ORIGINAL

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January 8, 2007

VIA HAND DELIVERY

Blanca S. Bayo, Director
Division of Commission Clerk and
Administrative Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0800

Re: Docket No. 060635-EU

Dear Ms. Bayo:

Attached please find the original and fifteen copies of the NRDC'S Request for Official Recognition and copies to be filed in the above styled docket.

Should you have questions or need any additional information, please contact me.

Very truly yours,

Suzanne Brownless
Attorney for NRDC

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GCL ______
OPC ______
RCA ______
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ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Petition for Determination of Need for electrical power plant in Taylor County by Florida Municipal Power Agency, JEA, Reedy Creek Improvement District, and the City of Tallahassee.
___________________________________/

DOCKET NO. 060635-EU
FILED: January 8, 2007

REQUEST FOR OFFICIAL RECOGNITION

Pursuant to §120.569(2)(i), F.S., and Order PSC-06-0819-PCO-EU, the National Resources Defense Council (NRDC) files this Request for Official Recognition and requests official recognition of the following:

1. Pursuant to §90.201, Florida Statutes:

a. Statutes

366.80- 366.85 and 403.519, Florida Statutes, Florida Energy Efficiency and Conservation Act;
403.501-403.518, Florida Statutes, Florida Electrical Power Plant Siting Act.

b. Laws of Florida

Chapter 2006-230, Committee Substitute for Committee Substitute for Committee Substitute for Senate Bill No. 888.

c. Acts of Congress

H.R. 6, Energy Policy Act of 2005

2. Pursuant to § 90.202, Florida Statutes:

a. Congressional Acts

McCain Lieberman Senate Bill 139, Climate Stewardship Act;
McCain Liberman Senate Amendment 2028, Climate Stewardship Act

b. Official Publications - Federal

Energy Information Agency, analysis of S. 139
Energy Information Agency, analysis of SA. 2028

c. Official Publications - State

Department of Environmental Protection, Whitepaper on Climate Change Science and Policy Options

d. Articles

Tallahassee Democrat, Editorial, December 29, 2006, "Carbon control DEP fires a warning shot".

Respectfully submitted this 8th day of January, 2007 by:

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been provided by electronic mail as listed and U.S. Mail, this 8th day of January, 2007 to the following:

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From: Williams, Sarah P. [Sarah.P.Williams@dep.state.fl.us]

Sent: Monday, January 08, 2007 1:26 PM

To: sbpa@comcast.net

Subject: Whitepaper

As requested...

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Department of Environmental Protection
Whitepaper on Climate Change Science and Policy Options

Introduction

The issue of global climate change involves changes in the radiative balance of the Earth – the balance between energy received from the sun and emitted from Earth – that may alter weather patterns and climates at global and regional scales. The Earth's radiative balance is influenced by variations in the sun's output and concentrations of so-called "greenhouse gases" (GHG) such as carbon dioxide (CO_2), methane (CH_4), nitrous oxides (N_2O), water vapor, and other gases which trap a portion of outgoing solar energy to retain heat. Other substances, such as carbon particulates (soot) and sulfate aerosols reflect incoming solar radiation or absorb its energy to provide a counterbalance to the effects of energy retention within the atmosphere. The net effect of these opposing forces is observable in global mean temperatures over time.

The primary objective of climate change policy is to stabilize and ultimately reduce the concentrations of greenhouse gases within the Earth's atmosphere in order to avert the presumed adverse impacts of increased global mean temperatures, altered climactic and weather patterns, and the subsequent impact on humans.

The purpose of this whitepaper is to provide a synopsis of the current science of global climate change, an overview of the potential impacts of this phenomenon to the State of Florida, and a summary of policy options for consideration in framing a GHG reduction strategy for Florida.

Current State of Climate Change Science

The body of science associated with human-induced climate change is extensive. Much of the science, particularly the results of instrument-aided observation over the past 150 years, is relatively undisputed. Because climate studies by necessity address trends over centuries or even millennia, the science associated with placing these instrument-based observations within the context of past centuries and projecting observed trends forward through modeling has been more often been disputed. The following overview of climate change science is carefully constructed from peer-reviewed studies from the most broadly accepted domestic and international policymakers.

The Global Carbon Cycle

Carbon cycles through land masses, the oceans, and the atmosphere in two primary pathways: the geological, which operates over large time scales (millions of years), and the biological/physical, which operates at shorter time scales (days to thousands of years). Of these, the biological/physical pathway is the most significant in characterizing the larger cycle. On land, the major exchange of carbon with the atmosphere results from the photosynthesis and respiration of plants and trees. During the daytime in the growing season, leaves absorb sunlight and take up CO_2 from the atmosphere. In parallel, plants, animals and soil microbes consume the carbon in organic matter and return carbon dioxide to the atmosphere. When conditions are too cold or too dry, photosynthesis and respiration cease along with the movement of carbon between the atmosphere and the land surface. The amounts of carbon that move from the atmosphere through photosynthesis, respiration, and back to the atmosphere are large and produce oscillations in atmospheric CO_2 concentrations. Over the course of a year, these biological fluxes of carbon are over ten times greater than the amount of carbon introduced to the atmosphere by fossil fuel burning.[1]

In the oceans, CO_2 exchange is largely controlled by sea surface temperatures, circulating currents, and by the biological processes of photosynthesis and respiration. Carbon dioxide dissolves easily into the ocean and the amount of CO_2 that the ocean can hold depends on ocean temperature and the amount of CO_2 already present. Cold ocean temperatures tend to uptake more CO_2 from the atmosphere while warm temperatures can cause the ocean surface to release CO_2.

In addition to the natural carbon cycle, human activities, particularly fossil fuel burning and deforestation, are also releasing CO_2 into the atmosphere. The result is that humans are adding ever-increasing amounts of extra carbon dioxide into the atmosphere. Because of this, atmospheric CO_2 concentrations are higher today than they have been over the last half-million years or longer.[2] The burning of fossil fuel globally releases about 5.5 billion tons per year into the atmosphere while deforestation contributes an estimated 1.6 billion tons per year. Measurements of atmospheric CO_2 levels since 1957 suggest that of the approximate total amount of 7.1 billion tons released per year by human activities, approximately 3.2 billion tons remain in the atmosphere, resulting in an increase in atmospheric CO_2. The balance is thought to be stored in the oceans and in the Earth's forested lands.[3]

The carbon cycle is operable within the lower atmosphere at a global scale. Emissions or sinks of carbon dioxide at any point on the planet contribute to the net concentration of the gas within the atmosphere.

Atmospheric GHG Concentrations

Over the past 150 years, CO_2 concentrations within the atmosphere have increased by 31 percent, methane by about 150 percent, and N_2O by 16 percent.[4] Based on analysis of ice core data, today's atmospheric CO_2 concentration is the greatest in 420,000 years—and likely in 20 million years.[5] From 1990 to 1999, CO_2, methane, and N_2O concentrations increased by 1.5 parts per million per year (annual increase of 0.4%), 7.0 parts per billion per year (annual increase of 0.5%), and 0.8 parts per billion per year (annual increase of 0.25%) respectively.[6] The present methane concentration has not been exceeded during

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[1] US National Aeronautics and Space Administration. "Earth Observatory: The Carbon Cycle." Available at: http://earthobservatory.nasa.gov/Library/CarbonCycle/carbon_cycle.html

[2] Ibid.

[3] Ibid.

[4] Intergovernmental Panel on Climate Change. *Climate Change 2001: The Scientific Basis. A Contribution of Working Group I to the Third Assessment Report of the IPCC*, Cambridge, UK and New York, NY: Cambridge University Press, 2001.

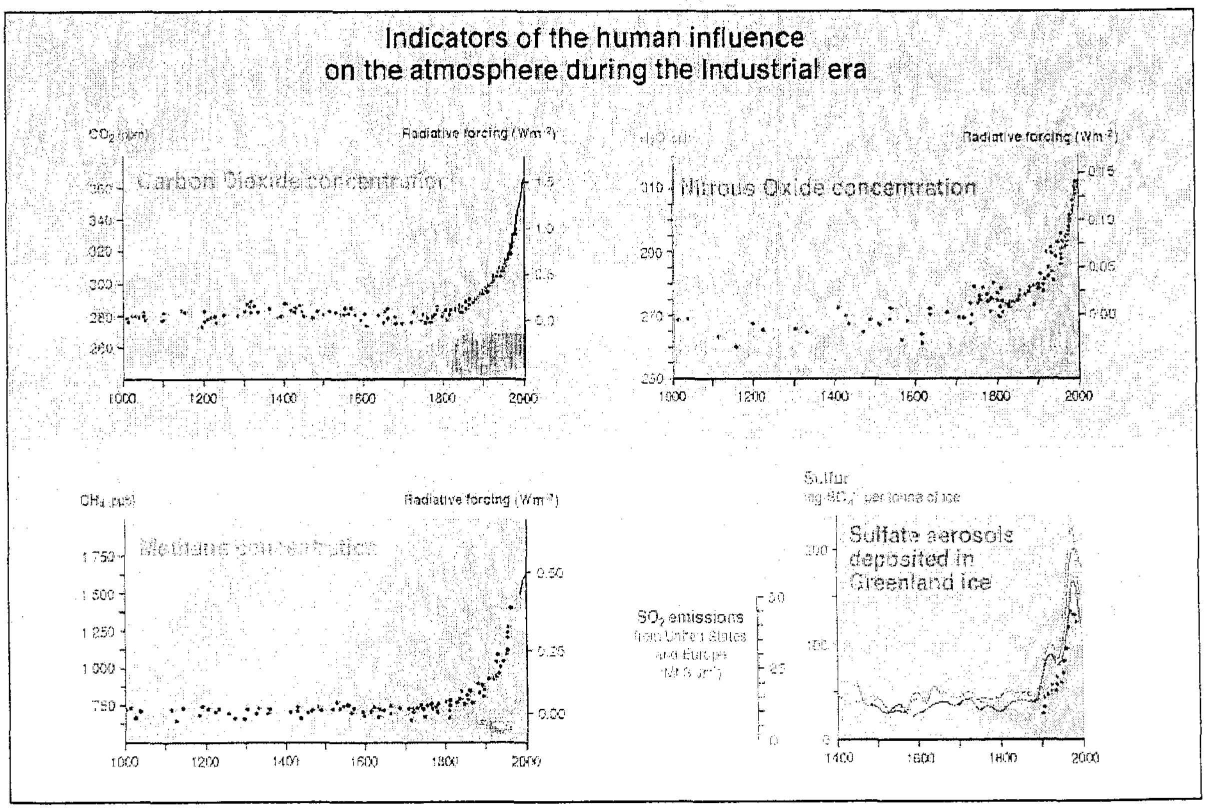
[5] IPCC. *Climate Change 2001: Synthesis Report*, 2001.

[6] IPCC. *Climate Change 2001: The Scientific Basis*, 2001. op. cit.

the past 420,000 years.[7] The present N_2O concentration has not been exceeded during at least the past thousand years.[8]

As noted previously, changes in climate occur as a result of both internal variability within the system as well as natural and human-induced external factors. The influence of external factors on climate is measured in terms of radiative forcing. A positive radiative forcing, such as that produced by increasing concentrations of greenhouse gases, tends to warm the surface. A negative radiative forcing tends to cool the surface. Negative forcing from an increase in some types of microscopic airborne particles (aerosols) are thought to have an influence on current net radiative forcing of the Earth's climate system.[9] The major sources of anthropogenic aerosols are fossil fuel and biomass burning. Aerosols vary considerably by region and respond quickly to changes in emissions. In addition to their direct radiative forcing, aerosols have an indirect radiative forcing through their effects on clouds. There is now more evidence for this indirect effect, which is negative, although of very uncertain magnitude. Figure 1 below illustrates trends in atmospheric concentrations over the last millennium.

Figure 1: Trends in Atmospheric concentrations of GHG and Sulfate Aerosols: 1000 – 2000 AD[10]



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7 Ibid.
8 Ibid.
9 Ibid.
10 Ibid.

Trends in GHG Emissions

Individual greenhouse gases have differing radiative effects once emitted because of the differing lengths of times these gases remain in the atmosphere and how well each gas absorbs outgoing radiation. To normalize the effects of key greenhouse gases, each is indexed against CO_2 to determine its "global warming potential." The global warming potentials for the six greenhouse gases addressed by the Kyoto Protocol are presented in the following table.[11]

Gas	Global Warming Potential*
Carbon dioxide (CO_2)	1
Methane (CH_4)	21
Nitrous Oxide (N_2O)	310
Hydrofluorocarbons (HFCs)	1,300 to 11,700
Perfluorocarbons (PFCs)	6,500 to 9,200
Sulfur hexafluoride (SF_6)	23,900
* The Global Warming Potential is the ratio of the warming caused by a substance to the warming caused by the same mass of carbon dioxide. It is a relative scale. For example, methane has 21 times the warming potential of carbon dioxide.[12]	

Carbon dioxide accounted for 84.7 percent of the nation's greenhouse gas emissions in 2003.[13] It results primarily from the combustion of fossil fuels used to produce electricity and to power motor vehicles as well as from a few industrial processes.[14] Forestry and other land use activities in the U.S. remove more carbon from the atmosphere than they emit, resulting in net carbon storage, called "sequestration." Methane released by landfills, coal mines, oil and gas systems, and agricultural activities accounted for 7.9 percent of the total U.S. greenhouse gas emissions in 2003.[15] Nitrous oxide is emitted during agricultural and industrial activities, and during combustion of solid waste and fossil fuels. In 2003, it accounted for 5.5 percent of the national greenhouse gas emissions.[16]

According to the 2004 Department of Energy, Energy Information Administration report[17], Florida ranks 5th in the nation for energy-related CO_2 emissions (based on energy usage). Of the total 238.8 million metric tons of carbon dioxide produced in Florida during 2001, the electric power and transportation sectors were responsible for over 90% of the emissions, respectively contributing 116.6 (49%) and 98.7 (41%) million metric tons. Florida's 2001 fossil fuel CO_2 emissions represent approximately one tenth of one percent of the global fossil fuel emissions total of 24.121 million metric tons in the

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[11] Ibid.

[12] US EPA, Climate Change Information at www.epa.gov/climate

[13] U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003*, EPA 430-R-05-003. Washington, DC: U.S. Environmental Protection Agency, Office of Atmospheric Programs, April 2005.

[14] Ibid.

[15] Ibid.

[16] Ibid.

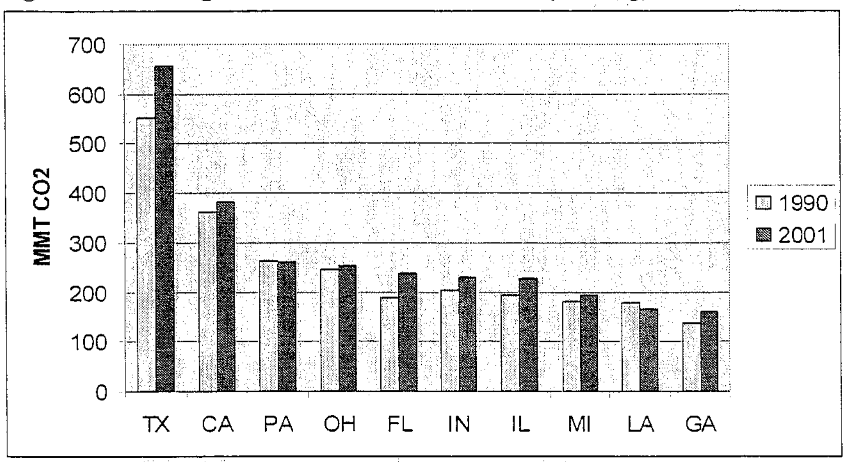
[17] U.S. Energy Information Administration. *State Carbon Dioxide Emissions: 2004.* Available at: http://www.eia.doe.gov/oiaf/1605/ggrpt/pdf/appc_tbl2.pdf

same year.[18] Florida's estimated emissions standing among the Kyoto signatory nations is presented in Appendix II of this document.

State	2001 Total CO_2 Emissions (in million metric tons)
Texas	656.1
California	383.1
Pennsylvania	261.9
Ohio	252.3
Florida	238.8

Emissions of greenhouse gases are linked to economic activity and population. Trending with the economic expansion of the 1990s, greenhouse gas emissions in the U.S. have increased 17 percent between 1990 and 2003.[19] However, U.S. greenhouse gases emitted per dollar of gross domestic product—or greenhouse gas intensity—decreased approximately 20 percent during this period.[20] Florida's growth and subsequent increase in energy-related CO_2 emissions between 1990 and 2001 ranked 2nd among states with an addition of over 51.5 metric tons.

Figure 2: Change in state-level emissions of energy-related CO_2: 1990 - 2001



Total greenhouse gas emissions are partially offset by the natural uptake of carbon (carbon sequestration) in the growth of forests, urban greenspaces, and on agricultural lands. In 2003, 12 percent of total U.S. emissions were offset by sequestration.[21] By subtracting sequestered carbon, national and state inventories can calculate net emissions. The total amount of carbon sequestered naturally within Florida is currently unknown, but can be reasonably assumed to represent a similar proportion to national offsets.

Effects of Climate Change

The global mean surface temperature of the Earth has increased by about 1° Fahrenheit since the late 19th century.[22] The years between 1990 and 2001 include the eight warmest since systematic measurement of temperatures by instruments began about 120 years

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[18] U.S. Energy Information Administration. *International Emissions Data: Energy-Related Emissions Data. 2006.* Available at: http://www.eia.doe.gov/pub/international/iealf/tableh1co2.xls

[19] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003.* op. cit.

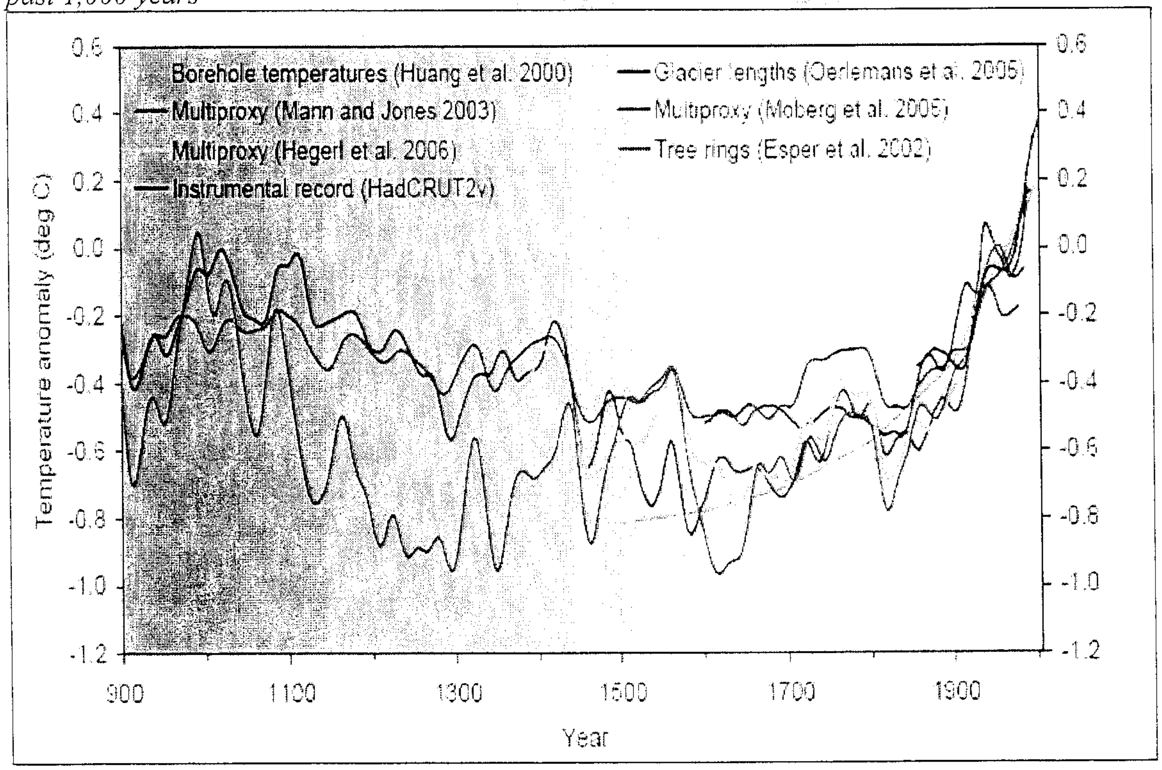
[20] Ibid.

[21] Ibid.

[22] IPCC. *Climate Change 2001: The Scientific Basis. op cit.*

ago.[23] Scientists have been able to extend the understanding of climate change far beyond that period by examining "proxy" data. Proxy data include natural archives of climate information such as tree rings, ice cores, corals, and sediments. In addition, historical documents such as ships' and farmers' logs, travelers' diaries, and newspaper accounts can provide insights into past weather and climate conditions. Proxy temperature reconstructions are more uncertain than direct instrumental measurements, and have been the subject of controversy. The so-called "hockey stick" reconstructions, named for their resemblance, were recently reviewed by the National Research Council of the National Academies of Science at the request of the Administration. The NRC found that the reconstructions indicate "with a high level of confidence" that global mean temperature was higher during the final decades of the 20th century than in any comparable period over the past four centuries.[24] Proxy data also indicate that the temperature in many, but not all localities within the last 25 years are "greater than at any time between 900AD and 1600AD."[25] The National Research Council (NRC) further concluded that global mean temperature reconstructions based on data from periods earlier than 900AD are less reliable because of the scarcity of data from representative points around the planet and variances in how data were analyzed. The global mean temperature reconstruction for the past 1,000 years is presented in Figure 2.

Figure 2: Reconstructions of average surface temperature of the Northern Hemisphere for the past 1,000 years



[23] Waple AM, JH Lawrimore, MS Halpert, et al. Climate Assessment for 2001. American Meteorological Society, 2002. Can be found at http://lwf.ncdc.noaa.gov/oa/climate/research/2001/ann/annsum.pdf

[24] Surface Temperature Reconstructions for the Last 2,000 Years. 2006. National Research Council.

[25] Ibid.

Global averages mask great regional variations; observed temperatures in some parts of the world have increased while other areas, temperatures have decreased. Many areas of the U.S. have warmed by more than 1°F, whereas the Southeast has cooled somewhat during the past century.[26] In some regions, particularly the Northeast, the Southwest, and the upper Midwest, the warming has been greater.[27] The increase in some places, such as the northern Great Plains, has reached as much as 3 °F.[28] During the 20th century, average U.S. temperatures dropped below freezing two fewer days per year than they did in the 19th century.[29]

Potential Effects of Climate Change in Florida

Climate change effects forecasting relies largely on global and regional models of the remarkably complex global climate system. The model results, while much improved in recent years by virtue of their ability to replicate past observed temperatures, still retain levels of uncertainty in projecting future global mean temperatures. Additional uncertainty is introduced when extrapolating global mean temperatures to address forecast effects such as sea level changes, rainfall patterns and impacts to ecosystems. Given these uncertainties however, some potential effects of global climate change that may be observed within Florida have been assessed.

Assuming continued growth in world greenhouse gas emissions, the modeling used by the 2000 National Assessment Synthesis Team of the U.S. Global Change Research Program suggested that average annual temperatures will increase by 5 to 9 °F by 2100.[30] The model results suggested that the Southeast would experience greater temperature increases than the nation as a whole with higher heat indexes (temperature plus humidity) of between 8 to 15 °F by the end of the current century.[31] Specific effects of increased temperatures could include reduced air quality due to ground-level ozone (smog) formation, greater incidences of heat stress and related mortality among the elderly, and increased incidence of water-borne illnesses, toxic algal blooms, and seafood-borne *Vibrio vulnificus* outbreaks.[32] Observed levels of sea level rise are expected to be between 18 and 20 inches along Florida coasts by 2100 which may result in the inundation of coastal areas, increased aquifer salinity, and alteration of Florida's estuaries.[33] Increased temperatures may impact the species composition and range within Florida's forests and natural areas.

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[26] Karl, TR, Knight RW, Easterling DR, Quayle RG. 1996. Indices of climate change for the United States. *Bulletin of the American Meteorological Society*, 77(2): 279-292.
[27] Ibid.
[28] Ibid.
[29] Easterling DR. 2002. Recent changes in frost days and the frost-free season in the United States. *Bulletin of the American Meteorological Society*, Sept: 1327-32.
[30] National Assessment Synthesis Team. *Climate Change Impacts on the United States: The Potential Consequences of Climate Variability and Change*. Washington, DC: U.S. Global Change Research Program. 2000
[31] Ibid.
[32] U.S. EPA. *Climate Change and Florida*, EPA 230-F-97-008i. Washington, DC: U.S. Environmental Protection Agency, Office of Policy, Planning and Evaluation, September 1997.
[33] Ibid.

Policy Options

While the scientific community continues to improve its ability to forecast potential effects of global climate change, policy makers are faced with the dilemma of how best to respond in light of model uncertainty. To be sure, any policy that substantively reduces greenhouse gas emissions will be costly. The task is to determine what actions any given polity should undertake to contribute to the global goal of stabilizing atmospheric concentrations of greenhouse gases, how to assign the costs of doing so most efficiently, and how best to engage its constituency in adapting to the necessary changes. A key feature of this policy decision is determining what measures are appropriate and effective for any given level of government.

For Florida, a comprehensive climate policy could perhaps be best considered as an exercise in prudent risk management. By virtue of our geography and the relative distribution of our population and development in our coastal areas, Florida is likely to be more adversely affected by global climate change than other interior states. While the worst of these effects may yet be years or decades in the future, prudent actions today may be cost effective over the longer timeframe.

Any set of policy options for Florida should consider that Florida's emissions of greenhouse gases represent a small fraction of total global emissions. If Florida were to act alone in reducing emissions, a considerable cost would accrue to Floridians without any real likelihood of changing the adverse impacts that the state may suffer in the future. A Florida greenhouse gas reduction policy must be viewed as an act of leadership designed to spur further action at the national and international level and thereby obtain the desired result of protecting the state's vital interests.

In designing a comprehensive climate policy for the state, one must consider the full range of issues to be addressed. Such a policy should consider not only emission reductions, but also actions to increase carbon sequestration through technology or enhancement of natural processes, steps to improve information about carbon emissions, and an appropriate public engagement process that influences the purchasing and energy consumption patterns of Floridians.

Element 1: Reducing Greenhouse Gas Emissions

The first element of a comprehensive climate policy is a focus on reducing an equitable share of emissions in contributing to a goal of stabilizing atmospheric concentrations of greenhouse gases by a given date. The following options provide an overview of the best options with a discussion of the benefits and costs associated with each option.

Management of the emissions of greenhouse gases can be categorized broadly into emission avoidance and emission control. Avoidance refers to strategies taken to prevent the formation or emission of the pollutant, while control refers to strategies for controlling the emission of the pollutant, often after the pollutant has been formed. Since carbon dioxide is the greenhouse gas emitted in the largest quantity nationally, the discussion of management will be focused largely on that pollutant. Avoidance strategies include the use of alternative fuels and energy efficiency improvements. Control strategies include technologies for carbon dioxide capture and storage, as well as transforming more potent greenhouse gases into less potent gases, such as the conversion of methane to carbon dioxide by combustion at landfill flares.

Emission Prices or "Carbon Taxes"

Carbon taxes are simply direct payments to the government based on the carbon content of the specific fuel being consumed (e.g. coal has more carbon content than natural gas so is taxed at a higher rate). As such, carbon taxes are a "priced-based" policy instrument which increases the price of certain goods and services thereby decreasing the quantity demanded. A cap and trade system, on the other hand, is considered a "quantity-based" environmental policy instrument. While both policy approaches are considered "market-based," the implementation details and expected outcomes of each policy are distinct. A carbon tax policy fixes the marginal cost for carbon emissions and allows quantities emitted to adjust, so the exact level of carbon dioxide reduction is unknown until the tax is actually implemented. Tradable permits, however, fix the total amount of carbon emitted and allow price levels to fluctuate according to market forces. This ensures a specific reduction of carbon but may not operate as efficiently as a direct carbon tax. According to a March 15, 2005 Congressional Budget Office brief, "analysts generally conclude that uncertainty about the cost of controlling carbon dioxide emissions makes price instruments preferable to quantity instruments because they are much more likely to minimize the adverse consequences (excess costs or forgone benefits) of choosing the wrong level of control." [34]

Since the objective of any abatement policy is to reduce emissions of carbon dioxide, a direct carbon tax has certain economic and environmental benefits because the externality (carbon) is taxed directly. The benefits of a direct carbon tax over a cap and trade system include a broader scope for emissions reduction (carbon taxes extend to all carbon based fuel consumption), lower transaction costs, a permanent incentive to reduce emissions, not as susceptible to gaming, and lower administration costs.

