Legislation and Regulations

Introduction

Because analyses by the Energy Information Administration (EIA) are required to be policy-neutral, the projections in this *Annual Energy Outlook 2004* (*AEO2004*) are based on Federal and State laws and regulations in effect on September 1, 2003. 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 Energy Policy Conservation Act of 1975
- 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 Federal Highway Bill of 1998, which included an extension of the ethanol tax incentive
- The Maritime Security Act of 2002, which amended the Deepwater Port Act of 1974 to include offshore natural gas facilities
- 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.

AEO2004 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 2002 levels in nominal terms. *AEO2004* 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 *AEO2004* assumes their continuation throughout the forecast.

Examples of Federal and State regulations incorporated in *AEO2004* include the following:

- Standards for energy-consuming equipment that have been announced
- 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 liquefied natural gas (LNG) terminals.

AEO2004 includes the CAAA90 requirement of a phased in reduction in vehicle emissions of regulated pollutants. In addition, AEO2004 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. *AEO2004* also incorporates nitrogen oxide (NO_x) boiler standards issued by the U.S. Environmental Protection Agency (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.

AEO2004 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by the EPA in February 2000. The Tier 2 standards for reformulated gasoline (RFG) will be required by 2004 but will not be fully realized in conventional gasoline until 2008 due to allowances for small refineries. *AEO2004* 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 G for more detail).

Because the new rules for nonroad diesel have not yet been finalized, they are not reflected in the *AEO2004* projections. The *AEO2004* 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 *AEO2004* projections include only those equipment standards for which final actions have been taken and for which specific efficiency levels are provided.

The *AEO2004* reference case projections include impacts of the programs in the Climate Change Action Plan (CCAP)—44 actions developed by the Clinton Administration in 1993 to achieve the stabilization of greenhouse gas emissions (carbon dioxide, methane, nitrous oxide, and others) in the United States at 1990 levels by 2000. Of the 44 CCAP actions, 13 are not related either to energy combustion or to carbon dioxide and, consequently, are not incorporated in the *AEO2004* projections. Although CCAP no longer exists as a unified program, most of the individual programs, which generally are voluntary, remain.

The projections do not include carbon dioxide mitigation actions that may be enacted as a result of the Kyoto Protocol, which was agreed to on December 11, 1997, but has not been ratified or submitted to the U.S. Senate for ratification.

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

Corporate Average Fuel Economy Standards for Light Trucks

The regulation of fuel economy for new light vehicles was established through the enactment of the Energy Policy Conservation Act of 1975. The regulation of light truck fuel economy was implemented in model year 1979. Increases in light truck CAFE standards continued to be made through the 1980s and 1990s, reaching 20.7 miles per gallon for model year 1996. Thereafter, Congress prohibited any further increases in fuel economy standards.

Congress lifted the prohibition on new CAFE standards on December 18, 2001. On April 1, 2003, NHTSA published a final rule for increasing CAFE standards for light trucks (all pickup trucks, vans, and sport utility vehicles with gross vehicle weight rating less than 8,500 pounds). The new CAFE standard requires that the light trucks sold by a manufacturer have a minimum average fuel economy of 21.0 miles per gallon for model year 2005, 21.6 miles per gallon for model year 2006, and 22.2 miles per gallon for model year 2007. The new light truck CAFE standards are incorporated in *AEO2004*.

California Low Emission Vehicle Program

The Low Emission Vehicle Program (LEVP) was originally passed into legislation in 1990 in the State of California. It began as the implementation of a voluntary opt-in pilot program under the purview of CAAA90, which included a provision that other States could “opt in” to the California program to achieve lower emissions levels than would otherwise be achieved through CAAA90.

The 1990 LEVP was an emissions-based policy, setting sales mandates for three categories of vehicles: low-emission vehicles (LEVs), ultra-low-emission vehicles (ULEVs), and zero-emission vehicles (ZEVs). The mandate required that ZEVs make up 2 percent of new vehicle sales in California by 1998, 5 percent by 2001, and 10 percent by 2003. At that time, the only vehicles certified as ZEVs by the California Air Resources Board (CARB) were battery-powered electric vehicles [*1*].

The LEVP program incorporates the ZEV mandate, which has been revised and delayed several times. In December 2001, the CARB amended the LEVP to include ZEV credits for partial zero-emission vehicles (PZEVs) and advanced technology partial zero-emission vehicles (AT-PZEVs), phase-in credits for pure ZEVs, and additional credits for vehicles with high fuel economy. The ZEV sales mandates were also modified, increasing the ZEV sales requirement from 10 percent in 2003 to 16 percent in 2018. Auto manufacturers in 2002 filed Federal suits in both California and New York, arguing that the CARB revisions to the ZEV program were preempted by the Federal authority over vehicle fuel economy standards. In June 2002, a Federal judge granted a preliminary injunction that prevented the CARB from enforcing the ZEV regulations for model year 2003 and 2004 vehicles.

In April 2003, the CARB proposed further amendments (Resolution 03-4) to the ZEV mandates in response to the suit filed by auto manufacturers, and the manufacturers agreed to settle their litigation with the State of California. The proposed mandate places a greater emphasis on emissions reductions from PZEVs and AT-PZEVs and requires that manufacturers produce a minimum number of fuel cell and electric vehicles. The mandate now requires that ZEVs make up 10 percent of new vehicles sales in 2005, increasing to 16 percent in 2018 and thereafter. The amendment also includes phase-in multipliers for pure ZEVs and allows 20 percent of the sales requirement to be met with AT-PZEVs and 60 percent with PZEVs. AT-ZEVs and PZEVs are allowed 0.2 credit per vehicle. Given the acquiescence of auto manufacturers to the proposed amendments, they are incorporated in the *AEO2004* forecast.

California Carbon Standard For Light-Duty Vehicles

In July 2002, California Assembly Bill 1493 (A.B. 1493) was signed into law. The bill requires the CARB to develop and adopt, by January 1, 2005, a maximum feasible carbon dioxide pollution standard for light-duty vehicles. In estimating the feasibility of the standard, the CARB is required to consider cost-effectiveness, technological capability, economic impacts, and flexibility for manufacturers in meeting the requirement. The standard will apply to light-duty noncommercial passenger vehicles manufactured for model year 2009 and beyond. The bill does not mandate the sale of any specific technology but prohibits the use of the following as options for carbon dioxide reduction: mandatory trip reduction; land use restrictions; additional fees and/or taxes on any motor vehicle, fuel, or vehicles miles traveled; a ban on any vehicle category; a reduction in vehicle weight; or a limitation or reduction of the speed limit on any street or highway in the State. Consequently, A.B. 1493 will rely heavily on vehicle efficiency improvements or a switch to low-carbon fuels to achieve the carbon dioxide emission standard.

