Legislation and Regulations

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Introduction

Because analyses by the EIA are required to be policy-neutral, the projections in this *AEO2005* generally are based on Federal and State laws and regulations in effect on or before October 31, 2004. The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require funds or implementing regulations that have not been provided or specified—are not reflected in the projections.

Examples of Federal and State legislation incorporated in the projections include the following:

- The National Appliance Energy Conservation Act of 1987
- The Clean Air Act Amendments of 1990 (CAAA90), which include new standards for motor gasoline and diesel fuel and for heavy-duty vehicle emissions
- The Energy Policy Act of 1992 (EPACT)
- The Omnibus Budget Reconciliation Act of 1993, which added 4.3 cents per gallon to the Federal tax on highway fuels
- The Outer Continental Shelf Deep Water Royalty Relief Act of 1995 and subsequent provisions on royalty relief for new leases issued after November 2000 on a lease-by-lease basis
- The Maritime Security Act of 2002, which amended the Deepwater Port Act of 1974 to include offshore natural gas facilities
- The American Jobs Creation Act of 2004, which includes incentives and tax credits for biodiesel fuels, a modified depreciation schedule for the Alaska natural gas pipeline, and an expansion of the 1.8-cent renewable energy production tax credit (PTC) to include geothermal and solar generation technologies
- The Military Construction Appropriations Act of 2005, which includes provisions to support construction of the Alaska natural gas pipeline, including Federal loan guarantees during construction
- The Working Families Tax Relief Act of 2004, which includes an extension of the 1.8-cent PTC for wind and closed-loop biomass to December 31, 2005; tax deductions for qualified clean-fuel and electric vehicles; and changes in the rules governing oil and gas well depletion
- State of Alaska's Right-Of-Way Leasing Act Amendments of 2001, which prohibit leases across State land for a "northern" or "over-the-top" natural gas pipeline route running east from the North Slope to Canada's MacKenzie River Valley
- State renewable portfolio standards, including the California renewable portfolio standards passed on September 12, 2002
- State programs for restructuring of the electricity industry.

AEO2005 assumes that State taxes on gasoline, diesel, jet fuel, and E85 (fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume) will increase with inflation, and that Federal taxes on those fuels will continue at 2003 levels in nominal terms. *AEO2005* also assumes the continuation of the ethanol tax incentive through 2025. Although these tax and tax incentive provisions include "sunset" clauses that limit their duration, they have been extended historically, and *AEO2005* assumes their continuation throughout the forecast.

Examples of Federal and State regulations incorporated in *AEO2005* include the following:

- Standards for energy-consuming equipment that have been announced, including the 13 seasonal energy efficiency ratio (SEER) [*2*] for new central air conditioners and heat pumps that were recently reestablished by the U.S. Court of Appeals after originally being set in January 2001
- The new corporate average fuel economy (CAFE) standards for light trucks published by the National Highway Traffic Safety Administration (NHTSA) in 2003
- Federal Energy Regulatory Commission (FERC), Orders 888 and 889, which provide open access to interstate transmission lines in electricity markets
- The December 2002 Hackberry Decision, which terminated open access requirements for new onshore LNG terminals
- The new boiler limits established by the U.S. Environmental Protection Agency (EPA) on February 26, 2004, which limit emissions of hazardous air pollutants from industrial, commercial, and institutional boilers and process heaters by requiring that they comply with a Maximum Achievable Control Technology (MACT) floor.

AEO2005 includes the CAAA90 requirement of a phased-in reduction in vehicle emissions of regulated pollutants. In addition, *AEO2005* incorporates the CAAA90 requirement of a phased-in reduction in annual emissions of sulfur dioxide by electricity generators, which in general are capped at 8.95 million tons per year in 2010 and thereafter, although "banking" of allowances from earlier years is permitted. *AEO2005* also incorporates nitrogen oxide (NO_x) boiler standards issued by the EPA under CAAA90. The 19-State NO_x cap and trade program in the Northeast and Midwest is also represented. Limits on emissions of mercury, which have not yet been promulgated, are not represented.

AEO2005 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by the EPA in February 2000 under CAAA90. The Tier 2 standards for reformulated gasoline (RFG) were required by 2004 but will not be fully realized in conventional gasoline until 2008 due to allowances for small refineries. *AEO2005* also incorporates the "ultra-low-sulfur diesel" (ULSD) regulation finalized by the EPA in December 2000, which requires the production of at least 80 percent ULSD (15 parts sulfur per million) highway diesel between June 2006 and June 2010 and a 100-percent requirement for ULSD thereafter (see Appendix F for more details). It also includes the new rules for nonroad diesel issued by the EPA on May 11, 2004, regulating nonroad diesel engine emissions and sulfur content in fuel. The *AEO2005* projections reflect legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in the next several years in 17 States and assumes that the Federal oxygen requirement for RFG in Federal nonattainment areas will remain intact.

The provisions of EPACT focus primarily on reducing energy demand. They require minimum building efficiency standards for Federal buildings and other new buildings that receive Federally backed mortgages. Efficiency standards for electric motors, lights, and other equipment are required, and Federal, State, and utility vehicle fleets are required to phase in vehicles that do not rely on petroleum products. The *AEO2005* projections include only those equipment standards for which final actions have been taken and for which specific efficiency levels are provided.

More detailed information on recent legislative and regulatory developments is provided below.

13 SEER Standard for Central Air Conditioners and Heat Pumps

In January 2004, after years of litigation in a case that pitted environmental groups and Attorneys General from 10 States against the U.S. Secretary of Energy, the U.S. Court of Appeals for the Second Circuit reestablished the central air conditioner and heat pump standard originally set in January 2001 [*3*]. The Court's ruling, which struck down a May 2002 rollback of the 2001 standard to a 12 SEER, mandates that all new central air conditioners and heat pumps meet a 13 SEER standard by January 2006, requiring a 30-percent increase in efficiency relative to current law. The *AEO2005* reference case incorporates the 13 SEER standard as mandated by the Court's ruling.

In order to gauge the impact of the new standard on electricity consumption, consumer expenditures, and carbon dioxide emissions, a sensitivity case assuming a continuation of the previous 12 SEER standard was modeled. Table 2 shows the impacts of the 13 SEER standard assumed in the reference case, as compared with the 12 SEER standard assumed in the sensitivity case. As expected, the projections for electricity consumption and expenditures are lower in the reference case than in the 12 SEER case; however, the savings come at an additional cost to consumers. Through 2015 the additional costs of new equipment outweigh savings, resulting in a negative net present value for the 13 SEER standard (assuming a 7-percent real discount rate). In the long run, however, additional years of savings per unit provide a positive ($3.6 billion) net present value, meaning that the standard, on average, provides economic benefits to consumers in the form of reduced energy expenditures.

Table 2. Impacts of 13 SEER central air conditioner and heat pump standard compared with 12 SEER standard, 2006-2025

			Cumulative	
Projection	**2015**	**2025**	**2006-2015**	**2006-2025**
Electricity consumption savings (billion kilowatthours)	*11.1*	*16.6*	*59.6*	*211.7*
Energy bill savings (billion 2004 dollars)	*0.8*	*0.7*	*5.7*	*12.6*
Equipment cost increase (billion 2004 dollars)	*0.5*	*0.2*	*5.8*	*8.9*
Net present value (billion 2004 dollars)	*—*	*—*	*-0.1*	*3.6*
Increase in air conditioner stock efficiency (percent)	*5.6*	*6.8*	*—*	*—*
Carbon dioxide emissions reduction (million metric tons)	*1.1*	*-3.6*	*7.8*	*1.0*

The difference between projected carbon dioxide emissions in the two cases depends on the fuel mix associated with the electricity generation. In the near term, the reduction in electricity demand in the reference case is not large enough to change the pattern of capacity additions or fuel mix, and lower electricity demand causes a decrease in carbon dioxide emissions both in 2015 and cumulatively from 2006 to 2015 (Table 2). In later years, the amount of peak demand relative to baseload demand is lower in the reference case, and more coal-fired capacity is added at the expense of natural gas capacity. The change in fuel mix causes carbon dioxide emissions to increase, despite slightly lower levels of electricity demand. Emissions in 2025 are 3.6 million metric tons (0.2 percent) higher in the reference case, but cumulative emissions from 2003 through 2025 are 1.0 million metric ton lower than in the 12 SEER case (1 metric ton is equal to 1,000 kilograms).

Maximum Achievable Control Technology for New Industrial Boilers

As part of CAAA90, the EPA on February 26, 2004, issued a final rule—the National Emission Standards for Hazardous Air Pollutants (NESHAP)—to reduce emissions of hazardous air pollutants (HAPs) from industrial, commercial, and institutional boilers and process heaters [*4*]. The rule requires industrial boilers and process heaters to meet limits on HAP emissions to comply with a MACT "floor level" of control that is the minimum level such sources must meet to comply with the rule. The major HAPs to be reduced are hydrochloric acid, hydrofluoric acid, arsenic, beryllium, cadmium, and nickel. The EPA predicts that the boiler MACT rule will reduce those HAP emissions from existing sources by about 59,000 tons per year in 2005 [*5*].

The MACT standards apply to major sources of HAPs, or units that emit or have the potential to emit a single HAP at 10 tons or more per year or a combination of HAPs at 25 tons or more per year. The EPA estimates that 58,000 existing boilers and process heaters and 800 new boilers and process heaters built each year over the next 5 years will be subject to the rule. Existing boilers and process heaters must comply with the rule no later than 3 years after it is published in the *Federal Register*. In addition, the owners of existing units may petition for an extra year to comply. New boilers and process heaters must comply when they are brought on line. The final rule provides flexibility in compliance through averaging of emissions from multiple units on a single site and lowering of emissions by altering work practices, installing control devices, or physically removing toxics. Fuel switching is not an available option to meet the MACT floor level, because it may increase emissions of some HAPs while reducing the emissions of others.

The industries most affected by the rule will be furniture, paper, lumber, and electrical services, which together account for nearly 60 percent of the affected units. The EPA estimates the total nationwide capital costs for the final rule to be $1.4 billion to $1.7 billion over the first 5 years, with annualized costs between $690 million and $800 million.

New boilers are expected to meet the standards in the absence of the rule, and retrofit costs are anticipated to be relatively small in aggregate. Consequently, inclusion of the rule does not materially affect the *AEO2005* projection for the industrial sector.

Clean Air Nonroad Diesel Rule

On June 29, 2004, the EPA issued a comprehensive final rule regulating emissions from nonroad diesel engines and sulfur content in nonroad diesel fuel [*6*]. The nonroad fuel market makes up more than 18 percent of the total distillate pool. The rule applies to new equipment covering a broad range of engine sizes, power ratings, and equipment types. There are currently about 6 million pieces of nonroad equipment operating in the United States, and more than 650,000 new units are sold each year.

The rulemaking covers such equipment as tractors, bulldozers, graders, backhoes, heavy construction, mining, and logging equipment, airport tugs, locomotives, and commercial marine vessels. The regulations represent a tiered emissions reduction approach based on engine horsepower, with phased-in restrictions on emissions of particulate matter (PM), NO_x, and nonmethane hydrocarbons. The rule reduces diesel engine emissions by more than 90 percent and fuel sulfur content by 99 percent from current levels.

The regulation addresses emissions and fuels simultaneously to maximize emission reductions by integrating engine and fuel controls as a system. To meet the standards, engine manufacturers will be required to produce new engines with advanced emission control technologies similar to those already expected for on-road (highway) heavy trucks and buses. Refiners will be supplying new lower sulfur diesel fuels in both cases.

Emission Standards

By 2014, the new Tier 4 regulations will require nonroad diesel engines to cut emissions of pollutants by

more than 90 percent [7]. Standards for new engines will be phased in starting with the smallest engines in 2008 until all but the very largest diesel engines meet both NO_x and PM standards in 2014 (Table 3). Some of the largest engines (750-plus horsepower) will have one additional year to meet the emissions standards.

The final rule includes flexibility provisions aimed at helping small engine manufacturers meet the requirements. The EPA Tier 4 standards do not require retrofitting older diesel engines currently in service and do not apply to diesel engines used in locomotives and marine vessels, but they do cover fuel requirements for those equipment categories.

In a separate action, the EPA took the first step toward proposing new emissions standards for diesel engines by issuing an Advanced Notice of Proposed Rulemaking on June 29, 2004 [8]. Contemplated standards would apply to marine diesels used in all new commercial, recreational, and auxiliary marine diesel engines except for very large engines used for propulsion of deep-sea vessels. For locomotives, both new and existing diesel units would require advanced emission control technologies similar to those for heavy-duty trucks and buses. The widespread availability of clean nonroad diesel fuel required under the new fuel standards will enable the use of advanced control technology on locomotive and marine engines.

The EPA estimates that anticipated compliance costs will vary with the size and complexity of equipment, in the range of 1 to 3 percent of total purchase price for most categories of nonroad diesel equipment [9]. The new nonroad diesel emission standards, when fully implemented, are expected to provide significant public health benefits.

Fuel Standards

The final rule, to be implemented in multiple steps, requires sulfur content for all nonroad locomotive and marine (NRLM) diesel fuel produced by refiners to be reduced to 500 parts per million (ppm) starting in mid-2007. It also establishes a new ULSD limit of 15 ppm for nonroad diesel by mid-2010. For locomotive and marine diesel, the action establishes a ULSD limit of 15 ppm in mid-2012, providing the refining industry flexibility to align fuel supply operations with all other on-road and nonroad ULSD fuel regulations, which take effect in mid-2010. After refiners, the new standards will apply to terminals, wholesalers, retailers, and end users in subsequent months as production flows through the distribution chain.