However, these efficiency gains of directly taxing the externality are somewhat offset by the inherently regressive nature of this tax. This regressive nature arises from the fact that as a percentage of income, a carbon tax would affect lower income taxpayers more profoundly than higher income taxpayers. One solution to this problem of regressive carbon taxes is to redistribute some portion of the revenue earned by this tax back to lower income people. This redistribution effort is often referred to as a "revenue neutral" tax and may shift the tax burden away from traditional "positives" such as productivity of labor to "negatives" such as pollution.

Emission Cap and Trade Approach

Another "market based" policy approach is an emissions trading system. With an emissions trading system, the quantity of emissions is fixed (capped) and the right to produce emissions becomes a tradable commodity. These tradable commodities are often referred to as "permits," "quotas," or "allowances." Under this system, compliance is

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[34] Congressional Budget Office; March 15, 2005 Economic and Budget Issue Brief: Limiting Carbon Dioxide Emissions: Prices Versus Caps, http://www.cbo.gov/showdoc.cfm?index=6148&sequence=0

achieved by holding permits or allowances greater than or equal to the actual emission levels. These permits or allowances become tradable after they are initially allocated (by auction, historical usage patterns, or free allocation) to all eligible participants.

As the objective of any abatement policy is to reduce emission of carbon dioxide, an emissions trading regime has inherent benefits as well. First and foremost, a policy of emissions trading ensures a fixed level of carbon reduction and the resulting environmental improvements. This may be more palatable since emission reduction levels may be easier to agree upon than relative tax rates. Emission trading regimes can allow emission reductions to cross over borders in search of the lowest abatement costs and unlocks the benefits of resource specialization. The notion of a cap and trade emissions trading policy may have broader appeal to private industry by equating marginal benefits and marginal costs through the buying and selling of excess carbon dioxide allowances. A policy of emissions trading can be more effective in dealing with multiple greenhouse gases within one strategy.

Carbon Price Transparency

Given the relative importance of the utility sector to total greenhouse gas emissions and the longevity of fixed assets when constructing generating capacity, regulatory policies that incorporate the potential future costs of carbon emissions can improve siting decisions made by utilities and the Public Service Commission (PSC). In evaluating the cost effectiveness of various fuel options for new generation, utilities currently present fuel price forecasts to the PSC as a key component of their filings. Should the Commission likewise consider the potential future costs of carbon emissions (as represented in forecasts of the commodities cost of carbon credits) in evaluating the appropriateness of a given filing, utilities may be incentivized to site plants fired with lower carbon fuels or to consider cost-effective means to reduce emissions elsewhere within its generating fleet to manage its over-all exposure to carbon costs. These carbon cost management outcomes will become increasingly likely if and when real carbon regulations are implemented.

In 1993, the Oregon Public Utilities Commission required utilities to incorporate a "carbon adder" ranging from $10 to $40 per ton of carbon to each generation-based request for proposals under its least-cost planning economic regulation. "While utilities have not credited the addition of a carbon adder with changing procurement decisions. . . the inclusion of a carbon adder institutionalizes the consideration of climate change in utility investment decision-making, which may encourage a broader examination of available generation resources. It also provides a mechanism for utilities to weight more heavily the importance of reducing carbon emissions in the future, as the utility becomes increasingly certain about impending regulated carbon constraints."[35]

Within Florida, such a policy will likely improve the standing of natural gas, nuclear, and renewables generation while reducing the competitiveness of coal as a utility fuel. The net result may be a further erosion of the state's future fuel diversity.

[35] Pew Center on Global Climate Change. "*State and Local Net GHG Emissions Reductions Programs.*"

Multi-pollutant Regulatory Strategies
Several multi-pollutant regulatory strategies have been offered at the national level to reduce emissions from the power industry. Recent federal legislation, the Clean Air Interstate Rule and the Clean Air Mercury Rule, are examples of cap and trade approaches to reducing the emission levels of several pollutants. Some of the proposals for multi-pollutant strategies included carbon dioxide emissions. If a cap and trade approach were used to regulate CO_2, that strategy could be incorporated into the current regulatory framework used now to regulate nitrogen oxides, sulfur dioxide, and mercury. This is an essential feature of these proposals, none of which have found acceptance with Congress. Because the current federal administration has moved forward with multi-pollutant regulatory strategies without the inclusion of CO_2, the opportunity for a combined approach that includes CO_2 seems lessened. It seems more likely that future approaches to CO_2 control will be on a stand-alone basis. To the extent that CO_2 reporting can be coupled with reporting of existing pollutants, it makes sense to consider CO_2 emissions in that context.

Carbon Capture
A complete discussion of emissions management should include a review of advanced technologies for capture of carbon dioxide that is produced from the combustion of fuels. In this case, combustion refers to the burning of carbon containing fuels, which results in the formation of carbon dioxide. Once captured, the carbon dioxide must be stored permanently (sequestered), so that it is not later released to the atmosphere. Collectively, the control of carbon dioxide emissions and subsequent permanent storage is known as carbon capture and storage (CCS). Three emerging approaches are being developed for control and capture of carbon dioxide: post combustion technologies, oxy-fuel combustion capture systems, and pre-combustion capture systems.[36]

These control technologies all have significant disadvantages. Each is an emerging technology that is largely not commercially developed or even ready for commercial scale pilot testing. The commercial technologies, such as IGCC, have not yet been proven feasible for the purpose of controlling carbon. While many of these controls will have promise, costs and commercial availability will continue to be challenges for the foreseeable future. All of the carbon controls must also be coupled with a feasible technology for storing the captured CO_2 (discussed in Element 2 in the section on CO_2 storage technologies).

Use of Alternative Fuels for Energy
In order to avoid the greenhouse gas emissions of traditional fossil fuels used for energy production, several alternative energy sources with relatively lower emissions signatures can be substituted. Promotion of alternative energy sources can be considered extensions of the 2006 Florida Energy Plan. Alternative energy technologies discussed here are biomass, biogas, waste-to-energy, and nuclear power.

[36] The following discussion has largely been adapted from the IPCC Special Report on Carbon Dioxide Capture and Storage; Chapter 3; Cambridge University Press; 2005.

Biomass Energy

Biomass is the energy from plants and plant-derived materials. Wood is the largest biomass energy resource today, but other sources of biomass can also be used including food crops, grassy and woody plants, residues from agriculture or forestry, and the organic component of municipal and industrial wastes. Since plants and trees absorb and store atmospheric carbon as they grow, growing and using biomass energy crops reduces CO_2 emissions into the atmosphere in that biomass energy from crops is "carbon neutral" as the emissions from burning the biomass is offset by carbon captured in the growth of the next crop. Planting bioenergy crops nationwide can supply an estimated 7.3 percent of U.S. electricity energy needs.[37] Consumer cost for biomass is estimated to be $0.08-$0.12/kWh.[38] This can be compared to Florida's average cost of $0.086/kWh for consumers in 2004.[39]

Biogas Energy

Anaerobic digestion is a process by which a complex mixture of microorganisms transforms organic materials under oxygen-free conditions into biogas. Raw biogas typically consists of methane (60%) and carbon dioxide (40%), water vapor and trace amounts of hydrogen sulfide. The process is successfully used for the treatment of municipal sludge, animal manure, industrial sludge, and industrial and municipal wastewaters. Biogas can be used as a fuel for electric generation with benefits for greenhouse gas emissions reduction, primarily in reducing methane emissions. Untreated organic waste will undergo uncontrolled anaerobic digestion and methane from these wastes is emitted to the atmosphere. By applying anaerobic digestion to these wastes and capturing and utilizing the biogas, the methane provides energy and is converted to CO_2 emissions with 21 times less warming potential than methane.

Waste-to-Energy

Waste-to-energy currently provides 506 megawatts of non-utility generator capacity in Florida from municipal solid waste, wood and wood waste, and waste heat. The 13 operating waste-to-energy facilities (WTE) in Florida have the capacity to generate over 534MW of electricity (less than 1% of Florida's installed capacity) and have become an essential component of Florida's municipal solid waste management strategy.[40] Landfills are the largest human-made source of methane in the nation. Landfill gas is roughly 50 percent methane, 50 percent CO_2 and less than 1 percent non-methane organic compounds (NMOCs). For every one million tons of municipal solid waste (MSW), roughly 0.8 MW of electricity or 400,000 cubic feet per day of landfill gas is generated.

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[37] Oak Ridge National Laboratory, *The Economic Impacts of Bioenergy Crop Production on U.S. Agriculture*, 1999.

[38] National Renewable Energy Laboratory (NREL), *Fulfilling the Promise of Renewable Energy: A Look at the Future*, presentation by Dr. Dan Arvizu, NREL Director, 2005.

[39] Florida Public Service Commission. *Facts and Figures of the Florida Utility Industry: 2006.* Tallahassee, Florida. 2006

[40] Florida Department of Environmental Protection, *Bureau of Solid and Hazardous Waste Management*, 2005.

There are 10 landfill gas energy projects in operation in Florida (39.7 MW) with potential to generate an additional 68 MW from 18 candidate landfills. Future waste-to-energy (WTE) facilities that burn municipal solid waste could acquire renewable energy credits for the electricity they generate. These credits could be sold or traded to retail electric suppliers in order to meet requirements for annual percentages of electric generation using renewable energy source by these retail producers. Bringing new facilities online will be challenging due to public skepticism and exceptionally high construction costs. The cost to deliver energy ranges from $0.04-0.15/kWh in Florida.[41] This can be compared to Florida's average cost of $0.086/kWh for consumers in 2004.[42]

Nuclear Energy

Nuclear energy makes up approximately 8 percent of Florida's installed generating capacity.[43] No new nuclear plants have entered service in Florida since 1983. While no utility's Ten-Year Site Plan contains proposed nuclear units, Progress Energy Florida recently announced its intention to pursue a new nuclear generating unit in Florida within the next ten years. Nuclear power plants are capable of producing electricity with no greenhouse gas emissions at scales necessary for powering the modern power grid. Nuclear plants are capital-intensive and take as much as ten years to certify and build; however, when compared to other energy types, nuclear is relatively cheap to operate. The cost of the raw fuel, uranium, is less than natural gas, oil, or coal. The costs of running the actual plant are similar to those of running a coal or gas plant.

Alternative Fuels for Industry

Substitution of alternative fuels for fossil fuels for industrial uses has potential to reduce net greenhouse gas emissions. Biomass materials are commonly thought of as essentially "carbon neutral", in that the carbon released during combustion was taken up during the growth of the biomass material. Carbonaceous fuel (a form of biomass) boilers have been in use in Florida in the pulp and sugar industries for decades. Waste materials also present opportunities for displacing fossil fuels, and make beneficial use of materials that would otherwise require disposal. Whether these materials decay or are burned, the inherent carbon is released to the environment, but burning allows for recovery of the heat from combustion.

Other wastes present possibilities for beneficial use, and displacement of fossil fuels. The cement industry has potential to utilize several different wastes for fuel. With six active cement plants, and one breaking ground, cement manufacturing is a significant industry in Florida, and a significant CO_2 emitter. The use of alternative fuels, such as sewage sludge and waste tires, replaces fossil fuels and reduces the overall amount of CO_2 that would have been produced if both fossil fuels and processed waste alternatives

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[41] Florida Public Service Commission, *An Assessment of Renewable Electric Generating Technologies for Florida*, 2003

[42] Florida Public Service Commission. *Facts and Figures of the Florida Utility Industry: 2006.* Tallahassee, Florida. 2006

[43] Florida Public Service Commission, *Statistics of the Florida Electric Utility Industry*, 2004

had been burned. Cement kilns are extremely effective at using the energy contained in waste materials. Rather than simply incinerate these materials, a cement kiln utilizes these wastes by recovering energy and saving fossil fuels. The use of alternative fuels has also played a role in increasing the efficiency of cement production that also results in reduced CO_2 emissions. For example, for every ton of waste tires consumed, fewer raw materials are mined and CO_2 emissions are reduced. Waste tires are an especially attractive form of alternative fuel due to their high energy value. The EPA estimates that waste tires produce the same amount of energy as oil and 25% more than coal. Alternative fuels like sewage sludge and waste tire are readily available in Florida, although the Florida industry does not presently make use of sewage sludge.

Transportation Technologies

Because of the large contribution of transportation-related CO_2 emissions to Florida's total, options to reduce CO_2 statewide should consider the role of transportation, and transportation fuel combustion. A gallon of gasoline weighs 6.3 pounds. When burned in an engine, the carbon from this gallon of gasoline combines with oxygen to produce about 20 pounds of carbon dioxide. For 2001, carbon dioxide emissions from the transportation sector were estimated at 98.7 million metric tons, or approximately 41 percent of the total 238.8 million metric tons.[44] Cars and light trucks in Florida consume 28 million gallons of gasoline each day. Combustion of this quantity of fuel contributes over a quarter million tons of carbon dioxide emissions every day in this state. Because transportation-related carbon dioxide emissions make up a large part of Florida's total emissions, it is appropriate to focus on approaches to promote reductions of GHG from this sector. These approaches include improving the energy efficiency of vehicles and substituting alternative fuels for conventional petroleum fuels.

Enhancing Fuel Economy

Ready technologies exist for improving the energy efficiency (fuel economy) of conventionally-fueled vehicles. Passenger cars particularly have benefited from approaches such as reducing vehicle weight through the use of light-weight alloys, valve timing, cylinder deactivation, and engine management systems to improve power output from smaller engines, and aerodynamic innovations to reduce drag. Extension of these to other types of vehicles is a natural next step. The use of diesel-powered engines with advanced emission controls for passenger cars is another approach to provide good fuel economy and low emissions of other pollutants. Emerging technologies have potential to increase fuel economy. Examples are direct fuel injection systems for gasoline engines, CNG and diesel co-firing systems, and hydrogen and diesel co-firing systems. Fuel efficiency improvements have good potential to reduce CO_2 emissions through increased energy efficiency.

Electric Vehicles

Battery electric vehicles were evaluated extensively during the 1990s due to the "ZEV [zero emission vehicle] Mandate" which was enacted by California in 1990, which required that 2% of vehicles sold in California by major automakers in

[44] U.S. EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003.* op. cit.

1998 would have no tailpipe emissions, rising to 10% in 2003. Several battery electric vehicles were manufactured and evaluated, including vehicles from General Motors, Toyota and Honda. These zero emission vehicles each performed comparable to gasoline powered cars (acceleration, cruising speed, braking) although they all suffered from limited range and long battery recharge (refueling) times compared to their gasoline counterparts. They were also more expensive partly due to limited production. Although the California Air Resources Board (CARB) concluded that electric vehicles reduce pollutants by more than 90 percent, there were several legal challenges to California's rule and eventually CARB virtually eliminated the requirement for manufactures to produce battery electric vehicles. Each manufacturer discontinued production of their battery electric vehicles claiming low consumer demand.

Hybrid-electric Vehicles

Hybrid electric cars make use of advanced batteries and electric motors to improve the efficiency of a gasoline-powered (or diesel-powered) vehicle. When the electric motor is not needed, the gasoline or diesel engine recharges the batteries, avoiding the need for a separate charging mechanism. In this way, the batteries remain charged and ready to power the electric motor. Recent hybrids also make use of systems to recover energy during braking that is also used to charge the batteries. Several models of gasoline/electric hybrid passenger cars are available from auto manufacturers, some having fuel efficiencies exceeding 40 mpg. Several hybrid electric SUVs are now offered with fuel efficiencies of about 33 mpg. These vehicles are gaining public acceptance, despite typically being more expensive than their gasoline-powered counterparts.

The use of hybrid technology offers one of the immediate and more significant steps to reduce CO_2 emissions because of the fuel efficiency of these vehicles. Also, hybrid utility trucks and school buses have been demonstrated to cut fuel consumption in half. For example, by switching from a conventional SUV to a hybrid, CO_2 emissions can be reduced by 50% or more, thereby eliminating more than two tons of greenhouse gas emissions per year. [45]

Plug-in Hybrid Vehicles

Another possible option is a vehicle which operates in the full battery mode for the majority of time and has the ability to engage a gasoline engine to extend the driving range. The batteries are recharged prior to vehicle use, by plugging into an electrical receptacle. This vehicle is known as a "plug-in" hybrid electric car, and has the potential to greatly reduce petroleum consumption from vehicles. No auto manufacturer has announced commercial production, although many are working on this technology. Battery life and costs represent major challenges to this technology.

[45] US Department of Energy's Fuel Economy Guide available online at www.fueleconomy.gov

Use of Alternative Fuels for Transportation
Another option for reducing the contribution of carbon dioxide emissions from the transportation sector is increasing the use of alternative fuels that have inherently lower carbon dioxide emissions. Liquid alternative fuels offer the advantage of being most readily established within our existing fuel distribution infrastructure. Also, liquid fuels are more readily used in existing vehicles, particularly blends of alternative fuels and petroleum products. Gaseous fuels are more challenging, because they will require the creation of a new fueling infrastructure, switching from liquid fuel handling and storage to gaseous fuel. Gaseous fuels also require the widespread use of new engines. Although, fuel cell technology is promising, commercial implementation in motor vehicles is years away.

Ethanol
The most commercially available of the alternative transportation fuels is corn-based ethanol. Ethanol can be blended with gasoline in small blends (10% ethanol and 90% gasoline, called E10), or in high blends (85% ethanol and 15% gasoline, called E85). In either blend, the ethanol displaces some of the gasoline and results in a net reduction in CO_2 emissions. Because ethanol is derived from a crop which absorbs CO_2 as part of the growing process, some of the tailpipe CO_2 emissions are assumed to be absorbed back into the biosphere. The result is a net reduction in CO_2 emissions of about 20% when considering a full life cycle analysis of the ethanol derived from corn.[46] Cellulosic feedstocks are essentially agricultural waste products with very few additional energy requirements. Although not feasible today, ethanol derived from low cost cellulose sources like corn waste or sugar cane stalks has the potential to reduce CO_2 emissions by up to 87% compared to gasoline. Cellulosic feedstocks are essentially agricultural waste products with very few additional energy requirements.[47] Another potential issue to consider regarding ethanol production is the potential choice of feedstocks, and the need to balance use of arable land for producing feedstocks for ethanol production against feedstocks for biomass combustion. The use of cellulosic waste, provides an opportunity to enhance this balance.

Biodiesel
For diesel powered vehicles the crop-based alternative fuel is biodiesel. Like ethanol, biodiesel has a net reduction in CO_2 emissions due to the uptake of this atmospheric gas as the crop grows in the field. The majority of biodiesel production in this country comes from soy crops in the mid-west. Biodiesel is mainly used in blends of 20% biodiesel with 80% diesel (known as "B20"). The full lifecycle analysis of this fuel results in a 15% reduction in CO_2 emissions compared to petroleum based diesel.[48] There is also the potential to derive

[46] Argonne National Labs Center for Transportation Research. *Ethanol, The Complete Energy Lifecycle Picture*" August 2006 available at: http://www.transportation.anl.gov/pdfs/TA/345.pdf [The 20% net reduction presented assumes the ethanol GHG benefit is 15% for E10 using the wet mill process and 26% for E85 using the dry mill process for an average of about 20% for corn grain feedstock]
[47] Ibid.
[48] US Department of Energy – US Department of Agriculture. *Lifecycle Inventory of Biodiesel and Petroleum Diesel for use in an Urban Bus.* 1998 NREL/SR-580-24089 UC Category 1503.

biodiesel from waste grease. The manufacturing process is similar to using soy, although the feedstock can be less expensive. The costs associated with collecting the grease from a variety of sources may limit the commercial feasibility of this approach.

Compressed Natural Gas

Some states have promoted the use of compressed natural gas (CNG) as a way to begin building the gaseous fuel infrastructure, especially for fleets with a central fueling station. This fuel is 13% lower in CO_2 emissions compared to the liquid petroleum-based fuels, gasoline and diesel.[49] This is because natural gas has fewer carbon atoms per molecule of gas, as compared with these liquid fuels. However, there are significant challenges to the use of CNG as a transportation fuel. As noted previously, conversion to CNG would necessitate a new fueling infrastructure. (There are fewer than five public CNG refueling stations in Florida, so a dedicated CNG vehicle is essentially limited to in-town use.) Additionally, there are virtually no automobiles that are equipped to burn CNG, so the existing automobile fleet would either have to be retrofitted with CNG capability, or completely replaced. Increasing use of CNG for transportation would also increase the demand for natural gas, raising the price for this fuel. Consideration would have to be given to the net benefit of increasing use of CNG for transportation, given that this will increase emissions of methane, a more potent greenhouse gas.

Hydrogen

In the long term, a switch to carbonless fuel like hydrogen would eliminate the tailpipe emissions of CO_2 altogether. There are many challenges to this switchover because there is no fueling infrastructure for gaseous fuels like hydrogen, and fuel cell vehicles are very expensive today. Hydrogen fuel is currently derived from natural gas so the production of this fuel is associated with significant CO_2 emissions. Two promising paths to producing hydrogen without resulting CO_2 emissions are nuclear power and gasification. Nuclear power can be used to produce hydrogen by electrolysis, which is the splitting of water into hydrogen and oxygen atoms using electrical energy. Gasification can be used to produce a hydrogen-rich synthesis gaseous ("syngas") fuels from other fuel sources such as coal or biomass. As with CNG, there are significant challenges to the use of hydrogen as a transportation fuel. Hydrogen would necessitate a new fueling infrastructure. There are presently no commercially available automobiles that are equipped to use hydrogen, although fuel cells offer promise for commercial development in the future, and a number of vehicle manufacturers have fuel cell vehicles on the road for testing.

In July 2003, Governor Bush launched "H2 Florida," a statewide initiative to accelerate the commercialization of hydrogen technologies, spur investment and economic opportunity and safeguard the nation's natural resources. H2 Florida partners the State of Florida with industry, governments and academia to

[49] Northeast Sustainable Energy Association available at http://www.nesea.org/

showcase hydrogen technologies and stimulate a consumer market for cleaner, sustainable sources of energy. Florida has 28 hydrogen demonstration projects underway and seven state universities are conducting more than 100 hydrogen research and development projects. In 2003, the Florida Energy Office and Florida Power and Light installed a fuel cell at Hugh Taylor Birch State Park. Since that installation, the Florida Energy Office has installed fuel cells at North Port High School and Homosassa Springs State Park. Additionally, the DEP has purchased 12 fuel cells to provide backup power at their District and Branch Offices statewide.

Transportation-Oriented Design

The transport sector accounts for approximately 41% of Florida's estimated CO_2 emissions in 2001. Growth patterns that result in "sprawl" increase transportation sector emissions and reduce quality of life. Florida's 2006 Energy Plan recommended that state government explore the potential for partnerships with local planning boards to foster smart growth, with emphasis on improved transportation and transit systems. These partnerships are not intended to create regulations or process but rather to facilitate information sharing about emerging technologies and existing infrastructure that reduce a community's dependence on fossil fuels. To build on the 2006 plan, state government could engage local governments and railways to develop new mass transit projects around Florida.

Methane Emissions

Methane accounts for 10 percent of U.S. greenhouse gas emissions, and reducing these emissions is a key goal of the U.S. Climate Change Action Plan (EPA, 1999).[50] According to EPA, landfills are the largest single source of methane emissions (37% of the total methane emissions in 1997), followed by agriculture (29%) (livestock enteric fermentation and manure management) and the U.S. natural gas (NG) system (20%).[51]

Methane from landfills is typically controlled by landfill gas collection and control systems. While these systems typically flare the landfill gas, with no heat recovery, a particularly interesting option is those systems that use landfill gases to generate electric power. Those systems control the methane emissions through combustion and recover useful energy from that combustion process. Increasing use of landfill gases to generate electricity in this manner is a beneficial long-term option to control methane. EPA estimated projections indicate that by 2020 the source of methane emissions from U.S. natural gas systems will increase by 15.2% as total methane emissions from all three major sources are forecasted to increase by 10% over the 1990 levels. The EPA expects methane emissions to increase as natural gas consumption increases, although at a lower rate than natural gas consumption growth.[52]

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[50] US EPA "U.S. Methane Emissions 1990-2020: Inventories, Projections and Opportunities for Reductions", *United States Environmental Protection Agency, Office of Air and Radiation (6202J), EPA 430-R-99-013,* September 1999, page ES-1.

[51] Ibid.

[52] Ibid, page ES-2.

A number of technologies and practices have been identified that can reduce methane emissions from natural gas systems. EPA and the natural gas industry, through the Natural Gas STAR Program, have identified several Best Management Practices (BMPs) that are cost-effective in reducing methane emissions. In addition, companies that are Natural Gas STAR Partners have identified other practices that also reduce methane emissions. Most of the practices relate to more frequent inspection of equipment, replacement with better performing materials or equipment, and control of vented emissions.[53] Continuing these practices and identifying other measures to prevent leaks and control emissions represents the currently feasible control options.

Hydrofluorocarbons
Refrigerants used in refrigeration and air-conditioning equipment are powerful greenhouse gases. A number of hydrofluorocarbons (HFCs) are released into the atmosphere during the operation and repair of this equipment. According to EPA, "…the majority of HFCs used today in the refrigeration and air-conditioning sector have global warming potentials (GWP) from 1.300 (i.e., HFC-134a) to 3,300 (i.e., R-507A)."[54] Historically, ozone-depleting substances (ODSs) such as chlorofluorocarbons (CFCs) or hydrochlorofluorocarbons (HCFCs) have been used in the refrigeration and air-conditioning appliance sector. Under the Montreal Protocol, an ODS phase-out is being implemented and equipment is being retrofitted or replaced with HFC-based substitutes; however, these HFC-based substitutes will ultimately need to be replaced with non-ozone depleting alternatives. In motor vehicle air conditioners, a variety of HCFC/hydrocarbon blends approved by the EPA Significant New Alternatives Policy (SNAP) have replaced CFC-12, a previously common refrigerant. However, concerns over the greenhouse gas potential of these alternatives has necessitated study of further alternatives, such as improved efficiency, new refrigerants, or even the use of CO_2 refrigerant systems. Similar concerns and interest applies to residential and small commercial air conditioning systems.[55] HFC emissions from refrigeration and air-conditioning equipment can be reduced through a variety of practice and technology options, such as leak repair, refrigerant recovery and recycling, alternative refrigerant options including improved refrigerants, improved equipment, and use of geothermal systems and other alternatives to air-to-air heat exchange.[56] Many of the options would entail voluntary action by the private sector and/or further government regulation. Continuation of these strategies at the Federal level is necessary to address these greenhouse gases across the nation.

Element 2: Greenhouse Gas Sink Development and Management
Any state, national, or international carbon regulatory framework will likely be structured in terms of *net* greenhouse gas emissions, meaning total emissions less carbon removed from the global cycle. Working in tandem with policy options to reduce emissions, policies that focus on increasing carbon storage form the second major element of a

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[53] Ibid, page 3-7
[54] US EPA. *Analysis of Costs to Abate International Ozone-Depleting Substance Substitute Emissions.* June 2004 430-R-04 006
[55] Ibid.
[56] Ibid.

comprehensive climate policy. Carbon storage can be achieved through natural processes such as increasing or retaining forested lands or through the use of advanced technology. Natural process sequestration involves the enhancement of the CO_2 uptake by plants and enhancement of carbon storage in soils where it may remain more permanently stored. Land management practices that increase carbon sequestration potential can provide an opportunity for low-cost CO_2 emissions offsets. Technological carbon sequestration, while still largely in the research and development mode, provides promise for carbon storage on a relatively large scale. The policy options presented below provide options across both categories.

Enhancing Carbon Storage in Agricultural Lands
Agricultural land can act as a sink for greenhouse gases, enhancing carbon storage potential by changing soil management practices. Changes in soil management can offset carbon emissions by sequestering the carbon in the soil. Traditional agricultural practices of plowing or tilling the land emit carbon due to the top layer of soil being disturbed. Disrupted soil looses most of its carbon content and releases carbon dioxide gas into the atmosphere through oxidation of carbon in soil's organic material. Studies indicate that carbon loss ranges from 30 to 50 percent over the first 40 years of cultivation for grassland and forest soils first brought into production using conventional tillage. After this soil carbon levels tend to stabilize at a new equilibrium.[57] Lack of carbon rich decaying organic matter contained in healthy topsoil which provides nutrients to plants, can result in the need to use more fertilizers. Carbon can be stored and retained in fields through no-till farming practices. When using no-till agriculture, farmers plant seeds into the soil without the use of a plow to turn the soil. It is suggested that affected lands acting as carbon sinks will have to stay in their no-till soil management use for extended periods of time (minimum of 20 years) in order to count as offsets to national greenhouse gas emissions, as they would quickly release any carbon that had been added to soils.[58]

Leveraging the Carbon Storage Services of State-owned Lands
With the ownership of public lands (e.g. State Forests, State Parks, Upland and Aquatic Preserves and other protected green spaces) the State of Florida has access to and authority over an increasingly valuable resource commodity. This resource commodity can have many valuable uses in the abatement of carbon dioxide through the development of greenhouse gas sinks. When viewed as a potential greenhouse gas sink, the lands owned by the State can, in effect, serve a dual purpose: 1) fulfilling the originally intended preservation or recreational use, as well as 2) acting as a natural carbon reservoir or sink (the opposite of a carbon source).