If it is determined that low-carbon alternatives are not a feasible solution, A.B. 1493 is likely to face considerable opposition from the auto industry, as evidenced by suits filed in 2002 against California's LEVP. Given that California has not yet set a specific carbon dioxide standard, and given the uncertainty surrounding the possible outcome of future standards, A.B. 1493 is not represented in *AEO2004.*

Regulation of Mercury and Fine Particulate Emissions

The EPA is currently developing regulations to reduce emissions of fine particulates and mercury from electric power plants. Efforts to reduce emissions of particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) began with the issuance of National Ambient Air Quality Standards (NAAQS) on July 16, 1997. Before then, only coarse particle emissions (10 microns and larger) were regulated.

The EPA and the States are now measuring fine particulate concentrations throughout the country to determine which areas are not in compliance with the $PM_{2.5}$, as required by the NAAQS. The EPA plans to make final designations identifying attainment and nonattainment areas by December 15, 2004 [*2*]. Following the EPA designations, States will have 3 years, until December 2007, to prepare State Implementation Plans (SIPs) identifying the steps they will take to bring nonattainment areas into compliance. The SIPs are likely to include plans to reduce emissions from power plants, cars, trucks, and various industrial sources. The States will generally have until 2009, 5 years from their designation, to bring nonattainment areas into compliance, but the deadline could be extended by 5 years under some circumstances. Until the final regulations and SIPs are in place, however, the full impacts on electricity generators will not be known.

On December 14, 2000, the EPA announced that regulating mercury emissions from oil- and coal-fired power plants as a hazardous air pollutant (HAP) under Section (112)(n)(1)(A) of CAAA90 is warranted. The EPA, which has been meeting with various stakeholder groups and reviewing the latest available data on mercury emissions control to develop emissions standards, plans to issue proposed standards on December 15, 2003, and final standards by December 14, 2004 [*3*]. Thereafter, electricity generators will have 3 years, until December 15, 2007, to comply. Although the new regulations are certain to have an impact, particularly on coal-fired plants, because SIPs have not been proposed, their effects are not known and are not reflected in *AEO2004*.

Extension of Deep Shelf Royalty Relief to Existing Leases

The Minerals Management Service (MMS) of the U.S. Department of the Interior [*4*] in March 2003 proposed a new rule that would extend to existing leases the same royalty relief that currently is provided for newly acquired leases, for natural gas production from wells drilled to deep vertical depth (below the "mudline") in the Outer Continental Shelf. Since March 2001, the MMS has provided royalty relief for production from wells drilled to 15,000 feet total vertical depth in newly acquired leases in the shallow waters (less than 200 meters of water depth) of the shelf. Royalty payments to the Federal Government are suspended for the first 20 billion cubic feet of such "deep shelf" production from wells beginning production within the first 5 years of a lease. The purpose of the new rule is to encourage more exploration in the deep shelf play [*5*], which has significant potential but presents substantial technical difficulties. Of the 10.5 trillion cubic feet of undiscovered resources in the deep shelf (as estimated by the MMS), about 6.3 trillion cubic feet is under existing leases. The proposed new rule would have granted relief for wells drilled after March 26, 2003. Leases currently eligible for royalty relief under the old rule may substitute the deep gas incentive of the new rule.

The proposed rule includes various levels of royalty relief. The first level covers wells drilled to at least 15,000 feet depth, providing relief on a minimum of 15 billion cubic feet of gas. A second level covers wells more than 18,000 feet deep, which would receive royalty relief on a minimum of 25 billion cubic feet. In addition, until a successful well is drilled, unsuccessful wells drilled to a depth of at least 15,000 feet would receive a royalty "credit" for 5 billion cubic feet of gas. Credits could be received for up to two wells. Thus, if two dry holes were drilled, the operator would accrue credits for 10 billion cubic feet, which could be added to the royalty relief for 15 billion cubic feet from a future, successful well drilled on the same lease. As of December 1, 2003, this proposal was still under review at the MMS. It is not included in *AEO2004*.

The Maritime Security Act of 2002 Amendments to the Deepwater Port Act

The Maritime Security Act of 2002, signed into law in November 2002, amended the Deepwater Port Act of 1974 to include offshore natural gas facilities. The legislation transferred jurisdiction for offshore natural gas facilities from the FERC to the Maritime Administration and the U.S. Coast Guard, both of which were at that time under the U.S. Department of Transportation. (The Coast Guard has since been moved to the Department of Homeland Security.)

The amendments in the Maritime Security Act of 2002 lowered the regulatory hurdles faced by potential developers of offshore LNG receiving terminals. Placing them under Coast Guard jurisdiction both streamlined the permitting process and relaxed regulatory requirements. Owners of offshore LNG terminals are allowed proprietary access to their own terminal capacity, removing what had once been a major stumbling block for potential developers of new LNG facilities. The Hackberry Decision, discussed below, has the same impact on onshore LNG facilities under FERC jurisdiction.

The streamlined application process under the new amendments promises a decision within 365 days of receipt of an application for construction of an offshore LNG terminal. Once the final public hearing on an application has been held, it must be either approved or denied within 90 days. The Maritime Administration will be responsible for reviewing the commercial aspects of the proposal, and the Coast Guard will consider safety, security, and environmental aspects.

Shortly after these changes went into effect, ChevronTexaco filed a preliminary application with the Coast Guard for its Port Pelican project, which was later approved. Plans for the project call for an LNG facility in 90 feet of water, with a baseload capacity of 800 million cubic feet per day. Subsequently, El Paso Natural Gas Company filed an application for its Energy Bridge project, which would use specialized tankers with on-board regasification equipment to offload regasified LNG through a submerged docking buoy into a pipeline to the mainland. AEO2004 incorporates the Deepwater Port Act amendments through reduced permitting costs and associated delays in such projects.

The Hackberry Decision

In December 2002, the FERC terminated open access requirements for new onshore LNG terminals in the United States, placing them on an equal footing with offshore terminals regulated under provisions of the Maritime Security Act of 2002. The FERC ruling, which granted preliminary approval to the proposed Dynergy/Sempra LNG terminal in Hackberry, Louisiana, is referred to as the Hackberry Decision. It authorized Hackberry LNG (now Cameron LNG) to provide services to its affiliates under rates and terms mutually agreed upon (i.e., market-based), rather than under regulated cost-of-service rates, and exempted the company from having to provide open access service. In essence, from a regulatory perspective, LNG import facilities will be treated as supply sources rather than as part of the transportation chain.