The nonroad diesel requirements have implications for the refining industry and, especially, for small refiners (defined as having less than 155,000 barrels per day of crude oil charge capacity and less than 1,500 corporate employees). Approximately 20 refiners fall into the small refiner category. They are dispersed across the country, with the largest concentration located in the Rocky Mountain Region. Small refiners are granted three additional years to meet the 500 ppm standard for NRLM diesel, starting in mid-2007 (Table 4). The challenges facing small refiners include additional time needed to secure capital funding, a need for longer leadtimes because of limited engineering expertise, and limits on the availability of contractors, who will be performing upgrades for major refiners.

Table 3. Final nonroad diesel emissions standards

Rated engine power	First year of standards or phase-in period	Particulate matter (grams per horsepower per hour)	Nitrogen oxides (grams per horsepower per hour)
Less than 25 horsepower	2008	0.30	—
25 to less than 75 horsepower	2013	0.02	3.5
75 to less than 175 horsepower	2012-2013	0.01	0.30
175 to less than 750 horsepower	2011-2013	0.01	0.30
750 horsepower or more	2011-2014	0.075	2.6 and 0.50
	2015	0.02 and 0.03	0.50

Note: Where a range of years is provided, 40 CFR 1039.102 prescribes a gradual phase-in whereby a cumulative percentage of total engines for a manufacturer must comply each year prior to the final year.

Table 4. Timeline for implementing nonroad diesel fuel sulfur limits

Fuel type and refiners	Mid-2007	Mid-2010	Mid-2012	Mid-2014 and after
Nonroad diesel				
Refiners other than small	500 ppm	15 ppm	15 ppm	15 ppm
Small refiners	—	500 ppm	15 ppm	15 ppm
Locomotive and marine diesel				
Refiners other than small	500 ppm	500 ppm	15 ppm	15 ppm
Small refiners	—	500 ppm	500 ppm	15 ppm

For early or overcompliance with the fuel sulfur standards, a regional averaging, banking, and trading program will be created; however, credits may not be used or traded for use outside the credit trading region in which they are generated [*10*]. For the 500 ppm standard beginning in mid-2007, small refiners outside the Northeast/Mid-Atlantic area can use credits to continue producing high-sulfur nonroad fuel until the credits expire in mid-2010. After mid-2014, small refiners must comply with the 15 ppm standard for NRLM diesel.

The rule recognizes certain exceptions. For Alaska, NRLM diesel covers only areas served by Federal highways. Rural and remote areas are not required to convert to ULSD until 2011. For stationary power sources, the rule excludes No. 4, 5, and 6 heavy distillates. In special marine situations, giant Category 3 ocean ship engines face a separate regulation expected by April 2007. Category 2 or 3 marine diesel engines using distillate with a distillation point over 700°F are excluded.

There are also special exceptions for transmix facilities on pipelines [*11*]. Because transmix facilities do not have sulfur removal equipment to clean up pipeline interface mixes, the final rule provides that they may produce fuels for sale into the NRLM markets that meet small refiner provisions, in order to avoid the burden of additional investment in treating equipment or returning mix to refineries for reprocessing. After the NRLM small refiner provisions expire in 2014, transmix processors may continue to sell 500 ppm fuel into the locomotive and marine market.

The rule also prescribes certain dyeing, tracking, and record keeping requirements to ensure that fuel is not diverted from authorized channels and that taxes are properly paid. The Internal Revenue Service ordinarily requires that fuel used in NRLM engines be dyed before leaving the terminal, to indicate its nontaxed status. Fuels that meet on-road diesel specifications but are destined for NRLM markets can leave the terminal undyed, provided that the tax is paid first. NRLM users can then apply for a tax refund. To minimize misfueling, a system of labels is prescribed on diesel retail pumps, fuel tank inlets, and dashboard and instrument panels, corresponding with the introduction of new diesel engines and equipment.

The EPA did not specify lubricity standards in the rule, because the industry has been working to finalize a universal standard for all diesel fuel. If the American Society for Testing and Materials does not establish a universal lubricity standard, a separate rulemaking applying to lubricity additives will be issued by the EPA.

Impacts of the Emission and Fuel Standards

The effects of the new NRLM diesel standards are represented in *AEO2005*. The National Energy Modeling System (NEMS) has been revised to reflect the nonroad rule and recalibrated for market shares of highway, NRLM diesel, and other distillate (mostly heating oil and excluding jet fuel and kerosene). The nonroad rule, following closely on the heels of the highway diesel rule, represents an incremental tightening of the entire diesel pool that will cause demand for high-sulfur distillate to diminish over time while demand for ULSD (both highway and NRLM) increases.

After 2007, during the rule's implementation, the projections for refinery distillate production are slightly lower with the rule in place because of the more stringent and costly processing requirements, and imports of distillate are higher. For the composite distillate market, prices are slightly higher with the rule in place and vary by sector. Table 5 shows key projections for distillate fuel prices, production, and imports in the *AEO2005* reference case, which includes the new nonroad diesel rule, and in a sensitivity case that does not include the new rule.

Because heating oil is not subject to NRLM diesel rules, residential distillate prices are not expected to be affected significantly. Eventually, however, residential prices are projected to parallel those in other sectors as the distillate market converges toward a universal ULSD standard. More than two-thirds of all high-sulfur distillate use after 2010 is projected to be concentrated in the Northeast.

In the commercial and industrial sectors, distillate fuel prices after 2010 are projected to be higher with the rule in place. Nonroad diesel is a relatively small portion of commercial distillate use, but it dominates industrial use. Thus, the price impact is greater for the industrial sector. For the electric power sector there is little or no projected impact on distillate prices. Diesel prices in the transportation sector are projected to be about 2 cents per gallon higher in 2010-2012 because of the nonroad diesel sulfur reduction and about 3 cents per gallon higher in 2014, when the sulfur content of all NRLM diesel fuel is reduced to 15 ppm.

EPA estimates [*12*] place the added cost of ULSD for NRLM diesel use in the range of about 7 cents per gallon; however, the EPA expects the added cost to be offset by reduced engine maintenance expenses, lowering the net incremental impact to about 4 cents per gallon. The EPA estimates assume complete turnover of nonroad diesel engines by 2030.

American Jobs Creation Act of 2004

The American Jobs Creation Act of 2004 [*13*] was signed into law on October 22, 2004. Most of the 650 pages of the Act are related to tax legislation. Provisions pertaining to energy are described below.

Diesel Excise Taxes

Section 241 phases out an excise fuel tax of 4.3 cents per gallon on railroads and inland waterway transportation incrementally between January 1, 2005, and January 1, 2007. Under current law, diesel fuel used in trains and fuels used in barges on certain inland waterways are subject to an excise tax of 4.4 cents per gallon. Revenues from 4.3 cents of the tax are retained in the General Fund. The remaining 0.1 cent is put in the Leaking Underground Storage Tank Fund, which is scheduled to expire on March 31, 2005. *AEO2005* reflects the phaseout of these excise taxes.

Ethanol Tax Credits

Section 301 establishes the Volumetric Ethanol Excise Tax Credit (VEETC). Before this Act, gasoline blenders could choose between an income tax credit of 51 cents per gallon of ethanol blended or a reduced rate of Federal excise tax on each gallon of gasoline blended with ethanol. Thus, gasoline containing 10 percent ethanol would be taxed at 13.2 cents per gallon instead of the usual 18.3 cents per gallon in calendar year 2005. Gasoline blended with 5.7 percent or 7.7 percent ethanol would receive a proportionally smaller reduction in the excise tax. The VEETC is instead assessed at a rate of 51 cents per gallon of ethanol, and the entire excise tax is assessed on the finished gasoline. This gives several advantages over the existing structure. VEETC applies to any blend of ethanol and gasoline. It also applies to ethyl tertiary butyl ether (ETBE), a gasoline blending component made from ethanol. The excise tax exemption does not apply to blends containing less than 5.7 percent or more than 10 percent ethanol, such as E85. The income tax credit can be taken for ethanol used in such blends or to make ETBE, but not all gasoline blenders have sufficient Federal income tax liability to take the credit. The VEETC is effective through 2010; the excise tax reduction will expire in 2007. This section also extends the alcohol income tax credit through 2010. *AEO2005* includes these tax credits and, in addition, assumes that they will remain in force indefinitely, given that historically they have been extended when they expired.

Biodiesel Tax Credits

The VEETC also applies to biodiesel blends. A diesel fuel blender can claim a credit of $1 per gallon of biodiesel made from agricultural commodities such as soybean oil and can claim a credit of 50 cents per gallon of biodiesel made from recycled oil such as yellow grease. Section 302 extends income tax credits for biodiesel blending similar to the alcohol income tax credits. The VEETC provision for biodiesel and the biodiesel income tax credits expire after 2006. Section 302 is modeled in the *AEO2005* reference case.

Rural Electric Cooperatives Income Treatment

Current law gives tax-exempt status for rural electric cooperatives if at least 85 percent of the cooperative's income comes from amounts collected from members for the sole purpose of meeting losses and expenses

Table 5. Key projections for distillate fuel markets in two cases, 2007-2014

		Projections							
		2007		2010		2012		2014	
Supply and prices	2003	Reference case	No NRLM rule case	Reference case	No NRLM rule case	Reference case	No NRLM rule case	Reference case	No NRLM rule case
Distillate prices (2003 cents per gallon)									
Residential	132.7	120.4	120.5	114.9	114.2	115.1	115.8	117.0	117.0
Commercial	97.3	90.3	90.2	86.9	84.4	88.5	85.6	89.2	86.2
Industrial	100.2	94.2	93.8	93.3	86.9	98.3	88.0	98.5	89.1
Transportation	150.4	151.0	150.6	147.5	145.5	148.1	145.8	147.1	144.2
Electric Power	89.8	81.3	81.5	74.4	73.8	74.5	75.1	75.9	76.7
Composite	136.7	134.4	134.1	131.0	128.6	132.8	129.6	133.5	129.2
Distillate supply (million barrels per day)									
Refinery production	3.76	4.21	4.20	4.64	4.65	4.76	4.87	4.93	5.07
Imports	0.22	0.41	0.41	0.31	0.29	0.34	0.22	0.33	0.19

incurred in providing service to those members. Section 319 provides that, under certain actions approved or accepted by the FERC, gains realized by a rural electric cooperative from a voluntary exchange or involuntary conversion of certain property are excluded in determining whether that cooperative meets the 85-percent test. This provision applies only to the extent that the gain would qualify for deferred recognition under tax laws or the replacement property is used to generate, transmit, distribute or sell electricity or natural gas. This provision represents a level of detail that is not characterized in NEMS.

Low-Sulfur Diesel Fuel Production Credit

Sections 338 and 339 contain provisions allowing small business refiners a 25-percent credit for production of ultra-low-sulfur diesel fuel (15 parts sulfur per million or less), with additional provisions for expensing the remaining 75 percent of the capital investment. Current law does not provide a credit for the production of low-sulfur diesel fuel. The Act allows a small business refiner to claim a credit at a capture rate equal to about 5 cents per gallon for each gallon of low-sulfur diesel fuel produced in compliance with the Highway Diesel Fuel Sulfur Control Requirements law. The credit is a qualified business credit under Section 169(c) of the Act. The existing carry-back and carry-forward provisions for a qualified business credit apply [*14*]. The effective date for this provision is December 31, 2002.

Taxpayers may currently recover the cost of investments in refinery property through annual depreciation deductions. A separate expensing provision permits small business refiners to deduct as an expense up to 75 percent of the costs paid or incurred in making upgrades to comply with the EPA's Highway Diesel Fuel Sulfur Control Requirements.

Small business refiners (up to 205,000 barrels per day and up to 1,500 employees in refining) can claim a tax credit of up to 25 percent of the capital investment costs incurred since 2003 for producing ultra-low-sulfur diesel. Most of the credit would result from refining the first 155,000 barrels per day, with *pro rata* credits for the next 50,000 barrels. The credit expires 1 year after EPA's applicable ultra-low-sulfur diesel deadline or by the end of 2009. Because NEMS does no model individual companies, these tax provisions are not included in the *AEO2005* reference case.

Marginal Wells Tax Credit

Section 341 creates a new tax credit of up to $3 per barrel for the production of crude oil and a credit of up to $0.50 per thousand cubic feet for the production of natural gas from qualified marginal wells. A marginal well is defined as one that produces less than 25 barrels per day of oil equivalent and produces water at a rate not less than 95 percent of total well effluent. Full credit is provided to such marginal wells at reference prices less than or equal to $15 per barrel for oil and $1.67 per thousand cubic feet for natural gas [*15*]. The credit declines linearly to zero when reference prices, adjusted for inflation, reach $18 per barrel of oil and $2 per thousand cubic feet of natural gas. The tax credit applies to the first 1,095 barrels of oil equivalent produced, and the limit is reduced in proportion to the numbers of days in the taxable year for which the well is not in production. The tax credit takes effect in taxable years beginning after December 31, 2004. Because NEMS does not contain a separate marginal well category, the impact of this legislative provision is not quantified in *AEO2005*.

Green Building Bonds

Section 701 contains a brownfields demonstration program that provides tax-exempt status for facility bonds issued to finance qualified "green" buildings and sustainable design projects. The program, designed to encourage the use of solar photovoltaic and fuel cell generation, applies to bonds issued from January 1, 2005, through December 31, 2009; however, projects must be nominated by a State or local government and meet several criteria in addition to the specific green or sustainable criteria. For example, eligible projects must include a brownfields site, be of a certain size, provide a certain level of employment, not include a sports stadium or restaurant, and receive State or local government resources of at least $5 million. Because of the process involved and the site- and company-specific nature of the provision, it is not characterized in the *AEO2005* reference case.

