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Analyses of Selected Provisions of Proposed Energy Legislation: 2003

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Preface

On July 31, 2003, Sen. Byron L. Dorgan requested that the Energy Information Administration (EIA) perform a quantitative analysis of the energy consumption and oil savings that would result from the Senate (H.R.6.EAS) and House (H.R.6.EH) energy bills in support of the Senate and House conferees. This report responds to that request by summarizing EIA's analysis of those provisions that have the largest potential to affect energy consumption and supply.

In order to provide this report in time for the Conference Committee review, EIA could not provide a complete analysis of all of the various provisions in each bill. The quantitative estimates discussed in this report are drawn from EIA analyses of proposed energy legislation over the past two years. The provisions modeled do not always correspond exactly to the text in the current bills, but in most cases the impacts would be similar to those provided in this report. An exception may be natural gas markets, where recent data have indicated that EIA's past projections of natural gas prices may be optimistic. Some additional provisions, not previously analyzed, are also covered, though mostly qualitatively.

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

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

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Executive Summary

This report was prepared at the request of Senator Byron L. Dorgan, a member of the Senate Committee on Energy and Natural Resources, to support the deliberations of the Senate and House energy bill conferees on H.R.6.EAS and H.R.6.EH. Senator Dorgan requested the Energy Information Administration (EIA) to perform a quantitative analysis of the energy savings and import reductions that would result from the Senate and House energy bills.

In order to provide this report in time for the conference committee review, EIA could not provide a complete analysis of all of the various provisions in each bill. This report primarily summarizes the findings in previous EIA analyses of earlier legislation with similar provisions. The lack of analysis on some provisions should not be interpreted as reflecting any EIA judgment regarding their relative importance or potential impact.

The earlier analyses discussed in this report were completed in 2002 and 2003, and some are based on energy market data from late 2001. Consequently, the analyses presented here are indicative of the direction and magnitude of the impacts of the proposed legislation, but they do not necessarily reflect the impacts that would result from new analyses of current legislative provisions based on the most recent available data and new long-run projections that are now being developed for release in November. For example, natural gas markets have recently faced concerns regarding the adequacy of natural gas supplies to the lower-48 market, with record low levels of working gas in storage at the end of the 2002-2003 winter season, and wellhead prices that, while declining, remain far above those typical of experience over the past decade. If these trends continue and change the longer-term view of natural gas prices, some of the effects of the proposed bills could be quite different than those presented here.

Because this report draws on earlier analyses, a variety of different Reference Cases reflecting the *Annual Energy Outlook 2002*, the *Annual Energy Outlook 2003*, or mid-year updates to those reports, are used as the jumping-off point for the analysis of specific provisions. Some of these previous analyses assume that new provisions were enacted in 2002 or early in 2003, in some cases resulting in reported impacts for those years that would not occur if the provisions were enacted now. Generally, the pattern and size of impacts, rather than their timing, will be of primary interest to users of this report. Users may also want to focus on differences in estimates with and without the modeled provisions rather than on the absolute levels of energy market prices or quantities in either the Reference or policy cases.

Even without the time limitation for this report, it would be extremely difficult to provide a detailed quantitative analysis of all the provisions of the bills. Some of the provisions address very small segments of energy markets, where detailed data are not available. Also, the energy model used for this analysis, the National Energy Modeling System, does not necessarily segment markets to the level of detail required for some of the provisions. For example, the bills provide a business tax credit for builders of energy-efficient homes, but the model does not distinguish consumer choice between builders and homeowners. The bills also include some provisions that are not completely specified, such as new equipment standards that are called for but no efficiency levels provided. In addition, some provisions call for voluntary initiatives and for additional funding for research and development (R&D) efforts, for which detailed quantitative analysis of market impacts is very difficult.

The provisions covered in this report were analyzed separately. Combined, certain provisions could have synergistic or offsetting impacts. One example is that efforts to increase energy efficiency reduce the future growth in electricity demand, thus creating a smaller market for more advanced or renewable generation technologies. As a result, the impacts are not necessarily additive.

Although additional provisions of the bills are discussed in the report, a summary of those provisions that have the greatest impact follows.

End-Use Energy Demand

Buildings

Tax Credit for Qualifying Residential Energy-Efficient Property (House 41001, Senate 2103). Tax credits for residential energy-efficient property in the Senate bill are projected to save 37 trillion British thermal units (Btu) of delivered energy through 2007 relative to the Reference Case, less than 0.1 percent of projected residential energy use over the period. Negligible energy savings are projected due to the House bill because the comparable House provision limits residential tax credits to solar water heaters and photovoltaic equipment.

Tax Credit for Energy-Efficiency Improvements in Existing Homes (House 41004, Senate 2109). The impact of tax credits for expenditures on building envelope improvements in existing homes will vary depending on the age and location of the home. However, in inefficient homes these tax credits could reduce heating and cooling energy use substantially by replacing old building components (e.g. windows) with the most efficient available. While data limitations make it impossible to develop a detailed estimate of the impact of the tax credit, this provision has the potential for relatively large energy savings when compared to other provisions. It is expected that the House version of the provision would result in greater energy savings since the Senate tax credit is smaller, a 10-percent credit with a $300 maximum compared to a 20-percent credit with a $2,000 maximum, even though the Senate version allows credits for heating and cooling equipment, in addition to building components.

Business Tax Credit for Construction of New Energy Efficient-Homes (House 41005, Senate 2101). A tax credit for builders who install energy-efficient heating and cooling appliances and building envelope components in new homes is likely to lead to a greater number of homes being built meeting these specifications than would a tax credit offered to home purchasers. Building a new home following the specifications in the provision could achieve a 30-percent increase in efficiency and save about 15 million Btu of energy per year per home. If all homes built in a given year met the specifications outlined in the House bill, these homes would save an aggregate of approximately 24 trillion Btu annually relative to an alternative that maintains efficiency at the current average level for new homes built today. Annual energy savings would continue to grow as additional efficient homes are added to the housing stock during the time period of the tax credit. However, given the short time period allowed for the tax credit, it is not likely that any long-term “market transformation effect,” or the continued construction of more efficient homes after the tax credits expire, would occur. The House provision is expected to save more energy then the Senate provision, given its higher tax credit.

Tax Credit for Combined Heat and Power (House 41006, Senate 2108). A 10-percent tax credit included in the bills for commercial combined heat and power (CHP) property could result in a projected 56-megawatt (MW) increase in CHP capacity over the 2003 to 2006 period specified in the Senate bill, compared to total commercial CHP capacity of 1,158 MW in 2006 in the Reference Case. CHP fuel requirements result in a slight increase in projected site-specific energy delivered energy consumption, while carbon dioxide emissions attributable to the commercial sector are projected to decline slightly compared to the Reference Case. The shorter effective time period of the House provision is expected to reduce the impact of the proposed credit.

Product Standards (House 11044, 11045, Senate 924, 928). A proposed 190-watt standard for torchieres included in the bills for energy-efficiency standards and test procedures could save 10 billion kilowatthours in annual residential electricity use in 2020 relative to the Reference Case. The savings represent 0.6 percent of total residential electricity sales in 2020. Additional standards for other equipment are specified, but the efficiency levels are not provided in the bills.

Use of Photovoltaic Energy in Public Buildings (House 11011, Senate none). A House amendment establishing a photovoltaic energy commercialization program to install at least 150 MW in public buildings during the 2004 to 2008 time period is projected to reduce commercial delivered energy use by 1.0 trillion Btu in 2008 relative to the Reference Case, about 0.1 percent of 2001 Federal energy consumption. Through 2020, cumulative savings reach 19.4 trillion Btu relative to Reference Case projections.

Industrial

Tax Credit for Combined Heat and Power (House 41006, Senate 2108). A 10-percent tax credit included in the provisions for qualifying CHP facilities is projected to increase industrial CHP capacity by 490 MW, compared with total industrial capacity of 26.1 gigawatts in the Reference Case in 2006. Total industrial sector carbon dioxide emissions, including emissions attributable to electricity purchases, are reduced by 0.4 million metric tons carbon equivalent over the 2003 to 2006 period due to the higher efficiency of CHP relative to central station electricity generation.

Transportation

Corporate Average Fuel Economy Standards (House 18001-18002, Senate 801-803). The current House and Senate bills do not specify an increase to the current corporate average fuel economy (CAFE) standards, although both request analyses that would determine a feasible increase to the current standards. It is not readily apparent that enactment of either provision would result in the adoption of more stringent CAFE standards than those that would occur in the absence of revisions to existing law. Chapter 2 provides a discussion of the energy and economic impacts associated with previous analyses of proposed CAFE standards.

Oil and Gas Supply

Nonconventional Fuels (House 43005, Senate 2310). The House bill provides a credit of $3 per barrel on a Btu equivalent basis, or 50 cents per thousand cubic feet (mcf), inflation-adjusted, for the first 4 years of natural gas production prior to 2010 for new wells placed in service through 2006 and for existing wells drilled between 1980 and 1992 from Devonian shales, coal seams, and tight formations. Compared to the Reference Case, this credit would increase cumulative natural gas production by 1.4 trillion cubic feet (tcf), or 2.9 percent, and decrease cumulative net imports by 0.6 tcf, or 1.5 percent, from 2003 to 2010. On average, wellhead prices are projected to be 7 cents per mcf, or 2.8 percent, lower than in the Reference Case from 2003 to 2010. The Senate-proposed credit, which is limited to only new wells and provides a credit period of only 3 years, would have less impact on both production and prices. This analysis was based upon prevailing market conditions in late 2001. Since that time, natural gas prices have been significantly higher. If the higher prices continue, the effects of the proposed credits could be less because the credit is reduced if the sale price exceeds $4.04 per mcf (2002 dollars).

Drilling in the Arctic National Wildlife Refuge (House 30401-30412, Senate none). Based on the mean reserve scenario provided by the United States Geological Survey (USGS), opening the Coastal Plain area of the Arctic National Wildlife Refuge (ANWR) to crude oil production is projected to increase oil production by 0.8 million barrels per day in 2020, compared to 5.6 million barrels per day in the Reference Case. This results in an equivalent decrease in U.S. oil imports, reducing the dependence on imported oil from 62 percent to 60 percent in 2020. The projected production from ANWR represents about 0.7 percent of projected world oil production in 2020.

Alaska Natural Gas Pipeline (House none, Senate 710 and 2503). The early introduction of an Alaska natural gas pipeline in 2013, rather than 2020, due to tax incentives in the Senate-passed bill (H.R.6.EAS) is expected to reduce lower-48 cumulative production over the 2013 to 2025 time period by 6.0 tcf (2.0 percent) and cumulative net imports by 3.3 tcf (3.8 percent). The early introduction of the pipeline results in a 25 cents per mcf reduction in the average lower-48 wellhead price in 2015. As a result of generally lower prices, consumers are expected to save 19.7 billion (2001 dollars) over the same period, while consuming 1.8 additional tcf of natural gas (a 0.4-percent increase). However, at the same time, revenues to lower 48 producers are expected to decline by 48 billion (2001 dollars), resulting in reduced Federal royalty receipts. Based on projected annual average lower-48 wellhead prices, the tax credit in the Senate-passed bill is not expected to take affect. However, actual Treasury impacts of the tax credit will depend on monthly natural gas prices at the AECO-C hub, which are expected to continue to be volatile in the future, as they have in the past. Additional indirect Federal budget impacts may also result from relative increases in the level of economic activity and tax revenue collections from the pipeline project itself and economic benefits to gas consumers that may be reflected in increased economic activity as a result of increased gas consumption and lower prices. Under alternative assumptions regarding future natural gas prices or the time needed to carry out the project, the pipeline might enter service earlier than 2020 without incentives or later than 2013 with them.

Alternative Motor Vehicle Fuels Credit (House none, Senate 2004). The Senate provision for a retail sales credit for alternative motor fuels through 2006 would raise the share of fuel consumed by the alternative fuel vehicles by 0.07 percentage points in 2006, about 5 thousand barrels per day oil equivalent. Currently, the alternative fuels covered in the bill amount to less than 0.3 percent of total fuel consumption in the transportation sector. Consumption of compressed natural gas would increase by 7 percent, liquefied petroleum gas by 59 percent, and E85, a mixture of 85-percent ethanol and 15-percent gasoline, by 28 percent in 2006.

Electricity Supply

Renewable Portfolio Standard (House none, Senate 264). The Senate bill establishes a renewable portfolio standard (RPS) and credit trading system, increasing the percent of electricity generated from qualifying renewable resources to 10 percent by 2019. Both bills extend the current production tax credit for certain renewable generation. It is expected that between 32 and 38 gigawatts of additional renewable capacity above the amount in the Reference Case will be built through 2020, mostly wind and biomass, depending on whether the 1.5-cent-per-kilowatthour credit is indexed to inflation or not. In the Reference Case, 14 gigawatts of renewable capacity are added through 2020. The RPS causes a small increase in electricity prices and industry costs, which is partially offset by reduced natural gas prices for all consumers. In 2025, the RPS increases total end-use expenditures for electricity and natural gas by two-tenths of 1 percent.

Clean Coal Incentives (House 3117, Senate Title XXII, 2201-2221). As natural gas prices rise overtime, EIA expects new coal-fired plants to become more economical over time. Approximately 77,000 megawatts of new coal capacity is projected to be built between 2001 and 2025, including 4,000 megawatts of advanced coal technologies, which is 1 percent of the total generation capacity added in that time. The investment tax credits and production tax incentives for clean coal technologies in the House and Senate bills could accelerate the development of some of the expected new plants and cause some developers to chose advanced technologies rather than conventional technologies. If fully successful, the House bill could result in as much as 7,500 megawatts of new clean coal capacity, which is the limit on the capacity receiving the tax credit. The Senate bill could lead to 8,000 megawatts (4,000 megawatts of new capacity and 4,000 megawatts of retrofitted, refurbished and/or replaced capacity), the limit receiving the credit in the Senate bill.

Ethanol, Biodiesel, and Renewable Fuels

Renewable Fuels Standards and Elimination of MTBE (House 17101-17104, Senate 820, 833, and 834). A renewable fuels standard (RFS) of 5 billion gallons with a nation-wide phase-out of methyl tertiary butyl ether (MTBE), as required by the Senate bill, would result in a larger price impact on gasoline than an RFS alone, as required by the House bill. Under the Senate bill, for example, the average price of reformulated gasoline (RFG) would increase by about 3.6 cents per gallon relative to the case with the current ban on MTBE in 17 States by 2004. Under the House bill, the average RFG price would increase by about 1 cent per gallon. The national average price of gasoline, including all grades, would show a smaller impact from the RFS, less than 1 cent per gallon under the Senate bill and less than 0.5 cents per gallon under the House bill since the ethanol can be used in conventional gasoline in this case. Fuel demand is also likely to be affected, since increased gasoline prices translate into lower demand. By 2013, total petroleum products demand is expected to be about 40,000 barrels per day less under the Senate bill, but not much less under the House bill. All of the price and demand impacts cited above assume the indefinite continuation of ethanol tax credits, presently set to expire in 2007. Without such an extension, national average gasoline prices would be 1 to 1.5 cents per gallon higher under an RFS.