By leveraging the investment made through the original purchase of these public lands, the State of Florida can lead by example in the reduction of carbon dioxide emissions and simultaneously foster statewide economic development. By designating state owned

[57] Lal, R., J.M. Kimble, R.F. Follet, and C.V. Cole. 1998. *The Potential of U.S. Cropland to Sequester Carbon and Mitigate the Greenhouse Effect.* Ann Arbor Press, Chelsea MI.
[58] Economic Research Service. 1998. Economic and Environmental Benefits and Costs of Conservation Tillage. Report to Congress by the U.S. Dept. of Agriculture, Economic Research Service, in collaboration with the Natural Resources Conservation Service (Feb.).

public lands as potential carbon sinks, the carbon emission signature of all State of Florida government operations could be negated with excess reserves to be used as a potential economic development incentive.

Advanced Sequestration Technologies (CO_2 Storage)

Carbon dioxide storage (a type of "sequestration") is the placement of carbon dioxide into a repository in such a way that it will remain unavailable to the atmosphere for an extended period of time. Storage of the carbon dioxide may be required essentially "forever" – on the order of hundreds of thousands of years – in order to reap the benefits of capturing it. Following is a summary of advanced storage technologies, which represent storage in geologic formations.[59] In general, geologic formations for CO_2 storage trap the gas by containing it under a "cap" of non-porous rock, dissolving it in brine, reacting it with minerals to form solid carbonates, or adsorbing it in porous rock. The degree to which a specific underground formation is amenable to CO_2 storage can be difficult to discern. Researchers are working to predict the storage capacity of given formations, and to develop injection techniques that maximize that capacity. There are three major types of geologic formations in which CO_2 can be stored: unminable coal seams, depleted oil and gas reservoirs, and saline formations. While storage within each of these geologic features has distinct advantages and disadvantages, the discussion is limited here to saline formations as this feature type is the only one of the three present within Florida.

Saline formations are layers of porous rock that are saturated with brine. They are much more commonplace than coal seams or oil and gas bearing rock, and may be able to store CO_2. However, much less is known about saline formations and their ability to store CO_2 is uncertain. It is harder to inject CO_2 into saline formations, so techniques must be developed to overcome issues with lower permeability. Saline formations also contain minerals that could react with injected CO_2 to form solid carbonates which can improve long-term storage but may also further decrease permeability near the injection zone. Saline formations are the predominant type available in Florida for CO_2 storage, but research is required into their use to better understand their capabilities and limitations. Location of new IGCC projects in the state may provide an opportunity to facilitate such research.

Saline formations may leak, or injection zones may plug because of reactions with minerals. Leaks will make these formations unusable, and plugging adds uncertainty to costs. Injection well construction costs will be high (the wells themselves will be deep, and must be free of leaks), and operating costs will likely be substantial because of the injection pressures required. Significant use of other formation types by Florida industries will require the construction of one or more pipelines for CO_2 transport, at high cost. Department of Energy researchers are testing CO_2 storage on an oil well near Mobile, Alabama; if that test is successful, it suggests that the required pipeline distances may be shorter than anticipated, particularly for power plants and industrial sites in the

[59] This discussion is drawn largely from the US Department of Energy, National Energy Technology Laboratory website at http://www.netl.doe.gov/technologies/carbon_seq/core_rd/storage.html

panhandle.[60] Since some type of permanent CO_2 storage is necessary for long-term reductions in atmospheric CO_2 concentrations, the state should foster research into these issues.

Element 3: Improving Greenhouse Gas Information & Data
Improving the extent and accuracy of greenhouse gas emissions and sinks within Florida must be a vital component of a comprehensive state climate policy.

Emissions inventory
One important element in developing a carbon reduction strategy is to clearly define the state's current status for greenhouse gas emissions and develop a method for affected industries to report greenhouse gas emissions. Several accepted methodologies are available that can be considered for establishing a reporting and monitoring structure for greenhouse gas emissions that will allow the state to create a baseline for greenhouse gases and a process of an ongoing greenhouse gas inventory.

Greenhouse gases are generally estimated using formulas based on specific emission factors that would allow the state to estimate greenhouse gas totals. Issues to be determined when deciding on a specific methodology include determining how data will be reported and compiled, what greenhouse gases will be included in the inventory, what emission sources will be included (e.g. industrial, residential, transportation, electric generators, etc), and which fuels are covered. The size of the source must be another consideration, as larger sources may need to use a more accurate reporting tool, than smaller sources. Reputable organizations, such as the EPA and the World Meteorological Organization and United Nation's Intergovernmental Panel on Climate Change offer specific guidance and methodologies for calculating greenhouse gas emissions and establishing inventories. In order to determine actual levels of emissions, provide a basis for comparison to a baseline, and to track progress in meeting emission targets, Florida would need to put in place a regular emissions inventory. The specific methodologies applicable to Florida would need to be determined after a thorough evaluation of the above considerations. The Department may need to seek legislative authority to require the reporting of greenhouse gas emissions from specific sources in Florida. Because major air pollution sources in the state regularly report emissions information to the Department, establishing a process for reporting of greenhouse gas emissions is feasible.

Energy Intensity Reporting
In developing information and an understanding of energy issues, it is important to measure not only energy consumption but energy intensity or the amount of energy used per unit of output (e.g. BTUs per square foot or energy used to Gross Domestic Product). The methodology can be adjusted for either energy used or expenditures. Declines in energy intensity can be considered a proxy for energy efficiency. Efficiency improvements in processes and equipment can improve energy intensity. Energy intensity data can be important when considering measures that can affect energy use that have no bearing on the efficiency with which the energy is used. For example, behavioral factors or weather can result in increases in consumption but the efficiency of production stays the same. Systems for tracking energy intensity involve developing

[60] Argus Air Daily, Argus Media Group, Volume 13, 171, September 7, 2006, page 6

indices for various economic sectors, such as transportation, industrial, commercial and residential. This information is already tracked nationally by the Department of Energy. As with the emissions reporting tools, Florida would need to develop appropriate energy intensity measures that provide sufficient information for policy development. To the extent that supplemental information might be required of regulated industries to determine energy intensity information, the Department may need specific legislative authority to require such reporting.

Element 4: Public Engagement for Energy Efficiency and Conservation
Reducing emissions of greenhouse gases will ultimately require using less energy and getting greater benefit from the energy that is used. Energy generation is customer driven and conscious decisions made by Floridians to conserve energy or seek greater energy efficiency will ultimately drive Florida's success in reducing greenhouse gas emissions. The final element of a comprehensive climate change policy must focus on how best to engage Floridians in a constructive conversation of how each individual plays a role in any statewide, national, or international goal to stabilize atmospheric concentrations of greenhouse gases.

Energy Efficiency and Conservation – Residential Sector
The load profile of Florida is heavily influenced by the residential customer class. Based on 2003 data, 51 percent of all electric energy was consumed by residential customers, 32 percent by commercial customers, and 12 percent by industrial customers, with approximately two percent being used for other purposes.[61] Demand-side management (DSM) reduces customer peak demand and energy requirements, resulting in the deferral of need for new generating units. The Public Service Commission (PSC) set new numeric demand and energy goals for seven utilities in July 2004. The new numeric goals were generally lower than the previous goals set by the PSC in 1999 for three primary reasons: (1) the Florida Building Code contains increased minimum energy efficiency levels, limiting the amount of incremental savings from utility sponsored programs; (2) many utility DSM programs have reached a saturation in participation levels; and (3) the relatively low cost of new generating units has reduced the cost-effectiveness of several DSM programs.[62]

Installation of small scale (kW) solar PV panels has the same impact as Demand Side Management (DSM) programs -- displacing fossil fuel peaking units. PV systems convert sunlight into electrical current but have high initial costs associated with installation. Similarly, while solar water heaters are considered cost effective, the thermal technology has a higher initial cost than traditional fossil-fuel based water heaters. When installed, however, solar water heaters can provide as much as 80 percent of the hot water demand of the typical Florida residence.

If every household in Florida replaced one 75 watt incandescent light bulb with an equivalent compact fluorescent bulb, assuming six hours of operation per day, seven days per week, the total energy saved would equal 694 million kilowatt-hours, and CO_2

[61] Florida Department of Environmental Protection, *Florida's Energy Plan,* 2006.
[62] Ibid.

emissions would be reduced by approximately 485 million pounds.[63] Compact fluorescents provide high quality light, requiring less energy while lasting longer than typical incandescent bulbs. ENERGY STAR qualified compact fluorescent lights use 66% less energy than a standard incandescent bulb and last up to 10 times longer.[64]

To increase the profile of greenhouse gas emissions to consumers, utilities could be required to include the energy-related emissions produced by a household within monthly bills. Promoting awareness about greenhouse gas emissions, renewable energy technologies and energy efficient products in tandem could assist Florida's native alternative energy industry and over time, reduce consumer energy costs.

Energy Efficiency and Conservation – Commercial & Industrial Sectors
In 2003, state government initiated contracts with Energy Service Companies (ESCOs) to evaluate state facilities for energy efficiency improvements. The ESCOs operate under performance contracts, receiving payment based on the savings generated for the State. In 1997, the Department of Corrections executed an energy savings contract with Florida Power and Light involving 16 institutions covering 4.6 million square feet. Over four years, the energy service contract has achieved a savings in electric, water and operating costs of more than $1.3 million annually. State government is leading by example with a strategic goal to reduce energy consumption by 25 percent below 2002 levels at all State government facilities by 2007. By 2006, state government should generate energy savings of over $1 million or 3.5 million kilowatt hours annually as a result of performance contracts with energy service companies.[65] To improve building efficiencies within State government and achieve the 2007 energy reduction goals, all new state buildings should meet the U.S. Green Building Council's Leadership in Energy and Environmental Design (LEED) standards or other comparable standards. Developed by all sectors of the building industry, the LEED program is a voluntary, consensus-based national standard for developing high-performance, sustainable buildings.

As advancements in clean energy technologies and energy efficient practices evolve, continued outreach and education is needed to make these opportunities mainstream. For example, Combined Heat and Power (CHP) is an efficient, clean, and reliable approach to generating power and thermal energy from a single fuel source. By better understanding the potential benefit of CHP, Florida's industrial sector can increase operational efficiency and decrease energy costs, while reducing emissions of greenhouse gases.

CHP can be considered a form of distributed generation which typically refers to self-generated, modular electricity generators sited close to the customer load. Distributed generation technologies include wind, solar, biomass, fuel cells, gas microturbines, hydrogen, combined heat and power, and hybrid power systems. Distributed generation systems can be integrated with electricity provided from a utility, enabling utilities to defer or eliminate costly investments in transmission and distribution system upgrades,

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[63] U.S. EPA and U.S. DOE, ENERGY STAR Savings Calculator, www.energystar.gov
[64] Ibid.
[65] Ibid.

and provide customers with better quality, more reliable energy supplies. Uniform connection standards will minimize barriers to distributed generation interconnection.

Energy Efficiency and Conservation – Research & Development
The Department of Environmental Protection is currently administering approximately $5 million in grant funding to advance renewable and emerging alternative energy technologies for electricity generation. Additional funding could build on these efforts and continue vital research and demonstration of these next generation technologies. Industry and the Florida's universities contain the experience and expertise necessary to improve alternative energy technologies. By sponsoring further research, development and demonstration projects, state government can continue fostering these technologies in the marketplace and spurring economic investment in Florida. The 2007 Legislature appropriated an additional $15 million in grant funding for research and demonstration projects associated with the development and implementation of renewable energy systems, expanding solar, hydrogen, biomass, wind, ocean current and other emerging technologies. By 2007, the grant portfolio should leverage the state government's investment at a rate greater than two to one.

Energy Efficiency – Zero Energy, Hurricane Resistant Homes
Zero Energy Homes (ZEH) are homes designed to use zero net energy from the utility grid. The concept is to couple the maximum possible building energy efficiency with the best available renewable energy resources in a way that maximizes the effectiveness of both. The Florida Solar Energy Center's first Zero Energy Home was built in Lakeland, Florida in 1998. A second-generation Zero Energy home has been constructed in New Smyrna Beach, Florida with many of the lessons learned during the design and construction of previous projects.

Some energy efficient building practices involve strengthened building systems and enhanced roof covering options that also provide exceptional windstorm resistance. Florida Green Building Coalition is working with developers, architects, builders, governments, realtors and academia to foster awareness of and voluntary standards for green buildings in Florida. As consumer awareness of green building performance grows, the market providing these options will grow as well. With over 185,000 detached single family homes being constructed in Florida annually, the combined energy savings would be significant.

Energy Efficiency and Conservation – Market Barriers
The U.S. Department of Energy's Building America is a housing research program organized and operated to conduct systems research for improving overall housing performance. Similarly, the U.S. Department of Housing and Urban Development's PATH program identifies, evaluates and publicizes new performance enhancing housing technologies. For years both programs have reported steadily and explicitly on many design, product selection and construction practices that measurably improve resource efficiency in housing, nevertheless the adoption rate of these ideas remains somewhat low. Even the relatively modest ENERGY STAR program only qualified 2,200 homes in Florida during 2004 out of 185,000 new, single-family detached homes built. In fact that

represents a drop from 2,400 qualified for the ENERGY STAR out of 155,000 Florida homes built in 2003. The benefits these programs offer are not widely recognized in Florida's housing market. As a policy option, developers of new buildings constructed and sold within Florida could be required to test the expected energy performance of the building and label that information to consumers much as is currently required for new appliances.

<u>Conclusions & Recommendations</u>

The public policy challenge presented by global climate change is immense. The scale and the complexity of the problems associated with managing greenhouse gas concentrations within the atmosphere will require sustained commitment over several generations of policy makers. Several other states have taken steps to address climate change. Appendix II contains a comprehensive overview of state policy approaches to the issues around global climate change. Despite these challenges, several conclusions and recommendations appropriate for Florida in 2006 can be presented.

Policy makers should consider climate policy as an exercise in prudent risk management, though the nature and the timing of the risk to be managed remains somewhat uncertain.

Element 1: Reducing Greenhouse Gas Emissions

Reduction policy solutions should focus on ensuring the total costs of goods and services correctly reflect the social costs associated with carbon emissions. The appropriate governmental role is to improve the efficiency and effectiveness of market processes to ensure private actions are executed with full cost information.

In the case of emission reduction policies, the market-based policies that guide the efficient allocation of reductions are less attractive at the state level as the costs involved are likely to decrease a state's competitive position versus its neighbors. Emission caps or carbon taxes should not be pursued within Florida at this time. We recommend that Florida look to the federal level for implementation of an equitable regulatory approach (whether carbon tax or cap-and-trade) across states. This said, the uncertainty around future carbon regulation clouds investment decisions for electricity generation in Florida and other high-growth states. The sooner this uncertainty is addressed, the better. To mitigate against an open-ended federal response, Florida may wish to set a target date three to five years in the future at which time carbon pricing will be required.

If active GHG emissions reduction policies are to be addressed, two possible scenarios (reducing emissions to 1990 levels by 2020 and capping future emissions at current levels) are presented in Appendix I.

In advance of active carbon regulation, the Legislature may wish to require that utilities incorporate potential carbon abatement or offset costs in filings before the Public Service Commission and to provide guidance to the Commission in how to interpret these costs in approving new generation investments.

State government should further the commitments made in the 2006 Florida Energy Plan to fully develop a Florida-based alternative energy sector. Alternative energy sources such as biomass, biogas, and advanced coal technologies (IGCC) for electric generation as well as biodiesel and ethanol for transportation can play a key role in avoiding future greenhouse gas emissions. Of particular note is the role of nuclear power in providing large-scale, cost effective energy with no emissions. Additional incentives to achieve these ends should be expanded.

Element 2: Greenhouse Gas Sink Development
Natural carbon storage will soften the cost of emission reductions while providing environmental benefits to the global commons. State climate policy should actively incorporate sink development and management.

State government should examine whether the enormous carbon storage capacity of state-owned lands could be monetized and used to support state climate policies or economic development objectives. The state's agricultural sector should be engaged to actively develop its "carbon cropping" potential through grants, extension services, and outreach. Research funding for state universities could be directed toward assessing and developing viable carbon storage strategies in the context of Florida's unique geology.

Element 3: Improving Greenhouse Gas Information and Data
The Legislature should provide authority to the Department of Environmental Protection to implement a statewide Greenhouse Gas Emissions Inventory to improve information and decision-making about carbon management. This inventory should incorporate emissions and sinks.

Element 4: Public Engagement
It is clear that individual energy use by citizens, whether at home or in driving, is the predominant factor in Florida's greenhouse gas emissions. Effective climate policy must incorporate outreach strategies, incentives, and improved information to citizens about their energy consumption choices. Building on the 2006 Florida Energy Plan to offer consumer incentives for efficient appliances could be extended. Improved information can be provided to consumers by providing energy cost labels on new homes or greenhouse gas emitted information on monthly power bills.

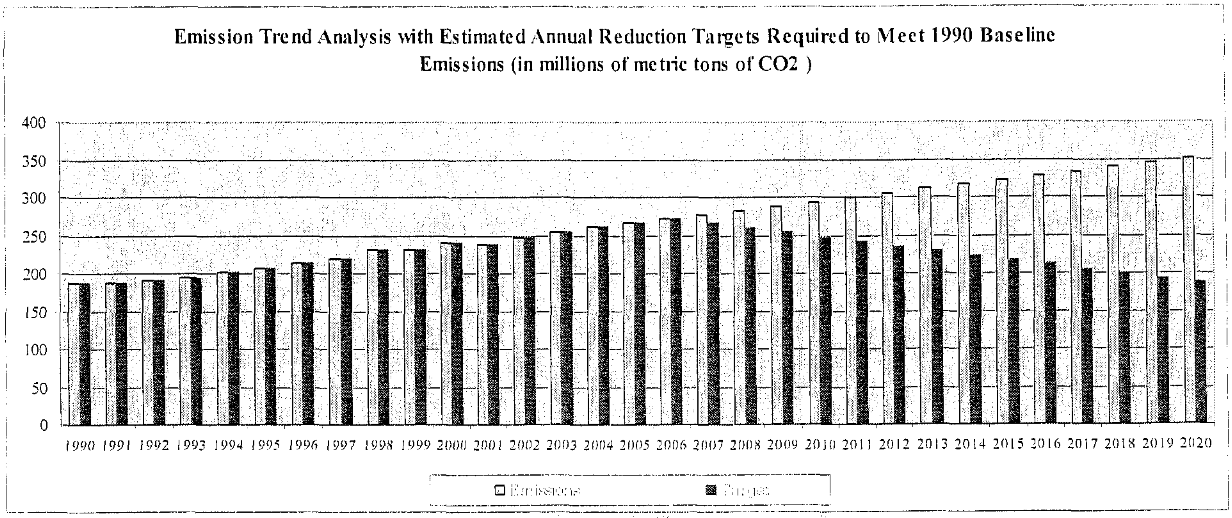
Developing a comprehensive climate policy for the State of Florida is appropriately the task of many stakeholders. Should policy development move forward at this time, a formal policy development process that includes industry, the public sector, and consumer interests should be established.

Appendix I: GHG Reduction Policy Scenarios

Option 1: Reduce Energy-Related CO_2 Emissions to 1990 Levels by 2020

Using current trends in population growth rates, economic activity, and regulations, by the year 2020, Florida would need to reduce CO_2 emissions by 164.1 MMT (over 45% of the projected "unabated" 2020 emissions level) to return to 1990 levels of 187.3 MMT.

Emission trends and reductions targets for energy-related CO_2 emissions



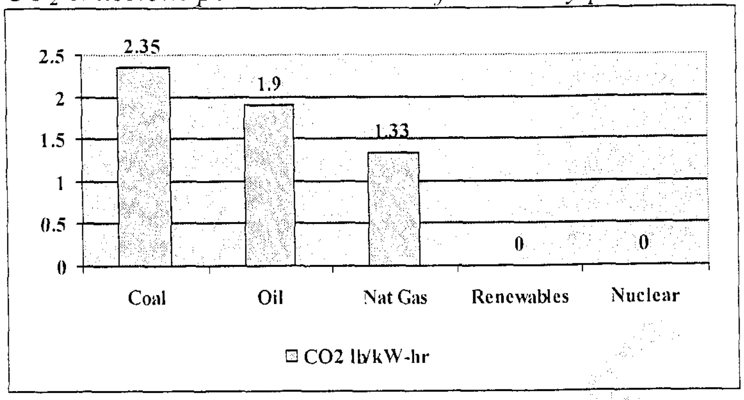
Given that 90 percent of Florida's 2001 energy-related CO_2 emissions were ascribed to the electric utility and transportation sectors, these sectors will bear the majority of the reductions needed to meet the 1990 baseline target by 2020.

- *Use of Renewable Fuels:* Possible CO_2 reductions may be had through use of renewable fuels to displace petroleum fuels. Maximizing Ethanol using E10 statewide for all grades of gasoline would provide a possible net reduction in CO_2 emissions from the combustion of gasoline of **1.8 million metric tons** (based on gasoline consumption of 2003). This option should leverage to the Governor's call for the '15 by '15 gallons of ethanol nationwide.

- *Increasing energy conservation and efficiency*: If energy use in Florida were reduced by 5 to 10 percent through a combination of conservation and energy efficiency programs, this would result in CO_2 reductions of between **9.1 and 18.2 million metric tons.**

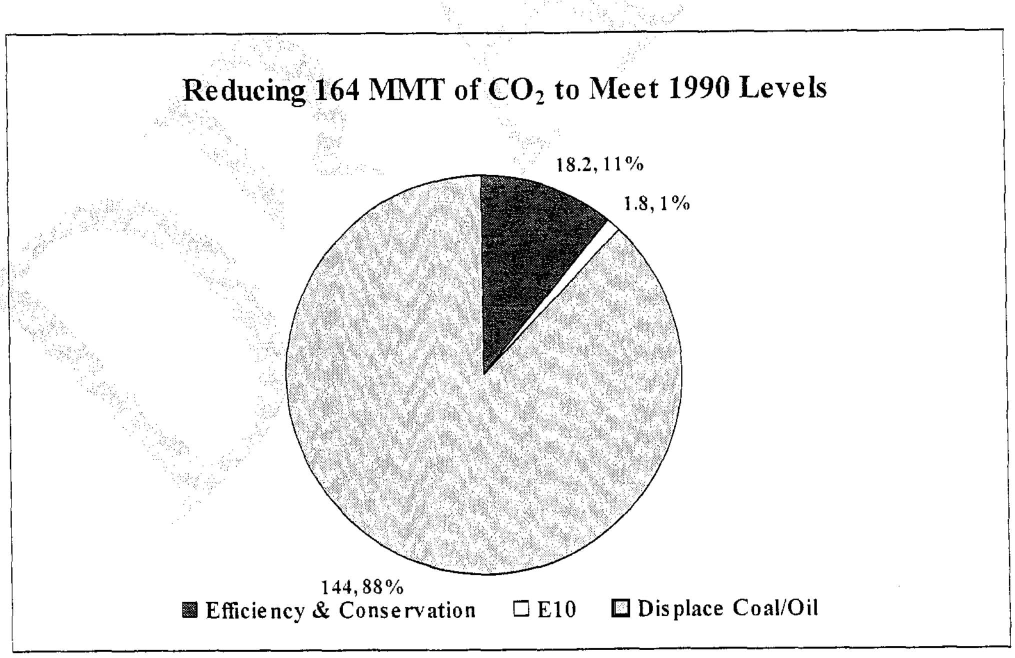
- *Achieving Significant CO_2 Reductions:* To achieve 1990 emissions levels by 2020 (and accounting for continued growth), Florida would need to reduce emissions from power plants by **144 MMT.** Because coal has the greatest CO_2 emission intensity, it would bear the brunt of this reduction.

CO_2 emissions per kilowatt hour of electricity produced



To achieve large CO_2 reductions, it is appropriate to consider displacing coal fired electric utilities with lesser emitting options. Displacing coal plants with oil or gas fired plants requires larger displacement than would be required with replacements that emit little or no net CO_2 (renewables or nuclear). In order to reduce CO_2 emissions from power plants to 1990 levels from future levels, **the existing (11,500 MW) and future (12,000 MW) capacity of coal and up to 6,600 MW (about 60 percent) of existing oil would need to be displaced to achieve a 144 MMT reduction in GHG emissions.**

The following graphic provides a summary of the best available options to meet the 1990 target without relying on offsets or credit trading outside of Florida.



Option 2: No New Growth in Electric Power-Related CO_2 Emissions
Florida could cap emissions of energy-related CO_2 emissions from the electric utility sector to the **2005 level of 131 MMT** and require future electric generation to find offsets or purchase credits from a Florida-only carbon market. Using current trends in

population growth rates, economic activity, and regulations, by the year 2020, **utilities would need to offset 41 MMT of CO_2 emissions in that year, representing 32% of the projected "unabated" 2020 emissions level.**

The exact mix of carbon offsets is unknowable in advance; the relative cost of carbon abatement strategies (conservation, demand-side management, changing fuels, and others) will drive utility decisions at each point when new capacity is required. Without conservation measures, by 2020 Florida utilities would need to displace 6,100 MW (50% of current installed capacity) of coal capacity to biomass or nuclear to remain under the 2005 cap.

Within this option, elements of option 1 including energy conservation and the ethanol E10 mandate could also be included. This second option is more equitable to the utility sector as they bear only the cost of CO_2 emission reductions within their own sector.

Reducing Other GHG Emissions

Aside from CO_2, methane and nitrous oxide represent the largest quantities of GHG to be addressed nationally. Specific emission levels within Florida are unknown. The largest sources of methane are landfills, natural gas pipelines, wastewater treatment, and manure from livestock. The largest source of nitrous oxide is the fertilization of agricultural lands. Under a Florida GHG Inventory, specific emission levels of these gases should be quantified. The Department proposes to further analyze estimated emissions of these gases and provide recommendations for reductions in tandem with CO_2 emissions.

Appendix II: Kyoto Signatory Nation Economic Analysis

State SDP of the top five U.S. states vs. GDP of Kyoto Signatory Nations committed to emission reductions and reduction targets by 2008-2012. Note that 127 other nations were signatories to the Kyoto Protocol, but did not commit to specific emission reductions.