Tax Incentives for Alaska Natural Gas Pipeline and Gas Processing Facilities

Section 706 provides a 7-year cost-of-investment recovery period for the Alaska natural gas pipeline, as opposed to the currently allowed 15-year recovery period, for tax purposes. The provision would be effective for property placed in service after 2013, or treated as such. The expected return on equity for the pipeline was lowered to reflect this provision in *AEO2005*.

Section 707 extends the 15-percent tax credit currently applied to costs related to enhanced oil recovery to construction costs for a gas treatment plant that supplies natural gas to a 2 trillion Btu per day pipeline, lies in Northern Alaska, and produces

carbon dioxide (CO_2) for injection into hydrocarbon-bearing geological formations. A gas treatment plant on the North Slope that feeds gas into an Alaska pipeline to Canada is expected to satisfy this requirement. The provision would be effective for costs incurred after 2004. For *AEO2005*, lowering the expected charges for gas treatment on the North Slope captured this provision.

Extension and Expansion of the Production Tax Credit for Renewable Electricity

Section 710 expands application of the renewable electricity PTC to wind, closed-loop biomass, and poultry-litter plants in service by December 31, 2005 [*16*]. Eligibility for a modified PTC is also extended to geothermal, solar, small irrigation hydropower, open-loop biomass, municipal solid waste, and landfill gas facilities, also with a December 31, 2005, in-service date. This change has been incorporated in *AEO2005*.

Modified Alternative Minimum Tax Rules for the PTC and Alcohol Fuels Tax Credit

The law exempts the alcohol fuel tax credit (Section 40 of the Internal Revenue Code) and the first 4 years of the PTC (Section 45 of the Internal Revenue Code) from tax liability under the Alternative Minimum Tax (AMT), allowing businesses with AMT liability to recover the full value of the affected tax credits. This provision is not included in the *AEO2005* reference case, because EIA assumes that these tax credits are generally able to be used at full value.

Section 45 Tax Credit for Coal Products

The refined coal provisions in Section 710 establish Section 45 tax credits for producers of qualified refined coal products. The refined product must be at least 50 percent higher in market value than the coal or high-carbon fly ash feedstock, and combustion of the refined product must result in 20 percent less emissions of NO_x and either SO_2 or mercury than the feedstock. The refined coal must be sold for the purpose of creating steam. This provision represents a level of detail that is not characterized in NEMS.

Alcohol Alternative Minimum Tax

Section 711 allows the alcohol income tax credit, biodiesel income tax credit, and small ethanol producer income tax credit to offset liability under the AMT. The small ethanol producer credit applies only to firms with capacity of 15 million gallons per year or less. Because NEMS does not model individual tax obligations, these changes are not incorporated in the *AEO2005* reference case.

Suspension of Duties on Nuclear Steam Generators and Reactor Vessel Heads

Section 714 extends from January 31, 2006, to January 31, 2008, the period in which nuclear steam generators can enter the United States duty-free. The law allows nuclear reactor vessel heads to enter the United States duty-free through January 31, 2008, suspending the current 3.3-percent duty. This provision represents a level of detail that is not characterized in NEMS.

Disposition of Transmission Property to Implement FERC Restructuring

Section 909 allows companies to spread capital gains from the sale of transmission assets over 8 years. This provision applies to property sold by a utility to comply with FERC electricity market restructuring efforts. Money from the sale must be used to buy reinvestment property within 4 years of the initial transaction. This restructuring provision is not incorporated in the *AEO2005* reference case.

Tax Evasion Provisions

Subtitle C, Part III, of Title VIII of the Act contains 21 provisions related to fuel tax evasion. Some of the more pertinent provisions and economic impacts are described below. Because NEMS does not model oil and gas income statements, these changes are not incorporated into *AEO2005*.

- Section 853 relates to taxation of aviation-grade kerosene and moves the point of taxation of aviation fuel to the supply rack. Fuel used in commercial aviation that is removed from any refinery or terminal and placed directly into the fuel tank of an aircraft for use in commercial aviation will be taxed at 4.3 cents per gallon. The regulation also stipulates that certain refueler trucks, tankers, and tank wagons be treated as part of a terminal. The person who uses the fuel for commercial aviation will be liable for and pay the tax. These regulations apply after December 31, 2004, and have no stated expiration date.
- Sections 860 and 861 provide clarifications and requirements for exemptions from taxes imposed on the removal of taxable fuel from any refinery or terminal. These amendments take effect on March 1, 2005. Exemptions were already allowed for bulk transfers to registered terminals or refineries. Section 860 clarifies that the transfer must occur by pipeline or vessel. Clarification is provided for the registration of such pipelines or vessels, the requirement to display proof of

registration, and the penalties for failure to display registration.

- Section 870 covers tax refunds for re-refined transmix [*17*] and diesel fuel blendstocks that were previously taxed. This amendment applies to fuel removed, sold, or used after December 31, 2004, and it has no stated expiration date. The Act redefines diesel fuel contaminated with transmix as a taxable diesel fuel if it is suitable for use in a highway vehicle or train. If the fuel is re-refined and then sold into nonroad markets (tax-free), it can qualify for tax refunds.

Working Families Tax Relief Act of 2004

The Working Families Tax Relief Act of 2004 [*18*] was signed into law on October 13, 2004. Primarily, the Act reduces taxes for individuals and businesses. At least two provisions relate to energy.

Depletion of Marginal Properties

Section 314 extends to oil and gas an exemption for marginal properties from the 100 percent of net income limitation on the percentage of assets that can be depleted in a year for tax purposes. In computing taxable income, oil and gas producers generally receive a reasonable allowance for depletion and for depreciation of improvements, based on the amount of resource extracted. Under current law, the deduction cannot exceed 100 percent of taxable income from the property (computed without allowance for depletion). An exemption from the limitation, allowing the deduction to exceed 100 percent of taxable income for production from marginal properties expired on December 31, 2003.

This provision extends the exemption to January 1, 2006. The exemption is applicable only to "marginal production," which is defined as production coming from property that is a stripper well property or a property from which substantially all the production is heavy oil (weighted average gravity of 20 degrees API or less). A stripper well property is a property from which the average production per well is less than 15 barrels of crude oil equivalent per day. Because production from stripper well properties and production of heavy oil are not projected separately from total oil and gas production in the EIA modeling framework, the impact of this provision is not quantified in *AEO2005*.

Qualified Vehicles

Sections 318 and 319 repeal the phaseout of credits allowed for qualified electric and clean fuel vehicles for property acquired in 2004 and 2005. For vehicles acquired in 2006, the 2004 and 2005 credits of $2,000 for clean fuel vehicles and $4,000 for electric vehicles are reduced by 75 percent. This provision is not included in *AEO2005*.

Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2005

H.R. 4837, The Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2005 [*19*], was signed into law on October 13, 2004. The Act provides for construction to support the operations of the U.S. Armed Forces and for military family housing. It also provides funds to help citizens in Florida and elsewhere in the aftermath of multiple hurricanes and other natural disasters. In addition, it authorizes construction of an Alaska Natural Gas Pipeline.

Alaska Natural Gas Pipeline Loan Guarantee

Section 116 gives the Secretary of Energy authority to issue Federal loan guarantees for an Alaska natural gas transportation project, including the Canadian portion, that would carry natural gas from northern Alaska through the Canadian border south of 68 degrees north latitude, into Canada, and to the lower 48 States. The authority would expire 2 years after the issuance of a final certificate of public convenience and necessity. In aggregate, the loan guarantee would not exceed: (1) 80 percent of total capital costs (including interest during construction), (2) $18 billion dollars (indexed for inflation at the time of enactment), and (3) a term of 30 years. The Act also promotes streamlined permitting and environmental review, an expedited court review process, and protection of rights-of-way for the pipeline. The impact of the loan guarantee is reflected in *AEO2005* by a reduction of the expected return on debt and an increase in the percentage of pipeline costs financed through debt. Additional assistance related to the construction of the Alaska Natural Gas Pipeline is provided in the American Jobs Creation Act of 2004.

State Renewable Energy Requirements and Goals: Status Through 2003

As of the end of 2003, 15 States had legislated programs to encourage the development of renewable energy for electricity generation. Of the 17 programs (two States have multiple programs), 9 are renewable portfolio standards (RPS), 4 are renewable energy mandates, and 4 are renewable energy goals.

Renewable Portfolio Standards

The type of program used most frequently by the States is an RPS requiring that some specified

percentage of electricity supply be provided by qualifying renewable energy sources (Table 6). Most State RPS programs were initiated when privately owned electric utilities were being deregulated, in order to ensure their continued investment in renewables.

Key differences among the State RPS programs include their definitions of qualifying renewables, alternatives to new renewable capacity, approaches to cost recovery, opt-out provisions, and enforcement mechanisms. For example, RPS definitions of qualifying renewable technologies vary widely among the States. Landfill gas, solar thermal electric, solar photovoltaic, and wind energy are acceptable in all nine RPS States, but the rules vary for other technologies. Some also include alternatives to new capacity, such as natural-gas-powered fuel cells or solar thermal water heating. Some favor certain renewable energy technologies, especially solar, by offering more than one credit per kilowatthour. This practice may stimulate favored technologies but reduce the effective size of the RPS if they are developed.

The States use several approaches for funding their RPS programs, including passing the higher costs directly to all utility ratepayers, applying charges on selected categories of sales, or encouraging voluntary purchases through "green power" programs. Most call for reducing or delaying RPS requirements if costs are excessive ("cost-outs"). They may also reduce or eliminate RPS requirements for non-cost reasons, such as if the entities are deemed not creditworthy or if existing contracts meet all the utility's requirements.

Most State RPS programs do not appear to have specific enforcement procedures, except for revoking operating licenses. Some provide for cost penalties for unmet requirements, payments into research and development funds, fines, and other sanctions; however, collaboration and cooperation appear to be the preferred enforcement tools. Through the end of 2003, no electric utility in any State had incurred a penalty for noncompliance with a State RPS.

Mandates

Four States have mandates that narrowly specify the new renewable capacity required (Table 6). Iowa's 1983 mandate, the oldest, ordered its three investor-owned utilities to develop 105 megawatts of new renewable energy capacity, with each utility's share based on its share of peak demand. Minnesota's 1994 mandate required Xcel Energy to acquire 425 megawatts of wind capacity by December 31, 2002, plus

Table 6. Basic features of State renewable energy requirements as of December 31, 2003

State	Part of deregulation	Initial year enacted	Beginning and last specified requirements	Accepts existing capacity	Out-of-State supply	Credit trading
Renewable Portfolio Standards						
Arizona	Yes	1996	0.2-1.1% of sales, 2001-2007	No	Solar only	Yes
California	No	2002	+1% of sales per year, to 20.0% by 2017	Yes	Yes	No
Connecticut	Yes	2003	6.5-10.0% of generation, 2003-2010	Yes	Yes	Yes
Maine	Yes	1997	30.0% of sales by 1999	Yes	Yes	Yes
Massachusetts	Yes	1997	1.0-4.0% of sales, 2003-2009	No	Yes	Yes
Nevada	No	2001	5.0-15.0% of sales, 2003-2013; 5% of requirements must be solar	Yes	Yes	Yes
New Jersey	Yes	1999	3.0-6.5% of sales, 2001-2008	Yes	Yes	Yes
New Mexico	No	2002	5.0-10.0% of sales, 2006-2011	Yes	Yes	Yes
Wisconsin	No	1999	0.5-2.2% of sales, 2001-2011	Yes	Yes	Yes
Mandates						
Iowa	No	1983	105 megawatts (no set date)	No	NS	No
Minnesota	No	1994	1,125 megawatts wind by 2010 + 125 megawatts biomass	No	Yes	No
Texas	No	1999	400-2,000 megawatts, 2003-2009	No	Yes	Yes
Wisconsin	No	1997	50 megawatts by 2000	No	No	No
Goals						
Hawaii	No	2001	9.0% of sales by 2010	Yes	NA	No
Illinois	No	2001	15.0% of sales by 2020	NS	No	No
Minnesota	No	2003	1.0-10.0% of sales, 2005-2015	NS	Yes	Yes
Pennsylvania	Yes	1998	Individual agreements with five utilities	NS	NS	NS

125 megawatts of biomass capacity, in exchange for storing additional nuclear waste at its Prairie Island plant. An additional 700 megawatts of new wind capacity has since been added to the mandate, some of which must come from small facilities (2 megawatts of capacity or less). The wind requirements are being met, but Minnesota's biomass requirements have not been met because of technological and financial difficulties. Additional legislation in 2003 requires a power purchase agreement for 10 to 20 megawatts of biomass energy, operational by 2005, at no more than $55 per megawatthour.

The 1999 renewable energy mandate in Texas requires the installation of 2,000 megawatts of new renewable generating capacity by 2009. The Texas mandate has resulted in more new renewable capacity than any other State-level requirement to date, including 1,180 megawatts of new wind capacity installed by the end of 2003 as well as small amounts of landfill gas and other renewable capacity. A fourth State, Wisconsin, in 1998 required four eastern utilities to install 50 megawatts of new renewable energy capacity by December 31, 2000, a requirement that was met by the utilities.