Biodiesel Incentives (House none, Senate 2008). The Senate-proposed excise tax exemption for soybean and yellow grease biodiesel, in conjunction with the Department of Agriculture's Commodity Credit Corporation grants, is expected to result in an increase in biodiesel production for the fiscal years 2004 to 2006. Currently, 60 to 80 million gallons of dedicated annual capacity exists, but another 200 million gallons of capacity, which could produce biodiesel, is used for other purposes. Much of this capacity could be converted to biodiesel given the incentives. These incentives are expected to increase biodiesel production to about 120 million gallons in 2004, compared to 33 million gallons without the incentives. However, because these programs are temporary, these increases are not likely to be sustainable.

1. Background and Scope of the Analysis

On July 31, 2003, Sen. Byron L. Dorgan, a member of the Senate Committee on Energy and Natural Resources requested the Energy Information Administration (EIA) to perform a quantitative analysis of the energy consumption and oil savings that would result from the Senate and House energy bills.[1] Specifically, EIA was requested to analyze the legislative text in H.R.6 as specified in the House (H.R.6.EH) and Senate (H.R.6.EAS), referred to as the House bill and Senate bill, respectively. In a separate request from Senator Dorgan's staff, EIA was asked to quantify the impacts of specific proposed energy amendments.[2]

This report includes an analysis of selected provisions that have, in EIA's estimation, significant potential to affect energy consumption and supply. Proposed legislation in the following areas are addressed in this paper:

- Energy demand reductions in the end-use demand sectors, including policy options that have the potential to significantly reduce petroleum consumption;
- Increased ethanol content of motor gasoline and the elimination of methyl tertiary butyl ether (MTBE);
- Tax credits for alternative vehicle fuels;
- Tax credits for nonconventional fuels production;
- Opening the Arctic National Wildlife Refuge to crude oil production;
- Assistance for constructing the Alaska Natural Gas Pipeline;
- Clean coal incentives;
- Renewable portfolio standard for the electricity industry; and
- Biodiesel credits.

Because of the need to provide a response that the Conference Committee could use in their deliberations, EIA concluded that it did not have sufficient time or resources to perform an extensive quantitative analysis of all of the provisions of the two bills and proposed amendments. Instead, EIA drew from previous studies of related proposed Congressional energy legislation it had analyzed over the past two years to provide an estimate of the magnitude of the impacts of the major provisions in these two bills and related amendments. Some additional provisions not previously analyzed are also covered, though mostly qualitatively.

The Reference Case projections have changed somewhat over the past two years to reflect new information.[3] However, since policy analysis necessarily focuses on the changes that might result from proposed legislation *relative to a Reference Case*, use of

[1] Letter from Sen. Dorgan to Guy F. Caruso, dated July 31, 2003. See Appendix A for a copy of the original letter.

[2] E-mail from Sen. Dorgan's staff to Mary J. Hutzler, dated August 17, 2003. See Appendix A for a copy of the e-mail.

[3] The base cased used for the quantitative analyses include the *Annual Energy Outlook 2002,* (December 2001) *(AEO2002), Annual Energy Outlook 2003,* (January 2003) *(AEO2003),* and mid-year revisions completed as part of service reports, such as the "Analysis of S.139, the Climate Stewardship Act of 2003", (June 2003).

the change from the Reference Case is likely, in most cases, to remain a good proxy for the change that might occur due to the policy. An exception may be natural gas markets, where recent data have indicated that EIA's past supply and price projections may be optimistic. In that area, either a high natural gas price case is included, or it is noted where major changes might be expected. The provisions modeled in these analyses do not always correspond exactly to the text in the current bills. These differences are noted, and the direction of impact is stated. Where other legislation is involved, it is cited as appropriate.

Methodology and Uncertainties

The majority of the analysis in this report is based on results of the National Energy Modeling System (NEMS).[4] NEMS, like all models, is a simplified representation of reality. Projections are highly dependent on the data, methodologies, model structure, and assumptions used to develop them. Because many of the events that shape energy markets are random and cannot be anticipated (including severe weather, technological breakthroughs, and geo-political disruptions), energy market projections are subject to uncertainty. Furthermore, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Nevertheless, well-formulated models are desirable ways to analyze complex policies because they ensure consistency in the accounting and represent the interrelationships, imperfectly, but often well enough to provide insight into the magnitude of the impact.

EIA's projections are not statements of what will happen but what might happen, given known technologies, current technology and demographic trends. Because EIA's Reference Cases are based on current laws and regulations, they provide a policy-neutral starting point that can be used to analyze energy policy initiatives. EIA does not propose, advocate, or speculate on future legislative or regulatory changes within its Reference Cases--rather, laws and regulations are assumed to remain as currently enacted or in force; however, the impacts of scheduled regulatory changes, when clearly defined, are reflected.

Representation of Individual Versus Integrated Results

Because the provisions were analyzed individually, the potential interactions among the various provisions are not included. Thus,

- The combined impact of the individual policies cannot be determined by simply adding the individual policy impacts together. For example, a provision establishing a renewable portfolio standard (RPS) for electricity production and one that establishes a biodiesel program for transportation fuels both increase the use of biomass. The simultaneous enactment of the two provisions would likely increase biomass costs because of the competition for land and other needed

[4] Energy Information Administration, *The National Energy Modeling System: An Overview 2003,* DOE/EIA-0581(2003) (Washington, DC, March 2003), web site http://www.eia.doe.gov/oiaf/aeo/overview/index.html.

resources. Therefore, the estimated fossil energy displaced could be lower than the sum of the two individual policy impacts because of the higher resource costs for biomass.

- Some policies may interact to increase the overall impact. For example, when two separate policies increase demand and, consequently, production of an advanced technology, the reductions in manufacturing costs expected from increased production are likely to be accelerated, making the technology even more attractive in later years. The total adoption of the advanced technology could be greater than the sum of the parts.

Stated another way, the impact of enactment of multiple simultaneous policies tends to be non-linear, sometimes less than the sum of the individual policies while at other times greater than the sum of the individual policies.

Analysis of Research and Development (R&D) Provisions

The Senate and House bills contain numerous sections authorizing increased R&D, including programs aimed at improving the efficiency of energy consumption devices, reducing the cost and improving the performance of renewable, fossil, and nuclear energy production technologies, together with programs to enhance consumer safety, environmental quality, and support basic science research programs. Some of these programs are new while others are extensions or expansions of existing programs.

The linkage between enactment of new authorizations for R&D programs and the additional amounts of funding provided in the appropriations process is highly uncertain. Moreover, even after actual impacts on funding are determined, it is difficult to relate funding directly to specific improvements in the characteristics, benefits, and availability of energy technologies. Therefore, analysis in this report does not attempt to assess the overall impact of the proposed R&D authorizations in the bills. EIA has previously qualitatively analyzed numerous R&D provisions that provide for increased R&D efforts.[5] In general, increased R&D would be expected to lead to technological advances, but it is impossible to determine which programs would or would not be successful or how successful they might be.

It is also difficult to determine if the programs would lead to advances beyond those already incorporated in the Reference Cases used for the quantitative analyses in this report. NEMS incorporates improvements in technology cost and performance over time in all sectors of the U.S. energy economy. These improvements are meant to capture the impacts of technology improvement trends seen in historical data and those expected to occur because of current levels of R&D. For example, the residential and commercial submodules assume improvements in the cost and performance of new lighting, heating, air conditioning, and office equipment over the next 20 years. Similarly, the fuel supply

5 Energy Information Administration, *Impacts of Energy Research and Development (S.1766 Sections 1211-1245, and Corresponding Sections of H.R.4) With Analyses of Price-Anderson Act and Hydroelectric Relicensing,* SR/OIAF/2002-04, (Washington, DC, March 2002), web site http://www.eia.doe.gov/oiaf/servicerpt/erd/pdf/sroiaf(2002)04.pdf.

and conversion submodules incorporate improvements in drilling, mining, refining, and electricity generation technologies. These improvements cannot be directly attributed to Federal or private R&D. It is possible that the programs called for in the Senate and House bills could lead to greater improvements than are projected in the Reference Cases used for the analyses, but their impact is unknown because the magnitude of the relationship between Federal R&D expenditures and technological improvements is unknown.

In addition to the difficulty in quantifying the potential impact of any individual R&D program, estimating the combined impact of a wide array of programs is even more difficult. Though it is possible that several programs may produce synergistic results, the opposite conclusion is more likely because, when analyzed together some programs may have smaller combined impacts than analysis of each individual program might suggest.[6] The R&D provisions of the Senate and House bills are broadly distributed across sectors and fuels so that if all technologies supported by the bills were to improve their cost and performance at a similar rate, the market penetration of those technologies would likely remain similar.

Finally, public sector R&D programs may mitigate certain market failures and still remain ineffective against other market barriers. Market failures addressed directly by Federal R&D investment include under investment in basic research in the private sector and consumers' lack of information. However, market barriers also pose a secondary and equally large challenge to the penetration of new technologies. Consumers may be fully aware of potential cost savings from a more-efficient technology but still prefer other characteristics of the less-efficient technology. The current trend for larger, more powerful personal vehicles is just one example of consumers' apparent preference for product attributes that compete with energy efficiency.[7] Other barriers to the penetration of new technologies include uncertainty as to the reliability, performance, and costs of new equipment; uncertainty about the availability of next-generation technology, which may be of even higher quality; and apprehension about the adequacy of the infrastructure required to support and maintain the technology. R&D expenditures are generally not effective against these types of market barriers.

While recognizing the success of past and current research, development, and deployment programs, it is difficult to establish a quantitative relationship between levels of funding and specific improvements in the characteristics, availability, and adoption of energy technologies. Even if such a relationship could be established, by its nature, R&D is highly uncertain. Seemingly plausible avenues of research may not achieve success, though genuine breakthroughs remain possible. Consequently, only a qualitative discussion of R&D provisions is provided in this document.

6 For example, efficiency improvements in electricity generation would be expected to reduce the price of electricity, consequently devaluing investment in end-use energy efficiency.

7 Consumer perceptions regarding the length of payback periods apparently exceed actual payback periods, discouraging new equipment purchases, as does the fact that consumers may base their decisions on current, rather than future, prices.

Structure of the Report

This report includes four additional chapters with the major provisions of the Senate and House bills addressed by market segment. Chapter 2 includes a discussion of the provisions that impact end-use energy demand in the buildings, industrial, and transportation sectors. This chapter also includes a discussion of options to reduce U.S. petroleum consumption as a way to reduce imports by one million barrels per day, an amendment proposed by Senator Landrieu. Chapter 3 examines those provisions that would impact oil and natural gas exploration, production, refining, and transmission. Chapter 4 looks at provisions impacting electric power supply. The renewable fuel standard and biodiesel provisions are discussed in Chapter 5. The original request letter and a follow-up e-mail from Senator Dorgan's staff are included in Appendix A.

2. End-Use Energy Demand

This chapter contains analysis of tax incentives, standards, voluntary programs, and other miscellaneous provisions in the House and Senate energy bills that affect the end-use demand sectors. Those provisions that affect the residential and commercial sectors are discussed together in the buildings section since many of the legislative proposals affect both sectors. Analysis of those provisions that primarily affect the industrial sector follows the buildings section. The numerous provisions that affect the transportation sector concludes the discussion of sector-specific legislative proposals. In addition, an analysis of the Landrieu amendment (S.871) to S.14 (the principal energy bill considered in the Senate during the first half of 2003) that requires the President to implement policies to reduce petroleum consumption by one million barrels per day below projected 2013 levels is provided at the end of this chapter.

A. Buildings

The major source of the discussion of the impact of the House and Senate energy bill provisions on energy consumption in the residential and commercial sectors is the report, *Analysis of Efficiency Standards for Air Conditioners, Heat Pumps, and Other Products (S. 1766 Section 921-929, H.R.4 Section 124, 142, and 143)*.[8] However, additional sources are used for portions of the following discussion. Those sources are indicated in the text. Except where noted, the Reference Case used for comparison in the buildings section was a mid-year revision to *AEO2002*.[9]

1. Tax Credit for Qualifying Residential Energy Efficient Property (House 41001, Senate 2103)

House Section 41001 provides a 15-percent tax credit for residential solar hot water heaters and solar photovoltaic equipment purchased between 2004 and 2006 (2008 for solar photovoltaic equipment), up to a maximum of $2,000.

In addition to the provisions in the House bill, the Senate bill (Section 2103) provides tax credits for fuel cells (30 percent), wind energy (30 percent), residential air-source and geothermal heat pumps ($250), central air conditioners ($250), natural gas furnaces ($250), heat pump water heaters ($75), and natural gas water heaters ($75) purchased from 2003 through 2007.

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[8] Energy Information Administration, *Analysis of Efficiency Standards for Air Conditioners, Heat Pumps, and Other Products (S. 1766 Section 921-929, H.R.4 Section 124, 142, and 143)*, SR/OIAF/2002-01 (Washington, DC, March 2002), web site http://www.eia.doe.gov/oiaf/servicerpt/eff/pdf/sroiaf(2002)01.pdf.

[9] Energy Information Administration, *Annual Energy Outlook 2002,* DOE/EIA-0383(2002) (Washington, DC, December 2001), web site http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2002).pdf.

Impact of Tax Credit for Qualifying Residential Energy Efficient Property

The tax credits are applied to qualifying equipment as a reduction in the cost of the unit for the specified time period.

Under the provisions in the House bill, the tax credit yields negligible energy savings when compared to the Reference Case due to the high cost of solar equipment.

Under the Senate version of the bill, a projected 37 trillion Btu of delivered energy and 1 million metric tons carbon equivalent of carbon dioxide emissions are saved over the period when the credit is in effect due to increased purchases of energy-efficient equipment. This represents less than 0.1 percent of the energy consumed in the residential sector over the period. Through 2020, a projected 136 trillion Btu (4 million metric tons of carbon dioxide emissions) are saved by the purchase of energy-efficient equipment targeted by the tax credits and these benefits are expected to continue to accumulate over the life of the equipment.[10] Given the short time horizon of the tax credit, it is not anticipated that any significant long-term market penetration increase for these products would persist beyond the period that the tax credit is offered. The Senate version of this provision is projected to save more energy than the House version, because of its application to more traditional appliances and wider coverage.

