VMT)	2409	2975	2997	2975	3547	3504	3551	3795	3862	3803
Commercial Light Trucks (VMT)[1]	66	83	83	83	104	103	104	115	116	116
Freight Trucks >10,000 pounds (VMT)	206	263	264	263	335	333	335	377	378	378
Air (seat miles available)	1109	1348	1354	1348	1928	1923	1928	2231	2229	2230
Rail (ton miles traveled)	1448	1579	1640	1573	1467	1384	1477	1486	1505	1498
Domestic Shipping (ton miles traveled)	788	869	874	871	950	929	950	992	1005	991
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	24.1	25.3	25.2	25.3	28.1	28.8	28.1	29.0	29.7	29.0
New Car (miles per gallon)[2]	28.1	28.8	28.6	28.8	32.6	33.5	32.6	32.9	33.7	32.9
New Light Truck (miles per gallon)[2]	20.7	22.5	22.4	22.5	24.6	25.3	24.6	25.8	26.4	25.8
Light-Duty Fleet (miles per gallon)[3]	19.8	19.6	19.6	19.6	20.9	21.0	20.9	21.8	22.0	21.8
New Commercial Light Truck (MPG)[1]	13.8	14.8	14.8	14.8	16.3	16.7	16.3	17.1	17.5	17.1
Stock Commercial Light Truck (MPG)[1]	13.7	14.3	14.3	14.3	15.4	15.4	15.4	16.2	16.4	16.2
Aircraft Efficiency (seat miles per gallon)	51.2	54.3	54.3	54.3	59.1	59.0	59.1	61.2	61.1	61.2
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.0	6.4	6.4	6.4	6.6	6.6	6.6
Rail Efficiency (ton miles per thousand Btu)	2.8	3.1	3.1	3.1	3.4	3.4	3.4	3.6	3.6	3.6
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	15.28	18.86	19.01	18.86	20.99	20.71	21.02	21.55	21.68	21.61
Commercial Light Trucks[1]	0.60	0.73	0.73	0.73	0.84	0.84	0.85	0.89	0.89	0.89
Freight Trucks[4]	4.68	5.88	5.90	5.87	6.94	6.92	6.94	7.55	7.58	7.56
Air[5]	3.47	3.96	3.97	3.96	5.07	5.07	5.07	5.63	5.63	5.62
Rail[6]	0.63	0.65	0.67	0.65	0.59	0.56	0.59	0.59	0.59	0.59
Marine[7]	1.45	1.49	1.49	1.49	1.56	1.55	1.56	1.60	1.61	1.60
Pipeline Fuel	0.63	0.81	0.78	0.80	1.05	1.02	1.04	1.11	1.06	1.09
Lubricants	0.19	0.21	0.22	0.21	0.26	0.25	0.26	0.28	0.28	0.28
Total	**26.94**	**32.58**	**32.76**	**32.57**	**37.30**	**36.93**	**37.32**	**39.19**	**39.31**	**39.24**
Energy Use by Mode (million barrels per day oil equivalent)										
Light-Duty Vehicles	8.05	9.96	10.04	9.96	11.07	10.93	11.09	11.36	11.43	11.39
Commercial Light Trucks[1]	0.32	0.38	0.39	0.38	0.45	0.44	0.45	0.47	0.47	0.47
Freight Trucks	2.05	2.59	2.60	2.59	3.09	3.08	3.09	3.37	3.38	3.38
Railroad	0.24	0.24	0.25	0.24	0.20	0.19	0.20	0.19	0.20	0.20
Domestic Shipping	0.16	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19	0.19
International Shipping	0.34	0.33	0.33	0.33	0.34	0.34	0.34	0.34	0.34	0.34
Air[5]	1.44	1.64	1.65	1.64	2.15	2.15	2.15	2.40	2.40	2.40
Military Use	0.30	0.34	0.34	0.34	0.38	0.38	0.38	0.40	0.40	0.40
Bus Transportation	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Rail Transportation[6]	0.05	0.06	0.06	0.06	0.08	0.08	0.08	0.08	0.08	0.08
Recreational Boats	0.16	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20
Lubricants	0.09	0.10	0.10	0.10	0.12	0.12	0.12	0.13	0.13	0.13
Pipeline Fuel	0.32	0.41	0.40	0.41	0.53	0.52	0.53	0.56	0.54	0.55
Total	**13.64**	**16.54**	**16.64**	**16.54**	**18.90**	**18.71**	**18.92**	**19.83**	**19.90**	**19.86**

[1] Commercial trucks 8,500 to 10,000 pounds.
[2] Environmental Protection Agency rated miles per gallon.
[3] Combined car and light truck "on-the-road" estimate.
[4] Includes energy use by buses and military distillate consumption.
[5] Includes jet fuel and aviation gasoline.
[6] Includes passenger rail.
[7] Includes military residual fuel use and recreational boats.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001); Federal Highway Administration, *Highway Statistics 2000* (Washington, DC, November 2001); Oak Ridge National Laboratory, Transportation Energy Data Book: *Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey" EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA,*State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2001/2000* (Washington, DC, 2001); EIA, *Fuel Oil and Kerosene Sales 2001*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/historical/foks.html; and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H10. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Generation by Fuel Type										
Electric Power Sector[1]										
Power Only[2]										
Coal	1848	1927	2068	1942	836	596	874	526	595	599
Petroleum	113	19	21	19	11	11	11	13	11	11
Natural Gas[3]	411	811	702	815	1745	1572	1756	1889	1488	1917
Nuclear Power	769	801	801	801	934	991	934	1186	1368	1186
Pumped Storage/Other	-9	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[4]	258	517	497	503	991	1236	990	1122	1250	1111
Distributed Generation (Natural Gas)	0	5	9	5	13	28	14	13	28	14
Non-Utility Generation for Own Use	-21	-26	-27	-27	-26	-26	-26	-25	-25	-25
Total	**3370**	**4053**	**4070**	**4059**	**4503**	**4408**	**4552**	**4725**	**4714**	**4812**
Combined Heat and Power[5]										
Coal	33	30	32	30	16	14	15	10	8	8
Petroleum	7	3	3	3	3	3	3	3	3	3
Natural Gas	124	161	157	159	131	141	133	115	121	118
Renewable Sources	5	4	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-9	-18	-18	-18	-17	-16	-16	-16	-16	-16
Total	**162**	**181**	**178**	**178**	**138**	**145**	**139**	**116**	**119**	**117**
Net Available to the Grid	**3532**	**4234**	**4249**	**4237**	**4641**	**4553**	**4691**	**4841**	**4833**	**4929**
End-Use Sector Generation										
Combined Heat and Power[6]										
Coal	23	23	23	23	23	23	23	23	23	23
Petroleum	6	6	6	6	6	6	6	6	7	6
Natural Gas	84	122	126	124	201	238	182	328	382	245
Other Gaseous Fuels[7]	6	7	7	7	7	7	7	7	7	7
Renewable Sources[4]	31	39	40	39	50	49	50	55	55	55
Other[8]	11	11	11	11	11	11	11	11	11	11
Total	**160**	**209**	**213**	**211**	**298**	**335**	**280**	**431**	**486**	**348**
Other End-Use Generators[9]	4	5	5	5	6	6	6	7	7	7
Generation for Own Use	-138	-173	-176	-174	-241	-261	-227	-328	-360	-279
Total Sales to the Grid	**27**	**41**	**42**	**41**	**63**	**80**	**58**	**110**	**133**	**75**
Net Imports	**20**	**41**	**40**	**41**	**48**	**53**	**48**	**31**	**18**	**28**
Electricity Sales by Sector										
Residential	1201	1429	1437	1430	1479	1457	1478	1498	1511	1500
Commercial	1197	1455	1459	1459	1659	1626	1711	1750	1734	1831
Industrial	994	1139	1139	1138	1293	1272	1289	1366	1353	1362
Transportation	22	27	27	27	35	35	35	39	39	39
Total	**3414**	**4050**	**4062**	**4054**	**4467**	**4390**	**4514**	**4653**	**4638**	**4732**
End-Use Prices[10] (2001 cents per kilowatthour)										
Residential	8.7	8.2	7.9	8.2	10.3	10.6	10.4	11.4	11.0	11.4
Commercial	7.9	7.3	7.0	7.3	9.4	9.7	9.4	10.6	10.2	10.6
Industrial	4.8	4.9	4.6	4.9	6.4	6.6	6.4	7.1	6.8	7.1
Transportation	7.5	7.1	6.8	7.1	8.3	8.5	8.3	8.9	8.6	8.9
All Sectors Average	**7.3**	**7.0**	**6.7**	**7.0**	**8.8**	**9.1**	**8.9**	**9.8**	**9.5**	**9.8**
Prices by Service Category[10] (2001 cents per kilowatthour)										
Generation	4.7	4.4	4.1	4.4	6.1	6.4	6.2	7.1	6.8	7.1
Transmission	0.5	0.6	0.6	0.6	0.7	0.8	0.7	0.8	0.8	0.8
Distribution	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0

Table H10. Electricity Supply, Disposition, Prices, and Emissions (Continued)

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Emissions										
Sulfur Dioxide (million tons)	10.63	9.84	8.95	9.84	5.87	3.88	6.08	1.93	2.09	1.90
Nitrogen Oxide (million tons)	4.75	3.50	3.72	3.53	1.48	0.98	1.48	0.67	0.54	0.58
Mercury (tons)	53.52	48.66	51.16	48.47	19.07	11.58	19.57	7.18	6.91	6.30

[1] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes plants that only produce electricity.

[3] Includes electricity generation from fuel cells.

[4] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.

[5] Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).

[6] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[7] Other gaseous fuels include refinery and still gas.

[8] Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.

[9] Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[10] Prices represent average revenue per kilowatthour.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Source: 2001 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and supporting databases. 2001 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2001 prices: EIA, National Energy Modeling System run MLBILL.D050503A. **Projections**: EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H11. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Electric Power Sector[2]										
Power Only[3]										
Coal Steam	305.3	289.0	289.1	288.2	209.3	179.1	213.5	139.9	157.8	153.6
Other Fossil Steam[4]	133.8	80.7	72.6	81.5	64.8	57.0	66.0	53.0	42.5	55.3
Combined Cycle	43.2	175.9	173.2	178.1	319.1	284.4	320.5	374.1	309.5	378.8
Combustion Turbine/Diesel	97.6	123.2	123.0	123.3	121.4	115.7	123.0	118.2	112.2	120.1
Nuclear Power[5]	98.2	100.3	100.3	100.3	117.2	124.4	117.2	149.2	173.1	149.2
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	90.4	129.0	123.0	124.7	225.0	266.8	226.1	245.6	269.0	243.9
Distributed Generation[7]	0.0	1.7	2.7	1.7	4.9	7.2	5.3	5.0	7.6	5.4
Total	**788.3**	**920.2**	**904.4**	**918.2**	**1082.2**	**1055.1**	**1092.1**	**1105.4**	**1092.2**	**1126.8**
Combined Heat and Power[8]										
Coal Steam	5.2	4.4	4.6	4.4	3.3	3.1	3.0	2.6	2.9	2.6
Other Fossil Steam[4]	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	22.6	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	4.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Renewable Sources[6]	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**33.7**	**44.0**	**44.2**	**44.0**	**42.9**	**42.7**	**42.6**	**42.2**	**42.5**	**42.2**
Total Electric Power Industry	**822.0**	**964.2**	**948.6**	**962.2**	**1125.1**	**1097.8**	**1134.7**	**1147.6**	**1134.7**	**1169.1**
Cumulative Planned Additions[9]										
Coal Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1
Combustion Turbine/Diesel	0.0	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	0.0	4.9	4.9	4.9	6.5	6.5	6.5	6.6	6.6	6.6
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**120.0**	**120.0**	**120.0**	**121.7**	**121.7**	**121.7**	**121.8**	**121.8**	**121.8**
Cumulative Unplanned Additions[9]										
Coal Steam	0.0	0.0	0.0	0.0	12.2	19.5	17.5	37.7	55.1	54.8
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	59.7	56.7	61.8	203.0	168.7	204.2	259.6	195.9	263.9
Combustion Turbine/Diesel	0.0	3.7	3.5	3.3	3.7	3.7	4.9	3.7	3.7	4.9
Nuclear Power	0.0	0.0	0.0	0.0	16.5	23.7	16.5	48.5	72.5	48.5
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	33.3	27.3	29.0	127.8	169.6	128.9	148.2	171.6	146.6
Distributed Generation[7]	0.0	1.7	2.7	1.7	4.9	7.2	5.3	5.0	7.6	5.4
Total	**0.0**	**98.4**	**90.3**	**95.9**	**368.1**	**392.4**	**377.2**	**502.8**	**506.4**	**524.1**
Cumulative Total Additions	**0.0**	**218.4**	**210.4**	**215.9**	**489.8**	**514.1**	**498.9**	**624.6**	**628.2**	**645.9**
Cumulative Retirements[10]										
Coal Steam	0.0	17.2	16.9	18.0	110.2	147.9	111.5	205.8	205.0	209.2
Other Fossil Steam[4]	0.0	51.6	59.7	50.8	67.5	75.3	66.3	79.3	89.8	77.0
Combined Cycle	0.0	0.9	0.6	0.7	0.9	1.4	0.7	2.6	3.4	2.1
Combustion Turbine/Diesel	0.0	9.1	9.1	8.7	10.9	16.6	10.5	14.2	20.1	13.4
Nuclear Power	0.0	0.8	0.8	0.8	1.8	1.8	1.8	1.8	1.8	1.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**79.7**	**87.2**	**79.2**	**191.4**	**243.1**	**190.9**	**303.8**	**320.2**	**303.6**

Table H11. Electricity Generating Capacity (Continued)

(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
End-Use Sector										
Combined Heat and Power[11]										
Coal	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Petroleum	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.0
Natural Gas	14.6	19.4	19.8	19.5	30.1	35.4	27.6	48.7	56.7	36.3
Other Gaseous Fuels	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Renewable Sources[6]	4.7	6.2	6.2	6.2	8.0	7.9	8.0	8.9	8.9	8.9
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.8**	**34.2**	**34.6**	**34.3**	**46.7**	**52.0**	**44.1**	**66.2**	**74.3**	**53.8**
Other End-Use Generators[12]										
Renewable Sources[13]	1.1	1.5	1.5	1.5	1.9	1.9	1.8	2.2	2.3	2.2
Cumulative Additions[9]										
Combined Heat and Power[11]	0.0	6.4	6.9	6.5	19.0	24.2	16.4	38.5	46.6	26.1
Other End-Use Generators[12]	0.0	0.4	0.4	0.4	0.7	0.8	0.7	1.1	1.2	1.1

[1] Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.

[2] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[3] Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.

[4] Includes oil-, gas-, and dual-fired capability.

[5] Nuclear capacity reflects operating capacity of existing units, including 4.3 gigawatts of uprates through 2025.

[6] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.

[7] Primarily peak-load capacity fueled by natural gas

[8] Includes combined heat and power plants whose primary business is to sell electricity and heat to the public(i.e., those that report NAICS code 22).

[9] Cumulative additions after December 31, 2001.

[10] Cumulative total retirements after December 31, 2001.

[11] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[12] Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[13] See Table H17 for more detail.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model estimates and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with capability for electric utility generators.

Source: 2001 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H12. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Crude Oil										
Domestic Crude Production[1]	5.80	5.63	5.64	5.64	5.41	5.40	5.41	5.27	5.19	5.25
Alaska	0.97	0.64	0.64	0.64	1.23	1.23	1.23	1.17	1.17	1.17
Lower 48 States	4.84	4.99	4.99	4.99	4.18	4.17	4.18	4.09	4.02	4.08
Net Imports	9.31	11.40	11.43	11.39	12.35	12.39	12.33	12.72	12.83	12.73
Gross Imports	9.33	11.46	11.49	11.45	12.40	12.44	12.38	12.77	12.87	12.78
Exports	0.02	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.04	0.05
Other Crude Supply[2]	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.13**	**17.03**	**17.06**	**17.02**	**17.76**	**17.79**	**17.74**	**17.99**	**18.02**	**17.98**
Natural Gas Plant Liquids	**1.87**	**2.27**	**2.21**	**2.25**	**2.63**	**2.58**	**2.62**	**2.69**	**2.61**	**2.67**
Other Inputs[3]	**0.30**	**0.43**	**0.44**	**0.43**	**0.36**	**0.35**	**0.35**	**0.35**	**0.35**	**0.34**
Refinery Processing Gain[4]	**0.90**	**0.89**	**0.90**	**0.89**	**0.94**	**0.95**	**0.94**	**0.93**	**0.95**	**0.93**
Net Product Imports[5]	**1.59**	**1.89**	**2.05**	**1.90**	**3.42**	**3.25**	**3.43**	**4.22**	**4.36**	**4.22**
Gross Refined Product Imports[6]	2.08	2.32	2.37	2.34	3.40	3.23	3.40	4.26	4.41	4.25
Unfinished Oil Imports	0.38	0.55	0.68	0.55	1.06	1.07	1.06	1.01	1.01	1.02
Ether Imports	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.95	0.98	1.00	0.98	1.03	1.04	1.03	1.05	1.06	1.05
Total Primary Supply[7]	**19.80**	**22.52**	**22.66**	**22.50**	**25.10**	**24.92**	**25.08**	**26.17**	**26.29**	**26.15**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.67	10.42	10.50	10.42	11.47	11.34	11.48	11.76	11.85	11.79
Jet Fuel[9]	1.66	1.89	1.90	1.89	2.42	2.42	2.42	2.69	2.69	2.69
Distillate Fuel[10]	3.81	4.57	4.59	4.56	5.19	5.14	5.15	5.54	5.52	5.48
Residual Fuel	0.97	0.54	0.55	0.53	0.52	0.52	0.52	0.53	0.53	0.53
Other[11]	4.58	5.12	5.14	5.12	5.50	5.51	5.51	5.66	5.71	5.67
Total	**19.69**	**22.53**	**22.67**	**22.52**	**25.11**	**24.93**	**25.09**	**26.18**	**26.30**	**26.16**
Refined Petroleum Products Supplied										
Residential and Commercial	1.21	1.18	1.18	1.17	1.16	1.16	1.11	1.15	1.14	1.09
Industrial[12]	4.67	5.21	5.24	5.21	5.62	5.62	5.63	5.79	5.84	5.81
Transportation	13.27	16.02	16.13	16.02	18.25	18.07	18.27	19.14	19.23	19.18
Electric Power[13]	0.55	0.12	0.12	0.12	0.08	0.08	0.08	0.09	0.08	0.09
Total	**19.69**	**22.53**	**22.67**	**22.52**	**25.11**	**24.93**	**25.09**	**26.18**	**26.30**	**26.16**
Discrepancy[14]	**0.10**	**-0.02**	**-0.02**	**-0.02**	**-0.01**	**-0.01**	**-0.01**	**-0.01**	**-0.00**	**-0.01**
World Oil Price (2001 dollars per barrel)[15]	**22.01**	**23.77**	**23.86**	**23.75**	**24.15**	**23.75**	**24.14**	**24.58**	**24.55**	**24.54**
Import Share of Product Supplied	**0.55**	**0.59**	**0.59**	**0.59**	**0.63**	**0.63**	**0.63**	**0.65**	**0.65**	**0.65**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2001 dollars)	**89.20**	**117.95**	**120.17**	**117.82**	**144.08**	**139.50**	**143.91**	**158.78**	**160.51**	**158.70**
Domestic Refinery Distillation Capacity[16]	**16.8**	**18.7**	**18.7**	**18.7**	**19.1**	**19.1**	**19.1**	**19.3**	**19.4**	**19.3**
Capacity Utilization Rate (percent)	**93.0**	**92.8**	**92.9**	**92.8**	**94.5**	**94.6**	**94.5**	**94.6**	**94.6**	**94.6**

[1] Includes lease condensate.
[2] Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.
[3] Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[4] Represents volumetric gain in refinery distillation and cracking processes.
[5] Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[6] Includes other hydrocarbons, alcohols, and blending components.
[7] Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[8] Includes ethanol and ethers blended into gasoline.
[9] Includes only kerosene type.
[10] Includes distillate and kerosene.
[11] Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[12] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14] Balancing item. Includes unaccounted for supply, losses, and gains.
[15] Average refiner acquisition cost for imported crude oil.
[16] End-of-year capacity.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). Other 2001 data: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H13. Petroleum Product Prices

(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
World Oil Price (2001 dollars per barrel)	**22.01**	**23.77**	**23.86**	**23.75**	**24.15**	**23.75**	**24.14**	**24.58**	**24.55**	**24.54**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	124.6	110.3	110.4	110.2	114.2	114.1	113.8	119.0	119.0	118.9
Liquefied Petroleum Gas	127.3	119.8	122.5	121.3	123.9	126.9	125.6	128.3	127.7	127.7
Commercial										
Distillate Fuel	88.7	78.0	78.1	78.0	82.6	81.9	82.4	87.3	87.3	87.4
Residual Fuel	51.8	58.9	59.1	59.0	59.3	58.4	59.4	60.2	60.1	60.3
Residual Fuel (2001 dollars per barrel)	21.75	24.73	24.83	24.77	24.92	24.51	24.96	25.30	25.26	25.33
Industrial[1]										
Distillate Fuel	90.8	79.2	79.3	79.1	85.7	84.3	85.3	90.6	90.6	90.4
Liquefied Petroleum Gas	105.9	82.2	84.6	83.6	87.0	89.7	88.5	91.0	90.1	90.1
Residual Fuel	49.1	54.7	55.0	54.7	55.4	54.4	55.3	56.4	56.3	56.2
Residual Fuel (2001 dollars per barrel)	20.61	22.99	23.09	22.95	23.26	22.86	23.24	23.67	23.64	23.62
Transportation										
Diesel Fuel (distillate)[2]	139.4	162.4	151.9	162.6	182.6	187.8	182.4	199.3	195.6	198.9
Jet Fuel[3]	83.7	95.9	86.1	95.8	125.0	130.0	124.6	139.7	135.5	139.7
Motor Gasoline[4]	143.3	160.8	151.6	160.7	179.9	178.3	179.6	189.6	183.9	190.0
Liquid Petroleum Gas	145.2	140.3	137.9	141.6	157.0	163.8	158.1	164.3	159.8	162.2
Residual Fuel	58.4	77.8	65.6	77.6	110.1	116.6	109.8	124.5	119.3	124.6
Residual Fuel (2001 dollars per barrel)	24.52	32.66	27.55	32.59	46.25	48.97	46.13	52.31	50.10	52.34
Electric Power[5]										
Distillate Fuel	86.0	69.5	69.6	69.4	74.7	73.4	74.3	78.2	79.1	78.5
Residual Fuel	67.4	64.2	64.0	64.5	73.1	72.6	73.3	74.6	74.5	74.3
Residual Fuel (2001 dollars per barrel)	28.30	26.98	26.87	27.11	30.71	30.50	30.78	31.31	31.29	31.21
Refined Petroleum Product Prices[6]										
Distillate Fuel	127.0	142.1	134.5	142.3	160.6	164.2	160.9	175.3	172.7	175.9
Jet Fuel[3]	83.7	95.9	86.1	95.8	125.0	130.0	124.6	139.7	135.5	139.7
Liquefied Petroleum Gas	110.3	89.4	91.8	90.8	93.8	96.5	95.3	97.8	96.8	96.8
Motor Gasoline[4]	143.4	160.6	151.5	160.5	179.4	177.8	179.1	189.1	183.4	189.5
Residual Fuel	61.5	71.7	63.6	71.8	96.1	100.7	96.2	106.5	103.0	107.0
Residual Fuel (2001 dollars per barrel)	25.85	30.13	26.71	30.17	40.35	42.28	40.41	44.75	43.28	44.94
Average	**123.6**	**137.0**	**129.9**	**137.1**	**154.1**	**154.9**	**154.2**	**164.3**	**160.3**	**164.5**
Greenhouse Gas Allowance Cost										
Commercial										
Distillate Fuel	0.0	0.0	0.0	21.5	0.0	0.0	48.7	0.0	0.0	60.6
Residual Fuel	0.0	0.0	0.0	25.0	0.0	0.0	56.6	0.0	0.0	70.5
Residual Fuel (2001 dollars per barrel)	0.00	0.00	0.00	10.51	0.00	0.00	23.76	0.00	0.00	29.61
Industrial[1]										
Distillate Fuel	0.0	21.6	11.0	21.5	48.9	55.3	48.7	60.5	56.0	60.6
Liquefied Petroleum Gas	0.0	11.6	5.9	11.5	26.1	29.6	26.0	32.4	30.0	32.4
Residual Fuel	0.0	25.1	12.7	25.0	56.8	64.3	56.6	70.3	65.1	70.5
Residual Fuel (2001 dollars per barrel)	0.00	10.55	5.35	10.51	23.86	27.00	23.76	29.53	27.36	29.61
Electric Power[5]										
Distillate Fuel	0.0	21.6	11.0	21.5	48.9	55.3	48.7	60.5	56.0	60.6
Residual Fuel	0.0	25.1	12.7	25.0	56.8	64.3	56.6	70.3	65.1	70.5
Residual Fuel (2001 dollars per barrel)	0.00	10.55	5.35	10.51	23.86	27.00	23.76	29.53	27.36	29.61

Table H13. Petroleum Product Prices (Continued)

(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Delivered Sector Product Prices with Greenhouse Gas Allowance Cost										
Commercial										
Distillate Fuel	88.7	78.0	78.1	99.5	82.6	81.9	131.0	87.3	87.3	148.0
Residual Fuel	51.8	58.9	59.1	84.0	59.3	58.4	116.0	60.2	60.1	130.8
Residual Fuel (2001 dollars per barrel)	21.75	24.73	24.83	35.28	24.92	24.51	48.73	25.30	25.26	54.94
Industrial[1]										
Distillate Fuel	90.8	100.8	90.2	100.6	134.6	139.6	134.0	151.0	146.6	151.0
Liquefied Petroleum Gas	105.9	93.8	90.5	95.1	113.1	119.3	114.6	123.3	120.1	122.5
Residual Fuel	49.1	79.9	67.7	79.7	112.2	118.7	111.9	126.7	121.4	126.7
Residual Fuel (2001 dollars per barrel)	20.61	33.55	28.44	33.46	47.12	49.85	47.00	53.20	51.00	53.23
Electric Power[5]										
Distillate Fuel	86.0	91.1	80.5	91.0	123.6	128.7	123.0	138.6	135.1	139.1
Residual Fuel	67.4	89.4	76.7	89.6	129.9	136.9	129.9	144.9	139.7	144.8
Residual Fuel (2001 dollars per barrel)	28.30	37.53	32.22	37.62	54.57	57.50	54.54	60.84	58.65	60.82

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[1] Includes combined heat and power, which produces electricity and other useful thermal energy.

[2] Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur. Includes Federal and State taxes while excluding county and local taxes.

[3] Kerosene-type jet fuel.

[4] Sales weighted-average price for all grades. Includes Federal, State and local taxes.

[5] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[6] Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources:. 2001 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A: “Refiners’/Gas Plant Operators’ Monthly Petroleum Product Sales Report.” 2001 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2001 world oil price: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections**: EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H14. Natural Gas Supply and Disposition

(Trillion Cubic Feet per Year)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Production										
Dry Gas Production[1]	19.45	22.21	21.59	22.03	26.61	26.15	26.54	27.32	26.54	27.18
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.73**	**4.85**	**4.71**	**4.94**	**8.80**	**8.54**	**8.56**	**10.87**	**9.43**	**10.43**
Canada	3.61	4.20	4.08	4.19	5.44	4.63	5.43	5.61	5.14	5.49
Mexico	-0.13	-0.21	-0.20	-0.20	0.16	0.05	0.09	0.66	0.47	0.55
Liquefied Natural Gas	0.26	0.86	0.84	0.96	3.21	3.86	3.05	4.60	3.82	4.39
Total Supply	**23.26**	**27.15**	**26.40**	**27.07**	**35.51**	**34.79**	**35.20**	**38.29**	**36.07**	**37.71**
Consumption by Sector										
Residential	4.81	5.47	5.47	5.47	5.80	5.81	5.80	6.03	6.15	6.04
Commercial	3.24	3.63	3.64	3.56	4.16	4.32	3.75	4.84	5.13	3.96
Industrial[3]	7.53	8.91	8.94	8.92	10.08	10.14	10.08	10.79	11.02	10.86
Electric Power[4]	5.30	7.20	6.47	7.20	13.00	12.09	13.09	14.03	11.26	14.27
Transportation[5]	0.01	0.06	0.06	0.06	0.09	0.09	0.09	0.10	0.10	0.10
Pipeline Fuel	0.61	0.79	0.76	0.78	1.02	1.00	1.01	1.08	1.03	1.06
Lease and Plant Fuel[6]	1.17	1.36	1.34	1.36	1.66	1.64	1.66	1.72	1.69	1.72
Total	**22.67**	**27.42**	**26.68**	**27.35**	**35.80**	**35.09**	**35.49**	**38.59**	**36.38**	**38.01**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.59**	**-0.26**	**-0.28**	**-0.28**	**-0.30**	**-0.30**	**-0.30**	**-0.30**	**-0.31**	**-0.30**

[1] Marketed production (wet) minus extraction losses.

[2] Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

[3] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as vehicle fuel.

[6] Represents natural gas used in the field gathering and processing plant machinery.

[7] Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2001 values include net storage injections.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H15. Natural Gas Prices, Margins, and Revenue
(2001 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Source Price										
Average Lower 48 Wellhead Price[1]	4.12	3.51	3.42	3.45	3.97	3.85	3.98	4.36	4.09	4.29
Average Import Price	4.43	3.46	3.39	3.45	4.17	3.77	4.19	4.65	4.00	4.53
Average[2]	**4.17**	**3.50**	**3.42**	**3.45**	**4.02**	**3.83**	**4.03**	**4.45**	**4.07**	**4.36**
Delivered Prices										
Residential	9.68	7.89	7.81	7.83	8.30	8.05	8.30	8.72	8.30	8.60
Commercial	8.32	6.78	6.70	6.73	7.27	7.02	7.30	7.69	7.27	7.62
Industrial[3]	5.01	4.23	4.13	4.17	4.81	4.57	4.82	5.21	4.79	5.11
Electric Power[4]	4.87	4.14	4.01	4.09	4.88	4.65	4.90	5.29	4.81	5.19
Transportation[5]	7.87	7.45	7.41	7.45	7.94	7.69	8.25	8.30	7.91	8.61
Average[6]	**6.57**	**5.38**	**5.31**	**5.32**	**5.78**	**5.57**	**5.77**	**6.19**	**5.84**	**6.05**
Transmission & Distribution Margins[7]										
Residential	5.50	4.39	4.40	4.38	4.27	4.22	4.27	4.28	4.24	4.25
Commercial	4.14	3.28	3.28	3.28	3.24	3.19	3.27	3.24	3.20	3.26
Industrial[3]	0.83	0.73	0.72	0.72	0.79	0.74	0.79	0.77	0.72	0.75
Electric Power[4]	0.70	0.65	0.59	0.64	0.86	0.81	0.86	0.84	0.74	0.84
Transportation[5]	3.69	3.95	3.99	4.00	3.92	3.86	4.22	3.86	3.84	4.26
Average[6]	**2.40**	**1.88**	**1.90**	**1.87**	**1.76**	**1.74**	**1.74**	**1.75**	**1.77**	**1.69**
Transmission & Distribution Revenue (billion 2001 dollars)										
Residential	26.45	24.00	24.05	23.97	24.78	24.51	24.76	25.78	26.06	25.65
Commercial	13.42	11.91	11.92	11.68	13.48	13.79	12.27	15.68	16.43	12.93
Industrial[3]	6.28	6.49	6.41	6.45	7.94	7.49	7.93	8.27	7.96	8.17
Electric Power[4]	3.69	4.64	3.85	4.62	11.18	9.85	11.31	11.80	8.34	11.93
Transportation[5]	0.04	0.22	0.23	0.23	0.36	0.35	0.38	0.39	0.39	0.42
Total	**49.88**	**47.27**	**46.46**	**46.96**	**57.74**	**55.98**	**56.65**	**61.91**	**59.18**	**59.09**
Greenhouse Gas Allowance Cost										
Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	0.00	0.00	0.00	1.16	0.00	0.00	2.63	0.00	0.00	3.28
Industrial[3]	0.00	1.15	0.58	1.14	2.59	2.93	2.58	3.21	2.98	3.22
Electric Power[4]	0.00	1.16	0.59	1.15	2.62	2.96	2.61	3.24	3.00	3.25
Transportation[5]	0.00	1.17	0.59	1.16	2.64	2.99	2.63	3.27	3.03	3.28
Average[6]	**0.00**	**0.74**	**0.37**	**0.90**	**1.83**	**2.03**	**2.15**	**2.25**	**1.99**	**2.69**
Delivered Prices with Greenhouse Gas Allowance Cost										
Residential	9.68	7.89	7.81	7.83	8.30	8.05	8.30	8.72	8.30	8.60
Commercial	8.32	6.78	6.70	7.89	7.27	7.02	9.93	7.69	7.27	10.89
Industrial[3]	5.01	5.37	4.71	5.31	7.40	7.50	7.40	8.42	7.76	8.33
Electric Power[4]	4.87	5.30	4.60	5.24	7.50	7.61	7.50	8.53	7.81	8.44
Transportation[5]	7.87	8.62	8.00	8.61	10.58	10.68	10.88	11.57	10.94	11.89
Average[6]	**6.57**	**6.12**	**5.68**	**6.22**	**7.61**	**7.60**	**7.92**	**8.44**	**7.83**	**8.74**

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[1] Represents lower 48 onshore and offshore supplies.

[2] Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.

[3] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.

[6] Weighted average allowance cost. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.