Voluntary Goals, Objectives, and Settlements

Four States—Hawaii, Illinois, Minnesota, and Pennsylvania—have instituted programs that encourage, but do not require, new renewable energy capacity (Table 6). Hawaii's 2001 goal resembles a typical RPS, except for the absence of penalties and the inability to obtain supplies from other States. Illinois in 2001 set targets for electricity production from qualified renewables; however, the goal is not supported by schedules, a menu of acceptable renewable technologies or alternatives other than solar and wind, compliance mechanisms, credit trading, or most of the other features of State RPS programs. In Minnesota, utilities other than Xcel are subject to the State's 2001 Renewable Energy Objective, which requires a "good faith effort" to increase renewable energy's contribution. The objective is considered a mandate for Xcel. In 1996, five Pennsylvania utilities settled restructuring cases on terms requiring a minimum percentage of renewables. Among these settlements, only the Pennsylvania Electric Company (PECO) energy program was implemented; however, the five utilities also established four sustainable energy funds that are reported to have supported development of significant amounts of new wind and other generating capacity.

Results

State renewable portfolio standards, mandates, and goals are all relatively new, with the majority just now entering their initial compliance years. Because of alternative compliance options and adjustments that would likely be made if renewable energy costs are found excessive in the future, it is difficult to assess the future impacts of these programs. Nevertheless, through the end of 2003, requirements or goals for new renewable energy capacity in 15 States has resulted in an estimated 2,335 megawatts of new renewable electricity supply (Table 7). Most of the new capacity is fueled by wind power (2,183 megawatts), with smaller amounts of landfill gas, hydroelectricity, biomass, and solar photovoltaic technologies. The 321 megawatts that entered service in the nine RPS States accounted for 14 percent of total new renewable energy capacity from RPS, mandates, and goals through 2003. State mandates—especially in Texas—have led to the development of 2,004 megawatts of renewable capacity, 86 percent of the total. Nearly 51 percent (1,186 megawatts) of all the new capacity was installed in Texas. Recognizing that States with renewable energy requirements have not added capacity as rapidly as projected in earlier forecasts, projections for new renewable energy capacity resulting from State RPS programs, mandates, and nonmandatory goals are reduced in *AEO2005*.

Update on State Air Emission Regulations That Affect Electric Power Producers

Several States have recently enacted air emission regulations that will affect the electricity generation sector. The regulations are intended to improve air quality in the States and assist them in complying with the revised 1997 National Ambient Air Quality Standards (NAAQS) for ground-level ozone and fine particulates. The affected States include Connecticut, Massachusetts, Maine, Missouri, New Hampshire, New Jersey, New York, North Carolina, Oregon, Texas, and Washington. The regulations govern emissions of NO_x, SO_2, CO_2, and mercury from power plants.

Where firm compliance plans have been announced, State regulations are represented in *AEO2005*. For example, installations of SO_2 scrubbers and selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) NO_x removal technologies associated with the largest State program, North Carolina's "Clean Smokestacks Initiative," are included. Overall, the *AEO2005* forecast includes 22 gigawatts of announced SO_2 scrubbers, 27 gigawatts of announced SCRs, and 3 gigawatts of announced SNCRs.

In addition to the existing regulations, Governor George Pataki of New York has announced proposed

greenhouse gas reduction targets for the State of New York and has invited nine other States (Connecticut, Delaware, Maryland, Maine, New Hampshire, New Jersey, Pennsylvania, Rhode Island, and Vermont) to participate in a future "Northeast CO_2 cap and trade" program. The program requires only CO_2 trading among power plants but would also allow trading of other emissions allowances among power plants burning coal, natural gas, or oil. The first Commissioner-level meeting was held in September 2003, and a final agreement is expected to be in place by April 2005. Maryland and Pennsylvania are participating in discussions but have not committed to participation in the program.

Table 8 summarizes current State regulatory initiatives on air emissions, and the following section gives brief descriptions of programs in the States that have enacted air emissions regulations more stringent than Federal regulations. State-level initiatives to limit greenhouse gas emissions without directly regulating the electricity generation sector, which are not discussed here, include the following: California law A.B. 1493, enacted in July 2002, which sets CO_2 pollution standards for 2009 model vehicles and those sold later (see "Legis.lation and Regulations,"page 27); Georgia's transportation initiative, which is focused on expanding the use of mass transit and other transportation sector measures; Minnesota's Releaf Program, which encourages tree planting as a way to reduce atmospheric CO_2 levels; Nebraska's carbon sequestration advisory committee, which proposes to sequester carbon through agricultural reform practices; North Carolina's program to develop new technologies for solid waste management practices that reduce emissions; RPS programs being adopted by several States (see discussion of State renewable energy requirements and goals, above); and Wisconsin's greenhouse gas emissions inventory.

Connecticut. The Connecticut "Abatement of Air Pollution" regulation was enacted in December 2000, and revisions are being made on an ongoing basis. It limits SO_2 and NO_x emissions from all NO_x budget program (NBP) sources that are more than 15 megawatts or require fuel input greater than 250 million Btu per hour [*20*]. The regulation applies to the electricity generation sector, the cogeneration sector, and industrial units. The NO_x limit is 0.15 pound per million Btu of heat input. The SO_2 limit applies to NBP sources that are also Acid Rain Program sources, and

Table 7. Estimated capacity contributing to State renewable energy programs through 2003 (megawatts, nameplate capacity)

State	Biomass	Geo-thermal	Conventional hydro-electric	Landfill gas	Municipal solid waste	Ocean or tidal	Solar photo-voltaics	Wind	Other/ unknown	Total
Renewable Portfolio Standards										
Arizona	0	0	0	5	0	0	9	0	0	**14**
California	0	0	20	6	0	0	0	175	0	**201**
Connecticut	0	0	0	0	0	0	0	0	0	**0**
Maine	0	0	0	0	0	0	0	0	0	**0**
Massachusetts	0	0	0	8	0	0	0	1	0	**9**
Nevada	0	0	0	0	0	0	0	0	0	**0**
New Jersey	0	0	0	0	0	0	0	0	0	**0**
New Mexico	0	0	0	0	0	0	0	0	0	**0**
Wisconsin	0	0	0	3	0	0	0.02	94	0	**97**
Mandates										
Iowa	16	0	0	0	0	0	0	237	7	**260**
Minnesota	25	0	0	0	0	0	0	476	0	**501**
Texas	5	0	10	31	0	0	0.2	1,140	0	**1,186**
Wisconsin	7	0	0	0	0	0	0	50	0	**57**
Goals										
Hawaii	0	0	0	0	0	0	0	0	0	**0**
Illinois	0	0	0	0	0	0	0	0	0	**0**
Minnesota	0	0	0	0	0	0	0	0	0	**0**
Pennsylvania	0	0	0	0	0	0	0	10	0	**10**
Total	**53**	**0**	**30**	**53**	**0**	**0**	**9.22**	**2,183**	**7**	**2,335**
Share of Total	**2.3%**	**0%**	**1.3%**	**2.3%**	**0%**	**0%**	**0.4%**	**93.5%**	**0.3%**	**100.0%**

the limit is 0.3 percent sulfur in fuel and 0.33 pound per million Btu. Modifications are being made to the current NBP rules to provide incentives in the form of allowances for renewable energy and energy efficiency programs [*21*].

In May 2003, the Connecticut General Assembly passed legislation (Connecticut Public Act 02-64) requiring coal-fired power plants to remove 90 percent of the mercury from smokestack emissions (or a maximum of 0.6 pound of mercury emitted per trillion Btu input, which is equivalent to 0.005 to 0.007 pound per gigawatthour) by July 2008. The legislature has recommended that the State Department of Environmental Protection consider stricter limits by July 2012 [*22*].

Table 8. Existing State air emissions legislation with potential impacts on the electricity generation sector

State	Activities	Emissions limits
Connecticut	Regulations for electric utility, industrial cogeneration, and industrial units	
	SO_2 emissions Phase I limit by 2002	0.55 pound per million Btu input
	SO_2 emissions Phase II limit by 2003	0.33 pound per million Btu input
	NO_x limit	0.15 pound per million Btu input
	Mercury emissions limit by July 2008	90% removal (or maximum of 0.6 pound mercury emitted per trillion Btu input, equivalent to 0.005-0.007 pound mercury per gigawatthour)
Maine	Regulation for greenhouse gas emissions reduction from all sectors	
	Greenhouse gas emissions by 2010	At 1990 levels
	Greenhouse gas emissions by 2020	10% below 1990 levels
	Greenhouse gas emissions in the "long term"	75% to 80% below 2003 levels
Massachusetts	Multi-pollutant cap for existing power plants	
	SO_2 emissions in 1999: 6.7 pounds per megawatthour	
	SO_2 cap 2004 or 2006 (depending on compliance strategy)	6.0 pounds per megawatthour
	SO_2 cap 2006 or 2008 (depending on compliance strategy)	3.0 pounds per megawatthour
	NO_x emissions in 1999: 2.4 pounds per megawatthour	
	NO_x cap 2004 or 2006 (depending on compliance strategy)	1.5 pounds per megawatthour
	CO_2 emissions (current): 2,200 pounds per megawatthour	
	CO_2 cap 2006 or 2008 (depending on compliance strategy)	1,800 pounds per megawatthour
	Mercury emissions cap, Phase I, January 2008	85% removal from 2004 levels or 0.0075 pound per gigawatthour
	Mercury emissions cap, Phase II, October 2012	95% removal from 2004 levels or 0.0025 pound per gigawatthour
Missouri	Summer NO_x regulations by May 2004	0.18 to 0.35 pound per million Btu input
New Hampshire	Regulation for existing fossil-fuel power plants	
	SO_2 emissions in 1999: 48,000 short tons	
	SO_2 cap 2006	7,289 short tons
	NO_x emissions in 1999: 9,000 short tons	
	NO_x cap 2006	3,644 short tons
	CO_2 emissions in 1990: 5,426 thousand short tons	
	CO_2 emissions in 1999: 5,594 thousand short tons	
	CO_2 cap 2006	5,426 thousand short tons
New Jersey	Greenhouse gas emissions in 1990: 136 million metric tons carbon dioxide equivalent	
	Greenhouse gas emissions 2005	3.5% below 1990
New York	Regulations for electric utilities, cogenerators, and industrial units	
	SO_2 Phase I limit January 2005, 25% below allocation	197,046 short tons
	SO_2 Phase II limit January 2008, 50% below allocation	131,364 short tons
	NO_x limit beginning in October 2004 (October 1 to April 30 cap)	39,908 short tons
North Carolina	Regulations for existing coal-fired plants only	
	SO_2 emissions in 1999: 429,000 short tons	
	SO_2 cap 2009	250,000 short tons
	SO_2 cap 2013	130,000 short tons
	NO_x emissions in 1999: 178,000 short tons	
	NO_x cap 2009	56,000 short tons
Oregon	CO_2 regulation for new or expanded power plants	675 pounds per megawatthour
Texas	Senate Bill 7, SO_2 and NO_x caps for grandfathered sources	
	SO_2 cap 2003	595,000 short tons
	NO_x cap 2003	302,000 short tons
Washington	CO_2 regulations for new fossil-fueled power plants	20% reduction over 30 years

In addition, Connecticut enacted a law in June 2004 called "An Act Concerning Climate Change," Public Act No. 04-252. The goal of the legislation is to reduce emissions of greenhouse gases from sources in Connecticut to 1990 levels by 2010 and to 10 percent below 1990 levels by 2020, and it establishes a process to determine reduction goals beyond 2020. The Act covers electricity generators, fleet vehicles, industrial facilities, and commercial establishments; however, there are no enforcement procedures in the law. There is a requirement for the Governor's Steering Committee on Climate Change to develop a Climate Action Plan by January 2005, and for the Commissioner of Environmental Protection to establish a regional greenhouse gas registry that will collect emissions data.

Maine. Maine enacted a climate change statute—"An Act to Provide Leadership in Addressing the Threat of Climate Change" (Public Law 2003, Chapter 237, H.P. 622, L.D. 845)—in June 2003 [*23*]. The statute requires the establishment of a greenhouse gas emissions inventory for State-owned facilities and State-funded programs and calls for a plan to reduce emissions to 1990 levels by 2010. It specifies that carbon emission reduction agreements must be signed with at least 50 businesses and nonprofit organizations by January 2006, and that Maine must participate in a regional greenhouse gas registry. The goals of the statute are a reduction of greenhouse gases to 1990 levels by January 2010, a reduction to 10 percent below 1990 levels by 2020, and a reduction to 75 and 80 percent below 2003 levels "in the long term." It authorizes the Department of Environmental Protection to submit to the Legislature a State climate action plan to meet the goals of the statute [*24*].

Massachusetts. The Massachusetts Department of Environmental Protection air pollution control regulations (310 CMR 7.29, "Emissions Standards for Power Plants"), approved in May 2001 [*25*], apply to six existing older power plants in Massachusetts. There are two options for utilities to comply with the regulations: either "repower" (defined as replacing existing boilers with new ones that meet the environmental standards, switching fuel to low-sulfur coal, or switching from coal to natural gas); or choose a standard path that includes installing low-NO_x burners, installing SO_2 scrubbers, and installing SCR or SNCR equipment.

The rule offers an incentive for a fuel shift by delaying the compliance deadline to October 2008 for any facility choosing to repower. Plants using other techniques, such as pollution control equipment, must comply by October 2006. The SO_2 standard is 6.0 pounds per megawatthour by October 2004 (standard) or October 2006 (repowering) and 3.0 pounds per megawatthour by October 2006 (standard) or October 2008 (repowering). The NO_x standard is 1.5 pounds per megawatthour by October 2004 (standard) or October 2006 (repowering). The SO_2 and NO_x regulations are considered by the State to be more stringent than CAAA90 would imply. Most of the facilities are choosing the repowering mode rather than the standard mode of compliance. Compliance plans have been submitted for the six power stations affected: Brayton Point, Salem Harbor, Somerset, Mount Tom, Canal, and Mystic stations [*26*].