State / Kyoto Signatory Nation	GDP (millions)	**Kyoto Targets** (Percent Reduction – Baseline Year 1990 by 2008 – 2012)
Japan	4,571,314	-6%
Germany	2,797,343	-8%
United Kingdom	2,201,473	-8%
France	2,105,864	-8%
Italy	1,766,160	-8%
California	**1,621,843**	N/A
Canada	1,130,208	-6%
Spain	1,126,565	-8%
Texas	**982,403**	N/A
New York	**963,466**	N/A
Russia	766,180	0%
Florida	**674,049**	N/A
Netherlands	625,271	-8%
Belgium	372,091	-8%
Switzerland	367,513	-8%
Sweden	358,819	-8%
Austria	307,036	-8%
Poland	300,533	-6%
Norway	296,017	+1%
Denmark	259,746	-8%
Greece	222,878	-8%
Ireland	199,722	-8%
Finland	193,491	-8%
Portugal	183,436	-8%
Czech Republic	123,603	-8%
Hungary	109,483	-6%
New Zealand	108,547	0%
Romania	98,566	-8%
Ukraine	81,664	0%
Slovakia	46,763	-8%
Luxembourg	34,184	-8%
Slovenia	34,030	-8%
Bulgaria	26,719	-8%
Lithuania	25,726	-8%
Latvia	16,648	-8%
Iceland	15,823	+10%
Estonia	13,108	-8%
Liechtenstein	Not Available	-8%
Monaco	Not Available	-8%

Appendix III: Comparative State Climate Policy Overview

State	Policy or Measure	Objective and / or Activity Affected
Alaska	House Bill 196 (2003)	Recognizes the potential for improved agricultural, forest and soil management practices to reduce CO_2 emissions. Creates a Carbon Sequestration Advisory Committee to recommend policies or programs to enhance state participation in carbon trading, identify sequestration research needs, review sequestration programs of other states, and evaluate potential GHG restriction regimes.
Arizona	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources.
	House Bill 2103	Expands the definition of "clean burning fuel" to include a diesel fuel that: contains a maximum of 15 parts per million by weight of sulfur, meets American Society for Testing and Materials standard, meets EPA's registration requirements for fuels and additives.
	House Bill 2442	Sets a limit of $10,000 on the total amount of money an owner of diesel vehicles registered as a fleet can receive to repair and retrofit the vehicles under the voluntary vehicle repair and retrofit program, known as V2R2.
	House Bill 2585	Authorizes the Department of Environmental Quality (DEQ) to submit to EPA a state implementation plan (SIP) to address regional haze visibility impairment in mandatory federal class I areas under the federal Clean Air Act
California	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
	Climate Registry	Voluntary GHG registry
	Executive Order	2005 – GHG reduction targets equivalent to reaching 2000 emission levels by 2010, 1990 levels by 2020, and 80% below current levels by 2050

	2001 Energy Conservation Package	Legislation dedicated $850 million to conservation initiatives and incentives including agricultural energy efficiency and load reduction, high-efficiency lighting in commercial buildings, low-interest loans for energy efficiency projects in schools and local jurisdictions, innovative peak load reduction, energy-efficient household appliances, and energy efficiency in state buildings.
	Greenhouse Gas Standard for Vehicles	Establishes nation's first GHG emission standards for light-duty vehicles. California Air Resource Board adopting standards that will achieve the maximum feasible and cost-effective reduction of greenhouse gas emissions from motor vehicles.
	Zero Emission Vehicle Incentive Program	Provides grants up to $5,000 per vehicle toward the purchase or lease of new zero-emission vehicles.
	California Renewables Program	Law authorized collection of $540 million from investor-owned utilities, between 1998 and 2002-- to be used to support renewable energy technologies within the state. Funds are placed in Renewable Resources Trust Fund and are distributed as incentives or rebates for those who generate or purchase renewable energy or for those who install renewable systems.
Colorado	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
Connecticut	Regional Greenhouse Gas Initiative (RGGI)	Participate in Regional Cap-and-trade system covering carbon dioxide (CO_2 emissions from regional power plants
	Eastern Climate Registry	GHG registry formerly known as Greenhouse Gas Registry
	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources

	Public Act 90-219, HB 5696	1990 – Requires specific actions for reducing CO_2 by establishing a broad range of energy conservation measures, including revisions to the building code to maximize energy efficiency and requirements that the state purchase energy efficient appliances and vehicles. The Act also establishes goals for improving public transportation and requires the Connecticut Public Transportation Commission (CPTC) to monitor progress in achieving them. The Act allows the Environmental Protection Commissioner, in connection with air discharge permits, to require trees or grass to be planted to offset carbon dioxide emitted into the atmosphere. The Act also reduces the ability of municipalities to provide tax abatement for multilevel parking garages.
Delaware	Regional Greenhouse Gas Initiative (RGGI)	Participate in Regional Cap-and-trade system covering carbon dioxide (CO_2 emissions from regional power plants
	Eastern Climate Registry	GHG registry formerly known as Greenhouse Gas Registry
	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
District of Columbia	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
Georgia	No-Tillage Assistance Program	Leases "no-till" equipment to farmers, allowing them to increase the amount of carbon sequestered in their soils.
	Senate Bill 356	Directs the Georgia Forestry Commission to create a registry of GHG reductions achieved through carbon sequestration activities.
Hawaii	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources.
	House Bill 1893 (2000)	Encourages GHG emission reductions and carbon sequestration through agriculture and forestry
	Senate Bill 1253 (2000)	Establishes a fee-based pollution fund to develop carbon offset forestry projects. Fund intended to aid in management and accounting of carbon sinks and carbon offset forestry projects
Idaho	Senate Bill 1379 (2002)	Creates the Carbon Sequestration Advisory Committee and the Carbon Sequestration Assessment Fund.
	Tax Deduction	Income tax deduction to taxpayers who install an alternative energy device including solar, wind or geothermal device used for heating or generating electricity (Idaho Tax Code 63-3022c)
Illinois	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources

	Senate Bill 372 (August 7, 2001).	Requires the Illinois Environmental Protection Agency to establish an interstate NOx trading program and issue findings that address the need to control or reduce emissions from fossil fuel-fired electric generating plants. The findings are to address the establishment of a banking system, consistent with the U.S. Department of Energy's voluntary reporting system, for certifying credits for voluntary offsets of emissions of greenhouse gases, or reductions of greenhouse gases.
	House Bill 842. (2001).	Carbon Sequestration Act. Creates the Carbon Sequestration Advisory Committee and establishes its membership and duties to prepare a report with findings and recommendations for studying carbon sequestration, including various trading options and alternatives, and considering air quality and the preservation of agricultural resources.
	Clean Energy Community Trust	Provides grants, loans and other financial incentives to develop, improve and implement energy efficiency and renewable energy projects and programs.
Indiana	Public Facility Energy Efficiency Program	Provides loans from the Indiana Efficiency Loan Fund to help schools, political subdivisions, and public libraries identify and implement energy projects. Zero-interest loans are available for up to $100,000 and do not require matching funds.
Iowa	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
	Mandatory Green Pricing Programs	Green Pricing (Pay premium on electric bill to have portion of power provided from designated renewable sources) options mandatory for electricity generators
	Pilot Program	Department of Natural Resources provides support, funding and information to promote switchgrass as a biomass energy crop with the potential for large-scale production across Iowa by improving production of switch grass to co-fire with coal in power plants.
	Building Energy Management Program	Enables schools, local governments, private colleges, hospitals and state agencies to identify and implement cost-effective energy management improvements without incurring any up-front costs.
Kansas	Tax Credit	Provides income tax credits equal to 50 percent of the incremental or conversion cost of an alternative-fuel vehicle.

Maine	Regional Greenhouse Gas Initiative (RGGI)	Participate in Regional Cap-and-trade system covering carbon dioxide (CO_2 emissions from regional power plants
	Eastern Climate Registry	GHG registry formerly known as Greenhouse Gas Registry
	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
	Public Law 1997, Ch. 316. (1999)	Establishes customer information disclosure requirements for electricity providers. The legislation, passed as part of a broader electricity restructuring package, requires a disclosure label showing electricity customers information on the price, resource mix and emissions in a uniform format. The provisional rule requires the disclosure of carbon dioxide (CO2), nitrogen oxide (NOx), and sulfur dioxide (SO2). The provision specifies that for each of the three emission categories, the emission rate of the resource portfolio will be compared to New England regional average emission.
Maryland	Regional Greenhouse Gas Initiative (RGGI) (2006)	Participate in Regional Cap-and-trade system covering carbon dioxide (CO_2 emissions from regional power plants
	Eastern Climate Registry	GHG registry formerly known as Greenhouse Gas Registry
	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
	Energy Executive Order to state facilities	Purchase a percentage of energy from green sources; evaluate energy efficiency in state building design and maintenance; purchase ENERGY STAR[R] labeled products when available.
	Tax Credits	Income Tax credits for the production and sale of electric power from biomass combustion, including energy crops and poultry litter
	Excise Tax Exemption	Tax Exemption for purchase of new electric vehicles and purchase of new hybrid-electric vehicles.
Massachusetts	Eastern Climate Registry	GHG registry formerly known as Greenhouse Gas Registry

	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
	Regulation of Electric Utility Emissions (April 2001)	Regulation binding reduction requirements for CO_2
	DEP Regulation 310 CMR 7.29. (APRIL 23, 2001).	Requires the six highest-polluting power plants in Massachusetts to meet overall emission limits for NOx (1.5 lbs/MWh) and SO2 (3.0 lbs./MWh) by October 1, 2004 and begin immediate monitoring and reporting of mercury emissions. For the six affected plants, the rule caps total CO2 emissions and creates an emission standard of 1,800 lbs. of carbon dioxide per megawatt-hour (a reduction of 10% below the current average CO2 emissions rate). The CO2 limits must be met by October 1, 2006 or October 1, 2008 for plant retrofit or replacement.
	Massachusetts Department of Telecommunications and Energy. 220 CMR 11.00: *Rules Governing The Restructuring Of The Electric Industry*. (February 20, 1998).	Establishes customer information disclosure requirements for electricity providers. The legislation, passed as part of a broader electricity restructuring package, requires a disclosure label showing electricity customers information on the price, resource mix and emissions in a uniform format. The provisional rule requires the disclosure of carbon dioxide (CO2), nitrogen oxide (NOx), and sulfur dioxide (SO2).
Minnesota	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
	Mandatory Green Pricing Programs	Green Pricing (Pay premium on electric bill to have portion of power provided from designated renewable sources) options mandatory for electricity generators
	Minnesota Public Utilities Commission. (January 3, 1997)	The Minnesota Public Utilities Commission voted to accept a .30 - 3.10 $/ton (1995 dollars) of CO2 valuation for the global warming impacts/costs of carbon emissions from utility power plants. They did so on the basis of a damage-cost assessment conducted by the Minnesota Pollution Control Agency
	Division of Lands and Forestry Statute Section 88.82	Establishes the Minnesota ReLeaf Program in the Department of Natural Resources to encourage, promote and fund planting, maintenance, and improvement of trees in the state to reduce CO_2 levels, promote energy conservation, and achieve other environmental benefits.

	E-10 Law	Requires that all gasoline sold in the state contain 10 percent ethanol by volume.
Missouri	Revolving Loan Fund	Department of Natural Resources has a revolving loan fund that provides schools and local governments with technological and financial assistance to implement energy-efficient upgrades.
Montana	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
	Mandatory Green Pricing Programs	Green Pricing (Pay premium on electric bill to have portion of power provided from designated renewable sources) options mandatory for electricity generators
Nebraska	Legislative Bill 957. (2000)	A bill to create the Carbon Sequestration Advisory Committee to document and quantify reductions related to agricultural practices; to provide duties; and to create the Carbon Sequestration Assessment Cash Fund
Nevada	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
New Hampshire	Regional Greenhouse Gas Initiative (RGGI)	Participate in Regional Cap-and-trade system covering carbon dioxide (CO_2 emissions from regional power plants
	Eastern Climate Registry	GHG registry formerly known as Greenhouse Gas Registry
	House Bill 284 (January 2, 2002)	Establishes caps for emissions of sulfur dioxide, oxides of nitrogen, mercury, and carbon dioxide by existing fossil fuel burning steam electric power plants. This bill permits the banking and trading of emissions reductions to achieve compliance with the caps. Sets goal of reducing CO2 emissions to 7% below 1990 levels by 2007.
New Jersey	Regional Greenhouse Gas Initiative (RGGI)	Participate in Regional Cap-and-trade system covering carbon dioxide (CO2) emissions from regional power plants
	Eastern Climate Registry	GHG registry formerly known as Greenhouse Gas Registry
	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
	Executive Order 1998-09	Reduce state's annual GHG emissions to 3.5 percent below 1990 levels by 2005
New Mexico	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
	Mandatory Green Pricing Programs	Green Pricing (Pay premium on electric bill to have portion of power provided from designated renewable sources) options mandatory for electricity generators

	Senate Bill 18	Requires state agencies and educational institutions to acquire vehicles capable of operating on alternative fuel; requires reporting of such acquisitions by state agencies.
	Forest ReLeaf Program (1990)	An environmental education and tree planting grant program, provides grants to municipalities, schools, and organizations for tree planting projects.
New York	Regional Greenhouse Gas Initiative (RGGI)	Participate in Regional Cap-and-trade system covering carbon dioxide (CO_2 emissions from regional power plants
	Eastern Climate Registry	GHG registry formerly known as Greenhouse Gas Registry
	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
	Energy Executive Order to state facilities	Purchase a percentage of energy from green sources; evaluate energy efficiency in state building design and maintenance; purchase ENERGY STAR[R] labeled products when available.
	Keep Cool Program	Provides bounty payments to consumers upon return of older working room air conditioners when they purchase new ENERGY STAR room air conditioners.
	Clean-fueled bus program	Provides funding to transit authorities, state agencies, universities, municipalities, and schools to cover the incremental cost of a clean-fueled bus over a diesel bus.
	Clean Air School Bus Program	Under this program, 2,200 diesel school buses across New York State will be retrofitted with diesel oxidation catalysts and diesel particulate filters.
North Carolina	Senate Bill 1078 and House Bill 1015. (April 23, 2001)	Requires reductions in the emissions of certain pollutants from large-scale coal-fired generating units owned by investor-owned public utilities. The bill establishes collective emission caps for nitrogen oxides (NOx) and sulfur dioxide, as well as a timetable for meeting these standards.
North Dakota	Tax Incentive	Provides tax incentives for geothermal heat pumps and other geothermal energy systems (North Dakota Tax Code 57-38-01.8)
Ohio	Carbon Sequestration Pilot	Pilot project to sequester carbon in a deep underground rock formation on border between West Virginia and Ohio.
Oklahoma	House Bill 1192: (April, 2001)	Create the Carbon Sequestration Advisory Committee to document and quantify reductions related to agricultural practices; to provide duties; and to create the Carbon Sequestration Assessment Cash Fund.

Oregon	House Bill 3283. (1997)	Siting legislation that establishes a CO_2 standard requiring new utilities to emit 17% less than most energy efficient plant available. The bill capped CO_2 emissions at 0.7 pounds of CO_2 per kilowatt-hour for base-load natural gas-fired power plants; in 1999 the cap was lowered to 0.675 pounds per kilowatt-hour.
	House Bill 2200 (2001)	Directs the Department of Forestry to link the Forest Resource Trust, state forestlands, and bring together representatives of other non-federal landowner's programs by developing a shared carbon accounting system.
	Tax Credits	Energy-efficient appliances that meet certain standards qualify for a state tax credit.
	Green Power Projects	Office of Energy manages two programs: Business Energy Tax Credit Program – provides 35 percent tax credit for eligible project costs Small-Scale Energy Loan Program – offers low-interest loans for projects that save energy, produce energy from renewable sources, use recycled materials or use alternative fuel.
Pennsylvania	Eastern Climate Registry	GHG registry formerly known as Greenhouse Gas Registry
	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
Rhode Island	Eastern Climate Registry	GHG registry formerly known as Greenhouse Gas Registry
	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
	House Bill 6899. (2000)	Responds to Climate Change issue by encouraging private property owners to maintain woodlands for sufficient time so as to maximize atmospheric carbon conversion to biomass.
South Dakota	Senate Bill 126 (2000)	Created the Carbon Sequestration Advisory Committee to evaluate the potential for landowners to participate in carbon trading systems.
	House Bill 1150	Establishes $250,000 fund for carbon sequestration research for agricultural lands through July 2001.
Tennessee	Senate Bill 2844 & House Bill 2546 (2000)	"Biobased Products for Farmers and Rural development Act of 2000", whereby the Assembly finds that the development of bio-based products would … decrease greenhouse gas emissions… and provide greater consumer choices for power, fuel, and commercial products.

Texas	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources, requires all electricity providers to obtain renewable energy capacity, finance construction of renewable energy facilities, and develop new renewable energy resources.
	Climate Registry	Voluntary GHG registry
Vermont	Regional Greenhouse Gas Initiative (RGGI)	Participate in Regional Cap-and-trade system covering carbon dioxide (CO_2 emissions from regional power plants
	Eastern Climate Registry	GHG registry formerly known as Greenhouse Gas Registry
	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
	Methane Pilot Project	Promotes the use of methane recovery technology on dairy farms.
	Residential Energy Efficiency Program (REEP)	Works with property developers, owners and managers to reduce energy costs and promote long-term affordability of low-income housing. This unique partnership between local utilities and the low income Weatherization Assistance Program (WAP) leverages utility incentives, WAP subsidies, and owner investments to implement all cost-effective energy measures.
Washington	Mandatory Green Pricing Programs	Green Pricing (Pay premium on electric bill to have portion of power provided from designated renewable sources) options mandatory for electricity generators
	House Bill 5121 (2000)	Establishes a carbon storage program as an economic incentive to maintain long-term forest production.
	Tax Exemption	Wind, solar, and landfill gas electric generating facilities are eligible for exemption from state sales and use taxes.
	Commute Trip Reduction Law	The law requires businesses with worksites employing more than 100 people in nine Washington counties to develop programs to encourage their workers to commute by mass transit, carpooling, vanpooling, telecommuting, walking or biking.
West Virginia	Carbon Sequestration Pilot	Pilot project to sequester carbon in a deep underground rock formation on border between West Virginia and Ohio.
	House Bill 4163	Authorizes the Division of Environmental Protection to promulgate legislative rules regarding ambient air quality standards for sulfur oxides, particulate matter, carbon monoxide and ozone. Further authorizes the division to promulgate legislative rules regarding a NOx budget trading program to control and reduce nitrogen oxides

	Tax Code Changes	Tax code changes to remove barriers to wind power development.
Wisconsin	Renewable Portfolio Standards	Mandate electric utilities to generate a specified amount of electricity from renewable sources
	Climate Registry	Voluntary GHG registry
Wyoming	House Bill 0047. (2001).	Created the Carbon Sequestration Advisory Committee to recommend policies or programs to enhance the ability of agriculture and forest landowners to participate in carbon trading systems. Created the Carbon Sequestration Advisory Committee to document and quantify reductions related to agricultural practices; to provide duties; and to create the Carbon Sequestration Assessment Cash Fund.

State and Regional Emissions Targets

State	Target	Notes and Source
Arizona	2000 levels by 2020 50% below 2000 by 2040	Executive Order 2006-13
California	2000 levels by 2010 1990 levels by 2020 80% below 1990 by 2050	Executive Order S-3-05
Connecticut	1990 levels by 2010 10% below 1990 by 2020	Connecticut Climate Change Action Plan
Maine	1990 levels by 2010 10% below 1990 by 2020 75-80% below 2003 long-term	LD 845 (HP622)
Massachusetts	1990 levels by 2010 10% below 1990 by 2020 75-85% below 1990 long-term	Massachusetts Climate Protection Plan of 2004
New Hampshire	1990 levels by 2010 10% below 1990 by 2020 75-85% below 2001 long-term	The Climate Change Challenge
New Jersey	3.5% below 1990 by 2005	Administrative order 1998-09
New Mexico	2000 levels by 2012 10% below 2000 by 2020 75% below 2000 by 2050	Executive Order 05-033
New York	5% below 1990 by 2010 10% below 1990 by 2020	State Energy Plan of 2002
Oregon	Stabilize by 2010 10% below 1990 by 2020 75% below 1990 by 2050	Oregon Strategy for Greenhouse Gas Reductions
Rhode Island	1990 levels by 2010 10% below 1990 by 2020	Rhode Island Greenhouse Gas Action Plan
Vermont	1990 levels by 2010 10% below 1990 by 2020 75-85% below 2001 long-term	

New England States - New England Governors and Eastern Canadian Premiers: Regional Economy-wide	1990 levels by 2010 10% below 1990 by 2020 75-85% below 2001 long-term	Climate Change Action Plan

SR/OIAF/2004-06

Analysis of Senate Amendment 2028, the Climate Stewardship Act of 2003

May 2004

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

Analysis of Senate Amendment 2028, the Climate Stewardship Act of 2003

Energy Information Administration
May 2004

Introduction

In June 2003, the Energy Information Administration (EIA) released an analysis[1] of the Climate Stewardship Act of 2003 (S.139) as introduced by Senators McCain and Lieberman in January 2003. S.139 would establish a cap on emissions of greenhouse gases[2] from covered sources that would be implemented in two phases beginning in 2010 and 2016 respectively. More recently, in October 2003, Senators McCain and Lieberman proposed an amended version of the bill, SA.2028, that included the first phase of emissions reductions beginning in 2010 but removed references to a second phase of reductions beginning in 2016.

On May 11, 2004, Senator Landrieu asked EIA to evaluate SA.2028. This paper responds to that request, relying on the modeling methodology, data sources, and assumptions used to analyze the original bill, as extensively documented in EIA's June 2003 report. By using the same modeling system and assumptions, the impacts of SA.2028 can be compared as a sensitivity case to the previously reported results for S.139. However, these results do not reflect updates to EIA's modeling system and the reference case energy forecast that were included in the *Annual Energy Outlook 2004 (AEO2004)*.[3] Given Senator Landrieu's request for an expedited response, it was not possible to undertake a completely new analysis using the latest updates to the model.

In addition to removing references to a second phase of emission reduction, SA.2028 made several other changes with possible implications for the results. These include:

- SA.2028 omits a provision in S.139 that would have allowed automobile manufacturers to obtain emission allowances in exchange for exceeding the Corporate Average Fuel Economy (CAFÉ) standards by over 20 percent. This change is reflected in EIA's analysis.

- SA.2028 now states explicitly that emissions from fuel sold for transportation outside the United States (i.e., "bunker fuels") are not covered sources. Because EIA's modeling system does not estimate emissions from bunker fuels separately, the exemption for bunker fuels is not reflected in EIA's analysis. Because carbon dioxide emissions from bunker fuels were 1.6 percent of total energy-related carbon dioxide emissions in 2002, the exclusion of bunker fuels from the cap should not materially affect the results.

- SA.2028 adds a provision entitled "Dedicated Program for Sequestration in Agricultural Soils." The provision allows an entity to satisfy up to 1.5 percent of its total allowance

[1] Energy Information Administration, *Analysis of S.139, the Climate Stewardship Act of 2003*, SR/OIAF/2003-02 (Washington, DC, June 2003). For full report, see http://www.eia.doe.gov/oiaf/servicerpt/ml/pdf/sroiaf(2003)02.pdf and for the highlights and summary, see http://www.eia.doe.gov/oiaf/servicerpt/ml/pdf/summary.pdf .
[2] S.139 covers emissions of the following greenhouse gases: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).
[3] Energy Information Administration, *Annual Energy Outlook 2004* includes a discussion of key changes between the 2003 and 2004 reference case forecasts. See http://www.eia.doe.gov/oiaf/aeo/index.html .

submission requirements by submitting registered increases in net carbon sequestration in agricultural soils. Entities remain subject to a 15-percent overall limit on offsets. EIA's analysis methodology incorporates this provision through marginal abatement cost curves for agricultural and forestry combined, but does not separately constrain the proportion of that carbon sequestration from agricultural soils.

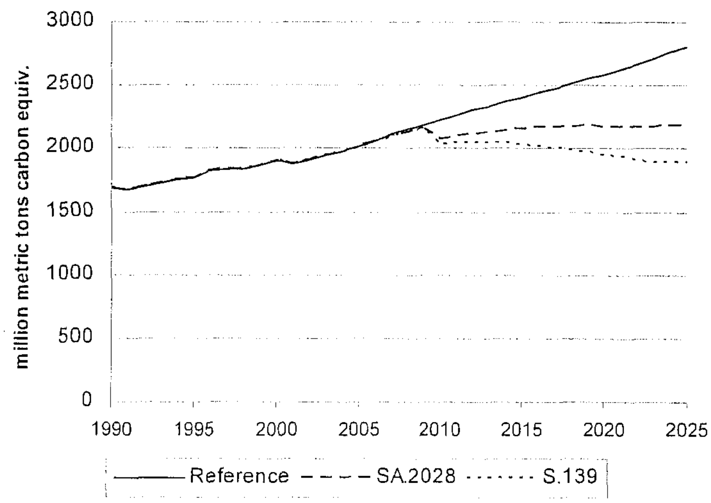
For the sake of brevity, the following discussion of the SA.2028 case assumes familiarity with EIA's previously published analysis of S.139. The SA.2028 case is compared both to the updated reference case from the *Annual Energy Outlook 2003*, on which the previous analysis was based, and the S.139 case.

Analysis of the SA.2028 Case

Emissions and Allowance Costs

The most significant change in SA.2028 relative to S.139 is the removal of references to a more restrictive second phase of emission caps beginning in 2016. While this change has its greatest impact after 2016, it also reduces some of the incentive to over-comply and bank allowances during the 2010 to 2015 period. Therefore, the realized level of covered emissions between 2010 and 2015 would tend to be higher in SA.2028, even though the allowance cap over that time period is the same as under S.139 (Figure 1). Eliminating the second phase also means that the cap on the use of offsets remains at 15 percent, instead of being reduced to 10 percent in 2016, as in S.139. This added flexibility helps to reduce the compliance costs of SA.2028 compared to S.139.

Figure 1. U.S. Greenhouse Gas Emissions in the Reference, S.139, and SA.2028 Cases, 1990-2025

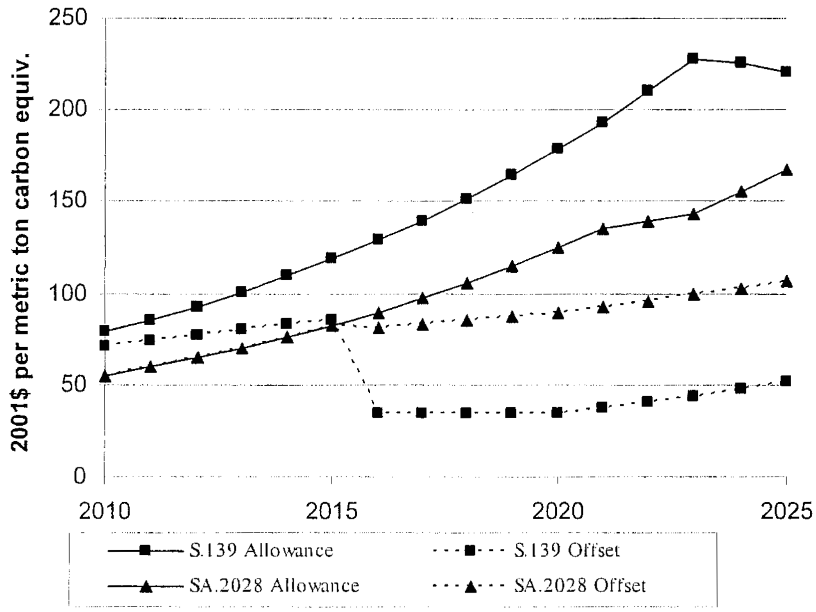


Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs, MLBASE.D050303A, MLBILL.D050503A, and SA2028.D051104A.

With a less restrictive emissions limit under SA.2028, the market for allowances would be expected to clear at a lower price than under S.139 (Figure 2). Estimated allowance prices (in 2001 dollars) grow from $55 per metric ton carbon equivalent in 2010 to $167 in 2025 under

SA.2028, compared to a growth of $79 to $221 dollars over the same period under S.139. Thus, on average, emission allowance costs are estimated to be about 30 percent less under SA.2028. With higher covered emissions and lower allowance costs from 2010 to 2015, the use of emissions offsets to comply is initially reduced under SA.2028. As a result, the limit on offset usage from 2010 to 2015 is not binding. In this situation, the markets for emission offsets and allowances are expected to clear at the same price. By 2016, however, the 15-percent limit on offsets is reached, and competition to supply this constrained demand for offsets causes the offset price to clear below the allowance market price. The allowance price remains higher than the offset price after 2016.

Figure 2. Estimated Greenhouse Gas Allowance and Offset Prices in the S.139 and SA.2028 Cases, 2010-2025



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBILL.D050503a and SA2028.D051104A.

The use of offsets is 75 percent greater beginning in 2016 under SA.2028 than under S.139, since the maximum allowable percentage remains at 15 percent instead of dropping to 10 percent and because the emission cap on which that percentage is applied is higher. This allows the offset market to clear at a higher price after 2015 than in S.139 case, but reduces overall compliance costs since offsets are still cheaper than allowances.

Table 1 compares the emissions-related results of the reference, S.139, and SA.2028 cases for 2010 and 2025.

Table 1. Summary of Greenhouse Gas Emission Results, Reference, S.139, and SA.2028 Cases, 2010 and 2025 (million metric tons of carbon equivalent)

	2001	2010			2025		
		Reference	S.139	SA.2028	Reference	S.139	SA.2028
Greenhouse Gas Emissions							
Energy-Related Carbon Dioxide	1,559	1,802	1,710	1,746	2,234	1,482	1,777
Non-Energy Carbon Dioxide	36	40	40	40	46	46	46
Methane	175	178	115	120	172	120	113
Nitrous Oxide	119	127	121	121	143	137	137
High-GWP Gases (HFCs, PFCs, and SF6)	39	84	50	52	209	106	107
Total	**1,928**	**2,230**	**2,036**	**2,079**	**2,806**	**1,891**	**2,181**
S.139 Compliance Summary							
Covered Energy-Related Carbon Dioxide	1,379	1,605	1,513	1,549	2,014	1,257	1,556
Other Covered GHG Emissions	75	124	70	72	251	128	129
Total Covered Emissions	**1,454**	**1,729**	**1,583**	**1,621**	**2,265**	**1,385**	**1,685**
Offset Reductions Purchased							
Noncovered Greenhouse Gases			49	44		39	46
Increases in Biological Carbon Sequestration			113	104		87	112
International Offsets			73	51		0	62
Total Offset Reductions			**235**	**199**		**126**	**220**
Covered Emissions, less Offsets	1,454	1,729	1,349	1,423	2,265	1,259	1,465
Emission Allowances Issued			1,465	1,465		1,258	1,465
Net Allowance Bank Change (+deposit, - withdrawal)			117	42		-1	0
Allowance Price							
(2001 dollars per metric ton carbon equivalent)			79	55		221	167
(2001 dollars per metric ton carbon dioxide equivalent)			22	15		60	46
Offset Trading Price							
(2001 dollars per metric ton carbon equivalent)			71	55		52	106
(2001 dollars per metric ton carbon dioxide equivalent)			19	15		14	29

GWP=Global warming potential.
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and SA2028.D051104A. 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 (EPA). The EPA data included a business-as-usual case, developed in preparing the *Climate Change Action Plan 2001* and extrapolated to 2025.