[7] Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 electric generators delivered price: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1998*. 2001 residential, commercial, and transportation delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H16. Oil and Gas Supply

Production and Supply	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Crude Oil										
Lower 48 Average Wellhead Price[1] (2001 dollars per barrel)	**22.91**	**23.56**	**23.72**	**23.56**	**23.65**	**23.03**	**23.61**	**24.11**	**23.92**	**24.07**
Production (million barrels per day)[2]										
U.S. Total	**5.80**	**5.63**	**5.64**	**5.64**	**5.41**	**5.40**	**5.41**	**5.27**	**5.19**	**5.25**
Lower 48 Onshore	3.13	2.47	2.47	2.47	2.05	2.04	2.05	1.90	1.90	1.90
Lower 48 Offshore	1.71	2.52	2.52	2.52	2.13	2.12	2.13	2.19	2.12	2.18
Alaska	0.97	0.64	0.64	0.64	1.23	1.23	1.23	1.17	1.17	1.17
Lower 48 End of Year Reserves (billion barrels)[2]	**19.48**	**17.70**	**17.72**	**17.71**	**15.34**	**15.26**	**15.35**	**14.92**	**14.72**	**14.88**
Natural Gas										
Lower 48 Average Wellhead Price[1] (2001 dollars per thousand cubic feet)	**4.12**	**3.51**	**3.42**	**3.45**	**3.97**	**3.85**	**3.98**	**4.36**	**4.09**	**4.29**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**19.45**	**22.21**	**21.59**	**22.03**	**26.61**	**26.16**	**26.54**	**27.32**	**26.54**	**27.18**
Lower 48 Onshore	13.72	16.17	15.68	16.01	18.65	18.30	18.58	18.72	18.10	18.57
Associated-Dissolved[4]	1.77	1.36	1.37	1.36	1.19	1.19	1.19	1.13	1.13	1.13
Non-Associated	11.94	14.81	14.32	14.64	17.46	17.11	17.39	17.59	16.98	17.44
Conventional	6.54	7.32	7.11	7.19	7.37	7.12	7.37	7.13	7.04	7.10
Unconventional	5.40	7.49	7.21	7.46	10.09	9.99	10.02	10.46	9.94	10.34
Lower 48 Offshore	5.30	5.56	5.43	5.55	5.58	5.47	5.57	5.77	5.60	5.77
Associated-Dissolved[4]	1.08	0.96	0.96	0.96	0.79	0.79	0.79	0.81	0.78	0.80
Non-Associated	4.22	4.60	4.47	4.58	4.78	4.68	4.78	4.96	4.82	4.97
Alaska	0.43	0.48	0.48	0.48	2.39	2.39	2.39	2.84	2.84	2.84
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**174.04**	**185.39**	**186.40**	**185.48**	**195.87**	**199.14**	**195.22**	**192.41**	**195.37**	**191.78**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Total Lower 48 Wells (thousands)	**33.94**	**25.75**	**25.72**	**25.65**	**27.25**	**27.36**	**27.20**	**29.30**	**27.77**	**28.91**

[1] Represents lower 48 onshore and offshore supplies.
[2] Includes lease condensate.
[3] Marketed production (wet) minus extraction losses.
[4] Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5] Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2001 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H17. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Production[1]										
Appalachia	443	415	405	413	212	174	217	145	164	165
Interior	147	153	144	154	88	60	89	42	45	43
West	548	513	617	506	185	118	195	128	138	128
East of the Mississippi	539	518	502	517	286	230	291	182	204	204
West of the Mississippi	599	563	664	556	199	123	211	132	143	132
Total	**1138**	**1081**	**1166**	**1073**	**485**	**352**	**502**	**315**	**347**	**336**
Net Imports										
Imports	19	11	11	11	11	11	11	10	10	10
Exports	49	33	33	33	29	29	29	24	23	24
Total	**-30**	**-22**	**-22**	**-22**	**-19**	**-18**	**-19**	**-13**	**-13**	**-13**
Total Supply[2]	**1109**	**1060**	**1144**	**1052**	**466**	**334**	**483**	**301**	**335**	**323**
Consumption by Sector										
Residential and Commercial	4	5	5	3	5	5	4	6	6	4
Industrial[3]	63	61	64	61	59	57	59	58	57	58
of which: Coal to Liquids	0	0	0	0	0	0	0	0	0	0
Coke Plants	26	24	24	24	17	17	17	14	15	14
Electric Power[4]	957	966	1056	973	390	267	404	227	249	247
Total	**1050**	**1055**	**1149**	**1061**	**471**	**346**	**484**	**306**	**326**	**324**
Discrepancy and Stock Change[5]	**58**	**4**	**-5**	**-10**	**-6**	**-12**	**-2**	**-4**	**8**	**-1**
Average Minemouth Price										
(2001 dollars per short ton)	17.59	15.84	14.99	15.90	15.27	15.22	15.26	13.67	13.60	14.11
(2001 dollars per million Btu)	0.83	0.76	0.73	0.76	0.71	0.69	0.71	0.63	0.63	0.65
Delivered Prices (2001 dollars per short ton)[6]										
Industrial	32.82	30.10	29.92	30.11	24.86	23.88	25.04	22.55	22.92	23.15
Coke Plants	46.42	41.37	41.30	41.24	38.31	38.37	38.18	36.64	36.57	36.72
Electric Power										
(2001 dollars per short ton)	25.06	23.76	23.72	23.77	20.83	20.65	20.86	18.81	18.33	19.30
(2001 dollars per million Btu)	1.25	1.16	1.17	1.16	0.99	0.97	1.00	0.90	0.88	0.92
Average	**26.06**	**24.53**	**24.44**	**24.53**	**21.98**	**22.10**	**21.99**	**20.39**	**19.99**	**20.79**
Exports[7]	36.97	32.41	32.44	32.35	28.76	28.44	28.76	27.46	27.50	27.72
Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]										
Industrial	0.00	43.59	22.09	43.41	98.28	111.23	97.89	121.42	112.49	121.76
Coke Plants	0.00	54.74	27.76	54.51	123.76	140.01	123.24	153.14	141.90	153.55
Electric Power										
(2001 dollars per short ton)	0.00	41.32	20.72	41.18	95.21	109.27	94.76	117.30	108.14	118.44
(2001 dollars per million Btu)	0.00	2.02	1.02	2.01	4.54	5.13	4.52	5.62	5.22	5.64
Average	**0.00**	**41.76**	**20.95**	**41.61**	**96.65**	**111.17**	**96.16**	**119.82**	**110.46**	**120.62**
Delivered Prices with Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]										
Industrial	32.82	73.69	52.00	73.52	123.14	135.10	122.93	143.97	135.41	144.92
Coke Plants	46.42	96.11	69.05	95.75	162.07	178.38	161.43	189.79	178.48	190.27
Electric Power										
(2001 dollars per short ton)	25.06	65.08	44.44	64.94	116.04	129.92	115.63	136.11	126.48	137.74
(2001 dollars per million Btu)	1.25	3.17	2.20	3.17	5.53	6.09	5.52	6.53	6.10	6.55
Average	**26.06**	**66.29**	**45.38**	**66.13**	**118.63**	**133.27**	**118.16**	**140.21**	**130.45**	**141.41**

[1] Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.1 million tons in 2000 and 10.6 million tons in 2001.

[2] Production plus net imports and net storage withdrawals.

[3] Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

[4] Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[5] Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.

[6] Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.

[7] F.a.s. price at U.S. port of exit.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H18. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Electric Power Sector[1]										
Net Summer Capacity										
Conventional Hydropower	78.10	78.66	78.66	78.66	78.65	78.65	78.65	78.65	78.65	78.65
Geothermal[2]	2.83	6.68	6.89	6.71	10.06	10.11	9.74	10.55	10.24	9.84
Municipal Solid Waste[3]	3.25	4.84	4.84	4.84	5.17	5.17	5.17	5.19	5.18	5.19
Wood and Other Biomass[4]	1.80	3.96	3.34	4.02	48.03	75.82	47.47	67.38	77.66	64.44
Solar Thermal	0.33	0.44	0.44	0.44	0.48	0.48	0.48	0.50	0.50	0.50
Solar Photovoltaic[5]	0.02	0.10	0.10	0.10	0.27	0.27	0.27	0.36	0.36	0.36
Wind	4.29	34.53	28.99	30.18	82.60	96.54	84.57	83.22	96.61	85.22
Total	**90.62**	**129.20**	**123.25**	**124.94**	**225.26**	**267.04**	**226.35**	**245.84**	**269.20**	**244.18**
Generation (billion kilowatthours)										
Conventional Hydropower	213.82	300.89	300.89	300.89	299.92	299.87	299.96	300.10	300.08	300.17
Geothermal[2]	13.81	44.61	46.24	44.82	73.14	73.90	70.63	77.22	74.89	71.74
Municipal Solid Waste[3]	19.55	35.17	35.18	35.18	37.63	37.63	37.64	37.83	37.80	37.84
Wood and Other Biomass[4]	9.38	27.11	22.58	27.22	304.95	503.13	298.92	429.32	514.84	415.66
Dedicated Plants	7.66	19.52	17.45	19.73	304.95	503.13	298.92	429.32	514.84	415.66
Cofiring	1.72	7.59	5.13	7.48	0.00	0.00	0.00	0.00	0.00	0.00
Solar Thermal	0.49	0.77	0.77	0.77	0.90	0.90	0.90	0.97	0.97	0.97
Solar Photovoltaic[5]	0.00	0.24	0.24	0.24	0.66	0.66	0.66	0.88	0.88	0.88
Wind	5.78	112.46	94.67	98.19	277.70	324.39	285.31	280.10	324.73	287.65
Total	**262.85**	**521.25**	**500.58**	**507.31**	**994.90**	**1240.48**	**994.02**	**1126.43**	**1254.19**	**1114.91**
End- Use Sector										
Net Summer Capacity										
Combined Heat and Power[6]										
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Biomass	4.41	5.89	5.91	5.89	7.67	7.61	7.67	8.60	8.62	8.61
Total	**4.69**	**6.17**	**6.19**	**6.17**	**7.95**	**7.89**	**7.95**	**8.88**	**8.90**	**8.90**
Other End-Use Generators[7]										
Conventional Hydropower[8]	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.38	0.38	0.38	0.76	0.78	0.75	1.15	1.18	1.14
Total	**1.12**	**1.47**	**1.47**	**1.47**	**1.85**	**1.87**	**1.84**	**2.25**	**2.27**	**2.23**
Generation (billion kilowatthours)										
Combined Heat and Power[6]										
Municipal Solid Waste	2.46	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15
Biomass	28.67	37.31	37.42	37.30	47.72	47.34	47.70	53.13	53.26	53.23
Total	**31.13**	**39.46**	**39.57**	**39.45**	**49.87**	**49.49**	**49.85**	**55.28**	**55.41**	**55.38**
Other End-Use Generators[7]										
Conventional Hydropower[8]	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.82	0.82	0.82	1.61	1.65	1.59	2.42	2.47	2.39
Total	**4.25**	**5.05**	**5.05**	**5.05**	**5.85**	**5.88**	**5.83**	**6.66**	**6.70**	**6.63**

[1] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes hydrothermal resources only (hot water and steam).

[3] Includes landfill gas.

[4] Includes projections for energy crops after 2010.

[5] Does not include off-grid photovoltaics (PV). See Annual Energy Review 2001 Table 10.6 for estimates of 1989-2000 PV shipments, including exports, for both grid-connected and off-grid applications.

[6] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[7] Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[8] Represents own-use industrial hydroelectric power.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2003. Net summer capacity is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.

Sources: 2001 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2001 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H19. Renewable Energy Consumption by Sector and Source[1]

(Quadrillion Btu per Year)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Marketed Renewable Energy[2]										
Residential	**0.39**	**0.41**	**0.41**	**0.41**	**0.40**	**0.40**	**0.40**	**0.40**	**0.40**	**0.40**
Wood	0.39	0.41	0.41	0.41	0.40	0.40	0.40	0.40	0.40	0.40
Commercial	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Industrial[3]	**1.82**	**2.21**	**2.21**	**2.21**	**2.74**	**2.72**	**2.74**	**3.02**	**3.03**	**3.02**
Conventional Hydroelectric	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.77	2.16	2.17	2.16	2.69	2.68	2.69	2.97	2.98	2.97
Transportation	**0.15**	**0.26**	**0.26**	**0.26**	**0.28**	**0.28**	**0.28**	**0.29**	**0.29**	**0.29**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Ethanol used in Gasoline Blending	0.15	0.26	0.26	0.26	0.28	0.27	0.28	0.28	0.29	0.29
Electric Power[5]	**3.01**	**6.30**	**6.17**	**6.15**	**11.42**	**13.71**	**11.34**	**12.69**	**13.86**	**12.45**
Conventional Hydroelectric	2.16	3.09	3.09	3.09	3.07	3.07	3.07	3.07	3.07	3.07
Geothermal	0.29	1.30	1.35	1.31	2.23	2.23	2.14	2.36	2.26	2.17
Municipal Solid Waste[6]	0.31	0.48	0.48	0.48	0.51	0.51	0.51	0.51	0.51	0.51
Biomass	0.15	0.31	0.27	0.31	2.78	4.55	2.73	3.89	4.65	3.77
Dedicated Plants	0.12	0.21	0.20	0.22	2.78	4.55	2.73	3.89	4.65	3.77
Cofiring	0.03	0.09	0.07	0.09	0.00	0.00	0.00	0.00	0.00	0.00
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.08	1.12	0.97	0.96	2.82	3.33	2.88	2.84	3.34	2.90
Total Marketed Renewable Energy	**5.46**	**9.28**	**9.16**	**9.13**	**14.95**	**17.22**	**14.87**	**16.50**	**17.68**	**16.27**
Sources of Ethanol										
From Corn	0.15	0.26	0.26	0.26	0.26	0.26	0.26	0.24	0.24	0.24
From Cellulose	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.05	0.05	0.05
Total	**0.15**	**0.26**	**0.26**	**0.26**	**0.28**	**0.28**	**0.28**	**0.29**	**0.29**	**0.29**
Non-Marketed Renewable Energy[7] **Selected Consumption**										
Residential	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**
Solar Hot Water Heating	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Geothermal Heat Pumps	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01

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[1] Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.

[2] Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table H8.

[3] Includes all electricity production by industrial and other combined heat and power for the grid and for own use.

[4] Excludes motor gasoline component of E85.

[5] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[6] Includes landfill gas.

[7] Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 electric generators: EIA, Form EIA-860: "Annual Electric Generator Report" (preliminary). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H20. Greenhouse Gas Emissions and Allowance Cost

(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Carbon Dioxide Emissions										
Residential										
Petroleum	27.2	27.6	27.6	27.6	25.8	25.8	25.8	25.0	25.0	25.0
Natural Gas	71.1	81.0	81.0	80.9	85.8	86.0	85.9	89.3	91.1	89.4
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3
Total	**98.7**	**109.0**	**109.0**	**108.9**	**112.0**	**112.2**	**112.1**	**114.7**	**116.4**	**114.8**
Commercial										
Petroleum	14.0	13.7	13.7	12.9	14.5	14.6	12.5	14.8	14.7	12.2
Natural Gas	48.0	53.8	53.8	52.7	61.5	64.0	55.6	71.6	75.9	58.7
Coal	2.3	2.5	2.4	1.4	2.8	2.8	1.9	2.9	2.9	1.9
Total	**64.3**	**69.9**	**69.9**	**67.1**	**78.8**	**81.3**	**70.0**	**89.3**	**93.4**	**72.8**
Industrial[1]										
Petroleum	97.9	96.0	96.7	96.1	99.1	99.0	99.2	101.1	101.5	101.0
Natural Gas[2]	123.4	149.8	149.7	149.6	171.0	171.6	171.0	182.4	185.3	183.3
Coal	52.1	53.1	54.9	53.1	48.9	47.7	48.9	47.3	47.0	47.2
Total	**273.4**	**298.9**	**301.2**	**298.8**	**319.0**	**318.3**	**319.1**	**330.8**	**333.9**	**331.6**
Transportation										
Petroleum[3]	501.4	605.1	609.2	605.1	690.4	683.9	691.0	725.3	728.4	726.6
Natural Gas[4]	9.2	12.5	12.1	12.4	16.4	16.1	16.3	17.4	16.8	17.1
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**510.6**	**617.6**	**621.3**	**617.5**	**706.8**	**699.9**	**707.3**	**742.7**	**745.2**	**743.7**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	640.5	742.5	747.1	741.8	829.8	823.2	828.5	866.2	869.6	864.9
Natural Gas	251.7	297.0	296.6	295.7	334.8	337.7	328.8	360.7	369.1	348.5
Coal	54.7	55.9	57.7	54.9	52.0	50.8	51.2	50.5	50.2	49.5
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**947.0**	**1095.4**	**1101.3**	**1092.4**	**1216.6**	**1211.7**	**1208.5**	**1277.4**	**1288.9**	**1262.9**
Electric Power[6]										
Petroleum	27.5	5.4	5.7	5.4	3.9	3.8	3.9	3.9	3.9	4.0
Natural Gas	77.7	105.0	94.7	105.0	158.0	165.5	160.0	132.6	133.9	134.5
Coal	506.4	504.4	545.6	508.7	190.0	113.4	190.4	68.3	58.7	56.5
Total	**611.6**	**614.8**	**646.1**	**619.0**	**351.9**	**282.6**	**354.4**	**204.8**	**196.5**	**195.1**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	668.0	747.9	752.8	747.2	833.7	827.0	832.5	870.2	873.5	868.9
Natural Gas	329.4	402.0	391.3	400.6	492.8	503.2	488.8	493.3	503.0	483.0
Coal	561.1	560.3	603.3	563.6	242.0	164.2	241.6	118.8	108.9	106.0
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1558.6**	**1710.1**	**1747.4**	**1711.4**	**1568.5**	**1494.3**	**1562.9**	**1482.2**	**1485.4**	**1457.9**
Non-Energy Related Carbon Dioxide Emissions	**36.3**	**39.5**	**39.5**	**39.5**	**43.9**	**43.9**	**43.9**	**46.2**	**46.2**	**46.2**
Total Carbon Dioxide Emissions	**1594.9**	**1749.7**	**1787.0**	**1750.9**	**1612.4**	**1538.2**	**1606.8**	**1528.4**	**1531.6**	**1504.1**
Other Greenhouse Gas Emissions	**332.9**	**286.4**	**300.1**	**285.3**	**339.5**	**339.4**	**338.1**	**362.9**	**363.1**	**361.3**
Methane	175.2	115.2	125.4	114.0	126.4	126.4	124.9	120.0	120.1	118.3
Nitrous Oxide	118.9	121.0	121.0	121.0	131.4	131.4	131.4	137.2	137.2	137.2
High Global Warming Potential Gases	38.8	50.2	53.7	50.2	81.8	81.7	81.8	105.8	105.8	105.8
Total Greenhouse Gas Emissions	**1927.8**	**2036.1**	**2087.1**	**2036.2**	**1951.9**	**1877.7**	**1944.9**	**1891.4**	**1894.7**	**1865.4**

Table H20. Greenhouse Gas Emissions and Allowance Cost (Continued)

(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
Greenhouse Gas Emission Cap Compliance										
Covered Emissions										
Energy-Related Carbon Dioxide	1378.2	1513.1	1550.4	1584.3	1357.5	1280.8	1430.7	1256.9	1254.2	1321.8
Other Greenhouse Gases	75.2	70.1	74.9	70.1	102.8	102.7	102.9	127.6	127.6	127.6
Offsets Purchased	0.0	234.7	161.4	244.9	126.1	125.9	132.0	125.6	125.1	131.4
Non-Covered Greenhouse Gas Offsets	0.0	48.5	39.6	49.7	34.3	34.2	35.8	39.0	38.9	40.7
U.S. Sequestration Offsets	0.0	112.8	92.7	115.4	91.8	91.7	96.2	86.5	86.2	89.9
International Offsets	0.0	73.4	29.1	79.8	0.0	0.0	0.0	0.1	0.0	0.8
Covered Emissions less Offsets	1453.4	1348.5	1463.9	1409.6	1334.2	1257.5	1401.6	1258.9	1256.7	1318.0
Covered Emissions Coal	N/A	1465.1	1465.1	1529.0	1257.9	1257.9	1318.3	1257.9	1257.9	1318.3
Allowance Bank Activity	0.0	116.5	1.2	119.4	-76.3	0.4	-83.3	-1.0	1.2	0.3
Cumulative Bank Balance	0.0	116.5	1.2	119.4	98.9	4.6	98.9	7.3	2.7	-3.8
Allowance Cost (2001 dollars per ton)										
Emissions Allowance Cost	0.00	78.89	40.00	78.56	178.36	201.78	177.62	220.71	204.50	221.30
Offset Price	0.00	71.49	40.00	76.10	34.84	34.68	39.55	51.73	51.13	58.78

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[1] Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes lease and plant fuel.

[3] This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons carbon equivalent of carbon dioxide annually.

[4] Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

[5] Includes methanol and liquid hydrogen.

[6] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.

[7] Emissions from electric power generators are distributed to the primary fuels.

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table H21. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2001	Projections								
		2010			2020			2025		
		S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered	S. 139 Case	No Banking	Commercial Covered
GDP Chain-Type Price Index										
(1996=1.000)	**1.094**	**1.321**	**1.318**	**1.322**	**1.735**	**1.752**	**1.737**	**2.028**	**2.025**	**2.028**
Potential Gross Domestic Product	**9456**	**12458**	**12459**	**12458**	**16729**	**16719**	**16731**	**19150**	**19161**	**19158**
Real Gross Domestic Product	**9215**	**12211**	**12239**	**12208**	**16364**	**16283**	**16368**	**18810**	**18860**	**18838**
Real Consumption	6377	8375	8395	8374	11284	11226	11285	12954	12991	12971
Real Investment	1575	2478	2489	2477	3724	3714	3725	4447	4476	4458
Real Government Spending	1640	1897	1896	1897	2204	2201	2203	2417	2419	2417
Real Exports	1076	1781	1782	1781	3329	3306	3327	4621	4609	4618
Real Imports	1492	2292	2293	2292	4027	4023	4022	5376	5391	5373
Real Disposable Personal Income	**6748**	**8607**	**8625**	**8606**	**11648**	**11588**	**11652**	**13432**	**13441**	**13445**
Federal Funds Rate (percent)	**3.89**	**5.63**	**5.58**	**5.64**	**6.58**	**6.28**	**6.62**	**6.97**	**7.02**	**7.00**
AA Utility Bond Rate (percent)										
Nominal	7.57	7.38	7.31	7.38	9.17	9.08	9.19	9.99	9.88	9.97
Real	5.60	5.20	5.23	5.19	6.18	6.26	6.19	6.76	6.91	6.80
Energy Intensity										
(thousand Btu per 1996 dollar of GDP)										
Delivered Energy	7.74	6.80	6.82	6.79	5.65	5.65	5.63	5.17	5.20	5.13
Total Energy	10.56	9.15	9.21	9.14	7.37	7.36	7.36	6.70	6.75	6.66
Consumer Price Index (1982-84=1.00)	**1.77**	**2.20**	**2.20**	**2.20**	**2.97**	**3.00**	**2.98**	**3.55**	**3.54**	**3.55**
Unemployment Rate (percent)	**4.79**	**4.55**	**4.48**	**4.56**	**6.03**	**6.34**	**6.02**	**5.85**	**5.76**	**5.80**
Housing Starts (millions)	**1.80**	**2.12**	**2.15**	**2.12**	**1.92**	**1.93**	**1.92**	**2.01**	**2.03**	**2.02**
Single-Family	1.27	1.31	1.32	1.31	1.11	1.11	1.11	1.11	1.12	1.11
Multifamily	0.33	0.45	0.46	0.45	0.49	0.49	0.49	0.57	0.58	0.57
Mobile Home Shipments	0.19	0.36	0.37	0.36	0.33	0.33	0.33	0.33	0.33	0.33
Commercial Floorspace, Total										
(billion square feet)	**70.2**	**82.0**	**82.0**	**82.0**	**94.2**	**94.0**	**94.2**	**100.6**	**100.3**	**100.6**
Value of Shipments (billion 1996 dollars)										
Total Industrial	5425	6920	6949	6918	8874	8823	8872	9990	10018	10006
Nonmanufacturing	1346	1500	1504	1500	1714	1691	1715	1828	1842	1830
Manufacturing	4079	5420	5444	5418	7160	7131	7157	8162	8176	8176
Energy-Intensive Manufacturing	1086	1255	1261	1255	1434	1425	1433	1515	1520	1517
Non-Energy-Intensive Manufacturing	2993	4164	4184	4163	5726	5707	5724	6647	6656	6659
Unit Sales of Light-Duty Vehicles (millions)	**17.11**	**17.87**	**18.08**	**17.86**	**20.06**	**20.46**	**20.04**	**20.15**	**20.21**	**20.24**
Population (millions)										
Population with Armed Forces Overseas	278.2	300.2	300.2	300.2	325.3	325.3	325.3	338.2	338.2	338.2
Population (aged 16 and over)	215.4	236.6	236.6	236.6	256.5	256.5	256.5	266.6	266.6	266.6
Employment, Non-Agriculture	131.7	147.1	147.2	147.0	158.8	158.1	158.8	165.5	165.9	165.7
Employment, Manufacturing	17.5	17.7	17.7	17.7	17.7	17.7	17.7	18.4	18.4	18.4
Labor Force	141.8	156.5	156.5	156.5	169.6	169.4	169.6	177.3	177.3	177.3

GDP = Gross domestic product.
Btu = British thermal unit.

Sources: 2001: Global Insight macroeconomic model CTL0802. **Projections:** Energy Information Administration, AEO2003 National Energy Modeling System runs MLBILL.D050503A, ML_NOBANK_4.D051203A, and ML_COVER_K.D050603A.

Table I1. Total Energy Supply and Disposition Summary

(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Production										
Crude Oil and Lease Condensate	12.29	11.94	11.27	11.23	11.50	10.65	10.55	11.23	9.96	9.89
Natural Gas Plant Liquids	2.65	3.12	2.96	3.01	3.53	3.10	3.24	3.70	3.05	3.06
Dry Natural Gas	19.97	22.11	21.00	21.36	25.52	22.63	23.64	27.08	22.37	22.46
Coal	23.97	25.69	25.79	23.23	27.83	30.06	13.89	29.61	32.86	11.85
Nuclear Power	8.03	8.25	8.25	8.37	8.28	8.28	9.80	8.28	8.28	13.69
Renewable Energy[1]	5.32	7.30	7.32	9.33	8.31	8.38	15.60	8.77	8.81	18.00
Other[2]	0.57	0.85	0.84	0.76	0.79	0.77	0.48	0.80	0.73	0.45
Total	**72.80**	**79.26**	**77.43**	**77.29**	**85.76**	**83.86**	**77.20**	**89.47**	**86.06**	**79.42**
Imports										
Crude Oil[3]	20.26	25.09	25.64	25.59	27.63	28.46	27.87	28.62	29.78	29.02
Petroleum Products[4]	5.04	6.32	6.69	5.93	11.72	12.31	9.39	14.79	16.73	11.94
Natural Gas	4.18	5.43	5.79	5.76	7.41	7.80	8.37	8.44	7.63	7.95
Other Imports[5]	0.71	0.92	0.94	0.84	0.95	0.93	1.10	0.93	0.93	0.86
Total	**30.19**	**37.76**	**39.05**	**38.12**	**47.71**	**49.50**	**46.73**	**52.78**	**55.07**	**49.77**
Exports										
Petroleum[6]	2.01	2.25	2.23	2.19	2.38	2.33	2.28	2.43	2.50	2.29
Natural Gas	0.37	0.56	0.53	0.53	0.38	0.38	0.38	0.37	0.37	0.37
Coal	1.27	0.86	0.86	0.83	0.74	0.74	0.67	0.62	0.61	0.62
Total	**3.64**	**3.67**	**3.62**	**3.56**	**3.50**	**3.46**	**3.33**	**3.42**	**3.48**	**3.28**
Discrepancy[7]	**2.06**	**0.22**	**0.25**	**0.41**	**0.23**	**0.21**	**0.15**	**0.20**	**0.17**	**0.09**
Consumption										
Petroleum Products[8]	38.46	44.45	44.53	43.68	52.15	52.33	48.60	56.11	57.14	51.32
Natural Gas	23.26	27.35	26.63	26.95	32.95	30.44	32.00	35.55	30.07	30.54
Coal	22.02	25.47	25.56	22.65	27.88	30.11	13.79	29.86	33.11	11.86
Nuclear Power	8.03	8.25	8.25	8.37	8.28	8.28	9.80	8.28	8.28	13.69
Renewable Energy[1]	5.32	7.30	7.32	9.33	8.31	8.38	15.60	8.77	8.81	18.01
Other[9]	0.21	0.31	0.33	0.46	0.17	0.15	0.65	0.06	0.07	0.39
Total	**97.29**	**113.13**	**112.62**	**111.44**	**129.74**	**129.69**	**120.45**	**138.63**	**137.48**	**125.81**
Net Imports - Petroleum	**23.29**	**29.16**	**30.10**	**29.33**	**36.97**	**38.43**	**34.98**	**40.98**	**44.02**	**38.67**
Prices (2001 dollars per unit)										
World Oil Price (dollars per barrel)[10]	22.01	23.99	23.99	23.77	25.48	25.48	24.15	26.57	26.57	24.58
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.12	3.39	3.81	3.86	3.70	4.03	4.88	3.95	5.55	5.70
Coal Minemouth Price (dollars per ton)	17.59	15.06	15.08	15.91	14.34	14.84	16.51	14.39	15.19	15.80
Average Electricity Price (cents per kilowatthour)	7.3	6.4	6.6	7.1	6.7	6.8	9.3	6.7	7.2	10.3

[1] Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table I18 for selected nonmarketed residential and commercial renewable energy.

[2] Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.

[3] Includes imports of crude oil for the Strategic Petroleum Reserve.

[4] Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.

[5] Includes coal, coal coke (net), and electricity (net).

[6] Includes crude oil and petroleum products.

[7] Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.

[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.

[9] Includes net electricity imports, methanol, and liquid hydrogen.

[10] Average refiner acquisition cost for imported crude oil.