The CO_2 standard annual facility cap is based on 3 years of data as of October 2004 (standard) or October 2006 (repowering) and an annual facility rate of 1,800 pounds CO_2 per megawatthour as of October 2006 (standard) or October 2008 (repowering) [*27*]. Credits for off-site reductions of CO_2 emissions can be obtained through carbon sequestration or renewable energy projects. The Massachusetts Department of Environmental Protection is developing regulations that would determine what projects could qualify as reductions. Greenhouse gas banking and trading regulations are also being developed. Plants that fail to achieve the reductions may purchase emissions credits.

The State of Massachusetts published final mercury emissions regulations in June 2004 that apply to the State's four largest existing coal-fired power plants (Brayton Point, Mount Tom, Salem Harbor, and Somerset Station) [*28*]. The regulations require compliance with at least one of the following standards: reduce mercury emissions by 85 percent from 2004 levels by January 2008 or a facility average mercury emissions rate of 0.0075 pound per gigawatthour or less. The affected facilities must reduce their mercury emissions by 95 percent from 2004 levels by October 2012, or achieve a facility average mercury emissions rate of 0.0025 pound per gigawatthour or less. The Massachusetts mercury emissions regulations are more stringent than EPA's proposed mercury emissions regulations as of January 2004 (69 CFR 4651).

Missouri. The Missouri NO_x rule, "Emission Limitation and Emissions Trading of Oxides of Nitrogen" (Rule 10 CSR 10-6.350) applies to fossil-fueled capacity larger than 25 megawatts. The emissions cap is based on a unit's heat input. Power plants had to be in compliance by May 2004. Allowances can be banked, with some restrictions, and some exchange of

allowances is allowed [*29*]. The seasonal NO_x limits (from May to September of each year) vary by county and generally range from 0.18 to 0.35 pound per million Btu.

New Hampshire. New Hampshire has enacted legislation—the "Clean Power Act" (House Bill 284)—to reduce emissions of SO_2, NO_x, CO_2, and mercury from existing fossil-fuel-burning steam-electric power plants. Governor Jeanne Shaheen signed the Act into law in May 2002, and implementing regulations have been finalized [*30*]. The legislation applies to the State's three existing fossil-fuel power plants only and does not apply to new capacity. The plants must either reduce emissions, purchase emissions credits from plants outside New Hampshire that have achieved such reductions, or use some combination of these strategies. Compliance plans submitted to the New Hampshire Department of Environmental Services are under review.

One of the affected plants is Schiller, a 150-megawatt coal-burning power plant made up of three 50-megawatt units. Part of the compliance action, the "Northern Wood Power Project," is the conversion of one of Schiller's 50-megawatt units from coal to a fluidized-bed combustor that will burn biomass. The converted power plant will burn wood chips, sawmill residue, and other woody material. The action is, in part, a result of the Massachusetts RPS program, under which plants in States neighboring Massachusetts can convert from coal to biomass and qualify for the program. Thus, Schiller's conversion from coal to biomass counts toward meeting both the Massachusetts RPS and the New Hampshire multi-pollutant requirements. The conversion, which is expected to cost $70 million (about $1,500 per kilowatt), is planned for completion by the end of 2005.

The SO_2 annual cap under New Hampshire's Clean Power Act is 7,289 short tons by 2006, which amounts to a 75-percent reduction from Phase II Acid Rain legislation requirements and an 85-percent reduction from 1999 emission levels. The NO_x annual cap is 3,644 short tons by 2006, which amounts to a 60-percent reduction from 1999 emission levels. The CO_2 annual cap is 5,425,866 short tons by 2006, which amounts to a 3-percent reduction from 1999 levels.

New Jersey. New Jersey's goal is to reduce Statewide emissions of greenhouse gases from all sectors by 3.5 percent from 1990 levels by 2005. "Covenants" have been signed, pledging organizations to reduce their greenhouse gas emissions in accordance with the State goal [*31*].

New York. New York's "Acid Deposition Reduction Budget Trading Programs"—Title 6 NYCRR Parts 237 and 238—were approved by the State Environmental Board in March 2003 and became effective in May 2003 [*32*], but implementation of the rule has been delayed by a court order. The NO_x regulations apply to electricity generators of 25 megawatts or greater, and the SO_2 regulations apply to all CAAA90 Title IV sources, including electric utilities and other sources of SO_2 and NO_x, such as cogenerators and industrial facilities. NO_x emissions were limited to 39,908 short tons beginning in October 2004. This is a non-ozone season cap (October 1 to April 31), based on the same rate (0.15 pound per million Btu) as the NO_x cap in the current State emissions regulation. SO_2 emissions are limited in two phases: Phase I, beginning in January 2005, limits SO_2 to 25 percent below Title IV allocations (197,046 short tons); Phase II, beginning in January 2008, increases the limit to 50 percent below Title IV allocations (131,364 short tons) [*33*]. A governor's task force was established in June 2001 to recommend greenhouse gas limits.

North Carolina. The General Assembly of North Carolina has passed the "Clean Smokestacks Act"—officially called the "Air Quality/Electric Utilities Act" (S.B. 1078)—which requires emissions reductions from 14 existing coal-fired power plants in the State. It was signed into law in June 2002. Under the Act, North Carolina power companies must reduce NO_x emissions from 178,000 short tons in 1999 to 56,000 short tons by 2009 and SO_2 emissions from 429,000 short tons in 1999 to 250,000 short tons by 2009 and 130,000 short tons by 2013. Progress Energy Carolinas, Inc., and Duke Power have submitted compliance plans to the North Carolina Department of Environment and Natural Resources and the North Carolina Utilities Commission. The utilities will comply with the Act by installing scrubbers and SNCR technology at their plants. Duke Power and Progress Energy have reported compliance costs for SO_2 and NO_x control, with SNCR costs ranging from $4.93 to $63.70 per kilowatt and scrubber costs ranging from $113 to $414 per kilowatt [*34*].

The Act requires the Department of Environment and Natural Resources to evaluate issues related to the control of mercury and CO_2 emissions and recommends the development of standards and plans to control them. In 2003, the Department of Air Quality prepared reports on mercury [*35*] and CO_2 [*36*] emissions reductions for the State, in the first of three sets of reports to be submitted to the Environmental Management Commission and the Environmental Review Commission. The objective of the 2003 report was to

provide general background on the topic of climate change and to define the scope of efforts needed to meet the legislative requirements. The 2004 and 2005 reports will build on this background, report on any developments in the Federal Government, and recommend courses of action that may follow [*37*].

The Act also requires North Carolina to persuade other States and power companies to reduce their emissions to similar levels and on similar timetables. The Act specifically mentions that discussions should be held with the Tennessee Valley Authority (TVA) to determine its emissions reduction policies. A meeting was held between the Department of Environment and Natural Resources/Department of Air Quality and TVA in August 2002 to discuss actions planned by TVA that would be comparable to the Clean Smokestacks Act. TVA presented its plans to add scrubbers to five additional power plants, primarily in the eastern portion of the TVA system, beginning with its Paradise plant in 2006. TVA plans to complete installation of the new scrubbers by 2010. TVA also plans to install the first eight SCR systems for NO_x control and to have 25 boiler units controlled by 2005, which will reduce NO_x emissions during the ozone season by 75 percent.

Oregon. Oregon has established its first formal State standards for CO_2 emissions from new electricity generating plants. The standards apply to power plants and non-generating facilities that emit CO_2. The Oregon Energy Facility Siting Council originally adopted the rules pursuant to House Bill 3283, which was passed by the Oregon legislature in June 1997, and has subsequently updated the rules, most recently in April 2002 [*38*]. For baseload natural gas plants and non-baseload plants, the standard CO_2 emission rate is 675 pounds per megawatthour, 17 percent below the rate for the most efficient natural-gas-fired plants currently in operation in the United States. The Council has not set CO_2 emission standards for baseload power plants using other fossil fuels. As of 2002, about 90 percent of Oregon's electricity was from hydroelectricity and natural gas and about 8 percent was from coal [*39*].

The Council's definition of a natural-gas-fired facility allows up to 10 percent of the expected annual energy to be provided by an alternative fuel, most likely distillate fuel. Proposed facilities may meet the requirement through cogeneration, using new technologies, or purchasing CO_2 offsets from carbon mitigation projects. It is possible to offset all excess CO_2 emissions through cogeneration offsets alone, and there are no limitations on the geographic location or types of CO_2 offset projects. The Council has set a monetary value that the generators may pay to buy offsets ($0.85 per short ton CO_2, equivalent to $3.12 per ton carbon, set in September 2001) [*40*]. This equates to an offset cost of 0.88 mill per kilowatthour [*41*].

Texas. Texas Senate Bill 7 (S.B. 7) imposes NO_x and SO_2 caps for grandfathered fossil fuel power plants [*42*]. The SO_2 annual cap is 595,000 short tons (East: 532,000, West: 63,000, and El Paso: 0 short tons). The NO_x annual cap is 302,000 short tons (East: 256,000, West: 44,000, and El Paso: 2,000 short tons), both of which had to have been achieved by May 2003. The State-wide caps have been met.

Washington. Washington's House Bill 3141, signed into law in May 2004, requires 20 percent of their CO_2 emissions from new power plants to be offset. Plant owners can either directly or indirectly invest in CO_2 mitigation projects, such as forest preservation or the conversion of buses from diesel to natural gas. Power plant CO_2 emissions must be reduced by 20 percent over a 30-year period. CO_2 emissions can be offset by payments to an independent qualified organization, by direct purchase of permanent carbon credits, or by direct investment in CO_2 mitigation projects. The rate of payment to third parties is fixed at $1.60 per metric ton CO_2 [*43*]. The Washington State Energy Facility Site Evaluation Council may adjust the rate every 2 years, but any decrease or increase may not exceed 50 percent of the current rate.

California Greenhouse Gas Emissions Standards for Light-Duty Vehicles

In July 2002, California Assembly Bill 1493 (A.B. 1493) was signed into law. The law requires that the California Air Resources Board (CARB) develop and adopt, by January 1, 2005, greenhouse gas emission standards for light-duty vehicles that provide the maximum feasible reduction in emissions. In estimating the feasibility of the standard, CARB is required to consider cost-effectiveness, technological capability, economic impacts, and flexibility for manufacturers in meeting the standard.

Tailpipe emissions of CO_2, which are directly proportional to vehicle fuel consumption, account for the vast majority of total greenhouse gas emissions from vehicles. A.B. 1493 does not mandate the sale of any specific technology and prohibits the use of the following as options for greenhouse gas reduction: mandatory trip reductions; land use restrictions; additional fees and/or taxes on any motor vehicle, fuel, or vehicle miles traveled; a ban on any vehicle category; reductions in vehicle weight; or a limitation or reduction on

the speed limit on any street or highway in the State. Given these limitations and the preponderant share of total vehicle greenhouse gas emissions resulting from fuel consumption, improvements in fuel economy are the only practical way to attain any standard that requires a significant reduction in emissions.

CARB released a report on August 6, 2004, detailing the reasons for the proposed rulemaking, providing light vehicle regulations to be considered for adoption, and outlining the required analyses used to develop the proposed regulations. The standards for light-duty vehicle greenhouse gas emissions were adopted in September 2004. The auto industry opposes A.B. 1493 and has filed suit against CARB, stating that the California greenhouse gas emissions standards are preempted by a Federal statute that gives the U.S. Department of Transportation the only authority to regulate fuel economy [*44*]. Given the uncertainty surrounding the possible outcome of this litigation, the A.B. 1493 greenhouse gas emission standards are not represented in the *AEO2005* reference case; however, the standards were analyzed to estimate the potential impact on vehicle prices, greenhouse gas emissions, regional energy demand, and regional fuel prices.

A.B. 1493 Regulation

The greenhouse gas emission standards adopted in September 2004 incorporate emissions associated with vehicle operation, air conditioning operation, refrigerant emissions from the air conditioning system, and upstream emissions associated with the production of vehicle fuel. The emission standards apply to light-duty noncommercial passenger vehicles manufactured for model year 2009 and beyond. The standards, specified in terms of CO_2 equivalent emissions, apply to two size classes of vehicles: (1) passenger cars and small light-duty trucks with a loaded vehicle weight rating of 3,750 pounds or less, and (2) heavy light-duty trucks with a loaded vehicle weight rating greater than 3,750 pounds and a gross vehicle weight rating less than 8,500 pounds. The CO_2 equivalent emission standard for heavy light trucks also includes noncommercial passenger trucks between 8,500 pounds and 10,000 pounds. The regulation adopted in September 2004 sets near-term emission standards, phased in between 2009 and 2012, and mid-term emission standards, phased in between 2013 and 2016. After 2016, the emissions standards are assumed to remain constant. Table 9 summarizes the CO_2 equivalent standards.

The regulations allow for CO_2 emission reduction credits that can be earned and traded for 2000 through 2008 model year vehicles. If a manufacturer decides to opt into the program before 2009, credits will be earned if average CO_2 equivalent emissions for that manufacturer's fleet are lower than the 2012 standards. The regulations also provide flexibility in complying with the CO_2 emission standards. Manufacturers can apply for alternative compliance credits for eligible 2009 vehicles and later model years if those vehicles achieve greenhouse gas reductions through the use of alternative fuels. In addition, credits are provided for the use of advanced leak reduction air conditioning components and for the use of HFC-152a as the refrigerant. The regulations also set light vehicle nitrous oxide (N_2O) and methane (CH_4) emission standards.