2. Tax Credit for Fuel Cell Power Plants (House 41003, Senate 2104)

The House provision (41003) provides a 10-percent tax credit for the purchase of stationary fuel cell power plants for businesses and individuals, up to $500 per half kilowatt of capacity. To qualify, the property must have an electric generation efficiency greater than 30 percent and be placed in service or the expenditures made during 2004 through 2006.

The Senate version (2104) provides the same incentive for businesses for stationary fuel cells for 2003 through 2007. The Senate version also provides a 10-percent tax credit of up to $200 per kilowatt of capacity for stationary microturbine power plants for systems placed in service during 2003 through 2006.

Impact of Tax Credit for Fuel Cells

The provision is expected to have negligible impact on residential and commercial delivered energy consumption and carbon dioxide emissions. A 10-percent fuel cell tax credit provision, analyzed using a 4-year effective period, is projected to result in the installation of 17 megawatts of additional fuel cell capacity by 2006, a 75 percent increase from Reference Case capacity. However, the savings in purchased electricity are offset by additional natural gas consumption in the sector. Implied residential and commercial carbon dioxide emissions (including emissions attributable to electricity purchases) are reduced by 0.02 million metric tons carbon equivalent (less than 0.01

[10] Runs SEER10.D021202A and SENATE1.D081302A.

percent), cumulatively, over the effective period. Although additional fuel cell installations are projected after the effective period, the increase in projected capacity relative to the Reference Case narrows to 6 percent by 2020. The provision in the House bill could be expected to have a slightly smaller impact than indicated in this analysis due to the shorter duration of the incentive. The provision in the Senate bill could be expected to have an impact similar to the analysis, with a slightly greater, but still negligible, effect on emissions due to the inclusion of a credit for microturbine systems.

3. Tax Credit for Energy Efficiency Improvements to Existing Homes (House 41004, Senate 2109)

Section 41004 of the House bill provides a 20-percent tax credit ($2000 maximum) for expenditures on building envelope components that meet the 2000 International Energy Conservation Code (IECC). The aggregate costs of the components must exceed $1000 and be certified by using specific software and/or relevant guidelines. Improvements must be initiated after December 31, 2003, and before January 1, 2007.

Section 2109 of the Senate amendment provides a 10-percent tax credit ($300 maximum) for expenditures on building envelope components that meet the 2000 IECC, or meet the Energy Star standard to reduce heating and cooling energy by 30 percent.

Impact of Tax Credit for Existing Homes

The NEMS residential module cannot analyze the economics of existing building envelope efficiency because of the lack of data regarding the installed efficiency of building shell characteristics in the housing stock. Therefore, it is not possible to accurately assess the energy impacts of this provision. However, knowledge of the average age of the heating and cooling equipment installed in the existing housing stock can provide some guidance in estimating potential energy savings.

In the House version of the bill, depending on the age and location of the house, the energy savings from meeting the IECC could vary greatly. The most inefficient homes could reduce their heating and cooling energy use substantially by replacing old building components (e.g., windows) with the most efficient available. Once these updates are made they are generally permanent as long as the home exists. Depending upon the number of upgraded homes, this provision has the potential for relatively large energy savings, when compared to the other buildings' provisions in the House bill.

The impacts of the Senate version of the amendment are similar to the House bill, except that improvements to heating and cooling equipment are included, but the tax credit is smaller.

4. Business Tax Credit for Construction of New Energy Efficient Homes (House 41005, Senate 2101)

Section 41005 of the House bill provides a tax credit of up to $2,000 to builders who install energy-efficient heating and cooling appliances and building envelope components in new homes that improve energy efficiency by at least 30 percent more than the 2000 IECC. To qualify, one-third of the savings must be achieved through building envelope improvements and the home must pass the standards set forth by computer software approved by the Secretary of Energy or by other approved home energy rating systems. The home must be acquired before January 1, 2007.

Section 2101 of the Senate bill provides a tax credit of up to $1,250 to builders who construct homes that have projected annual heating and cooling costs that are at least 30 percent lower than dwellings constructed in compliance with the 2000 IECC and $2,000 to homes that are at least 50 percent more efficient than the 2000 IECC. To qualify, the home must pass the standards set forth by computer software approved by the Secretary of Energy or by other approved home energy rating systems. The home must be acquired before January 1, 2008.

Impact of Business Tax Credit

The NEMS residential module is not designed to analyze the impact of tax credits on homebuilders. All economic criteria in the module are specified at the consumer level. It is believed, however, that since the builders would get the tax credit, more homes would be built under this arrangement than had the tax credit been designated to the home purchaser. Although the NEMS residential module does not explicitly represent business tax credits, a short analysis of the potential impact of this provision is presented here.

The number of new homes (single family and mobile homes) built each year represents about 1.5 percent of the total existing housing stock in a given year. Heating and cooling represent about 55 percent of the delivered energy consumed in a household. Each house consumes on average about 105 million Btu of energy per year, implying that about 58 million Btu are consumed for heating and cooling in an average home. New homes, on average, use about 14 percent less energy for heating and cooling, or about 50 million Btu. Building a new home by following the specifications outlined in this proposal would achieve a 30 percent increase in efficiency and save about 15 million Btu of energy per year per home.

Since 1.6 million homes are built on average per year, if every new home were constructed to the House bill standards, roughly 24 trillion Btu per year would be saved compared to average new homes built today. This represents about 0.2 percent of delivered energy consumption to the residential sector in 2000. Through the end of the tax credit period (2007), 96 trillion Btu would be saved, which represents a permanent reduction in total energy consumption, which is not dependent on the continued existence of the tax credit. Because of the short time period allowed for the tax credit, it is not likely that any long-term market penetration increase will be sustained.

Given the higher tax credit in the House bill, relative to the Senate amendment, the House bill would be expected to save more energy, since more builders would adopt the measure with the higher tax credit. The $2,000 tax credit for homes 50 percent more efficient than the IECC is not expected to save much additional energy, relative to the House bill, because of the higher costs associated with meeting the larger energy savings.

5. Tax Credit for Combined Heat and Power (House 41006, Senate 2108)

The House provision (41006) provides a 10-percent tax credit for qualifying combined heat and power (CHP) property installed after December 31, 2003, and before January 1, 2007. Qualifying CHP property must have the following characteristics:

Capacity	Greater than 50 KW
Efficiency	Greater than 60 percent (70 percent if capacity greater than 50 MW)
Thermal	At least 20 percent of useful output
Electricity	At least 20 percent of useful output

In addition, if the CHP property had a tax depreciation life of 15 years or less (which is common to industrial facilities but not commercial property), the class life must be increased to 22 years if the credit is taken. The legislation specifies that support and distribution equipment are not included in the qualified property.

The Senate version (2108) basically repeats the House provisions. Systems that use back-pressure steam turbines or waste heat are not required to meet either the efficiency standard or the 20-20 thermal/electric standard. To qualify, the property must be placed in service after December 31, 2002 and before January 1, 2007.

Impact of Commercial CHP Tax Credit

Previous analysis indicates that the 10-percent tax credit results in a projected 56megawatt (5 percent) increase in commercial CHP capacity over the period when the tax credit is in effect, relative to the Reference Case.[11] This analysis used Reference Case assumptions from *AEO2002.*[12] Commercial delivered energy consumption and site-specific carbon dioxide emissions increase slightly due to increased fuel requirements for CHP. However, total emissions (including carbon dioxide emissions attributable to electricity purchases) are projected to decline slightly over the period. Projected commercial carbon dioxide emissions drop by a cumulative 0.19 million metric tons carbon equivalent (0.02 percent) over the period when the tax credit is in effect when compared to the Reference Case. By comparison, a new 300-megawatt natural gas power plant would emit approximately 0.16 million metric tons carbon equivalent annually. The analysis indicates that the provision results in a sustained 4-percent increase in projected commercial CHP capacity in 2020. Assuming the relative length of the

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11 Runs IBASE.D081402B and CHPTAUZIN.D081502C.

12 Energy Information Administration, *Annual Energy Outlook 2002,* DOE/EIA-0383(2002) (Washington, DC, December 2001), web site http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2002).pdf.

effective period of the provisions would be maintained as stated in the Senate and House bills, the slightly shorter effective time period of the House provision would reduce the impact of the proposed credit relative to the analysis.

6. Tax Deduction for New Energy Efficient Commercial Buildings (House none, Senate 2105)

The Senate bill provides taxpayers with a tax deduction for energy-efficient commercial building property expenditures. The deduction amount is limited to $2.25 times the square footage of the building for which the expenditures are made. To qualify, energy-efficient property must be placed in service between 2003 and 2007 and demonstrate a 50-percent reduction in total annual energy and electric power costs for the commercial building with respect to lighting, heating, cooling, ventilation, and hot water supply systems. Energy and power cost savings are measured relative to a reference building meeting American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE) Standard 90.1-1999.

Impact of Commercial Building Tax Deduction

The quantitative effects of this provision cannot be estimated at this time because the methods for calculating energy and electricity consumption and costs and the procedures for determining compliance will be prescribed only after the legislation becomes law, if passed. Further, the NEMS commercial module does not allow for an economic analysis of energy efficiency at the building level. In addition to the indeterminate investment required to reduce energy and power costs 50 percent relative to the ASHRAE Standard, compliance certification by a third party will be required. The effectiveness of this provision also depends on the timeliness of developing calculation methods for determining compliance, the complexity of those methods, and training and proficiency tests for those who will perform compliance certification. Due to the limited duration of the provision and the issues stated above, only small to negligible energy savings and emissions reductions can be expected as a result of the provision.

7. Product Standards (House 11044, 11045, Senate 924, 928)

The energy bills provide for a number of energy efficiency standards and test procedures that could affect the buildings sector. The provisions of the House and Senate bills are the same. Section 11045 of the House bill and Section 928 of the Senate bill specify a standard level of 190 watts for torchieres manufactured on or after January 1, 2005.

The standardization of test procedures in Section 11044 of the House bill and Section 924 of the Senate bill does not directly lead to energy savings, but should facilitate the standards process. The efficiency levels of standards for ceiling fans, vending machines, unit heaters, and commercial refrigerators and freezers are not determined in Section 11045 of the House bill and Section 928 of the Senate bill, thus savings due to these standards cannot be quantified. The same is true for standby mode energy consumption.

Impact of Product Standards

The torchiere standard provision under Section 11045 of the House bill and Section 928 of the Senate bill lead to a 7-percent reduction (10 billion kilowatthours, which is equivalent to about seven 300-megawatt power plants) in residential lighting electricity use in 2020 relative to the Reference Case. The savings represents 0.6 percent of projected total residential electricity sales in 2020.

The impact of both energy bills' requirement to meet the Version 2.0 Energy Star performance requirements for illuminated exit signs depends on the mix of light source technologies used in existing exit signs, the rate of sign replacement, and the rate of construction for new non-residential buildings. Exit signs can last longer than 25 years, slowing the rate of replacement and limiting the near-term effects of the proposed standard on energy consumption in existing buildings.

Distribution transformers are not explicitly represented in NEMS, precluding quantitative analysis of the energy bills' requirement to meet the Class I Efficiency Levels for low voltage dry-type transformers specified by the National Electrical Manufacturers Association (NEMA) in 2005. The effects of minimum efficiency standards for low voltage dry-type transformers would be expected to accumulate gradually due to the slow rate of turnover in the stock of equipment in use. Distribution transformers have an estimated average useful life of 30 years; thus new construction, expansions, and major renovations are the primary reasons for transformer purchases. In addition, a significant market exists for used equipment, further delaying the introduction of new transformers into the equipment stock.

8. Federal Building Energy Programs (House 11001 – 11006, Senate 911 – 917, 919)

Section 11001 of the House bill adds conservation measures for congressional buildings. The sections dealing with energy use in Federal buildings in Sections 11002 - 11005 of the House bill essentially codify the purchasing mandates of Executive Order 13123, Greening the Government Through Efficient Energy Management, updating the base year to 2001 and updating mandated energy intensity reductions as specified in Table 1. Section 11006 provides a permanent extension of Energy Savings Performance Contracts.

Table 1. Reduction in Energy Intensity by Federal Buildings, House Bill Section 11002 (Percent)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Reduction Relative to 2001	2.0	4.0	6.0	8.0	10.0	12.0	14.0	16.0	18.0	20.0

The Senate bill (Sections 911 – 917) provides the same provisions as the House bill, except for an amendment regarding photovoltaics, with a base year of 2000 and target reductions in Table 1 to be reached two years sooner.

Impact of Federal Building Programs

The provision is expected to have negligible additional impact on commercial delivered energy consumption and carbon dioxide emissions relative to the Executive Order already in place. The Order already mandates that Federal agencies complete life cycle cost-effective projects, making maximum use of Energy Star and other energy-efficient products, alternative financing, sustainable design, and renewable energy technologies. The bill provisions turn those mandates into law. The addition of measures for congressional buildings and the permanent extension of Energy Savings Performance Contracts may add slightly to the expected energy savings.

9. Use of Photovoltaic Energy in Public Buildings (House 11011, Senate none)

The House agreed to an amendment resulting in Section 11011 establishing a photovoltaic energy commercialization program to install at least 150 megawatts cumulative in public buildings during the 2004 through 2008 time period. There was no corresponding provision in the Senate bill.

Impact of Use of Photovoltaics Energy in Public Buildings

This analysis used a mid-year revision to *AEO2003* completed for the study, *Analysis of S.139, the Climate Stewardship Act of 2003* as a Reference Case.[13] The NEMS model was modified to include the photovoltaic capacity specified in the amendment to the House bill as commercial sector installations, distributed evenly over the 2004 through 2008 time period. This is equivalent to 1500 systems similar in size to the General Services Administration installation at the Suitland Federal Center in Maryland.

Additional photovoltaic installations due to the amendment reduce projected commercial delivered energy use 1.0 trillion Btu in 2008[14] relative to the Reference Case, about 0.01 percent of commercial consumption (0.1 percent of 2001 Federal energy consumption). The cumulative reduction in projected commercial energy use over the effective period of the proposed program is 3.1 trillion Btu (0.01 percent) and projected commercial carbon dioxide emissions, including carbon dioxide emissions attributable to electricity purchases, are reduced by a cumulative 0.15 million metric tons carbon equivalent (0.01 percent). Through 2020, cumulative savings reach 19.4 trillion Btu (0.01 percent) and 0.95 million metric tons carbon equivalent of carbon dioxide emissions (0.02 percent) relative to Reference Case projections.

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[13] Energy Information Administration, *Analysis of S.139, the Climate Stewardship Act of 2003,* SR/OIAF/2003-02 (Washington, DC, June 2003), web site http://www.eia.doe.gov/oiaf/servicerpt/ml/pdf/summary.pdf, run MLBASE.D050303A.

[14] Run BLDHR6PV.D081903A.