[11] Represents lower 48 onshore and offshore supplies.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Energy Consumption										
Residential										
Distillate Fuel	0.91	0.91	0.91	0.91	0.84	0.84	0.84	0.81	0.81	0.81
Kerosene	0.10	0.08	0.08	0.08	0.06	0.06	0.06	0.06	0.06	0.06
Liquefied Petroleum Gas	0.50	0.47	0.47	0.47	0.46	0.46	0.46	0.46	0.47	0.47
Petroleum Subtotal	1.50	1.46	1.46	1.46	1.36	1.37	1.37	1.33	1.33	1.34
Natural Gas	4.94	5.63	5.55	5.54	6.10	6.01	5.77	6.38	6.09	5.89
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.41	0.41	0.41	0.41	0.40	0.40	0.40	0.40	0.40
Electricity	4.10	4.93	4.91	4.85	5.60	5.57	4.96	5.95	5.86	4.97
Delivered Energy	**10.94**	**12.45**	**12.34**	**12.27**	**13.48**	**13.36**	**12.51**	**14.08**	**13.69**	**12.61**
Electricity Related Losses	9.15	10.37	10.37	10.23	11.03	11.17	9.60	11.42	11.53	9.70
Total	**20.08**	**22.82**	**22.70**	**22.50**	**24.51**	**24.53**	**22.11**	**25.50**	**25.22**	**22.31**
Commercial										
Distillate Fuel	0.46	0.51	0.52	0.52	0.52	0.55	0.58	0.52	0.57	0.63
Residual Fuel	0.09	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.10
Motor Gasoline[2]	0.05	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.71	0.70	0.71	0.71	0.72	0.75	0.78	0.72	0.77	0.84
Natural Gas	3.33	3.74	3.67	3.67	4.23	4.14	4.09	4.50	4.24	4.60
Coal	0.09	0.10	0.10	0.09	0.10	0.10	0.11	0.11	0.11	0.11
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.08	5.01	4.98	4.93	6.17	6.14	5.60	6.79	6.70	5.92
Delivered Energy	**8.32**	**9.65**	**9.57**	**9.52**	**11.33**	**11.24**	**10.69**	**12.23**	**11.93**	**11.57**
Electricity Related Losses	9.12	10.53	10.52	10.41	12.16	12.30	10.86	13.02	13.19	11.56
Total	**17.44**	**20.19**	**20.09**	**19.92**	**23.50**	**23.55**	**21.55**	**25.25**	**25.12**	**23.13**
Industrial[4]										
Distillate Fuel	1.13	1.21	1.22	1.20	1.36	1.37	1.32	1.44	1.48	1.40
Liquefied Petroleum Gas	2.10	2.55	2.55	2.57	3.06	3.11	3.05	3.28	3.38	3.64
Petrochemical Feedstock	1.14	1.44	1.43	1.40	1.70	1.70	1.52	1.82	1.81	1.57
Residual Fuel	0.23	0.19	0.19	0.18	0.20	0.20	0.18	0.20	0.23	0.19
Motor Gasoline[2]	0.15	0.17	0.16	0.16	0.18	0.18	0.18	0.19	0.19	0.19
Other Petroleum[5]	4.03	4.27	4.29	4.14	4.46	4.49	4.02	4.57	4.60	4.02
Petroleum Subtotal	8.79	9.82	9.84	9.65	10.96	11.05	10.28	11.50	11.69	11.01
Natural Gas	7.74	9.06	8.87	9.02	10.39	10.09	10.02	11.23	10.41	9.89
Lease and Plant Fuel[6]	1.20	1.37	1.32	1.34	1.60	1.49	1.54	1.73	1.51	1.51
Natural Gas Subtotal	8.94	10.43	10.19	10.36	11.98	11.58	11.56	12.96	11.92	11.40
Metallurgical Coal	0.72	0.66	0.66	0.65	0.55	0.55	0.47	0.50	0.50	0.39
Steam Coal	1.42	1.46	1.47	1.34	1.51	1.52	1.29	1.54	1.59	1.30
Net Coal Coke Imports	0.03	0.11	0.11	0.10	0.16	0.16	0.18	0.18	0.17	0.21
Coal Subtotal	2.16	2.23	2.23	2.10	2.22	2.23	1.94	2.22	2.26	1.90
Renewable Energy[7]	1.82	2.22	2.21	2.20	2.77	2.77	2.74	3.05	3.03	3.01
Electricity	3.39	3.97	3.97	3.88	4.65	4.69	4.44	5.01	5.05	4.72
Delivered Energy	**25.10**	**28.67**	**28.45**	**28.19**	**32.58**	**32.32**	**30.96**	**34.75**	**33.95**	**32.05**
Electricity Related Losses	7.57	8.35	8.38	8.18	9.17	9.40	8.60	9.61	9.93	9.21
Total	**32.67**	**37.02**	**36.83**	**36.37**	**41.75**	**41.72**	**39.56**	**44.36**	**43.88**	**41.26**

Table I2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Transportation										
Distillate Fuel[8]	5.44	7.09	7.07	7.00	8.68	8.71	8.29	9.55	9.54	8.97
Jet Fuel[9]	3.43	3.93	3.93	3.90	5.09	5.09	5.01	5.67	5.67	5.56
Motor Gasoline[2]	16.26	19.81	19.78	19.53	23.57	23.56	21.35	25.48	25.39	21.90
Residual Fuel	0.84	0.83	0.83	0.83	0.85	0.85	0.84	0.87	0.86	0.85
Liquefied Petroleum Gas	0.02	0.05	0.05	0.05	0.07	0.07	0.08	0.09	0.08	0.08
Other Petroleum[10]	0.24	0.26	0.26	0.26	0.30	0.30	0.30	0.32	0.32	0.32
Petroleum Subtotal	26.22	31.98	31.91	31.56	38.57	38.58	35.88	41.98	41.86	37.69
Pipeline Fuel Natural Gas	0.63	0.78	0.73	0.74	0.94	0.84	0.91	1.03	0.87	0.93
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.10	0.10	0.09	0.11	0.10	0.09
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Electricity	0.07	0.09	0.09	0.09	0.12	0.12	0.12	0.14	0.14	0.13
Delivered Energy	**26.94**	**32.91**	**32.80**	**32.46**	**39.73**	**39.65**	**37.01**	**43.26**	**42.99**	**38.85**
Electricity Related Losses	0.17	0.20	0.20	0.20	0.24	0.25	0.23	0.27	0.28	0.26
Total	**27.10**	**33.10**	**32.99**	**32.65**	**39.98**	**39.90**	**37.24**	**43.53**	**43.26**	**39.11**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.94	9.74	9.72	9.63	11.40	11.46	11.04	12.32	12.39	11.81
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.93	3.90	5.09	5.09	5.01	5.67	5.67	5.56
Liquefied Petroleum Gas	2.70	3.16	3.17	3.18	3.69	3.74	3.69	3.92	4.03	4.29
Motor Gasoline[2]	16.46	20.01	19.98	19.73	23.79	23.78	21.57	25.71	25.62	22.13
Petrochemical Feedstock	1.14	1.44	1.43	1.40	1.70	1.70	1.52	1.82	1.81	1.57
Residual Fuel	1.15	1.06	1.06	1.05	1.10	1.10	1.07	1.12	1.14	1.09
Other Petroleum[12]	4.24	4.51	4.52	4.37	4.74	4.77	4.30	4.87	4.89	4.32
Petroleum Subtotal	37.21	43.97	43.93	43.38	51.61	51.75	48.31	55.53	55.65	50.87
Natural Gas	16.02	18.49	18.15	18.29	20.82	20.34	19.98	22.23	20.84	20.47
Lease and Plant Fuel Plant[6]	1.20	1.37	1.32	1.34	1.60	1.49	1.54	1.73	1.51	1.51
Pipeline Natural Gas	0.63	0.78	0.73	0.74	0.94	0.84	0.91	1.03	0.87	0.93
Natural Gas Subtotal	17.86	20.64	20.20	20.37	23.35	22.67	22.43	24.98	23.23	22.91
Metallurgical Coal	0.72	0.66	0.66	0.65	0.55	0.55	0.47	0.50	0.50	0.39
Steam Coal	1.53	1.56	1.58	1.45	1.63	1.64	1.41	1.66	1.71	1.42
Net Coal Coke Imports	0.03	0.11	0.11	0.10	0.16	0.16	0.18	0.18	0.17	0.21
Coal Subtotal	2.27	2.34	2.34	2.20	2.34	2.35	2.06	2.34	2.38	2.02
Renewable Energy[13]	2.31	2.74	2.73	2.72	3.28	3.29	3.25	3.57	3.54	3.52
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Electricity	11.65	14.00	13.95	13.76	16.54	16.52	15.12	17.90	17.75	15.75
Delivered Energy	**71.29**	**83.68**	**83.15**	**82.43**	**97.13**	**96.57**	**91.17**	**104.32**	**102.55**	**95.08**
Electricity Related Losses	26.00	29.45	29.47	29.02	32.61	33.12	29.28	34.32	34.93	30.72
Total	**97.29**	**113.13**	**112.62**	**111.44**	**129.74**	**129.69**	**120.45**	**138.63**	**137.48**	**125.81**
Electric Power[14]										
Distillate Fuel	0.17	0.09	0.13	0.09	0.13	0.12	0.14	0.18	0.87	0.31
Residual Fuel	1.08	0.39	0.47	0.21	0.41	0.46	0.15	0.40	0.63	0.14
Petroleum Subtotal	1.25	0.48	0.60	0.30	0.54	0.58	0.29	0.58	1.50	0.45
Natural Gas	5.40	6.71	6.44	6.59	9.60	7.77	9.57	10.56	6.84	7.62
Steam Coal	19.75	23.13	23.22	20.44	25.54	27.76	11.73	27.52	30.73	9.83
Nuclear Power	8.03	8.25	8.25	8.37	8.28	8.28	9.80	8.28	8.28	13.69
Renewable Energy[15]	3.01	4.57	4.59	6.62	5.02	5.09	12.35	5.21	5.27	14.49
Electricity Imports	0.21	0.31	0.33	0.46	0.17	0.15	0.65	0.06	0.07	0.39
Total	**37.65**	**43.45**	**43.42**	**42.77**	**49.15**	**49.64**	**44.40**	**52.21**	**52.68**	**46.48**

Table I2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Total Energy Consumption										
Distillate Fuel	8.10	9.83	9.85	9.72	11.53	11.59	11.18	12.50	13.26	12.12
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.93	3.90	5.09	5.09	5.01	5.67	5.67	5.56
Liquefied Petroleum Gas	2.70	3.16	3.17	3.18	3.69	3.74	3.69	3.92	4.03	4.29
Motor Gasoline[2]	16.46	20.01	19.98	19.73	23.79	23.78	21.57	25.71	25.62	22.13
Petrochemical Feedstock	1.14	1.44	1.43	1.40	1.70	1.70	1.52	1.82	1.81	1.57
Residual Fuel	2.23	1.45	1.54	1.26	1.51	1.56	1.21	1.52	1.77	1.23
Other Petroleum[12]	4.24	4.51	4.52	4.37	4.74	4.77	4.30	4.87	4.89	4.32
Petroleum Subtotal	38.46	44.45	44.53	43.68	52.15	52.33	48.60	56.11	57.14	51.32
Natural Gas	21.42	25.20	24.58	24.87	30.42	28.11	29.56	32.79	27.68	28.10
Lease and Plant Fuel[6]	1.20	1.37	1.32	1.34	1.60	1.49	1.54	1.73	1.51	1.51
Pipeline Natural Gas	0.63	0.78	0.73	0.74	0.94	0.84	0.91	1.03	0.87	0.93
Natural Gas Subtotal	23.26	27.35	26.63	26.95	32.95	30.44	32.00	35.55	30.07	30.54
Metallurgical Coal	0.72	0.66	0.66	0.65	0.55	0.55	0.47	0.50	0.50	0.39
Steam Coal	21.28	24.70	24.79	21.89	27.17	29.40	13.15	29.18	32.44	11.25
Net Coal Coke Imports	0.03	0.11	0.11	0.10	0.16	0.16	0.18	0.18	0.17	0.21
Coal Subtotal	22.02	25.47	25.56	22.65	27.88	30.11	13.79	29.86	33.11	11.86
Nuclear Power	8.03	8.25	8.25	8.37	8.28	8.28	9.80	8.28	8.28	13.69
Renewable Energy[16]	5.32	7.30	7.32	9.33	8.31	8.38	15.60	8.77	8.81	18.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Electricity Imports	0.21	0.31	0.33	0.46	0.17	0.15	0.65	0.06	0.07	0.39
Total	**97.29**	**113.13**	**112.62**	**111.44**	**129.74**	**129.69**	**120.45**	**138.63**	**137.48**	**125.81**
Energy Use and Related Statistics										
Delivered Energy Use	71.29	83.68	83.15	82.43	97.13	96.57	91.17	104.32	102.55	95.08
Total Energy Use	97.29	113.13	112.62	111.44	129.74	129.69	120.45	138.63	137.48	125.81
Population (millions)	278.18	300.24	300.24	300.24	325.32	325.32	325.32	338.24	338.24	338.24
Gross Domestic Product (billion 1996 dollars)	9215	12258	12230	12187	16444	16465	16354	18916	18854	18787
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1558.6	1802.2	1796.2	1709.0	2077.7	2101.6	1576.8	2234.4	2259.6	1474.2

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[1] Includes wood used for residential heating. See Table I18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.

[2] Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.

[3] Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table I18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.

[4] Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.

[5] Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.

[6] Represents natural gas used in the field gathering and processing plant machinery.

[7] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.

[8] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.

[9] Includes only kerosene type.

[10] Includes aviation gasoline and lubricants.

[11] E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).

[12] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.

[13] Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

[14] Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[15] Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.

[16] Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.

Sources: 2001 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 population and gross domestic product: Global Insight macroeconomic model CTL0802. 2001 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I3. Delivered Energy Prices by Sector and Source

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Residential	**15.81**	**13.97**	**14.38**	**15.03**	**14.62**	**15.02**	**18.52**	**14.89**	**16.30**	**20.20**
Primary Energy[1]	9.73	8.07	8.44	8.45	8.33	8.63	9.28	8.57	9.81	9.96
Petroleum Products[2]	10.85	10.02	10.06	9.93	10.91	10.93	10.48	11.21	11.27	10.79
Distillate Fuel	8.99	7.99	8.06	7.92	8.70	8.73	8.28	8.93	8.93	8.58
Liquefied Petroleum Gas	14.84	14.35	14.31	14.21	15.28	15.28	14.89	15.52	15.67	14.98
Natural Gas	9.41	7.57	8.03	8.08	7.77	8.13	9.01	8.04	9.51	9.79
Electricity	25.37	22.48	22.88	24.54	23.03	23.48	31.86	23.09	24.52	35.13
Commercial	**15.50**	**13.45**	**13.93**	**14.81**	**14.58**	**15.02**	**19.02**	**15.00**	**16.53**	**20.81**
Primary Energy[1]	7.81	6.43	6.80	6.82	6.78	7.06	7.68	7.05	8.28	8.37
Petroleum Products[2]	7.27	6.78	6.81	6.69	7.51	7.49	6.98	7.81	7.79	7.18
Distillate Fuel	6.40	5.67	5.73	5.60	6.45	6.48	5.98	6.75	6.77	6.28
Residual Fuel	3.46	4.01	4.03	3.94	4.23	4.24	3.96	4.39	4.42	4.02
Natural Gas	8.09	6.49	6.93	6.98	6.79	7.12	7.98	7.07	8.54	8.75
Electricity	23.28	19.81	20.35	22.07	20.98	21.51	29.09	21.25	22.83	32.46
Industrial[3]	**7.11**	**6.39**	**6.63**	**6.85**	**7.01**	**7.23**	**8.42**	**7.25**	**8.13**	**9.35**
Primary Energy	5.83	5.18	5.38	5.36	5.74	5.92	6.14	5.99	6.76	6.70
Petroleum Products[2]	7.72	7.07	7.09	7.01	7.85	7.88	7.52	8.13	8.25	7.84
Distillate Fuel	6.55	5.75	5.82	5.68	6.74	6.78	6.19	7.19	7.24	6.53
Liquefied Petroleum Gas	12.34	9.93	9.90	9.83	10.85	10.88	10.58	11.13	11.26	10.66
Residual Fuel	3.28	3.71	3.73	3.66	3.94	3.94	3.70	4.10	4.13	3.77
Natural Gas[4]	4.87	4.00	4.43	4.47	4.39	4.72	5.57	4.63	6.19	6.38
Metallurgical Coal	1.69	1.50	1.51	1.50	1.39	1.39	1.40	1.34	1.33	1.34
Steam Coal	1.46	1.39	1.39	1.39	1.31	1.34	1.22	1.30	1.33	1.17
Electricity	14.13	12.82	13.22	14.78	13.37	13.71	19.75	13.48	14.64	22.03
Transportation	**10.28**	**10.22**	**10.24**	**11.81**	**10.37**	**10.36**	**13.46**	**10.82**	**10.79**	**14.07**
Primary Energy	10.25	10.19	10.21	11.79	10.35	10.33	13.42	10.79	10.76	14.03
Petroleum Products[2]	10.25	10.20	10.22	11.79	10.35	10.34	13.43	10.80	10.76	14.04
Distillate Fuel[5]	10.05	10.19	10.19	11.82	10.27	10.18	13.43	10.64	10.54	14.25
Jet Fuel[6]	6.20	5.66	5.70	7.17	6.34	6.34	9.46	6.72	6.73	10.22
Motor Gasoline[7]	11.57	11.45	11.48	13.06	11.55	11.56	14.68	12.07	12.04	15.23
Residual Fuel	3.90	3.56	3.57	5.29	3.78	3.78	7.57	3.94	3.95	8.17
Liquefied Petroleum Gas[8]	16.93	15.55	15.40	16.65	16.06	16.07	18.91	15.99	16.37	19.10
Natural Gas[9]	7.65	7.19	7.63	7.55	7.75	8.06	8.55	8.09	9.52	9.32
Electricity	21.87	19.10	19.51	21.26	18.45	18.81	25.64	17.90	19.05	27.37
Average End-Use Energy	**10.75**	**9.97**	**10.18**	**11.10**	**10.47**	**10.64**	**13.30**	**10.82**	**11.44**	**14.33**
Primary Energy	8.52	8.07	8.22	8.99	8.46	8.57	10.30	8.84	9.28	10.93
Electricity	21.34	18.76	19.20	20.88	19.52	19.94	27.23	19.66	21.03	30.13
Electric Power[10]										
Fossil Fuel Average	2.14	1.82	1.90	1.99	2.04	1.94	3.13	2.13	2.16	3.35
Petroleum Products	4.73	4.28	4.26	4.47	4.72	4.63	5.11	5.04	5.40	5.49
Distillate Fuel	6.20	5.13	5.20	5.01	5.94	5.98	5.43	6.16	6.14	5.73
Residual Fuel	4.50	4.08	4.01	4.23	4.33	4.28	4.81	4.55	4.39	4.97
Natural Gas	4.78	3.88	4.31	4.41	4.35	4.62	5.62	4.64	6.04	6.24
Steam Coal	1.25	1.17	1.17	1.17	1.12	1.14	1.05	1.11	1.14	1.01

Table I3. Delivered Energy Prices by Sector and Source (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Average Price to All Users[11]										
Petroleum Products[2]	9.54	9.46	9.46	10.61	9.81	9.80	11.99	10.22	10.14	12.49
Distillate Fuel	9.16	9.15	9.15	10.30	9.52	9.46	11.69	9.90	9.62	12.35
Jet Fuel	6.20	5.66	5.70	7.17	6.34	6.34	9.46	6.72	6.73	10.22
Liquefied Petroleum Gas	12.85	10.75	10.71	10.66	11.58	11.59	11.35	11.81	11.93	11.35
Motor Gasoline[7]	11.57	11.45	11.47	13.04	11.55	11.56	14.64	12.07	12.04	15.19
Residual Fuel	4.11	3.73	3.74	4.84	3.96	3.96	6.53	4.14	4.14	6.97
Natural Gas	6.40	5.15	5.60	5.64	5.40	5.79	6.60	5.64	7.26	7.46
Coal	1.26	1.18	1.19	1.18	1.13	1.15	1.07	1.12	1.15	1.03
Ethanol (E85)[10]	17.72	21.29	21.42	20.70	22.85	22.95	20.80	23.44	23.89	21.07
Electricity	21.34	18.76	19.20	20.88	19.52	19.94	27.23	19.66	21.03	30.13
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)										
Residential	166.77	168.16	171.58	178.33	191.19	194.57	224.31	203.68	216.65	246.76
Commercial	127.30	128.40	131.83	139.42	163.77	167.31	201.31	181.88	195.41	238.70
Industrial	135.32	137.86	142.38	146.53	172.27	177.20	199.58	190.69	211.00	231.92
Transportation	270.41	328.32	328.36	374.58	402.37	401.96	485.62	456.80	454.28	533.51
Total Non-Renewable Expenditures	699.80	762.73	774.16	838.87	929.60	941.04	1110.82	1033.06	1077.35	1250.90
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.10	0.10	0.11	0.13	0.13	0.15
Total Expenditures	**699.81**	**762.78**	**774.20**	**838.92**	**929.70**	**941.14**	**1110.93**	**1033.19**	**1077.48**	**1251.05**

[1] Weighted average price includes fuels below as well as coal.

[2] This quantity is the weighted average for all petroleum products, not just those listed below.

[3] Includes combined heat and power, which produces electricity and other useful thermal energy.

[4] Excludes use for lease and plant fuel.

[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.

[6] Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.

[7] Sales weighted-average price for all grades. Includes Federal, State and local taxes.

[8] Includes Federal and State taxes while excluding county and local taxes.

[9] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.

[10] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

[11] Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.

Btu = British thermal unit.

Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I4. Greenhouse Gas Allowance Cost by End-Use Sector and Source

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Commercial										
Petroleum Products[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residual Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[3]										
Petroleum Products[2]	0.00	0.00	0.00	1.00	0.00	0.00	2.29	0.00	0.00	2.65
Distillate Fuel	0.00	0.00	0.00	1.65	0.00	0.00	3.72	0.00	0.00	4.22
Liquefied Petroleum Gas	0.00	0.00	0.00	1.42	0.00	0.00	3.22	0.00	0.00	3.65
Residual Fuel	0.00	0.00	0.00	1.77	0.00	0.00	4.01	0.00	0.00	4.55
Natural Gas[4]	0.00	0.00	0.00	1.18	0.00	0.00	2.66	0.00	0.00	3.02
Metallurgical Coal	0.00	0.00	0.00	2.11	0.00	0.00	4.77	0.00	0.00	5.41
Steam Coal	0.00	0.00	0.00	2.11	0.00	0.00	4.78	0.00	0.00	5.42
Electric Power[5]										
Fossil Fuel Average	0.00	0.00	0.00	1.90	0.00	0.00	3.86	0.00	0.00	4.40
Petroleum Products	0.00	0.00	0.00	1.73	0.00	0.00	3.87	0.00	0.00	4.32
Distillate Fuel	0.00	0.00	0.00	1.65	0.00	0.00	3.72	0.00	0.00	4.22
Residual Fuel	0.00	0.00	0.00	1.77	0.00	0.00	4.01	0.00	0.00	4.55
Natural Gas	0.00	0.00	0.00	1.20	0.00	0.00	2.71	0.00	0.00	3.08
Steam Coal	0.00	0.00	0.00	2.13	0.00	0.00	4.79	0.00	0.00	5.44
Average Allowance Cost to All Users[6]										
Petroleum Products[2]	0.00	0.00	0.00	0.24	0.00	0.00	0.52	0.00	0.00	0.62
Distillate Fuel	0.00	0.00	0.00	0.22	0.00	0.00	0.49	0.00	0.00	0.60
Jet Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquefied Petroleum Gas	0.00	0.00	0.00	1.15	0.00	0.00	2.67	0.00	0.00	3.10
Motor Gasoline	0.00	0.00	0.00	0.01	0.00	0.00	0.03	0.00	0.00	0.03
Residual Fuel	0.00	0.00	0.00	0.55	0.00	0.00	1.07	0.00	0.00	1.21
Natural Gas	0.00	0.00	0.00	0.75	0.00	0.00	1.79	0.00	0.00	1.91
Coal	0.00	0.00	0.00	2.12	0.00	0.00	4.75	0.00	0.00	5.38

[1] Weighted average allowance cost includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3] Includes combined heat and power, which produces electricity and other useful thermal energy.
[4] Excludes use for lease and plant fuel.
[5] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[6] Weighted averages of allowance costs are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Projections: EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I5. Energy Prices by Sector and Source with Greenhouse Gas Allowance Cost

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Residential	**15.81**	**13.97**	**14.38**	**15.03**	**14.62**	**15.02**	**18.52**	**14.89**	**16.30**	**20.20**
Primary Energy[1]	9.73	8.07	8.44	8.45	8.33	8.63	9.28	8.57	9.81	9.96
Petroleum Products[2]	10.85	10.02	10.06	9.93	10.91	10.93	10.48	11.21	11.27	10.79
Distillate Fuel	8.99	7.99	8.06	7.92	8.70	8.73	8.28	8.93	8.93	8.58
Liquefied Petroleum Gas	14.84	14.35	14.31	14.21	15.28	15.28	14.89	15.52	15.67	14.98
Natural Gas	9.41	7.57	8.03	8.08	7.77	8.13	9.01	8.04	9.51	9.79
Electricity	25.37	22.48	22.88	24.54	23.03	23.48	31.86	23.09	24.52	35.13
Commercial	**15.50**	**13.45**	**13.93**	**14.81**	**14.58**	**15.02**	**19.02**	**15.00**	**16.53**	**20.81**
Primary Energy[1]	7.81	6.43	6.80	6.82	6.78	7.06	7.68	7.05	8.28	8.37
Petroleum Products[2]	7.27	6.78	6.81	6.69	7.51	7.49	6.98	7.81	7.79	7.18
Distillate Fuel	6.40	5.67	5.73	5.60	6.45	6.48	5.98	6.75	6.77	6.28
Residual Fuel	3.46	4.01	4.03	3.94	4.23	4.24	3.96	4.39	4.42	4.02
Natural Gas	8.09	6.49	6.93	6.98	6.79	7.12	7.98	7.07	8.54	8.75
Electricity	23.28	19.81	20.35	22.07	20.98	21.51	29.09	21.25	22.83	32.46
Industrial[3]	**7.11**	**6.39**	**6.63**	**7.85**	**7.01**	**7.23**	**10.63**	**7.25**	**8.13**	**11.85**
Primary Energy	5.83	5.18	5.38	6.55	5.74	5.92	8.79	5.99	6.76	9.72
Petroleum Products[2]	7.72	7.07	7.09	8.01	7.85	7.88	9.81	8.13	8.25	10.49
Distillate Fuel	6.55	5.75	5.82	7.33	6.74	6.78	9.92	7.19	7.24	10.75
Liquefied Petroleum Gas	12.34	9.93	9.90	11.25	10.85	10.88	13.80	11.13	11.26	14.31
Residual Fuel	3.28	3.71	3.73	5.43	3.94	3.94	7.71	4.10	4.13	8.31
Natural Gas[4]	4.87	4.00	4.43	5.65	4.39	4.72	8.23	4.63	6.19	9.40
Metallurgical Coal	1.69	1.50	1.51	3.61	1.39	1.39	6.17	1.34	1.33	6.74
Steam Coal	1.46	1.39	1.39	3.50	1.31	1.34	6.00	1.30	1.33	6.59
Electricity	14.13	12.82	13.22	14.78	13.37	13.71	19.75	13.48	14.64	22.03
Transportation	**10.28**	**10.22**	**10.24**	**11.82**	**10.37**	**10.36**	**13.46**	**10.82**	**10.79**	**14.08**
Primary Energy	10.25	10.19	10.21	11.79	10.35	10.33	13.42	10.79	10.76	14.03
Petroleum Products[2]	10.25	10.20	10.22	11.79	10.35	10.34	13.43	10.80	10.76	14.04
Distillate Fuel[5]	10.05	10.19	10.19	11.82	10.27	10.18	13.43	10.64	10.54	14.25
Jet Fuel[6]	6.20	5.66	5.70	7.17	6.34	6.34	9.46	6.72	6.73	10.22
Motor Gasoline[7]	11.57	11.45	11.48	13.06	11.55	11.56	14.68	12.07	12.04	15.23
Residual Fuel	3.90	3.56	3.57	5.29	3.78	3.78	7.57	3.94	3.95	8.17
Liquefied Petroleum Gas[8]	16.93	15.55	15.40	16.65	16.06	16.07	18.91	15.99	16.37	19.10
Natural Gas[9]	7.65	7.19	7.63	8.75	7.75	8.06	11.26	8.09	9.52	12.40
Electricity	21.87	19.10	19.51	21.26	18.45	18.81	25.64	17.90	19.05	27.37
Average End-Use Energy	**10.75**	**9.97**	**10.18**	**11.42**	**10.47**	**10.64**	**13.99**	**10.82**	**11.44**	**15.10**
Primary Energy	8.52	8.07	8.22	9.37	8.46	8.57	11.14	8.84	9.28	11.87
Electricity	21.34	18.76	19.20	20.88	19.52	19.94	27.23	19.66	21.03	30.13
Electric Power[10]										
Fossil Fuel Average	2.14	1.82	1.90	3.89	2.04	1.94	6.99	2.13	2.16	7.75
Petroleum Products	4.73	4.28	4.26	6.20	4.72	4.63	8.98	5.04	5.40	9.81
Distillate Fuel	6.20	5.13	5.20	6.65	5.94	5.98	9.15	6.16	6.14	9.95
Residual Fuel	4.50	4.08	4.01	6.01	4.33	4.28	8.82	4.55	4.39	9.51
Natural Gas	4.78	3.88	4.31	5.61	4.35	4.62	8.33	4.64	6.04	9.31
Steam Coal	1.25	1.17	1.17	3.30	1.12	1.14	5.84	1.11	1.14	6.45

Table I5. Energy Prices by Sector and Source with Greenhouse Gas Allowance Cost (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Average Price to All Users[11]										
Petroleum Products[2]	9.54	9.46	9.46	10.85	9.81	9.80	12.51	10.22	10.14	13.11
Distillate Fuel	9.16	9.15	9.15	10.52	9.52	9.46	12.18	9.90	9.62	12.94
Jet Fuel	6.20	5.66	5.70	7.17	6.34	6.34	9.46	6.72	6.73	10.22
Liquefied Petroleum Gas	12.85	10.75	10.71	11.81	11.58	11.59	14.02	11.81	11.93	14.45
Motor Gasoline[7]	11.57	11.45	11.47	13.05	11.55	11.56	14.67	12.07	12.04	15.23
Residual Fuel	4.11	3.73	3.74	5.38	3.96	3.96	7.60	4.14	4.14	8.18
Natural Gas	6.40	5.15	5.60	6.38	5.40	5.79	8.39	5.64	7.26	9.36
Coal	1.26	1.18	1.19	3.30	1.13	1.15	5.82	1.12	1.15	6.41
Electricity	21.34	18.76	19.20	20.88	19.52	19.94	27.23	19.66	21.03	30.13
Non-Renewable Energy and Allowance Expenditures by Sector (billion 2001 dollars)										
Residential	166.77	168.16	171.58	178.33	191.19	194.57	224.31	203.68	216.65	246.76
Commercial	127.30	128.40	131.83	139.42	163.77	167.31	201.31	181.88	195.41	238.70
Industrial	135.32	137.86	142.38	167.97	172.27	177.20	251.86	190.69	211.00	294.09
Transportation	270.41	328.32	328.36	374.65	402.37	401.96	485.87	456.80	454.28	533.82
Total Non-Renewable Expenditures	699.80	762.73	774.16	860.38	929.60	941.04	1163.35	1033.06	1077.35	1313.37
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.10	0.10	0.12	0.13	0.13	0.16
Total Expenditures	**699.81**	**762.78**	**774.20**	**860.43**	**929.70**	**941.14**	**1163.47**	**1033.19**	**1077.48**	**1313.52**

[1] Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3] Includes combined heat and power, which produces electricity and other useful thermal energy.
[4] Excludes use for lease and plant fuel.
[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6] Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7] Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8] Includes Federal and State taxes while excluding county and local taxes.
[9] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[10] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[11] Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I6. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Key Indicators										
Households (millions)										
Single-Family	77.50	86.16	86.15	86.12	94.13	94.14	93.98	97.63	97.63	97.42
Multifamily	22.19	24.15	24.13	24.11	27.09	27.10	26.98	28.82	28.80	28.69
Mobile Homes	6.57	7.11	7.10	7.10	7.86	7.87	7.86	8.11	8.11	8.12
Total	**106.27**	**117.42**	**117.38**	**117.33**	**129.08**	**129.10**	**128.82**	**134.55**	**134.54**	**134.22**
Average House Square Footage	**1685**	**1740**	**1740**	**1740**	**1782**	**1782**	**1782**	**1798**	**1798**	**1798**
Energy Intensity										
(million Btu per household)										
Delivered Energy Consumption	102.9	106.0	105.1	104.6	104.4	103.5	97.1	104.6	101.8	93.9
Total Energy Consumption	189.0	194.3	193.4	191.8	189.9	190.0	171.7	189.5	187.5	166.2
(thousand Btu per square foot)										
Delivered Energy Consumption	61.1	60.9	60.4	60.1	58.6	58.1	54.5	58.2	56.6	52.2
Total Energy Consumption	112.2	111.7	111.2	110.2	106.6	106.6	96.3	105.4	104.2	92.4
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.39	0.46	0.46	0.45	0.50	0.50	0.45	0.52	0.51	0.44
Space Cooling	0.52	0.60	0.60	0.59	0.65	0.65	0.58	0.69	0.67	0.58
Water Heating	0.45	0.47	0.47	0.46	0.44	0.44	0.37	0.44	0.43	0.32
Refrigeration	0.42	0.34	0.34	0.34	0.32	0.32	0.32	0.33	0.33	0.33
Cooking	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.13
Clothes Dryers	0.22	0.25	0.25	0.24	0.27	0.26	0.25	0.28	0.27	0.25
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.93	0.93	0.90	1.03	1.02	0.77	1.07	1.03	0.68
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers[1]	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.20	0.19	0.19	0.25	0.25	0.23	0.27	0.26	0.24
Personal Computers	0.06	0.08	0.08	0.08	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.09	0.10	0.10	0.09	0.11	0.10	0.10
Other Uses[2]	0.83	1.26	1.25	1.24	1.66	1.65	1.52	1.87	1.84	1.66
Delivered Energy	**4.10**	**4.93**	**4.91**	**4.85**	**5.60**	**5.57**	**4.96**	**5.95**	**5.86**	**4.97**
Natural Gas										
Space Heating	3.13	3.70	3.64	3.63	4.10	4.03	3.83	4.30	4.08	3.88
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.48	1.55	1.53	1.53	1.59	1.57	1.54	1.65	1.58	1.56
Cooking	0.20	0.23	0.22	0.22	0.25	0.25	0.25	0.26	0.26	0.26
Clothes Dryers	0.06	0.08	0.08	0.08	0.10	0.10	0.09	0.10	0.10	0.10
Other Uses[3]	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.07	0.10
Delivered Energy	**4.94**	**5.63**	**5.55**	**5.54**	**6.10**	**6.01**	**5.77**	**6.38**	**6.09**	**5.89**
Distillate										
Space Heating	0.74	0.76	0.76	0.76	0.71	0.71	0.71	0.69	0.69	0.69
Water Heating	0.16	0.14	0.14	0.14	0.12	0.12	0.12	0.11	0.11	0.12
Other Uses[4]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.91**	**0.91**	**0.91**	**0.91**	**0.84**	**0.84**	**0.84**	**0.81**	**0.81**	**0.81**
Liquefied Petroleum Gas										
Space Heating	0.26	0.25	0.25	0.25	0.24	0.24	0.24	0.24	0.24	0.24
Water Heating	0.09	0.07	0.07	0.07	0.06	0.06	0.06	0.06	0.06	0.06
Cooking	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Other Uses[3]	0.12	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14
Delivered Energy	**0.50**	**0.47**	**0.47**	**0.47**	**0.46**	**0.46**	**0.46**	**0.46**	**0.47**	**0.47**
Marketed Renewables (wood)[5]	0.39	0.41	0.41	0.41	0.41	0.40	0.40	0.40	0.40	0.40
Other Fuels[6]	0.11	0.09	0.09	0.09	0.08	0.08	0.08	0.07	0.07	0.07

Table I6. Residential Sector Key Indicators and End-Use Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Delivered Energy Consumption by End-Use										
Space Heating	5.01	5.68	5.61	5.60	6.04	5.96	5.71	6.22	6.00	5.72
Space Cooling	0.52	0.60	0.60	0.59	0.65	0.65	0.58	0.69	0.67	0.58
Water Heating	2.19	2.24	2.22	2.21	2.21	2.19	2.09	2.26	2.19	2.05
Refrigeration	0.42	0.34	0.34	0.34	0.32	0.32	0.32	0.33	0.33	0.33
Cooking	0.33	0.36	0.36	0.36	0.39	0.39	0.39	0.40	0.40	0.40
Clothes Dryers	0.28	0.33	0.33	0.33	0.36	0.36	0.34	0.38	0.37	0.35
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.93	0.93	0.90	1.03	1.02	0.77	1.07	1.03	0.68
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.20	0.19	0.19	0.25	0.25	0.23	0.27	0.26	0.24
Personal Computers	0.06	0.08	0.08	0.08	0.10	0.10	0.10	0.11	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.09	0.10	0.10	0.09	0.11	0.10	0.10
Other Uses[7]	1.01	1.46	1.45	1.44	1.87	1.87	1.74	2.09	2.06	1.90
Delivered Energy	**10.94**	**12.45**	**12.34**	**12.27**	**13.48**	**13.36**	**12.51**	**14.08**	**13.69**	**12.61**
Electricity Related Losses	**9.15**	**10.37**	**10.37**	**10.23**	**11.03**	**11.17**	**9.60**	**11.42**	**11.53**	**9.70**
Total Energy Consumption by End-Use										
Space Heating	5.89	6.64	6.58	6.55	7.03	6.97	6.58	7.22	7.01	6.58
Space Cooling	1.68	1.86	1.86	1.84	1.94	1.95	1.71	2.00	2.00	1.72
Water Heating	3.20	3.23	3.21	3.19	3.08	3.08	2.81	3.10	3.05	2.67
Refrigeration	1.36	1.06	1.06	1.06	0.96	0.97	0.94	0.97	0.98	0.97
Cooking	0.55	0.59	0.59	0.59	0.63	0.63	0.63	0.65	0.65	0.65
Clothes Dryers	0.78	0.85	0.85	0.84	0.89	0.89	0.81	0.91	0.91	0.83
Freezers	0.36	0.28	0.28	0.28	0.26	0.27	0.26	0.27	0.27	0.27
Lighting	2.40	2.90	2.89	2.81	3.06	3.06	2.26	3.12	3.07	2.00
Clothes Washers	0.10	0.10	0.10	0.10	0.09	0.09	0.08	0.08	0.08	0.08
Dishwashers	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.09	0.08
Color Televisions	0.43	0.61	0.61	0.60	0.75	0.76	0.69	0.78	0.78	0.71
Personal Computers	0.19	0.25	0.25	0.25	0.31	0.31	0.30	0.33	0.34	0.33
Furnace Fans	0.23	0.27	0.27	0.27	0.30	0.30	0.27	0.31	0.31	0.28
Other Uses[7]	2.86	4.10	4.10	4.05	5.14	5.18	4.68	5.67	5.69	5.14
Total	**20.08**	**22.82**	**22.70**	**22.50**	**24.51**	**24.53**	**22.11**	**25.50**	**25.22**	**22.31**
Non-Marketed Renewables										
Geothermal[8]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar[9]	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.05	0.05
Total	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**