For this analysis, the CO_2 equivalent emission standards were converted to miles per gallon fuel economy equivalents (Table 10) [*45*]. The fuel economy equivalents shown in Table 10 assume that manufacturers will earn the maximum allowable air conditioning credits. The methodology used to estimate the fuel economy equivalents assumes that manufacturers will meet the N_2O and CH_4 standards and includes CO_2 equivalent emissions associated with N_2O and CH_4 emissions, which are generated by the exhaust

Table 9. CARB CO_2 equivalent emission standards for light-duty vehicles, model years 2009-2016

		CO_2 equivalent emission standard (grams per mile)	
Tier	*Model Year*	*Passenger cars and small light trucks (under 3,751 pounds)*	*Heavy light trucks (3,751 to 8,500 pounds)*
Near term	*2009*	*323*	*439*
	2010	*301*	*420*
	2011	*267*	*390*
	2012	*233*	*361*
Mid-term	*2013*	*227*	*355*
	2014	*222*	*350*
	2015	*213*	*241*
	2016	*205*	*332*

catalyst and incomplete combustion. The fuel economy equivalent standards are assumed to remain constant after 2016.

Analysis and Results

Two cases were developed to measure the potential impact of the California light vehicle greenhouse gas emission standards on energy demand, fuel prices, and vehicle prices. The *A.B. 1493 California-only case* assumes that only California will adopt the new standards. The *A.B. 1493 extended case* assumes that New York, Maine, Massachusetts, and Vermont will also adopt the California standards for greenhouse gas emissions for light-duty vehicles. Those States have already adopted California emissions standards applicable to other types of vehicle emissions [*46*].

Both cases examined here assume that fuel economy impacts are limited to those States adopting the regulation and that the fuel economy and sales mix of vehicles sold in non-adopting States remain at levels achieved in the *AEO2005* reference case. Although not addressed in this analysis, it is conceivable that State-based fuel economy regulation could cause unintended shifts in light vehicle markets. State-specified fuel economy standards might inadvertently provide manufacturers an opportunity to maintain or increase profits through the sale of larger, less efficient vehicles (sport utility vehicles, minivans, and large cars) in areas that do not adopt the California standards, while complying with the nationally based CAFE standards.

As noted above, A.B. 1493 allows CO_2 emission credits for early compliance and for the sale of alternative-fuel vehicles. However, this analysis does not attempt to quantify the impact that either would have on the fuel economy required to meet the CO_2 equivalent emission standards.

Impacts on Vehicle Sales and Prices

For States adopting A.B. 1493, it is projected that advanced technologies implemented in conventional light-duty vehicles will account for the majority of the fuel economy improvements needed to achieve the required reductions in CO_2 emissions. For cars, in addition to the fuel economy gains achieved through advanced conventional technologies, increased sales of hybrid and diesel vehicles will be required to meet the fuel economy goal. Relative to the projections in the *AEO2005* reference case, hybrid car sales in those States adopting A.B. 1493 are projected to increase from 5.8 percent to 11.0 percent of total new car sales in 2016, and diesel car sales are projected to increase from 0.3 percent to 0.9 percent of total new car sales in 2016.

As a result of increased use of advanced conventional technologies and increased market penetration of hybrid and diesel vehicles, the average price of a new car in 2016 is projected to increase by $1,860, and the average price of a new truck is projected to increase by $500 (2003 dollars) in both cases in the analysis. These cost estimates do not include the costs associated with credits earned from improved air conditioning systems or the emission control equipment needed to achieve the N_2O and CH_4 emission standards. They do account for increased demand for heavier vehicles, improved performance, and increased fuel economy that is projected to continue throughout the forecast period in the *AEO2005* reference case.

The EIA projections for vehicle sales and price impacts can be compared with those reported in the CARB staff analysis [*47*], which estimates that the average price of new passenger cars and small light trucks will increase by $1,064, and the average price of a new heavy light truck will increase by $1,029, in

Table 10. CARB fuel economy equivalent standards for light-duty vehicles, model years 2009-2016

		Fuel economy equivalent standard (miles per gallon)	
Tier	*Year*	*Passenger cars and small light trucks (<3,751 pounds loaded vehicle weight)*	*Heavy light trucks (3,751 pounds loaded vehicle weight to 8,500 pounds gross vehicle weight)*
Near term	*2009*	*26.4*	*19.5*
	2010	*28.3*	*20.4*
	2011	*31.8*	*21.9*
	2012	*36.2*	*23.6*
Mid-term	*2013*	*36.3*	*23.6*
	2014	*37.1*	*23.9*
	2015	*38.6*	*24.5*
	2016	*39.9*	*25.2*

2016 compared with the price of a model year 2009 base vehicle. Comparisons of the 2016 model year vehicle price to the 2009 base vehicle price implicitly assume that continued consumer demand for increased vehicle weight and performance will have no impact on the cost of complying with the regulation. CARB provided no information about its assumptions for fuel economy, weight, and performance ratings for the 2009 base vehicle.

Impacts on Transportation Energy Use and CO_2 Equivalent Emissions

In the A.B. 1493 California-only case, EIA estimates that total national transportation energy use in 2025 would be reduced by 0.15 million barrels per day (0.7 percent) and CO_2 equivalent emissions would be reduced by 21 million metric tons (0.8 percent) relative to the *AEO2005* reference case projections. In the A.B. 1493 extended case, EIA estimates that total national transportation energy use in 2025 would be reduced by 0.22 million barrels per day (1.1 percent) and CO_2 equivalent emissions by 33 million metric tons (1.2 percent) relative to the *AEO2005* reference case projections.

The CARB staff analysis provides estimated emissions reduction impacts for 2020 and 2030, which allow for a direct comparison with EIA's results for 2020. In the A.B. 1493 California-only case, EIA projects that 2020 light vehicle CO_2 equivalent emissions would be reduced by 14.9 million metric tons (Table 11). CARB's analysis determined that by 2020 CO_2 equivalent emissions from light-duty vehicles would be reduced by 29 million metric tons, approximately double EIA's estimate [*48*].

The difference in projected reductions in CO_2 equivalent emissions in the two analyses can be explained by three key factors. The first is the projected distribution of cars and light trucks in use. The CARB analysis projects that, in 2020, passenger cars and light trucks under 3,750 pounds loaded vehicle weight (so-called "small light trucks") would account for approximately 80 percent of the light-duty vehicle stock and associated vehicle miles traveled. Specifically, passenger cars account for 63.6 percent of the total stock, small light trucks account for 18.2 percent of the total stock, and heavy light trucks account for 18.1 percent of the total stock [*49*]. In comparison, EIA's analysis projects that passenger cars would account for 46.5 percent of the light vehicle stock, and all light trucks, which are predominantly over 3,750 pounds loaded vehicle weight, would account for 53.5 percent [*50*]. This is significant because, as shown in the CARB analysis, passenger cars and small light trucks are required to meet the more stringent CO_2 equivalent standard, which will result in greater projected emission reductions.

Although NEMS does not specifically model light trucks less than 3,750 pounds loaded vehicle weight, light trucks are disaggregated by vehicle class. The fuel economy equivalent standards shown in Table 10 were modified to reflect an assumption that light trucks under 3,750 pounds gross vehicle weight would account for 12.3 percent of new light truck sales [*51*]. As a result, the light truck fuel economy equivalent standard used in EIA's analysis would increase to 26.4 miles per gallon by 2016.

The second significant difference between the two analyses is projected baseline fuel economy. Although no data were available for the baseline fuel economy projected in the CARB analysis, CARB staff informed EIA that their baseline for greenhouse gas emissions from light-duty vehicles does not project increases in new light vehicle fuel economy [*52*]. The *AEO2005* reference case projects that new car fuel economy will increase from 29.5 miles per gallon in 2003 to 30.6 miles per gallon in 2020, and that new light truck fuel economy will increase from 21.8 miles per gallon in 2003 to 24.1 miles per gallon in 2020. As a result, the EIA projection of baseline fuel economy improvement reduces the amount of CO_2 that can be saved by the

Table 11. Comparison of key factors in the CARB and EIA analyses, 2020

	CARB			EIA		
Projection	*Passenger cars and small light trucks*	*Heavy light trucks*	*Total*	*Passenger cars*	*Light trucks*	*Total*
CO_2 equivalent emission reductions						
Million metric tons	22.2	6.8	**29.0**	5.8	9.1	**14.9**
Percent of total	76.6	23.4	**100.0**	39.0	61.0	**100.0**
Distribution of light-duty vehicle stock (percent of total)	81.9	18.1	**100.0**	46.5	53.5	**100.0**
Distribution of light-duty vehicle miles traveled (percent of total)	82.1	17.9	**100.0**	47.4	52.6	**100.0**

A.B. 1493 standards relative to savings available under the CARB baseline assumption of no change in new vehicle fuel efficiency.

The third significant difference between the analyses is the projected impact of improved air conditioning systems on the reduction of CO_2 equivalent emissions. The CARB analysis includes CO_2 equivalent emission reductions associated with improved air conditioning. EIA's analysis assumes that manufacturers will use the maximum allowable air conditioning credits, but it does not explicitly model air conditioning systems or associated emissions. Analyses of the credits allowed for this technology indicate that approximately 4 to 7 percent of the total CO_2 equivalent emission reductions reported by CARB could be attributed to improved light vehicle air conditioning systems.

Regional Impacts on Transportation Fuel Supply and Prices

Relative to the *AEO2005* reference case, the A.B. 1493 California-only case projects reduced consumption of gasoline and diesel fuel in 2025 by 153,000 and 6,000 barrels per day, respectively, in Census Division 9 [*53*]. As a result, production of gasoline in 2025 is projected to decrease by 34,000 barrels per day, with an additional reduction of 109,000 barrels per day in gasoline imports. The balance of the difference results from changes in interregional transfers. Diesel fuel production in Census Division 9 is projected to decrease by 7,000 barrels per day in 2025. The reduction in diesel supply is slightly greater than the reduction in diesel consumption due to refinery optimization for gasoline production. As a result, disproportionate reductions in gasoline demand, as projected in the A.B. 1493 California-only case, affect the production of diesel even though the demand for diesel fuel is not projected to fall by as much.

A.B. 1493 has little projected impact on diesel prices in Census Division 9. Because the reduction in gasoline demand causes an almost equal reduction in supply in the A.B. 1493 California-only case, the average gasoline price for Census Division 9 between 2016 and 2025 is projected to be 0.6 cents per gallon lower, than projected in the *AEO2005* reference case.

The A.B. 1493 extended case, which applies the same light vehicle greenhouse gas reduction requirements to selected States in Census Divisions 1 and 2 in addition to California, projects reduced consumption of gasoline and diesel fuel in 2025, by 88,000 and 4,000 barrels per day, respectively, in the New England and Mid-Atlantic regions [*54*]. This demand reduction results in a similar reduction in gasoline imports to the two regions, although the projected reduction of 74,000 barrels per day in gasoline imports is less than the reduction in demand. In contrast to Census Division 9, Census Divisions 1 and 2 are traditionally more integrated to fuel supplies from other refining regions. As such, a reduction in gasoline consumption of 4.5 percent (or 88,000 barrels per day) in Census Divisions 1 and 2, relative to the *AEO2005* reference case, represents a reduction of only 0.9 percent when a broader market east of the Rocky Mountains including Census Divisions 1 through 7 (or Petroleum Administration for Defense Districts 1 through 3) is considered. The A.B. 1493 extended case has negligible impact on gasoline and diesel prices in Census Divisions 1 and 2.

Conclusion

Analysis of two A.B. 1493 cases indicates small national impacts on energy demand and fuel prices. The impact of A.B. 1493 could be more or less significant depending on manufacturer behavior, consumer response, and the number of States assumed to adopt the program if its legality is upheld. Because the required improvements in car fuel economy are much more stringent then those required for light trucks, above 3,750 pounds, a category that includes 88 percent of total light truck sales, consumer preference for larger high performance vehicles could spur further increases in the demand for light trucks, which counters the intent of the regulation. Further complicating the issue is the behavior of vehicle manufacturers with respect to their fiduciary responsibility to comply with nationally-based CAFE standards while also meeting niche market CO_2 emissions requirements. These issues, coupled with pending National Highway Traffic Safety Administration modifications to the current CAFE structure and the legal challenges facing A.B. 1493, create significant uncertainty with respect to the evaluation of the new California regulation.

Multi-Pollutant Legislation and Regulations

The 108th Congress proposed and debated a variety of bills addressing pollution control at electric power plants but did not pass any of them into law. In addition, the EPA currently is preparing two regulations—a proposed Clean Air Interstate Rule (pCAIR) and a Clean Air Mercury Rule (CAMR)—to address emissions from coal-fired power plants. Several States also have taken legislative actions to limit

pollutants from power plants in their jurisdictions. This section discusses three Congressional air pollution bills and the EPA's pCAIR and CAMR regulations.

Clear Skies Act of 2003, Clean Air Planning Act of 2003, and Clean Power Act of 2003

Several bills introduced in the 108th Congress proposed to regulate emissions of NO_x, sulfur dioxide (SO_2), mercury, and CO_2 from electric power plants. EIA received a request from Senator James M. Inhofe to conduct an analysis of S. 843, the Clean Air Planning Act of 2003, introduced by Senator Thomas Carper; S. 366, the Clean Power Act of 2003, introduced by Senator James Jeffords; and S. 1844, the Clear Skies Act of 2003, introduced by Senator Inhofe. The emissions targets and implementation timetables proposed in the bills are summarized in Table 12.

A report on the results of EIA's analysis [*55*] was released in May 2004. The analysis in the report was based on the assumptions used in *AEO2004*, which differed from those used in *AEO2005*. One of the most significant differences for the electricity sector is in projected natural gas prices. In *AEO2005*, the reference case projection for wellhead natural gas prices in 2025 is more than 30 cents higher than the *AEO2004* projection, primarily as a result of lower assumed finding rates (reserve additions per well) for onshore resources. The following summary of EIA's Inhofe-Carper-Jeffords analysis is based on the *AEO2004* projections.