Energy Sector Results

Under SA.2028, the effective cost of using energy increases compared to the reference case. This occurs because the costs of emission allowances (or their opportunity costs) are passed through to energy consumers. Consumers in the covered sectors will face higher costs for fossil fuels. Electricity consumers in all sectors are expected to face higher prices, as electricity suppliers pass their compliance costs on to customers.

Table 2 presents a summary of the key energy-related results for 2010 and 2025 for the reference, S.139, and SA.2028 cases. In general, the direction of changes in the SA.2028 case is the same as in the S.139 case, but the magnitudes of the changes are reduced, as the SA.2028 case is not as restrictive. In both the S.139 and SA.2028 cases, the use of natural gas, nuclear power, and renewable energy sources is greater than in the reference case, and the use of petroleum and coal is lower.

Energy price increases under SA.2028 are also lower than those under SA.139, resulting in correspondingly lower reductions in energy demand. Impacts of SA.2028 on delivered energy prices vary across sectors and fuels. The variation across sectors depends on whether or not a particular sector is covered under the bill and on the importance of distribution-related costs not impacted by the bill in the overall delivered energy price to each sector. For example, in the residential and commercial sectors, the delivered price of natural gas is virtually unchanged from the reference case level in 2010 and only 4 percent higher than the reference case in 2025. Greater increases occur in the average price of natural gas in the industrial and electric power sectors, 21 percent in 2010 and 58 percent in 2025, because the prices in these sectors include the allowance cost and distribution costs are a smaller component of delivered prices to these sectors.

The increases in gasoline prices projected to occur under SA.2028, 9 percent in 2010 and 19 percent in 2025 relative to the reference case, are expected to result in gradually increasing fuel economy in new passenger vehicles, reaching 27.2 miles per gallon by 2025, an increase of 0.8 miles per gallon over the reference case. Under the S.139 case, projected fuel economy for new vehicles reaches 29 miles per gallon by 2025. SA.2028 eliminates the additional incentive under S.139 that would allow automobile manufacturers to obtain emission allowances in exchange for exceeding the CAFE standards by over 20 percent. Had this incentive been retained in SA.2028, the average fuel economy for new light-duty vehicles in 2025 would be an estimated 0.6 miles per gallon higher, or 27.8 miles per gallon.

In both the SA.2028 and S.139 cases, the electric power sector accounts for about 88 percent of estimated emission reductions. Under SA.2028, however, the reduction in electric-power sector carbon dioxide from the reference case in 2025 is estimated at 404 million metric tons carbon equivalent (47 percent), compared to 663 (76 percent) in the S.139 case. As a result, only 26 gigawatts of nuclear power capacity are added by 2025 under SA.2028, compared to 49 gigawatts in the S.139 case. Relative to the reference case, the price of electricity increases less under SA.2028 (35 percent by 2025) than under S.139 (46 percent by 2025).

The production of coal is not expected to be as severely curtailed under SA.2028 as under S.139. Under SA.2028, coal production is reduced by 8 percent in 2010 and by 59 percent in 2025 relative to their respective reference case levels. Under S.139, the reductions in coal production relative to the reference case are estimated to be 14 percent in 2010 and 78 percent in 2025.

Table 2. Summary of Energy Sector Results in the Reference, S.139, and SA.2028 Cases, 2010 and 2025

Summary Indicators	2001	2010 Reference	2010 S.139	2010 SA.2028	2025 Reference	2025 S.139	2025 SA.2028
Greenhouse Gas Allowance Cost (2001 dollars per metric ton carbon equivalent)	---	---	79	55	---	221	167
Effective Delivered Energy Prices (2001 dollars per million Btu)							
Coal	1.26	1.18	3.18	2.59	1.12	6.44	5.22
Natural Gas	6.40	5.15	5.96	5.66	5.64	8.22	7.51
Residential and Commercial	8.88	7.14	7.24	7.15	7.63	8.04	7.90
Industrial and Electric Power	4.84	3.95	5.22	4.78	4.64	8.29	7.31
Motor Gasoline	11.57	11.45	12.98	12.53	12.07	15.31	14.41
Jet Fuel	6.20	5.66	7.10	6.64	6.72	10.35	9.42
Distillate Fuel	9.16	9.15	10.45	10.04	9.90	13.17	12.28
Residential and Commercial	8.12	7.16	7.12	7.11	8.07	7.65	7.72
Industrial and Electric Power	6.50	5.71	7.23	6.74	7.08	10.85	9.93
Transportation	10.05	10.19	11.71	11.23	10.64	14.37	13.32
Electricity	21.34	18.76	20.40	19.94	19.66	28.70	26.57
Primary Energy Use (quadrillion Btu)							
Natural Gas	23.26	27.35	28.12	27.63	35.55	39.54	37.54
Petroleum	38.46	44.45	43.74	43.97	56.11	50.76	53.04
Coal	22.02	25.47	22.00	23.50	29.86	6.74	13.86
Nuclear	8.03	8.25	8.37	8.37	8.28	12.39	10.50
Renewable	5.32	7.30	9.03	8.62	8.77	16.22	15.31
Other	0.21	0.31	0.43	0.42	0.06	0.32	0.24
Total	**97.29**	**113.13**	**111.67**	**112.50**	**138.63**	**125.97**	**130.50**
Electricity Sales (quadrillion Btu)	11.65	14.00	13.82	13.86	17.90	15.87	16.38
Carbon Dioxide Emissions by Fuel (million metric tons carbon equivalent)							
Natural Gas	329	391	402	395	509	493	533
Petroleum	668	761	748	752	963	870	912
Coal	561	650	560	599	763	119	332
Total	**1,559**	**1,802**	**1,710**	**1,746**	**2,234**	**1,482**	**1,777**
Carbon Dioxide Emissions by Sector (million metric tons carbon equivalent)							
Residential	314	355	326	337	406	181	266
Commercial	279	320	291	302	411	166	260
Industrial	451	500	472	482	592	391	467
Transportation	514	628	622	625	826	744	784
Total	**1,559**	**1,802**	**1,710**	**1,746**	**2,234**	**1,482**	**1,777**
Electricity Generation	612	697	615	647	868	205	463

Notes: "Other" includes net electricity imports, methanol, and liquid hydrogen. "Effective Delivered Energy Prices" include the costs of greenhouse gas allowances where applicable.
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and SA2028.D051104A.

Macroeconomic Results

The estimated macroeconomic impacts of SA.2028 are also significantly less than those estimated for S.139, with the impacts reduced in rough proportion to the corresponding impacts on energy markets. The effects on the economy from higher energy costs result in output losses and shifting of resources.

The measurement of losses in output for the economy, or actual gross domestic product (GDP), incorporates the transitional cost to the aggregate economy as it adjusts to its long-run path. Alternatively, the economic impact of the bill can be measured by its effects on potential GDP, which represents the long-run equilibrium path of the economy in which all resources are fully employed. Table 3 compares the estimated economic losses from SA.2028 and S.139 using these two measures. On an undiscounted basis, the cumulative losses in actual GDP are about $776 billion (1996 dollars) in the SA.2028 case, 43 percent less than in the S.139 case. The peak, single-year impact on actual GDP under SA.2028 occurs in 2025, with a loss of $76 billion (1996 dollars), or about 0.4 percent of GDP. The largest percentage change in actual GDP, 0.5 percent, occurs in 2011, where the estimated loss in actual GDP that year is $57 billion.

Table 3. Economic Impacts of S.139 and SA.2028 (billion 1996 dollars and percent change relative to the reference case)

	Potential GDP		Actual GDP	
	S.139	SA.2028	S.139	SA.2028
Cumulative GDP Loss, 2004-2025 (billion 1996 dollars)				
Undiscounted	559	304	1,354	776
Discounted at 7 Percent per Year	165	86	507	290
Percent Change from Reference Case				
Undiscounted	-0.2%	-0.1%	-0.4%	-0.3%
Discounted at 7 Percent per Year	-0.1%	-0.1%	-0.3%	-0.2%
Economic Impact, 2025				
GDP Loss (billion 1996 dollars)	90	55	106	76
Percent Change from Reference Case	-0.5%	-0.3%	-0.6%	-0.4%

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and SA2028.D051104A.

Additional Context

As noted in our original S.139 analysis, the assessment of impacts over a 20-year time period is subject to considerable uncertainty. The sensitivity cases presented in the original report illustrate some of the uncertainties, but do not encompass the full range of energy and economic outcomes that might result from the bill's enactment. The magnitude of the differences across comparable sensitivity cases for SA.2028 would, in most cases, likely be smaller, reflecting the lesser impacts projected under SA.2028.

Another study that has analyzed several variants of S.139 was issued by researchers at the Massachusetts Institute of Technology (MIT) in June 2003.[4] This study included two scenarios that maintained the emissions cap at the 2010 level beyond 2015, as contemplated in SA.2028. One of these scenarios (Case 2) did not provide for any offset credits. The other scenario (Case 12) allowed for unlimited offsets for non-carbon dioxide greenhouse gases, notwithstanding the 15-percent limit on offsets imposed under SA.2028. These two scenarios bound a hypothetical case representing SA.2028. Table 4 compares the allowance costs for these two scenarios with those from EIA's SA.2028 case, with costs from the MIT researchers' paper converted from 1997 to 2001 dollars. Allowance costs in EIA's SA.2028 case fall within the range of estimates for the two relevant scenarios in the MIT paper through 2015 and match the Case 2 allowance price in 2020. Other significant differences between the EIA and MIT researchers' analyses are discussed in EIA's earlier report, including the much greater responsiveness of oil demand to the introduction of the allowance system in the MIT researchers' scenarios, which reduces the need for higher allowance prices to encourage adjustments in the electric power and industrial sectors.

Table 4. Comparison of Emission Allowance Prices from the EIA and MIT Researchers' Analyses

	2010	2015	2020
Greenhouse Gas Emission Allowance Price (2001 dollars per metric ton carbon equivalent)			
MIT Researchers' Case 2 (no offset credits)	83	106	125
MIT Researchers' Case 12 (unlimited offset credits)	31	40	52
EIA, SA.2028 case	55	83	125

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, Case 2 and Case 12. EIA: Office of Integrated Analysis and Forecasting, National Energy Modeling System run SA2028.D041104A.

Finally, like other EIA analyses, our analysis of SA.2028 focuses on impacts regarding 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. EIA did not quantify, or place any value on, possible health or environmental benefits of curtailing greenhouse gas emissions.

[4] 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.)

Appendix A: Request Letter from Senator Landrieu

L. LANDRIEU
LOUISIANA

United States Senate

WASHINGTON, DC 20510-1804

May 11, 2004

VIA U.S. MAIL AND FACSIMILE (202) 586-0329
The Honorable Guy Caruso
Administrator
Energy Information Administration
1000 Independence Avenue S.W.
Washington, DC 20585

Dear Administrator Caruso:

I am writing to request that the Energy Information Administration (EIA) provide me with information regarding the energy and economic impacts that might result from enactment of legislation to limit emissions of green house gases.

EIA had previously (June 2003) provided a detailed analysis of S.139, the Climate Stewardship Act as introduced in January 2003. More recently, during a floor debate last October, Senators McCain and Lieberman, the primary sponsors of S.139, proposed an amended bill that included the first phase of emissions reductions beginning in 2010, but removed references to a second phase of reductions beginning in 2016. The amended bill leaves a decision regarding further reductions to future policymakers.

While EIA's June 2003 analysis considered only the original version of S.139, I understand that the revised bill mandating only the first phase of reductions may again be considered by the Senate in the near future. Accordingly, I request that EIA provide me with any information it may have regarding the energy and economic impacts of the revised proposal.

Given the possibility of floor debate on this matter, I would appreciate receiving your response as quickly as possible, recognizing that you may need to rely on modeling results already in hand to meet this request. Please contact me or Neil Naraine of my office at 202-224-8854 with any questions.

With warmest regards, I am

Sincerely,

Mary L. Landrieu
Mary L. Landrieu
United States Senator

MLL\njn

Appendix B: Comparison Tables for Reference Case, S.139 Case, S.A.2028 Case

Table B1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Production										
Crude Oil and Lease Condensate	12.29	11.94	11.92	11.93	11.50	11.45	11.45	11.23	11.15	11.00
Natural Gas Plant Liquids	2.65	3.12	3.21	3.17	3.53	3.75	3.61	3.70	3.84	3.80
Dry Natural Gas	19.97	22.11	22.81	22.49	25.52	27.33	26.34	27.08	28.06	27.79
Coal	23.97	25.69	22.57	23.94	27.83	10.46	17.57	29.61	6.82	12.92
Nuclear Power	8.03	8.25	8.37	8.37	8.28	9.75	9.05	8.28	12.39	10.50
Renewable Energy[1]	5.32	7.30	9.03	8.62	8.31	14.68	12.80	8.77	16.22	15.31
Other[2]	0.57	0.85	0.82	0.83	0.79	0.62	0.66	0.80	0.59	0.60
Total	**72.80**	**79.26**	**78.73**	**79.35**	**85.76**	**78.04**	**81.48**	**89.47**	**79.06**	**81.92**
Imports										
Crude Oil[3]	20.26	25.09	24.88	24.88	27.63	26.92	27.14	28.62	27.72	28.04
Petroleum Products[4]	5.04	6.32	5.73	6.03	11.72	8.82	10.37	14.79	10.43	12.61
Natural Gas	4.18	5.43	5.53	5.34	7.41	9.37	8.12	8.44	11.48	9.81
Other Imports[5]	0.71	0.92	0.81	0.81	0.95	0.94	0.84	0.93	0.79	0.71
Total	**30.19**	**37.76**	**36.94**	**37.05**	**47.71**	**46.05**	**46.47**	**52.78**	**50.42**	**51.17**
Exports										
Petroleum[6]	2.01	2.25	2.21	2.23	2.38	2.29	2.32	2.43	2.32	2.36
Natural Gas	0.37	0.56	0.57	0.57	0.38	0.37	0.37	0.37	0.36	0.36
Coal	1.27	0.86	0.84	0.84	0.74	0.76	0.69	0.62	0.61	0.60
Total	**3.64**	**3.67**	**3.61**	**3.64**	**3.50**	**3.42**	**3.38**	**3.42**	**3.29**	**3.33**
Discrepancy[7]	**2.06**	**0.22**	**0.39**	**0.26**	**0.23**	**0.18**	**0.14**	**0.20**	**0.22**	**-0.74**
Consumption										
Petroleum Products[8]	38.46	44.45	43.74	43.97	52.15	48.65	50.29	56.11	50.76	53.04
Natural Gas	23.26	27.35	28.12	27.63	32.95	36.69	34.46	35.55	39.54	37.54
Coal	22.02	25.47	22.00	23.50	27.88	10.23	17.44	29.86	6.74	13.86
Nuclear Power	8.03	8.25	8.37	8.37	8.28	9.75	9.05	8.28	12.39	10.50
Renewable Energy[1]	5.32	7.30	9.03	8.62	8.31	14.68	12.80	8.77	16.22	15.31
Other[9]	0.21	0.31	0.43	0.42	0.17	0.50	0.40	0.06	0.32	0.24
Total	**97.29**	**113.13**	**111.67**	**112.50**	**129.74**	**120.50**	**124.43**	**138.63**	**125.97**	**130.50**
Net Imports - Petroleum	**23.29**	**29.16**	**28.40**	**28.68**	**36.97**	**33.45**	**35.19**	**40.98**	**35.83**	**38.29**
Prices (2001 dollars per unit)										
World Oil Price (dollars per barrel)[10]	22.01	23.99	23.77	23.77	25.48	24.15	24.15	26.57	24.58	24.58
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.12	3.39	3.51	3.41	3.70	3.97	3.71	3.95	4.36	4.19
Coal Minemouth Price (dollars per ton)	17.59	15.06	15.84	15.56	14.34	15.27	15.06	14.39	13.67	15.63
Average Electricity Price (cents per kilowatthour)	7.3	6.4	7.0	6.8	6.7	8.8	8.0	6.7	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 B19 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, MLBILL.D050503A, and SA2028.D051104A.

Table B2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
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	0.47	0.46	0.46	0.47	0.46
Petroleum Subtotal	1.50	1.46	1.46	1.46	1.36	1.37	1.36	1.33	1.33	1.32
Natural Gas	4.94	5.63	5.62	5.63	6.10	5.96	6.01	6.38	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	0.41	0.40	0.40	0.40	0.40	0.40
Electricity	4.10	4.93	4.88	4.89	5.60	5.05	5.24	5.95	5.11	5.33
Delivered Energy	**10.94**	**12.45**	**12.38**	**12.40**	**13.48**	**12.80**	**13.03**	**14.08**	**13.06**	**13.29**
Electricity Related Losses	9.15	10.37	10.11	10.32	11.03	9.29	10.04	11.42	9.26	10.05
Total	**20.08**	**22.82**	**22.50**	**22.72**	**24.51**	**22.09**	**23.07**	**25.50**	**22.32**	**23.35**
Commercial										
Distillate Fuel	0.46	0.51	0.51	0.51	0.52	0.54	0.53	0.52	0.56	0.53
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	0.10	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	0.70	0.72	0.75	0.73	0.72	0.76	0.73
Natural Gas	3.33	3.74	3.74	3.74	4.23	4.27	4.25	4.50	4.97	4.73
Coal	0.09	0.10	0.10	0.09	0.10	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	5.01	4.97	4.97	6.17	5.66	5.81	6.79	5.97	6.17
Delivered Energy	**8.32**	**9.65**	**9.60**	**9.61**	**11.33**	**10.89**	**11.00**	**12.23**	**11.92**	**11.85**
Electricity Related Losses	9.12	10.53	10.30	10.49	12.16	10.42	11.14	13.02	10.82	11.64
Total	**17.44**	**20.19**	**19.90**	**20.10**	**23.50**	**21.31**	**22.14**	**25.25**	**22.74**	**23.49**
Industrial[4]										
Distillate Fuel	1.13	1.21	1.20	1.20	1.36	1.30	1.32	1.44	1.36	1.39
Liquefied Petroleum Gas	2.10	2.55	2.54	2.54	3.06	2.99	3.01	3.28	3.14	3.19
Petrochemical Feedstock	1.14	1.44	1.41	1.41	1.70	1.53	1.55	1.82	1.57	1.59
Residual Fuel	0.23	0.19	0.18	0.18	0.20	0.17	0.18	0.20	0.17	0.18
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	4.27	4.18	4.20	4.46	4.09	4.24	4.57	4.12	4.24
Petroleum Subtotal	8.79	9.82	9.67	9.71	10.96	10.26	10.47	11.50	10.55	10.77
Natural Gas	7.74	9.06	9.16	9.13	10.39	10.36	10.30	11.23	11.09	10.98
Lease and Plant Fuel[6]	1.20	1.37	1.40	1.39	1.60	1.70	1.66	1.73	1.77	1.76
Natural Gas Subtotal	8.94	10.43	10.56	10.52	11.98	12.06	11.95	12.96	12.86	12.74
Metallurgical Coal	0.72	0.66	0.65	0.65	0.55	0.47	0.48	0.50	0.39	0.41
Steam Coal	1.42	1.46	1.33	1.38	1.51	1.28	1.34	1.54	1.26	1.32
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.18	0.18	0.18	0.21	0.21
Coal Subtotal	2.16	2.23	2.09	2.14	2.22	1.93	2.00	2.22	1.87	1.94
Renewable Energy[7]	1.82	2.22	2.21	2.21	2.77	2.74	2.75	3.05	3.02	3.02
Electricity	3.39	3.97	3.89	3.91	4.65	4.41	4.49	5.01	4.66	4.74
Delivered Energy	**25.10**	**28.67**	**28.41**	**28.48**	**32.58**	**31.40**	**31.67**	**34.75**	**32.96**	**33.22**
Electricity Related Losses	7.57	8.35	8.06	8.25	9.17	8.12	8.61	9.61	8.45	8.95
Total	**32.67**	**37.02**	**36.47**	**36.73**	**41.75**	**39.53**	**40.28**	**44.36**	**41.40**	**42.17**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Transportation										
Distillate Fuel[8]	5.44	7.09	7.01	7.05	8.68	8.30	8.49	9.55	8.98	9.19
Jet Fuel[9]	3.43	3.93	3.91	3.92	5.09	5.01	5.03	5.67	5.56	5.58
Motor Gasoline[2]	16.26	19.81	19.58	19.70	23.57	21.55	22.76	25.48	22.10	23.89
Residual Fuel	0.84	0.83	0.83	0.83	0.85	0.85	0.85	0.87	0.86	0.86
Liquefied Petroleum Gas	0.02	0.05	0.05	0.05	0.07	0.08	0.08	0.09	0.09	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	31.98	31.64	31.81	38.57	36.09	37.50	41.98	37.91	39.93
Pipeline Fuel Natural Gas	0.63	0.78	0.81	0.79	0.94	1.05	0.98	1.03	1.11	1.06
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.10	0.09	0.09	0.11	0.10	0.10
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	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	0.14	0.13	0.14
Delivered Energy	**26.94**	**32.91**	**32.61**	**32.75**	**39.73**	**37.36**	**38.70**	**43.26**	**39.25**	**41.24**
Electricity Related Losses	0.17	0.20	0.19	0.20	0.24	0.22	0.23	0.27	0.24	0.26
Total	**27.10**	**33.10**	**32.80**	**32.95**	**39.98**	**37.58**	**38.94**	**43.53**	**39.50**	**41.50**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.94	9.74	9.64	9.67	11.40	10.99	11.17	12.32	11.71	11.91
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	3.91	3.92	5.09	5.01	5.03	5.67	5.56	5.58
Liquefied Petroleum Gas	2.70	3.16	3.16	3.16	3.69	3.63	3.64	3.92	3.78	3.83
Motor Gasoline[2]	16.46	20.01	19.78	19.90	23.79	21.77	22.97	25.71	22.33	24.12
Petrochemical Feedstock	1.14	1.44	1.41	1.41	1.70	1.53	1.55	1.82	1.57	1.59
Residual Fuel	1.15	1.06	1.05	1.05	1.10	1.07	1.07	1.12	1.08	1.09
Other Petroleum[12]	4.24	4.51	4.41	4.44	4.74	4.36	4.51	4.87	4.42	4.53
Petroleum Subtotal	37.21	43.97	43.48	43.68	51.61	48.47	50.05	55.53	50.55	52.76
Natural Gas	16.02	18.49	18.57	18.56	20.82	20.68	20.66	22.23	22.36	22.03
Lease and Plant Fuel Plant[6]	1.20	1.37	1.40	1.39	1.60	1.70	1.66	1.73	1.77	1.76
Pipeline Natural Gas	0.63	0.78	0.81	0.79	0.94	1.05	0.98	1.03	1.11	1.06
Natural Gas Subtotal	17.86	20.64	20.78	20.74	23.35	23.43	23.30	24.98	25.23	24.85
Metallurgical Coal	0.72	0.66	0.65	0.65	0.55	0.47	0.48	0.50	0.39	0.41
Steam Coal	1.53	1.56	1.44	1.48	1.63	1.40	1.46	1.66	1.39	1.45
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.18	0.18	0.18	0.21	0.21
Coal Subtotal	2.27	2.34	2.20	2.25	2.34	2.05	2.12	2.34	1.99	2.06
Renewable Energy[13]	2.31	2.74	2.72	2.73	3.28	3.26	3.27	3.57	3.53	3.54
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	14.00	13.82	13.86	16.54	15.24	15.66	17.90	15.87	16.38
Delivered Energy	**71.29**	**83.68**	**83.01**	**83.24**	**97.13**	**92.45**	**94.40**	**104.32**	**97.19**	**99.60**
Electricity Related Losses	26.00	29.45	28.66	29.26	32.61	28.05	30.03	34.32	28.78	30.90
Total	**97.29**	**113.13**	**111.67**	**112.50**	**129.74**	**120.50**	**124.43**	**138.63**	**125.97**	**130.50**
Electric Power[14]										
Distillate Fuel	0.17	0.09	0.07	0.08	0.13	0.05	0.06	0.18	0.06	0.10
Residual Fuel	1.08	0.39	0.19	0.21	0.41	0.14	0.17	0.40	0.14	0.18
Petroleum Subtotal	1.25	0.48	0.26	0.29	0.54	0.19	0.23	0.58	0.21	0.28
Natural Gas	5.40	6.71	7.33	6.90	9.60	13.25	11.16	10.56	14.30	12.69
Steam Coal	19.75	23.13	19.79	21.25	25.54	8.18	15.32	27.52	4.74	11.80
Nuclear Power	8.03	8.25	8.37	8.37	8.28	9.75	9.05	8.28	12.39	10.50
Renewable Energy[15]	3.01	4.57	6.30	5.89	5.02	11.42	9.54	5.21	12.69	11.77
Electricity Imports	0.21	0.31	0.43	0.42	0.17	0.50	0.40	0.06	0.32	0.24
Total	**37.65**	**43.45**	**42.48**	**43.11**	**49.15**	**43.29**	**45.69**	**52.21**	**44.65**	**47.28**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Total Energy Consumption										
Distillate Fuel	8.10	9.83	9.71	9.76	11.53	11.04	11.23	12.50	11.77	12.00
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	3.91	3.92	5.09	5.01	5.03	5.67	5.56	5.58
Liquefied Petroleum Gas	2.70	3.16	3.16	3.16	3.69	3.63	3.64	3.92	3.78	3.83
Motor Gasoline[2]	16.46	20.01	19.78	19.90	23.79	21.77	22.97	25.71	22.33	24.12
Petrochemical Feedstock	1.14	1.44	1.41	1.41	1.70	1.53	1.55	1.82	1.57	1.59
Residual Fuel	2.23	1.45	1.24	1.26	1.51	1.20	1.24	1.52	1.22	1.27
Other Petroleum[12]	4.24	4.51	4.41	4.44	4.74	4.36	4.51	4.87	4.42	4.53
Petroleum Subtotal	38.46	44.45	43.74	43.97	52.15	48.65	50.29	56.11	50.76	53.04
Natural Gas	21.42	25.20	25.91	25.45	30.42	33.94	31.82	32.79	36.67	34.73
Lease and Plant Fuel[6]	1.20	1.37	1.40	1.39	1.60	1.70	1.66	1.73	1.77	1.76
Pipeline Natural Gas	0.63	0.78	0.81	0.79	0.94	1.05	0.98	1.03	1.11	1.06
Natural Gas Subtotal	23.26	27.35	28.12	27.63	32.95	36.69	34.46	35.55	39.54	37.54
Metallurgical Coal	0.72	0.66	0.65	0.65	0.55	0.47	0.48	0.50	0.39	0.41
Steam Coal	21.28	24.70	21.24	22.73	27.17	9.58	16.77	29.18	6.13	13.25
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.18	0.18	0.18	0.21	0.21
Coal Subtotal	22.02	25.47	22.00	23.50	27.88	10.23	17.44	29.86	6.74	13.86
Nuclear Power	8.03	8.25	8.37	8.37	8.28	9.75	9.05	8.28	12.39	10.50
Renewable Energy[16]	5.32	7.30	9.03	8.62	8.31	14.68	12.80	8.77	16.22	15.31
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	0.31	0.43	0.42	0.17	0.50	0.40	0.06	0.32	0.24
Total	**97.29**	**113.13**	**111.67**	**112.50**	**129.74**	**120.50**	**124.43**	**138.63**	**125.97**	**130.50**
Energy Use and Related Statistics										
Delivered Energy Use	71.29	83.68	83.01	83.24	97.13	92.45	94.40	104.32	97.19	99.60
Total Energy Use	97.29	113.13	111.67	112.50	129.74	120.50	124.43	138.63	125.97	130.50
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	12211	12226	16444	16364	16408	18916	18810	18840
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1558.6	1802.2	1710.1	1746.4	2077.7	1568.5	1797.5	2234.4	1482.2	1777.3

[1]Includes wood used for residential heating. See Table B18 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 B19 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, MLBILL.D050503A, and SA2028.D051104A.