[1] Does not include electric water heating portion of load.
[2] Includes small electric devices, heating elements, and motors.
[3] Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).
[4] Includes such appliances as swimming pool and hot tub heaters.
[5] Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.
[6] Includes kerosene and coal.
[7] Includes all other uses listed above.
[8] Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.
[9] Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I7. Commercial Sector Key Indicators and Consumption

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Key Indicators										
Total Floorspace (billion square feet)										
Surviving	66.6	79.0	78.9	78.9	91.2	91.1	90.7	97.4	97.3	96.9
New Additions	3.6	3.0	3.0	3.0	3.4	3.4	3.4	3.4	3.3	3.4
Total	**70.2**	**82.0**	**81.9**	**81.9**	**94.6**	**94.5**	**94.1**	**100.8**	**100.7**	**100.3**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	118.4	117.8	116.8	116.2	119.8	119.0	113.6	121.3	118.5	115.4
Electricity Related Losses	129.9	128.5	128.5	127.1	128.5	130.2	115.4	129.1	131.0	115.2
Total Energy Consumption	248.3	246.2	245.3	243.3	248.3	249.2	229.0	250.4	249.5	230.5
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating[1]	0.14	0.16	0.15	0.15	0.15	0.15	0.14	0.15	0.15	0.13
Space Cooling[1]	0.43	0.43	0.42	0.42	0.45	0.45	0.41	0.46	0.46	0.39
Water Heating[1]	0.15	0.16	0.15	0.15	0.16	0.15	0.14	0.15	0.15	0.13
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.17	0.19	0.19	0.16
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02
Lighting	1.02	1.21	1.19	1.16	1.30	1.28	0.96	1.33	1.28	0.86
Refrigeration	0.21	0.24	0.24	0.23	0.26	0.26	0.24	0.27	0.27	0.23
Office Equipment (PC)	0.16	0.24	0.24	0.24	0.32	0.32	0.31	0.36	0.36	0.34
Office Equipment (non-PC)	0.31	0.47	0.47	0.47	0.75	0.74	0.72	0.92	0.92	0.87
Other Uses[2]	1.46	1.90	1.90	1.90	2.57	2.56	2.50	2.92	2.91	2.80
Delivered Energy	**4.08**	**5.01**	**4.98**	**4.93**	**6.17**	**6.14**	**5.60**	**6.79**	**6.70**	**5.92**
Natural Gas										
Space Heating[1]	1.32	1.53	1.50	1.50	1.65	1.60	1.50	1.71	1.60	1.44
Space Cooling[1]	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.03	0.03
Water Heating[1]	0.57	0.69	0.68	0.68	0.81	0.79	0.74	0.86	0.82	0.73
Cooking	0.25	0.30	0.30	0.30	0.35	0.34	0.32	0.37	0.35	0.33
Other Uses[3]	1.17	1.20	1.18	1.18	1.39	1.38	1.51	1.52	1.45	2.06
Delivered Energy	**3.33**	**3.74**	**3.67**	**3.67**	**4.23**	**4.14**	**4.09**	**4.50**	**4.24**	**4.60**
Distillate										
Space Heating[1]	0.17	0.24	0.24	0.24	0.25	0.28	0.30	0.25	0.29	0.33
Water Heating[1]	0.07	0.08	0.08	0.08	0.08	0.08	0.09	0.08	0.08	0.10
Other Uses[4]	0.22	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.19	0.21
Delivered Energy	**0.46**	**0.51**	**0.52**	**0.52**	**0.52**	**0.55**	**0.58**	**0.52**	**0.57**	**0.63**
Other Fuels[5]	**0.34**	**0.29**	**0.28**	**0.29**	**0.30**	**0.30**	**0.31**	**0.31**	**0.31**	**0.31**
Marketed Renewable Fuels										
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Energy	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Delivered Energy Consumption by End-Use										
Space Heating[1]	1.63	1.92	1.90	1.89	2.05	2.03	1.93	2.11	2.03	1.90
Space Cooling[1]	0.44	0.45	0.44	0.44	0.48	0.48	0.44	0.50	0.49	0.42
Water Heating[1]	0.79	0.92	0.91	0.91	1.04	1.03	0.96	1.09	1.05	0.96
Ventilation	0.17	0.18	0.18	0.18	0.19	0.19	0.17	0.19	0.19	0.16
Cooking	0.29	0.33	0.33	0.33	0.38	0.37	0.35	0.40	0.38	0.35
Lighting	1.02	1.21	1.19	1.16	1.30	1.28	0.96	1.33	1.28	0.86
Refrigeration	0.21	0.24	0.24	0.23	0.26	0.26	0.24	0.27	0.27	0.23
Office Equipment (PC)	0.16	0.24	0.24	0.24	0.32	0.32	0.31	0.36	0.36	0.34
Office Equipment (non-PC)	0.31	0.47	0.47	0.47	0.75	0.74	0.72	0.92	0.92	0.87
Other Uses[6]	3.30	3.69	3.67	3.67	4.56	4.54	4.62	5.05	4.96	5.48
Delivered Energy	**8.32**	**9.65**	**9.57**	**9.52**	**11.33**	**11.24**	**10.69**	**12.23**	**11.93**	**11.57**

Table I7. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Electricity Related Losses	**9.12**	**10.53**	**10.52**	**10.41**	**12.16**	**12.30**	**10.86**	**13.02**	**13.19**	**11.56**
Total Energy Consumption by End-Use										
Space Heating[1]	1.95	2.25	2.22	2.21	2.36	2.33	2.20	2.40	2.32	2.15
Space Cooling[1]	1.39	1.34	1.34	1.33	1.38	1.38	1.23	1.39	1.39	1.19
Water Heating[1]	1.12	1.25	1.24	1.23	1.35	1.34	1.24	1.39	1.35	1.21
Ventilation	0.55	0.56	0.56	0.55	0.56	0.56	0.49	0.57	0.57	0.46
Cooking	0.37	0.40	0.40	0.40	0.44	0.43	0.40	0.45	0.43	0.40
Lighting	3.31	3.74	3.71	3.61	3.86	3.86	2.81	3.88	3.80	2.53
Refrigeration	0.69	0.74	0.74	0.73	0.77	0.77	0.70	0.78	0.79	0.68
Office Equipment (PC)	0.52	0.75	0.75	0.75	0.95	0.96	0.91	1.05	1.06	1.00
Office Equipment (non-PC)	0.99	1.45	1.45	1.45	2.21	2.23	2.12	2.69	2.73	2.57
Other Uses[6]	6.56	7.70	7.68	7.67	9.62	9.67	9.46	10.65	10.68	10.94
Total	**17.44**	**20.19**	**20.09**	**19.92**	**23.50**	**23.55**	**21.55**	**25.25**	**25.12**	**23.13**
Non-Marketed Renewable Fuels										
Solar[7]	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

[1] Includes fuel consumption for district services.

[2] Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.

[3] Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.

[4] Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.

[5] Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.

[6] Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.

[7] Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.

Btu = British thermal unit.

PC = Personal computer.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I8. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Key Indicators										
Value of Shipments (billion 1996 dollars)										
Manufacturing	4079	5466	5450	5406	7226	7239	7155	8258	8226	8160
Nonmanufacturing	1346	1510	1502	1491	1744	1742	1703	1870	1850	1810
Total	**5425**	**6977**	**6951**	**6897**	**8969**	**8981**	**8858**	**10128**	**10075**	**9970**
Energy Prices (2001 dollars per million Btu)										
Electricity	14.13	12.82	13.22	14.78	13.37	13.71	19.75	13.48	14.64	22.03
Natural Gas	4.87	4.00	4.43	5.65	4.39	4.72	8.23	4.63	6.19	9.40
Steam Coal	1.46	1.39	1.39	3.50	1.31	1.34	6.00	1.30	1.33	6.59
Residual Oil	3.28	3.71	3.73	5.43	3.94	3.94	7.71	4.10	4.13	8.31
Distillate Oil	6.55	5.75	5.82	7.33	6.74	6.78	9.92	7.19	7.24	10.75
Liquefied Petroleum Gas	12.34	9.93	9.90	11.25	10.85	10.88	13.80	11.13	11.26	14.31
Motor Gasoline	11.57	11.40	11.42	13.02	11.52	11.53	14.64	12.05	12.02	15.21
Metallurgical Coal	1.69	1.50	1.51	3.61	1.39	1.39	6.17	1.34	1.33	6.74
Energy Consumption[1]										
Purchased Electricity	3.39	3.97	3.97	3.88	4.65	4.69	4.44	5.01	5.05	4.72
Natural Gas	7.74	9.06	8.87	9.02	10.39	10.09	10.02	11.23	10.41	9.89
Lease and Plant Fuel[2]	1.20	1.37	1.32	1.34	1.60	1.49	1.54	1.73	1.51	1.51
Natural Gas Subtotal	8.94	10.43	10.19	10.36	11.98	11.58	11.56	12.96	11.92	11.40
Steam Coal	1.42	1.46	1.47	1.34	1.51	1.52	1.29	1.54	1.59	1.30
Metallurgical Coal and Coke[3]	0.74	0.77	0.77	0.76	0.71	0.71	0.65	0.68	0.67	0.60
Residual Fuel	0.23	0.19	0.19	0.18	0.20	0.20	0.18	0.20	0.23	0.19
Distillate	1.13	1.21	1.22	1.20	1.36	1.37	1.32	1.44	1.48	1.40
Liquefied Petroleum Gas	2.10	2.55	2.55	2.57	3.06	3.11	3.05	3.28	3.38	3.64
Petrochemical Feedstocks	1.14	1.44	1.43	1.40	1.70	1.70	1.52	1.82	1.81	1.57
Other Petroleum[4]	4.18	4.44	4.45	4.30	4.64	4.68	4.20	4.76	4.79	4.21
Renewables[5]	1.82	2.22	2.21	2.20	2.77	2.77	2.74	3.05	3.03	3.01
Delivered Energy	**25.10**	**28.67**	**28.45**	**28.19**	**32.58**	**32.32**	**30.96**	**34.75**	**33.95**	**32.05**
Electricity Related Losses	7.57	8.35	8.38	8.18	9.17	9.40	8.60	9.61	9.93	9.21
Total	**32.67**	**37.02**	**36.83**	**36.37**	**41.75**	**41.72**	**39.56**	**44.36**	**43.88**	**41.26**
Energy Consumption per dollar of Shipments[1] (thousand Btu per 1996 dollars)										
Purchased Electricity	0.63	0.57	0.57	0.56	0.52	0.52	0.50	0.49	0.50	0.47
Natural Gas	1.43	1.30	1.28	1.31	1.16	1.12	1.13	1.11	1.03	0.99
Lease and Plant Fuel[2]	0.22	0.20	0.19	0.19	0.18	0.17	0.17	0.17	0.15	0.15
Natural Gas Subtotal	1.65	1.49	1.47	1.50	1.34	1.29	1.30	1.28	1.18	1.14
Steam Coal	0.26	0.21	0.21	0.19	0.17	0.17	0.15	0.15	0.16	0.13
Metallurgical Coal and Coke[3]	0.14	0.11	0.11	0.11	0.08	0.08	0.07	0.07	0.07	0.06
Residual Fuel	0.04	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Distillate	0.21	0.17	0.18	0.17	0.15	0.15	0.15	0.14	0.15	0.14
Liquefied Petroleum Gas	0.39	0.37	0.37	0.37	0.34	0.35	0.34	0.32	0.34	0.37
Petrochemical Feedstocks	0.21	0.21	0.21	0.20	0.19	0.19	0.17	0.18	0.18	0.16
Other Petroleum[4]	0.77	0.64	0.64	0.62	0.52	0.52	0.47	0.47	0.48	0.42
Renewables[5]	0.33	0.32	0.32	0.32	0.31	0.31	0.31	0.30	0.30	0.30
Delivered Energy	**4.63**	**4.11**	**4.09**	**4.09**	**3.63**	**3.60**	**3.50**	**3.43**	**3.37**	**3.21**
Electricity Related Losses	1.40	1.20	1.21	1.19	1.02	1.05	0.97	0.95	0.99	0.92
Total	**6.02**	**5.31**	**5.30**	**5.27**	**4.65**	**4.65**	**4.47**	**4.38**	**4.35**	**4.14**

[1] Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2] Represents natural gas used in the field gathering and processing plant machinery.
[3] Includes net coal coke imports.
[4] Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[5] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 coal prices are based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 consumption values based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **2001** shipments: Global Insight macroeconomic model CTL0802. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I9. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 pounds (VMT)	2409	3006	3001	2967	3752	3752	3524	4133	4121	3779
Commercial Light Trucks (VMT)[1]	66	84	84	83	107	107	104	120	119	115
Freight Trucks >10,000 pounds (VMT)	206	265	264	262	339	339	335	382	379	376
Air (seat miles available)	1109	1356	1356	1344	1944	1946	1928	2258	2260	2231
Rail (ton miles traveled)	1448	1691	1692	1595	2003	2072	1553	2173	2263	1614
Domestic Shipping (ton miles traveled)	788	882	865	852	1012	990	913	1088	1046	947
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	24.1	25.1	25.1	25.3	26.0	26.0	28.3	26.4	26.4	29.2
New Car (miles per gallon)[2]	28.1	28.5	28.5	28.8	29.7	29.8	32.8	30.1	30.0	33.1
New Light Truck (miles per gallon)[2]	20.7	22.3	22.3	22.5	23.1	23.1	24.8	23.5	23.6	26.0
Light-Duty Fleet (miles per gallon)[3]	19.8	19.6	19.6	19.6	20.3	20.3	21.0	20.5	20.6	21.9
New Commercial Light Truck (MPG)[1]	13.8	14.7	14.7	14.9	15.2	15.3	16.4	15.5	15.5	17.2
Stock Commercial Light Truck (MPG)[1]	13.7	14.3	14.3	14.3	14.9	14.9	15.5	15.2	15.2	16.3
Aircraft Efficiency (seat miles per gallon)	51.2	54.3	54.3	54.3	58.6	58.7	59.1	60.7	60.7	61.2
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.0	6.3	6.3	6.4	6.5	6.5	6.6
Rail Efficiency (ton miles per thousand Btu)	2.8	3.1	3.1	3.1	3.4	3.4	3.4	3.6	3.6	3.6
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4	2.4
Energy Use by Mode (quadrillion Btu)										
Light-Duty Vehicles	15.28	18.88	18.85	18.81	22.76	22.75	20.78	24.71	24.63	21.35
Commercial Light Trucks[1]	0.60	0.73	0.73	0.73	0.89	0.90	0.84	0.98	0.98	0.89
Freight Trucks[4]	4.68	5.92	5.90	5.86	7.11	7.12	6.93	7.81	7.77	7.52
Air[5]	3.47	3.98	3.98	3.94	5.15	5.15	5.07	5.73	5.73	5.63
Rail[6]	0.63	0.68	0.68	0.65	0.75	0.77	0.61	0.78	0.81	0.62
Marine[7]	1.45	1.49	1.49	1.48	1.59	1.58	1.55	1.64	1.62	1.58
Pipeline Fuel	0.63	0.78	0.73	0.74	0.94	0.84	0.91	1.03	0.87	0.93
Lubricants	0.19	0.22	0.22	0.21	0.26	0.26	0.26	0.28	0.28	0.28
Total	**26.94**	**32.68**	**32.57**	**32.43**	**39.45**	**39.36**	**36.95**	**42.96**	**42.69**	**38.79**
Energy Use by Mode (million barrels per day oil equivalent)										
Light-Duty Vehicles	8.05	9.93	9.91	9.94	11.96	11.95	10.97	12.98	12.94	11.26
Commercial Light Trucks[1]	0.32	0.39	0.39	0.38	0.47	0.47	0.44	0.52	0.52	0.47
Freight Trucks	2.05	2.61	2.60	2.58	3.16	3.17	3.08	3.49	3.47	3.36
Railroad	0.24	0.26	0.26	0.24	0.28	0.29	0.21	0.28	0.30	0.21
Domestic Shipping	0.16	0.17	0.17	0.17	0.20	0.19	0.18	0.21	0.20	0.18
International Shipping	0.34	0.33	0.33	0.33	0.34	0.34	0.34	0.34	0.34	0.34
Air[5]	1.44	1.65	1.65	1.64	2.19	2.19	2.15	2.45	2.45	2.40
Military Use	0.30	0.34	0.34	0.34	0.38	0.38	0.38	0.40	0.40	0.40
Bus Transportation	0.12	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Rail Transportation[6]	0.05	0.06	0.06	0.06	0.08	0.08	0.08	0.08	0.08	0.08
Recreational Boats	0.16	0.18	0.18	0.18	0.19	0.19	0.19	0.20	0.20	0.20
Lubricants	0.09	0.10	0.10	0.10	0.12	0.12	0.12	0.13	0.13	0.13
Pipeline Fuel	0.32	0.39	0.37	0.38	0.47	0.43	0.46	0.52	0.44	0.47
Total	**13.64**	**16.54**	**16.49**	**16.47**	**19.97**	**19.92**	**18.72**	**21.74**	**21.60**	**19.62**

[1] Commercial trucks 8,500 to 10,000 pounds.
[2] Environmental Protection Agency rated miles per gallon.
[3] Combined car and light truck "on-the-road" estimate.
[4] Includes energy use by buses and military distillate consumption.
[5] Includes jet fuel and aviation gasoline.
[6] Includes passenger rail.
[7] Includes military residual fuel use and recreational boats.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001); Federal Highway Administration, *Highway Statistics 2000* (Washington, DC, November 2001); Oak Ridge National Laboratory, Transportation Energy Data Book: *Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey" EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA,*State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2001/2000* (Washington, DC, 2001); EIA, *Fuel Oil and Kerosene Sales 2001*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/historical/foks.html; and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I10. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Generation by Fuel Type										
Electric Power Sector[1]										
Power Only[2]										
Coal	1848	2237	2246	1986	2512	2785	1213	2747	3160	1105
Petroleum	113	40	53	24	47	50	24	52	153	44
Natural Gas[3]	411	671	634	705	1143	872	1238	1314	780	961
Nuclear Power	769	790	790	801	793	793	939	793	793	1311
Pumped Storage/Other	-9	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[4]	258	394	395	541	414	418	1081	423	429	1301
Distributed Generation (Natural Gas)	0	1	1	3	5	5	7	8	7	7
Non-Utility Generation for Own Use	-21	-24	-24	-27	-24	-24	-26	-24	-24	-25
Total	**3370**	**4107**	**4093**	**4032**	**4889**	**4898**	**4475**	**5312**	**5296**	**4704**
Combined Heat and Power[5]										
Coal	33	33	33	31	33	33	18	33	33	13
Petroleum	7	4	4	4	3	4	4	3	10	5
Natural Gas	124	171	171	160	156	152	110	149	133	98
Renewable Sources	5	4	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-9	-18	-18	-18	-18	-18	-17	-18	-18	-16
Total	**162**	**193**	**194**	**181**	**178**	**175**	**119**	**171**	**162**	**103**
Net Available to the Grid	**3532**	**4301**	**4287**	**4213**	**5067**	**5073**	**4594**	**5483**	**5458**	**4807**
End-Use Sector Generation										
Combined Heat and Power[6]										
Coal	23	23	23	23	23	23	23	23	23	23
Petroleum	6	6	6	6	6	6	6	6	6	7
Natural Gas	84	105	99	117	142	123	178	174	139	280
Other Gaseous Fuels[7]	6	7	7	7	7	7	7	8	8	7
Renewable Sources[4]	31	40	40	39	51	51	50	56	56	55
Other[8]	11	11	11	11	11	11	11	11	11	11
Total	**160**	**192**	**186**	**204**	**240**	**222**	**276**	**278**	**243**	**383**
Other End-Use Generators[9]	4	5	5	5	6	6	6	6	6	7
Generation for Own Use	-138	-154	-151	-169	-183	-173	-224	-207	-187	-294
Total Sales to the Grid	**27**	**43**	**40**	**40**	**63**	**54**	**58**	**78**	**62**	**96**
Net Imports	**20**	**30**	**32**	**45**	**16**	**15**	**64**	**6**	**7**	**38**
Electricity Sales by Sector										
Residential	1201	1445	1439	1422	1640	1632	1452	1745	1717	1457
Commercial	1197	1468	1460	1446	1808	1799	1643	1990	1965	1736
Industrial	994	1164	1163	1137	1364	1374	1301	1469	1479	1384
Transportation	22	27	27	27	36	36	35	42	41	39
Total	**3414**	**4104**	**4089**	**4032**	**4848**	**4842**	**4431**	**5246**	**5202**	**4617**
End-Use Prices[10] (2001 cents per kilowatthour)										
Residential	8.7	7.7	7.8	8.4	7.9	8.0	10.9	7.9	8.4	12.0
Commercial	7.9	6.8	6.9	7.5	7.2	7.3	9.9	7.2	7.8	11.1
Industrial	4.8	4.4	4.5	5.0	4.6	4.7	6.7	4.6	5.0	7.5
Transportation	7.5	6.5	6.7	7.3	6.3	6.4	8.7	6.1	6.5	9.3
All Sectors Average	**7.3**	**6.4**	**6.6**	**7.1**	**6.7**	**6.8**	**9.3**	**6.7**	**7.2**	**10.3**
Prices by Service Category[10] (2001 cents per kilowatthour)										
Generation	4.7	3.9	4.0	4.6	4.2	4.3	6.6	4.2	4.7	7.6
Transmission	0.5	0.6	0.6	0.6	0.6	0.6	0.7	0.6	0.6	0.8
Distribution	2.0	2.0	2.0	2.0	1.9	1.9	2.0	1.9	1.9	2.0

Table I10. Electricity Supply, Disposition, Prices, and Emissions (Continued)

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Emissions										
Sulfur Dioxide (million tons)	10.63	9.69	9.69	9.97	8.95	8.94	8.25	8.95	8.94	5.03
Nitrogen Oxide (million tons)	4.75	3.90	3.91	3.60	4.02	4.06	1.90	4.08	4.11	1.05
Mercury (tons)	53.52	53.60	53.51	50.11	54.05	53.65	25.32	54.82	54.19	14.81

[1] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes plants that only produce electricity.

[3] Includes electricity generation from fuel cells.

[4] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.

[5] Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).

[6] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[7] Other gaseous fuels include refinery and still gas.

[8] Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.

[9] Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[10] Prices represent average revenue per kilowatthour.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Source: 2001 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and supporting databases. 2001 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2001 prices: EIA, National Energy Modeling System run MLBILL.D050503A. **Projections**: EIA, AEO2003 National Energy Modeling System run MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I11. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Electric Power Sector[2]										
Power Only[3]										
Coal Steam	305.3	310.6	311.6	291.2	343.9	384.4	246.0	376.0	439.8	224.0
Other Fossil Steam[4]	133.8	77.9	77.5	81.3	71.9	70.6	63.2	71.1	69.2	58.4
Combined Cycle	43.2	148.4	144.2	163.1	233.0	199.2	278.6	278.1	224.1	293.6
Combustion Turbine/Diesel	97.6	126.4	127.6	121.7	148.0	139.7	119.0	164.3	157.0	118.5
Nuclear Power[5]	98.2	98.7	98.7	100.3	99.0	99.0	117.8	99.0	99.0	165.2
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	90.4	97.2	97.3	136.9	101.0	102.0	246.0	102.6	104.1	275.1
Distributed Generation[7]	0.0	1.7	1.6	1.3	11.7	10.4	4.2	17.7	16.3	4.3
Total	**788.3**	**881.2**	**879.0**	**916.3**	**1029.0**	**1025.9**	**1095.3**	**1129.3**	**1130.1**	**1159.6**
Combined Heat and Power[8]										
Coal Steam	5.2	4.7	4.7	4.6	4.7	4.7	3.3	4.7	4.7	2.6
Other Fossil Steam[4]	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	22.6	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	4.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Renewable Sources[6]	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**33.7**	**44.3**	**44.3**	**44.2**	**44.3**	**44.3**	**42.9**	**44.3**	**44.3**	**42.2**
Total Electric Power Industry	**822.0**	**925.6**	**923.3**	**960.5**	**1073.4**	**1070.3**	**1138.2**	**1173.7**	**1174.4**	**1201.8**
Cumulative Planned Additions[9]										
Coal Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1
Combustion Turbine/Diesel	0.0	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	0.0	4.9	4.9	4.9	6.5	6.5	6.5	6.6	6.6	6.6
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**120.0**	**120.0**	**120.0**	**121.7**	**121.7**	**121.7**	**121.8**	**121.8**	**121.8**
Cumulative Unplanned Additions[9]										
Coal Steam	0.0	12.3	13.3	0.0	47.5	88.0	27.5	80.7	144.4	80.9
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	32.0	28.3	46.8	116.7	83.3	162.2	161.8	108.3	177.5
Combustion Turbine/Diesel	0.0	9.0	9.6	3.3	33.7	25.9	3.9	52.3	44.8	3.9
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	17.1	0.0	0.0	64.6
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	1.5	1.6	41.2	3.8	4.7	148.8	5.2	6.8	177.7
Distributed Generation[7]	0.0	1.7	1.6	1.3	11.7	10.4	4.2	17.7	16.3	4.3
Total	**0.0**	**56.5**	**54.4**	**92.6**	**213.3**	**212.3**	**363.7**	**317.8**	**320.6**	**508.8**
Cumulative Total Additions	**0.0**	**176.6**	**174.4**	**212.7**	**334.9**	**334.0**	**485.4**	**439.5**	**442.4**	**630.6**
Cumulative Retirements[10]										
Coal Steam	0.0	7.6	7.5	14.8	9.4	9.4	88.7	10.5	10.5	164.8
Other Fossil Steam[4]	0.0	54.4	54.8	51.0	60.4	61.6	69.1	61.2	63.1	73.9
Combined Cycle	0.0	0.7	1.2	0.7	0.7	1.2	0.7	0.7	1.2	0.9
Combustion Turbine/Diesel	0.0	11.2	10.6	10.2	14.3	14.8	13.5	16.7	16.4	14.1
Nuclear Power	0.0	2.4	2.4	0.8	3.4	3.4	1.8	3.4	3.4	1.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**76.5**	**76.6**	**77.6**	**88.3**	**90.5**	**173.9**	**92.6**	**94.7**	**255.6**

Table I11. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
End-Use Sector										
Combined Heat and Power[11]										
Coal	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Petroleum	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1
Natural Gas	14.6	17.0	16.2	18.7	22.1	19.5	27.1	26.4	21.7	41.9
Other Gaseous Fuels	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.2
Renewable Sources[6]	4.7	6.2	6.2	6.2	8.1	8.1	7.9	9.0	9.0	8.8
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.8**	**31.8**	**31.0**	**33.4**	**38.8**	**36.3**	**43.7**	**44.2**	**39.5**	**59.5**
Other End-Use Generators[12]										
Renewable Sources[13]	1.1	1.5	1.5	1.5	1.7	1.7	1.9	2.0	2.1	2.3
Cumulative Additions[9]										
Combined Heat and Power[11]	0.0	4.1	3.4	5.7	11.1	8.7	15.9	16.6	11.9	31.8
Other End-Use Generators[12]	0.0	0.4	0.4	0.4	0.6	0.6	0.8	0.9	0.9	1.2

[1] Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.

[2] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[3] Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.

[4] Includes oil-, gas-, and dual-fired capability.

[5] Nuclear capacity reflects operating capacity of existing units, including 4.3 gigawatts of uprates through 2025.

[6] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.

[7] Primarily peak-load capacity fueled by natural gas

[8] Includes combined heat and power plants whose primary business is to sell electricity and heat to the public(i.e., those that report NAICS code 22).

[9] Cumulative additions after December 31, 2001.

[10] Cumulative total retirements after December 31, 2001.

[11] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[12] Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[13] See Table I17 for more detail.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model estimates and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with capability for electric utility generators.

Source: 2001 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I12. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Crude Oil										
Domestic Crude Production[1]	5.80	5.64	5.33	5.30	5.43	5.03	4.99	5.30	4.70	4.67
Alaska	0.97	0.64	0.61	0.60	1.23	1.19	1.19	1.17	1.13	1.13
Lower 48 States	4.84	5.00	4.71	4.70	4.20	3.84	3.79	4.13	3.57	3.54
Net Imports	9.31	11.49	11.76	11.74	12.67	13.07	12.80	13.14	13.69	13.34
Gross Imports	9.33	11.56	11.81	11.79	12.73	13.11	12.84	13.18	13.72	13.37
Exports	0.02	0.06	0.05	0.05	0.05	0.04	0.04	0.05	0.02	0.02
Other Crude Supply[2]	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.13**	**17.13**	**17.08**	**17.04**	**18.10**	**18.10**	**17.79**	**18.44**	**18.40**	**18.02**
Natural Gas Plant Liquids	**1.87**	**2.20**	**2.09**	**2.13**	**2.48**	**2.16**	**2.27**	**2.59**	**2.12**	**2.14**
Other Inputs[3]	**0.30**	**0.44**	**0.44**	**0.40**	**0.44**	**0.43**	**0.29**	**0.44**	**0.41**	**0.28**
Refinery Processing Gain[4]	**0.90**	**0.91**	**0.91**	**0.90**	**0.96**	**0.97**	**0.95**	**0.96**	**0.98**	**0.93**
Net Product Imports[5]	**1.59**	**2.17**	**2.37**	**2.02**	**4.88**	**5.30**	**3.78**	**6.48**	**7.49**	**5.20**
Gross Refined Product Imports[6]	2.08	2.55	2.73	2.47	4.89	5.31	3.77	6.51	7.59	5.26
Unfinished Oil Imports	0.38	0.63	0.64	0.54	1.07	1.06	1.06	1.08	1.07	1.01
Ether Imports	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.95	1.00	1.01	0.99	1.08	1.07	1.05	1.11	1.17	1.07
Total Primary Supply[7]	**19.80**	**22.86**	**22.89**	**22.49**	**26.86**	**26.96**	**25.08**	**28.90**	**29.40**	**26.57**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.67	10.54	10.52	10.39	12.53	12.53	11.36	13.55	13.50	11.66
Jet Fuel[9]	1.66	1.90	1.90	1.88	2.46	2.46	2.42	2.74	2.74	2.69
Distillate Fuel[10]	3.81	4.62	4.63	4.57	5.42	5.45	5.26	5.88	6.24	5.70
Residual Fuel	0.97	0.63	0.67	0.55	0.66	0.68	0.53	0.66	0.77	0.54
Other[11]	4.58	5.18	5.19	5.12	5.80	5.86	5.52	6.09	6.18	6.00
Total	**19.69**	**22.87**	**22.91**	**22.51**	**26.87**	**26.97**	**25.09**	**28.92**	**29.42**	**26.58**
Refined Petroleum Products Supplied										
Residential and Commercial	1.21	1.18	1.19	1.19	1.14	1.16	1.18	1.13	1.15	1.19
Industrial[12]	4.67	5.28	5.29	5.21	5.96	6.02	5.65	6.28	6.40	6.16
Transportation	13.27	16.19	16.16	15.98	19.53	19.54	18.14	21.25	21.19	19.03
Electric Power[13]	0.55	0.21	0.27	0.13	0.24	0.26	0.13	0.26	0.68	0.21
Total	**19.69**	**22.87**	**22.91**	**22.51**	**26.87**	**26.97**	**25.09**	**28.92**	**29.42**	**26.58**
Discrepancy[14]	**0.10**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.01**	**-0.01**	**-0.02**	**-0.02**	**-0.01**
World Oil Price (2001 dollars per barrel)[15]	**22.01**	**23.99**	**23.99**	**23.77**	**25.48**	**25.48**	**24.15**	**26.57**	**26.57**	**24.58**
Import Share of Product Supplied	**0.55**	**0.60**	**0.62**	**0.61**	**0.65**	**0.68**	**0.66**	**0.68**	**0.72**	**0.70**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2001 dollars)	**89.20**	**122.23**	**126.22**	**122.34**	**172.92**	**180.83**	**151.45**	**205.85**	**222.27**	**173.37**
Domestic Refinery Distillation Capacity[16]	**16.8**	**18.7**	**18.7**	**18.7**	**19.5**	**19.5**	**19.1**	**19.8**	**19.8**	**19.4**
Capacity Utilization Rate (percent)	**93.0**	**93.1**	**93.0**	**92.9**	**94.6**	**94.6**	**94.6**	**94.6**	**94.6**	**94.6**

[1] Includes lease condensate.

[2] Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.

[3] Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.

[4] Represents volumetric gain in refinery distillation and cracking processes.