To comply with the provisions of S. 1844, the Clear Skies Act (Inhofe), electricity producers would be expected to rely primarily on adding emissions control equipment to existing generators. Switching fuels from coal to natural gas and renewables would be expected to play a relatively small role. Producers would be expected to begin reducing mercury emissions before 2010 in order to take advantage of the early credit program included in S. 1844; however, emissions of mercury would remain above the 15-ton target in 2018, because the bill also specifies an "allowance price safety valve." Among the three bills analyzed by EIA, total costs to the electric power industry and projected impacts on electricity prices are lowest for S. 1844.

S. 843, the Clean Air Planning Act (Carper) would impose more stringent limits on emissions of SO_2, NO_x, and mercury than those proposed in S. 1844. In addition, S. 843 proposes a cap on CO_2 emissions. Emissions control equipment added to existing generators would also be expected to play an important role in compliance strategies under S. 843, but fuel switching from coal to natural gas and renewables would play a more important role. In addition, the impacts would be sensitive to the availability and cost of greenhouse gas offsets. Because of this uncertainty, two separate cases were included in EIA's analysis of S. 843—one (Carper domestic) assuming that only domestic offset programs would be approved and another (Carper international) assuming that both domestic and international offsets would be available. Overall, the resource costs and electricity price impacts under S. 843 were projected to be larger than those under S. 1844.

S. 366, the Clean Power Act (Jeffords), includes a more stringent cap on CO_2 emissions, which would be expected to make switching from coal to natural gas, renewables, and nuclear especially important in compliance strategies. S. 366 would require all older power plants to be retrofitted with emissions control

Table 12. Emissions targets in multi-pollutant legislation

Emissions	*S. 1844, Clear Skies Act (Inhofe)*	*S. 843, Clean Air Planning Act (Carper)*	*S. 366, Clean Power Act (Jeffords)*
NO_x	*2.19 million tons in 2008* *1.79 million tons in 2018*	*1.87 million tons in 2009* *1.7 million tons in 2013*	*1.51 million tons in 2009*
SO_2	*4.4 million tons in 2010* *3.0 million tons in 2018*	*4.5 million tons in 2009* *3.5 million tons in 2013* *2.25 million tons in 2016*	*2.25 million tons in 2009*
Mercury	*34 tons in 2010* *15 tons in 2018*	*24 tons in 2009* *10 tons in 2013*	*5 tons in 2008*
CO_2	*No cap*	*2,332 million metric tons CO_2 (636 million metric tons carbon equivalent) in 2009* *2,244 million metric tons CO_2 (612 million metric tons carbon equivalent) in 2013*	*1,863 million metric tons CO_2 (508 million metric tons carbon equivalent) in 2009*

equipment, even if emissions of SO_2, NO_x, and mercury fell below the respective aggregate reduction targets as a result of fuel switching. The early timing and stringency of the emissions limits, among other factors, would lead to the largest resource cost and electricity price impacts among the three bills. Because of the higher projected electricity prices under S. 366, consumers would also be expected to reduce their use of electricity.

Table 13 shows a summary of EIA's analysis results. Significantly, power plant emissions of NO_x in 2025 were projected to remain at about the levels of the respective phase 2 targets under S. 843 (1.7 million tons) and S. 1844 (1.79 million tons) shown in Table 12, because neither bill would be expected to provide significant opportunity for economical banking of NO_x allowances. Only under S. 366, which requires emissions controls at all plants over 40 years old, were NO_x emissions in 2025 projected to fall below the bill's emission target of 1.51 million tons shown in Table 12.

SO_2 emissions from electric power plants were projected to be reduced under the provisions of each of the three bills, as well as in the *AEO2004* reference case. Under S. 843 and S. 1844, however, SO_2 emissions in 2025 were projected to remain above the bills' target levels because of allowances banked from the existing SO_2 reduction program. Under S. 366, SO_2 emissions in 2025, like NO_x emissions, were projected to fall below the bill's target level.

Average retail electricity prices in 2025 were projected to be 3.2 percent higher under S. 1844 than in the *AEO2004* reference case forecast, and they were projected to be as much as 7.8 percent higher under S. 843 (Figure 9). Much larger price impacts were projected under S. 366—47 percent above reference case prices in 2010 and 27 percent above reference case prices in 2025—primarily because the proposed limit on CO_2 emissions at 1990 levels in 2009 would require rapid transformation of the Nation's power plant capacity from coal to natural gas, renewables, and nuclear fuel.

Proposed Clean Air Interstate Rule

The EPA's proposed CAIR [*56*] was published in the *Federal Register* [*57*] in January 2004 and in a supplemental notice [*58*] in June 2004. pCAIR is intended to reduce the atmospheric interstate transport of fine particulate matter ($PM_{2.5}$) and ozone. SO_2 and NO_x are precursors of $PM_{2.5}$. NO_x is also a precursor to the formation of ground-level ozone. pCAIR would require 29 States and the District of Columbia to develop plans to reduce SO_2 and/or NO_x emissions. The proposed rules would apply to all fossil-fuel-fired boilers and turbines serving electrical generators with capacity greater than 25 megawatts that provide electricity for sale. The proposed rules also would apply to combined heat and power (CHP) units that are larger than 25 megawatts, that sell at least one-third of their potential electrical output, and that meet certain operating and efficiency criteria. Table 14 shows the pCAIR emissions caps and timetables for meeting the caps.

Under pCAIR, the States would be responsible for allocating NO_x emissions allowances and taking the lead in pursuing enforcement actions, and they would have flexibility in choosing the sources to be controlled. They could meet the emissions reduction requirements either by joining the EPA-managed cap

Table 13. Key projections from EIA's 2004 analysis of proposed multi-pollutant control bills, 2025

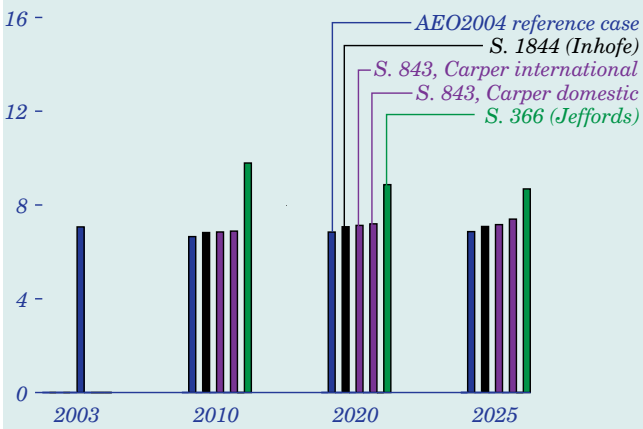
		2025				
				S. 843		
Projection	2003	AEO2004 reference case	S. 1844	Carper international	Carper domestic	S. 366
Total U.S. emissions						
NO_x (million tons)	4.1	3.7	1.8	1.7	1.7	0.61
SO_2 (million tons)	10.6	9.0	3.6	2.8	2.9	1.2
Mercury (tons)	49.7	54.6	29.0	10.0	10.0	3.7
CO_2 (million metric tons)	2,286	3,272	3,164	2,905	2,720	1,733
Electricity generation by fuel (billion kilowatthours)						
Coal	1,971	3,008	2,861	2,467	2,280	1,363
Nuclear	764	824	824	824	824	1,261
Natural gas	632	1,287	1,350	1,576	1,579	1,394
Renewables	350	537	597	758	930	1,310
Average retail electricity price (2002 cents per kilowatthour)	7.4	6.9	7.1	7.2	7.4	8.7

and trade programs for power plants, or by achieving reductions through emissions control measures on sources in other sectors (industrial, transportation, residential, or commercial), or on a combination of electricity generating units and sources in other sectors.

To participate in the cap and trade program, the States would be required to regulate power plant emissions within their boundaries. The EPA would be responsible for assigning State emissions budgets, reviewing and approving State plans, and administering the emissions and allowance tracking systems. State rules could allow sources currently subject to the CAAA90 Title IV rules and to the NO_x State Implementation Plan (SIP) Call trading program to use allowances banked from those programs before 2010 for compliance with pCAIR. pCAIR also would require additional reductions in NO_x emissions for States affected by the NO_x SIP Call.

The EPA plans to meet the SO_2 emission reduction requirements by implementing a progressively more stringent retirement ratio on SO_2 allowances for electricity generating units of different vintages under the CAAA90 Title IV acid rain program. New SO_2 allowances would not be issued under pCAIR; power plants would instead use the current pool of SO_2 allowances issued under Title IV. Allowances issued for vintage years 2004 through 2009 could be retired on a 1-to-1 basis, but allowances issued for vintage years 2010 through 2014 would have to be retired on a 2-to-1 basis, requiring 2 Title IV allowances to be retired for each ton of SO_2 emissions. Allowances issued for vintage years 2015 and later would be retired on a basis of approximately 2.9 to 1. This retirement procedure is proposed in order to integrate the pCAIR rules with the existing Title IV SO_2 emissions reduction program.

Figure 9. Projected electricity prices under proposed multi-pollutant control bills, 2010, 2020, and 2025 (2002 cents per kilowatthour)



NO_x emissions would be treated differently, with State emissions caps to be based on each State's share of region-wide heat input. In addition, new NO_x allowances would be issued, and banked SIP Call allowances could be traded under pCAIR.

pCAIR Analysis

Although the *AEO2005* reference case does not assume enactment of pCAIR, an alternative case has been developed to analyze its potential impacts. The pCAIR sensitivity case assumes the adoption of pCAIR emissions caps on SO_2 and NO_x and the proposed SO_2 allowance vintaging methodology. The caps are assumed to be imposed on all electricity generators and CHP units that sell electricity to the grid, and it is assumed that electricity producers would opt to participate in the EPA cap and trade program rather than relying on State emission reduction programs. Other than those assumptions, the pCAIR case uses the *AEO2005* reference case assumptions.

Table 15 compares the key results of the pCAIR case and the *AEO2005* reference case. In 2025, the pCAIR case results in a 46-percent reduction in national NO_x emissions from their 2003 level and a 63-percent reduction in SO_2 emissions from the 2003 level.

NO_x allowance prices are projected to increase in the pCAIR case. In the reference case, the NO_x SIP Call affects States primarily in the Northeast with a summer season NO_x cap. In the pCAIR case, the SIP Call caps are replaced by the pCAIR NO_x caps, which affect a different combination of States and are annual limits. Because the NO_x allowance prices under the two inherently different programs cannot be compared, Table 15 shows only the allowance prices under pCAIR.

SO_2 allowance prices are projected to be significantly higher in the pCAIR case than in the reference case, which assumes continuation of the currently enacted

Table 14. Historical emissions and proposed future caps for the combination of affected pCAIR States (million tons)

Emissions	Emissions in 2002	Emissions cap in 2010	Emissions cap in 2015
NO_x	3.78	1.60	1.33
SO_2	9.39	3.86	2.71

CAAA90 allowance program. The higher SO_2 allowance prices in the pCAIR case reflect the need for utilities to reduce emissions to lower levels than currently required under CAAA90.

One of the key results of the pCAIR case is that electric power producers would be required to install significantly more pollution control equipment than in the reference case. To comply with the pCAIR limits in SO_2 emissions, electricity producers are projected to install flue gas desulfurization (FGD) scrubbers on nearly 100 gigawatts more coal-fired capacity than in the reference case through 2025. Similarly, to meet the pCAIR NO_x limits, SCR equipment is projected to be installed on about 60 gigawatts more coal-fired capacity than in the reference case. In the reference case, total coal-fired capacity in the United States is projected to grow from 314 gigawatts in 2003 to 398 gigawatts in 2025. Thus, in the pCAIR case, roughly one-third of all coal-fired power plants would be retrofitted with FGD and SCR equipment by 2025. The pCAIR case does not project a significant change in the fuel mix for electricity generation in 2025 relative to that in the reference case, showing only a slight reduction in coal use, a small increase in natural gas use, and a small increase in renewable fuel use (Figure 10).

Only modest changes in regional coal production are projected in the pCAIR case (Figure 11). In both the reference and pCAIR cases, coal production increases from 2003 to 2025. Relative to the reference case, the pCAIR case projects a decrease in Appalachian coal production of about 2 percent in 2025, a decrease in Interior coal production of about 13 percent (24 million tons), and an increase in Western coal production of about 1.1 percent, based on the generally lower sulfur content of Western than Appalachian and Interior coal resources.