10. Low Income Home Energy Assistance Program and Weatherization Assistance (House 11021, Senate 901)

Section 11021 of the House bill provides $3.4 billion for the Low Income Home Energy Assistance Program (LIHEAP) in fiscal years 2004 to 2006 and weatherization assistance of $325 million in fiscal year 2004, $400 million in fiscal years 2005, and $500 million in fiscal year 2006. For comparison, the fiscal year 2004 budget request was $288.2 million for weatherization. Amendment 4 to the House bill provides an estimated $400 million per year to LIHEAP from the proceeds of the leases to drill in the Arctic National Wildlife Refuge.

Section 901 of the Senate bill is the same except that the funds are provided one year earlier.

Impact of LIHEAP and Weatherization Assistance

LIHEAP offsets expenditures for heating fuels. More assistance might increase energy consumption if low-income households have more money to spend on energy. (These programs are not modeled in NEMS.) The weatherization program estimates that each house costs $2,000 to weatherize for an annual energy savings of $300. Using these results, fiscal year 2004 would provide funding for an additional 18,400 homes and $5.5 million in energy bill savings.

11. Energy Efficient Appliance Rebate Programs (House 11023, Senate 905)

Section 11023 of the House bill provides $50 million in fiscal year 2004 to 2008 to States with Energy Star appliance rebate programs.

Section 905 of the Senate bill is similar to the House bill, except the fiscal years are 2003-2012 and the funding level is "sums as necessary."

Impact of the Energy Efficient Appliance Rebate Programs

This provision is not modeled in NEMS due to the State level nature of the program. Since the Senate version covers more years, the potential for energy savings is greater.

12. Research and Development Related to Energy Efficiency (House 21101-21121, Senate 1211-1213)

Sections 21101-21121 of the House bill provides funding for various research and development projects such as the Next Generation Lighting Initiative and the National Building Performance Initiative.

Sections 1211-1213 of the Senate bill is essentially the same, but with more targeted funding levels for each program.

Impact of Research and Development Related to Energy Efficiency

As discussed in the Chapter 1, this analysis did not attempt to assess the overall impact of proposed R&D funding in the House and Senate energy bills. EIA has previously qualitatively analyzed numerous R&D provisions that provide for increased R&D efforts.[15]

B. Industrial

The industrial analysis includes tax credits for CHP, blending cements, and voluntary programs. The source of the industrial analysis on the impact of tax credits for CHP is an internal EIA analysis[16] using *AEO2002* as a Reference Case. The source of the discussion on voluntary programs is the report, *Analysis of Efficiency Standards for Air Conditioners, Heat Pumps, and Other Products (S. 1766 Section 921-929, H.R.4 Section 124, 142, and 143)*.[17] The Reference Case used for the voluntary programs discussion was a mid-year revision to *AEO2002*.

1. Tax Credit for Combined Heat and Power (House 41006, Senate 2108)

Section 41006 of the House bill provides a 10-percent tax credit for CHP system property placed in service after December 31, 2003, and before January 1, 2007.

Section 2108 of the Senate amendment also provides a 10-percent tax credit, but the qualifying property may be placed in service after December 31, 2002, and before January 1, 2007. The efficiency exception for back-pressure systems included in the House bill has been removed.

Assuming the relative length of the effective period of the provisions would be maintained as stated in the Senate and House bills, the slightly shorter effective time period of the House bill would reduce the impact of the proposed credit relative to the Senate bill. The back-pressure provision would have negligible impacts on the previous analysis.

Impact of Tax Credit for CHP

The 10-percent tax credit results in a projected 490-megawatt (1.9 percent) increase in industrial CHP capacity over the period when the tax credit is in effect, compared with the Reference Case. Carbon dioxide emissions directly attributable to the industrial

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15 Energy Information Administration, *Impacts of Energy Research and Development (S.1766 Sections 1211-1245, and Corresponding Sections of H.R.4) With Analyses of Price-Anderson Act and Hydroelectric Relicensing,*SR/OIAF/2002-04 (Washington, DC, March 2002), web site http://www.eia.doe.gov/oiaf/servicerpt/erd/pdf/sroiaf(2002)04.pdf.

16 Run HR4CONF.D082602A.

17 Energy Information Administration, *Analysis of Efficiency Standards for Air Conditioners, Heat Pumps, and Other Products (S. 1766 Section 921-929, H.R.4 Section 124, 142, and 143)*, SR/OIAF/2002-01 (Washington, DC, March 2002), web site http://www.eia.doe.gov/oiaf/servicerpt/eff/pdf/sroiaf(2002)01.pdf.

sector increase slightly due to increased CHP fuel consumption. However, total industrial carbon dioxide emissions, which include carbon dioxide emissions attributable to electricity purchases, are projected to be slightly lower over the period due to higher efficiency of CHP relative to central station electricity generation and separate on-site steam generation. Projected industrial carbon dioxide emissions are reduced by a cumulative 0.42 million metric tons (0.02 percent) carbon equivalent over the effective period of the tax credit when compared with the Reference Case. These reductions will be sustained as long as the equipment remains in operation. No permanent impact from the temporary tax credit is anticipated.

2. Voluntary Industrial Programs (House 11007, Senate 921)

Both the House and Senate energy bills have provisions for voluntary agreements to improve industrial energy intensity by 2.5 percent per year.

Section 921 of the Senate bill and Section 11007 of the House bill require the Department of Energy to enter into voluntary agreements with industrial sector entities that consume significant amounts of energy to reduce their primary energy intensity. For these entities, the goal is to reduce primary energy intensity at an average rate of 2.5 percent per year over the period 2002 to 2012 (2004 to 2014 for the House bill). Entities participating in the program "shall be eligible to receive ... a grant or technical assistance as appropriate to assist in the achievement of those goals." Energy intensity is defined as "primary energy consumed per unit of physical output in an industrial process."

The proposed legislation does not specify the size of the potential grant or the nature of the technical assistance. However, Department of Energy programs have similar functions. Financial assistance is available in the Inventions and Innovations program and in the National Industrial Competitiveness through Energy, Environment, and Economics program. Technical assistance is available through the Industrial Assessment Centers program. It is not clear whether the proposed legislation is intended to change the participation requirements for these programs (e.g., pledge to reduce energy intensity by the specified amount) or change the firm size allowed to participate.

As written, the proposed legislation seems to specify that the primary energy intensity reduction must be measured for a process. However, process is not defined, nor is primary energy. Generally, primary energy is defined to include the losses incurred in generating electricity. Primary energy intensity can decline due to improvements in electricity generating efficiency irrespective of changes at the plant or process. Presumably, the intent of the proposed legislation is to exclude efficiency improvements by electricity suppliers when calculating intensity improvements by industrial sector entities.

Impact of Voluntary Industrial Programs

It is extremely difficult to quantify the impacts of voluntary programs. It is assumed that these impacts are captured in the baseline assumptions regarding energy intensity improvements. In the *AEO2003* Reference Case projection, industrial primary energy intensity falls by 1.6 percent annually over the 2002-2012 period specified in the Senate bill. Industrial primary energy intensity fell by 1.6 percent annually over the 1978-2000 period. Thus, the 2.5-percent goal is almost 60 percent higher than the intensity decline rate in the Reference Case and in recent history. If the 2.5-percent goal were met for the industrial sector, primary energy consumption in at the end of the period would be 9 percent or 3.2 quadrillion Btu lower than in the *AEO2003* Reference Case. The *AEO2003* also includes a High Technology Case, which assumes earlier availability, lower costs, and higher efficiency for more advanced equipment. In the High Technology Case, industrial primary energy intensity is projected to fall 1.9 percent per year. If the 2.5-percent goal were achieved for the industrial sector in this case, primary energy consumption in 2012 would be 2.5 quadrillion Btu lower than projected in the *AEO2003* High Technology Case.

In summary, the 2.5-percent goal is quite ambitious and not likely to be achieved for the industrial sector overall. Some individual plants or industrial sub-sectors may be able to meet that goal.

3. Other Industrial Provisions (House 11010, Senate 920)

Both bills have provisions (Section 11010 in the House and Section 920 in the Senate) intended to increase the amount of recovered mineral component in Federally-funded projects involving procurement of cement or concrete (i.e., blended cements). The provisions call for an initial study of barriers to greater use of blended cements, such as buildings codes and product standards. Implementation of the purchasing requirements is dependent on the results of the initial study. Blended cements have the potential to reduce energy consumption in cement production and concomitant carbon emissions.

Impact of Other Industrial Provisions

The impact of the other industrial provisions included in the House and Senate energy bills were not evaluated.

C. Transportation

A variety of legislative proposals have targeted the transportation sector. Although neither of the bills specifies higher CAFE standards, Senator Dorgan's staff requested that an assessment of higher CAFE standards be included in this Service Report subsequent to receipt of the Request Letter.[18] In the past, several proposals to increase the corporate average fuel economy (CAFE) standards for cars and light trucks have been analyzed. The potential impact of these past CAFE analyses is discussed below followed by a discussion of the impacts of current proposed legislation that would affect Federal, State, and local vehicle fleets. Since fuel cell vehicles are frequently targeted in the legislative proposals, the potential impacts of these proposals are discussed next. Finally,

[18] Telephone conversation between Mary J. Hutzler and Jerry Hinkle, August 15, 2003.

a host of targeted demonstration or credit programs are discussed, even though none is likely to have a significant impact on transportation sector energy consumption.

1. Corporate Average Fuel Economy (House 18001-18002, Senate 801-803)

The Senate energy bill does not prescribe specific fuel economy standards for light duty vehicles. The bill requires the Department of Transportation (DOT) to develop a feasible increase in fuel economy standards for light-duty vehicles no later than two years after enactment. Feasibility criteria are outlined in Section 803 of the Senate bill. If DOT fails to make recommendations within the allotted time, Section 802 of the Senate bill allows Congress the ability to introduce new standards for light-duty vehicles. Section 804 of the Senate bill extends the current CAFE credit allowed for vehicles capable of using an alternative fuel through 2012. Section 811 exempts "pickup trucks" from fuel economy increases, keeping the standard at 20.7 miles per gallon (mpg). DOT will develop the criteria for the definition of a "pickup truck."

The House bill has similar provisions (Sections 18001 and 18002) that require the evaluation of feasible fuel economy increases with proposed recommendations. The House version requires the study to be submitted within a year of the date of enactment and does not provide an exemption for pickup trucks.

Impact of CAFE

The current Senate and House bills do not provide specific fuel economy standards for light-duty vehicles, requiring instead that the issue be studied with action taken by Congress if recommendations to increase CAFE are not issued within a set period of time. Enactment of these provisions would not necessarily result in different standards than those that would be promulgated under existing law. In fact, even the direction of any impact of future standards is unclear.

EIA has previously analyzed fuel economy standards for light-duty vehicles as part of an evaluation of H.R.4 (the Securing America's Future Energy Act of 2001), S.804 (the Automobile Fuel Economy Act of 2001), and S.517 (the Energy Policy Act of 2002)[19] for Senator Murkowski using a mid-year revision to *AEO2002* as the Reference Case.[20] The following discussion of CAFÉ, which is not directly relevant to the current House and Senate CAFÉ provisions, is based on that analysis. Five CAFE cases were developed as part of that analysis as follows:

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19 Energy Information Administration, *Analysis of Corporate Average Fuel Economy Standards for Light Trucks and Increased Alternative Fuel Use*, SR/OIAF/2002-05, (Washington, DC, March 2002), web site http://www.eia.doe.gov/oiaf/servicerpt/cafe/pdf/sroiaf(2002)05.pdf.

20 Run s804base.d020702b.

1) H.R. 4 Section 201, specifying that light truck[21] (8,500 pounds or less gross vehicle weight) CAFE standards are to increase to a level that would provide a cumulative 5 billion gallon reduction in gasoline use between 2004 and 2010;
2) A sensitivity case, specifying that new light vehicle (including cars) fuel economy increases 5 percent in 2005 and 10 percent in 2010, relative to the current standards (27.5 mpg for cars and 20.7 mpg for light trucks);
3) S. 804, specifying that light truck (10,000 pounds or less gross vehicle weight) fuel economy standards increase to 22.5 mpg in model years 2003 through 2004, 25 mpg in model years 2005 through 2007, and 27.5 mpg for model years 2008 and beyond;
4) An S.804 sensitivity case in which the introduction dates for advanced conventional technologies are moved forward three to four years and are analyzed for potential fuel economy gains relative the CAFE standards defined in S.804; and
5) S. 517, specifying that the combined average fuel economy of new light vehicles increases to 35 mpg by 2013. For cars, the standard increases from 27.5 mpg to 38.3 mpg and for light trucks (10,000 pounds or less gross vehicle weight), the standard increases from 20.7 mpg to 32 mpg.

These individual cases are referred to as H.R.4 Case, Sensitivity Case, S.804 Case, S.804 Advanced Date Case, and S.517 Case, respectively. The S.804 and S.517 proposals also included an important provision that expands the definition and coverage of CAFE standards from light trucks with a gross vehicle weight of 8,500 lbs or less to 10,000 lbs or less. The definition brings in the heavy light truck fleet, which has much poorer fuel efficiency than light trucks under the previous standards and definition.

For the H.R.4 Case, EIA calculated that the light truck CAFÉ standard would need to be increased to 21.5 mpg, 0.8 mpg above the standard that was in effect when the analysis was conducted, to meet the fuel savings goal. EIA had projected efficiency improvements in its Reference Case would have provided this savings even with no change in standards. Subsequent to this analysis, CAFÉ standards for light trucks were increased to 22.2 mpg through rulemaking under existing law. The detailed projections for the other four cases, from EIA's earlier CAFÉ analysis are shown in Table 2.

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21 Light trucks include vehicles defined as pickup trucks, vans or minivans, and sport utility vehicles (SUVs).