The LNG industry had been lobbying strongly for a relaxation of regulatory requirements, arguing that the FERC should focus on doing whatever it can to ensure that the United States has adequate natural gas supplies. Industry participants at a public conference hosted by the FERC in October 2002 on issues facing the natural gas industry maintained that the

Commission's open season [6] and open access requirements were a deterrent to the construction of new LNG terminals in the United States. They stressed that investors needed assurance that they would have access to terminal capacity, and that such assurance could not be given under the FERC's existing open season bidding requirements.

The FERC has specifically stated that it hopes the new policy will encourage the construction of new LNG facilities by removing some of the economic and regulatory barriers to investment. Existing terminals will continue to operate under open access and regulated rates, but FERC has indicated a willingness to allow them to modify their regulatory status as long as their existing customers are in agreement. AEO2004 incorporates the Hackberry Decision through reduced permitting costs and delays associated with LNG projects.

State Air Emission Regulations

Several States, primarily in the Northeast, 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, North Carolina, Massachusetts, Maine, New Hampshire, New Jersey, New York, and Oregon. The regulations govern emissions of NO_x, sulfur dioxide (SO_2), carbon dioxide (CO_2), and mercury from power plants. Table 2 shows emissions of NO_x, SO_2, and CO_2 by electricity generators in the eight States and in the rest of the country. Comparable data on mercury emissions by State are not available.

Where firm compliance plans have been announced, State regulations are represented in *AEO2004*. For example, the SO_2 scrubbers, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR) installations associated with the largest State program, North Carolina's "Clean Smokestacks Initiative," are included. As shown in Table 2, North Carolina accounts for nearly one-half of the emissions in the eight affected States. Overall, the *AEO2004* forecast includes 23 gigawatts of announced SO_2 scrubbers, 41.6 gigawatts of announced SCRs, and 4.5 gigawatts of announced SNCRs (both SCRs and SNCRs are NO_x removal technologies).

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 he 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.

Table 3 summarizes current State regulatory initiatives on air emissions, and the following section gives brief descriptions of programs in the eight States that have enacted air emission 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 examples: California's CO_2 pollution standards for 2009 model vehicles and those sold later; Georgia's transportation initiative, focusing on expanding 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; Texas's renewable portfolio standard program; and Wisconsin's greenhouse gas emissions inventory.

Table 2. Emissions from electricity generators in selected States, 2002 (tons)

State	*SO_2*	*NO_x*	*CO_2*
Connecticut	*10,814*	*5,100*	*7,827,884*
Massachusetts	*90,726*	*28,500*	*21,486,936*
Maine	*2,022*	*1,154*	*5,784,562*
New Hampshire	*43,946*	*6,826*	*5,556,992*
New Jersey	*48,268*	*27,581*	*12,440,663*
New York	*231,875*	*69,334*	*51,293,393*
North Carolina	*462,993*	*145,706*	*72,866,548*
Oregon	*12,280*	*8,840*	*7,607,557*
Subtotal	*902,925*	*293,039*	*184,864,534*
Rest of country	*9,287,292*	*4,068,670*	*2,240,690,001*
Total	***10,190,216***	***4,361,709***	***2,425,554,535***
Percent of total for selected States	*8.86%*	*6.72%*	*7.62%*

Connecticut. The Connecticut "Abatement of Air Pollution" regulation was enacted in December 2000. 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 [7]. 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 is enforced in two phases. Under Phase I, the limit for all NBP sources is 0.5 percent sulfur in fuel or 0.55 pound per million Btu of heat input by January 2002. The Phase II limit applies to all NBP sources that are also Acid Rain Program Sources, and the limit is 0.3 percent sulfur in fuel and 0.33 pound per million Btu by January 2003.

In May 2003, the Connecticut State legislature passed legislation requiring coal-fired power plants to remove 90 percent of their mercury (or a maximum of 0.6 pound 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 [8].

Connecticut is developing a climate change action plan that is designed to help meet the New England

Table 3. Existing State air emissions legislation with potential impacts on the electricity generation sector

State	*Activities*	*Emissions limits*
Connecticut	*"Abatement of Air Pollution" 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 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	*"An Act to Provide Leadership in Addressing the Threat of Climate Change," 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*
	Potential participant in Northeast CO_2 cap and trade program	
Massachusetts	*"Emissions Standards for Power Plants," multi-pollutant cap for existing power plants*	
	SO_2 emissions 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 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*
New Hampshire	*"Clean Power Act" for existing fossil-fuel power plants*	
	SO_2 emissions 1999: 48,000 tons	
	SO_2 cap 2006	*7,289 tons*
	NO_x emissions 1999: 9,000 tons	
	NO_x cap 2006	*3,644 tons*
	CO_2 emissions 1990: 5,426 thousand tons	
	CO_2 emissions 1999: 5,594 thousand tons	
	CO_2 cap 2006	*5,426 thousand tons*
New Jersey	*Greenhouse gas emissions 1990: 136 million metric tons carbon dioxide equivalent*	
	Greenhouse gas emissions 2005	*3.5% below 1990*
New York	*Title 6 NYCRR Parts 237 and 238 applicable to electric utilities, cogenerators, and industrial units*	
	SO_2 Phase I limit January 2005, 25% below allocation	*197,046 tons*
	SO_2 Phase II limit January 2008, 50% below allocation	*131,364 tons*
	NO_x limit beginning in October 2004	*39,908 tons*
North Carolina	*"Clean Smokestacks Act" for existing coal-fired plants only*	
	SO_2 emissions 1999: 429,000 tons	
	SO_2 cap 2009	*250,000 tons*
	SO_2 cap 2013	*130,000 tons*
	NO_x emissions 1999: 178,000 tons	
	NO_x cap 2009	*56,000 tons*
Oregon	*CO_2 for new or expanded power plants*	*675 pounds per megawatthour*

Governors/Eastern Canadian Provinces goal for CO_2 reduction (stabilization of greenhouse gas emissions at 1990 levels by 2010, and a 10-percent reduction from 1990 levels by 2020). The State is also a potential participant in the Northeast CO_2 cap and trade program. Modifications are being made to the current NBP rules to provide incentives in the form of allowances for renewable energy and energy efficiency programs [*9*].

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 May 2003. 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. The statute 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 between 75 and 80 percent below 2003 levels "in the long term." It authorizes the Department of Environmental Quality to adopt a State climate action plan by July 2004 to meet the goals of the statute [*10*].

Massachusetts. The Massachusetts Department of Environmental Protection air pollution control regulations (310 CMR 7.29, "Emissions Standards for Power Plants") [*11*] apply to existing power plants in Massachusetts. They would affect six older power plants. 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 the Clean Air Act Amendments of 1990 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 [*12*].