Table B3. Energy Prices by Sector and Source Including Greenhouse Gas Allowance Cost Where Applicable
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Residential	**15.81**	**13.97**	**14.62**	**14.39**	**14.62**	**17.37**	**16.34**	**14.89**	**18.74**	**17.91**
Primary Energy[1]	9.73	8.07	8.11	8.05	8.33	8.48	8.31	8.57	8.88	8.75
Petroleum Products[2]	10.85	10.02	9.88	9.91	10.91	10.32	10.58	11.21	10.79	10.79
Distillate Fuel	8.99	7.99	7.95	7.94	8.70	8.23	8.42	8.93	8.58	8.61
Liquefied Petroleum Gas	14.84	14.35	13.97	14.11	15.28	14.44	14.87	15.52	14.96	14.92
Natural Gas	9.41	7.57	7.67	7.58	7.77	8.07	7.81	8.04	8.48	8.33
Electricity	25.37	22.48	24.10	23.59	23.03	30.32	27.68	23.09	33.29	30.90
Commercial	**15.50**	**13.45**	**14.35**	**14.08**	**14.58**	**17.78**	**16.61**	**15.00**	**19.27**	**18.45**
Primary Energy[1]	7.81	6.43	6.50	6.43	6.78	6.93	6.75	7.05	7.33	7.21
Petroleum Products[2]	7.27	6.78	6.70	6.70	7.51	6.96	7.19	7.81	7.28	7.35
Distillate Fuel	6.40	5.67	5.63	5.62	6.45	5.96	6.15	6.75	6.30	6.37
Residual Fuel	3.46	4.01	3.93	3.94	4.23	3.96	3.97	4.39	4.02	4.03
Natural Gas	8.09	6.49	6.59	6.50	6.79	7.07	6.81	7.07	7.48	7.33
Electricity	23.28	19.81	21.51	21.07	20.98	27.61	25.24	21.25	30.97	28.60
Industrial[3]	**7.11**	**6.39**	**7.55**	**7.18**	**7.01**	**9.89**	**8.93**	**7.25**	**11.03**	**10.09**
Primary Energy	5.83	5.18	6.28	5.92	5.74	8.16	7.39	5.99	9.06	8.26
Petroleum Products[2]	7.72	7.07	7.87	7.62	7.85	9.55	9.11	8.13	10.34	9.75
Distillate Fuel	6.55	5.75	7.27	6.79	6.74	9.70	8.84	7.19	10.89	10.00
Liquefied Petroleum Gas	12.34	9.93	10.93	10.64	10.85	13.19	12.65	11.13	14.38	13.40
Residual Fuel	3.28	3.71	5.34	4.83	3.94	7.49	6.35	4.10	8.46	7.33
Natural Gas[4]	4.87	4.00	5.23	4.80	4.39	7.20	6.17	4.63	8.19	7.25
Metallurgical Coal	1.69	1.50	3.50	2.90	1.39	5.91	4.54	1.34	6.92	5.57
Steam Coal	1.46	1.39	3.38	2.78	1.31	5.67	4.41	1.30	6.64	5.41
Electricity	14.13	12.82	14.34	13.92	13.37	18.65	16.67	13.48	20.86	19.13
Transportation	**10.28**	**10.22**	**11.73**	**11.28**	**10.37**	**13.28**	**12.40**	**10.82**	**14.17**	**13.28**
Primary Energy	10.25	10.19	11.70	11.25	10.35	13.24	12.37	10.79	14.13	13.24
Petroleum Products[2]	10.25	10.20	11.71	11.26	10.35	13.25	12.37	10.80	14.14	13.25
Distillate Fuel[5]	10.05	10.19	11.71	11.23	10.27	13.17	12.23	10.64	14.37	13.32
Jet Fuel[6]	6.20	5.66	7.10	6.64	6.34	9.26	8.35	6.72	10.35	9.42
Motor Gasoline[7]	11.57	11.45	12.98	12.54	11.55	14.52	13.62	12.07	15.31	14.41
Residual Fuel	3.90	3.56	5.19	4.69	3.78	7.36	6.21	3.94	8.32	7.18
Liquefied Petroleum Gas[8]	16.93	15.55	16.35	16.12	16.06	18.30	17.77	15.99	19.15	18.09
Natural Gas[9]	7.65	7.19	8.38	7.98	7.75	10.29	9.32	8.09	11.26	10.39
Electricity	21.87	19.10	20.82	20.29	18.45	24.39	22.30	17.90	26.05	24.16
Average End-Use Energy	**10.75**	**9.97**	**11.17**	**10.80**	**10.47**	**13.38**	**12.42**	**10.82**	**14.50**	**13.60**
Primary Energy	8.52	8.07	9.18	8.83	8.46	10.70	10.01	8.84	11.49	10.83
Electricity	21.34	18.76	20.40	19.94	19.52	25.89	23.57	19.66	28.70	26.57
Electric Power[10]										
Fossil Fuel Average	2.14	1.82	3.75	3.14	2.04	6.68	5.09	2.13	7.93	6.37
Petroleum Products	4.73	4.28	6.13	5.60	4.72	8.74	7.48	5.04	9.77	8.51
Distillate Fuel	6.20	5.13	6.57	6.08	5.94	8.91	8.04	6.16	9.99	9.02
Residual Fuel	4.50	4.08	5.97	5.41	4.33	8.68	7.28	4.55	9.68	8.24
Natural Gas	4.78	3.88	5.20	4.74	4.35	7.36	6.25	4.64	8.37	7.37
Steam Coal	1.25	1.17	3.17	2.58	1.12	5.53	4.22	1.11	6.53	5.24

Table B3. Energy Prices by Sector and Source Including Greenhouse Gas Allowance Cost Where Applicable (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Average Price to All Users[11]										
Petroleum Products[2]	9.54	9.46	10.76	10.37	9.81	12.34	11.61	10.22	13.20	12.43
Distillate Fuel	9.16	9.15	10.45	10.04	9.52	12.01	11.24	9.90	13.17	12.28
Jet Fuel	6.20	5.66	7.10	6.64	6.34	9.26	8.35	6.72	10.35	9.42
Liquefied Petroleum Gas	12.85	10.75	11.51	11.29	11.58	13.44	13.05	11.81	14.52	13.68
Motor Gasoline[7]	11.57	11.45	12.98	12.53	11.55	14.52	13.62	12.07	15.31	14.41
Residual Fuel	4.11	3.73	5.29	4.80	3.96	7.39	6.29	4.14	8.33	7.23
Natural Gas	6.40	5.15	5.96	5.66	5.40	7.41	6.60	5.64	8.22	7.51
Coal	1.26	1.18	3.18	2.59	1.13	5.50	4.21	1.12	6.44	5.22
Electricity	21.34	18.76	20.40	19.94	19.52	25.89	23.57	19.66	28.70	26.57
Non-Renewable Energy and Allowance Expenditures by Sector (billion 2001 dollars)										
Residential	166.77	168.16	175.14	172.54	191.19	215.33	206.32	203.68	237.11	230.84
Commercial	127.30	128.40	136.28	133.84	163.77	191.81	180.97	181.88	227.72	216.67
Industrial	135.32	137.86	162.27	154.55	172.27	235.92	214.13	190.69	277.18	255.19
Transportation	270.41	328.32	372.97	360.38	402.37	482.08	467.59	456.80	540.60	533.37
Total Non-Renewable Expenditures	699.80	762.73	846.66	821.30	929.60	1125.14	1069.01	1033.06	1282.60	1236.07
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.10	0.12	0.11	0.13	0.16	0.15
Total Expenditures	**699.81**	**762.78**	**846.72**	**821.36**	**929.70**	**1125.26**	**1069.12**	**1033.19**	**1282.76**	**1236.22**

[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, MLBILL.D050503A, and SA2028.D051104A.

Table B4. 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 Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Residential										
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
Liquefied Petroleum Gas	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
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	0.94	0.66	0.00	2.15	1.50	0.00	2.66	2.02
Distillate Fuel	0.00	0.00	1.56	1.09	0.00	3.52	2.46	0.00	4.36	3.30
Liquefied Petroleum Gas	0.00	0.00	1.35	0.94	0.00	3.05	2.13	0.00	3.77	2.86
Residual Fuel	0.00	0.00	1.68	1.17	0.00	3.80	2.65	0.00	4.70	3.56
Natural Gas[4]	0.00	0.00	1.11	0.78	0.00	2.52	1.76	0.00	3.12	2.37
Metallurgical Coal	0.00	0.00	2.00	1.39	0.00	4.51	3.15	0.00	5.58	4.23
Steam Coal	0.00	0.00	2.00	1.40	0.00	4.53	3.16	0.00	5.60	4.24
Transportation										
Petroleum Products[2]	0.00	0.00	1.52	1.06	0.00	3.44	2.40	0.00	4.25	3.22
Distillate Fuel[5]	0.00	0.00	1.56	1.09	0.00	3.52	2.46	0.00	4.36	3.30
Jet Fuel[6]	0.00	0.00	1.51	1.05	0.00	3.41	2.38	0.00	4.22	3.20
Motor Gasoline[7]	0.00	0.00	1.51	1.05	0.00	3.42	2.38	0.00	4.23	3.20
Residual Fuel	0.00	0.00	1.68	1.17	0.00	3.80	2.65	0.00	4.70	3.56
Liquefied Petroleum Gas[8]	0.00	0.00	1.35	0.94	0.00	3.05	2.13	0.00	3.77	2.86
Natural Gas[9]	0.00	0.00	1.14	0.79	0.00	2.57	1.79	0.00	3.18	2.41
Electric Power[10]										
Fossil Fuel Average	0.00	0.00	1.78	1.26	0.00	3.32	2.59	0.00	3.80	3.30
Petroleum Products	0.00	0.00	1.65	1.15	0.00	3.72	2.60	0.00	4.60	3.47
Distillate Fuel	0.00	0.00	1.56	1.09	0.00	3.52	2.46	0.00	4.36	3.30
Residual Fuel	0.00	0.00	1.68	1.17	0.00	3.80	2.65	0.00	4.70	3.56
Natural Gas	0.00	0.00	1.14	0.79	0.00	2.57	1.79	0.00	3.18	2.41
Steam Coal	0.00	0.00	2.02	1.41	0.00	4.54	3.18	0.00	5.62	4.26

[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]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.
Btu = British thermal unit.
Projections: EIA, AEO2003 National Energy Modeling System runs MLBASE.D050303A, MLBILL.D050503A, and SA2028.D051104A.

Table B5. Delivered Energy Prices by Sector and Source Excluding Greenhouse Gas Allowance Costs in the Industrial and Electric Power Sectors
(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Residential	**15.81**	**13.97**	**14.62**	**14.39**	**14.62**	**17.37**	**16.34**	**14.89**	**18.74**	**17.91**
Primary Energy[1]	9.73	8.07	8.11	8.05	8.33	8.48	8.31	8.57	8.88	8.75
Petroleum Products[2]	10.85	10.02	9.88	9.91	10.91	10.32	10.58	11.21	10.79	10.79
Distillate Fuel	8.99	7.99	7.95	7.94	8.70	8.23	8.42	8.93	8.58	8.61
Liquefied Petroleum Gas	14.84	14.35	13.97	14.11	15.28	14.44	14.87	15.52	14.96	14.92
Natural Gas	9.41	7.57	7.67	7.58	7.77	8.07	7.81	8.04	8.48	8.33
Electricity	25.37	22.48	24.10	23.59	23.03	30.32	27.68	23.09	33.29	30.90
Commercial	**15.50**	**13.45**	**14.35**	**14.08**	**14.58**	**17.78**	**16.61**	**15.00**	**19.27**	**18.45**
Primary Energy[1]	7.81	6.43	6.50	6.43	6.78	6.93	6.75	7.05	7.33	7.21
Petroleum Products[2]	7.27	6.78	6.70	6.70	7.51	6.96	7.19	7.81	7.28	7.35
Distillate Fuel	6.40	5.67	5.63	5.62	6.45	5.96	6.15	6.75	6.30	6.37
Residual Fuel	3.46	4.01	3.93	3.94	4.23	3.96	3.97	4.39	4.02	4.03
Natural Gas	8.09	6.49	6.59	6.50	6.79	7.07	6.81	7.07	7.48	7.33
Electricity	23.28	19.81	21.51	21.07	20.98	27.61	25.24	21.25	30.97	28.60
Industrial[3]	**7.11**	**6.39**	**6.61**	**6.52**	**7.01**	**7.80**	**7.47**	**7.25**	**8.45**	**8.14**
Primary Energy	5.83	5.18	5.16	5.14	5.74	5.65	5.64	5.99	5.97	5.91
Petroleum Products[2]	7.72	7.07	6.93	6.96	7.85	7.40	7.61	8.13	7.68	7.72
Distillate Fuel	6.55	5.75	5.71	5.70	6.74	6.18	6.38	7.19	6.53	6.69
Liquefied Petroleum Gas	12.34	9.93	9.58	9.70	10.85	10.14	10.52	11.13	10.60	10.54
Residual Fuel	3.28	3.71	3.66	3.66	3.94	3.70	3.70	4.10	3.77	3.77
Natural Gas[4]	4.87	4.00	4.11	4.02	4.39	4.68	4.41	4.63	5.07	4.88
Metallurgical Coal	1.69	1.50	1.51	1.51	1.39	1.40	1.39	1.34	1.34	1.33
Steam Coal	1.46	1.39	1.38	1.39	1.31	1.14	1.25	1.30	1.04	1.17
Electricity	14.13	12.82	14.34	13.92	13.37	18.65	16.67	13.48	20.86	19.13
Transportation	**10.28**	**10.22**	**11.73**	**11.28**	**10.37**	**13.27**	**12.39**	**10.82**	**14.17**	**13.27**
Primary Energy	10.25	10.19	11.70	11.25	10.35	13.24	12.36	10.79	14.12	13.23
Petroleum Products[2]	10.25	10.20	11.71	11.26	10.35	13.25	12.37	10.80	14.14	13.25
Distillate Fuel[5]	10.05	10.19	11.71	11.23	10.27	13.17	12.23	10.64	14.37	13.32
Jet Fuel[6]	6.20	5.66	7.10	6.64	6.34	9.26	8.35	6.72	10.35	9.42
Motor Gasoline[7]	11.57	11.45	12.98	12.54	11.55	14.52	13.62	12.07	15.31	14.41
Residual Fuel	3.90	3.56	5.19	4.69	3.78	7.36	6.21	3.94	8.32	7.18
Liquefied Petroleum Gas[8]	16.93	15.55	16.35	16.12	16.06	18.30	17.77	15.99	19.15	18.09
Natural Gas[9]	7.65	7.19	7.25	7.19	7.75	7.72	7.53	8.09	8.08	7.98
Electricity	21.87	19.10	20.82	20.29	18.45	24.39	22.30	17.90	26.05	24.16
Average End-Use Energy	**10.75**	**9.97**	**10.87**	**10.59**	**10.47**	**12.73**	**11.97**	**10.82**	**13.71**	**13.01**
Primary Energy	8.52	8.07	8.82	8.58	8.46	9.90	9.47	8.84	10.52	10.11
Electricity	21.34	18.76	20.40	19.94	19.52	25.89	23.57	19.66	28.70	26.57
Electric Power[10]										
Fossil Fuel Average	2.14	1.82	1.97	1.88	2.04	3.36	2.50	2.13	4.13	3.07
Petroleum Products	4.73	4.28	4.49	4.45	4.72	5.02	4.88	5.04	5.18	5.03
Distillate Fuel	6.20	5.13	5.01	4.99	5.94	5.39	5.58	6.16	5.64	5.72
Residual Fuel	4.50	4.08	4.29	4.24	4.33	4.88	4.63	4.55	4.98	4.68
Natural Gas	4.78	3.88	4.07	3.95	4.35	4.79	4.46	4.64	5.19	4.96
Steam Coal	1.25	1.17	1.16	1.17	1.12	0.99	1.04	1.11	0.90	0.99

Table B5. Delivered Energy Prices by Sector and Source Excluding Greenhouse Gas Allowance Costs in the Industrial and Electric Power Sectors (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Average Price to All Users[11]										
Petroleum Products[2]	9.54	9.46	10.54	10.22	9.81	11.85	11.28	10.22	12.61	11.99
Distillate Fuel	9.16	9.15	10.25	9.89	9.52	11.58	10.94	9.90	12.64	11.87
Jet Fuel	6.20	5.66	7.10	6.64	6.34	9.26	8.35	6.72	10.35	9.42
Liquefied Petroleum Gas	12.85	10.75	10.43	10.53	11.58	10.93	11.29	11.81	11.40	11.30
Motor Gasoline[7]	11.57	11.45	12.97	12.53	11.55	14.49	13.60	12.07	15.27	14.38
Residual Fuel	4.11	3.73	4.79	4.44	3.96	6.42	5.55	4.14	7.12	6.22
Natural Gas	6.40	5.15	5.24	5.16	5.40	5.63	5.40	5.64	6.03	5.87
Coal	1.26	1.18	1.17	1.19	1.13	1.02	1.06	1.12	0.94	1.01
Electricity	21.34	18.76	20.40	19.94	19.52	25.89	23.57	19.66	28.70	26.57
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)										
Residential	166.77	168.16	175.14	172.54	191.19	215.33	206.32	203.68	237.11	230.84
Commercial	127.30	128.40	136.28	133.84	163.77	191.81	180.97	181.88	227.72	216.67
Industrial	135.32	137.86	141.86	140.25	172.27	185.88	178.88	190.69	212.44	205.69
Transportation	270.41	328.32	372.90	360.33	402.37	481.84	467.41	456.80	540.27	533.12
Total Non-Renewable Expenditures	699.80	762.73	826.18	806.96	929.60	1074.86	1033.59	1033.06	1217.53	1186.31
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.10	0.11	0.11	0.13	0.15	0.14
Total Expenditures	**699.81**	**762.78**	**826.23**	**807.01**	**929.70**	**1074.97**	**1033.70**	**1033.19**	**1217.69**	**1186.46**

[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, MLBILL.D050503A, and SA2028.D051104A.

Table B6. 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 Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Key Indicators										
Households (millions)										
Single-Family	77.50	86.16	86.14	86.14	94.13	93.99	94.04	97.63	97.43	97.49
Multifamily	22.19	24.15	24.13	24.14	27.09	26.99	27.03	28.82	28.71	28.74
Mobile Homes	6.57	7.11	7.10	7.10	7.86	7.86	7.86	8.11	8.11	8.11
Total	**106.27**	**117.42**	**117.37**	**117.38**	**129.08**	**128.83**	**128.93**	**134.55**	**134.25**	**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	105.5	105.6	104.4	99.3	101.1	104.6	97.3	99.0
Total Energy Consumption	189.0	194.3	191.7	193.6	189.9	171.4	179.0	189.5	166.3	173.8
(thousand Btu per square foot)										
Delivered Energy Consumption	61.1	60.9	60.7	60.7	58.6	55.7	56.7	58.2	54.1	55.0
Total Energy Consumption	112.2	111.7	110.2	111.3	106.6	96.2	100.4	105.4	92.5	96.7
Delivered Energy Consumption by Fuel										
Electricity										
Space Heating	0.39	0.46	0.46	0.46	0.50	0.46	0.47	0.52	0.45	0.47
Space Cooling	0.52	0.60	0.60	0.60	0.65	0.59	0.61	0.69	0.59	0.61
Water Heating	0.45	0.47	0.46	0.47	0.44	0.38	0.40	0.44	0.33	0.36
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	0.24	0.25	0.27	0.25	0.25	0.28	0.25	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	0.91	0.92	1.03	0.81	0.90	1.07	0.74	0.84
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	0.24	0.24	0.27	0.24	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	0.09	0.10	0.11	0.10	0.10
Other Uses[2]	0.83	1.26	1.25	1.25	1.66	1.54	1.58	1.87	1.69	1.74
Delivered Energy	**4.10**	**4.93**	**4.88**	**4.89**	**5.60**	**5.05**	**5.24**	**5.95**	**5.11**	**5.33**
Natural Gas										
Space Heating	3.13	3.70	3.69	3.70	4.10	3.97	4.01	4.30	4.11	4.15
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	1.59	1.58	1.59	1.65	1.62	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	0.11	0.08
Delivered Energy	**4.94**	**5.63**	**5.62**	**5.63**	**6.10**	**5.96**	**6.01**	**6.38**	**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**	**0.46**	**0.47**	**0.46**	**0.46**	**0.47**	**0.46**
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 B6. 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 Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Delivered Energy Consumption by End-Use										
Space Heating	5.01	5.68	5.66	5.67	6.04	5.86	5.91	6.22	5.96	6.01
Space Cooling	0.52	0.60	0.60	0.60	0.65	0.59	0.61	0.69	0.59	0.61
Water Heating	2.19	2.24	2.23	2.24	2.21	2.14	2.17	2.26	2.13	2.17
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	0.34	0.35	0.38	0.35	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	0.91	0.92	1.03	0.81	0.90	1.07	0.74	0.84
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	0.24	0.24	0.27	0.24	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	0.09	0.10	0.11	0.10	0.10
Other Uses[7]	1.01	1.46	1.45	1.45	1.87	1.76	1.80	2.09	1.94	1.96
Delivered Energy	**10.94**	**12.45**	**12.38**	**12.40**	**13.48**	**12.80**	**13.03**	**14.08**	**13.06**	**13.29**
Electricity Related Losses	**9.15**	**10.37**	**10.11**	**10.32**	**11.03**	**9.29**	**10.04**	**11.42**	**9.26**	**10.05**
Total Energy Consumption by End-Use										
Space Heating	5.89	6.64	6.61	6.63	7.03	6.70	6.81	7.22	6.78	6.89
Space Cooling	1.68	1.86	1.83	1.85	1.94	1.68	1.77	2.00	1.67	1.76
Water Heating	3.20	3.23	3.20	3.22	3.08	2.84	2.93	3.10	2.74	2.84
Refrigeration	1.36	1.06	1.05	1.06	0.96	0.91	0.94	0.97	0.93	0.95
Cooking	0.55	0.59	0.59	0.59	0.63	0.61	0.62	0.65	0.63	0.64
Clothes Dryers	0.78	0.85	0.84	0.85	0.89	0.80	0.84	0.91	0.81	0.85
Freezers	0.36	0.28	0.27	0.28	0.26	0.25	0.26	0.27	0.25	0.26
Lighting	2.40	2.90	2.81	2.86	3.06	2.31	2.63	3.12	2.09	2.42
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	0.60	0.60	0.75	0.67	0.71	0.78	0.68	0.72
Personal Computers	0.19	0.25	0.25	0.25	0.31	0.29	0.30	0.33	0.32	0.33
Furnace Fans	0.23	0.27	0.26	0.27	0.30	0.27	0.28	0.31	0.27	0.29
Other Uses[7]	2.86	4.10	4.03	4.08	5.14	4.59	4.83	5.67	4.99	5.23
Total	**20.08**	**22.82**	**22.50**	**22.72**	**24.51**	**22.09**	**23.07**	**25.50**	**22.32**	**23.35**
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 MLBASE.D050303A, MLBILL.D050503A, and SA2028.D051104A.

Table B7. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Key Indicators										
Total Floorspace (billion square feet)										
Surviving	66.6	79.0	79.0	79.0	91.2	90.8	91.0	97.4	97.1	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**	**94.2**	**94.5**	**100.8**	**100.6**	**100.7**
Energy Consumption Intensity (thousand Btu per square foot)										
Delivered Energy Consumption	118.4	117.8	117.1	117.2	119.8	115.6	116.5	121.3	118.6	117.6
Electricity Related Losses	129.9	128.5	125.6	128.0	128.5	110.6	117.9	129.1	107.6	115.5
Total Energy Consumption	248.3	246.2	242.7	245.2	248.3	226.1	234.4	250.4	226.2	233.1
Delivered Energy Consumption by Fuel										
Purchased Electricity										
Space Heating[1]	0.14	0.16	0.15	0.15	0.15	0.14	0.14	0.15	0.13	0.13
Space Cooling[1]	0.43	0.43	0.42	0.42	0.45	0.41	0.43	0.46	0.40	0.42
Water Heating[1]	0.15	0.16	0.15	0.15	0.16	0.14	0.15	0.15	0.13	0.14
Ventilation	0.17	0.18	0.18	0.18	0.19	0.17	0.18	0.19	0.16	0.17
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.03
Lighting	1.02	1.21	1.18	1.18	1.30	0.99	1.06	1.33	0.88	0.96
Refrigeration	0.21	0.24	0.24	0.24	0.26	0.24	0.25	0.27	0.23	0.24
Office Equipment (PC)	0.16	0.24	0.24	0.24	0.32	0.31	0.31	0.36	0.34	0.35
Office Equipment (non-PC)	0.31	0.47	0.47	0.47	0.75	0.72	0.73	0.92	0.87	0.89
Other Uses[2]	1.46	1.90	1.90	1.90	2.57	2.51	2.53	2.92	2.80	2.85
Delivered Energy	**4.08**	**5.01**	**4.97**	**4.97**	**6.17**	**5.66**	**5.81**	**6.79**	**5.97**	**6.17**
Natural Gas										
Space Heating[1]	1.32	1.53	1.53	1.53	1.65	1.58	1.62	1.71	1.56	1.63
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	0.69	0.69	0.81	0.77	0.79	0.86	0.78	0.81
Cooking	0.25	0.30	0.30	0.30	0.35	0.33	0.34	0.37	0.35	0.35
Other Uses[3]	1.17	1.20	1.20	1.20	1.39	1.57	1.48	1.52	2.25	1.90
Delivered Energy	**3.33**	**3.74**	**3.74**	**3.74**	**4.23**	**4.27**	**4.25**	**4.50**	**4.97**	**4.73**
Distillate										
Space Heating[1]	0.17	0.24	0.23	0.23	0.25	0.27	0.25	0.25	0.28	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**	**0.54**	**0.53**	**0.52**	**0.56**	**0.53**
Other Fuels[5]	**0.34**	**0.29**	**0.29**	**0.29**	**0.30**	**0.31**	**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	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	2.05	1.98	2.01	2.11	1.97	2.02
Space Cooling[1]	0.44	0.45	0.44	0.44	0.48	0.44	0.46	0.50	0.43	0.45
Water Heating[1]	0.79	0.92	0.92	0.92	1.04	0.99	1.01	1.09	0.99	1.02
Ventilation	0.17	0.18	0.18	0.18	0.19	0.17	0.18	0.19	0.16	0.17
Cooking	0.29	0.33	0.33	0.33	0.38	0.36	0.37	0.40	0.37	0.38
Lighting	1.02	1.21	1.18	1.18	1.30	0.99	1.06	1.33	0.88	0.96
Refrigeration	0.21	0.24	0.24	0.24	0.26	0.24	0.25	0.27	0.23	0.24
Office Equipment (PC)	0.16	0.24	0.24	0.24	0.32	0.31	0.31	0.36	0.34	0.35
Office Equipment (non-PC)	0.31	0.47	0.47	0.47	0.75	0.72	0.73	0.92	0.87	0.89
Other Uses[6]	3.30	3.69	3.69	3.69	4.56	4.69	4.62	5.05	5.68	5.37
Delivered Energy	**8.32**	**9.65**	**9.60**	**9.61**	**11.33**	**10.89**	**11.00**	**12.23**	**11.92**	**11.85**

Table B7. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Electricity Related Losses	**9.12**	**10.53**	**10.30**	**10.49**	**12.16**	**10.42**	**11.14**	**13.02**	**10.82**	**11.64**
Total Energy Consumption by End-Use										
Space Heating[1]	1.95	2.25	2.24	2.24	2.36	2.24	2.29	2.40	2.20	2.27
Space Cooling[1]	1.39	1.34	1.32	1.34	1.38	1.21	1.28	1.39	1.15	1.24
Water Heating[1]	1.12	1.25	1.24	1.25	1.35	1.25	1.29	1.39	1.23	1.29
Ventilation	0.55	0.56	0.55	0.56	0.56	0.48	0.51	0.57	0.45	0.49
Cooking	0.37	0.40	0.40	0.40	0.44	0.41	0.42	0.45	0.41	0.42
Lighting	3.31	3.74	3.62	3.67	3.86	2.80	3.09	3.88	2.48	2.76
Refrigeration	0.69	0.74	0.73	0.73	0.77	0.68	0.72	0.78	0.66	0.70
Office Equipment (PC)	0.52	0.75	0.74	0.75	0.95	0.88	0.92	1.05	0.96	1.01
Office Equipment (non-PC)	0.99	1.45	1.43	1.45	2.21	2.06	2.14	2.69	2.45	2.57
Other Uses[6]	6.56	7.70	7.63	7.70	9.62	9.31	9.48	10.65	10.76	10.74
Total	**17.44**	**20.19**	**19.90**	**20.10**	**23.50**	**21.31**	**22.14**	**25.25**	**22.74**	**23.49**
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, MLBILL.D050503A, and SA2028.D051104A.