Table 2. Summary of Key Results of Four CAFE Cases[1] Compared to the Reference Case, 2010 and 2020

	2000	Reference Case[2]	Sensitivity	S. 804	S. 804 Advanced Date	S. 517
		2010				
Light Vehicle Consumption (billion gallons)	124.9	154.0	152.4	147.6	146.6	147.4
Net Petroleum Imports (million barrels per day)	10.49	14.30	14.19	13.91	13.83	13.90
World Oil Price (2001$)	28.33	23.87	23.87	23.64	23.59	23.64
GDP (billion 2001$)	10,091	13,466	13,464	13,447	13,437	13,447
Light Vehicle Carbon Equivalent Emissions (million metric tons)	297.9	366.0	362.1	350.9	348.4	350.3
Average New Car Fuel Economy (miles per gallon)	28.90	29.58	30.82	29.53	29.52	33.44
Average New Light Truck Fuel Economy (miles per gallon)	21.08	22.52	23.25	25.56	26.41	25.05
Average New Car Horsepower	165	202	194	202	202	174
Average New Light Truck Horsepower[3]	193	237	235	203	203	215
Average New Car Weight (pounds)	3087	3257	3160	3258	3258	2826
Average New Light Truck Weight (pounds)[3]	4257	4554	4513	4053	3966	4105
		2020				
Light Vehicle Consumption (billion gallons)		181.8	176.3	167.1	166.8	159.4
Net Petroleum Imports (million barrels per day)		16.69	16.38	15.86	15.83	15.40
World Oil Price (2001$)		25.22	25.22	24.79	24.73	24.54
GDP (billion 2001$)		18,084	18,078	18,072	18,081	18,056
Light Vehicle Carbon Equivalent Emissions (million metric tons)		432.1	419.2	397.3	396.6	379.1
Average New Car Fuel Economy (miles per gallon)		29.63	31.79	29.53	29.53	35.84
Average New Light Truck Fuel Economy (miles per gallon)[3]		23.18	23.57	26.48	26.47	26.49
Average New Car Horsepower		220	198	220	220	168
Average New Light Truck Horsepower[4]		252	249	206	206	206
Average New Car Weight (pounds)		3359	3100	3360	3360	2723
Average New Light Truck Weight (pounds)[4]		4784	4721	3984	3960	3936

[1] The four cases summarized here are not representative of the CAFÉ provisions in the current House and Senate bills.
[2] The Reference Case also represents the H.R.4 Case.
[3] Average new light truck fuel economy for the Reference and Sensitivity Cases represent light trucks less than 8,500 pounds gross vehicle weight. Light truck fuel economy shown for the S.804, S.804 Advanced Date, and S.517 Cases represent light trucks less than 10,000 pounds gross vehicle weight.
[4] The values shown in the table represent vehicles less than 8,500 pounds gross vehicle weight. NEMS does not address the horsepower or weight aspects of Class 2b vehicles (8,500 to 10,000 pound vehicles).

Source: National Energy Modeling System runs: s804base.d020702b, s8045and10.d020702a, s804base.d020702b, s804advd.d021102a, and s517cafe.d022502a.

2. Miscellaneous Federal, State, and Local Fleet Requirements

a. Hybrid Vehicle Requirements (House none, Senate 805)

Section 805 of the Senate bill requires that in 2005 and 2006 5 percent of the Federal fleet light truck purchases for all executive agencies not covered under section 303 of the Energy Policy Act of 1992 will be hybrid vehicles. After 2006, 10 percent of those vehicles will be hybrid light-duty trucks. The House bill does not set a requirement for the percentage of hybrid vehicles.

Impact of Hybrid Vehicle Requirement

Although the purchase of higher efficiency hybrid light trucks will reduce energy demand from Federal fleet vehicles, limited availability of these vehicles and the relatively small number of vehicles purchased will have little impact on total U.S. demand for highway fuels.

b. Alternative Fuel Requirement (House 15046, Senate 806)

Section 806 of the Senate bill and Section 15046 of the House bill require that by 2009 Federal fleet vehicles capable of using an alternative fuel will use 50-percent alternative fuel. By 2011 the percent of alternative fuel use for those vehicles increases to 75 percent. The House bill requires that all Federal fleet vehicles capable of using an alternative fuel use that alternative fuel. Both bills allow for waivers if the alternative fuel is not available, but the Senate version allows for no waivers after 2012. The House bill also allows for a waiver if the cost of the alternative fuel is unreasonable.

Impact of Alternative Fuel Requirement

Little, if any, additional impact on future transportation energy is expected. Estimated alternative fuel consumption by Federal agencies was 5.8 million gallons in 1999, which was 1.7 percent of total U.S. alternative fuel consumption of 339.3 million gallons. At the same time, Federal agencies accounted for about 276 million gallons of gasoline consumption, which amounts to 0.2 percent of total U.S. gasoline consumption. Overall, alternative fuels make up about 0.3 percent of the combined total of alternative fuels plus gasoline.

c. Allowing Some Electric Vehicles to Count Toward Alternative Vehicle Purchase Requirements (House 15011, Senate 818)

Section 818 of the Senate bill and Section 15011 of the House bill would amend the Energy Policy Act of 1992 to allow some electric vehicles that are not designed to be used on highways to count as alternative fuel vehicle purchase requirements for covered fleets.

Impact of Allowing Some Electric Vehicles to Count Toward Alternative Vehicle Purchase Requirements

This provision will have little impact on total highway energy use.

d. Fleet Alternative Fuel Vehicles Credits (House 15011 and 15012, Senate 819)

Section 819 of the Senate bill and Sections 15011 and 15012 of the House bill establishes fleet alternative fuel vehicle credits for the purchase of hybrid vehicles. Credit is based on vehicle inertia weight, efficiency improvement relative to a 2000 model year vehicle, the maximum power available from the battery, and vehicle size class.

Impact of Fleet Alternative Fuel Vehicles Credits

Although this will provide an incentive to purchase hybrid vehicles, little impact will be realized on total highway energy use.

e. Fuel Efficiency of the Federal Fleet of Automobiles (House none, Senate 821)

Section 821 of the Senate bill requires that the average fuel economy of new automobiles purchased for the Federal fleet after September 2003 be at least 1 mpg higher than the 1999 average.

Impact of Requirement that Fuel Economy of New Automobiles Increase

This provision will result in increased efficiency for light duty Federal fleet vehicles, but because Federal fleet vehicles account for less than 0.2 percent of total U.S. gasoline consumption this will have little impact on total gasoline consumption.

3. Fuel Cell Vehicles (House none, Senate 824)

Section. 824 of the Senate bill requires that that the Secretary of Energy develop a program to develop technologies that enable at least 100,000 hydrogen-fueled fuel cell vehicles to be available for sale in the United States by 2010 and at least 2.5 million of such vehicles to be available by 2020 and annually thereafter.

Impact of the Fuel Cell Provisions

Given the current state of development of fuel cell vehicles and hydrogen fueling infrastructure required for their use, it is unlikely this provision will be met. The success of this goal will depend on how and if serious obstacles will be overcome: reduction of the cost of fuel stack capital costs by over 95 percent (to about $30 per kilowatt); reduction of the costs to integrate the fuel cell electronics within the automotive drive train; economic sources of hydrogen production; the development of a hydrogen transportation infrastructure, including refueling stations; and safe storage of high-density hydrogen on the vehicle to allow for adequate driving range. EIA believes that these obstacles are insurmountable in the 2010 time frame, making the goals unachievable. If the obstacles could be overcome, reducing fuel cell vehicle costs to that of gasoline vehicles and developing the infrastructure in the time frame of S.824, then 1 million barrels of oil per day could be displaced by 2025.

4. Miscellaneous Provisions Affecting Transportation

a. Hybrids in HOV Lanes (House none, Senate 812)

Section 812 of the Senate bill allows States the ability to classify single occupancy hybrid vehicles as HOV capable. This provision would allow single passenger hybrid vehicles to use HOV lanes.

Impact of Allowing Hybrids in HOV Lanes

This provision probably would increase the incentive to purchase hybrid vehicles. However, allowing single passenger vehicles in HOV lanes may lead to additional congestion in the HOV lanes and longer commuting distances, which would lead to increased overall fuel consumption. Any additional congestion or miles driven will offset part of the higher fuel efficiency of hybrid vehicles. As a result, the impact on fuel consumption of the HOV exception cannot be quantified.

b. Tax Credits for Certain Vehicles (House 41011, Senate none)

Section 41011 of the House bill establishes an income tax credit for fuel cell vehicles based on vehicle weight class and efficiency improvement. The fuel cell vehicle tax credit ranges from $5,000 to $44,000. The House bill also establishes an income tax credit for advanced lean burn technology based on fuel economy improvement over a 2000 model year vehicle. The advanced lean burn tax credit ranges from $750 to $3,500.

Impact of Tax Credits for Certain Vehicles

This provision provides a financial incentive for purchasers of hybrid and fuel cell vehicles. Since interest and availability of these vehicles has been limited, the potential size of the market is expected to remain very small. Most likely, the credit will be applied to currently mandated purchases of these types of vehicles and will provide little stimulus to significantly increase production or sales. The overall impacts on emissions, oil imports, and energy expenditures are expected to be minimal.

5. Research, Development and Demonstration

While several legislative proposals would expand R&D efforts, as discussed earlier, it is not feasible to quantify the impacts of such programs.[22]

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[22] The difficulties in assessing R&D impacts are discussed at length in Energy Information Administration, *Impacts of Energy Research and Development (S.1766 Sections 1211-1245,*

Section 807 of the Senate bill expands current R&D activities for hybrid and fuel cell vehicles at the Department of Energy. The House bill does not specify any changes to these programs. Due to the uncertain success of R&D programs, it is difficult estimate the outcome of the program.

Section 808 of the Senate bill requires accelerated R&D toward the improvement of diesel combustion and after treatment technologies for use in achieving Tier II compliance. The House version is very similar in content. Due to the uncertain success of R&D programs, it is difficult to estimate the outcome of the program.

D. Development and Implementation of Measures to Reduce Total U.S. Petroleum Demand by One Million Barrels Per Day in 2013. (Senate Amendment 871 to S.14)

In June 2003, during its consideration of S.14, the Senate overwhelmingly adopted Amendment 871, proposed by Senator Landrieu and others. In part, the provision states that “the President shall develop and implement measures to conserve petroleum in end-uses throughout the economy of the United States sufficient to reduce total demand for petroleum in the United States by 1,000,000 barrels per day from the amount projected for calendar year 2013 in the Reference Case contained in the report of the Energy Information Administration entitled, ’Annual Energy Outlook 2003’."

Prior to its August recess, the Senate set aside consideration of S.14 and passed comprehensive energy legislation with the same provisions as the Senate-passed bill from the prior Congress, which did not include the provisions of this amendment. Although this provision is therefore not a part of either the Senate- or House-passed bills in the present Congress, staff of Senator Dorgan’s office specifically requested that EIA address it as a part of this analysis.[23]

EIA could not develop new analysis given the abbreviated time frame for this project, which was further compressed due to the acceleration of the conference process following the events of August 14, 2003. However, EIA is able to provide some information relevant to this provision. The *AEO2003* outlook for oil demand and recent updates to that projection are discussed. Then, the impacts that might be expected to result from the enactment of other provisions being considered by the Conference are considered. Finally, some policy instruments potentially available under existing authorities to reduce oil demand are identified. The restriction to existing authorities is specified in the Landrieu amendment.

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and Corresponding Sections of H.R.4) With Analyses of Price-Anderson Act and Hydroelectric Relicensing, SR/OIAF/2002-04, (Washington, DC, March 2002), web site http://www.eia.doe.gov/oiaf/servicerpt/erd/pdf/sroiaf(2002)04.pdf

23 Letter from Senator Dorgan to Guy F. Caruso, dated July 31, 2003 and e-mail from Senator Dorgan’s staff to Mary J. Hutzler, dated August 17, 2003, are included in Appendix A.

1. The *AEO2003* Projection for Petroleum Demand

Table 3, taken from *AEO2003*,[24] illustrates that the transportation sector currently accounts for more than two thirds of all petroleum products used in the United States. Petroleum product use is projected to grow from 19.7 million barrels per day in 2001 to 24.4 million barrels per day in 2013. The share of all petroleum products used in the transportation sector is also expected to grow over this period, reaching 72 percent in 2013 (67 percent in 2001). The industrial sector is another significant user of petroleum products, both as an energy source and as a feedstock. Residential and commercial uses of petroleum products in 2001 averaged 1.2 million barrels per day in 2001, and were projected to decline both absolutely and as a share of total petroleum product usage in *AEO2003*. Finally, use of petroleum products by electric generators averaged 0.55 million barrels per day in 2001, a year of high natural gas prices. Generation use of oil is projected to fall by 60 percent or more from this level over the forecast horizon.

Table 3. Summary of Petroleum Products Supplied by Sector and Product from *AEO2003* (million barrels per day)

	2001	2005	2010	2013	2015	2020	2025
Refined Petroleum Products Supplied							
Residential and Commercial	1.2	1.2	1.2	1.2	1.2	1.1	1.1
Industrial	4.7	4.9	5.3	5.6	5.7	6.0	6.3
Transportation	13.3	14.3	16.3	17.5	18.2	19.8	21.5
Electric Generators	0.6	0.2	0.2	0.2	0.2	0.2	0.2
Total	19.7	20.5	23.0	24.4	25.2	27.1	29.2
Refined Petroleum Products Supplied							
Motor Gasoline	8.7	9.4	10.7	11.4	11.8	12.8	13.8
Jet Fuel	1.7	1.7	1.9	2.1	2.2	2.5	2.7
Distillate Fuel	3.8	4.0	4.6	4.9	5.1	5.4	5.9
Residual Fuel	1.0	0.6	0.6	0.6	0.6	0.6	0.6
Other	4.6	4.8	5.2	5.5	5.6	5.9	6.2
Total	19.7	20.5	23.0	24.4	25.2	27.1	29.2

Source: Energy Information Administration, *Annual Energy Outlook 2003,* DOE/EIA-0383(2003) (Washington, DC, January 2003), Table A11, web site http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2003).pdf.

Subsequent to release of *AEO2003*, the National Highway Traffic Safety Administration (NHTSA) raised the CAFE standard for cars and light trucks for model years 2005 through 2007. Consistent with standard EIA practice requiring policy neutrality in baseline projections, the effects of this action on oil demand were not included in the *AEO2003*, since final regulatory action had not occurred when our projection was issued. However, a recent EIA service report, *Analysis of S.139, the Climate Stewardship Act of*

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

2003,[25] was prepared following this issuance of NHTSA's final rule and includes a modified Reference Case that reflects its effect on oil demand. Table 4 summarizes this revised Reference Case. Petroleum demand in the transportation section in 2013 is projected to be 0.22 million barrels per day lower than in the *AEO2003*.

Table 4. Summary of Petroleum Products Supplied by Sector and Product including NHTSA's Recent Increase in CAFE (million barrels per day)

	2001	2005	2010	2013	2015	2020	2025
Refined Petroleum Products Supplied							
Residential and Commercial	1.2	1.2	1.2	1.2	1.2	1.1	1.1
Industrial	4.7	4.9	5.3	5.5	5.6	6.0	6.3
Transportation	13.3	14.3	16.2	17.3	18.0	19.5	21.3
Electric Generators	0.6	0.2	0.2	0.2	0.2	0.2	0.3
Total	19.7	20.5	22.9	24.2	25.0	26.9	28.9
Refined Petroleum Products Supplied							
Motor Gasoline	8.7	9.4	10.5	11.2	11.6	12.5	13.6
Jet Fuel	1.7	1.7	1.9	2.1	2.2	2.5	2.7
Distillate Fuel	3.8	4.0	4.6	4.9	5.1	5.4	5.9
Residual Fuel	1.0	0.6	0.6	0.7	0.7	0.7	0.7
Other	4.6	4.8	5.2	5.4	5.5	5.8	6.1
Total	19.7	20.5	22.9	24.2	25.0	26.9	28.9

Source: Energy Information Administration, *Analysis of S.139, the Climate Stewardship Act of 2003,* SR/OIAF/2003-02, (Washington, DC, June 2003), web site http://www.eia.doe.gov/oiaf/servicerpt/ml/pdf/sroiaf(2003)02.pdf.