[5] Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.

[6] Includes other hydrocarbons, alcohols, and blending components.

[7] Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.

[8] Includes ethanol and ethers blended into gasoline.

[9] Includes only kerosene type.

[10] Includes distillate and kerosene.

[11] Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.

[12] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[13] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[14] Balancing item. Includes unaccounted for supply, losses, and gains.

[15] Average refiner acquisition cost for imported crude oil.

[16] End-of-year capacity.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). Other 2001 data: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I13. Petroleum Product Prices

(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
World Oil Price (2001 dollars per barrel)	**22.01**	**23.99**	**23.99**	**23.77**	**25.48**	**25.48**	**24.15**	**26.57**	**26.57**	**24.58**
Delivered Sector Product Prices										
Residential										
Distillate Fuel	124.6	110.9	111.8	109.9	120.7	121.1	114.8	123.8	123.9	119.0
Liquefied Petroleum Gas	127.3	123.1	122.8	121.9	131.1	131.1	127.7	133.1	134.4	128.5
Commercial										
Distillate Fuel	88.7	78.6	79.5	77.6	89.5	89.9	83.0	93.7	93.9	87.1
Residual Fuel	51.8	60.1	60.4	58.9	63.3	63.4	59.3	65.7	66.1	60.2
Residual Fuel (2001 dollars per barrel)	21.75	25.24	25.36	24.74	26.57	26.63	24.92	27.58	27.77	25.30
Industrial[1]										
Distillate Fuel	90.8	79.7	80.7	78.8	93.4	94.0	85.9	99.7	100.4	90.6
Liquefied Petroleum Gas	105.9	85.2	84.9	84.3	93.1	93.3	90.7	95.4	96.6	91.5
Residual Fuel	49.1	55.6	55.8	54.8	58.9	59.0	55.4	61.4	61.9	56.4
Residual Fuel (2001 dollars per barrel)	20.61	23.35	23.44	23.01	24.75	24.80	23.27	25.77	25.99	23.68
Transportation										
Diesel Fuel (distillate)[2]	139.4	141.4	141.3	164.0	142.4	141.2	186.2	147.5	146.1	197.7
Jet Fuel[3]	83.7	76.3	76.9	96.8	85.6	85.6	127.7	90.7	90.8	138.0
Motor Gasoline[4]	143.3	141.8	142.1	161.7	143.1	143.1	181.8	149.4	149.1	188.7
Liquid Petroleum Gas	145.2	133.4	132.1	142.9	137.8	137.8	162.2	137.1	140.5	163.9
Residual Fuel	58.4	53.4	53.4	79.2	56.6	56.6	113.3	59.0	59.1	122.3
Residual Fuel (2001 dollars per barrel)	24.52	22.41	22.44	33.26	23.76	23.77	47.59	24.80	24.82	51.35
Electric Power[5]										
Distillate Fuel	86.0	71.2	72.1	69.4	82.4	83.0	75.3	85.4	85.1	79.4
Residual Fuel	67.4	61.0	60.0	63.4	64.8	64.0	71.9	68.1	65.7	74.4
Residual Fuel (2001 dollars per barrel)	28.30	25.63	25.20	26.62	27.23	26.89	30.22	28.60	27.60	31.23
Refined Petroleum Product Prices[6]										
Distillate Fuel	127.0	127.0	126.9	142.9	132.0	131.1	162.2	137.3	133.5	171.2
Jet Fuel[3]	83.7	76.3	76.9	96.8	85.6	85.6	127.7	90.7	90.8	138.0
Liquefied Petroleum Gas	110.3	92.2	91.9	91.5	99.3	99.4	97.4	101.3	102.4	97.4
Motor Gasoline[4]	143.4	141.8	142.1	161.5	143.1	143.1	181.3	149.4	149.1	188.1
Residual Fuel	61.5	55.9	55.9	72.4	59.3	59.3	97.7	61.9	62.0	104.3
Residual Fuel (2001 dollars per barrel)	25.85	23.48	23.50	30.40	24.92	24.91	41.04	26.02	26.04	43.81
Average	**123.6**	**122.0**	**122.0**	**137.8**	**125.7**	**125.5**	**155.9**	**131.1**	**129.9**	**161.5**
Greenhouse Gas Allowance Cost										
Commercial										
Distillate Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residual Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residual Fuel (2001 dollars per barrel)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[1]										
Distillate Fuel	0.0	0.0	0.0	22.8	0.0	0.0	51.6	0.0	0.0	58.5
Liquefied Petroleum Gas	0.0	0.0	0.0	12.2	0.0	0.0	27.6	0.0	0.0	31.3
Residual Fuel	0.0	0.0	0.0	26.5	0.0	0.0	60.0	0.0	0.0	68.1
Residual Fuel (2001 dollars per barrel)	0.00	0.00	0.00	11.15	0.00	0.00	25.21	0.00	0.00	28.58
Electric Power[5]										
Distillate Fuel	0.0	0.0	0.0	22.8	0.0	0.0	51.6	0.0	0.0	58.5
Residual Fuel	0.0	0.0	0.0	26.5	0.0	0.0	60.0	0.0	0.0	68.1
Residual Fuel (2001 dollars per barrel)	0.00	0.00	0.00	11.15	0.00	0.00	25.21	0.00	0.00	28.58

Table I13. Petroleum Product Prices (Continued)
(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Delivered Sector Product Prices with Greenhouse Gas Allowance Cost										
Commercial										
Distillate Fuel	88.7	78.6	79.5	77.6	89.5	89.9	83.0	93.7	93.9	87.1
Residual Fuel	51.8	60.1	60.4	58.9	63.3	63.4	59.3	65.7	66.1	60.2
Residual Fuel (2001 dollars per barrel)	21.75	25.24	25.36	24.74	26.57	26.63	24.92	27.58	27.77	25.30
Industrial[1]										
Distillate Fuel	90.8	79.7	80.7	101.6	93.4	94.0	137.5	99.7	100.4	149.1
Liquefied Petroleum Gas	105.9	85.2	84.9	96.5	93.1	93.3	118.4	95.4	96.6	122.8
Residual Fuel	49.1	55.6	55.8	81.3	58.9	59.0	115.4	61.4	61.9	124.4
Residual Fuel (2001 dollars per barrel)	20.61	23.35	23.44	34.16	24.75	24.80	48.47	25.77	25.99	52.26
Electric Power[5]										
Distillate Fuel	86.0	71.2	72.1	92.3	82.4	83.0	126.9	85.4	85.1	138.0
Residual Fuel	67.4	61.0	60.0	89.9	64.8	64.0	132.0	68.1	65.7	142.4
Residual Fuel (2001 dollars per barrel)	28.30	25.63	25.20	37.77	27.23	26.89	55.42	28.60	27.60	59.82

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[1] Includes combined heat and power, which produces electricity and other useful thermal energy.

[2] Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur. Includes Federal and State taxes while excluding county and local taxes.

[3] Kerosene-type jet fuel.

[4] Sales weighted-average price for all grades. Includes Federal, State and local taxes.

[5] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[6] Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources:. 2001 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A: "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2001 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2001 world oil price: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections**: EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I14. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Production										
Dry Gas Production[1]	19.45	21.53	20.45	20.80	24.85	22.03	23.02	26.36	21.78	21.87
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.73**	**4.76**	**5.14**	**5.10**	**6.88**	**7.26**	**7.82**	**7.90**	**7.10**	**7.42**
Canada	3.61	4.16	3.79	3.76	5.14	3.31	3.74	5.21	3.02	3.21
Mexico	-0.13	-0.20	0.01	0.01	-0.02	0.50	0.56	0.29	0.81	0.94
Liquefied Natural Gas	0.26	0.80	1.34	1.33	1.76	3.44	3.53	2.40	3.26	3.26
Total Supply	**23.26**	**26.39**	**25.69**	**26.00**	**31.83**	**29.39**	**30.94**	**34.36**	**28.98**	**29.38**
Consumption by Sector										
Residential	4.81	5.48	5.39	5.39	5.93	5.85	5.62	6.21	5.92	5.73
Commercial	3.24	3.64	3.57	3.57	4.12	4.03	3.98	4.38	4.13	4.47
Industrial[3]	7.53	8.81	8.63	8.77	10.10	9.81	9.75	10.93	10.12	9.62
Electric Power[4]	5.30	6.58	6.32	6.46	9.42	7.62	9.40	10.37	6.71	7.48
Transportation[5]	0.01	0.06	0.06	0.06	0.10	0.10	0.09	0.11	0.11	0.10
Pipeline Fuel	0.61	0.76	0.71	0.72	0.91	0.82	0.89	1.00	0.85	0.91
Lease and Plant Fuel[6]	1.17	1.33	1.29	1.30	1.56	1.45	1.49	1.68	1.47	1.47
Total	**22.67**	**26.66**	**25.97**	**26.28**	**32.14**	**29.68**	**31.22**	**34.67**	**29.31**	**29.78**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.59**	**-0.28**	**-0.28**	**-0.28**	**-0.31**	**-0.30**	**-0.28**	**-0.31**	**-0.34**	**-0.39**

[1] Marketed production (wet) minus extraction losses.

[2] Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

[3] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as vehicle fuel.

[6] Represents natural gas used in the field gathering and processing plant machinery.

[7] Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2001 values include net storage injections.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I15. Natural Gas Prices, Margins, and Revenue
(2001 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Source Price										
Average Lower 48 Wellhead Price[1]	4.12	3.39	3.81	3.86	3.70	4.03	4.88	3.95	5.55	5.70
Average Import Price	4.43	3.40	3.95	3.99	3.88	4.41	5.24	4.19	5.74	5.91
Average[2]	**4.17**	**3.39**	**3.84**	**3.89**	**3.74**	**4.13**	**4.97**	**4.01**	**5.59**	**5.75**
Delivered Prices										
Residential	9.68	7.79	8.26	8.31	7.99	8.35	9.26	8.26	9.78	10.06
Commercial	8.32	6.67	7.13	7.18	6.98	7.32	8.21	7.26	8.78	9.00
Industrial[3]	5.01	4.11	4.56	4.60	4.51	4.85	5.73	4.76	6.36	6.56
Electric Power[4]	4.87	3.95	4.40	4.49	4.44	4.71	5.73	4.73	6.16	6.36
Transportation[5]	7.87	7.39	7.84	7.76	7.97	8.29	8.79	8.32	9.79	9.58
Average[6]	**6.57**	**5.28**	**5.75**	**5.79**	**5.55**	**5.94**	**6.78**	**5.80**	**7.45**	**7.66**
Transmission & Distribution Margins[7]										
Residential	5.50	4.39	4.42	4.42	4.25	4.23	4.29	4.25	4.19	4.31
Commercial	4.14	3.28	3.29	3.29	3.24	3.19	3.23	3.25	3.19	3.25
Industrial[3]	0.83	0.72	0.72	0.71	0.77	0.72	0.75	0.75	0.77	0.81
Electric Power[4]	0.70	0.56	0.55	0.60	0.70	0.58	0.75	0.72	0.56	0.60
Transportation[5]	3.69	4.00	4.00	3.87	4.23	4.16	3.81	4.31	4.19	3.83
Average[6]	**2.40**	**1.89**	**1.91**	**1.90**	**1.81**	**1.81**	**1.81**	**1.79**	**1.86**	**1.90**
Transmission & Distribution Revenue (billion 2001 dollars)										
Residential	26.45	24.08	23.83	23.80	25.22	24.70	24.11	26.39	24.80	24.69
Commercial	13.42	11.94	11.74	11.74	13.33	12.87	12.87	14.25	13.15	14.52
Industrial[3]	6.28	6.36	6.19	6.20	7.82	7.08	7.36	8.23	7.79	7.80
Electric Power[4]	3.69	3.70	3.50	3.90	6.57	4.41	7.08	7.42	3.78	4.51
Transportation[5]	0.04	0.23	0.23	0.22	0.41	0.40	0.34	0.47	0.44	0.37
Total	**49.88**	**46.31**	**45.49**	**45.86**	**53.36**	**49.46**	**51.75**	**56.76**	**49.96**	**51.89**
Greenhouse Gas Allowance Cost										
Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[3]	0.00	0.00	0.00	1.21	0.00	0.00	2.74	0.00	0.00	3.10
Electric Power[4]	0.00	0.00	0.00	1.22	0.00	0.00	2.76	0.00	0.00	3.13
Transportation[5]	0.00	0.00	0.00	1.23	0.00	0.00	2.79	0.00	0.00	3.16
Average[6]	**0.00**	**0.00**	**0.00**	**0.77**	**0.00**	**0.00**	**1.84**	**0.00**	**0.00**	**1.96**
Delivered Prices with Greenhouse Gas Allowance Cost										
Residential	9.68	7.79	8.26	8.31	7.99	8.35	9.26	8.26	9.78	10.06
Commercial	8.32	6.67	7.13	7.18	6.98	7.32	8.21	7.26	8.78	9.00
Industrial[3]	5.01	4.11	4.56	5.81	4.51	4.85	8.46	4.76	6.36	9.66
Electric Power[4]	4.87	3.95	4.40	5.72	4.44	4.71	8.49	4.73	6.16	9.49
Transportation[5]	7.87	7.39	7.84	8.99	7.97	8.29	11.58	8.32	9.79	12.74
Average[6]	**6.57**	**5.28**	**5.75**	**6.56**	**5.55**	**5.94**	**8.62**	**5.80**	**7.45**	**9.62**

[1] Represents lower 48 onshore and offshore supplies.

[2] Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.

[3] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.

[6] Weighted average allowance cost. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.

[7] Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 electric generators delivered price: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1998*. 2001 residential, commercial, and transportation delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I16. Oil and Gas Supply

Production and Supply	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Crude Oil										
Lower 48 Average Wellhead Price[1] (2001 dollars per barrel)	**22.91**	**23.89**	**23.82**	**23.50**	**24.98**	**24.93**	**23.62**	**26.22**	**26.04**	**24.07**
Production (million barrels per day)[2]										
U.S. Total	**5.80**	**5.64**	**5.33**	**5.30**	**5.43**	**5.03**	**4.99**	**5.30**	**4.70**	**4.67**
Lower 48 Onshore	3.13	2.47	2.48	2.48	2.06	2.03	2.01	1.92	1.87	1.85
Lower 48 Offshore	1.71	2.52	2.23	2.23	2.14	1.81	1.78	2.22	1.71	1.69
Alaska	0.97	0.64	0.61	0.60	1.23	1.19	1.19	1.17	1.13	1.13
Lower 48 End of Year Reserves (billion barrels)[2]	**19.48**	**17.72**	**17.22**	**17.18**	**15.39**	**14.91**	**14.81**	**15.04**	**13.91**	**13.79**
Natural Gas										
Lower 48 Average Wellhead Price[1] (2001 dollars per thousand cubic feet)	**4.12**	**3.39**	**3.81**	**3.86**	**3.70**	**4.03**	**4.88**	**3.95**	**5.55**	**5.70**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**19.45**	**21.54**	**20.46**	**20.80**	**24.86**	**22.03**	**23.02**	**26.37**	**21.79**	**21.87**
Lower 48 Onshore	13.72	15.57	15.04	15.22	17.96	15.18	16.14	17.77	15.64	15.85
Associated-Dissolved[4]	1.77	1.37	1.37	1.37	1.19	1.18	1.17	1.13	1.11	1.10
Non-Associated	11.94	14.20	13.67	13.85	16.77	14.00	14.96	16.64	14.54	14.75
Conventional	6.54	7.04	7.28	7.37	7.15	7.20	7.56	7.04	7.40	7.12
Unconventional	5.40	7.16	6.39	6.48	9.61	6.80	7.40	9.60	7.14	7.63
Lower 48 Offshore	5.30	5.49	4.94	5.10	5.43	4.46	4.50	5.74	3.29	3.18
Associated-Dissolved[4]	1.08	0.96	0.85	0.85	0.80	0.67	0.66	0.82	0.63	0.63
Non-Associated	4.22	4.53	4.09	4.25	4.63	3.79	3.84	4.93	2.66	2.55
Alaska	0.43	0.48	0.48	0.48	1.47	2.39	2.39	2.85	2.85	2.84
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**174.04**	**186.42**	**169.20**	**169.24**	**194.24**	**159.17**	**158.08**	**190.10**	**144.26**	**144.81**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Total Lower 48 Wells (thousands)	**33.94**	**25.73**	**24.64**	**24.67**	**26.21**	**23.63**	**25.31**	**27.53**	**24.91**	**25.49**

[1] Represents lower 48 onshore and offshore supplies.
[2] Includes lease condensate.
[3] Marketed production (wet) minus extraction losses.
[4] Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5] Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2001 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I17. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Production[1]										
Appalachia	443	420	419	423	416	443	281	433	473	251
Interior	147	161	159	158	151	158	123	159	170	84
West	548	669	676	532	801	871	235	865	964	213
East of the Mississippi	539	527	528	531	529	564	383	554	605	319
West of the Mississippi	599	723	726	583	839	907	257	902	1002	228
Total	**1138**	**1250**	**1254**	**1114**	**1367**	**1471**	**639**	**1456**	**1607**	**547**
Net Imports										
Imports	19	20	20	11	25	25	11	28	28	10
Exports	49	33	34	33	29	29	26	24	24	24
Total	**-30**	**-14**	**-14**	**-22**	**-4**	**-4**	**-15**	**3**	**4**	**-14**
Total Supply[2]	**1109**	**1236**	**1240**	**1092**	**1363**	**1467**	**624**	**1460**	**1611**	**534**
Consumption by Sector										
Residential and Commercial	4	5	5	5	5	5	5	5	5	5
Industrial[3]	63	67	68	62	70	70	60	71	74	60
of which: Coal to Liquids	0	0	0	0	0	0	0	0	0	0
Coke Plants	26	24	24	24	20	20	17	18	18	14
Electric Power[4]	957	1146	1149	998	1274	1378	550	1371	1519	463
Total	**1050**	**1242**	**1245**	**1088**	**1369**	**1473**	**632**	**1466**	**1616**	**543**
Discrepancy and Stock Change[5]	**58**	**-6**	**-5**	**4**	**-6**	**-6**	**-8**	**-6**	**-6**	**-9**
Average Minemouth Price										
(2001 dollars per short ton)	17.59	15.06	15.08	15.91	14.34	14.84	16.51	14.39	15.19	15.80
(2001 dollars per million Btu)	0.83	0.73	0.73	0.76	0.70	0.73	0.76	0.71	0.74	0.73
Delivered Prices (2001 dollars per short ton)[6]										
Industrial	32.82	30.11	30.16	30.25	28.45	29.02	26.46	28.04	28.58	25.30
Coke Plants	46.42	41.27	41.32	41.23	38.08	38.10	38.36	36.67	36.59	36.70
Electric Power										
(2001 dollars per short ton)	25.06	23.63	23.67	23.94	22.44	22.93	22.42	22.27	23.03	21.42
(2001 dollars per million Btu)	1.25	1.17	1.17	1.17	1.12	1.14	1.05	1.11	1.14	1.01
Average	**26.06**	**24.33**	**24.37**	**24.68**	**22.98**	**23.43**	**23.24**	**22.74**	**23.44**	**22.26**
Exports[7]	36.97	32.68	32.79	32.43	30.94	31.24	30.24	30.36	30.38	28.86
Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]										
Industrial	0.00	0.00	0.00	46.04	0.00	0.00	103.96	0.00	0.00	117.57
Coke Plants	0.00	0.00	0.00	57.82	0.00	0.00	130.73	0.00	0.00	148.24
Electric Power										
(2001 dollars per short ton)	0.00	0.00	0.00	43.64	0.00	0.00	102.27	0.00	0.00	115.52
(2001 dollars per million Btu)	0.00	0.00	0.00	2.13	0.00	0.00	4.79	0.00	0.00	5.44
Average	**0.00**	**0.00**	**0.00**	**44.09**	**0.00**	**0.00**	**103.20**	**0.00**	**0.00**	**116.63**
Delivered Prices with Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]										
Industrial	32.82	30.11	30.16	76.30	28.45	29.02	130.42	28.04	28.58	142.86
Coke Plants	46.42	41.27	41.32	99.05	38.08	38.10	169.09	36.67	36.59	184.95
Electric Power										
(2001 dollars per short ton)	25.06	23.63	23.67	67.58	22.44	22.93	124.68	22.27	23.03	136.95
(2001 dollars per million Btu)	1.25	1.17	1.17	3.30	1.12	1.14	5.84	1.11	1.14	6.45
Average	**26.06**	**24.33**	**24.37**	**68.77**	**22.98**	**23.43**	**126.44**	**22.74**	**23.44**	**138.89**

[1] Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.1 million tons in 2000 and 10.6 million tons in 2001.

[2] Production plus net imports and net storage withdrawals.

[3] Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

[4] Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[5] Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.

[6] Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.

[7] F.a.s. price at U.S. port of exit.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I18. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Electric Power Sector[1]										
Net Summer Capacity										
Conventional Hydropower	78.10	78.66	78.66	78.66	78.65	78.65	78.65	78.65	78.65	78.65
Geothermal[2]	2.83	3.81	3.87	6.81	5.19	5.32	10.43	5.77	5.77	11.20
Municipal Solid Waste[3]	3.25	4.08	4.12	4.83	4.41	4.46	5.17	4.42	4.46	5.19
Wood and Other Biomass[4]	1.80	2.09	2.09	3.45	2.20	2.31	60.49	2.33	2.74	87.36
Solar Thermal	0.33	0.44	0.44	0.44	0.48	0.48	0.48	0.50	0.50	0.50
Solar Photovoltaic[5]	0.02	0.10	0.10	0.10	0.27	0.27	0.27	0.36	0.36	0.36
Wind	4.29	8.24	8.26	42.86	10.05	10.73	90.78	10.81	11.88	92.04
Total	**90.62**	**97.42**	**97.54**	**137.15**	**101.24**	**102.21**	**246.27**	**102.83**	**104.36**	**275.30**
Generation (billion kilowatthours)										
Conventional Hydropower	213.82	300.90	300.90	300.88	300.07	300.06	299.89	300.36	300.35	300.07
Geothermal[2]	13.81	22.04	22.47	45.66	33.43	34.49	76.24	38.12	38.05	82.78
Municipal Solid Waste[3]	19.55	29.20	29.55	35.17	31.67	32.01	37.63	31.81	32.17	37.81
Wood and Other Biomass[4]	9.38	21.47	21.68	23.50	22.06	22.64	364.99	22.82	24.28	573.27
Dedicated Plants	7.66	12.47	12.47	17.53	13.22	13.92	364.99	14.09	16.22	573.27
Cofiring	1.72	9.00	9.20	5.97	8.84	8.72	0.00	8.73	8.06	0.00
Solar Thermal	0.49	0.77	0.77	0.77	0.90	0.90	0.90	0.97	0.97	0.97
Solar Photovoltaic[5]	0.00	0.24	0.24	0.24	0.66	0.66	0.66	0.88	0.88	0.88
Wind	5.78	22.91	22.98	139.07	29.20	31.63	304.22	32.03	35.91	309.07
Total	**262.85**	**397.53**	**398.59**	**545.28**	**417.98**	**422.40**	**1084.53**	**427.00**	**432.62**	**1304.85**
End- Use Sector										
Net Summer Capacity										
Combined Heat and Power[6]										
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Biomass	4.41	5.93	5.90	5.87	7.79	7.80	7.66	8.74	8.68	8.57
Total	**4.69**	**6.21**	**6.19**	**6.15**	**8.07**	**8.08**	**7.94**	**9.03**	**8.96**	**8.85**
Other End-Use Generators[7]										
Conventional Hydropower[8]	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.38	0.38	0.38	0.61	0.62	0.77	0.94	0.97	1.19
Total	**1.12**	**1.47**	**1.47**	**1.47**	**1.71**	**1.72**	**1.87**	**2.04**	**2.06**	**2.29**
Generation (billion kilowatthours)										
Combined Heat and Power[6]										
Municipal Solid Waste	2.46	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15
Biomass	28.67	37.53	37.39	37.19	48.39	48.45	47.63	53.98	53.61	52.94
Total	**31.13**	**39.68**	**39.54**	**39.34**	**50.54**	**50.60**	**49.78**	**56.13**	**55.76**	**55.09**
Other End-Use Generators[7]										
Conventional Hydropower[8]	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.82	0.82	0.82	1.32	1.34	1.65	1.99	2.04	2.51
Total	**4.25**	**5.05**	**5.05**	**5.05**	**5.55**	**5.57**	**5.88**	**6.23**	**6.28**	**6.74**

[1] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes hydrothermal resources only (hot water and steam).

[3] Includes landfill gas.

[4] Includes projections for energy crops after 2010.

[5] Does not include off-grid photovoltaics (PV). See Annual Energy Review 2001 Table 10.6 for estimates of 1989-2000 PV shipments, including exports, for both grid-connected and off-grid applications.

[6] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[7] Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[8] Represents own-use industrial hydroelectric power.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2003. Net summer capacity is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.

Sources: 2001 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2001 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I19. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Marketed Renewable Energy[2]										
Residential	**0.39**	**0.41**	**0.41**	**0.41**	**0.41**	**0.40**	**0.40**	**0.40**	**0.40**	**0.40**
Wood	0.39	0.41	0.41	0.41	0.41	0.40	0.40	0.40	0.40	0.40
Commercial	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Industrial[3]	**1.82**	**2.22**	**2.21**	**2.20**	**2.77**	**2.77**	**2.74**	**3.05**	**3.03**	**3.01**
Conventional Hydroelectric	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.77	2.17	2.17	2.15	2.72	2.72	2.69	3.00	2.98	2.96
Transportation	**0.15**	**0.26**	**0.26**	**0.26**	**0.31**	**0.31**	**0.28**	**0.33**	**0.33**	**0.29**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Ethanol used in Gasoline Blending	0.15	0.26	0.26	0.25	0.30	0.30	0.28	0.33	0.32	0.28
Electric Power[5]	**3.01**	**4.57**	**4.59**	**6.62**	**5.02**	**5.09**	**12.35**	**5.21**	**5.27**	**14.49**
Conventional Hydroelectric	2.16	3.09	3.09	3.09	3.07	3.07	3.07	3.07	3.07	3.07
Geothermal	0.29	0.57	0.58	1.34	0.93	0.96	2.31	1.07	1.07	2.54
Municipal Solid Waste[6]	0.31	0.40	0.40	0.48	0.43	0.44	0.51	0.43	0.44	0.51
Biomass	0.15	0.26	0.27	0.28	0.27	0.28	3.32	0.28	0.29	5.17
Dedicated Plants	0.12	0.14	0.14	0.20	0.15	0.16	3.32	0.16	0.19	5.17
Cofiring	0.03	0.12	0.13	0.08	0.12	0.12	0.00	0.12	0.11	0.00
Solar Thermal	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.08	0.24	0.24	1.43	0.30	0.32	3.13	0.33	0.37	3.18
Total Marketed Renewable Energy	**5.46**	**7.56**	**7.57**	**9.59**	**8.61**	**8.68**	**15.87**	**9.10**	**9.13**	**18.29**
Sources of Ethanol										
From Corn	0.15	0.26	0.26	0.25	0.28	0.28	0.26	0.28	0.28	0.24
From Cellulose	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.05	0.05	0.05
Total	**0.15**	**0.26**	**0.26**	**0.26**	**0.31**	**0.31**	**0.28**	**0.33**	**0.33**	**0.29**
Non-Marketed Renewable Energy[7] **Selected Consumption**										
Residential	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**0.05**	**0.06**	**0.06**	**0.06**
Solar Hot Water Heating	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Geothermal Heat Pumps	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01

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[1] Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.

[2] Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table I8.

[3] Includes all electricity production by industrial and other combined heat and power for the grid and for own use.

[4] Excludes motor gasoline component of E85.

[5] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[6] Includes landfill gas.

[7] Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 electric generators: EIA, Form EIA-860: "Annual Electric Generator Report" (preliminary). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I20. Greenhouse Gas Emissions and Allowance Cost

(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Carbon Dioxide Emissions										
Residential										
Petroleum	27.2	27.6	27.6	27.6	25.7	25.7	25.8	25.0	25.0	25.1
Natural Gas	71.1	81.1	79.9	79.7	87.9	86.5	83.2	91.9	87.7	84.8
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3
Total	**98.7**	**109.1**	**107.8**	**107.7**	**113.9**	**112.6**	**109.3**	**117.2**	**113.1**	**110.3**
Commercial										
Petroleum	14.0	13.7	13.9	13.9	14.1	14.7	15.3	14.1	14.9	16.3
Natural Gas	48.0	53.9	52.9	52.9	60.9	59.7	58.9	64.8	61.1	66.2
Coal	2.3	2.4	2.4	2.4	2.7	2.7	2.7	2.8	2.8	2.8
Total	**64.3**	**70.0**	**69.2**	**69.2**	**77.7**	**77.0**	**76.9**	**81.7**	**78.8**	**85.3**
Industrial[1]										
Petroleum	97.9	97.9	98.5	96.0	105.5	106.8	99.4	109.1	113.0	109.2
Natural Gas[2]	123.4	147.7	144.2	146.6	169.4	163.8	163.8	183.3	168.4	161.3
Coal	52.1	56.5	56.6	53.1	56.2	56.5	49.2	56.2	57.2	48.1
Total	**273.4**	**302.1**	**299.4**	**295.7**	**331.2**	**327.1**	**312.4**	**348.6**	**338.6**	**318.6**
Transportation										
Petroleum[3]	501.4	611.5	610.3	603.5	737.5	737.8	686.3	802.8	800.5	721.1
Natural Gas[4]	9.2	12.0	11.3	11.5	14.9	13.5	14.5	16.4	14.2	14.8
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**510.6**	**623.6**	**621.6**	**615.1**	**752.5**	**751.3**	**700.8**	**819.2**	**814.7**	**735.9**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	640.5	750.8	750.3	741.0	882.8	885.0	826.7	950.9	953.5	871.7
Natural Gas	251.7	294.7	288.3	290.7	333.1	323.5	320.3	356.4	331.3	327.1
Coal	54.7	59.3	59.4	55.9	59.3	59.6	52.3	59.4	60.3	51.3
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**947.0**	**1104.8**	**1098.1**	**1087.7**	**1275.2**	**1268.0**	**1199.3**	**1366.7**	**1345.2**	**1250.1**
Electric Power[6]										
Petroleum	27.5	10.1	12.6	6.2	11.3	12.2	5.4	12.0	30.5	7.4
Natural Gas	77.7	96.6	92.7	94.1	138.2	111.9	113.5	152.1	98.7	75.7
Coal	506.4	590.8	592.9	521.1	653.0	709.4	258.6	703.6	785.2	140.9
Total	**611.6**	**697.4**	**698.1**	**621.4**	**802.5**	**833.5**	**377.5**	**867.8**	**914.4**	**224.1**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	668.0	760.8	762.9	747.2	894.1	897.2	832.1	962.9	984.0	879.1
Natural Gas	329.4	391.3	381.0	384.8	471.3	435.4	433.9	508.5	430.0	402.9
Coal	561.1	650.1	652.3	577.0	712.2	769.0	310.9	763.0	845.5	192.2
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1558.6**	**1802.2**	**1796.2**	**1709.0**	**2077.7**	**2101.6**	**1576.8**	**2234.4**	**2259.6**	**1474.2**
Non-Energy Related Carbon Dioxide Emissions	**36.3**	**39.5**	**39.5**	**39.5**	**43.9**	**43.9**	**43.9**	**46.2**	**46.2**	**46.2**
Total Carbon Dioxide Emissions	**1594.9**	**1841.7**	**1835.7**	**1748.6**	**2121.6**	**2145.5**	**1620.7**	**2280.6**	**2305.8**	**1520.4**
Other Greenhouse Gas Emissions	**332.9**	**388.3**	**388.3**	**286.5**	**466.6**	**466.6**	**339.5**	**525.0**	**525.0**	**362.9**
Methane	175.2	177.6	177.6	115.2	174.3	174.3	126.4	172.2	172.2	120.0
Nitrous Oxide	118.9	126.5	126.5	121.0	137.3	137.3	131.4	143.4	143.4	137.2
High Global Warming Potential Gases	38.8	84.2	84.2	50.2	155.0	155.0	81.7	209.4	209.4	105.8
Total Greenhouse Gas Emissions	**1927.8**	**2230.1**	**2224.1**	**2035.0**	**2588.2**	**2612.1**	**1960.2**	**2805.6**	**2830.8**	**1883.3**

Table I20. Greenhouse Gas Emissions and Allowance Cost (Continued)

(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
Greenhouse Gas Emission Cap Compliance										
Covered Emissions										
Energy-Related Carbon Dioxide	1378.2	1605.0	1601.0	1514.0	1866.0	1891.7	1370.5	2014.2	2046.3	1257.3
Other Greenhouse Gases	75.2	123.5	123.5	70.1	195.7	195.7	102.7	250.7	250.7	127.6
Offsets Purchased	0.0	0.0	0.0	234.3	0.0	0.0	125.8	0.0	0.0	125.6
Non-Covered Greenhouse Gas Offsets	0.0	0.0	0.0	48.5	0.0	0.0	34.2	0.0	0.0	39.0
U.S. Sequestration Offsets	0.0	0.0	0.0	112.7	0.0	0.0	91.6	0.0	0.0	86.5
International Offsets	0.0	0.0	0.0	73.1	0.0	0.0	0.0	0.0	0.0	0.1
Covered Emissions less Offsets	1453.4	1728.5	1724.6	1349.8	2061.6	2087.4	1347.4	2264.9	2297.0	1259.3
Covered Emissions Coal	N/A	N/A	N/A	1465.1	N/A	N/A	1257.9	N/A	N/A	1257.9
Allowance Bank Activity	0.0	0.0	0.0	115.2	0.0	0.0	-89.5	0.0	0.0	-1.4
Cumulative Bank Balance	0.0	0.0	0.0	115.2	0.0	0.0	4.9	0.0	0.0	-86.2
Allowance Cost (2001 dollars per ton)										
Emissions Allowance Cost	0.00	0.00	0.00	83.33	0.00	0.00	188.40	0.00	0.00	213.65
Offset Price	0.00	0.00	0.00	71.28	0.00	0.00	34.59	0.00	0.00	51.74

[1] Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2] Includes lease and plant fuel.
[3] This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons carbon equivalent of carbon dioxide annually.
[4] Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5] Includes methanol and liquid hydrogen.
[6] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.
[7] Emissions from electric power generators are distributed to the primary fuels.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table I21. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2001	Projections								
		2010			2020			2025		
		Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price	Reference	High Natural Gas Price	S. 139 with High Natural Gas Price
GDP Chain-Type Price Index (1996=1.000)	**1.094**	**1.313**	**1.313**	**1.322**	**1.708**	**1.698**	**1.731**	**1.981**	**1.976**	**2.024**
Potential Gross Domestic Product	**9456**	**12454**	**12443**	**12448**	**16772**	**16766**	**16721**	**19240**	**19225**	**19147**
Real Gross Domestic Product	**9215**	**12258**	**12230**	**12187**	**16444**	**16465**	**16354**	**18916**	**18854**	**18787**
Real Consumption	6377	8412	8394	8359	11346	11356	11268	13008	12954	12919
Real Investment	1575	2499	2490	2471	3755	3760	3721	4496	4468	4444
Real Government Spending	1640	1895	1894	1896	2211	2211	2203	2429	2426	2416
Real Exports	1076	1784	1784	1781	3361	3372	3334	4696	4706	4624
Real Imports	1492	2302	2302	2291	4060	4056	4014	5395	5373	5350
Real Disposable Personal Income	**6748**	**8635**	**8608**	**8583**	**11693**	**11694**	**11626**	**13425**	**13360**	**13379**
Federal Funds Rate (percent)	**3.89**	**5.48**	**5.38**	**5.55**	**6.37**	**6.36**	**6.54**	**6.49**	**6.26**	**6.74**
AA Utility Bond Rate (percent)										
Nominal	**7.57**	**7.22**	**7.17**	**7.34**	**9.00**	**8.96**	**9.14**	**9.61**	**9.51**	**9.83**
Real	**5.60**	**5.26**	**5.23**	**5.18**	**6.12**	**6.12**	**6.14**	**6.54**	**6.36**	**6.66**
Energy Intensity (thousand Btu per 1996 dollar of GDP)										
Delivered Energy	7.74	6.83	6.80	6.77	5.91	5.87	5.58	5.52	5.44	5.07
Total Energy	10.56	9.24	9.21	9.15	7.89	7.88	7.37	7.33	7.30	6.70
Consumer Price Index (1982-84=1.00)	**1.77**	**2.19**	**2.19**	**2.20**	**2.93**	**2.91**	**2.97**	**3.47**	**3.46**	**3.55**
Unemployment Rate (percent)	**4.79**	**4.42**	**4.50**	**4.62**	**5.88**	**5.79**	**6.02**	**5.77**	**5.89**	**5.93**
Housing Starts (millions)	**1.80**	**2.18**	**2.17**	**2.12**	**1.93**	**1.94**	**1.92**	**2.01**	**2.00**	**2.02**
Single-Family	1.27	1.34	1.34	1.31	1.12	1.12	1.11	1.12	1.12	1.11
Multifamily	0.33	0.47	0.47	0.45	0.49	0.49	0.48	0.57	0.56	0.57
Mobile Home Shipments	0.19	0.37	0.37	0.37	0.32	0.33	0.33	0.33	0.33	0.33
Commercial Floorspace, Total (billion square feet)	**70.2**	**82.0**	**81.9**	**81.9**	**94.6**	**94.5**	**94.1**	**100.8**	**100.7**	**100.3**
Value of Shipments (billion 1996 dollars)										
Total Industrial	5425	6977	6951	6897	8969	8981	8858	10128	10075	9970
Nonmanufacturing	1346	1510	1502	1491	1744	1742	1703	1870	1850	1810
Manufacturing	4079	5466	5450	5406	7226	7239	7155	8258	8226	8160
Energy-Intensive Manufacturing	1086	1264	1259	1251	1451	1450	1427	1538	1524	1505
Non-Energy-Intensive Manufacturing	2993	4203	4190	4155	5774	5790	5728	6720	6702	6655
United Sales of Light-Duty Vehicles	**17.11**	**18.29**	**18.22**	**17.85**	**20.02**	**20.16**	**20.10**	**20.00**	**19.87**	**20.27**
Population (millions)										
Population with Armed Forces Overseas	278.2	300.2	300.2	300.2	325.3	325.3	325.3	338.2	338.2	338.2
Population (aged 16 and over)	215.4	236.6	236.6	236.6	256.5	256.5	256.5	266.6	266.6	266.6
Employment, Non-Agriculture	131.7	147.3	147.0	146.8	159.1	159.3	158.7	165.8	165.4	165.3
Employment, Manufacturing	17.5	17.7	17.7	17.6	17.8	17.9	17.8	18.5	18.5	18.4
Labor Force	141.8	156.5	156.5	156.4	169.8	169.8	169.6	177.4	177.4	177.2

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2001: Global Insight macroeconomic model CTL0802. **Projections:** Energy Information Administration, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBASE_HGP.D052103A, and MLBILL_HGP.D052303A.