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). 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 governor of Massachusetts has sent a letter expressing interest in working with New York State to develop a cap and trade program for CO_2 emission reductions from power plants [*13*]. Data collection and feasibility assessment on mercury control are ongoing. Draft mercury regulations have been publicly released and are going through a comment period before consideration by the State legislature [*14*].

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 [*15*]. 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 other 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 (DES) are under review.

The SO_2 annual cap is 7,289 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 (see Table 3). The NO_x annual cap is 3,644 tons by 2006, which amounts to a 60-percent reduction from 1999 emission levels. The CO_2 annual cap is 5,425,866 tons by

2006, which amounts to a 3-percent reduction from 1999 levels. The Governor of New Hampshire has sent a letter expressing interest in working with New York State to develop a cap and trade program for reducing CO_2 emissions from power plants.

The mercury cap is to be determined after the U.S. Environmental Protection Agency (EPA) establishes a Maximum Achievable Control Technology (MACT) standard for mercury control, but no later than March 31, 2004. Emissions allowances from Federal or regional trading and banking programs can be used to comply with the State cap. For CO_2 and mercury, early reductions can be banked for future use. NO_x allowances can be pooled but cannot be applied to emissions between May and September. SO_2 allowances obtained under the Federal acid rain program can be used against the cap. The statute includes incentives for investment in energy efficiency, new renewable energy projects, conservation, and load management. It does not apply to utilities that have installed "qualifying repowering technology" or replacement units meeting certain pollution control criteria [*16*].

New Jersey. New Jersey's goal is to reduce State-wide 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 [*17*]. In January 2002, the U.S. Department of Justice, the U.S. EPA, and the State of New Jersey obtained a Clean Air Act Consent Decree involving Public Service Enterprise Group Fossil, LLC (PSEG). In addition to a $1.4 million monetary penalty to be paid to the Federal Government [*18*], the settlement commits PSEG to reduce SO_2, NO_x, and particulate matter emissions on all its coal-fired units, to retire SO_2 and NO_x allowances, and to undertake other environmental projects. This is a part of the Prevention of Significant Deterioration/New Source Review (PSD/NSR) enforcement effort. The Governor of New Jersey has also sent a letter expressing interest in working with New York to develop a cap and trade program for CO_2 emission reductions from power plants.

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 [*19*]. The NO_x regulations apply to electricity generators of 25 megawatts or greater, and the SO_2 regulations apply to all Title IV sources under the Clean Air Act [*20*], including electric utilities and other sources of SO_2 and NO_x, such as cogenerators and industrial facilities. NO_x emissions are limited to 39,908 tons beginning in October 2004. SO_2 emissions are limited in two phases: Phase I, beginning in January 2005, limits SO_2 emissions to 25 percent below Title IV allocations (197,046 tons), and Phase II, beginning in January 2008, increases the limits to 50 percent below Title IV allocations (131,364 tons) [*21*]. A governor's task force was established in June 2001 to recommend greenhouse gas limits. Further details on the recommendations of the Task Force are provided below.

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 coal-fired power plants in the State. Under the Act, North Carolina utilities must reduce NO_x emissions from 245,000 tons in 1998 to 56,000 tons by 2009 and SO_2 emissions from 489,000 tons in 1998 to 250,000 tons by 2009 and 130,000 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.

The Act requires the Department of Environment and Natural Resources to evaluate issues related to the control of mercury and CO_2 emissions and recommend the development of standards and plans to control them. In 2003, the Department of Air Quality has prepared a report on mercury [*22*] and CO_2 reductions for the State [*23*]. This is the first of three sets of reports submitted to the Environmental Management Commission and the Environmental Review Commission. The subsequent reports are due in September 2004 and September 2005. The objective of the 2003 report is to provide a 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. A proposed workshop being planned for spring 2004 will form the basis for the September 2004 report.

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 emission 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 8 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. Duke Power and Progress Energy have reported compliance costs for SO_2 and NO_x control. For the North Carolina utilities, SNCR costs range from \$4.93 to \$63.70 per kilowatt, and scrubber costs range from \$113 to \$414 per kilowatt [*24*].

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 [*25*]. For baseload natural gas plants and non-baseload plants, the standard is CO_2 emission rates of 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.

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 locations 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) [*26*]. This equates to an offset cost of 0.88 mills per kilowatthour [*27*].

New Source Review

On August 27, 2003, the EPA issued a final rule defining certain power plant and industrial facility activities as "routine maintenance, repair and replacement," which are not subject to new source review (NSR) under CAAA90. As stated by the EPA, "these changes provide a category of equipment replacement activities that are not subject to Major NSR requirements under the routine maintenance, repair and replacement (RMRR) exclusion" [*28*]. Essentially this means that power plants and industrial facilities engaging in RMRR activities will not be required to obtain State or EPA approval for those activities and will not have to install the "best available" emissions control technologies that might be required if NSR were triggered.

Although the RMRR exclusion is not new, in the past it has been evaluated on a case-by-case basis. The new rule attempts to give affected entities some regulatory clarity by defining the specific activities that qualify for the exclusion. The new rule "specifies that the replacement of components of a process unit with identical components or their functional equivalents will come within the scope of the exclusion, provided the cost of replacing the component falls below 20 percent of the replacement value of the process unit of which the component is a part, the replacement does not change the unit's basic design parameters, and the unit continues to meet enforceable emission and operational limitations" [*29*]. Knowing the costs and scope of any changes they are considering, industrial and power plant facility owners will be able to determine whether they might trigger NSR.

The potential impact of the new rule is unknown. During its development, some observers argued that uncertainty about whether actions under consideration would trigger NSR had led facility owners to forgo investments that might improve the efficiency, reliability, and/or capacity of their units, and that the change in rules could lead to significant increases in the efficiency of coal-fired power plants and their electricity production [*30*].

Even without the rule change, however, coal-fired generation has been increasing. For example, between 1990 and 2002 coal-fired generation in the electric power sector increased by 21 percent, while coal-fired capacity increased by only 2 percent. Clearly, operators have been able to maintain their coal-fired power plants and increase their output under the old rules. These revisions should enable coal plant operators to continue maintaining their plants and increase their use with less worry about triggering NSR. In *AEO2004*, coal-fired generation is projected to increase significantly as existing plants are used more intensively and new plants are added. No explicit changes to address the impacts of the new NSR rule have been made in *AEO2004*. As more data become available, they will be included in future *AEO*s.

The Energy Policy Act of 2003

The U.S. House of Representatives passed H.R. 6.EH, The Energy Policy Act of 2003 (EPACT03), on April 11, 2003. The Senate passed H.R. 6.EAS (the same bill it had passed in 2002) on July 31, 2003. A Conference Committee was convened to resolve differences between the two bills, and a conference report was approved and issued on November 17, 2003 [*31*]. The House approved the conference report on November 18, 2003, but a Senate vote on cloture failed, and further action has been delayed at least until January 2004.