After the first phase of the pCAIR emissions caps begins to take effect in 2010, average U.S. retail electricity prices are projected to be higher by a maximum of 2.3 percent in the pCAIR case than in the reference case, with a similar difference in projected resource costs for the electric power sector (the amount that power companies spend on fuel, capital, and operations and maintenance). Projected resource costs

Table 15. Key electricity sector projections from EIA's analysis of proposed pCAIR regulations, 2015 and 2025

		2015		2025	
Projection	*2003*	*AEO2005 reference case*	*pCAIR case*	*AEO2005 reference case*	*pCAIR case*
Total U.S. emissions					
NO_x (million tons)	*4.1*	*4.1*	*2.1*	*4.3*	*2.2*
SO_2 (million tons)	*10.6*	*9.0*	*4.7*	*9.0*	*3.9*
Allowance prices (2003 dollars per ton)					
NO_x	*—*	*—*	*2,524*	*—*	*2,789*
SO_2	*172*	*290*	*1,160*	*247*	*1,463*
Coal-fired capacity retrofits (gigawatts)					
Flue gas desulfurization	*0*	*26*	*107*	*27*	*128*
Selective catalytic reduction	*0*	*70*	*131*	*74*	*133*

Figure 10. Projected electricity generation by fuel in two cases, 2025 (billion kilowatthours)

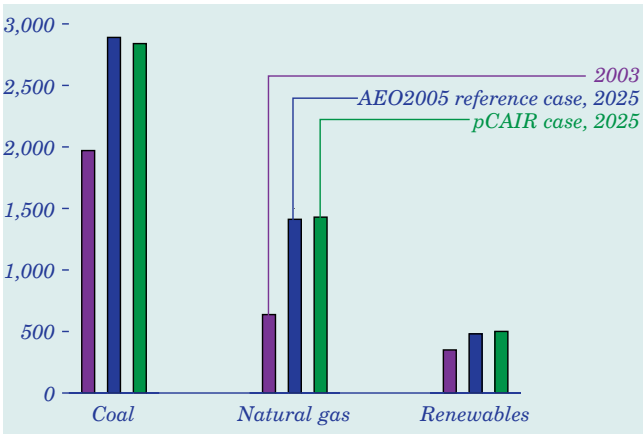
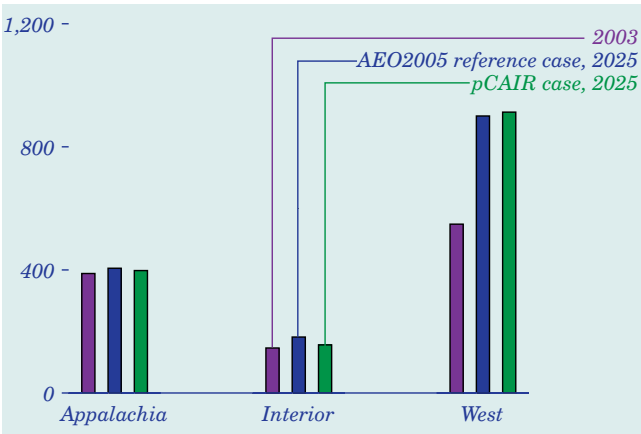


Figure 11. Projected coal production by region in two cases, 2025 (million tons)



from 2010 through 2025 are higher by a maximum of $3.5 billion per year (about 2.5 percent) in the pCAIR case than in the *AEO2005* reference case.

Proposed Clean Air Mercury Rule

The EPA's CAMR (proposed as the Utility Mercury Reductions Rule) [*59*] for controlling mercury emissions from new and existing coal-fired power plants was published in the *Federal Register* [*60*] in January 2004 and in a supplemental notice [*61*] in March 2004. Nickel emissions from new and existing oil-fired power plants would also be capped under the proposed rule; however, as of 2002 only 2.3 percent of the electricity generated in the United States was from oil-fired units, and 50.2 percent was from coal-fired units [*62*]. Therefore, the focus in this section is on the proposed regulations applicable to coal-fired units. Power plants with capacity greater than 25 megawatts and CHP units that are larger than 25 megawatts and sell at least one-third of their electricity would be subject to CAMR.

The EPA estimates that CAMR, using a cap and trade approach, would reduce mercury emissions by nearly 70 percent when fully implemented. Two alternative approaches were proposed for reducing mercury emissions. The first, which would require the installation of MACT under CAAA90 Section 112, would reduce annual emissions from the electricity generation sector by about 29 percent, from 48 tons in 2002 to 34 tons in 2008. The second approach would modify Section 112 to allow regulation of mercury emissions under a cap and trade program. The program would be implemented in two phases, with a banking provision that would allow for reductions as early as 2010 and a second phase that would set a cap of 15 tons in 2018.

Under the cap and trade approach, States would submit plans to the EPA to demonstrate that they would meet their assigned State-wide mercury emissions budgets. With EPA approval, the States could then participate in the cap and trade program. Allowances would be allocated by the States to power companies, which could either sell or bank any excess allowances. The EPA proposed a safety valve price of $2,187.50 per ounce of mercury ($35,000 per pound), adjusted annually for inflation. The price of allowances would effectively be capped at that level, and power plant operators could buy allowances at any time at the safety valve price, reducing the State's budget in the future. Public comments on CAMR have been received, and the EPA expects to issue the final rules in March 2005.

Climate Stewardship Act of 2004

Senators John McCain and Joseph I. Lieberman introduced the Climate Stewardship Act of 2003 (S. 139) in the U.S. Senate in 2003. S. 139 would establish regulations to limit U.S. emissions of greenhouse gases [*63*], primarily through a program of tradable emission allowances and related emissions reporting requirements. In October 2003, Senators McCain and Lieberman proposed an amended version of the bill, S.A. 2028, which included the first phase of emissions reductions beginning in 2010 as proposed in S. 139 but removed references to a second phase of reductions beginning in 2016. On October 30, 2003, the Senate voted 43-55 to reject the measure. In July 2004, the Senators submitted the bill as the Climate Stewardship Act of 2004 (S.A. 3546), intending it as an amendment to legislation on class action lawsuits (S. 2062); however, the proposed amendment was tabled. Senator McCain has stated his intention to continue resubmitting the Climate Stewardship Act until it is passed by the Senate.

In March 2004, Representative Wayne Gilchrest submitted a version of the same bill, also called the Climate Stewardship Act of 2004, in the U.S. House of Representatives (H.R. 4067). It was cosponsored by 70 other Representatives. The House bill is essentially the same as the most recent Senate version, S.A. 3546. H.R. 4067 has been referred to the House Science Committee and Energy and Commerce Committee.

Overview

The Climate Stewardship Act of 2004 [*64*] would establish a system of tradable allowances to reduce greenhouse gas emissions. The bill includes requirements for mandatory emissions reporting by covered entities and for voluntary reporting of emissions reduction activities by noncovered entities; a national greenhouse gas database and registry of reductions; and a research program on climate change and related activities. The emissions allowance program would apply to most greenhouse gas emissions sources, the exceptions being those in the residential sector and entities in all sectors whose annual emissions are less than a certain threshold. Entities not directly covered by the allowance program would nevertheless be affected by its impacts on energy prices and the economy as a whole, as well as by the program's incentives to reward voluntary reductions of emissions.

The bill defines the covered sectors for the emission allowance program as the commercial, industrial,

electric power, and transportation sectors [*65*]. Covered entities in the commercial, industrial, and electricity sectors are those that emit, from any single facility, greenhouse gas emissions from stationary sources exceeding 10,000 metric tons carbon dioxide equivalent per year [*66*]. In effect, this threshold would exempt most entities in the agriculture and commercial sectors. All petroleum used for transportation within the United States would be covered, and refiners would be responsible for submitting allowances for emissions related to petroleum sold for transportation use. Producers and importers of hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride would be required to submit allowances for emissions associated with their products, subject to the 10,000 metric ton threshold.

The bill provides for the exemption of emission sources if the EPA deems their measurement or estimation to be impractical. This exemption would most likely apply to a large share of U.S. nitrous oxide and methane emissions, because many of their sources are difficult or uneconomical to measure.

Emission Allowance Program

The market-driven system of emission allowances proposed in the Climate Stewardship Act of 2004 would control greenhouse gas emissions by creating a fixed number of tradable emission allowances each year. The EPA is charged with establishing the regulations to create the tradable allowances, and the bill defines many of the provisions governing the allowances. The bill would provide entities with options for banking and borrowing allowances; for limited use of registered reductions from noncovered entities in lieu of allowances [*67*]; and for obtaining allowance allocation credits to reward past emissions reductions and early action reductions. The bill would establish a nonprofit Climate Change Credit Corporation (CCCC) to facilitate the market in emission allowances, to buy and sell allowances, and to distribute proceeds from sales to mitigate the economic impacts of the program. The Secretary of Commerce would be responsible for allocating allowances to the covered sectors and to the CCCC, subject to the final approval of Congress.

Each emission allowance would provide the right for an entity to emit one ton of greenhouse gases, measured in carbon dioxide equivalent units based on 100-year global warming potential. The number of allowances created each year would effectively establish a cap on total U.S. emissions; however, with the banking of allowances for future use permitted under the bill, emissions in any year could differ from the number of allowances issued [*68*]. The bill would require individual covered entities to submit allowances equal to their emissions but would not otherwise limit their emissions. An entity's emission allowance obligation would be based on its reported annual emissions, mandated under the program. The bill calls for the future development of emissions measurement and verification procedures that could be used to audit an entity's allowance obligation. Entities would be able to buy and sell allowances and to bank allowances for future use. Under limited conditions, covered entities could borrow against future emissions reductions [*69*].

Emission Caps

The bill specifies emission allowance caps based on aggregate emissions for the covered sectors in 2000, excluding emissions from the residential sector, the agriculture sector, and U.S. territories [*70*]. The bill specifies the total number of annual allowances at 5,896 million metric tons carbon dioxide equivalent, adding the phrase "reduced by the amount of emissions of greenhouse gases in calendar year 2000 from noncovered entities." This wording leaves the level of allowances that establishes the cap open to interpretation and questions of emissions accounting. Noncovered entities are those that have no facilities with annual emissions above 10,000 metric tons carbon dioxide equivalent; neither the identification of those entities nor their aggregate level of emissions in 2000 is known precisely. Because noncovered entities would not be required to report emissions, their emissions could be estimated only by subtracting covered entities' reported emissions from estimates of total emissions. Noncovered emissions would also include emissions from sources the EPA deemed impractical to measure. Under these definitions, the level of emissions from noncovered sources would be unknown, and the number of allowances to be created after adjusting for noncovered emissions is uncertain.

In a June 2003 analysis of S. 139 [*71*], EIA estimated that approximately 75 percent of total U.S. greenhouse gas emissions would be covered under the bill. The impact of the bill on total emissions would depend on growth in noncovered emissions and how covered entities made use of alternative compliance provisions, such as registered increases in carbon sequestration.

Allowance Allocation, Allowance Banking, and Alternative Compliance Provisions

The allocation of emission allowances to covered sectors and entities is not completely fixed by the bill. Some of the Government-issued allowances would be distributed directly to covered entities, and the rest would go to the CCCC. A number of criteria for allocating emissions allowances are defined in the bill, but neither the total percentage of allowances to be distributed free nor the share to be distributed to each of the covered sectors is specified. The bill does, however, describe an allocation procedure to reward entities for registered emissions reductions made since 1990 and reductions made in advance of the 2010 start date. Entities with creditable reductions would be granted a corresponding increase in their future allocations of allowances for the compliance period beginning in 2010. Credits for early action would not affect the overall compliance cap, only the allocation of free allowances to covered entities. Nevertheless, this provision would provide an incentive to reduce emissions early in exchange for future allowance allocations.

The bill's allowance trading and alternative compliance provisions would result in markets for emission allowances and registered offset credits. The market for allowances and related incentives should result in a market-clearing price for allowances that would reflect both the cost of reducing emissions and the flexibility of allowance banking. Because allowances could be sold or held for future use, covered entities would have an incentive to reduce emissions under the bill, even if they were allocated sufficient allowances to cover their annual emissions. Some entities would find it economical to over-comply and sell or bank emission allowances, depending on the cost of emissions reduction opportunities, future expansion plans, and expectations about future allowance prices.

A market for the alternative compliance emission credits, or offsets, would also provide economic incentives for noncovered entities to reduce emissions and register their reductions. The bill would allow covered entities to submit such registered credits in place of up to 15 percent of their allowance obligations. Offsets could be registered by domestic sources as well as from other countries that have greenhouse gas emissions limits and comparable allowance trading provisions in place. The allowance offsets could also come from increases in biological carbon sequestration, such as through reforestation, and to a limited extent from changes in agricultural practices to increase net carbon sequestration in the soil [*72*]. Offsets would likely sell at or below the price for allowances. Suppliers competing to meet the limited demand for offsets could bid down the offset price to a level below the allowance price.

Energy Market Impacts

Energy consumers would incur higher effective costs of using energy as a result of the bill's allowance program. In the transportation sector, end-use consumers would face higher delivered prices of refined products when refiners passed on the cost of allowances required for emissions of petroleum-based fuels sold for transportation [*73*]. Covered entities in the commercial, industrial, and electric power sectors would implicitly face a higher cost of consuming fossil energy, because they would be required to obtain allowances for carbon dioxide emitted in direct fuel use. To the extent that electricity generators could pass through the opportunity cost of allowances and related incremental capital costs to their customers, electricity prices would increase in all consuming sectors. The increased energy costs, whether incorporated in delivered prices or reflected implicitly as opportunity costs of consuming energy, would affect all energy sectors of the economy.

The energy cost impacts on consumers and businesses could be substantially reduced by actions of the CCCC, which would be tasked to use proceeds from allowance sales to diminish the economic impact of the program. The extent to which the CCCC could funnel allowance proceeds back into the economy would depend on the allocation of allowances it received. The bill leaves the allocation of available allowances between the CCCC and covered entities unspecified. The CCCC share of allowances would be determined on an annual basis by the Secretary of Commerce, subject to approval by the Congress.

The funds collected by the CCCC could be dispersed to energy consumers by various methods, including cash rebates, rebates for energy-efficient appliances, subsidies, and general transition assistance to displaced workers. The bill specifies that the CCCC must allocate a percentage of the proceeds from allowances to provide transition assistance to dislocated workers and communities; however, the transition assistance amount probably would be a small fraction of the total allowance proceeds collected. The remaining proceeds would be returned to the economy, possibly as rebates. As a result, the bill has the potential to compensate consumers to some extent for higher direct energy costs and the indirect impacts of higher prices for non-energy goods and services.