Table J1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Production							
Crude Oil and Lease Condensate	12.29	11.92	11.93	11.45	11.46	11.15	11.14
Natural Gas Plant Liquids	2.65	3.21	3.19	3.75	3.68	3.84	3.75
Dry Natural Gas	19.97	22.81	22.60	27.33	26.79	28.06	27.44
Coal	23.97	22.57	23.58	10.46	14.67	6.82	11.45
Nuclear Power	8.03	8.37	8.37	9.75	9.76	12.39	12.39
Renewable Energy[1]	5.32	9.03	8.68	14.68	13.28	16.22	15.68
Other[2]	0.57	0.82	0.83	0.62	0.64	0.59	0.61
Total	**72.80**	**78.73**	**79.16**	**78.04**	**80.28**	**79.06**	**82.46**
Imports							
Crude Oil[3]	20.26	24.88	24.86	26.92	26.96	27.72	27.80
Petroleum Products[4]	5.04	5.73	5.96	8.82	9.71	10.43	11.87
Natural Gas	4.18	5.53	5.40	9.37	8.48	11.48	9.80
Other Imports[5]	0.71	0.81	0.81	0.94	0.88	0.79	0.70
Total	**30.19**	**36.94**	**37.03**	**46.05**	**46.04**	**50.42**	**50.17**
Exports							
Petroleum[6]	2.01	2.21	2.23	2.29	2.31	2.32	2.35
Natural Gas	0.37	0.57	0.57	0.37	0.36	0.36	0.35
Coal	1.27	0.84	0.84	0.76	0.68	0.61	0.61
Total	**3.64**	**3.61**	**3.63**	**3.42**	**3.35**	**3.29**	**3.32**
Discrepancy[7]	**2.06**	**0.39**	**0.31**	**0.18**	**0.29**	**0.22**	**0.34**
Consumption							
Petroleum Products[8]	38.46	43.74	43.91	48.65	49.53	50.76	52.16
Natural Gas	23.26	28.12	27.79	36.69	35.29	39.54	37.26
Coal	22.02	22.00	23.07	10.23	14.38	6.74	11.25
Nuclear Power	8.03	8.37	8.37	9.75	9.76	12.39	12.39
Renewable Energy[1]	5.32	9.03	8.68	14.68	13.28	16.22	15.69
Other[9]	0.21	0.43	0.42	0.50	0.44	0.32	0.23
Total	**97.29**	**111.67**	**112.24**	**120.50**	**122.69**	**125.97**	**128.97**
Net Imports - Petroleum	**23.29**	**28.40**	**28.59**	**33.45**	**34.37**	**35.83**	**37.32**
Prices (2001 dollars per unit)							
World Oil Price (dollars per barrel)[10]	22.01	23.77	23.77	24.15	24.15	24.58	24.58
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.12	3.51	3.44	3.97	3.79	4.36	4.31
Coal Minemouth Price (dollars per ton)	17.59	15.84	15.83	15.27	15.73	13.67	15.03
Average Electricity Price (cents per kilowatthour)	7.3	7.0	6.9	8.8	8.3	9.8	9.1

[1] Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table E18 for selected nonmarketed residential and commercial renewable energy.

[2] Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.

[3] Includes imports of crude oil for the Strategic Petroleum Reserve.

[4] Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.

[5] Includes coal, coal coke (net), and electricity (net).

[6] Includes crude oil and petroleum products.

[7] Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.

[8] Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.

[9] Includes net electricity imports, methanol, and liquid hydrogen.

[10] Average refiner acquisition cost for imported crude oil.

[11] Represents lower 48 onshore and offshore supplies.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J2. Energy Consumption by Sector and Source

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Energy Consumption							
Residential							
Distillate Fuel	0.91	0.91	0.91	0.84	0.84	0.81	0.81
Kerosene	0.10	0.08	0.08	0.06	0.06	0.06	0.06
Liquefied Petroleum Gas	0.50	0.47	0.47	0.47	0.46	0.47	0.46
Petroleum Subtotal	1.50	1.46	1.46	1.37	1.36	1.33	1.33
Natural Gas	4.94	5.62	5.63	5.96	6.00	6.20	6.23
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.41	0.41	0.40	0.40	0.40	0.40
Electricity	4.10	4.88	4.88	5.05	5.18	5.11	5.30
Delivered Energy	**10.94**	**12.38**	**12.39**	**12.80**	**12.96**	**13.06**	**13.27**
Electricity Related Losses	9.15	10.11	10.26	9.29	9.73	9.26	9.87
Total	**20.08**	**22.50**	**22.65**	**22.09**	**22.69**	**22.32**	**23.14**
Commercial							
Distillate Fuel	0.46	0.51	0.51	0.54	0.53	0.56	0.54
Residual Fuel	0.09	0.04	0.04	0.05	0.05	0.05	0.05
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.09	0.10	0.09
Motor Gasoline[2]	0.05	0.03	0.03	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.71	0.70	0.70	0.75	0.73	0.76	0.74
Natural Gas	3.33	3.74	3.74	4.27	4.25	4.97	4.77
Coal	0.09	0.10	0.09	0.11	0.11	0.11	0.11
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.08	4.97	4.96	5.66	5.76	5.97	6.11
Delivered Energy	**8.32**	**9.60**	**9.60**	**10.89**	**10.95**	**11.92**	**11.84**
Electricity Related Losses	9.12	10.30	10.43	10.42	10.83	10.82	11.39
Total	**17.44**	**19.90**	**20.03**	**21.31**	**21.78**	**22.74**	**23.23**
Industrial[4]							
Distillate Fuel	1.13	1.20	1.20	1.30	1.31	1.36	1.37
Liquefied Petroleum Gas	2.10	2.54	2.54	2.99	3.04	3.14	3.21
Petrochemical Feedstock	1.14	1.41	1.41	1.53	1.54	1.57	1.59
Residual Fuel	0.23	0.18	0.18	0.17	0.17	0.17	0.18
Motor Gasoline[2]	0.15	0.17	0.17	0.18	0.18	0.19	0.19
Other Petroleum[5]	4.03	4.18	4.20	4.09	4.17	4.12	4.23
Petroleum Subtotal	8.79	9.67	9.69	10.26	10.41	10.55	10.77
Natural Gas	7.74	9.16	9.15	10.36	10.30	11.09	10.97
Lease and Plant Fuel[6]	1.20	1.40	1.39	1.70	1.68	1.77	1.74
Natural Gas Subtotal	8.94	10.56	10.54	12.06	11.97	12.86	12.71
Metallurgical Coal	0.72	0.65	0.65	0.47	0.48	0.39	0.40
Steam Coal	1.42	1.33	1.36	1.28	1.31	1.26	1.31
Net Coal Coke Imports	0.03	0.11	0.11	0.18	0.18	0.21	0.21
Coal Subtotal	2.16	2.09	2.12	1.93	1.97	1.87	1.92
Renewable Energy[7]	1.82	2.21	2.21	2.74	2.75	3.02	3.02
Electricity	3.39	3.89	3.90	4.41	4.46	4.66	4.73
Delivered Energy	**25.10**	**28.41**	**28.46**	**31.40**	**31.56**	**32.96**	**33.17**
Electricity Related Losses	7.57	8.06	8.19	8.12	8.39	8.45	8.82
Total	**32.67**	**36.47**	**36.65**	**39.53**	**39.95**	**41.40**	**41.99**

Table J2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Transportation							
Distillate Fuel[8]	5.44	7.01	7.04	8.30	8.39	8.98	9.11
Jet Fuel[9]	3.43	3.91	3.92	5.01	5.02	5.56	5.58
Motor Gasoline[2]	16.26	19.58	19.68	21.55	22.17	22.10	23.10
Residual Fuel	0.84	0.83	0.83	0.85	0.85	0.86	0.86
Liquefied Petroleum Gas	0.02	0.05	0.05	0.08	0.08	0.09	0.09
Other Petroleum[10]	0.24	0.26	0.26	0.30	0.30	0.32	0.32
Petroleum Subtotal	26.22	31.64	31.77	36.09	36.81	37.91	39.06
Pipeline Fuel Natural Gas	0.63	0.81	0.80	1.05	1.01	1.11	1.05
Compressed Natural Gas	0.01	0.06	0.06	0.09	0.09	0.10	0.10
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.07	0.09	0.09	0.12	0.12	0.13	0.14
Delivered Energy	**26.94**	**32.61**	**32.72**	**37.36**	**38.04**	**39.25**	**40.36**
Electricity Related Losses	0.17	0.19	0.20	0.22	0.23	0.24	0.25
Total	**27.10**	**32.80**	**32.92**	**37.58**	**38.27**	**39.50**	**40.61**
Delivered Energy Consumption for All Sectors							
Distillate Fuel	7.94	9.64	9.66	10.99	11.07	11.71	11.83
Kerosene	0.15	0.12	0.12	0.11	0.11	0.10	0.10
Jet Fuel[9]	3.43	3.91	3.92	5.01	5.02	5.56	5.58
Liquefied Petroleum Gas	2.70	3.16	3.15	3.63	3.67	3.78	3.86
Motor Gasoline[2]	16.46	19.78	19.88	21.77	22.39	22.33	23.33
Petrochemical Feedstock	1.14	1.41	1.41	1.53	1.54	1.57	1.59
Residual Fuel	1.15	1.05	1.05	1.07	1.07	1.08	1.08
Other Petroleum[12]	4.24	4.41	4.43	4.36	4.45	4.42	4.52
Petroleum Subtotal	37.21	43.48	43.63	48.47	49.32	50.55	51.90
Natural Gas	16.02	18.57	18.57	20.68	20.63	22.36	22.07
Lease and Plant Fuel Plant[6]	1.20	1.40	1.39	1.70	1.68	1.77	1.74
Pipeline Natural Gas	0.63	0.81	0.80	1.05	1.01	1.11	1.05
Natural Gas Subtotal	17.86	20.78	20.76	23.43	23.32	25.23	24.87
Metallurgical Coal	0.72	0.65	0.65	0.47	0.48	0.39	0.40
Steam Coal	1.53	1.44	1.47	1.40	1.43	1.39	1.43
Net Coal Coke Imports	0.03	0.11	0.11	0.18	0.18	0.21	0.21
Coal Subtotal	2.27	2.20	2.23	2.05	2.09	1.99	2.05
Renewable Energy[13]	2.31	2.72	2.73	3.26	3.26	3.53	3.54
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.65	13.82	13.84	15.24	15.52	15.87	16.28
Delivered Energy	**71.29**	**83.01**	**83.18**	**92.45**	**93.52**	**97.19**	**98.64**
Electricity Related Losses	26.00	28.66	29.06	28.05	29.17	28.78	30.33
Total	**97.29**	**111.67**	**112.24**	**120.50**	**122.69**	**125.97**	**128.97**
Electric Power[14]							
Distillate Fuel	0.17	0.07	0.08	0.05	0.06	0.06	0.09
Residual Fuel	1.08	0.19	0.21	0.14	0.16	0.14	0.17
Petroleum Subtotal	1.25	0.26	0.28	0.19	0.21	0.21	0.26
Natural Gas	5.40	7.33	7.03	13.25	11.96	14.30	12.39
Steam Coal	19.75	19.79	20.84	8.18	12.29	4.74	9.21
Nuclear Power	8.03	8.37	8.37	9.75	9.76	12.39	12.39
Renewable Energy[15]	3.01	6.30	5.95	11.42	10.02	12.69	12.15
Electricity Imports	0.21	0.43	0.42	0.50	0.44	0.32	0.23
Total	**37.65**	**42.48**	**42.90**	**43.29**	**44.70**	**44.65**	**46.62**

Table J2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Total Energy Consumption							
Distillate Fuel	8.10	9.71	9.74	11.04	11.13	11.77	11.92
Kerosene	0.15	0.12	0.12	0.11	0.11	0.10	0.10
Jet Fuel[9]	3.43	3.91	3.92	5.01	5.02	5.56	5.58
Liquefied Petroleum Gas	2.70	3.16	3.15	3.63	3.67	3.78	3.86
Motor Gasoline[2]	16.46	19.78	19.88	21.77	22.39	22.33	23.33
Petrochemical Feedstock	1.14	1.41	1.41	1.53	1.54	1.57	1.59
Residual Fuel	2.23	1.24	1.26	1.20	1.23	1.22	1.25
Other Petroleum[12]	4.24	4.41	4.43	4.36	4.45	4.42	4.52
Petroleum Subtotal	38.46	43.74	43.91	48.65	49.53	50.76	52.16
Natural Gas	21.42	25.91	25.60	33.94	32.60	36.67	34.46
Lease and Plant Fuel[6]	1.20	1.40	1.39	1.70	1.68	1.77	1.74
Pipeline Natural Gas	0.63	0.81	0.80	1.05	1.01	1.11	1.05
Natural Gas Subtotal	23.26	28.12	27.79	36.69	35.29	39.54	37.26
Metallurgical Coal	0.72	0.65	0.65	0.47	0.48	0.39	0.40
Steam Coal	21.28	21.24	22.31	9.58	13.73	6.13	10.64
Net Coal Coke Imports	0.03	0.11	0.11	0.18	0.18	0.21	0.21
Coal Subtotal	22.02	22.00	23.07	10.23	14.38	6.74	11.25
Nuclear Power	8.03	8.37	8.37	9.75	9.76	12.39	12.39
Renewable Energy[16]	5.32	9.03	8.68	14.68	13.28	16.22	15.69
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.21	0.43	0.42	0.50	0.44	0.32	0.23
Total	**97.29**	**111.67**	**112.24**	**120.50**	**122.69**	**125.97**	**128.97**
Energy Use and Related Statistics							
Delivered Energy Use	71.29	83.01	83.18	92.45	93.52	97.19	98.64
Total Energy Use	97.29	111.67	112.24	120.50	122.69	125.97	128.97
Population (millions)	278.18	300.24	300.24	325.32	325.32	338.24	338.24
Gross Domestic Product (billion 1996 dollars)	9215	12211	12219	16364	16374	18810	18852
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1558.6	1710.1	1736.8	1568.5	1714.8	1482.2	1696.8

[1] Includes wood used for residential heating. See Table E18 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.

[2] Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.

[3] Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table J18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.

[4] Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.

[5] Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.

[6] Represents natural gas used in the field gathering and processing plant machinery.

[7] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.

[8] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.

[9] Includes only kerosene type.

[10] Includes aviation gasoline and lubricants.

[11] E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).

[12] Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.

[13] Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

[14] Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[15] Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.

[16] Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.

Sources: 2001 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 population and gross domestic product: Global Insight macroeconomic model CTL0802. 2001 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J3. Delivered Energy Prices by Sector and Source
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Residential	**15.81**	**14.62**	**14.46**	**17.37**	**16.65**	**18.74**	**17.92**
Primary Energy[1]	9.73	8.11	8.07	8.48	8.36	8.88	8.82
Petroleum Products[2]	10.85	9.88	9.90	10.32	10.54	10.79	10.78
Distillate Fuel	8.99	7.95	7.94	8.23	8.37	8.58	8.59
Liquefied Petroleum Gas	14.84	13.97	14.09	14.44	14.87	14.96	14.93
Natural Gas	9.41	7.67	7.61	8.07	7.88	8.48	8.42
Electricity	25.37	24.10	23.74	30.32	28.44	33.29	30.92
Commercial	**15.50**	**14.35**	**14.17**	**17.78**	**16.97**	**19.27**	**18.40**
Primary Energy[1]	7.81	6.50	6.45	6.93	6.80	7.33	7.29
Petroleum Products[2]	7.27	6.70	6.70	6.96	7.13	7.28	7.32
Distillate Fuel	6.40	5.63	5.62	5.96	6.08	6.30	6.33
Residual Fuel	3.46	3.93	3.94	3.96	3.97	4.02	4.03
Natural Gas	8.09	6.59	6.53	7.07	6.89	7.48	7.42
Electricity	23.28	21.51	21.22	27.61	25.94	30.97	28.62
Industrial[3]	**7.11**	**6.61**	**6.55**	**7.80**	**7.60**	**8.45**	**8.19**
Primary Energy	5.83	5.16	5.15	5.65	5.68	5.97	5.96
Petroleum Products[2]	7.72	6.93	6.96	7.40	7.60	7.68	7.71
Distillate Fuel	6.55	5.71	5.70	6.18	6.30	6.53	6.59
Liquefied Petroleum Gas	12.34	9.58	9.68	10.14	10.54	10.60	10.55
Residual Fuel	3.28	3.66	3.66	3.70	3.70	3.77	3.77
Natural Gas[4]	4.87	4.11	4.05	4.68	4.51	5.07	5.00
Metallurgical Coal	1.69	1.51	1.51	1.40	1.39	1.34	1.34
Steam Coal	1.46	1.38	1.39	1.14	1.21	1.04	1.13
Electricity	14.13	14.34	14.05	18.65	17.28	20.86	19.23
Transportation	**10.28**	**11.73**	**11.44**	**13.27**	**12.69**	**14.17**	**13.35**
Primary Energy	10.25	11.70	11.41	13.24	12.66	14.12	13.31
Petroleum Products[2]	10.25	11.71	11.42	13.25	12.67	14.14	13.33
Distillate Fuel[5]	10.05	11.71	11.37	13.17	12.59	14.37	13.38
Jet Fuel[6]	6.20	7.10	6.81	9.26	8.69	10.35	9.47
Motor Gasoline[7]	11.57	12.98	12.70	14.52	13.91	15.31	14.54
Residual Fuel	3.90	5.19	4.87	7.36	6.63	8.32	7.33
Liquefied Petroleum Gas[8]	16.93	16.35	16.25	18.30	18.11	19.15	18.23
Natural Gas[9]	7.65	7.25	7.21	7.72	7.60	8.08	8.07
Electricity	21.87	20.82	20.46	24.39	22.95	26.05	24.22
Average End-Use Energy	**10.75**	**10.87**	**10.68**	**12.73**	**12.22**	**13.71**	**13.05**
Primary Energy	8.52	8.82	8.66	9.90	9.62	10.52	10.15
Electricity	21.34	20.40	20.09	25.89	24.26	28.70	26.60
Electric Power[10]							
Fossil Fuel Average	2.14	1.97	1.90	3.36	2.80	4.13	3.34
Petroleum Products	4.73	4.49	4.42	5.02	4.91	5.18	5.07
Distillate Fuel	6.20	5.01	5.00	5.39	5.50	5.64	5.67
Residual Fuel	4.50	4.29	4.21	4.88	4.70	4.98	4.75
Natural Gas	4.78	4.07	3.98	4.79	4.58	5.19	5.07
Steam Coal	1.25	1.16	1.17	0.99	1.02	0.90	0.96

Table J3. Delivered Energy Prices by Sector and Source (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Average Price to All Users[11]							
Petroleum Products[2]	9.54	10.54	10.33	11.85	11.48	12.61	12.02
Distillate Fuel	9.16	10.25	10.00	11.58	11.19	12.64	11.90
Jet Fuel	6.20	7.10	6.81	9.26	8.69	10.35	9.47
Liquefied Petroleum Gas	12.85	10.43	10.53	10.93	11.30	11.40	11.31
Motor Gasoline[7]	11.57	12.97	12.69	14.49	13.88	15.27	14.51
Residual Fuel	4.11	4.79	4.56	6.42	5.86	7.12	6.35
Natural Gas	6.40	5.24	5.18	5.63	5.47	6.03	5.99
Coal	1.26	1.17	1.19	1.02	1.04	0.94	0.98
Electricity	21.34	20.40	20.09	25.89	24.26	28.70	26.60
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)							
Residential	166.77	175.14	173.27	215.33	208.96	237.11	230.63
Commercial	127.30	136.28	134.63	191.81	184.07	227.72	215.98
Industrial	135.32	141.86	140.80	185.88	181.61	212.44	206.91
Transportation	270.41	372.90	365.02	481.84	469.95	540.27	524.67
Total Non-Renewable Expenditures	699.80	826.18	813.73	1074.86	1044.59	1217.53	1178.20
Transportation Renewable Expenditures	0.01	0.05	0.05	0.11	0.11	0.15	0.15
Total Expenditures	**699.81**	**826.23**	**813.78**	**1074.97**	**1044.70**	**1217.69**	**1178.34**

[1] Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3] Includes combined heat and power, which produces electricity and other useful thermal energy.
[4] Excludes use for lease and plant fuel.
[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6] Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7] Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8] Includes Federal and State taxes while excluding county and local taxes.
[9] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[10] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[11] Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J4. Greenhouse Gas Allowance Cost by End-Use Sector and Source

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Commercial							
Petroleum Products[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residual Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[3]							
Petroleum Products[2]	0.00	0.94	0.76	2.15	1.74	2.66	2.11
Distillate Fuel	0.00	1.56	1.26	3.52	2.85	4.36	3.44
Liquefied Petroleum Gas	0.00	1.35	1.09	3.05	2.47	3.77	2.98
Residual Fuel	0.00	1.68	1.36	3.80	3.07	4.70	3.71
Natural Gas[4]	0.00	1.11	0.90	2.52	2.04	3.12	2.47
Metallurgical Coal	0.00	2.00	1.61	4.51	3.65	5.58	4.41
Steam Coal	0.00	2.00	1.62	4.53	3.66	5.60	4.43
Electric Power[5]							
Fossil Fuel Average	0.00	1.78	1.45	3.32	2.89	3.80	3.34
Petroleum Products	0.00	1.65	1.33	3.72	3.01	4.60	3.62
Distillate Fuel	0.00	1.56	1.26	3.52	2.85	4.36	3.44
Residual Fuel	0.00	1.68	1.36	3.80	3.07	4.70	3.71
Natural Gas	0.00	1.14	0.92	2.57	2.08	3.18	2.51
Steam Coal	0.00	2.02	1.63	4.54	3.67	5.62	4.44
Average Allowance Cost to All Users[6]							
Petroleum Products[2]	0.00	0.22	0.18	0.48	0.39	0.59	0.47
Distillate Fuel	0.00	0.20	0.17	0.43	0.35	0.53	0.42
Jet Fuel	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquefied Petroleum Gas	0.00	1.09	0.88	2.51	2.04	3.13	2.48
Motor Gasoline	0.00	0.01	0.01	0.03	0.02	0.04	0.03
Residual Fuel	0.00	0.50	0.42	0.98	0.83	1.21	1.03
Natural Gas	0.00	0.72	0.58	1.78	1.41	2.19	1.70
Coal	0.00	2.00	1.62	4.48	3.64	5.50	4.39

[1] Weighted average allowance cost includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3] Includes combined heat and power, which produces electricity and other useful thermal energy.
[4] Excludes use for lease and plant fuel.
[5] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[6] Weighted averages of allowance cost are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Projections: EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J5. Energy Prices by Sector and Source with Greenhouse Gas Allowance Cost
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Residential	**15.81**	**14.62**	**14.46**	**17.37**	**16.65**	**18.74**	**17.92**
Primary Energy[1]	9.73	8.11	8.07	8.48	8.36	8.88	8.82
Petroleum Products[2]	10.85	9.88	9.90	10.32	10.54	10.79	10.78
Distillate Fuel	8.99	7.95	7.94	8.23	8.37	8.58	8.59
Liquefied Petroleum Gas	14.84	13.97	14.09	14.44	14.87	14.96	14.93
Natural Gas	9.41	7.67	7.61	8.07	7.88	8.48	8.42
Electricity	25.37	24.10	23.74	30.32	28.44	33.29	30.92
Commercial	**15.50**	**14.35**	**14.17**	**17.78**	**16.97**	**19.27**	**18.40**
Primary Energy[1]	7.81	6.50	6.45	6.93	6.80	7.33	7.29
Petroleum Products[2]	7.27	6.70	6.70	6.96	7.13	7.28	7.32
Distillate Fuel	6.40	5.63	5.62	5.96	6.08	6.30	6.33
Residual Fuel	3.46	3.93	3.94	3.96	3.97	4.02	4.03
Natural Gas	8.09	6.59	6.53	7.07	6.89	7.48	7.42
Electricity	23.28	21.51	21.22	27.61	25.94	30.97	28.62
Industrial[3]	**7.11**	**7.55**	**7.31**	**9.89**	**9.30**	**11.03**	**10.23**
Primary Energy	5.83	6.28	6.06	8.16	7.71	9.06	8.41
Petroleum Products[2]	7.72	7.87	7.72	9.55	9.34	10.34	9.82
Distillate Fuel	6.55	7.27	6.96	9.70	9.15	10.89	10.03
Liquefied Petroleum Gas	12.34	10.93	10.77	13.19	13.00	14.38	13.53
Residual Fuel	3.28	5.34	5.02	7.49	6.77	8.46	7.48
Natural Gas[4]	4.87	5.23	4.95	7.20	6.55	8.19	7.47
Metallurgical Coal	1.69	3.50	3.12	5.91	5.04	6.92	5.75
Steam Coal	1.46	3.38	3.01	5.67	4.88	6.64	5.56
Electricity	14.13	14.34	14.05	18.65	17.28	20.86	19.23
Transportation	**10.28**	**11.73**	**11.44**	**13.28**	**12.70**	**14.17**	**13.36**
Primary Energy	10.25	11.70	11.41	13.24	12.66	14.13	13.32
Petroleum Products[2]	10.25	11.71	11.42	13.25	12.67	14.14	13.33
Distillate Fuel[5]	10.05	11.71	11.37	13.17	12.59	14.37	13.38
Jet Fuel[6]	6.20	7.10	6.81	9.26	8.69	10.35	9.47
Motor Gasoline[7]	11.57	12.98	12.70	14.52	13.91	15.31	14.54
Residual Fuel	3.90	5.19	4.87	7.36	6.63	8.32	7.33
Liquefied Petroleum Gas[8]	16.93	16.35	16.25	18.30	18.11	19.15	18.23
Natural Gas[9]	7.65	8.38	8.13	10.29	9.68	11.26	10.58
Electricity	21.87	20.82	20.46	24.39	22.95	26.05	24.22
Average End-Use Energy	**10.75**	**11.17**	**10.93**	**13.38**	**12.75**	**14.50**	**13.68**
Primary Energy	8.52	9.18	8.96	10.70	10.26	11.49	10.91
Electricity	21.34	20.40	20.09	25.89	24.26	28.70	26.60
Electric Power[10]							
Fossil Fuel Average	2.14	3.75	3.36	6.68	5.68	7.93	6.67
Petroleum Products	4.73	6.13	5.76	8.74	7.92	9.77	8.68
Distillate Fuel	6.20	6.57	6.26	8.91	8.35	9.99	9.12
Residual Fuel	4.50	5.97	5.57	8.68	7.77	9.68	8.46
Natural Gas	4.78	5.20	4.90	7.36	6.66	8.37	7.58
Steam Coal	1.25	3.17	2.80	5.53	4.70	6.53	5.40

Table J5. Energy Prices by Sector and Source with Greenhouse Gas Allowance Cost (Continued)
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Average Price to All Users[11]							
Petroleum Products[2]	9.54	10.76	10.51	12.34	11.87	13.20	12.49
Distillate Fuel	9.16	10.45	10.16	12.01	11.54	13.17	12.32
Jet Fuel	6.20	7.10	6.81	9.26	8.69	10.35	9.47
Liquefied Petroleum Gas	12.85	11.51	11.40	13.44	13.34	14.52	13.79
Motor Gasoline[7]	11.57	12.98	12.70	14.52	13.90	15.31	14.54
Residual Fuel	4.11	5.29	4.98	7.39	6.69	8.33	7.38
Natural Gas	6.40	5.96	5.76	7.41	6.89	8.22	7.68
Coal	1.26	3.18	2.81	5.50	4.69	6.44	5.37
Electricity	21.34	20.40	20.09	25.89	24.26	28.70	26.60
Non-Renewable Energy and Allowance Expenditures by Sector (billion 2001 dollars)							
Residential	166.77	175.14	173.27	215.33	208.96	237.11	230.63
Commercial	127.30	136.28	134.63	191.81	184.07	227.72	215.98
Industrial	135.32	162.27	157.35	235.92	222.33	277.18	258.49
Transportation	270.41	372.97	365.07	482.08	470.15	540.60	524.94
Total Non-Renewable Expenditures	699.80	846.66	830.33	1125.14	1085.51	1282.60	1230.03
Transportation Renewable Expenditures	0.01	0.05	0.05	0.12	0.11	0.16	0.15
Total Expenditures	**699.81**	**846.72**	**830.38**	**1125.26**	**1085.62**	**1282.76**	**1230.18**