2. Effects of Other Analyzed Provisions on Oil Demand in 2013

Several provisions of the Senate- and House-passed versions could have the effect of reducing the projected level of oil demand in 2013. However, while significant demand reductions are always possible, there are few measures in either bill that would provide oil demand reductions with a reasonable degree of assurance. Measures falling into this category include:

- Renewable Fuels Standard with or without MTBE Ban (Chapter 5, Section A)
- Alternative Fuel Requirements for Federal Fleets (Chapter 3, Section A)
- Biodiesel Incentives (Chapter 5, Sections E)
- Tax Credits for Energy-Efficiency Retrofits (Chapter 2, Section A)

Of the provisions listed above, the Renewable Fuels Standard (RFS) mandating the use of 5 billion gallons of renewables in motor fuels by 2012 (Senate bill) or 2015 (House bill) would probably have the largest direct impacts on oil demand. For example, the *AEO2003* projects 3.3 billion gallons of ethanol use in 2012. The extra ethanol (1.6 billion gallons per year) mandated under the RFS contains the energy content of 68,000

[25] Energy Information Administration, *Analysis of S.139, the Climate Stewardship Act of 2003,* SR/OIAF/2003-02, (Washington, DC, June 2003), web site http://www.eia.doe.gov/oiaf/servicerpt/ml/pdf/sroiaf(2003)02.pdf.

barrels of gasoline per day. However, since expanded ethanol use will be displacing natural gas-based additives as well as petroleum, and because extra RFS credits will be awarded for production of cellulosic ethanol, actual petroleum displacement at a constant demand level would probably be less than 68,000 barrels per day.

Fuel demand, however, is also likely to be affected, since increased gasoline prices as a result of an RFS with or without an MTBE ban (more of an increase in the former case) translate into lower demand. These issues were explored in a study EIA performed in 2002, *Renewable Motor Fuel Production Capacity Under H.R.4*.[26] That study used *AEO2002* as a Reference Case.[27] The Reference Case includes consideration of the MTBE ban in the 17 States that have already passed laws banning it. When a total MTBE ban is imposed, as in the Senate Bill, petroleum consumption in 2013 is lower because consumers reduce consumption in response to the higher prices that result from the ban of MTBE (see Table 5). Note that this analysis also assumes that the existing tax benefits provided to ethanol are extended indefinitely. If ethanol's tax benefits are not extended, the RFS will have a larger impact on gasoline prices, as discussed in Chapter 5 of this report, with further effects on demand.

Table 5. Renewables Fuel Standard/MTBE Ban Based on AEO2002 (million barrels per day)

	2001	**2013**	
		Reference Case[a]	**RFS/Total Ban**
Total Petroleum Products Supplied	19.81	24.08	24.04
Ethanol Content supplied	0.112	0.193	0.324
Natural Gas Content supplied	1.81	2.49	2.48
Oil content supplied	17.24	21.56	21.47

a Includes consideration of the MTBE ban in the 17 states that have already passed laws banning MTBE.

Note: Individual supplies may not add to the total due to unaccounted for supplies and losses.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System date codes Ens1mXoX.d082302b and Ens1m087.d082302c.

Several other provisions in the Senate and House bills could also impact oil demand, but their effects are more speculative. Measures falling into this category include:

- Numerical Targets for Fuel Cell Vehicle Availability (Chapter 2, Section C.3)
- CAFE program provisions (Chapter 2, Section C.1)

26 Energy Information Administration, *Renewable Motor Fuel Production Capacity Under H.R.*4 (Washington, DC, March 2002), website http://tonto.eia.doe.gov/FTPROOT/service/question2.pdf, run ens1mxox.d082302b.

27 Energy Information Administration, *Annual Energy Outlook 2002,* DOE/EIA-0383(2002) (Washington, DC, September 2002), website http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2002).pdf.

- Voluntary Commitments for Faster Energy Intensity Reduction in Industry (Chapter 2, Section B.2)

While policies implemented pursuant to these provisions could affect oil use in transportation and industry, these provisions by themselves do not assure that such actions will be taken or that changes in oil use would occur. It is not readily apparent, for example, that enactment of the CAFE provisions of the House and Senate bills[28] would result in higher CAFE requirements than the continuation of existing law. It is beyond EIA's mission to speculate on future policy decisions.

3. **Examples of Policies to Reduce Oil Demand Under Existing Authorities.**

The discussion in the two previous sections suggests that actions already taken, or those mandated under provisions included in the House and Senate bills, are themselves unlikely to provide the 1 million barrel per day reduction in projected oil demand by 2013 called for in Amendment 871.

While it is beyond EIA's mission to speculate on future policy decisions, this section identifies several generic policies that might be included in a plan to reduce oil demand using existing authorities. The quantity of oil demand reduction available through these measures would depend on the specific parameters and timetables adopted if and when a particular policy is implemented.

a. Transportation

Available transportation sector policy options to help reduce U.S. petroleum consumption include revisions to CAFE standards, conversion of Federal fleets to alternative fuel sources, and Federal encouragement of pay-as-you-drive insurance arrangements that would reduce vehicle miles of travel by increasing consumers' perceived cost of incremental travel. Other transportation policies could also be considered, including increased use of high occupancy vehicle lanes, road pricing, and mass transit subsidies. However, studies examining the travel and energy impacts of these policies are very localized, and do not reflect the impact that might occur on a national level due to differences in travel behavior or access to facilities. As a result, it would be extremely difficult to quantify the national energy impacts of such policies given currently available data.

Increase CAFE

CAFE increases beyond those already announced could reduce oil demand. However, CAFE increases could have differential effects on manufacturers, and increase the cost of

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28 The existing provisions in both the House and Senate bills do not specify fuel economy standards for light duty vehicles. The House and Senate bills only require that the Department of Transportation to study and develop feasible fuel economy increases and provide proposed recommendations within a set period of time.

new vehicles, leading to some reduction in new car sales and consequent macroeconomic effects. (See Chapter 2, Section C on impact of various CAFE provisions).

Convert All Existing Gasoline Consumption in the Federal Fleet to Natural Gas or other Fuels

The Federal fleet consumes relatively small amounts of gasoline. In 2001, the Federal fleet consumed 0.019 million barrels per day of petroleum. By 2013, it is expected that the Federal fleet would consume 0.014 million barrels per day of petroleum, which could be converted to other fuels.

Pay-As-You-Drive Insurance

Traditionally, vehicle insurance is sold on an "all you can drive" basis and is generally considered a fixed cost by drivers. Motorists do not usually perceive insurance cost varying with mileage. Pay-As-You-Drive insurance pricing converts fixed insurance payments to a variable cost with respect to usage rates. This gives motorists the opportunity to save money if they reduce personal vehicle travel. From a review of the literature, Pay-As-You-Drive insurance programs have been estimated to reduce personal vehicle travel by 2 to10 percent annually.[29,30] The Federal Highway Administration is currently funding analysis of Pay-As-You-Drive programs to determine the impact on personal travel.[31]

b. Industrial Sector

Most petroleum consumed in the industrial sector is not easily reduced. Approximately half (4.3 quadrillion Btu) of industrial petroleum consumption is used as a feedstock or as a material in construction. An additional 25 percent of industrial petroleum consumption (2.3 quadrillion Btu) results from combustion of the refinery byproducts, still gas and petroleum coke (see Table 6).

Petroleum consumed as a boiler fuel in the industrial sector is also minimal, approximately 300 trillion Btu.

Options to reduce petroleum consumption in the industrial sector are limited. For example, there are ongoing research programs to reduce the feedstock requirements for chemical processes. Boiler efficiency standards were enacted with the Energy Policy Act of 1992. However, given the limited number of industrial boiler capacity additions, these standards would have minimal impact on petroleum energy consumption. *AEO2003*

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29 University of Delaware, Center for Energy and Environmental Policy, *"Delaware Climate Change Action Plan,"* prepared for Delaware Climate Change Consortium, Pg. 82, January, 2000.

30 Litman, Todd, *"Implementing Pay-As-You-Drive Vehicle Insurance Policy Options"*, prepared for Institute for Public Policy Research, Pg. 7, London, July, 2002.

31 Federal Highway Administration, http://www.hhh.umn.edu/centers/slp/projects/conpric/learn/types_b.htm

included a case representing a more optimistic view of energy-related technology improvements. In that case, industrial petroleum consumption in 2013 was reduced from the Reference Case value of 10.3 quadrillion Btu to 10.1 quadrillion Btu (1.5 percent) in the High Technology Case.[32]

Table 6. Industrial Petroleum Consumption, Selected Products, 2001 (quadrillion Btu)

	2001
LPG Feed	1.90
Petrochemical Feed	1.14
Asphalt	1.26
Non-combustion Total	4.29
Petroleum Coke	0.84
Still Gas	1.44
Byproduct Total	2.28
Total Petroleum	8.79

Source: Unpublished detail from Energy Information Administration, *Annual Energy Outlook 2003,* DOE/EIA-0383(2003) (Washington, DC, January 2003), web site http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2003).pdf

c. Residential and Commercial Sectors

Higher Federal Efficiency Standards Issued for Oil and Gas Furnaces, Boilers, and Water Heaters and Increased Weatherization Project Support

Higher efficiency standards for oil-using furnaces, more stringent building codes, and increased weatherization efforts could all contribute to reductions in residential petroleum consumption. A similar approach could be applicable in the commercial sector.

However, residential and commercial demand accounts for a small and declining proportion of oil use, buildings and equipment turn over slowly, and many of the key decisions about building code stringency are made below the federal level.
These conditions limit available oil demand savings in these sectors.

d. Electricity Sector

Very little petroleum is consumed in the electricity sector. Since petroleum is typically the most expensive fuel, oil-fired plants tend to have relatively low utilization rates. Consequently, oil consumption in the electricity sector is minimized even in the Reference Case projections. In 2001, there were over 5,000 generating plants, but fewer

[32] Energy Information Administration, *Annual Energy Outlook 2003,* DOE/EIA-0383(2003), (Washington, DC, January 2003), Table F2, web site http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2003).pdf.

than 900 plants generated at least one million kilowatthours of electricity from oil combustion. Electricity sector petroleum consumption is projected to be 200 thousand barrels per day (1.2 percent of total generation) in 2013.

3. Oil and Gas Supply Provisions

Numerous provisions have appeared in the energy bills that would affect oil and gas supply. The specific issues analyzed by EIA are:

- Incentives to Sell Alternative Vehicle Transportation Fuels;
- Credits for Nonconventional Fuels Production;
- Opening the Coastal Plain area of the Arctic National Wildlife Refuge to Crude Oil Production; and
- Impact of Provisions to Provide Incentive for the Construction of an Alaska Natural Gas Pipeline to the Lower-48 States.

A. Alternative Motor Vehicle Fuels Credit

1. Credit for Retail Sale of Alternative Fuels as Motor Vehicle Fuel (Senate 2004)

Under Section 2004 of the Senate bill (there is no comparable provision in the House bill), a retail sales credit is proposed for alternative fuels used in motor vehicles, including compressed natural gas, liquefied natural gas, liquefied petroleum gas, hydrogen, and any liquid that consists of at least 85 percent methanol or ethanol by volume. The sales credit is specified in nominal cents per gallon of gasoline equivalent. The credit is 30 cents per gallon from September 2002 through the end of 2003, 40 cents in 2004, and 50 cents in 2005 and 2006.[33]

Impact of Alternative Motor Vehicle Fuels Credit

The discussion of the impact of the alternative motor vehicle fuels credit is based on the Reference Case assumptions in *AEO2002.*[34] NEMS only represents prices for three types of alternative fuels: compressed natural gas (CNG), liquefied petroleum gas (LPG), and a fuel mixture of 85 percent ethanol and 15 percent gasoline (E85). Currently there are no liquefied natural gas or hydrogen vehicles on the market and future sales are estimated using a simplified methodology. In order to analyze the impact of the bill, the end-use prices for CNG, LPG, and E85 were reduced by the sales credit values specified in the bill for the given years (after appropriate unit conversions were performed). The analysis was based on the Reference Case used for the CAFE standards analysis.[35] The resulting average national alternative fuel prices for the Reference and the Credit Case for the years 2003 through 2006 are shown in Table 7.

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[33] The dates are as stated in the Senate bill. Clearly, they will not need to be updated by the conferees.

[34] Energy Information Administration, *Annual Energy Outlook 2002,* DOE/EIA-0383(2002), (Washington, DC, December 2002), web site http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2002).pdf, run taxbas.d081202a.

[35] Run s804base.d020702b.

Table 7. Alternative Fuel Prices in the Reference Case and Credit Case

	CNG (2001$/mcf)				LPG (2001$/gal)				E85 (2001$/gal)			
	2003	**2004**	**2005**	**2006**	**2003**	**2004**	**2005**	**2006**	**2003**	**2004**	**2005**	**2006**
Reference	6.72	6.90	6.99	7.07	1.24	1.25	1.24	1.25	1.74	1.80	1.76	1.79
Credit Case	4.39	3.88	3.32	3.53	1.04	0.99	0.94	0.94	1.53	1.53	1.48	1.55

Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs taxbas.d081202a and taxalt.d081302d.

Currently the total amount of fuel consumed on a Btu basis by the alternative fuel vehicles identified in the bill represents less than 0.3 percent of the total fuel consumed in the transportation sector. The proposed credit would raise this share by an additional 0.07 percentage points in 2006, the year with the largest credit. As a result, the impact on all primary energy indicators is negligible. However, in 2006, consumption of each fuel under the Credit Case is expected to be higher than in the Reference Case by 7, 59, and 28 percent for CNG, LPG, and E85, respectively. The more limited response to the large CNG price reduction is attributable to the longer lead times required to produce natural gas-capable vehicles and develop the necessary infrastructure. Consumption of the petroleum-based products increases more rapidly because of the lower incremental vehicle costs. The impact of the sales credit rapidly diminishes, especially for the petroleum products, once the credit is removed.