Table B8. Industrial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Key Indicators										
Value of Shipments (billion 1996 dollars)										
Manufacturing	4079	5466	5420	5435	7226	7160	7188	8258	8162	8183
Nonmanufacturing	1346	1510	1500	1503	1744	1714	1726	1870	1828	1841
Total	**5425**	**6977**	**6920**	**6938**	**8969**	**8874**	**8914**	**10128**	**9990**	**10024**
Delivered Energy Prices Including Greenhouse Gas Allowance Cost [1]										
(2001 dollars per million Btu)										
Electricity	14.13	12.82	14.34	13.92	13.37	18.65	16.67	13.48	20.86	19.13
Natural Gas	4.87	4.00	5.23	4.80	4.39	7.20	6.17	4.63	8.19	7.25
Steam Coal	1.46	1.39	3.38	2.78	1.31	5.67	4.41	1.30	6.64	5.41
Residual Oil	3.28	3.71	5.34	4.83	3.94	7.49	6.35	4.10	8.46	7.33
Distillate Oil	6.55	5.75	7.27	6.79	6.74	9.70	8.84	7.19	10.89	10.00
Liquefied Petroleum Gas	12.34	9.93	10.93	10.64	10.85	13.19	12.65	11.13	14.38	13.40
Motor Gasoline	11.57	11.40	12.94	12.49	11.52	14.49	13.59	12.05	15.28	14.38
Metallurgical Coal	1.69	1.50	3.50	2.90	1.39	5.91	4.54	1.34	6.92	5.57
Energy Consumption[2]										
Purchased Electricity	3.39	3.97	3.89	3.91	4.65	4.41	4.49	5.01	4.66	4.74
Natural Gas	7.74	9.06	9.16	9.13	10.39	10.36	10.30	11.23	11.09	10.98
Lease and Plant Fuel[3]	1.20	1.37	1.40	1.39	1.60	1.70	1.66	1.73	1.77	1.76
Natural Gas Subtotal	8.94	10.43	10.56	10.52	11.98	12.06	11.95	12.96	12.86	12.74
Steam Coal	1.42	1.46	1.33	1.38	1.51	1.28	1.34	1.54	1.26	1.32
Metallurgical Coal and Coke[4]	0.74	0.77	0.76	0.76	0.71	0.65	0.66	0.68	0.60	0.61
Residual Fuel	0.23	0.19	0.18	0.18	0.20	0.17	0.18	0.20	0.17	0.18
Distillate	1.13	1.21	1.20	1.20	1.36	1.30	1.32	1.44	1.36	1.39
Liquefied Petroleum Gas	2.10	2.55	2.54	2.54	3.06	2.99	3.01	3.28	3.14	3.19
Petrochemical Feedstocks	1.14	1.44	1.41	1.41	1.70	1.53	1.55	1.82	1.57	1.59
Other Petroleum[5]	4.18	4.44	4.34	4.37	4.64	4.27	4.42	4.76	4.32	4.43
Renewables[5]	1.82	2.22	2.21	2.21	2.77	2.74	2.75	3.05	3.02	3.02
Delivered Energy	**25.10**	**28.67**	**28.41**	**28.48**	**32.58**	**31.40**	**31.67**	**34.75**	**32.96**	**33.22**
Electricity Related Losses	7.57	8.35	8.06	8.25	9.17	8.12	8.61	9.61	8.45	8.95
Total	**32.67**	**37.02**	**36.47**	**36.73**	**41.75**	**39.53**	**40.28**	**44.36**	**41.40**	**42.17**
Energy Consumption per dollar of Shipments[2]										
(thousand Btu per 1996 dollars)										
Purchased Electricity	0.63	0.57	0.56	0.56	0.52	0.50	0.50	0.49	0.47	0.47
Natural Gas	1.43	1.30	1.32	1.32	1.16	1.17	1.16	1.11	1.11	1.10
Lease and Plant Fuel[3]	0.22	0.20	0.20	0.20	0.18	0.19	0.19	0.17	0.18	0.18
Natural Gas Subtotal	1.65	1.49	1.53	1.52	1.34	1.36	1.34	1.28	1.29	1.27
Steam Coal	0.26	0.21	0.19	0.20	0.17	0.14	0.15	0.15	0.13	0.13
Metallurgical Coal and Coke[4]	0.14	0.11	0.11	0.11	0.08	0.07	0.07	0.07	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	0.32	0.31	0.32
Petrochemical Feedstocks	0.21	0.21	0.20	0.20	0.19	0.17	0.17	0.18	0.16	0.16
Other Petroleum[5]	0.77	0.64	0.63	0.63	0.52	0.48	0.50	0.47	0.43	0.44
Renewables[6]	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**	**4.10**	**3.63**	**3.54**	**3.55**	**3.43**	**3.30**	**3.31**
Electricity Related Losses	1.40	1.20	1.16	1.19	1.02	0.92	0.97	0.95	0.85	0.89
Total	**6.02**	**5.31**	**5.27**	**5.29**	**4.65**	**4.45**	**4.52**	**4.38**	**4.14**	**4.21**

[1]Allowance costs would apply to those industrial entities with at least one facility emitting greenhouse gas greater than 10,000 metric tons carbon dioxide equivalent. Exempt entities would not be required to submit allowances and their cost of consuming fuel would exclude the allowance cost.
[2]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.
[3]Represents natural gas used in the field gathering and processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes petroleum coke, asphalt, road oil, lubricants, motor gasoline, still gas, and miscellaneous petroleum products.
[6]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, MLBILL.D050503A, and SA2028.D051104A.

Table B9. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Key Indicators										
Level of Travel (billions)										
Light-Duty Vehicles <8,500 pounds (VMT)	2409	3006	2975	2992	3752	3547	3663	4133	3795	3945
Commercial Light Trucks (VMT)[1]	66	84	83	83	107	104	106	120	115	117
Freight Trucks >10,000 pounds (VMT)	206	265	263	264	339	335	337	382	377	378
Air (seat miles available)	1109	1356	1348	1353	1944	1928	1933	2258	2231	2237
Rail (ton miles traveled)	1448	1691	1579	1625	2003	1467	1677	2173	1486	1650
Domestic Shipping (ton miles traveled)	788	882	869	874	1012	950	974	1088	992	1032
Energy Efficiency Indicators										
New Light-Duty Vehicle (miles per gallon)[2]	24.1	25.1	25.3	25.2	26.0	28.1	26.6	26.4	29.0	27.2
New Car (miles per gallon)[2]	28.1	28.5	28.8	28.6	29.7	32.6	30.4	30.1	32.9	30.9
New Light Truck (miles per gallon)[2]	20.7	22.3	22.5	22.4	23.1	24.6	23.6	23.5	25.8	24.3
Light-Duty Fleet (miles per gallon)[3]	19.8	19.6	19.6	19.6	20.3	20.9	20.5	20.5	21.8	20.9
New Commercial Light Truck (MPG)[1]	13.8	14.7	14.8	14.8	15.2	16.3	15.6	15.5	17.1	16.0
Stock Commercial Light Truck (MPG)[1]	13.7	14.3	14.3	14.3	14.9	15.4	15.1	15.2	16.2	15.5
Aircraft Efficiency (seat miles per gallon)	51.2	54.3	54.3	54.3	58.6	59.1	59.1	60.7	61.2	61.2
Freight Truck Efficiency (miles per gallon)	6.0	6.0	6.0	6.0	6.3	6.4	6.4	6.5	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	18.88	18.86	18.98	22.76	20.99	22.20	24.71	21.55	23.38
Commercial Light Trucks[1]	0.60	0.73	0.73	0.73	0.89	0.84	0.87	0.98	0.89	0.94
Freight Trucks[4]	4.68	5.92	5.88	5.89	7.11	6.94	7.02	7.81	7.55	7.61
Air[5]	3.47	3.98	3.96	3.97	5.15	5.07	5.08	5.73	5.63	5.64
Rail[6]	0.63	0.68	0.65	0.66	0.75	0.59	0.65	0.78	0.59	0.63
Marine[7]	1.45	1.49	1.49	1.49	1.59	1.56	1.57	1.64	1.60	1.62
Pipeline Fuel	0.63	0.78	0.81	0.79	0.94	1.05	0.98	1.03	1.11	1.06
Lubricants	0.19	0.22	0.21	0.22	0.26	0.26	0.26	0.28	0.28	0.28
Total	**26.94**	**32.68**	**32.58**	**32.73**	**39.45**	**37.30**	**38.64**	**42.96**	**39.19**	**41.16**
Energy Use by Mode (million barrels per day oil equivalent)										
Light-Duty Vehicles	8.05	9.93	9.96	10.03	11.96	11.07	11.71	12.98	11.36	12.33
Commercial Light Trucks[1]	0.32	0.39	0.38	0.38	0.47	0.45	0.46	0.52	0.47	0.50
Freight Trucks	2.05	2.61	2.59	2.60	3.16	3.09	3.12	3.49	3.37	3.40
Railroad	0.24	0.26	0.24	0.25	0.28	0.20	0.23	0.28	0.19	0.22
Domestic Shipping	0.16	0.17	0.17	0.17	0.20	0.18	0.19	0.21	0.19	0.20
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	1.64	1.65	2.19	2.15	2.16	2.45	2.40	2.41
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	0.41	0.40	0.47	0.53	0.50	0.52	0.56	0.54
Total	**13.64**	**16.54**	**16.54**	**16.62**	**19.97**	**18.90**	**19.60**	**21.74**	**19.83**	**20.87**

[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, MLBILL.D050503A, and SA2028.D051104A.

Table B10. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Generation by Fuel Type										
Electric Power Sector[1]										
Power Only[2]										
Coal	1848	2237	1927	2057	2512	836	1510	2747	526	1174
Petroleum	113	40	19	22	47	11	16	52	13	23
Natural Gas[3]	411	671	811	724	1143	1745	1466	1314	1889	1646
Nuclear Power	769	790	801	801	793	934	866	793	1186	1005
Pumped Storage/Other	-9	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[4]	258	394	517	475	414	991	800	423	1122	1039
Distributed Generation (Natural Gas)	0	1	5	2	5	13	5	8	13	6
Non-Utility Generation for Own Use	-21	-24	-26	-27	-24	-26	-26	-24	-25	-26
Total	**3370**	**4107**	**4053**	**4053**	**4889**	**4503**	**4635**	**5312**	**4725**	**4867**
Combined Heat and Power[5]										
Coal	33	33	30	32	33	16	23	33	10	18
Petroleum	7	4	3	4	3	3	3	3	3	3
Natural Gas	124	171	161	173	156	131	137	149	115	136
Renewable Sources	5	4	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-9	-18	-18	-18	-18	-17	-17	-18	-16	-17
Total	**162**	**193**	**181**	**195**	**178**	**138**	**151**	**171**	**116**	**145**
Net Available to the Grid	**3532**	**4301**	**4234**	**4247**	**5067**	**4641**	**4786**	**5483**	**4841**	**5011**
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	122	116	142	201	173	174	328	259
Other Gaseous Fuels[7]	6	7	7	7	7	7	7	8	7	7
Renewable Sources[4]	31	40	39	40	51	50	50	56	55	55
Other[8]	11	11	11	11	11	11	11	11	11	11
Total	**160**	**192**	**209**	**203**	**240**	**298**	**270**	**278**	**431**	**362**
Other End-Use Generators[9]	4	5	5	5	6	6	6	6	7	6
Generation for Own Use	-138	-154	-173	-168	-183	-241	-221	-207	-328	-286
Total Sales to the Grid	**27**	**43**	**41**	**39**	**63**	**63**	**55**	**78**	**110**	**83**
Net Imports	**20**	**30**	**41**	**41**	**16**	**48**	**39**	**6**	**31**	**24**
Electricity Sales by Sector										
Residential	1201	1445	1429	1433	1640	1479	1535	1745	1498	1562
Commercial	1197	1468	1455	1456	1808	1659	1703	1990	1750	1808
Industrial	994	1164	1139	1145	1364	1293	1317	1469	1366	1390
Transportation	22	27	27	27	36	35	36	42	39	40
Total	**3414**	**4104**	**4050**	**4061**	**4848**	**4467**	**4591**	**5246**	**4653**	**4801**
End-Use Prices[10] **(2001 cents per kilowatthour)**										
Residential	8.7	7.7	8.2	8.1	7.9	10.3	9.4	7.9	11.4	10.5
Commercial	7.9	6.8	7.3	7.2	7.2	9.4	8.6	7.2	10.6	9.8
Industrial	4.8	4.4	4.9	4.7	4.6	6.4	5.7	4.6	7.1	6.5
Transportation	7.5	6.5	7.1	6.9	6.3	8.3	7.6	6.1	8.9	8.2
All Sectors Average	**7.3**	**6.4**	**7.0**	**6.8**	**6.7**	**8.8**	**8.0**	**6.7**	**9.8**	**9.1**
Prices by Service Category[10] **(2001 cents per kilowatthour)**										
Generation	4.7	3.9	4.4	4.3	4.2	6.1	5.4	4.2	7.1	6.5
Transmission	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.6	0.8	0.7
Distribution	2.0	2.0	2.0	2.0	1.9	2.0	2.0	1.9	2.0	2.0

Table B10. Electricity Supply, Disposition, Prices, and Emissions (Continued)
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections 2010 Reference Case	2010 S.139 Case	2010 SA.2028 Case	2020 Reference Case	2020 S.139 Case	2020 SA.2028 Case	2025 Reference Case	2025 S.139 Case	2025 SA.2028 Case
Emissions										
Sulfur Dioxide (million tons)	10.63	9.69	9.84	9.48	8.95	5.87	8.95	8.95	1.93	8.41
Nitrogen Oxide (million tons)	4.75	3.90	3.50	3.73	4.02	1.48	2.75	4.08	0.67	2.17
Mercury (tons)	53.52	53.60	48.66	51.32	54.05	19.07	37.58	54.82	7.18	26.36

[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, MLBILL.D050503A, and SA2028.D051104A.

Table B11. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Electric Power Sector[2]										
Power Only[3]										
Coal Steam	305.3	310.6	289.0	291.2	343.9	209.3	253.5	376.0	139.9	219.7
Other Fossil Steam[4]	133.8	77.9	80.7	77.0	71.9	64.8	64.7	71.1	53.0	62.4
Combined Cycle	43.2	148.4	175.9	160.5	233.0	319.1	280.6	278.1	374.1	313.7
Combustion Turbine/Diesel	97.6	126.4	123.2	128.5	148.0	121.4	130.9	164.3	118.2	134.3
Nuclear Power[5]	98.2	98.7	100.3	100.3	99.0	117.2	108.6	99.0	149.2	126.7
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	97.2	129.0	116.3	101.0	225.0	187.1	102.6	245.6	228.4
Distributed Generation[7]	0.0	1.7	1.7	1.6	11.7	4.9	6.5	17.7	5.0	9.3
Total	**788.3**	**881.2**	**920.2**	**895.9**	**1029.0**	**1082.2**	**1052.4**	**1129.3**	**1105.4**	**1115.1**
Combined Heat and Power[8]										
Coal Steam	5.2	4.7	4.4	4.7	4.7	3.3	3.6	4.7	2.6	3.3
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**	**44.0**	**44.2**	**44.3**	**42.9**	**43.2**	**44.3**	**42.2**	**42.9**
Total Electric Power Industry	**822.0**	**925.6**	**964.2**	**940.1**	**1073.4**	**1125.1**	**1095.6**	**1173.7**	**1147.6**	**1158.0**
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	12.3	0.0	0.0	47.5	12.2	0.4	80.7	37.7	2.4
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	59.7	44.0	116.7	203.0	164.2	161.8	259.6	197.3
Combustion Turbine/Diesel	0.0	9.0	3.7	8.4	33.7	3.7	12.9	52.3	3.7	16.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	16.5	7.9	0.0	48.5	26.1
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	33.3	20.6	3.8	127.8	89.8	5.2	148.2	131.1
Distributed Generation[7]	0.0	1.7	1.7	1.6	11.7	4.9	6.5	17.7	5.0	9.3
Total	**0.0**	**56.5**	**98.4**	**74.6**	**213.3**	**368.1**	**281.7**	**317.8**	**502.8**	**382.6**
Cumulative Total Additions	**0.0**	**176.6**	**218.4**	**194.7**	**334.9**	**489.8**	**403.4**	**439.5**	**624.6**	**504.4**
Cumulative Retirements[10]										
Coal Steam	0.0	7.6	17.2	14.8	9.4	110.2	53.8	10.5	205.8	89.9
Other Fossil Steam[4]	0.0	54.4	51.6	55.3	60.4	67.5	67.6	61.2	79.3	69.9
Combined Cycle	0.0	0.7	0.9	0.6	0.7	0.9	0.6	0.7	2.6	0.6
Combustion Turbine/Diesel	0.0	11.2	9.1	8.4	14.3	10.9	10.6	16.7	14.2	10.8
Nuclear Power	0.0	2.4	0.8	0.8	3.4	1.8	1.8	3.4	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**	**76.5**	**79.7**	**80.0**	**88.3**	**191.4**	**134.5**	**92.6**	**303.8**	**173.1**

Table B11. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
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	19.4	18.4	22.1	30.1	26.3	26.4	48.7	38.2
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	6.2	6.2	8.1	8.0	8.0	9.0	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**	**31.8**	**34.2**	**33.2**	**38.8**	**46.7**	**42.9**	**44.2**	**66.2**	**55.8**
Other End-Use Generators[12]										
Renewable Sources[13]	1.1	1.5	1.5	1.5	1.7	1.9	1.8	2.0	2.2	2.2
Cumulative Additions[9]										
Combined Heat and Power[11]	0.0	4.1	6.4	5.6	11.1	19.0	15.2	16.6	38.5	28.1
Other End-Use Generators[12]	0.0	0.4	0.4	0.4	0.6	0.7	0.7	0.9	1.1	1.0

[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 B17 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, MLBILL.D050503A, and SA2028.D051104A.

Table B12. Petroleum Supply and Disposition Balance
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Crude Oil										
Domestic Crude Production[1]	5.80	5.64	5.63	5.64	5.43	5.41	5.41	5.30	5.27	5.20
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	4.99	4.99	4.20	4.18	4.18	4.13	4.09	4.02
Net Imports	9.31	11.49	11.40	11.40	12.67	12.35	12.45	13.14	12.72	12.87
Gross Imports	9.33	11.56	11.46	11.46	12.73	12.40	12.50	13.18	12.77	12.92
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**	**17.03**	**17.03**	**18.10**	**17.76**	**17.86**	**18.44**	**17.99**	**18.07**
Natural Gas Plant Liquids	**1.87**	**2.20**	**2.27**	**2.24**	**2.48**	**2.63**	**2.53**	**2.59**	**2.69**	**2.66**
Other Inputs[3]	**0.30**	**0.44**	**0.43**	**0.43**	**0.44**	**0.36**	**0.37**	**0.44**	**0.35**	**0.35**
Refinery Processing Gain[4]	**0.90**	**0.91**	**0.89**	**0.90**	**0.96**	**0.94**	**0.95**	**0.96**	**0.93**	**0.96**
Net Product Imports[5]	**1.59**	**2.17**	**1.89**	**2.03**	**4.88**	**3.42**	**4.22**	**6.48**	**4.22**	**5.32**
Gross Refined Product Imports[6]	2.08	2.55	2.32	2.37	4.89	3.40	4.21	6.51	4.26	5.38
Unfinished Oil Imports	0.38	0.63	0.55	0.65	1.07	1.06	1.06	1.08	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	1.00	0.98	0.99	1.08	1.03	1.05	1.11	1.05	1.08
Total Primary Supply[7]	**19.80**	**22.86**	**22.52**	**22.63**	**26.86**	**25.10**	**25.93**	**28.90**	**26.17**	**27.36**
Refined Petroleum Products Supplied										
Motor Gasoline[8]	8.67	10.54	10.42	10.48	12.53	11.47	12.10	13.55	11.76	12.71
Jet Fuel[9]	1.66	1.90	1.89	1.89	2.46	2.42	2.43	2.74	2.69	2.70
Distillate Fuel[10]	3.81	4.62	4.57	4.59	5.42	5.19	5.28	5.88	5.54	5.65
Residual Fuel	0.97	0.63	0.54	0.55	0.66	0.52	0.54	0.66	0.53	0.55
Other[11]	4.58	5.18	5.12	5.13	5.80	5.50	5.59	6.09	5.66	5.76
Total	**19.69**	**22.87**	**22.53**	**22.65**	**26.87**	**25.11**	**25.94**	**28.92**	**26.18**	**27.37**
Refined Petroleum Products Supplied										
Residential and Commercial	1.21	1.18	1.18	1.18	1.14	1.16	1.14	1.13	1.15	1.13
Industrial[12]	4.67	5.28	5.21	5.23	5.96	5.62	5.72	6.28	5.79	5.91
Transportation	13.27	16.19	16.02	16.11	19.53	18.25	18.98	21.25	19.14	20.20
Electric Power[13]	0.55	0.21	0.12	0.13	0.24	0.08	0.10	0.26	0.09	0.12
Total	**19.69**	**22.87**	**22.53**	**22.65**	**26.87**	**25.11**	**25.94**	**28.92**	**26.18**	**27.37**
Discrepancy[14]	**0.10**	**-0.02**	**-0.02**	**-0.02**	**-0.02**	**-0.01**	**-0.01**	**-0.02**	**-0.01**	**-0.01**
World Oil Price (2001 dollars per barrel)[15]	**22.01**	**23.99**	**23.77**	**23.77**	**25.48**	**24.15**	**24.15**	**26.57**	**24.58**	**24.58**
Import Share of Product Supplied	**0.55**	**0.60**	**0.59**	**0.59**	**0.65**	**0.63**	**0.64**	**0.68**	**0.65**	**0.66**
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2001 dollars)	**89.20**	**122.23**	**117.95**	**119.27**	**172.92**	**144.08**	**154.82**	**205.85**	**158.78**	**174.62**
Domestic Refinery Distillation Capacity[16]	**16.8**	**18.7**	**18.7**	**18.7**	**19.5**	**19.1**	**19.2**	**19.8**	**19.3**	**19.4**
Capacity Utilization Rate (percent)	**93.0**	**93.1**	**92.8**	**92.8**	**94.6**	**94.5**	**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, MLBILL.D050503A, and SA2028.D051104A.

Table B13. Petroleum Product Prices
(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
World Oil Price (2001 dollars per barrel)	**22.01**	**23.99**	**23.77**	**23.77**	**25.48**	**24.15**	**24.15**	**26.57**	**24.58**	**24.58**
Delivered Sector Prices Including Greenhouse Gas Allowance Cost										
Residential										
Distillate Fuel	124.6	110.9	110.3	110.1	120.7	114.2	116.8	123.8	119.0	119.4
Liquefied Petroleum Gas	127.3	123.1	119.8	121.0	131.1	123.9	127.6	133.1	128.3	128.0
Commercial										
Distillate Fuel	88.7	78.6	78.0	77.9	89.5	82.6	85.3	93.7	87.3	88.3
Residual Fuel	51.8	60.1	58.9	58.9	63.3	59.3	59.4	65.7	60.2	60.3
Residual Fuel (2001 dollars per barrel)	21.75	25.24	24.73	24.74	26.57	24.92	24.94	27.58	25.30	25.32
Industrial[1]										
Distillate Fuel	90.8	79.7	100.8	94.1	93.4	134.6	122.6	99.7	151.0	138.6
Liquefied Petroleum Gas	105.9	85.2	93.8	91.2	93.1	113.1	108.5	95.4	123.3	114.9
Residual Fuel	49.1	55.6	79.9	72.3	58.9	112.2	95.1	61.4	126.7	109.7
Residual Fuel (2001 dollars per barrel)	20.61	23.35	33.55	30.37	24.75	47.12	39.94	25.77	53.20	46.07
Transportation										
Diesel Fuel (distillate)[2]	139.4	141.4	162.4	155.7	142.4	182.6	169.6	147.5	199.3	184.7
Jet Fuel[3]	83.7	76.3	95.9	89.7	85.6	125.0	112.7	90.7	139.7	127.1
Motor Gasoline[4]	143.3	141.8	160.8	155.3	143.1	179.9	168.7	149.4	189.6	178.4
Liquid Petroleum Gas	145.2	133.4	140.3	138.3	137.8	157.0	152.5	137.1	164.3	155.2
Residual Fuel	58.4	53.4	77.8	70.2	56.6	110.1	92.9	59.0	124.5	107.5
Residual Fuel (2001 dollars per barrel)	24.52	22.41	32.66	29.47	23.76	46.25	39.03	24.80	52.31	45.13
Electric Power[5]										
Distillate Fuel	86.0	71.2	91.1	84.3	82.4	123.6	111.5	85.4	138.6	125.1
Residual Fuel	67.4	61.0	89.4	81.0	64.8	129.9	109.0	68.1	144.9	123.3
Residual Fuel (2001 dollars per barrel)	28.30	25.63	37.53	34.00	27.23	54.57	45.76	28.60	60.84	51.80
Delivered Sector Prices Excluding Greenhouse Gas Allowance Cost										
Residential										
Distillate Fuel	124.6	110.9	110.3	110.1	120.7	114.2	116.8	123.8	119.0	119.4
Liquefied Petroleum Gas	127.3	123.1	119.8	121.0	131.1	123.9	127.6	133.1	128.3	128.0
Commercial										
Distillate Fuel	88.7	78.6	78.0	77.9	89.5	82.6	85.3	93.7	87.3	88.3
Residual Fuel	51.8	60.1	58.9	58.9	63.3	59.3	59.4	65.7	60.2	60.3
Residual Fuel (2001 dollars per barrel)	21.75	25.24	24.73	24.74	26.57	24.92	24.94	27.58	25.30	25.32
Industrial[1]										
Distillate Fuel	90.8	79.7	79.2	79.1	93.4	85.7	88.5	99.7	90.6	92.8
Liquefied Petroleum Gas	105.9	85.2	82.2	83.2	93.1	87.0	90.3	95.4	91.0	90.4
Residual Fuel	49.1	55.6	54.7	54.8	58.9	55.4	55.4	61.4	56.4	56.4
Residual Fuel (2001 dollars per barrel)	20.61	23.35	22.99	23.01	24.75	23.26	23.28	25.77	23.67	23.70
Transportation										
Diesel Fuel (distillate)[2]	139.4	141.4	140.8	140.6	142.4	133.8	135.5	147.5	138.8	138.9
Jet Fuel[3]	83.7	76.3	75.5	75.5	85.6	78.9	80.6	90.7	82.7	83.9
Motor Gasoline[4]	143.3	141.8	142.1	142.2	143.1	137.6	139.1	149.4	137.3	138.8
Liquid Petroleum Gas	145.2	133.4	128.7	130.2	137.8	130.9	134.2	137.1	131.9	130.7
Residual Fuel	58.4	53.4	52.6	52.6	56.6	53.3	53.3	59.0	54.2	54.2
Residual Fuel (2001 dollars per barrel)	24.52	22.41	22.11	22.11	23.76	22.38	22.37	24.80	22.78	22.76
Electric Power[5]										
Distillate Fuel	86.0	71.2	69.5	69.3	82.4	74.7	77.4	85.4	78.2	79.3
Residual Fuel	67.4	61.0	64.2	63.4	64.8	73.1	69.3	68.1	74.6	70.1
Residual Fuel (2001 dollars per barrel)	28.30	25.63	26.98	26.63	27.23	30.71	29.11	28.60	31.31	29.42

Table B13. Petroleum Product Prices (Continued)
(2001 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Greenhouse Gas Allowance Cost										
Residential										
Distillate Fuel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Liquefied Petroleum Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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	21.6	15.1	0.0	48.9	34.1	0.0	60.5	45.8
Liquefied Petroleum Gas	0.0	0.0	11.6	8.1	0.0	26.1	18.3	0.0	32.4	24.5
Residual Fuel	0.0	0.0	25.1	17.5	0.0	56.8	39.7	0.0	70.3	53.3
Residual Fuel (2001 dollars per barrel)	0.00	0.00	10.55	7.37	0.00	23.86	16.66	0.00	29.53	22.37
Transportation										
Diesel Fuel (distillate)[2]	0.0	0.0	21.6	15.1	0.0	48.9	34.1	0.0	60.5	45.8
Jet Fuel[3]	0.0	0.0	20.4	14.2	0.0	46.1	32.2	0.0	57.0	43.2
Motor Gasoline[4]	0.0	0.0	18.7	13.1	0.0	42.3	29.5	0.0	52.3	39.7
Liquid Petroleum Gas	0.0	0.0	11.6	8.1	0.0	26.1	18.3	0.0	32.4	24.5
Residual Fuel	0.0	0.0	25.1	17.5	0.0	56.8	39.7	0.0	70.3	53.3
Residual Fuel (2001 dollars per barrel)	0.00	0.00	10.55	7.37	0.00	23.86	16.66	0.00	29.53	22.37
Electric Power[5]										
Distillate Fuel	0.0	0.0	21.6	15.1	0.0	48.9	34.1	0.0	60.5	45.8
Residual Fuel	0.0	0.0	25.1	17.5	0.0	56.8	39.7	0.0	70.3	53.3
Residual Fuel (2001 dollars per barrel)	0.00	0.00	10.55	7.37	0.00	23.86	16.66	0.00	29.53	22.37

[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, MLBILL.D050503A, and SA2028.D051104A.