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[1] Weighted average price includes fuels below as well as coal.
[2] This quantity is the weighted average for all petroleum products, not just those listed below.
[3] Includes combined heat and power, which produces electricity and other useful thermal energy.
[4] Excludes use for lease and plant fuel.
[5] Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6] Kerosene-type jet fuel. Price includes Federal and State taxes while excluding county and local taxes.
[7] Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8] Includes Federal and State taxes while excluding county and local taxes.
[9] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[10] Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[11] Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J6. Residential Sector Key Indicators and End-Use Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Key Indicators							
Households (millions)							
Single-Family	77.50	86.14	86.14	93.99	94.02	97.43	97.49
Multifamily	22.19	24.13	24.13	26.99	27.00	28.71	28.73
Mobile Homes	6.57	7.10	7.10	7.86	7.86	8.11	8.11
Total	**106.27**	**117.37**	**117.37**	**128.83**	**128.88**	**134.25**	**134.33**
Average House Square Footage	**1685**	**1740**	**1740**	**1782**	**1782**	**1798**	**1798**
Energy Intensity							
(million Btu per household)							
Delivered Energy Consumption	102.9	105.5	105.6	99.3	100.5	97.3	98.8
Total Energy Consumption	189.0	191.7	193.0	171.4	176.0	166.3	172.3
(thousand Btu per square foot)							
Delivered Energy Consumption	61.1	60.7	60.7	55.7	56.4	54.1	54.9
Total Energy Consumption	112.2	110.2	110.9	96.2	98.8	92.5	95.8
Delivered Energy Consumption by Fuel							
Electricity							
Space Heating	0.39	0.46	0.46	0.46	0.47	0.45	0.46
Space Cooling	0.52	0.60	0.60	0.59	0.60	0.59	0.61
Water Heating	0.45	0.46	0.46	0.38	0.39	0.33	0.35
Refrigeration	0.42	0.34	0.34	0.32	0.32	0.33	0.33
Cooking	0.10	0.11	0.11	0.12	0.12	0.13	0.13
Clothes Dryers	0.22	0.24	0.25	0.25	0.25	0.25	0.26
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.91	0.92	0.81	0.87	0.74	0.82
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers[1]	0.02	0.02	0.02	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.19	0.19	0.24	0.24	0.24	0.25
Personal Computers	0.06	0.08	0.08	0.10	0.10	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.09	0.09	0.10	0.10
Other Uses[2]	0.83	1.25	1.25	1.54	1.57	1.69	1.73
Delivered Energy	**4.10**	**4.88**	**4.88**	**5.05**	**5.18**	**5.11**	**5.30**
Natural Gas							
Space Heating	3.13	3.69	3.70	3.97	4.00	4.11	4.15
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Heating	1.48	1.55	1.55	1.58	1.59	1.62	1.64
Cooking	0.20	0.23	0.23	0.25	0.25	0.26	0.26
Clothes Dryers	0.06	0.08	0.08	0.10	0.10	0.10	0.10
Other Uses[3]	0.06	0.07	0.07	0.07	0.07	0.11	0.08
Delivered Energy	**4.94**	**5.62**	**5.63**	**5.96**	**6.00**	**6.20**	**6.23**
Distillate							
Space Heating	0.74	0.76	0.76	0.71	0.71	0.69	0.69
Water Heating	0.16	0.14	0.14	0.12	0.12	0.11	0.11
Other Uses[4]	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Delivered Energy	**0.91**	**0.91**	**0.91**	**0.84**	**0.84**	**0.81**	**0.81**
Liquefied Petroleum Gas							
Space Heating	0.26	0.25	0.25	0.24	0.24	0.24	0.24
Water Heating	0.09	0.07	0.07	0.06	0.06	0.06	0.06
Cooking	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Other Uses[3]	0.12	0.13	0.13	0.14	0.14	0.14	0.14
Delivered Energy	**0.50**	**0.47**	**0.47**	**0.47**	**0.46**	**0.47**	**0.46**
Marketed Renewables (wood)[5]	0.39	0.41	0.41	0.40	0.40	0.40	0.40
Other Fuels[6]	0.11	0.09	0.09	0.08	0.08	0.07	0.07

Table J6. Residential Sector Key Indicators and End-Use Consumption (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Delivered Energy Consumption by End-Use							
Space Heating	5.01	5.66	5.67	5.86	5.89	5.96	6.01
Space Cooling	0.52	0.60	0.60	0.59	0.60	0.59	0.61
Water Heating	2.19	2.23	2.23	2.14	2.16	2.13	2.17
Refrigeration	0.42	0.34	0.34	0.32	0.32	0.33	0.33
Cooking	0.33	0.36	0.36	0.39	0.39	0.40	0.40
Clothes Dryers	0.28	0.33	0.33	0.34	0.35	0.35	0.36
Freezers	0.11	0.09	0.09	0.09	0.09	0.09	0.09
Lighting	0.74	0.91	0.92	0.81	0.87	0.74	0.82
Clothes Washers	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers	0.02	0.02	0.02	0.03	0.03	0.03	0.03
Color Televisions	0.13	0.19	0.19	0.24	0.24	0.24	0.25
Personal Computers	0.06	0.08	0.08	0.10	0.10	0.11	0.11
Furnace Fans	0.07	0.09	0.09	0.09	0.09	0.10	0.10
Other Uses[7]	1.01	1.45	1.45	1.76	1.78	1.94	1.95
Delivered Energy	**10.94**	**12.38**	**12.39**	**12.80**	**12.96**	**13.06**	**13.27**
Electricity Related Losses	**9.15**	**10.11**	**10.26**	**9.29**	**9.73**	**9.26**	**9.87**
Total Energy Consumption by End-Use							
Space Heating	5.89	6.61	6.62	6.70	6.77	6.78	6.88
Space Cooling	1.68	1.83	1.85	1.68	1.74	1.67	1.74
Water Heating	3.20	3.20	3.21	2.84	2.90	2.74	2.82
Refrigeration	1.36	1.05	1.06	0.91	0.93	0.93	0.94
Cooking	0.55	0.59	0.59	0.61	0.62	0.63	0.64
Clothes Dryers	0.78	0.84	0.84	0.80	0.82	0.81	0.84
Freezers	0.36	0.27	0.28	0.25	0.25	0.25	0.26
Lighting	2.40	2.81	2.84	2.31	2.52	2.09	2.36
Clothes Washers	0.10	0.10	0.10	0.08	0.08	0.08	0.08
Dishwashers	0.07	0.07	0.07	0.08	0.08	0.08	0.08
Color Televisions	0.43	0.60	0.60	0.67	0.69	0.68	0.71
Personal Computers	0.19	0.25	0.25	0.29	0.30	0.32	0.32
Furnace Fans	0.23	0.26	0.27	0.27	0.27	0.27	0.28
Other Uses[7]	2.86	4.03	4.07	4.59	4.73	4.99	5.18
Total	**20.08**	**22.50**	**22.65**	**22.09**	**22.69**	**22.32**	**23.14**
Non-Marketed Renewables							
Geothermal[8]	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar[9]	0.03	0.03	0.03	0.04	0.04	0.04	0.04
Total	**0.03**	**0.04**	**0.04**	**0.05**	**0.05**	**0.06**	**0.06**

[1] Does not include electric water heating portion of load.

[2] Includes small electric devices, heating elements, and motors.

[3] Includes such appliances as swimming pool heaters, outdoor grills, and outdoor lighting (natural gas).

[4] Includes such appliances as swimming pool and hot tub heaters.

[5] Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 1997*.

[6] Includes kerosene and coal.

[7] Includes all other uses listed above.

[8] Includes primary energy displaced by geothermal heat pumps in space heating and cooling applications.

[9] Includes primary energy displaced by solar thermal water heaters and electricity generated using photovoltaics.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J7. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		S. 139 Case	No Geologic Sequestration and New Nuclear	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Key Indicators							
Total Floorspace (billion square feet)							
Surviving	66.6	79.0	79.0	90.8	90.9	97.1	97.0
New Additions	3.6	3.0	3.0	3.4	3.4	3.4	3.4
Total	**70.2**	**82.0**	**82.0**	**94.2**	**94.3**	**100.6**	**100.4**
Energy Consumption Intensity (thousand Btu per square foot)							
Delivered Energy Consumption	118.4	117.1	117.2	115.6	116.2	118.6	118.0
Electricity Related Losses	129.9	125.6	127.2	110.6	114.9	107.6	113.5
Total Energy Consumption	248.3	242.7	244.3	226.1	231.0	226.2	231.4
Delivered Energy Consumption by Fuel							
Purchased Electricity							
Space Heating[1]	0.14	0.15	0.15	0.14	0.14	0.13	0.13
Space Cooling[1]	0.43	0.42	0.42	0.41	0.42	0.40	0.41
Water Heating[1]	0.15	0.15	0.15	0.14	0.15	0.13	0.14
Ventilation	0.17	0.18	0.18	0.17	0.17	0.16	0.17
Cooking	0.03	0.03	0.03	0.03	0.03	0.02	0.02
Lighting	1.02	1.18	1.18	0.99	1.04	0.88	0.94
Refrigeration	0.21	0.24	0.24	0.24	0.24	0.23	0.24
Office Equipment (PC)	0.16	0.24	0.24	0.31	0.31	0.34	0.35
Office Equipment (non-PC)	0.31	0.47	0.47	0.72	0.73	0.87	0.88
Other Uses[2]	1.46	1.90	1.90	2.51	2.52	2.80	2.83
Delivered Energy	**4.08**	**4.97**	**4.96**	**5.66**	**5.76**	**5.97**	**6.11**
Natural Gas							
Space Heating[1]	1.32	1.53	1.53	1.58	1.60	1.56	1.61
Space Cooling[1]	0.01	0.02	0.02	0.03	0.03	0.03	0.03
Water Heating[1]	0.57	0.69	0.69	0.77	0.78	0.78	0.80
Cooking	0.25	0.30	0.30	0.33	0.34	0.35	0.35
Other Uses[3]	1.17	1.20	1.20	1.57	1.50	2.25	1.98
Delivered Energy	**3.33**	**3.74**	**3.74**	**4.27**	**4.25**	**4.97**	**4.77**
Distillate							
Space Heating[1]	0.17	0.23	0.23	0.27	0.25	0.28	0.26
Water Heating[1]	0.07	0.08	0.08	0.08	0.08	0.08	0.08
Other Uses[4]	0.22	0.20	0.20	0.20	0.20	0.20	0.20
Delivered Energy	**0.46**	**0.51**	**0.51**	**0.54**	**0.53**	**0.56**	**0.54**
Other Fuels[5]	**0.34**	**0.29**	**0.28**	**0.31**	**0.31**	**0.32**	**0.31**
Marketed Renewable Fuels							
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Delivered Energy	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Delivered Energy Consumption by End-Use							
Space Heating[1]	1.63	1.92	1.92	1.98	2.00	1.97	2.00
Space Cooling[1]	0.44	0.44	0.44	0.44	0.45	0.43	0.44
Water Heating[1]	0.79	0.92	0.92	0.99	1.00	0.99	1.02
Ventilation	0.17	0.18	0.18	0.17	0.17	0.16	0.17
Cooking	0.29	0.33	0.33	0.36	0.36	0.37	0.38
Lighting	1.02	1.18	1.18	0.99	1.04	0.88	0.94
Refrigeration	0.21	0.24	0.24	0.24	0.24	0.23	0.24
Office Equipment (PC)	0.16	0.24	0.24	0.31	0.31	0.34	0.35
Office Equipment (non-PC)	0.31	0.47	0.47	0.72	0.73	0.87	0.88
Other Uses[6]	3.30	3.69	3.69	4.69	4.63	5.68	5.43
Delivered Energy	**8.32**	**9.60**	**9.60**	**10.89**	**10.95**	**11.92**	**11.84**

Table J7. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Electricity Related Losses	**9.12**	**10.30**	**10.43**	**10.42**	**10.83**	**10.82**	**11.39**
Total Energy Consumption by End-Use							
Space Heating[1]	1.95	2.24	2.24	2.24	2.27	2.20	2.25
Space Cooling[1]	1.39	1.32	1.33	1.21	1.25	1.15	1.21
Water Heating[1]	1.12	1.24	1.25	1.25	1.28	1.23	1.27
Ventilation	0.55	0.55	0.56	0.48	0.50	0.45	0.48
Cooking	0.37	0.40	0.40	0.41	0.42	0.41	0.42
Lighting	3.31	3.62	3.65	2.80	3.00	2.48	2.69
Refrigeration	0.69	0.73	0.73	0.68	0.70	0.66	0.69
Office Equipment (PC)	0.52	0.74	0.75	0.88	0.90	0.96	0.99
Office Equipment (non-PC)	0.99	1.43	1.45	2.06	2.10	2.45	2.53
Other Uses[6]	6.56	7.63	7.68	9.31	9.37	10.76	10.70
Total	**17.44**	**19.90**	**20.03**	**21.31**	**21.78**	**22.74**	**23.23**
Non-Marketed Renewable Fuels							
Solar[7]	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Total	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

[1] Includes fuel consumption for district services.

[2] Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.

[3] Includes miscellaneous uses, such as pumps, emergency electric generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.

[4] Includes miscellaneous uses, such as cooking, emergency electric generators, and combined heat and power in commercial buildings.

[5] Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.

[6] Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, lighting, emergency electric generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.

[7] Includes primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.

Btu = British thermal unit.

PC = Personal computer.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J8. Industrial Sector Key Indicators and Consumption

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Key Indicators							
Value of Shipments (billion 1996 dollars)							
Manufacturing	4079	5420	5430	7160	7180	8162	8211
Nonmanufacturing	1346	1500	1502	1714	1720	1828	1841
Total	**5425**	**6920**	**6932**	**8874**	**8901**	**9990**	**10051**
Energy Prices (2001 dollars per million Btu)							
Electricity	14.13	14.34	14.05	18.65	17.28	20.86	19.23
Natural Gas	4.87	5.23	4.95	7.20	6.55	8.19	7.47
Steam Coal	1.46	3.38	3.01	5.67	4.88	6.64	5.56
Residual Oil	3.28	5.34	5.02	7.49	6.77	8.46	7.48
Distillate Oil	6.55	7.27	6.96	9.70	9.15	10.89	10.03
Liquefied Petroleum Gas	12.34	10.93	10.77	13.19	13.00	14.38	13.53
Motor Gasoline	11.57	12.94	12.66	14.49	13.87	15.28	14.51
Metallurgical Coal	1.69	3.50	3.12	5.91	5.04	6.92	5.75
Energy Consumption[1]							
Purchased Electricity	3.39	3.89	3.90	4.41	4.46	4.66	4.73
Natural Gas	7.74	9.16	9.15	10.36	10.30	11.09	10.97
Lease and Plant Fuel[2]	1.20	1.40	1.39	1.70	1.68	1.77	1.74
Natural Gas Subtotal	8.94	10.56	10.54	12.06	11.97	12.86	12.71
Steam Coal	1.42	1.33	1.36	1.28	1.31	1.26	1.31
Metallurgical Coal and Coke[3]	0.74	0.76	0.76	0.65	0.66	0.60	0.61
Residual Fuel	0.23	0.18	0.18	0.17	0.17	0.17	0.18
Distillate	1.13	1.20	1.20	1.30	1.31	1.36	1.37
Liquefied Petroleum Gas	2.10	2.54	2.54	2.99	3.04	3.14	3.21
Petrochemical Feedstocks	1.14	1.41	1.41	1.53	1.54	1.57	1.59
Other Petroleum[4]	4.18	4.34	4.36	4.27	4.36	4.32	4.42
Renewables[5]	1.82	2.21	2.21	2.74	2.75	3.02	3.02
Delivered Energy	**25.10**	**28.41**	**28.46**	**31.40**	**31.56**	**32.96**	**33.17**
Electricity Related Losses	7.57	8.06	8.19	8.12	8.39	8.45	8.82
Total	**32.67**	**36.47**	**36.65**	**39.53**	**39.95**	**41.40**	**41.99**
Energy Consumption per dollar of Shipments[1] (thousand Btu per 1996 dollars)							
Purchased Electricity	0.83	0.717	0.71782	0.61624	0.62155	0.57096	0.5766
Natural Gas	1.89	1.68959	1.68437	1.44691	1.43382	1.35862	1.33617
Lease and Plant Fuel[2]	0.29	0.25864	0.25643	0.23789	0.23372	0.2167	0.21203
Natural Gas Subtotal	2.19	1.94823	1.9408	1.6848	1.66753	1.57533	1.5482
Steam Coal	0.34	0.24622	0.25023	0.17867	0.18299	0.15448	0.15949
Metallurgical Coal and Coke[3]	0.18	0.1401	0.14027	0.0908	0.0914	0.0741	0.0747
Residual Fuel	0.05	0.0324	0.0326	0.0241	0.0244	0.0209	0.0214
Distillate	0.27	0.22125	0.22136	0.18148	0.1819	0.16687	0.16733
Liquefied Petroleum Gas	0.51	0.46937	0.46825	0.41787	0.4228	0.38417	0.39141
Petrochemical Feedstocks	0.27	0.25974	0.25996	0.2131	0.21432	0.19233	0.19368
Other Petroleum[4]	1.02	0.80098	0.80344	0.59607	0.60653	0.52874	0.53847
Renewables[5]	0.44	0.40744	0.40713	0.38298	0.3824	0.36975	0.3683
Delivered Energy	**6.15**	**5.24274**	**5.24182**	**4.38613**	**4.39574**	**4.03765**	**4.03953**
Electricity Related Losses	1.85	1.48702	1.50773	1.13421	1.16799	1.03496	1.07404
Total	**8.00**	**6.72976**	**6.74955**	**5.52034**	**5.56373**	**5.07262**	**5.11357**

[1] Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Represents natural gas used in the field gathering and processing plant machinery.

[3] Includes net coal coke imports.

[4] Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.

[5] Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline and distillate are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 coal prices are based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 natural gas prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 consumption values based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 shipments: Global Insight macroeconomic model CTL0802. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J9. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Key Indicators							
Level of Travel (billions)							
Light-Duty Vehicles <8,500 pounds (VMT)	2409	2975	2989	3547	3620	3795	3903
Commercial Light Trucks (VMT)[1]	66	83	83	104	105	115	117
Freight Trucks >10,000 pounds (VMT)	206	263	263	335	336	377	378
Air (seat miles available)	1109	1348	1352	1928	1932	2231	2239
Rail (ton miles traveled)	1448	1579	1609	1467	1583	1486	1612
Domestic Shipping (ton miles traveled)	788	869	872	950	960	992	1001
Energy Efficiency Indicators							
New Light-Duty Vehicle (miles per gallon)[2]	24.1	25.3	25.3	28.1	27.4	29.0	28.2
New Car (miles per gallon)[2]	28.1	28.8	28.7	32.6	31.8	32.9	32.1
New Light Truck (miles per gallon)[2]	20.7	22.5	22.5	24.6	24.1	25.8	25.1
Light-Duty Fleet (miles per gallon)[3]	19.8	19.6	19.6	20.9	20.8	21.8	21.4
New Commercial Light Truck (MPG)[1]	13.8	14.8	14.8	16.3	15.9	17.1	16.6
Stock Commercial Light Truck (MPG)[1]	13.7	14.3	14.3	15.4	15.3	16.2	15.9
Aircraft Efficiency (seat miles per gallon)	51.2	54.3	54.3	59.1	59.1	61.2	61.2
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.4	6.4	6.6	6.6
Rail Efficiency (ton miles per thousand Btu)	2.8	3.1	3.1	3.4	3.4	3.6	3.6
Domestic Shipping Efficiency (ton miles per thousand Btu)	2.3	2.3	2.3	2.4	2.4	2.4	2.4
Energy Use by Mode (quadrillion Btu)							
Light-Duty Vehicles	15.28	18.86	18.96	20.99	21.61	21.55	22.57
Commercial Light Trucks[1]	0.60	0.73	0.73	0.84	0.86	0.89	0.92
Freight Trucks[4]	4.68	5.88	5.88	6.94	6.98	7.55	7.60
Air[5]	3.47	3.96	3.97	5.07	5.08	5.63	5.65
Rail[6]	0.63	0.65	0.66	0.59	0.62	0.59	0.62
Marine[7]	1.45	1.49	1.49	1.56	1.57	1.60	1.60
Pipeline Fuel	0.63	0.81	0.80	1.05	1.01	1.11	1.05
Lubricants	0.19	0.21	0.22	0.26	0.26	0.28	0.28
Total	**26.94**	**32.58**	**32.69**	**37.30**	**37.98**	**39.19**	**40.29**
Energy Use by Mode (million barrels per day oil equivalent)							
Light-Duty Vehicles	8.05	9.96	10.01	11.07	11.40	11.36	11.90
Commercial Light Trucks[1]	0.32	0.38	0.38	0.45	0.45	0.47	0.48
Freight Trucks	2.05	2.59	2.59	3.09	3.10	3.37	3.39
Railroad	0.24	0.24	0.24	0.20	0.22	0.19	0.21
Domestic Shipping	0.16	0.17	0.17	0.18	0.19	0.19	0.19
International Shipping	0.34	0.33	0.33	0.34	0.34	0.34	0.34
Air[5]	1.44	1.64	1.65	2.15	2.15	2.40	2.41
Military Use	0.30	0.34	0.34	0.38	0.38	0.40	0.40
Bus Transportation	0.12	0.13	0.13	0.13	0.13	0.13	0.13
Rail Transportation[6]	0.05	0.06	0.06	0.08	0.08	0.08	0.08
Recreational Boats	0.16	0.18	0.18	0.19	0.19	0.20	0.20
Lubricants	0.09	0.10	0.10	0.12	0.12	0.13	0.13
Pipeline Fuel	0.32	0.41	0.40	0.53	0.51	0.56	0.53
Total	**13.64**	**16.54**	**16.60**	**18.90**	**19.26**	**19.83**	**20.40**

[1] Commercial trucks 8,500 to 10,000 pounds.
[2] Environmental Protection Agency rated miles per gallon.
[3] Combined car and light truck "on-the-road" estimate.
[4] Includes energy use by buses and military distillate consumption.
[5] Includes jet fuel and aviation gasoline.
[6] Includes passenger rail.
[7] Includes military residual fuel use and recreational boats.
Btu = British thermal unit.
VMT=Vehicle miles traveled.
MPG = Miles per gallon.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001: Energy Information Administration (EIA), *Natural Gas Annual 2000*, DOE/EIA-0131(2000) (Washington, DC, November 2001); Federal Highway Administration, *Highway Statistics 2000* (Washington, DC, November 2001); Oak Ridge National Laboratory, Transportation Energy Data Book: *Edition 22 and Annual* (Oak Ridge, TN, September 2002); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, February 2000); EIA, *Household Vehicle Energy Consumption 1994*, DOE/EIA-0464(94) (Washington, DC, August 1997); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey" EC97TV (Washington, DC, October 1999); EIA, *Describing Current and Potential Markets for Alternative-Fuel Vehicles*, DOE/EIA-0604(96) (Washington, DC, March 1996); EIA, *Alternatives to Traditional Transportation Fuels 1998*, http://www.eia.doe.gov/cneaf/alt_trans98/table1.html; EIA,*State Energy Data Report 1999*, DOE/EIA-0214(99) (Washington, DC, May 2001); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2001/2000* (Washington, DC, 2001); EIA, *Fuel Oil and Kerosene Sales 2001*, http://www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/historical/foks.html; and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J10. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Generation by Fuel Type							
Electric Power Sector[1]							
Power Only[2]							
Coal	1848	1927	2021	836	1221	526	923
Petroleum	113	19	22	11	14	13	20
Natural Gas[3]	411	811	753	1745	1610	1889	1670
Nuclear Power	769	801	801	934	935	1186	1186
Pumped Storage/Other	-9	-1	-1	-1	-1	-1	-1
Renewable Sources[4]	258	517	479	991	837	1122	1066
Distributed Generation (Natural Gas)	0	5	4	13	10	13	11
Non-Utility Generation for Own Use	-21	-26	-27	-26	-26	-25	-26
Total	**3370**	**4053**	**4053**	**4503**	**4600**	**4725**	**4848**
Combined Heat and Power[5]							
Coal	33	30	31	16	21	10	18
Petroleum	7	3	3	3	3	3	3
Natural Gas	124	161	168	131	127	115	126
Renewable Sources	5	4	4	4	4	4	4
Non-Utility Generation for Own Use	-9	-18	-18	-17	-17	-16	-16
Total	**162**	**181**	**189**	**138**	**138**	**116**	**134**
Net Available to the Grid	**3532**	**4234**	**4242**	**4641**	**4738**	**4841**	**4982**
End-Use Sector Generation							
Combined Heat and Power[6]							
Coal	23	23	23	23	23	23	23
Petroleum	6	6	6	6	6	6	6
Natural Gas	84	122	118	201	180	328	272
Other Gaseous Fuels[7]	6	7	7	7	7	7	7
Renewable Sources[4]	31	39	40	50	50	55	55
Other[8]	11	11	11	11	11	11	11
Total	**160**	**209**	**205**	**298**	**277**	**431**	**376**
Other End-Use Generators[9]	4	5	5	6	6	7	7
Generation for Own Use	-138	-173	-170	-241	-226	-328	-294
Total Sales to the Grid	**27**	**41**	**40**	**63**	**57**	**110**	**89**
Net Imports	**20**	**41**	**41**	**48**	**43**	**31**	**22**
Electricity Sales by Sector							
Residential	1201	1429	1431	1479	1518	1498	1553
Commercial	1197	1455	1455	1659	1689	1750	1792
Industrial	994	1139	1142	1293	1308	1366	1388
Transportation	22	27	27	35	35	39	40
Total	**3414**	**4050**	**4055**	**4467**	**4550**	**4653**	**4773**
End-Use Prices[10] (2001 cents per kilowatthour)							
Residential	8.7	8.2	8.1	10.3	9.7	11.4	10.5
Commercial	7.9	7.3	7.2	9.4	8.9	10.6	9.8
Industrial	4.8	4.9	4.8	6.4	5.9	7.1	6.6
Transportation	7.5	7.1	7.0	8.3	7.8	8.9	8.3
All Sectors Average	**7.3**	**7.0**	**6.9**	**8.8**	**8.3**	**9.8**	**9.1**
Prices by Service Category[10] (2001 cents per kilowatthour)							
Generation	4.7	4.4	4.3	6.1	5.6	7.1	6.5
Transmission	0.5	0.6	0.6	0.7	0.7	0.8	0.7
Distribution	2.0	2.0	2.0	2.0	2.0	2.0	2.0

Table J10. Electricity Supply, Disposition, Prices, and Emissions (Continued)

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Emissions							
Sulfur Dioxide (million tons)	10.63	9.84	9.91	5.87	8.95	1.93	7.36
Nitrogen Oxide (million tons)	4.75	3.50	3.67	1.48	2.24	0.67	1.70
Mercury (tons)	53.52	48.66	50.83	19.07	30.51	7.18	22.89

[1] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes plants that only produce electricity.

[3] Includes electricity generation from fuel cells.

[4] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.

[5] Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).

[6] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[7] Other gaseous fuels include refinery and still gas.

[8] Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.

[9] Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[10] Prices represent average revenue per kilowatthour.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Source: 2001 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and supporting databases. 2001 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2001 prices: EIA, National Energy Modeling System run MLBILL.D050503A. **Projections**: EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A and OFFSET50.D052303A.

Table J11. Electricity Generating Capacity

(Gigawatts)

Net Summer Capacity[1]	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Electric Power Sector[2]							
Power Only[3]							
Coal Steam	305.3	289.0	290.4	209.3	233.9	139.9	198.2
Other Fossil Steam[4]	133.8	80.7	79.3	64.8	60.2	53.0	59.6
Combined Cycle	43.2	175.9	165.5	319.1	303.3	374.1	322.2
Combustion Turbine/Diesel	97.6	123.2	126.2	121.4	125.2	118.2	127.0
Nuclear Power[5]	98.2	100.3	100.3	117.2	117.3	149.2	149.3
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.2	0.2	0.2	0.2
Renewable Sources[6]	90.4	129.0	117.8	225.0	197.4	245.6	232.7
Distributed Generation[7]	0.0	1.7	1.7	4.9	6.3	5.0	9.0
Total	**788.3**	**920.2**	**901.7**	**1082.2**	**1064.2**	**1105.4**	**1118.5**
Combined Heat and Power[8]							
Coal Steam	5.2	4.4	4.5	3.3	3.6	2.6	3.1
Other Fossil Steam[4]	1.2	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	22.6	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	4.6	5.3	5.3	5.3	5.3	5.3	5.3
Renewable Sources[6]	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**33.7**	**44.0**	**44.1**	**42.9**	**43.2**	**42.2**	**42.7**
Total Electric Power Industry	**822.0**	**964.2**	**945.9**	**1125.1**	**1107.4**	**1147.6**	**1161.2**
Cumulative Planned Additions[9]							
Coal Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	83.1	83.1	83.1	83.1	83.1	83.1
Combustion Turbine/Diesel	0.0	31.5	31.5	31.5	31.5	31.5	31.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.1	0.2	0.2	0.2	0.2
Renewable Sources[6]	0.0	4.9	4.9	6.5	6.5	6.6	6.6
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**120.0**	**120.0**	**121.7**	**121.7**	**121.8**	**121.8**
Cumulative Unplanned Additions[9]							
Coal Steam	0.0	0.0	0.0	12.2	1.8	37.7	5.0
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	59.7	49.2	203.0	187.0	259.6	205.9
Combustion Turbine/Diesel	0.0	3.7	5.4	3.7	7.4	3.7	9.2
Nuclear Power	0.0	0.0	0.0	16.5	16.6	48.5	48.6
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	33.3	22.1	127.8	100.2	148.2	135.3
Distributed Generation[7]	0.0	1.7	1.7	4.9	6.3	5.0	9.0
Total	**0.0**	**98.4**	**78.5**	**368.1**	**319.3**	**502.8**	**413.1**
Cumulative Total Additions	**0.0**	**218.4**	**198.5**	**489.8**	**440.9**	**624.6**	**534.9**
Cumulative Retirements[10]							
Coal Steam	0.0	17.2	15.6	110.2	74.8	205.8	114.3
Other Fossil Steam[4]	0.0	51.6	53.0	67.5	72.1	79.3	72.7
Combined Cycle	0.0	0.9	0.7	0.9	0.7	2.6	0.7
Combustion Turbine/Diesel	0.0	9.1	7.9	10.9	10.8	14.2	10.8
Nuclear Power	0.0	0.8	0.8	1.8	1.8	1.8	1.8
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**79.7**	**78.1**	**191.4**	**160.3**	**303.8**	**200.4**

Table J11. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
End-Use Sector							
Combined Heat and Power[11]							
Coal	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Petroleum	0.9	1.0	1.0	1.0	1.0	1.0	1.0
Natural Gas	14.6	19.4	18.8	30.1	27.3	48.7	40.2
Other Gaseous Fuels	2.1	2.2	2.2	2.2	2.2	2.2	2.2
Renewable Sources[6]	4.7	6.2	6.2	8.0	8.0	8.9	8.9
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.8**	**34.2**	**33.6**	**46.7**	**43.9**	**66.2**	**57.8**
Other End-Use Generators[12]							
Renewable Sources[13]	1.1	1.5	1.5	1.9	1.8	2.2	2.2
Cumulative Additions[9]							
Combined Heat and Power[11]	0.0	6.4	5.9	19.0	16.2	38.5	30.1
Other End-Use Generators[12]	0.0	0.4	0.4	0.7	0.7	1.1	1.1

[1] Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3] Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4] Includes oil-, gas-, and dual-fired capability.
[5] Nuclear capacity reflects operating capacity of existing units, including 4.3 gigawatts of uprates through 2025.
[6] Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[7] Primarily peak-load capacity fueled by natural gas
[8] Includes combined heat and power plants whose primary business is to sell electricity and heat to the public(i.e., those that report NAICS code 22).
[9] Cumulative additions after December 31, 2001.
[10] Cumulative total retirements after December 31, 2001.
[11] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[12] Other end-use generators include small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[13] See Table J17 for more detail.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model estimates and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with capability for electric utility generators.

Source: 2001 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J12. Petroleum Supply and Disposition Balance

(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Crude Oil							
Domestic Crude Production[1]	5.80	5.63	5.64	5.41	5.41	5.27	5.26
Alaska	0.97	0.64	0.64	1.23	1.23	1.17	1.17
Lower 48 States	4.84	4.99	4.99	4.18	4.18	4.09	4.09
Net Imports	9.31	11.40	11.39	12.35	12.37	12.72	12.76
Gross Imports	9.33	11.46	11.45	12.40	12.42	12.77	12.81
Exports	0.02	0.06	0.06	0.05	0.05	0.05	0.05
Other Crude Supply[2]	0.02	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.13**	**17.03**	**17.02**	**17.76**	**17.78**	**17.99**	**18.02**
Natural Gas Plant Liquids	**1.87**	**2.27**	**2.25**	**2.63**	**2.57**	**2.69**	**2.62**
Other Inputs[3]	**0.30**	**0.43**	**0.43**	**0.36**	**0.37**	**0.35**	**0.35**
Refinery Processing Gain[4]	**0.90**	**0.89**	**0.90**	**0.94**	**0.95**	**0.93**	**0.95**
Net Product Imports[5]	**1.59**	**1.89**	**2.00**	**3.42**	**3.89**	**4.22**	**4.95**
Gross Refined Product Imports[6]	2.08	2.32	2.38	3.40	3.87	4.26	5.01
Unfinished Oil Imports	0.38	0.55	0.61	1.06	1.07	1.01	1.01
Ether Imports	0.08	0.00	0.00	0.00	0.00	0.00	0.00
Exports	0.95	0.98	0.99	1.03	1.04	1.05	1.07
Total Primary Supply[7]	**19.80**	**22.52**	**22.60**	**25.10**	**25.55**	**26.17**	**26.90**
Refined Petroleum Products Supplied							
Motor Gasoline[8]	8.67	10.42	10.47	11.47	11.79	11.76	12.29
Jet Fuel[9]	1.66	1.89	1.89	2.42	2.43	2.69	2.70
Distillate Fuel[10]	3.81	4.57	4.58	5.19	5.23	5.54	5.60
Residual Fuel	0.97	0.54	0.55	0.52	0.53	0.53	0.55
Other[11]	4.58	5.12	5.13	5.50	5.58	5.66	5.77
Total	**19.69**	**22.53**	**22.62**	**25.11**	**25.57**	**26.18**	**26.91**
Refined Petroleum Products Supplied							
Residential and Commercial	1.21	1.18	1.18	1.16	1.15	1.15	1.13
Industrial[12]	4.67	5.21	5.22	5.62	5.70	5.79	5.92
Transportation	13.27	16.02	16.09	18.25	18.62	19.14	19.74
Electric Power[13]	0.55	0.12	0.13	0.08	0.10	0.09	0.12
Total	**19.69**	**22.53**	**22.62**	**25.11**	**25.57**	**26.18**	**26.91**
Discrepancy[14]	**0.10**	**-0.02**	**-0.02**	**-0.01**	**-0.01**	**-0.01**	**-0.01**
World Oil Price (2001 dollars per barrel)[15]	**22.01**	**23.77**	**23.77**	**24.15**	**24.15**	**24.58**	**24.58**
Import Share of Product Supplied	**0.55**	**0.59**	**0.59**	**0.63**	**0.64**	**0.65**	**0.66**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2001 dollars)	**89.20**	**117.95**	**118.91**	**144.08**	**149.83**	**158.78**	**168.23**
Domestic Refinery Distillation Capacity[16]	**16.8**	**18.7**	**18.7**	**19.1**	**19.1**	**19.3**	**19.4**
Capacity Utilization Rate (percent)	**93.0**	**92.8**	**92.8**	**94.5**	**94.6**	**94.6**	**94.6**

[1] Includes lease condensate.