Consistent with the approach adopted in the *AEO* to include only Federal and State laws and regulations in effect, the various provisions of EPACT03 are not represented in the *AEO2004* projections. This discussion focuses on selected provisions of the current version of EPACT03 that have, in EIA's estimation, significant potential to affect energy consumption and supply at the national level. Proposed provisions in the following areas are addressed:

- Tax credits, grants, low-income subsidies, mandatory standards, and voluntary programs that act to reduce the cost and use of energy in the buildings sectors
- Industrial programs providing tax credits for combined heat and power (CHP) generation, blended cement, and voluntary programs to reduce energy intensity
- Tax credits for alternative fuel vehicles
- Establishment of a renewable fuels standard
- Elimination of the use of methyl tertiary butyl ether (MTBE) in gasoline
- Elimination of oxygen content requirements for reformulated gasoline
- Creation of tax deductions and credits for small refiners to encourage the production of low-sulfur diesel fuels
- Ethanol and biodiesel tax credits
- Extension of royalty relief to natural gas production from deep wells on existing leases in shallow waters
- Establishment and funding of a research program for ultra-deepwater and nonconventional natural gas and other petroleum resources from royalty payments
- Section 29 tax credits for nonconventional fuels production
- Assistance for constructing the Alaska Natural Gas Pipeline
- Establishment of a series of tax credits for natural gas gathering, distribution, and high-volume pipelines and gas processing facilities
- Provisions to improve the reliability of the electricity transmission grid
- Tax incentives and other provisions to encourage generation from renewable and nuclear fuels.

End-Use Energy Demand

EPACT03 includes tax incentives, standards, voluntary programs, and other miscellaneous provisions that affect the end-use demand sectors. Provisions that affect the residential and commercial sectors (the buildings sectors) are discussed together, because many of the legislative proposals affect both sectors.

Buildings

EPACT03 contains several provisions designed to mitigate future energy consumption in the buildings sectors. They encompass a multifaceted policy approach, employing tax credits, grants, low-income subsidies, mandatory standards, and voluntary programs in an attempt to reduce both expenditures for and use of residential and commercial energy. Each of these approaches can yield different results in terms of program effectiveness.

Of all the provisions included in EPACT03, only the mandatory standards for products such as torchiere lighting and traffic signals (Section 133) force a direct impact on buildings sector energy use; the other provisions require homeowners, occupants, builders, and/or government officials to pursue a specific course of action to spur measurable energy savings. In terms of proposed tax credits, for the next 3 years, builders can claim $1,000 to $2,000 for each home built that meets certain efficiency criteria (Section 1305). Likewise, homeowners who upgrade the building envelopes of existing homes can claim a 20-percent tax credit (up to $2,000) from 2004 to 2006 (Section 1304).

Other provisions include production tax credits for efficient refrigerators and clothes washers through 2007, as well as credits for the installation of fuel cells, CHP systems, and solar thermal and photovoltaic equipment (Sections 1307, 1303, 1306, and 1301). Commercial businesses can also claim a tax deduction of $1.50 per square foot for expenditures on energy-efficient building property (Section 1308). In terms of subsidies, EPACT03 directs funding increases over the next several years for both the Low Income Home Energy Assistance Program (LIHEAP) and the Department of Energy's weatherization program (Sections 121 and 122), which could reduce future energy use by allowing more low-income homes to be weatherized. Other provisions update Executive Order mandates regarding Federal purchasing requirements and energy intensity reductions (Sections 102 through 104); allow for energy conservation measures in congressional buildings (Section 101); and establish a program to install photovoltaic energy systems in public buildings over the next 5 years (Section 205).

Several provisions of EPACT03 either are less specific in terms of what the future law might require or are difficult to assess and, therefore, have less certain impacts. They include the establishment of test procedures for several products (Section 133), programs to educate homeowners on the importance of maintaining heating and cooling equipment (Section 132), and grants to States for rebates on the purchase of energy-efficient products (Section 124).

Industrial

The industrial sector provisions of EPACT03 include tax credit programs for CHP, blended cements, and voluntary programs to reduce industrial energy intensity. Section 1306 would extend the current 10-percent business credit for solar power generation equipment to CHP systems. Qualifying equipment must have electrical capacity of not more than 15 megawatts or mechanical energy no greater than 2,000 horsepower. Qualifying equipment must produce at least 20 percent of its useful output as thermal energy and at least 20 percent as electricity. Such equipment must also have a system efficiency of at least 60 percent. The credit would be effective from December 31, 2003, to January 1, 2007. The tax credit would create an incentive to increase CHP generation, but that incentive would be diminished by the relatively small size limit for qualifying facilities. Further, the short time frame of the credit probably would limit CHP expansion to plants that would have been built in its absence.

Section 110 would encourage Federal agencies to require greater use of blended cements but does not specify the amount of blending that would be allowed. Generally, increasing the recovered mineral component would decrease the amount of new cement production required to produce a given output of concrete.

Section 107 would authorize the Secretary of Energy to enter into voluntary agreements with one or more persons in the industrial sector to reduce their energy intensity by a significant amount compared with recent years. This program appears similar to the existing Climate Vision program, which is part of the Administration's effort to reduce greenhouse gas intensity by 18 percent over the next decade [*32*].

Transportation

Present law provides a maximum tax deduction for alternative fuel motor vehicles of $50,000 for a truck or van weighing over 26,000 pounds and $2,000 for a vehicle weighing 10,000 pounds or less. In addition, current law provides a 10-percent tax credit toward the cost of a qualified electric vehicle, up to $4,000. The tax deductions and credit are scheduled to be phased out between January 1, 2002, and December 31, 2004.

Section 1317 of EPACT03 would extend the existing alternative fuel motor vehicle deduction through December 31, 2006; repeal an existing credit for electric fuel cell vehicles; and provide credits for the purchase of fuel cell powered motor vehicles, hybrid motor vehicles, mixed-fuel motor vehicles, and advanced lean-burn technology motor vehicles. Unused credits could be carried forward 20 years and would apply to hybrid and advanced lean-burn technology vehicles placed in service before 2008 and to fuel cell vehicles placed in service before 2012. Property placed in service after the enactment of EPACT03 could also receive the tax credits. Credits for hybrid and advanced lean-burn technology vehicles would be phased out after cumulative sales of the specific technology exceeded 80,000 units. Section 1318 specifies allowable tax credits by vehicle and fuel type.