Table B14. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Production										
Dry Gas Production[1]	19.45	21.53	22.21	21.90	24.85	26.61	25.65	26.36	27.32	27.06
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**	**4.85**	**4.66**	**6.88**	**8.80**	**7.58**	**7.90**	**10.87**	**9.24**
Canada	3.61	4.16	4.20	4.10	5.14	5.44	5.20	5.21	5.61	5.43
Mexico	-0.13	-0.20	-0.21	-0.21	-0.02	0.16	-0.01	0.29	0.66	0.33
Liquefied Natural Gas	0.26	0.80	0.86	0.77	1.76	3.21	2.38	2.40	4.60	3.47
Total Supply	**23.26**	**26.39**	**27.15**	**26.66**	**31.83**	**35.51**	**33.32**	**34.36**	**38.29**	**36.39**
Consumption by Sector										
Residential	4.81	5.48	5.47	5.48	5.93	5.80	5.85	6.21	6.03	6.05
Commercial	3.24	3.64	3.63	3.64	4.12	4.16	4.14	4.38	4.84	4.60
Industrial[3]	7.53	8.81	8.91	8.88	10.10	10.08	10.02	10.93	10.79	10.68
Electric Power[4]	5.30	6.58	7.20	6.77	9.42	13.00	10.95	10.37	14.03	12.45
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	0.79	0.77	0.91	1.02	0.96	1.00	1.08	1.03
Lease and Plant Fuel[6]	1.17	1.33	1.36	1.35	1.56	1.66	1.61	1.68	1.72	1.71
Total	**22.67**	**26.66**	**27.42**	**26.94**	**32.14**	**35.80**	**33.62**	**34.67**	**38.59**	**36.63**
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**	**-0.26**	**-0.28**	**-0.31**	**-0.30**	**-0.30**	**-0.31**	**-0.30**	**-0.24**

[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, MLBILL.D050503A, and SA2028.D051104A.

Table B15. 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 Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Source Price										
Average Lower 48 Wellhead Price[1]	4.12	3.39	3.51	3.41	3.70	3.97	3.71	3.95	4.36	4.19
Average Import Price	4.43	3.40	3.46	3.40	3.88	4.17	3.91	4.19	4.65	4.47
Average[2]	**4.17**	**3.39**	**3.50**	**3.41**	**3.74**	**4.02**	**3.76**	**4.01**	**4.45**	**4.26**
Delivered Prices Including Greenhouse Gas Allowance Cost										
Residential	9.68	7.79	7.89	7.80	7.99	8.30	8.02	8.26	8.72	8.57
Commercial	8.32	6.67	6.78	6.69	6.98	7.27	7.00	7.26	7.69	7.53
Industrial[3]	5.01	4.11	5.37	4.94	4.51	7.40	6.34	4.76	8.42	7.45
Electric Power[4]	4.87	3.95	5.30	4.83	4.44	7.50	6.37	4.73	8.53	7.51
Transportation[5]	7.87	7.39	8.62	8.21	7.97	10.58	9.58	8.32	11.57	10.68
Average[6]	**6.57**	**5.28**	**6.12**	**5.81**	**5.55**	**7.61**	**6.78**	**5.80**	**8.44**	**7.71**
Delivered Prices Excluding Greenhouse Gas Allowance Cost										
Residential	9.68	7.79	7.89	7.80	7.99	8.30	8.02	8.26	8.72	8.57
Commercial	8.32	6.67	6.78	6.69	6.98	7.27	7.00	7.26	7.69	7.53
Industrial[3]	5.01	4.11	4.23	4.14	4.51	4.81	4.53	4.76	5.21	5.02
Electric Power[4]	4.87	3.95	4.14	4.02	4.44	4.88	4.54	4.73	5.29	5.06
Transportation[5]	7.87	7.39	7.45	7.39	7.97	7.94	7.74	8.32	8.30	8.21
Average[6]	**6.57**	**5.28**	**5.38**	**5.30**	**5.55**	**5.78**	**5.54**	**5.80**	**6.19**	**6.03**
Transmission & Distribution Margins[7]										
Residential	5.50	4.39	4.39	4.39	4.25	4.27	4.26	4.25	4.28	4.30
Commercial	4.14	3.28	3.28	3.27	3.24	3.24	3.24	3.25	3.24	3.27
Industrial[3]	0.83	0.72	0.73	0.72	0.77	0.79	0.77	0.75	0.77	0.76
Electric Power[4]	0.70	0.56	0.65	0.61	0.70	0.86	0.78	0.72	0.84	0.80
Transportation[5]	3.69	4.00	3.95	3.98	4.23	3.92	3.98	4.31	3.86	3.95
Average[6]	**2.40**	**1.89**	**1.88**	**1.89**	**1.81**	**1.76**	**1.78**	**1.79**	**1.75**	**1.77**
Transmission & Distribution Revenue (billion 2001 dollars)										
Residential	26.45	24.08	24.00	24.01	25.22	24.78	24.94	26.39	25.78	26.05
Commercial	13.42	11.94	11.91	11.91	13.33	13.48	13.39	14.25	15.68	15.04
Industrial[3]	6.28	6.36	6.49	6.43	7.82	7.94	7.70	8.23	8.27	8.08
Electric Power[4]	3.69	3.70	4.64	4.14	6.57	11.18	8.54	7.42	11.80	9.91
Transportation[5]	0.04	0.23	0.22	0.23	0.41	0.36	0.37	0.47	0.39	0.41
Total	**49.88**	**46.31**	**47.27**	**46.72**	**53.36**	**57.74**	**54.94**	**56.76**	**61.91**	**59.49**
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	1.15	0.80	0.00	2.59	1.81	0.00	3.21	2.43
Electric Power[4]	0.00	0.00	1.16	0.81	0.00	2.62	1.83	0.00	3.24	2.45
Transportation[5]	0.00	0.00	1.17	0.82	0.00	2.64	1.84	0.00	3.27	2.48
Average[6]	**0.00**	**0.00**	**0.74**	**0.51**	**0.00**	**1.83**	**1.24**	**0.00**	**2.25**	**1.68**

[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, MLBILL.D050503A, and SA2028.D051104A.

Table B16. Oil and Gas Supply

Production and Supply	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Crude Oil										
Lower 48 Average Wellhead Price[1]										
(2001 dollars per barrel)	22.91	23.89	23.56	23.57	24.98	23.65	23.54	26.22	24.11	23.98
Production (million barrels per day)[2]										
U.S. Total	5.80	5.64	5.63	5.64	5.43	5.41	5.41	5.30	5.27	5.20
Lower 48 Onshore	3.13	2.47	2.47	2.47	2.06	2.05	2.05	1.92	1.90	1.90
Lower 48 Offshore	1.71	2.52	2.52	2.52	2.14	2.13	2.13	2.22	2.19	2.13
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	17.70	17.71	15.39	15.34	15.31	15.04	14.92	14.74
Natural Gas										
Lower 48 Average Wellhead Price[1]										
(2001 dollars per thousand cubic feet)	4.12	3.39	3.51	3.41	3.70	3.97	3.71	3.95	4.36	4.19
Dry Production (trillion cubic feet)[3]										
U.S. Total	19.45	21.54	22.21	21.90	24.86	26.61	25.65	26.37	27.32	27.06
Lower 48 Onshore	13.72	15.57	16.17	15.90	17.96	18.65	17.73	17.77	18.72	18.28
Associated-Dissolved[4]	1.77	1.37	1.36	1.37	1.19	1.19	1.19	1.13	1.13	1.13
Non-Associated	11.94	14.20	14.81	14.54	16.77	17.46	16.54	16.64	17.59	17.15
Conventional	6.54	7.04	7.32	7.15	7.15	7.37	7.16	7.04	7.13	7.22
Unconventional	5.40	7.16	7.49	7.39	9.61	10.09	9.38	9.60	10.46	9.94
Lower 48 Offshore	5.30	5.49	5.56	5.52	5.43	5.58	5.53	5.74	5.77	5.94
Associated-Dissolved[4]	1.08	0.96	0.96	0.96	0.80	0.79	0.79	0.82	0.81	0.78
Non-Associated	4.22	4.53	4.60	4.56	4.63	4.78	4.74	4.93	4.96	5.15
Alaska	0.43	0.48	0.48	0.48	1.47	2.39	2.39	2.85	2.84	2.84
Lower 48 End of Year Dry Reserves[3]										
(trillion cubic feet)	174.04	186.42	185.39	185.58	194.24	195.87	192.82	190.10	192.41	189.09
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	25.75	25.56	26.21	27.25	26.22	27.53	29.30	27.97

[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, MLBILL.D050503A, and SA2028.D051104A.

Table B17. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections 2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Production[1]										
Appalachia	443	420	415	422	416	212	320	433	145	253
Interior	147	161	153	158	151	88	130	159	42	112
West	548	669	513	576	801	185	387	865	128	236
East of the Mississippi	539	527	518	527	529	286	415	554	182	345
West of the Mississippi	599	723	563	628	839	199	422	902	132	255
Total	**1138**	**1250**	**1081**	**1155**	**1367**	**485**	**838**	**1456**	**315**	**600**
Net Imports										
Imports	19	20	11	11	25	11	11	28	10	10
Exports	49	33	33	33	29	29	27	24	24	23
Total	**-30**	**-14**	**-22**	**-22**	**-4**	**-19**	**-16**	**3**	**-13**	**-13**
Total Supply[2]	**1109**	**1236**	**1060**	**1133**	**1363**	**466**	**821**	**1460**	**301**	**587**
Consumption by Sector										
Residential and Commercial	4	5	5	5	5	5	5	5	6	6
Industrial[3]	63	67	61	63	70	59	62	71	58	61
of which: Coal to Liquids	0	0	0	0	0	0	0	0	0	0
Coke Plants	26	24	24	24	20	17	18	18	14	15
Electric Power[4]	957	1146	966	1044	1274	390	744	1371	227	558
Total	**1050**	**1242**	**1055**	**1136**	**1369**	**471**	**829**	**1466**	**306**	**640**
Discrepancy and Stock Change[5]	**58**	**-6**	**4**	**-2**	**-6**	**-6**	**-7**	**-6**	**-4**	**-53**
Average Minemouth Price										
(2001 dollars per short ton)	17.59	15.06	15.84	15.56	14.34	15.27	15.06	14.39	13.67	15.63
(2001 dollars per million Btu)	0.83	0.73	0.76	0.75	0.70	0.71	0.72	0.71	0.63	0.73
Delivered Prices Including Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]										
Industrial	32.82	30.11	73.69	60.61	28.45	123.14	95.85	28.04	143.97	117.22
Coke Plants	46.42	41.27	96.11	79.52	38.08	162.07	124.51	36.67	189.79	152.64
Electric Power										
(2001 dollars per short ton)	25.06	23.63	65.08	52.54	22.44	116.04	86.78	22.27	136.11	110.86
(2001 dollars per million Btu)	1.25	1.17	3.17	2.58	1.12	5.53	4.22	1.11	6.53	5.24
Average	**26.06**	**24.33**	**66.29**	**53.56**	**22.98**	**118.63**	**88.26**	**22.74**	**140.21**	**112.46**
Delivered Prices Excluding Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]										
Industrial	32.82	30.11	30.10	30.19	28.45	24.86	27.11	28.04	22.55	25.27
Coke Plants	46.42	41.27	41.37	41.31	38.08	38.31	38.12	36.67	36.64	36.60
Electric Power										
(2001 dollars per short ton)	25.06	23.63	23.76	23.87	22.44	20.83	21.36	22.27	18.81	20.87
(2001 dollars per million Btu)	1.25	1.17	1.16	1.17	1.12	0.99	1.04	1.11	0.90	0.99
Average	**26.06**	**24.33**	**24.53**	**24.59**	**22.98**	**21.98**	**22.15**	**22.74**	**20.39**	**21.67**
Exports[7]	36.97	32.68	32.41	32.51	30.94	28.76	30.28	30.36	27.46	28.68
Greenhouse Gas Allowance Cost (2001 dollars per short ton)[6]										
Industrial	0.00	0.00	43.59	30.42	0.00	98.28	68.74	0.00	121.42	91.96
Coke Plants	0.00	0.00	54.74	38.21	0.00	123.76	86.39	0.00	153.14	116.04
Electric Power										
(2001 dollars per short ton)	0.00	0.00	41.32	28.66	0.00	95.21	65.42	0.00	117.30	89.99
(2001 dollars per million Btu)	0.00	0.00	2.02	1.41	0.00	4.54	3.18	0.00	5.62	4.26
Average	**0.00**	**0.00**	**41.76**	**28.96**	**0.00**	**96.65**	**66.12**	**0.00**	**119.82**	**90.79**

[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, MLBILL.D050503A, and SA2028.D051104A.

Table B18. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2001	Projections 2010 Reference Case	2010 S.139 Case	2010 SA.2028 Case	2020 Reference Case	2020 S.139 Case	2020 SA.2028 Case	2025 Reference Case	2025 S.139 Case	2025 SA.2028 Case
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	6.68	6.58	5.19	10.06	9.56	5.77	10.55	9.87
Municipal Solid Waste[3]	3.25	4.08	4.84	4.78	4.41	5.17	5.17	4.42	5.19	5.19
Wood and Other Biomass[4]	1.80	2.09	3.96	3.27	2.20	48.03	31.71	2.33	67.38	64.08
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	34.53	22.71	10.05	82.60	61.48	10.81	83.22	70.02
Total	**90.62**	**97.42**	**129.20**	**116.54**	**101.24**	**225.26**	**187.31**	**102.83**	**245.84**	**228.67**
Generation (billion kilowatthours)										
Conventional Hydropower	213.82	300.90	300.89	300.89	300.07	299.92	299.96	300.36	300.10	300.17
Geothermal[2]	13.81	22.04	44.61	43.85	33.43	73.14	69.13	38.12	77.22	71.94
Municipal Solid Waste[3]	19.55	29.20	35.17	34.78	31.67	37.63	37.64	31.81	37.83	37.86
Wood and Other Biomass[4]	9.38	21.47	27.11	24.55	22.06	304.95	188.02	22.82	429.32	396.20
Dedicated Plants	7.66	12.47	19.52	17.15	13.22	304.95	188.02	14.09	429.32	396.20
Cofiring	1.72	9.00	7.59	7.40	8.84	0.00	0.00	8.73	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	22.91	112.46	73.69	29.20	277.70	207.45	32.03	280.10	234.93
Total	**262.85**	**397.53**	**521.25**	**478.78**	**417.98**	**994.90**	**803.75**	**427.00**	**1126.43**	**1042.96**
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	5.89	5.90	7.79	7.67	7.72	8.74	8.60	8.63
Total	**4.69**	**6.21**	**6.17**	**6.18**	**8.07**	**7.95**	**8.00**	**9.03**	**8.88**	**8.92**
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	0.76	0.70	0.94	1.15	1.07
Total	**1.12**	**1.47**	**1.47**	**1.47**	**1.71**	**1.85**	**1.79**	**2.04**	**2.25**	**2.16**
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	37.31	37.37	48.39	47.72	48.01	53.98	53.13	53.34
Total	**31.13**	**39.68**	**39.46**	**39.53**	**50.54**	**49.87**	**50.16**	**56.13**	**55.28**	**55.49**
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	1.61	1.50	1.99	2.42	2.26
Total	**4.25**	**5.05**	**5.05**	**5.05**	**5.55**	**5.85**	**5.73**	**6.23**	**6.66**	**6.49**

[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, MLBILL.D050503A, and SA2028.D051104A.

Table B19. Renewable Energy Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
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**	**2.21**	**2.77**	**2.74**	**2.75**	**3.05**	**3.02**	**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	2.17	2.16	2.16	2.72	2.69	2.71	3.00	2.97	2.98
Transportation	**0.15**	**0.26**	**0.26**	**0.26**	**0.31**	**0.28**	**0.30**	**0.33**	**0.29**	**0.31**
Ethanol used in E85[4]	0.00	0.00	0.00	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	0.26	0.30	0.28	0.29	0.33	0.28	0.31
Electric Power[5]	**3.01**	**4.57**	**6.30**	**5.89**	**5.02**	**11.42**	**9.54**	**5.21**	**12.69**	**11.77**
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	1.30	1.28	0.93	2.23	2.07	1.07	2.36	2.16
Municipal Solid Waste[6]	0.31	0.40	0.48	0.47	0.43	0.51	0.51	0.43	0.51	0.51
Biomass	0.15	0.26	0.31	0.29	0.27	2.78	1.74	0.28	3.89	3.59
Dedicated Plants	0.12	0.14	0.21	0.19	0.15	2.78	1.74	0.16	3.89	3.59
Cofiring	0.03	0.12	0.09	0.10	0.12	0.00	0.00	0.12	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	0.24	1.12	0.76	0.30	2.82	2.13	0.33	2.84	2.41
Total Marketed Renewable Energy	**5.46**	**7.56**	**9.28**	**8.88**	**8.61**	**14.95**	**13.10**	**9.10**	**16.50**	**15.62**
Sources of Ethanol										
From Corn	0.15	0.26	0.26	0.26	0.28	0.26	0.27	0.28	0.24	0.27
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**	**0.28**	**0.30**	**0.33**	**0.29**	**0.31**
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 B8.
[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, MLBILL.D050503A, and SA2028.D051104A.

Table B20. Greenhouse Gas Emissions and Allowance Cost
(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Carbon Dioxide Emissions										
Residential										
Petroleum	27.2	27.6	27.6	27.6	25.7	25.8	25.6	25.0	25.0	24.9
Natural Gas	71.1	81.1	81.0	81.0	87.9	85.8	86.6	91.9	89.3	89.6
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**	**109.0**	**109.0**	**113.9**	**112.0**	**112.6**	**117.2**	**114.7**	**114.9**
Commercial										
Petroleum	14.0	13.7	13.7	13.7	14.1	14.5	14.2	14.1	14.8	14.3
Natural Gas	48.0	53.9	53.8	53.9	60.9	61.5	61.2	64.8	71.6	68.1
Coal	2.3	2.4	2.5	2.4	2.7	2.8	2.7	2.8	2.9	2.9
Total	**64.3**	**70.0**	**69.9**	**70.0**	**77.7**	**78.8**	**78.1**	**81.7**	**89.3**	**85.2**
Industrial[1]										
Petroleum	97.9	97.9	96.0	96.5	105.5	99.1	101.3	109.1	101.1	103.6
Natural Gas[2]	123.4	147.7	149.8	148.9	169.4	171.0	169.4	183.3	182.4	180.5
Coal	52.1	56.5	53.1	54.2	56.2	48.9	50.7	56.2	47.3	49.2
Total	**273.4**	**302.1**	**298.9**	**299.6**	**331.2**	**319.0**	**321.3**	**348.6**	**330.8**	**333.3**
Transportation										
Petroleum[3]	501.4	611.5	605.1	608.2	737.5	690.4	717.1	802.8	725.3	763.7
Natural Gas[4]	9.2	12.0	12.5	12.2	14.9	16.4	15.5	16.4	17.4	16.8
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**	**617.6**	**620.5**	**752.5**	**706.8**	**732.7**	**819.2**	**742.7**	**780.5**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	640.5	750.8	742.5	746.0	882.8	829.8	858.2	950.9	866.2	906.5
Natural Gas	251.7	294.7	297.0	296.1	333.1	334.8	332.7	356.4	360.7	355.0
Coal	54.7	59.3	55.9	57.0	59.3	52.0	53.8	59.4	50.5	52.3
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**	**1095.4**	**1099.1**	**1275.2**	**1216.6**	**1244.7**	**1366.7**	**1277.4**	**1313.9**
Electric Power[6]										
Petroleum	27.5	10.1	5.4	6.0	11.3	3.9	4.8	12.0	3.9	5.8
Natural Gas	77.7	96.6	105.0	99.3	138.2	158.0	160.2	152.1	132.6	178.1
Coal	506.4	590.8	504.4	542.0	653.0	190.0	387.8	703.6	68.3	279.5
Total	**611.6**	**697.4**	**614.8**	**647.3**	**802.5**	**351.9**	**552.8**	**867.8**	**204.8**	**463.4**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	668.0	760.8	747.9	752.0	894.1	833.7	863.0	962.9	870.2	912.2
Natural Gas	329.4	391.3	402.0	395.4	471.3	492.8	492.9	508.5	493.3	533.1
Coal	561.1	650.1	560.3	599.0	712.2	242.0	441.6	763.0	118.8	331.9
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**	**1710.1**	**1746.4**	**2077.7**	**1568.5**	**1797.5**	**2234.4**	**1482.2**	**1777.3**
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**	**1749.7**	**1786.0**	**2121.6**	**1612.4**	**1841.4**	**2280.6**	**1528.4**	**1823.5**
Other Greenhouse Gas Emissions	**332.9**	**388.3**	**286.4**	**292.6**	**466.6**	**339.5**	**333.7**	**525.0**	**362.9**	**357.7**
Methane	175.2	177.6	115.2	119.8	174.3	126.4	115.3	172.2	120.0	113.1
Nitrous Oxide	118.9	126.5	121.0	121.0	137.3	131.4	131.4	143.4	137.2	137.2
High Global Warming Potential Gases	38.8	84.2	50.2	51.8	155.0	81.8	87.0	209.4	105.8	107.4
Total Greenhouse Gas Emissions	**1927.8**	**2230.1**	**2036.1**	**2078.6**	**2588.2**	**1951.9**	**2175.1**	**2805.6**	**1891.4**	**2181.2**

Table B20. Greenhouse Gas Emissions and Allowance Cost (Continued)
(Million Metric Tons Carbon Equivalent)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
Greenhouse Gas Emission Cap Compliance										
Covered Emissions										
Energy-Related Carbon Dioxide	1378.2	1605.0	1513.1	1549.3	1866.0	1357.5	1586.7	2014.2	1256.9	1555.8
Other Greenhouse Gases	75.2	123.5	70.1	72.2	195.7	102.8	108.4	250.7	127.6	129.4
Offsets Purchased	0.0	0.0	234.7	198.7	0.0	126.1	219.8	0.0	125.6	219.9
Non-Covered Greenhouse Gas Offsets	0.0	0.0	48.5	44.4	0.0	34.3	45.7	0.0	39.0	46.0
U.S. Sequestration Offsets	0.0	0.0	112.8	103.6	0.0	91.8	127.9	0.0	86.5	112.3
International Offsets	0.0	0.0	73.4	50.7	0.0	0.0	46.2	0.0	0.1	61.6
Covered Emissions less Offsets	1453.4	1728.5	1348.5	1422.8	2061.6	1334.2	1475.2	2264.9	1258.9	1465.3
Covered Emissions Goal	N/A	N/A	1465.1	1465.1	N/A	1257.9	1465.1	N/A	1257.9	1465.1
Allowance Bank Activity	0.0	0.0	116.5	42.2	0.0	-76.3	-10.2	0.0	-1.0	-0.2
Cumulative Bank Balance	0.0	0.0	116.5	42.2	0.0	98.9	8.5	0.0	7.3	-1.8
Allowance Cost (2001 dollars per ton)										
Emissions Allowance Cost	0.00	0.00	78.89	55.07	0.00	178.36	124.50	0.00	220.71	167.24
Offset Price	0.00	0.00	71.49	55.07	0.00	34.84	89.00	0.00	51.73	106.48

[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, MLBILL.D050503A, and SA2028.D051104A.

Table B21. Macroeconomic Indicators
(Billion 1996 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2001	Projections								
		2010			2020			2025		
		Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case	Reference Case	S.139 Case	SA.2028 Case
GDP Chain-Type Price Index (1996=1.000)	1.094	1.313	1.321	1.319	1.708	1.735	1.726	1.981	2.028	2.019
Potential Gross Domestic Product	9456	12454	12458	12458	16772	16729	16750	19240	19150	19185
Real Gross Domestic Product	9215	12258	12211	12226	16444	16364	16408	18916	18810	18840
Real Consumption	6377	8412	8375	8387	11346	11284	11325	13008	12954	12982
Real Investment	1575	2499	2478	2485	3755	3724	3738	4496	4447	4456
Real Government Spending	1640	1895	1897	1896	2211	2204	2207	2429	2417	2421
Real Exports	1076	1784	1781	1782	3361	3329	3338	4696	4621	4636
Real Imports	1492	2302	2292	2294	4060	4027	4047	5395	5376	5395
Real Disposable Personal Income	6748	8635	8607	8617	11693	11648	11687	13425	13432	13446
Federal Funds Rate (percent)	3.89	5.48	5.63	5.59	6.37	6.58	6.58	6.49	6.97	6.88
AA Utility Bond Rate (percent)										
Nominal	7.57	7.22	7.38	7.33	9.00	9.17	9.16	9.61	9.99	9.94
Real	5.60	5.26	5.20	5.22	6.12	6.18	6.19	6.54	6.76	6.71
Energy Intensity (thousand Btu per 1996 dollar of GDP)										
Delivered Energy	7.74	6.83	6.80	6.81	5.91	5.65	5.76	5.52	5.17	5.29
Total Energy	10.56	9.24	9.15	9.21	7.89	7.37	7.59	7.33	6.70	6.93
Consumer Price Index (1982-84=1.00)	1.77	2.19	2.20	2.20	2.93	2.97	2.96	3.47	3.55	3.53
Unemployment Rate (percent)	4.79	4.42	4.55	4.52	5.88	6.03	5.94	5.77	5.85	5.85
Housing Starts (millions)	1.80	2.18	2.12	2.14	1.93	1.92	1.93	2.01	2.01	2.00
Single-Family	1.27	1.34	1.31	1.32	1.12	1.11	1.11	1.12	1.11	1.11
Multifamily	0.33	0.47	0.45	0.45	0.49	0.49	0.49	0.57	0.57	0.56
Mobile Home Shipments	0.19	0.37	0.36	0.37	0.32	0.33	0.33	0.33	0.33	0.33
Commercial Floorspace, Total (billion square feet)	70.2	82.0	82.0	82.0	94.6	94.2	94.5	100.8	100.6	100.7
Value of Shipments (billion 1996 dollars)										
Total Industrial	5425	6977	6920	6938	8969	8874	8914	10128	9990	10024
Nonmanufacturing	1346	1510	1500	1503	1744	1714	1726	1870	1828	1841
Manufacturing	4079	5466	5420	5435	7226	7160	7188	8258	8162	8183
Energy-Intensive Manufacturing	1086	1264	1255	1259	1451	1434	1441	1538	1515	1522
Non-Energy-Intensive Manufacturing	2993	4203	4164	4177	5774	5726	5748	6720	6647	6662
United Sales of Light-Duty Vehicles	17.11	18.29	17.87	18.01	20.02	20.06	20.06	20.00	20.15	20.11
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	147.1	147.1	159.1	158.8	159.0	165.8	165.5	165.6
Employment, Manufacturing	17.5	17.7	17.7	17.7	17.8	17.7	17.8	18.5	18.4	18.4
Labor Force	141.8	156.5	156.5	156.5	169.8	169.6	169.7	177.4	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 MLBASE.D050303A, MLBILL.D050503A, and SA2028.D051104A.

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OUR OPINION

Carbon control

DEP fires a warning shot

Gov. Jeb Bush has become an outspoken advocate for alternative fuel sources. A proponent of developing a vibrant ethanol industry in Florida, Mr. Bush understands that continuing to do business as usual on the energy front is foolhardy.

Changing the energy consumption equation is multifaceted. More vehicles that burn ethanol won't get us out of the danger zone with regard to the supply of nonrenewable sources of energy — and, importantly, the reduction of greenhouse gases.

Few at this point dispute evidence that global warming is a real and present danger. Now the Florida Department of Environmental Protection is suggesting that state government consider requiring "carbon pricing" for the generation of electricity — *if* the federal government doesn't take firm action first. Carbon pricing could include, for example, a cap or tax on certain levels of emissions.

This is potentially significant for several reasons — not the least of which is Florida's status as a high-growth, high-energy-consumption state.

The online publication *Carbon Control News* (www.carboncontrolnews.com), which reports on the regulation of greenhouse gases, broke the story on DEP's 42-page report titled "Whitepaper on Climate Change Science and Policy Options."

DEP spokeswoman Sarah Williams said the report, sought by Mr. Bush earlier this year, is intended as "more of an overview" than a list of specific policy recommendations that should be implemented immediately. But it is clearly intended as food for thought for lawmakers and Charlie Crist, who will be sworn in as governor Tuesday.

The report makes it clear that it's crucial for Florida to reduce greenhouse gases through alternative energy sources and the reduction of carbon emissions. In three to five years, the state should consider carbon pricing "to mitigate against an open-ended federal response." But pursuing that immediately probably would hurt Florida's economy.

Democratic control of Congress is likely to boost the chances that federal legislation will seek similar regulation. Several key Democrats already have expressed support for a carbon emissions tax.

It's a matter of speculation at this point what the impact might be, but Tallahasseeans have a direct stake in the outcome, with the continuing participation of city government in the coal-based Taylor Energy Center project.

In fact, all Floridians will be affected, as local, state and national governments have moved energy-related issues to the top of the agenda. Economic and environmental implications of climate change are huge for Florida, so policymakers at all levels would be wise to give this "white paper" more than a passing glance.

YOUR THOUGHTS

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