[2] Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude products supplied.

[3] Includes alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.

[4] Represents volumetric gain in refinery distillation and cracking processes.

[5] Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.

[6] Includes other hydrocarbons, alcohols, and blending components.

[7] Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.

[8] Includes ethanol and ethers blended into gasoline.

[9] Includes only kerosene type.

[10] Includes distillate and kerosene.

[11] Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.

[12] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[13] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[14] Balancing item. Includes unaccounted for supply, losses, and gains.

[15] Average refiner acquisition cost for imported crude oil.

[16] End-of-year capacity.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). Other 2001 data: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J13. Petroleum Product Prices

(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
World Oil Price (2001 dollars per barrel)	**22.01**	**23.77**	**23.77**	**24.15**	**24.15**	**24.58**	**24.58**
Delivered Sector Product Prices							
Residential							
Distillate Fuel	124.6	110.3	110.1	114.2	116.0	119.0	119.1
Liquefied Petroleum Gas	127.3	119.8	120.9	123.9	127.6	128.3	128.1
Commercial							
Distillate Fuel	88.7	78.0	77.9	82.6	84.4	87.3	87.7
Residual Fuel	51.8	58.9	58.9	59.3	59.4	60.2	60.3
Residual Fuel (2001 dollars per barrel)	21.75	24.73	24.76	24.92	24.94	25.30	25.32
Industrial[1]							
Distillate Fuel	90.8	79.2	79.1	85.7	87.4	90.6	91.3
Liquefied Petroleum Gas	105.9	82.2	83.1	87.0	90.4	91.0	90.5
Residual Fuel	49.1	54.7	54.8	55.4	55.4	56.4	56.4
Residual Fuel (2001 dollars per barrel)	20.61	22.99	23.01	23.26	23.27	23.67	23.69
Transportation							
Diesel Fuel (distillate)[2]	139.4	162.4	157.7	182.6	174.7	199.3	185.6
Jet Fuel[3]	83.7	95.9	91.9	125.0	117.3	139.7	127.8
Motor Gasoline[4]	143.3	160.8	157.3	179.9	172.2	189.6	180.1
Liquid Petroleum Gas	145.2	140.3	139.4	157.0	155.4	164.3	156.4
Residual Fuel	58.4	77.8	73.0	110.1	99.2	124.5	109.8
Residual Fuel (2001 dollars per barrel)	24.52	32.66	30.64	46.25	41.68	52.31	46.10
Electric Power[5]							
Distillate Fuel	86.0	69.5	69.3	74.7	76.3	78.2	78.7
Residual Fuel	67.4	64.2	63.1	73.1	70.3	74.6	71.1
Residual Fuel (2001 dollars per barrel)	28.30	26.98	26.50	30.71	29.54	31.31	29.84
Refined Petroleum Product Prices[6]							
Distillate Fuel	127.0	142.1	138.7	160.6	155.2	175.3	165.0
Jet Fuel[3]	83.7	95.9	91.9	125.0	117.3	139.7	127.8
Liquefied Petroleum Gas	110.3	89.4	90.3	93.8	97.0	97.8	97.0
Motor Gasoline[4]	143.4	160.6	157.2	179.4	171.9	189.1	179.7
Residual Fuel	61.5	71.7	68.3	96.1	87.8	106.5	95.1
Residual Fuel (2001 dollars per barrel)	25.85	30.13	28.68	40.35	36.86	44.75	39.93
Average	**123.6**	**137.0**	**134.1**	**154.1**	**148.8**	**164.3**	**156.0**
Greenhouse Gas Allowance Cost							
Commercial							
Distillate Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residual Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residual Fuel (2001 dollars per barrel)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[1]							
Distillate Fuel	0.0	21.6	17.5	48.9	39.5	60.5	47.8
Liquefied Petroleum Gas	0.0	11.6	9.4	26.1	21.2	32.4	25.6
Residual Fuel	0.0	25.1	20.3	56.8	46.0	70.3	55.5
Residual Fuel (2001 dollars per barrel)	0.00	10.55	8.54	23.86	19.30	29.53	23.33
Electric Power[5]							
Distillate Fuel	0.0	21.6	17.5	48.9	39.5	60.5	47.8
Residual Fuel	0.0	25.1	20.3	56.8	46.0	70.3	55.5
Residual Fuel (2001 dollars per barrel)	0.00	10.55	8.54	23.86	19.30	29.53	23.33

Table J13. Petroleum Product Prices (Continued)

(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Delivered Sector Product Prices with Greenhouse Gas Allowance Cost							
Commercial							
Distillate Fuel	88.7	78.0	77.9	82.6	84.4	87.3	87.7
Residual Fuel	51.8	58.9	58.9	59.3	59.4	60.2	60.3
Residual Fuel (2001 dollars per barrel)	21.75	24.73	24.76	24.92	24.94	25.30	25.32
Industrial[1]							
Distillate Fuel	90.8	100.8	96.5	134.6	126.9	151.0	139.1
Liquefied Petroleum Gas	105.9	93.8	92.4	113.1	111.6	123.3	116.1
Residual Fuel	49.1	79.9	75.1	112.2	101.4	126.7	112.0
Residual Fuel (2001 dollars per barrel)	20.61	33.55	31.55	47.12	42.58	53.20	47.02
Electric Power[5]							
Distillate Fuel	86.0	91.1	86.8	123.6	115.8	138.6	126.4
Residual Fuel	67.4	89.4	83.4	129.9	116.3	144.9	126.6
Residual Fuel (2001 dollars per barrel)	28.30	37.53	35.04	54.57	48.84	60.84	53.17

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[1] Includes combined heat and power, which produces electricity and other useful thermal energy.

[2] Diesel fuel containing 500 part per million (ppm) or 15 ppm sulfur. Includes Federal and State taxes while excluding county and local taxes.

[3] Kerosene-type jet fuel.

[4] Sales weighted-average price for all grades. Includes Federal, State and local taxes.

[5] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[6] Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.

Note: Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources:. 2001 prices for motor gasoline, distillate, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A: “Refiners’/Gas Plant Operators’ Monthly Petroleum Product Sales Report.” 2001 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2001 world oil price: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections**: EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J14. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Production							
Dry Gas Production[1]	19.45	22.21	22.00	26.61	26.09	27.32	26.72
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.73**	**4.85**	**4.72**	**8.80**	**7.94**	**10.87**	**9.24**
Canada	3.61	4.20	4.14	5.44	5.32	5.61	5.47
Mexico	-0.13	-0.21	-0.20	0.16	-0.00	0.66	0.34
Liquefied Natural Gas	0.26	0.86	0.78	3.21	2.62	4.60	3.42
Total Supply	**23.26**	**27.15**	**26.82**	**35.51**	**34.13**	**38.29**	**36.05**
Consumption by Sector							
Residential	4.81	5.47	5.47	5.80	5.83	6.03	6.06
Commercial	3.24	3.63	3.64	4.16	4.13	4.84	4.64
Industrial[3]	7.53	8.91	8.90	10.08	10.02	10.79	10.67
Electric Power[4]	5.30	7.20	6.90	13.00	11.74	14.03	12.15
Transportation[5]	0.01	0.06	0.06	0.09	0.09	0.10	0.10
Pipeline Fuel	0.61	0.79	0.78	1.02	0.98	1.08	1.03
Lease and Plant Fuel[6]	1.17	1.36	1.36	1.66	1.63	1.72	1.70
Total	**22.67**	**27.42**	**27.10**	**35.80**	**34.43**	**38.59**	**36.35**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.59**	**-0.26**	**-0.28**	**-0.30**	**-0.30**	**-0.30**	**-0.30**

[1] Marketed production (wet) minus extraction losses.

[2] Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

[3] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as vehicle fuel.

[6] Represents natural gas used in the field gathering and processing plant machinery.

[7] Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2001 values include net storage injections.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J15. Natural Gas Prices, Margins, and Revenue

(2001 Dollars per Thousand Cubic Feet, Unless Otherwise Noted)

Prices, Margins, and Revenue	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Source Price							
Average Lower 48 Wellhead Price[1]	4.12	3.51	3.44	3.97	3.79	4.36	4.31
Average Import Price	4.43	3.46	3.42	4.17	4.02	4.65	4.56
Average[2]	**4.17**	**3.50**	**3.44**	**4.02**	**3.85**	**4.45**	**4.38**
Delivered Prices							
Residential	9.68	7.89	7.83	8.30	8.10	8.72	8.66
Commercial	8.32	6.78	6.72	7.27	7.08	7.69	7.63
Industrial[3]	5.01	4.23	4.16	4.81	4.63	5.21	5.14
Electric Power[4]	4.87	4.14	4.06	4.88	4.67	5.29	5.16
Transportation[5]	7.87	7.45	7.42	7.94	7.81	8.30	8.29
Average[6]	**6.57**	**5.38**	**5.32**	**5.78**	**5.62**	**6.19**	**6.15**
Transmission & Distribution Margins[7]							
Residential	5.50	4.39	4.39	4.27	4.25	4.28	4.28
Commercial	4.14	3.28	3.28	3.24	3.23	3.24	3.25
Industrial[3]	0.83	0.73	0.73	0.79	0.79	0.77	0.76
Electric Power[4]	0.70	0.65	0.62	0.86	0.82	0.84	0.79
Transportation[5]	3.69	3.95	3.98	3.92	3.97	3.86	3.91
Average[6]	**2.40**	**1.88**	**1.89**	**1.76**	**1.78**	**1.75**	**1.77**
Transmission & Distribution Revenue (billion 2001 dollars)							
Residential	26.45	24.00	24.02	24.78	24.82	25.78	25.95
Commercial	13.42	11.91	11.92	13.48	13.36	15.68	15.11
Industrial[3]	6.28	6.49	6.46	7.94	7.87	8.27	8.13
Electric Power[4]	3.69	4.64	4.27	11.18	9.66	11.80	9.55
Transportation[5]	0.04	0.22	0.23	0.36	0.37	0.39	0.40
Total	**49.88**	**47.27**	**46.89**	**57.74**	**56.07**	**61.91**	**59.14**
Greenhouse Gas Allowance Cost							
Residential	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial[3]	0.00	1.15	0.93	2.59	2.10	3.21	2.54
Electric Power[4]	0.00	1.16	0.94	2.62	2.12	3.24	2.56
Transportation[5]	0.00	1.17	0.94	2.64	2.14	3.27	2.58
Average[6]	**0.00**	**0.74**	**0.59**	**1.83**	**1.45**	**2.25**	**1.74**
Delivered Prices with Greenhouse Gas Allowance Cost							
Residential	9.68	7.89	7.83	8.30	8.10	8.72	8.66
Commercial	8.32	6.78	6.72	7.27	7.08	7.69	7.63
Industrial[3]	5.01	5.37	5.09	7.40	6.73	8.42	7.67
Electric Power[4]	4.87	5.30	4.99	7.50	6.79	8.53	7.72
Transportation[5]	7.87	8.62	8.36	10.58	9.95	11.57	10.87
Average[6]	**6.57**	**6.12**	**5.92**	**7.61**	**7.07**	**8.44**	**7.89**

[1] Represents lower 48 onshore and offshore supplies.

[2] Quantity-weighted average of the average lower 48 wellhead price and the average price of imports at the U.S. border.

[3] Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[5] Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.

[6] Weighted average allowance cost. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.

[7] Within the table, "transmission and distribution" margins equal the difference between the delivered price and the source price (average of the wellhead price and the price of imports at the U.S. border) of natural gas and, thus, reflect the total cost of bringing natural gas to market. When the term "transmission and distribution" margins is used in today's natural gas market, it generally does not include the cost of independent natural gas marketers or costs associated with aggregation of supplies, provisions of storage, and other services. As used here, the term includes the cost of all services and the cost of pipeline fuel used in compressor stations.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 electric generators delivered price: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial delivered prices based on Energy Information Administration (EIA), *Manufacturing Energy Consumption Survey 1998*. 2001 residential, commercial, and transportation delivered prices, average lower 48 wellhead price, and average import price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J16. Oil and Gas Supply

Production and Supply	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Crude Oil							
Lower 48 Average Wellhead Price[1] (2001 dollars per barrel)	**22.91**	**23.56**	**23.58**	**23.65**	**23.59**	**24.11**	**24.07**
Production (million barrels per day)[2]							
U.S. Total	**5.80**	**5.63**	**5.64**	**5.41**	**5.41**	**5.27**	**5.26**
Lower 48 Onshore	3.13	2.47	2.47	2.05	2.05	1.90	1.90
Lower 48 Offshore	1.71	2.52	2.52	2.13	2.13	2.19	2.19
Alaska	0.97	0.64	0.64	1.23	1.23	1.17	1.17
Lower 48 End of Year Reserves (billion barrels)[2]	**19.48**	**17.70**	**17.71**	**15.34**	**15.34**	**14.92**	**14.88**
Natural Gas							
Lower 48 Average Wellhead Price[1] (2001 dollars per thousand cubic feet)	**4.12**	**3.51**	**3.44**	**3.97**	**3.79**	**4.36**	**4.31**
Dry Production (trillion cubic feet)[3]							
U.S. Total	**19.45**	**22.21**	**22.01**	**26.61**	**26.09**	**27.32**	**26.72**
Lower 48 Onshore	13.72	16.17	16.00	18.65	18.14	18.72	18.24
Associated-Dissolved[4]	1.77	1.36	1.36	1.19	1.19	1.13	1.13
Non-Associated	11.94	14.81	14.63	17.46	16.95	17.59	17.11
Conventional	6.54	7.32	7.19	7.37	7.21	7.13	7.20
Unconventional	5.40	7.49	7.45	10.09	9.74	10.46	9.92
Lower 48 Offshore	5.30	5.56	5.53	5.58	5.57	5.77	5.63
Associated-Dissolved[4]	1.08	0.96	0.96	0.79	0.80	0.81	0.81
Non-Associated	4.22	4.60	4.57	4.78	4.77	4.96	4.83
Alaska	0.43	0.48	0.48	2.39	2.39	2.84	2.84
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**174.04**	**185.39**	**185.51**	**195.87**	**193.96**	**192.41**	**190.87**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Total Lower 48 Wells (thousands)	**33.94**	**25.75**	**25.63**	**27.25**	**26.41**	**29.30**	**28.51**

[1] Represents lower 48 onshore and offshore supplies.

[2] Includes lease condensate.

[3] Marketed production (wet) minus extraction losses.

[4] Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).

[5] Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2001 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J17. Coal Supply, Disposition, and Prices

(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Production[1]							
Appalachia	443	415	425	212	288	145	222
Interior	147	153	161	88	120	42	98
West	548	513	547	185	276	128	213
East of the Mississippi	539	518	534	286	384	182	304
West of the Mississippi	599	563	599	199	299	132	229
Total	**1138**	**1081**	**1133**	**485**	**683**	**315**	**534**
Net Imports							
Imports	19	11	11	11	11	10	10
Exports	49	33	33	29	26	24	24
Total	**-30**	**-22**	**-22**	**-19**	**-16**	**-13**	**-13**
Total Supply[2]	**1109**	**1060**	**1111**	**466**	**668**	**301**	**520**
Consumption by Sector							
Residential and Commercial	4	5	5	5	5	6	5
Industrial[3]	63	61	62	59	60	58	60
of which: Coal to Liquids	0	0	0	0	0	0	0
Coke Plants	26	24	24	17	17	14	15
Electric Power[4]	957	966	1020	390	583	227	438
Total	**1050**	**1055**	**1111**	**471**	**667**	**306**	**519**
Discrepancy and Stock Change[5]	**58**	**4**	**1**	**-6**	**1**	**-4**	**1**
Average Minemouth Price							
(2001 dollars per short ton)	17.59	15.84	15.83	15.27	15.73	13.67	15.03
(2001 dollars per million Btu)	0.83	0.76	0.76	0.71	0.73	0.63	0.70
Delivered Prices (2001 dollars per short ton)[6]							
Industrial	32.82	30.10	30.28	24.86	26.40	22.55	24.48
Coke Plants	46.42	41.37	41.28	38.31	38.13	36.64	36.62
Electric Power							
(2001 dollars per short ton)	25.06	23.76	23.92	20.83	21.56	18.81	20.15
(2001 dollars per million Btu)	1.25	1.16	1.17	0.99	1.02	0.90	0.96
Average	**26.06**	**24.53**	**24.65**	**21.98**	**22.44**	**20.39**	**21.13**
Exports[7]	36.97	32.41	32.51	28.76	30.01	27.46	28.44
Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]							
Industrial	0.00	43.59	35.25	98.28	79.55	121.42	95.86
Coke Plants	0.00	54.74	44.28	123.76	100.11	153.14	121.00
Electric Power							
(2001 dollars per short ton)	0.00	41.32	33.35	95.21	77.40	117.30	93.24
(2001 dollars per million Btu)	0.00	2.02	1.63	4.54	3.67	5.62	4.44
Average	**0.00**	**41.76**	**33.69**	**96.65**	**78.19**	**119.82**	**94.34**
Delivered Prices with Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]							
Industrial	32.82	73.69	65.54	123.14	105.95	143.97	120.34
Coke Plants	46.42	96.11	85.56	162.07	138.24	189.79	157.62
Electric Power							
(2001 dollars per short ton)	25.06	65.08	57.27	116.04	98.96	136.11	113.39
(2001 dollars per million Btu)	1.25	3.17	2.80	5.53	4.70	6.53	5.40
Average	**26.06**	**66.29**	**58.35**	**118.63**	**100.63**	**140.21**	**115.47**

[1] Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.1 million tons in 2000 and 10.6 million tons in 2001.

[2] Production plus net imports and net storage withdrawals.

[3] Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

[4] Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[5] Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.

[6] Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.

[7] F.a.s. price at U.S. port of exit.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run MLBILL.D050503A. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J18. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Electric Power Sector[1]							
Net Summer Capacity							
Conventional Hydropower	78.10	78.66	78.66	78.65	78.65	78.65	78.65
Geothermal[2]	2.83	6.68	6.69	10.06	10.04	10.55	10.41
Municipal Solid Waste[3]	3.25	4.84	4.79	5.17	5.17	5.19	5.19
Wood and Other Biomass[4]	1.80	3.96	3.46	48.03	31.08	67.38	64.98
Solar Thermal	0.33	0.44	0.44	0.48	0.48	0.50	0.50
Solar Photovoltaic[5]	0.02	0.10	0.10	0.27	0.27	0.36	0.36
Wind	4.29	34.53	23.90	82.60	71.96	83.22	72.84
Total	**90.62**	**129.20**	**118.04**	**225.26**	**197.64**	**245.84**	**232.93**
Generation (billion kilowatthours)							
Conventional Hydropower	213.82	300.89	300.89	299.92	299.95	300.10	300.16
Geothermal[2]	13.81	44.61	44.69	73.14	72.85	77.22	76.12
Municipal Solid Waste[3]	19.55	35.17	34.81	37.63	37.63	37.83	37.85
Wood and Other Biomass[4]	9.38	27.11	24.47	304.95	182.98	429.32	404.97
Dedicated Plants	7.66	19.52	17.61	304.95	182.98	429.32	404.97
Cofiring	1.72	7.59	6.86	0.00	0.00	0.00	0.00
Solar Thermal	0.49	0.77	0.77	0.90	0.90	0.97	0.97
Solar Photovoltaic[5]	0.00	0.24	0.24	0.66	0.66	0.88	0.88
Wind	5.78	112.46	77.14	277.70	246.24	280.10	249.42
Total	**262.85**	**521.25**	**483.02**	**994.90**	**841.22**	**1126.43**	**1070.37**
End- Use Sector							
Net Summer Capacity							
Combined Heat and Power[6]							
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Biomass	4.41	5.89	5.90	7.67	7.69	8.60	8.63
Total	**4.69**	**6.17**	**6.18**	**7.95**	**7.97**	**8.88**	**8.91**
Other End-Use Generators[7]							
Conventional Hydropower[8]	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.38	0.38	0.76	0.71	1.15	1.10
Total	**1.12**	**1.47**	**1.47**	**1.85**	**1.81**	**2.25**	**2.19**
Generation (billion kilowatthours)							
Combined Heat and Power[6]							
Municipal Solid Waste	2.46	2.15	2.15	2.15	2.15	2.15	2.15
Biomass	28.67	37.31	37.35	47.72	47.84	53.13	53.30
Total	**31.13**	**39.46**	**39.50**	**49.87**	**49.99**	**55.28**	**55.45**
Other End-Use Generators[7]							
Conventional Hydropower[8]	4.23	4.23	4.23	4.23	4.23	4.23	4.23
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.82	0.82	1.61	1.53	2.42	2.31
Total	**4.25**	**5.05**	**5.05**	**5.85**	**5.76**	**6.66**	**6.55**

[1] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes hydrothermal resources only (hot water and steam).

[3] Includes landfill gas.

[4] Includes projections for energy crops after 2010.

[5] Does not include off-grid photovoltaics (PV). See Annual Energy Review 2001 Table 10.6 for estimates of 1989-2000 PV shipments, including exports, for both grid-connected and off-grid applications.

[6] Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.

[7] Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

[8] Represents own-use industrial hydroelectric power.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2003. Net summer capacity is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.

Sources: 2001 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2001 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J19. Renewable Energy Consumption by Sector and Source[1]

(Quadrillion Btu per Year)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Marketed Renewable Energy[2]							
Residential	**0.39**	**0.41**	**0.41**	**0.40**	**0.40**	**0.40**	**0.40**
Wood	0.39	0.41	0.41	0.40	0.40	0.40	0.40
Commercial	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**
Biomass	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Industrial[3]	**1.82**	**2.21**	**2.21**	**2.74**	**2.75**	**3.02**	**3.02**
Conventional Hydroelectric	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Biomass	1.77	2.16	2.16	2.69	2.70	2.97	2.98
Transportation	**0.15**	**0.26**	**0.26**	**0.28**	**0.29**	**0.29**	**0.30**
Ethanol used in E85[4]	0.00	0.00	0.00	0.00	0.00	0.01	0.01
Ethanol used in Gasoline Blending	0.15	0.26	0.26	0.28	0.29	0.28	0.30
Electric Power[5]	**3.01**	**6.30**	**5.95**	**11.42**	**10.02**	**12.69**	**12.15**
Conventional Hydroelectric	2.16	3.09	3.09	3.07	3.07	3.07	3.07
Geothermal	0.29	1.30	1.31	2.23	2.20	2.36	2.31
Municipal Solid Waste[6]	0.31	0.48	0.47	0.51	0.51	0.51	0.51
Biomass	0.15	0.31	0.29	2.78	1.69	3.89	3.67
Dedicated Plants	0.12	0.21	0.20	2.78	1.69	3.89	3.67
Cofiring	0.03	0.09	0.09	0.00	0.00	0.00	0.00
Solar Thermal	0.01	0.01	0.01	0.02	0.02	0.02	0.02
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.08	1.12	0.79	2.82	2.53	2.84	2.56
Total Marketed Renewable Energy	**5.46**	**9.28**	**8.94**	**14.95**	**13.57**	**16.50**	**15.98**
Sources of Ethanol							
From Corn	0.15	0.26	0.26	0.26	0.27	0.24	0.25
From Cellulose	0.00	0.00	0.00	0.02	0.02	0.05	0.05
Total	**0.15**	**0.26**	**0.26**	**0.28**	**0.29**	**0.29**	**0.30**
Non-Marketed Renewable Energy[7] **Selected Consumption**							
Residential	**0.03**	**0.04**	**0.04**	**0.05**	**0.05**	**0.06**	**0.06**
Solar Hot Water Heating	0.03	0.03	0.03	0.04	0.04	0.04	0.04
Geothermal Heat Pumps	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.02**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.01	0.01

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[1] Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,280 Btu per kilowatthour.

[2] Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table J8.

[3] Includes all electricity production by industrial and other combined heat and power for the grid and for own use.

[4] Excludes motor gasoline component of E85.

[5] Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

[6] Includes landfill gas.

[7] Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 electric generators: EIA, Form EIA-860: "Annual Electric Generator Report" (preliminary). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J20. Greenhouse Gas Emissions and Allowance Cost
(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Carbon Dioxide Emissions							
Residential							
Petroleum	27.2	27.6	27.6	25.8	25.7	25.0	24.9
Natural Gas	71.1	81.0	81.0	85.8	86.4	89.3	89.7
Coal	0.3	0.4	0.4	0.4	0.4	0.3	0.3
Total	**98.7**	**109.0**	**109.0**	**112.0**	**112.4**	**114.7**	**115.0**
Commercial							
Petroleum	14.0	13.7	13.7	14.5	14.2	14.8	14.4
Natural Gas	48.0	53.8	53.8	61.5	61.2	71.6	68.7
Coal	2.3	2.5	2.4	2.8	2.7	2.9	2.9
Total	**64.3**	**69.9**	**69.9**	**78.8**	**78.1**	**89.3**	**85.9**
Industrial[1]							
Petroleum	97.9	96.0	96.4	99.1	100.4	101.1	103.2
Natural Gas[2]	123.4	149.8	149.2	171.0	169.7	182.4	180.2
Coal	52.1	53.1	53.7	48.9	49.9	47.3	48.8
Total	**273.4**	**298.9**	**299.4**	**319.0**	**320.0**	**330.8**	**332.2**
Transportation							
Petroleum[3]	501.4	605.1	607.5	690.4	704.1	725.3	747.1
Natural Gas[4]	9.2	12.5	12.3	16.4	15.9	17.4	16.7
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**510.6**	**617.6**	**619.9**	**706.8**	**720.0**	**742.7**	**763.8**
Total Carbon Dioxide Emissions by Delivered Fuel							
Petroleum[3]	640.5	742.5	745.2	829.8	844.4	866.2	889.7
Natural Gas	251.7	297.0	296.4	334.8	333.1	360.7	355.3
Coal	54.7	55.9	56.6	52.0	53.0	50.5	51.9
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**947.0**	**1095.4**	**1098.2**	**1216.6**	**1230.5**	**1277.4**	**1296.9**
Electric Power[6]							
Petroleum	27.5	5.4	5.9	3.9	4.5	3.9	5.3
Natural Gas	77.7	105.0	101.3	158.0	168.9	132.6	168.8
Coal	506.4	504.4	531.4	190.0	310.8	68.3	225.7
Total	**611.6**	**614.8**	**638.6**	**351.9**	**484.2**	**204.8**	**399.9**
Total Carbon Dioxide Emissions by Primary Fuel[7]							
Petroleum[3]	668.0	747.9	751.1	833.7	848.8	870.2	894.9
Natural Gas	329.4	402.0	397.7	492.8	502.1	493.3	524.2
Coal	561.1	560.3	588.0	242.0	363.9	118.8	277.7
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1558.6**	**1710.1**	**1736.8**	**1568.5**	**1714.8**	**1482.2**	**1696.8**
Non-Energy Related Carbon Dioxide Emissions	**36.3**	**39.5**	**39.5**	**43.9**	**43.9**	**46.2**	**46.2**
Total Carbon Dioxide Emissions	**1594.9**	**1749.7**	**1776.4**	**1612.4**	**1758.7**	**1528.4**	**1743.0**
Other Greenhouse Gas Emissions	**332.9**	**286.4**	**289.6**	**339.5**	**329.6**	**362.9**	**355.0**
Methane	175.2	115.2	117.4	126.4	113.1	120.0	111.4
Nitrous Oxide	118.9	121.0	121.0	131.4	131.4	137.2	137.2
High Global Warming Potential Gases	38.8	50.2	51.2	81.8	85.2	105.8	106.4
Total Greenhouse Gas Emissions	**1927.8**	**2036.1**	**2066.0**	**1951.9**	**2088.3**	**1891.4**	**2098.0**

Table J20. Greenhouse Gas Emissions and Allowance Cost (Continued)

(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
Greenhouse Gas Emission Cap Compliance							
Covered Emissions							
Energy-Related Carbon Dioxide	1378.2	1513.1	1539.8	1357.5	1504.1	1256.9	1474.5
Other Greenhouse Gases	75.2	70.1	71.4	102.8	106.4	127.6	128.4
Offsets Purchased	0.0	234.7	217.9	126.1	339.2	125.6	346.4
Non-Covered Greenhouse Gas Offsets	0.0	48.5	46.6	34.3	47.7	39.0	47.7
U.S. Sequestration Offsets	0.0	112.8	108.5	91.8	153.2	86.5	134.1
International Offsets	0.0	73.4	62.8	0.0	138.2	0.1	164.6
Covered Emissions less Offsets	1453.4	1348.5	1393.2	1334.2	1271.3	1258.9	1256.5
Covered Emissions Coal	N/A	1465.1	1465.1	1257.9	1257.9	1257.9	1257.9
Allowance Bank Activity	0.0	116.5	71.8	-76.3	-13.4	-1.0	1.4
Cumulative Bank Balance	0.0	116.5	71.8	98.9	10.2	7.3	9.9
Allowance Cost (2001 dollars per ton)							
Emissions Allowance Cost	0.00	78.89	63.81	178.36	144.27	220.71	174.39
Offset Price	0.00	71.49	63.81	34.84	144.27	51.73	174.39

[1] Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.

[2] Includes lease and plant fuel.

[3] This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons carbon equivalent of carbon dioxide annually.

[4] Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.

[5] Includes methanol and liquid hydrogen.

[6] Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.

[7] Emissions from electric power generators are distributed to the primary fuels.

N/A = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.

Table J21. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2001	Projections					
		2010		2020		2025	
		S. 139 Case	50% Offsets	S. 139 Case	50% Offsets	S. 139 Case	50% Offsets
GDP Chain-Type Price Index (1996=1.000)	**1.094**	**1.321**	**1.320**	**1.735**	**1.726**	**2.028**	**2.007**
Potential Gross Domestic Product	**9456**	**12458**	**12458**	**16729**	**16744**	**19150**	**19187**
Real Gross Domestic Product	**9215**	**12211**	**12219**	**16364**	**16374**	**18810**	**18852**
Real Consumption	6377	8375	8382	11284	11299	12954	12982
Real Investment	1575	2478	2482	3724	3731	4447	4470
Real Government Spending	1640	1897	1896	2204	2206	2417	2421
Real Exports	1076	1781	1782	3329	3338	4621	4648
Real Imports	1492	2292	2293	4027	4049	5376	5403
Real Disposable Personal Income	**6748**	**8607**	**8611**	**11648**	**11648**	**13432**	**13425**
Federal Funds Rate (percent)	**3.89**	**5.63**	**5.59**	**6.58**	**6.42**	**6.97**	**6.72**
AA Utility Bond Rate (percent)							
Nominal	7.57	7.38	7.34	9.17	9.06	9.99	9.79
Real	5.60	5.20	5.21	6.18	6.12	6.76	6.68
Energy Intensity (thousand Btu per 1996 dollar of GDP)							
Delivered Energy	7.74	6.80	6.81	5.65	5.72	5.17	5.24
Total Energy	10.56	9.15	9.19	7.37	7.50	6.70	6.85
Consumer Price Index (1982-84=1.00)	**1.77**	**2.20**	**2.20**	**2.97**	**2.96**	**3.55**	**3.51**
Unemployment Rate (percent)	**4.79**	**4.55**	**4.54**	**6.03**	**6.03**	**5.85**	**5.83**
Housing Starts (millions)	**1.80**	**2.12**	**2.13**	**1.92**	**1.92**	**2.01**	**2.01**
Single-Family	1.27	1.31	1.32	1.11	1.11	1.11	1.11
Multifamily	0.33	0.45	0.45	0.49	0.49	0.57	0.57
Mobile Home Shipments	0.19	0.36	0.37	0.33	0.33	0.33	0.33
Commercial Floorspace, Total (billion square feet)	**70.2**	**82.0**	**82.0**	**94.2**	**94.3**	**100.6**	**100.4**
Value of Shipments (billion 1996 dollars)							
Total Industrial	5425	6920	6932	8874	8901	9990	10051
Nonmanufacturing	1346	1500	1502	1714	1720	1828	1841
Manufacturing	4079	5420	5430	7160	7180	8162	8211
Energy-Intensive Manufacturing	1086	1255	1257	1434	1438	1515	1522
Non-Energy-Intensive Manufacturing	2993	4164	4172	5726	5743	6647	6688
Unit Sales of Light-Duty Vehicles (millions)	**17.11**	**17.87**	**17.96**	**20.06**	**20.05**	**20.15**	**20.28**
Population (millions)							
Population with Armed Forces Overseas	278.2	300.2	300.2	325.3	325.3	338.2	338.2
Population (aged 16 and over)	215.4	236.6	236.6	256.5	256.5	266.6	266.6
Employment, Non-Agriculture	131.7	147.1	147.1	158.8	158.8	165.5	165.7
Employment, Manufacturing	17.5	17.7	17.7	17.7	17.8	18.4	18.5
Labor Force	141.8	156.5	156.5	169.6	169.6	177.3	177.3

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2001: Global Insight macroeconomic model CTL0802. **Projections:** Energy Information Administration, AEO2003 National Energy Modeling System runs MLBILL.D050503A and OFFSET50.D052303A.