Although EPACT03 does not prescribe a change in corporate average fuel economy (CAFE) standards, Section 772 sets out specific items that the Secretary of Transportation should consider when evaluating a potential increase, including technological feasibility, economic practicability, the effect of other government motor vehicles standards on fuel economy, the need of the United States to conserve energy, the effects of fuel economy standards on safety, and the effect of compliance on automobile industry employment. Further, Section 774 would require the Administrator of the National Highway Traffic Safety Administration to initiate a study no later than 30 days after enactment of EPACT03 to look at the feasibility and effects of requiring a significant percentage reduction in automobile fuel consumption beginning in model year 2012.

Petroleum, Ethanol, and Biofuel Tax Provisions

Numerous provisions of EPACT03 would affect the supply, composition, and refining of petroleum and related products. The major issues include:

- Establishment of a renewable fuels standard
- Elimination of MTBE
- Elimination of the oxygen content requirement for reformulated gasoline
- Small refiner deductions to encourage investment in low-sulfur fuel production
- Ethanol and biofuel tax provisions.

Renewable Fuels Standard

Section 1501 of EPACT03 requires the production and use of 3.1 billion gallons of renewable fuel in 2005, increasing to 5.0 billion gallons by 2012. For calendar year 2013 and each year thereafter, the minimum renewable fuels required would be determined by the volume percentage of 5.0 billion gallons over the total gasoline sold in the Nation in 2012. Small refineries with a capacity not exceeding 75,000 barrels per calendar year, and the States of Alaska and Hawaii, are exempted from the renewable fuels standard. Both ethanol and biodiesel are considered as renewable fuels, with a 1.5-gallon credit toward the renewable fuels standard for every gallon of biomass ethanol produced and a 2.5-gallon credit if the biomass ethanol is derived from agricultural residue or is an agricultural byproduct. A renewable fuels credit program would allow refiners, blenders, and importers flexibility to comply with the renewable fuels standard across geographical regions and successive years.

MTBE Phaseout

Section 1502 exempts MTBE and renewable fuels used in motor vehicles from being deemed "defective products." However, the exemption does not "affect the liability of any person for environmental remediation costs, drinking water contamination, negligence for spills or other reasonably foreseeable events, public or private nuisance, trespass, breach of warranty, breach of contract, or any other liability other than liability based on a claim of defect product." Section 1503 provides for transition assistance up to $250 million per year between 2005 and 2012 to merchant MTBE producers moving to production of iso-octane, iso-octene, alkylates, or renewable fuels. Section 1504 prohibits the use of MTBE after December 31, 2014, but trace quantities not exceeding 0.5 percent by volume are allowed. The Governor of a State may submit a notification to the EPA authorizing the continued use of MTBE, and the President of the United States may also void the MTBE restrictions by June 30, 2014, based on findings by the National Academy of Sciences on the costs and benefits of motor fuel additives, including MTBE.

Oxygen Requirement for Reformulated Gasoline

Section 1506 would eliminate the oxygen content requirement for reformulated gasoline. It would take effect 270 days after enactment of EPACT03, except for California, which would receive the exemption immediately. Volatile organic compound (VOC) Control Regions 1 and 2 for reformulated gasoline would be consolidated by eliminating the less stringent requirements applicable to gasoline designated for VOC Control Region 2 (northern).

Small Refiners

Section 1324 allows small refiners to deduct 75 percent of qualified capital expenditures in the year of the expense for costs related to compliance with the EPA's Tier 2 low-sulfur gasoline and highway diesel fuel requirements. The provision applies as a deduction for expenses incurred in a taxable year beginning after December 31, 2002. Gasoline sulfur reductions could be phased in between 2004 and 2007; diesel sulfur reductions would take effect starting in mid-2006.

Section 1325 of EPACT03 provides for a 5-cent-per-gallon tax credit to small refiners of low-sulfur diesel fuel (15 ppm or less) for expenses incurred after December 31, 2002. The total amount of the credit is limited to 25 percent of qualified capital costs incurred to reach compliance with EPA diesel fuel regulations, and no credit is allowed until the refiner obtains certification of compliance. The credit is reduced *pro rata* for refiners processing over 155,000 barrels per day but less than 205,000 barrels per day. It applies to organizations with no more than 1,500 individuals engaged in refinery business operations on any day during the year. For cooperative organizations, the credit can be apportioned among members. The effective period runs from January 1, 2003, to one year after the date the refiner must comply with EPA regulations, but no later than December 31, 2009.

Ethanol and Biofuel Tax Provisions

The current gasoline and highway diesel fuel excise taxes are 18.4 and 24.4 cents per gallon, respectively.

For each gallon of highway fuel, 0.1 cents is deposited in the Leaking Underground Storage Tank Trust Fund, and the balance is deposited in the Highway Trust Fund. Gasoline blended with 10 percent ethanol receives an excise tax reduction of 5.2 cents per gallon. Gasoline blended with 5.7 percent or 7.7 percent ethanol receives a proportionally smaller excise tax reduction. Under current law, if gasoline is blended with ethanol, the General Fund receives 2.5 cents, the Leaking Underground Storage Tank Trust Fund receives 0.1 cent, and the Highway Trust Fund receives the remainder.

Section 1314 would establish a biodiesel fuels credit analogous to the existing alcohol fuels income tax credit. A biodiesel mixture tax credit of 50 cents per gallon of biodiesel produced from recycled oil or $1 per gallon of biodiesel produced from virgin oil or virgin animal fat applies to biodiesel blended with petroleum diesel. A biodiesel credit in the same amount applies to each gallon of neat biodiesel. A taxpayer's biodiesel fuels tax credit is the sum of the biodiesel mixture credit and the biodiesel credit and is claimed against business income tax. The credit would be effective from December 31, 2003, through December 31, 2005.

Section 1315 would give fuel blenders the options of the alcohol fuel mixture excise tax credit and the biodiesel fuel mixture excise tax credit. Gasoline blended with renewable-source alcohol or ethers produced from renewable-source alcohol would be taxed at the full 18.4 cents per gallon. Diesel blended with biodiesel would be taxed at the full 24.4 cents per gallon. A tax credit of 52 or 51 cents per gallon of ethanol blended into gasoline or used to produce ethyl tertiary butyl ether blended into gasoline would be paid out of the General Fund. Receipts to the Highway Trust Fund would not be reduced by the use of ethanol in gasoline if blenders choose these credits. The credit is 60 cents per gallon of alcohol other than ethanol (such as methanol) derived from renewable sources. The excise tax credit for biodiesel is 50 cents per gallon of biodiesel from recycled oil or $1 per gallon of biodiesel from virgin oil or virgin animal fat. The excise tax credits cannot be claimed for alcohol or biodiesel for which an income tax credit is claimed or which are taxed at a reduced excise tax rate. The new alcohol excise tax credits would be available through December 31, 2010, and the new biodiesel excise tax credit would be available through December 31, 2005.