B. Nonconventional Fuels

1. Tax Credits for Nonconventional Fuels Production (House 43005, Senate 2310)

Under present law, a credit of $6.28 per barrel (or Btu equivalent) is provided for fuels produced from nonconventional sources: oil from shale or tar sands; gas from geopressured brine, Devonian shale, coal seams, tight formations, or biomass; and liquid, gaseous, or solid fuels produced from coal (including lignite). For facilities producing gas from biomass or synthetic fuel from coal, the credit is available for production through 2007 from facilities placed in service before July 1, 1998. For other sources, credit was available for production through 2002 for facilities placed in service from 1980 to 1992. Section 43005 of the House bill and Section 2310 of the Senate bill extend and expand the tax credit for producing fuel from certain nonconventional sources.

Section 43005 of the House bill allows a credit of $3 (indexed for inflation) per barrel (or Btu equivalent) for production from all nonconventional sources except landfills for the first four years of production prior to 2010 for new wells placed in service through 2006. Production from existing wells (drilled 1980-1992) is eligible for the credit for production in 2003-2006. For landfills regulated by the Environmental Protection Agency (EPA) the credit is $2. Landfill gas facilities placed in service after June 30, 1998, and before January 1, 2007, are eligible for five years of credit. The credit in this provision is limited to an average daily production of 200,000 cubic feet of gas (or oil equivalent) per project.

Section 2310 of the Senate bill allows a credit of $3 (unindexed for inflation) per barrel (or Btu equivalent) for three years of production from nonconventional fuel sources for new wells placed in service after the date of the enactment of this subsection and before January 1, 2005. Qualifying fuels are oil from shale or tar sands and gas from geopressured brine, Devonian shale, coal seams, or a tight formation. The bill also permits a similar $3 per barrel credit for the production of "viscous oil," the production of "coalmine methane gas" at active (or soon to be active) coal mines, and the production of liquid, gaseous, or solid fuels from agricultural and animal wastes. These credits also extend for three years of production commencing when facilities are placed in service.

Impact of Extending Nonconventional Fuels Credits

The following analysis of the provisions of the House and Senate bills concerning nonconventional fuel credits was completed in August 2002 using the Reference Case from the *AEO2002*.[36] After that Reference Case was finalized in October 2001, natural gas wellhead prices moved substantially higher then expected. If this trend continues, the effect of the proposed bills might be less than projected in this analysis because the size of the credit is reduced if the sale price exceeds $4.04 per mcf in 2002 dollars. The credit is reduced by the ratio of the sale price minus $4.04 to $1.03. If the price were $5, for example, the tax credit would be reduced by 93 percent ((5.00-4.04)/1.03). Prices above $4.04 were not projected for the periods of the proposed tax credit in *AEO2002*, and the allowable credit was, accordingly, not reduced in this analysis. Should the current price levels continue, some reduction in the credit would occur.

For this analysis, the major assumptions relate to the resource base that would be eligible for the credit. For undeveloped natural gas resources in coal seams, Devonian shales, and tight formations it was assumed that 60 tcf, 55 tcf, and 228 tcf, respectively, would be eligible for the credit.

For the House bill, EIA analyzed the impact of allowing a credit of 50 cents per mcf ($3 per barrel Btu equivalent) for the first four years of gas production prior to 2010 for production from Devonian shales, coal seams, and tight formations for new wells placed in service through 2006. The primary impacts are a slight increase in the production of gas from nonconventional sources and a slight decrease in production from conventional sources and net imports of natural gas relative to the Reference Case (Table 8). Cumulative production from nonconventional gas sources is projected to be 2.9 percent (1.4 tcf) higher then the Reference Case for the period 2003 to 2010 and 0.5 percent (0.4 tcf) higher from 2011 to 2020 than that production in the Reference Case without the credit. Cumulative net natural gas imports are projected to be 1.5 percent lower (0.6 tcf) from 2003 to 2010 and 1 percent (0.5 tcf) lower from 2011 to 2020 than projected in the Reference Case. Because consumption levels are the same in the tax credit case as in the Reference Case, total natural gas supply does not change from the Reference Case. Thus,

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[36] Energy Information Administration, *Annual Energy Outlook 2002,* DOE/EIA-0383(2002), (Washington, DC, December 2002), web site http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2002).pdf.

the incremental production from nonconventional sources in the tax credit case displaces imported supplies and, to some extent, production from conventional sources.

Table 8. Incremental Impact of House Version - Section 43005 (Selected Components)

Variable	Projections						
	2004	2005	2006	2007	2008	2009	2010
Nonconventional Prod. (tcf)							
Change Relative to Reference	0.1	0.2	0.2	0.3	0.3	0.2	0.2
%Change Relative to Reference	1.1%	2.6%	3.6%	4.4%	4.1%	3.6%	2.8%
Conventional Prod. (tcf)							
Change Relative to Reference	-0.1	-0.1	-0.2	-0.2	-0.2	-0.1	0.0
%Change Relative to Reference	-0.4%	-0.8%	-1.1%	-1.2%	-1.1%	-0.7%	-0.2%
Net Imports (tcf)							
Change Relative to Reference	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.2
%Change Relative to Reference	-0.1%	-0.6%	-1.2%	-1.8%	-2.1%	-2.6%	-3.1%
Wellhead Price (2001 $/mcf)							
Change Relative to Reference	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1
%Change Relative to Reference	-0.7%	-1.8%	-2.9%	-3.9%	-4.4%	-4.4%	-3.6%

Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, AEO2002 National Energy Modeling System runs AEO2002.D102001B and ENER_AEO.D081402A.

The House version of the bill is also projected to have a small impact on the natural gas wellhead price. From 2003 to 2010 the projected wellhead price averages 2.8 percent (7 cents per mcf) lower than in the Reference Case. However, the price is projected to be very slightly higher, 1.2 percent (4 cents per mcf) on average, in the last ten years of the forecast, as the effect of the tax incentive wanes.

For the Senate bill, EIA analyzed the impact of a credit of 50 cents (unindexed for inflation) per mcf for the first 3 years of gas production from Devonian shales, coal seams, and tight formations for new wells placed in service through 2004. The effects are projected to be very slight. Cumulative production from nonconventional sources is projected to be 1 percent (0.5 tcf) higher from 2003 to 2010 than projected production in a Reference Case without the credit (Table 9). From 2011 to 2020 nonconventional gas production in the two cases is projected to be virtually the same. The effect on net natural gas imports is also expected to be very slight, as cumulative imports are projected to be 0.7 percent (0.2 tcf) lower from 2003 to 2010 and 0.6 percent (0.3 tcf) lower from 2011 to 2020 than projected in the Reference Case.

Table 9. Impact of Senate Section 2310 (Selected Components)

Variable	Projections						
	2004	2005	2006	2007	2008	2009	2010
Nonconventional Prod. (tcf)							
Change Relative to Reference	0.0	0.1	0.1	0.1	0.1	0.1	0.0
%Change Relative to Reference	0.8%	1.5%	1.6%	1.4%	1.0%	1.0%	0.7%
Conventional Prod. (tcf)							
Change Relative to Reference	0.0	-0.1	-0.1	0.0	0.0	0.0	0.0
%Change Relative to Reference	-0.3%	-0.5%	-0.4%	-0.3%	-0.2%	-0.1%	0.1%
Net Imports (tcf)							
Change Relative to Reference	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1
%Change Relative to Reference	-0.1%	-0.4%	-0.6%	-0.8%	-1.0%	-1.1%	-1.1%
Wellhead Price (2001 $/mcf)							
Change Relative to Reference	-0.01	-0.03	-0.04	-0.04	-0.04	-0.04	-0.02
%Change Relative to Reference	-0.5%	-1.1%	-1.4%	-1.6%	-1.5%	-1.3%	-0.8%

Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, AEO2002 National Energy Modeling System runs AEO2002.D102001B and ENER_SEN.D082002B.

The effect of the Section 2310 of the Senate bill on the price of natural gas is projected to be minimal. The projected natural gas wellhead price averages 1.1 percent lower than in the Reference Case from 2003 to 2010 and is virtually the same thereafter.

C. Drilling in the Arctic National Wildlife Refuge

1. Opening the Coastal Plain Area of the Arctic National Wildlife Refuge to Crude Oil Production (House 30401 – 30412)

Sections 30401-30412 of the House Energy Bill, “Arctic Coastal Plain Domestic Energy Security Act of 2003,” call for establishing a competitive oil and gas leasing program in the coastal plain of the Arctic National Wildlife Refuge (ANWR), resulting in an “environmentally sound” program for the exploration, development, and production of oil and gas resources in this area.

The Federal Government now prohibits oil and natural gas development in ANWR, which is located on the northern coast of Alaska, due east of both Prudhoe Bay, the largest oil field ever discovered in the United States, and the National Petroleum Reserve-Alaska (NPRA). Surveys conducted by the U.S. Geological Survey (USGS) suggest that between 5.7 and 16.0 billion barrels of technically-recoverable oil are in the coastal plain area of ANWR (also referred to as the 1002 Area), with a mean estimate of 10.4 billion barrels, divided into many fields. (Technically-recoverable resources are resources that can be recovered with today's technology.) This estimate includes oil resources in Native lands and State waters out to a 3-mile boundary within the coastal plain area. The mean estimated size of oil resources on Federal lands alone is 7.7 billion barrels. In comparison, the estimated volume of technically-recoverable undiscovered oil in the rest of the United States is 136 billion barrels. Ultimate recovery at the Prudhoe Bay field, including production to date, is estimated to be 13.0 billion barrels.

ANWR was created by the Alaska National Interest Lands Conservation Act (ANILCA) in 1980. Section 1002 of ANILCA deferred a decision on the management of oil and gas exploration and development of 1.5 million acres of potentially productive lands in the coastal plain of ANWR. The "Arctic Coastal Plain Domestic Energy Security Act of 2003" proposes to open this coastal plain area to exploration and production. The coastal plain area represents about 8 percent of the total area of ANWR. The USGS estimates that 74 percent of the oil resources in ANWR's coastal plain area are on Federal lands, with the remaining 26 percent on State and Native lands. To date, there has been no assessment of the oil and natural gas resources in the portion of ANWR outside of the coastal plain area. However, it is unlikely that the non-coastal plain area of ANWR has the same levels of resources that are estimated to be in the coastal plain area, due to differences in geology.

At the present time, there has been no exploration and development activity in the coastal plain region. An earlier EIA report, *Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment,*[37] suggested that between seven and twelve years were required from an approval to explore and develop to first production from the coastal region of ANWR. The study further noted that the time to first production could vary significantly based on time required for leasing after approval to develop is awarded and that environmental considerations and the possibility of drilling restrictions also could significantly affect projected schedules. This earlier analysis assumed that the earliest date that production from ANWR could occur was 2011. Since the bill was not passed in 2002, the earliest production date is now 2012 and the 2020 impact discussed below would occur in 2021 or later.

The current analysis uses the USGS assessment of potential field sizes in the coastal plain area, based on its assessment of the underlying geology. For the purposes of evaluating

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[37] Energy Information Administration, *Potential Oil Production form the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment,* SR/O&G/2000-02, (Washington, DC, May 2002), http://www.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/arctic_national_wildlife_refuge/html/anwr101.html.

the impact of opening ANWR on U.S. markets, EIA assumed that State and Native lands within the coastal plain of ANWR would be opened for development.

In the mean resource expectation case, the total volume of technically recoverable crude oil projected to be found within the coastal plain area is 10.4 billion barrels. The largest projected field in ANWR is nearly 1.4 billion barrels. While considerably smaller than the 13-billion-barrel Prudhoe Bay field, this would be larger than any new field brought into production in decades. Subsequent fields are expected to be considerably smaller, with two additional fields with 700 million barrels of oil, five additional fields each with 340 million barrels of oil, and a large number of smaller fields. To put this in context with recent domestic oil discoveries, the Alpine Oil field in Alaska, the largest field to start producing in recent years, is estimated to have 413 million barrels of ultimate recovery.

Potential production from ANWR fields is based on the size of the field discovered and the production profiles of other fields of the same size in Alaska with similar geological characteristics. In general, fields are assumed to take three to four years to reach peak production, maintain peak production for three to four years, and then decline until they are no longer profitable and are closed.

The USGS estimates the total volume of non-associated, technically-recoverable natural gas resources available in ANWR to be between 0 and 10 tcf, with a mean estimated value of 3.5 tcf. An additional 2.0 to 5.5 tcf of technically-recoverable natural gas is estimated to exist in ANWR as associated gas, with a mean estimate of 3.6 tcf. The 35 tcf of stranded natural gas assets estimated to have been found already in Prudhoe Bay and other areas of the North Slope is not currently being commercially developed. These reserves would most likely be developed first if the infrastructure is developed to market North Slope natural gas.

Impact of ANWR Provisions

The basis of the discussion of the ANWR provisions is a study completed by EIA, *The Effects of the Alaska Oil and Natural Gas Provisions of H.R.4 and S.1766 on U.S. Energy Markets*[38] completed in 2002 using *AEO2002* as a Reference Case.[39] After opening ANWR, total Alaskan oil production in the mean resource expectation case is estimated to reach 1.9 million barrels per day in 2020 in this analysis, 800,000 barrels per day higher than it is in the Reference Case, which does not include opening ANWR. The projected volume of production from ANWR represents roughly 0.7 percent of projected world oil production in 2020. Total U.S. crude oil production is projected to reach 6.4

[38] Energy Information Administration, *The Effects of the Alaska Oil and Natural Gas Provisions of H.R. 4 and S. 1766 on U.S. Energy Markets,* SR/OIAF/2002-02, (Washington, DC, February 2002), web site http://www.eia.doe.gov/oiaf/servicerpt/aong/pdf/sroiaf(2002)02.pdf, run anwr_bs.d012202a.

[39] Energy Information Administration, *Annual Energy Outlook 2002,* DOE/EIA-0383(2002), (Washington, DC, September 2002), web site http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2002).pdf.

million barrels per day, compared to 5.6 million barrels per day in 2020 in the Reference Case.

The increase in ANWR production would lead to a decline in the U.S. dependence on foreign oil. In the Reference Case, net imports are projected to supply 62 percent of all oil used in the United States by 2020. Opening ANWR is estimated to reduce the percentage share of net imports to 60 percent. Nearly 89 percent of the offset imports comes from reducing crude oil imports, with the rest of the offset coming from reducing product imports. Opening ANWR is also projected to increase U.S. employment in the oil and gas sector, but estimating the size of the employment effects is beyond the scope of this analysis.

There are several areas of uncertainty when considering the impact of ANWR production on U.S. energy markets:

- *The size of the underlying resource base*. There has not been an extensive geological study of the ANWR area. Determining the precise size of oil resources within ANWR will take further study and exploration. The size of the resources will determine the potential ultimate recovery in the region as well as the potential yearly production.

- *The underlying field structure*. The size of reservoirs that are found in ANWR will determine the rate at which ANWR oil and gas resources are developed. If the reservoirs are larger than expected, production will be larger in earlier years.