The current alcohol fuels income tax credit includes the alcohol mixture credit, the alcohol credit, and the small ethanol producer credit. Gasoline blended with ethanol qualifies for an alcohol mixture credit of 52 or 51 cents per gallon. Gasoline blended with an alcohol other than ethanol qualifies for an alcohol mixture credit of 60 cents per gallon. Alcohol tax credits in the same amount apply to fuel alcohols not blended with gasoline. A small ethanol producer qualifies for an additional credit up to 10 cents per gallon for annual production of 15 million gallons or less. Small ethanol producers currently cannot have production capacity above 30 million gallons per year. Section 1313 would raise the capacity limit to 60 million gallons per year. Section 1315 would move the expiration date of the alcohol fuels income tax credit from December 31, 2007, to December 31, 2010.

Natural Gas Supply Provisions

EPACT03 includes a number of provisions that would affect natural gas supply, including:

- Extension of royalty relief to natural gas production from deep wells in shallow waters
- Establishment of a research program covering ultra-deepwater offshore and unconventional natural gas and petroleum resources and funding from existing royalties
- Extension and modification of the Section 29 tax credit for nonconventional production
- Assistance for constructing the Alaska Natural Gas Pipeline
- Tax incentives for natural gas gathering and distribution
- Tax incentives for high-volume natural gas pipelines and gas processing facilities.

Royalty Relief for Natural Gas Production from Deep Wells in the Shallow Waters of the Gulf of Mexico

Section 314 of EPACT03 would authorize the Secretary of Energy to publish a final regulation to complete the rulemaking begun by the Notice of Proposed Rulemaking entitled "Relief or Reduction in Royalty Rates—Deep Gas Provisions," published in March 2003. The rule would grant various levels of royalty relief for wells drilled within the first 5 years of a lease in the shallow waters (less than 200 meters) of the Gulf of Mexico. The minimum volume of production with suspended royalty payments is 15 billion cubic feet for wells drilled to at least 15,000 feet and 25 billion cubic feet for wells drilled to more than 18,000 feet. In addition, unsuccessful wells drilled to a depth of at least 15,000 feet would receive a royalty tax credit for 5 billion cubic feet of natural gas. Credits could be received for up to two wells.

Section 314 would further grant royalty suspension volumes of not less than 35 billion cubic feet from ultra-deep wells on leases issued before January 1, 2001. An ultra-deep well is defined as a well drilled to at least 20,000 feet.

Funding and Establishment of a Research Program for Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources

Sections 941 through 949 would provide for the establishment of a research program covering the ultra-deepwater offshore and unconventional natural gas and petroleum resources (onshore) to advance activities related to development, demonstration, and commercialization of new technologies.

A separate fund will be established in the U.S. Treasury under this provision. Program funding will consist of $150 million annually from Federal royalties, rents, and bonuses for each fiscal year from 2004 through 2013. In addition, another $50 million for each corresponding year is authorized is to be appropriated by Congress, and the funds will remain available until expended. Total program impacts range from $1.5 billion to $2.0 billion over the 10-year period, representing more than a doubling of current annual funding for research.

Amounts obligated from the fund will be allocated in each fiscal year as follows. One-half of the funds shall be for activities under Section 942 for an ultra-deepwater program. A nonprofit, tax-exempt consortium will be selected and awarded a contract to perform authorized research activities in this offshore area. The next 35 percent of the funds are allotted for activities under Section 943(d)(1), which includes work related to coalbed methane, deep drilling, natural gas production from tight sands, stranded gas, innovative exploration and production techniques, enhanced recovery techniques, and environmental mitigation of unconventional natural gas and exploration and production of other petroleum resources. The next 10 percent of the funds shall be for activities under Section 943(d)(2) and awarded to consortia of small producers focusing on changes in complex geology and reservoirs, low reservoir pressure, unconventional natural gas reservoirs in coalbeds, deep reservoirs, tight sands, and shales as well as unconventional oil reservoirs in tar sands and oil shales. The remaining 5 percent of the funds are allocated under Section 941(d) to corresponding research activities at the National Energy Technology Laboratory.

Extension and Modification of the Section 29 Tax Credit for Producing Fuel from a Nonconventional Source

Section 1345 of EPACT03 would extend and modify the Section 29 tax credit for producing fuel from nonconventional sources. It would allow a credit of $3 (indexed for inflation with 2002 as the base year) per barrel (or Btu equivalent) for production from all nonconventional sources except landfills for 4 years of production prior to 2010 for new wells placed in service through 2006. Production from existing wells (drilled in 1980-1992), previously eligible through 2002, would also be eligible for the credit through 2006. For landfills regulated by the EPA there would be a credit of $3 for facilities placed in service after June 30, 1998, and before January 1, 2007. These facilities would be eligible for 5 years of credit. The credit in Section 1345 would be limited to an average daily production of 200,000 cubic feet of gas (or oil equivalent) per well or facility. The credit would be fully effective when the price of crude oil is $35 per barrel or less and would phase out gradually as the price rises to $41 per barrel.

Assistance for Constructing the Alaska Natural Gas Pipeline

Section 386 of EPACT03 would give the Secretary of Energy authority to issue Federal loan guarantees for any natural gas pipeline system that carries Alaskan natural gas to the border between Alaska and Canada south of 68 degrees north latitude. This authority would expire 2 years after the final certificate of public convenience and necessity is issued. The 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); or (3) a term of 30 years. Other assistance for construction of the Alaska Natural Gas Pipeline would be provided by the tax incentives for natural gas gathering, high-volume natural gas pipelines, and gas processing summarized below.

Tax Incentives for Natural Gas Gathering and Distribution

Section 1321 would provide a 7-year recovery period for natural gas gathering lines, as opposed to the current 15-year recovery period, for tax purposes. It also would allow for alternative minimum tax relief by not adjusting the allowable amount of depreciation. The treatment would apply to property placed in service after the date of enactment. The Joint Committee on Taxation estimates the negative effect on the budget from the provision at $16 million from 2004 to 2013.

Section 1322 would provide a 15-year recovery period for natural gas distribution lines, as opposed to the current 20-year recovery life available for taxpayers. The provision would be effective for property placed in service after the date of enactment.

Tax Incentives for High-Volume Natural Gas Pipelines and Gas Processing Facilities

Section 1355 would allow a 7-year recovery period for natural gas pipelines with a pipe diameter of at least 42 inches, and any related equipment, as opposed to the current 15-year recovery life available for taxpayers. The provision would be effective for property placed in service after the date of enactment. An Alaska pipeline to Canada is expected to satisfy the 42-inch requirement.

Section 1356 would extend 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 1 trillion Btu per day pipeline and produces carbon dioxide for injection into hydrocarbon-bearing geological formations. A gas treatment plant on the North Slope that feeds gas into an Alaska pipeline to Canada could be built to satisfy this requirement. The provision would be effective for costs incurred after 2003.

Electricity Provisions

EPACT03 includes provisions targeted at improving the reliability and operation of the electricity transmission grid; investment tax credits for "basic" and "advanced" clean coal generating technologies; tax provisions, targeted programs, and changes in regulatory structure to support the introduction of renewable electricity generation; and nuclear production tax credits.

Reliability and Operation of the Grid

The electricity title of EPACT03 contains numerous provisions aimed at improving the reliability and operation of the electricity grid, encouraging additional investment in critical grid infrastructure, and revising rules on utility ownership structure and power purchase requirements. For example, to improve reliability, it calls for the creation of mandatory grid reliability standards to replace the voluntary standards that exist today. These standards would be administered by new "electric reliability organizations," which are to be certified by the Federal Energy Regulatory Commission (FERC) and responsible for developing and enforcing reliability standards for their regions. Subject to FERC approval, electric reliability organizations can propose and modify reliability standards and issue fines to those who violate them.

To improve grid operation, EPACT03 calls for open nondiscriminatory access to the grid for all market participants. In other words, transmission-owning utilities are required to offer grid services to others under the same terms and conditions that they provide for themselves. The bill would call for FERC to reconsider its standard market design, and no final rule would be issued before October 31, 2006. However, through a sense of the Congress provision, utilities engaging in interstate commerce would be encouraged to voluntarily join regional transmission organizations. The bill states that regional transmission organizations are needed "in order to promote fair, open access to electric transmission service, benefit retail consumers, facilitate wholesale competition, improve efficiencies in transmission grid management, promote grid reliability, remove opportunities for unduly discriminatory or preferential transmission practices, and provide for the efficient development of transmission infrastructure needed to meet the growing demands of competitive wholesale power markets."

To stimulate investment in the Nation's transmission grid, the bill would give the Secretary of Energy the authority to designate national interest electric transmission corridors in areas experiencing transmission constraints or congestion. Once an area has been designated a national interest electric transmission corridor, within certain limitations, the FERC could issue a permit to modify existing or construct new transmission infrastructure. The goal of these provisions is to expedite the review, permitting, and construction of needed grid enhancements. The FERC would also be required to develop incentive rate structures for transmission pricing and to provide incentives for investments in advanced transmission equipment.

EPACT03 also calls for key changes in the Public Utility Holding Company Act of 1935 (PUHCA) and the Public Utility Regulatory Policies Act of 1978 (PURPA). PUHCA places significant limitations on the corporate structure and geographic scope of utility companies. It does not allow utility holding companies to own noncontiguous utilities and limits their investments outside the utility business. EPACT03 would repeal PUHCA but require that public utility holding companies provide Federal and State regulators access to their books. PURPA was enacted to promote alternative energy sources and energy efficiency, and to diversify the electric power industry. One of its key provisions required utilities to purchase power from qualifying cogeneration and small power production facilities. EPACT03 would remove the purchase requirement for new qualifying facilities, provided that the facility has open access to transmission services and wholesale energy markets.

Key Coal-Fired Electricity Provisions

EPACT03 provides investment tax credits for two specific categories of new coal-fired generating capacity. New coal-fired generating units employing "basic" clean coal technologies—such as advanced pulverized coal, fluidized bed, or integrated gasification combined cycle—are eligible for a tax credit that amounts to 15 percent of the basis of the property placed in service during a specific year. The tax credit for this category of coal plants applies to new facilities placed in service before January 1, 2014, and is limited to a national cap of 4,000 megawatts.

New coal-fired generating units employing "advanced" clean coal technologies are eligible for a tax credit that amounts to 17.5 percent of the basis of the property placed in service during a specific year. The "advanced" technologies include primarily the same technologies specified for the "basic" category, but they must meet both a higher standard for energy conversion efficiency and a cap on carbon emissions. The tax credit for this category of coal plants applies to new facilities placed in service before January 1, 2017, and is limited to a national cap of 6,000 megawatts.

Key Renewable Electricity Provisions

EPACT03 contains three types of provision that would affect renewable electricity markets: tax provisions, authorized programs, and changes to regulatory structures. The primary tax provisions relate to the renewable electricity production tax credit, which currently provides a tax credit of 1.8 cents per kilowatthour for 10 years from the initial online date of wind energy and qualifying biomass facilities entering service by December 31, 2003. EPACT03 would extend the eligibility period for the credit through December 31, 2006, and expand the program to include new biomass feedstocks, biomass co-firing facilities, geothermal facilities, solar power, and power from small irrigation systems. Facilities using "closed-loop" biomass supplies (energy crops grown specifically for energy production), either in dedicated use or in co-firing, would be eligible for the full credit value, but facilities using "open-loop" biomass resources (waste or byproducts from other processes) would receive a credit reduced by 33 percent for the first 5 years of operation from the initial online date. Co-firing facilities would receive the credit pro-rated to the thermal content of the biomass fuel. The tax credit and payment period would also be reduced for some of the other newly eligible technologies. Also, the credit would be allowed to reduce Alternative Minimum Tax payments, which should increase its value to project owners subject to Alternative Minimum Tax liability.

Authorized programs, including direct subsidies, research and development activities, and other programs to support renewable electricity, would be established with maximum allowable funding levels; however, actual execution of the programs would depend on annual budget appropriations. Newly authorized programs would include a direct production incentive payment for some new and incremental hydroelectric power facilities; a direct subsidy to encourage the use of forest thinnings for power production; and new research and development programs, such as the use of concentrating solar power to produce hydrogen.

Changes to regulatory structures would affect both hydroelectric licensing and geothermal leasing. The hydroelectric licensing revisions would allow license applicants to propose alternatives to proposed Federal agency fishway and other license conditions. Leasing and royalty procedures for use of geothermal resources on Federal lands would also be streamlined.

Nuclear Electricity Production Tax Credit

EPACT03 introduces a production tax credit for generation from advanced nuclear power facilities, similar to that in existence for renewables. The provision provides a tax credit of 1.8 cents per kilowatthour for the first 8 years of operation by qualified nuclear facilities. (Unlike the renewable provision, the credit is not adjusted for inflation.) Qualifying facilities must enter service after enactment of the bill and by December 31, 2020. There is a national capacity limitation of 6,000 megawatts; the bill does not specify the allocation of the limit but leaves it to the discretion of the Secretary of Energy. The provision also puts a limit of $125 million per 1,000 megawatts of capacity on the annual credit that can be received by any facility.