- *The costs of developing oil resources in ANWR*. This analysis assumes that the costs of developing ANWR are not significantly different than the costs of developing oil resources in other parts of northern Alaska. If these costs are higher, ANWR production may be delayed.

- *Timing of ANWR production*. This analysis assumes that production in ANWR will begin in 2011. It also assumes that production in each new field could not open until two years after production begins in the last field to be previously opened. The actual timing of ANWR production could vary from that assumed in this study.

- *Environmental considerations.* Environmental restrictions could affect access for exploration and development.

D. Alaska Natural Gas Pipeline

Alaska's North Slope has extensive natural gas resources, 35 tcf of which have been discovered to date, with initial estimates of 16 tcf yet-to-be discovered resources.[40] While this gas could be produced at relatively low cost, a particularly large and long pipeline would need to be constructed to bring it to market in the lower-48 States. A pipeline for Alaska natural gas has been discussed since the 1970s. In 1977, the United States and Canada signed an agreement in principle for the Alaska Natural Gas Transportation System (ANGTS) that proposed the delivery of 2 billion cubic feet (bcf) per day from the Alaska North Slope, along the Alaska-Canadian highway to near Calgary, Alberta, and down to the lower-48 States.

With deregulation of U.S. natural gas supply and development of lower-cost resources both in the lower-48 States and Canada, interest in ANGTS waned. Discussion of a natural gas pipeline from Alaska resurfaced in 1999 and 2000, when high gas prices led to a reevaluation of the feasibility of developing "stranded" Alaska gas reserves. Conoco Phillips, BP, and ExxonMobil formed a partnership to investigate the potential of developing a gas pipeline, following roughly the route proposed by ANGTS (the "Southern" route) or an alternate route across the Beaufort Sea to the MacKenzie Delta in Canada and then down to Alberta (the Northern Route"). The results of their analysis, released in May 2002, indicated that the project was not commercially viable at that time and that the Governments will need to play a role in reducing project costs and scheduling risks.

Using cost estimates from the Conoco Phillips, BP, and ExxonMobil analysis and an assortment of other assumptions, EIA has estimated in its *Annual Energy Outlook 2003 (AEO2003)* that it would require an average lower-48 wellhead gas price of $3.48 per mcf (in 2001 dollars) for the pipeline project to be viable and that it would be built by around 2020 without added incentives. With total project cost estimates of $19.4 billion (in 2001 dollars), lead times of between 7 and 10 years, and the volatile nature of natural gas prices, the risks associated with such an undertaking are significant.

1. Alaska Pipeline Bill Provisions in the House and the Senate Bills

Both of the separately-passed Senate and House energy bills prohibit northern routes for an Alaska natural gas pipeline and promote its expedited approval. However, only the Senate bill provides for a pipeline loan guarantee (Sec. 710) and a northern Alaska natural gas production tax credit (Sec. 2503). The pipeline loan guarantee is intended to cover "not more than 80 percent of the principal of any loan" issued "for the purpose of constructing an Alaska natural gas transportation project" and is limited to $10 billion dollars. The loan guarantee is only available if an application for a certificate of public convenience and necessity for the pipeline has been filed within 18 months after the bill's enactment. The production tax credit applies to the production of marketed Alaska

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[40] Alaska Producer Pipeline Update, sponsored by BP ExxonMobil, and Conoco Phillips, May 2002 PowerPoint presentation.

natural gas entering the pipeline from an area lying north of 64 degrees North Latitude. The amount of the credit is calculated as the difference between $3.25 per million Btu (in nominal dollars in the first year of operation, adjusted for inflation thereafter) and the average monthly price at the AECO-C Hub in Alberta, Canada, effectively guaranteeing producers a floor price of $3.25 per million Btu in Alberta, including the tax credit. This credit is to start no earlier than January 1, 2010, and to extend for 15 years after the initial flow of gas. Three years after the flow of gas commences, the credited amount is to be repaid to the Government on a monthly basis in increments equal to the AECO-C Hub price minus $4.87 per million Btu (in nominal dollars in the first year of operation, adjusted for inflation thereafter), should this difference be positive, times the monthly flow of marketed natural gas.

Alaska natural gas pipeline provisions were also included in S.14 and S.1149, which were debated in the Senate this year but were set aside prior to the August recess when the Senate passed comprehensive energy legislation with the same provisions as the Senate-passed bill from the prior Congress. The tax credit provisions in S.1149 are set relative to a price in Alaska rather than Alberta. The loan guarantee in S.14 differs from those in the Senate-passed bill in that it includes qualifying facilities in Canada and has a higher cap of $18 billion dollars.

The discussion of the Alaska natural gas pipeline incentives below is organized into three distinct parts.

- The first part outlines the key factors affecting the entry-into-service (EIS) of the pipeline, both with and without the incentives. A wide range of EIS dates, both with and without incentives, appears to be possible.
- The second part examines gas market implications of the incentives in the Senate-passed version of H.R. 6, comparing a Reference Case in which the pipeline does not enter service until 2020 with an alternative case in which the pipeline enters service in 2013. These cases reflect the same set of assumptions regarding baseline natural gas prices and the time required to complete the pipeline. While results could differ substantially under other assumptions, these cases provide insight into the implications of earlier EIS dates for the pipeline on natural gas markets.
- The third part discusses the differences between the tax credit provisions in the Senate-passed bill and those in S. 14 and S.1149, including implications for the construction of the pipeline and projected effects on tax revenue.

2. Key Factors Affecting EIS of an Alaska Natural Gas Pipeline

a. Natural Gas Prices

As noted above, projected natural gas prices in the period following EIS are a key factor affecting the economic viability of a pipeline to bring natural gas from Alaska's North Slope to markets in the lower-48 States. Traditionally, natural gas producers have used current prices as a guide for investment decisions. However, most investments, such as the decision to drill a well, have relatively short gestation periods and relatively rapid payouts. For example, a typical gas well can be connected to the system within a year of project initiation and produces more than 75 percent of its total output within 2 years of being connected. Because a pipeline to transport natural gas from Alaska's North Slope to the lower-48 markets will have a long gestation period and operate for many years, investment in such a project will tend to be less influenced by short-term natural gas price movements. As a proxy for the sustained higher prices required to motivate investment in a pipeline, the assumption used in EIA's *AEO2003* is that the pipeline project would begin construction once the average price of natural gas at the wellhead exceeds $3.48 per mcf (in 2001 dollars) for 3 consecutive years, during which time permits would be obtained. Under this Reference Case, the pipeline does not enter service until 2021. The reference case from a more recent study, with the same assumptions for the pipeline and slightly higher prices, had an in-service date of 2020.

Since publication of the *AEO2003*, there have been increasing questions regarding the adequacy of natural gas supplies for the lower-48 market. The amount of working gas in storage reached record lows at the end of the 2002 to 2003 winter season. Prices throughout 2003 have averaged well above $3.48 per mcf, and EIA's *Short-Term Energy Outlook (STEO)* projects that average prices at the wellhead will remain above that level through 2004, the end of the *STEO* projection horizon. New supply options, consisting of liquefied natural gas imports, imports from the MacKenzie Delta, unconventional gas, and gas from Alaska, have been identified. Because of the high capital costs and long construction lead time involved, bringing gas from Alaska by a pipeline through Canada is among the most risky options. This high level of risk has prompted developers to wait. However, were average wellhead natural gas prices in 2004 and 2005 to remain clearly above the $3.48 level and if planning were to commence in 2006, an Alaska pipeline could be expected to be completed between 2013 and 2016. The longer the natural gas price remains at high levels, the greater the incentive for completion.

b. Pipeline Project Gestation Period

The *AEO2003* assumes that an Alaska natural gas pipeline can enter into service within 7 years of project initiation, including planning and approvals. Other information, including an estimate by the three major North Slope producers, suggests a longer period, perhaps 9 or 10 years, from initiation of the project to its completion. With this in mind EIA has now set the earliest likely start year at 2013.

A 7-to-10 year period probably represents a reasonable range of estimates for the amount of time to complete the pipeline project once the planning phase is launched. It is not clear where the actual time-to-build might fall within this range or whether the time-to-build would itself be significantly affected by the availability of incentives or the other provisions regarding the pipeline project that are also included in proposed legislation. The actual amount of time required to build the project will clearly affect the timing of EIS, with or without incentives.

3. Market Impacts of Alternative Alaska Pipeline Entry into Service Dates

To estimate the impacts on natural gas markets of alternative pipeline EIS dates, two cases were compared: one where EIS occurs in 2020 (the 2020 Start Case), the other where EIS occurs in 2013 (the 2013 Start Case).

Impact of an Earlier Alaska Pipeline Start Date

The analysis of the market impacts of an earlier pipeline start date in response to the proposed production tax credit provisions was based on the Reference Case[41] developed as part of a mid-year revision to *AEO2003* completed for the study, *Analysis of S.139, the Climate Stewardship Act of 2003*.[42] The natural gas price, consumption, and production impacts from this analysis reflect specific reference and policy cases based on *AEO2003*, originally released in November 2002, with some limited updating. Under this Reference Case the pipeline enters service in 2020, with a capacity expansion with added compression assumed to start in 2024. Significant changes in the EIA's long-term outlook could occur when the *AEO2004* is released this Fall. For this reason, it is recommended that users focus their review of these variables on the differences between the two EIS cases rather than the absolute results for either case.

Table 10 provides a summary of the results. Without the tax credit, an Alaska gas pipeline is projected to begin operation in 2020, with initial delivery at 3.9 bcf per day. In this case expansion was assumed not to occur before the end of the forecast horizon in 2025. However, a tax credit is expected to provide sufficient incentive for project planning, followed by construction, to commence upon legislative enactment. Under such a scenario, the pipeline is expected to begin operation in 2013, with no significant opposition or construction delays, at a dry gas delivery rate of 3.9 Bcf per day throughout the forecast period. While it is possible that a capacity expansion will occur, EIA assumed no expansion for the purposes of this analysis. Expansion is likely to occur if market conditions in the lower 48 States warrant it and supplies in Alaska are deemed adequate upon further exploration for natural gas on the North Slope.

[41] This Reference Case updated the *AEO2003* Reference Case by 1) an adjustment in near-term natural gas supply curves to reflect higher projected prices for 2003 and 2004 and 2) increased planned natural gas generation capacity.

[42] Energy Information Administration, *Analysis of S.139, the Climate Stewardship Act of 2003,* SR/OIAF/2003-02 (Washington, DC, June 2003), web site http://www.eia.doe.gov/oiaf/servicerpt/ml/pdf/summary.pdf.

Table 10. Introduction of Alaska Gas Pipeline Under a Tax Credit Incentive in 2013 Relative to the Projected 2020 Introduction[43] (volumes in trillion cubic feet, prices in 2001 dollars per thousand cubic feet, revenues in billions of 2001 dollars)

2020 Start Case

	2013	2015	2017	2020	2025	Cumulative 2013-2025
Total Dry Gas Production	22.73	23.10	23.31	24.84	25.93	318.31
Lower 48 Production	22.23	22.59	22.79	23.49	23.75	302.50
Conventional Production	14.11	13.96	13.77	13.87	13.97	181.61
Unconventional Production	8.12	8.63	9.02	9.62	9.78	120.89
Alaska Production	0.50	0.51	0.53	1.35	2.18	15.81
Total Net Gas Imports	5.35	5.85	6.49	6.97	8.11	86.73
Net Imports from Canada	4.40	4.73	5.13	5.10	5.06	64.12
Net Imports from Mexico	-0.17	-0.13	-0.09	0.11	0.47	0.75
Net LNG Imports	1.12	1.25	1.46	1.76	2.58	21.86
Total Consumption	28.46	29.34	30.19	32.19	34.46	410.17
Average Gas Prices						
Lower-48 Wellhead	3.55	3.67	3.73	3.71	4.08	NA
Delivered to Consumers	5.41	5.53	5.57	5.54	5.86	NA

2013 Start Case

	2013	2015	2017	2020	2025	Cumulative 2013-2025
Total Dry Gas Production	23.05	24.04	24.48	25.42	26.01	323.48
Lower 48 Production	21.75	21.92	22.35	23.28	23.83	296.47
Conventional Production	13.90	13.76	13.69	13.94	13.89	179.26
Unconventional Production	7.85	8.16	8.66	9.33	9.94	117.22
Alaska Production	1.30	2.11	2.13	2.15	2.18	27.01
Total Net Gas Imports	5.19	5.36	5.76	6.47	8.01	83.40
Net Imports from Canada	4.30	4.44	4.72	5.11	5.31	63.66
Net Imports from Mexico	-0.17	-0.14	-0.11	-0.03	0.29	-0.15
Net LNG Imports	1.06	1.05	1.14	1.40	2.41	19.89
Total Consumption	28.62	29.78	30.64	32.28	34.43	412.00
Average Gas Prices						
Lower-48 Wellhead	3.45	3.42	3.57	3.81	3.97	NA
Delivered to Consumers	5.33	5.28	5.40	5.61	5.81	NA
Net Revenue Impact						
U.S. Consumer Savings	1.53	5.14	2.75	-2.67	1.87	19.72
Lower 48 Producer Revenue Losses	3.94	7.99	5.19	-1.36	2.27	48.29

43 The Reference Case with a 2020 start date in the original analysis included an expansion of the pipeline, resulting in slightly different results.

Difference Between 2020 Start Case and 2013 Start Case Results

	2013	2015	2017	2020	2025	Cumulative 2010-2025
Average Natural Gas Prices						
Lower-48 Wellhead	-0.10	-0.25	-0.16	0.09	-0.11	NA
Delivered to Consumers	-0.09	-0.25	-0.17	0.07	-0.05	NA
Gas Volumes						
Consumption	0.17	0.43	0.44	0.08	-0.03	1.83
Lower 48 Production	-0.48	-0.67	-0.43	-0.21	0.08	-6.03
Alaska Production	0.80	1.60	1.60	0.80	0.00	11.20
Net Imports	-0.15	-0.49	-0.73	-0.49	-0.10	-3.32

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs bsangts3.d100703b and angts3.d100603a.

Under both cases Alaska production continues to provide for consumption in the State itself and for liquefied natural gas (LNG) exports to Japan. Total Alaska production is projected to increase from 0.4 trillion cubic feet (tcf) in 2002 to 2.2 tcf by 2025. Of the 11.6-tcf increase in supply needed by the United States in 2025 compared with 2002, 15 percent is expected from Alaska in both cases. On a cumulative basis from 2002 through 2025 Alaska production represents 3.9 and 6.6 percent of U.S. supply in the 2020 Start Case and the 2013 Start Case, respectively. However, Alaska is expected to represent an even greater share of the cumulative growth in U.S. supply during the forecast over 2002 levels – 8.3 percent in the 2020 Start Case and 16.0 percent in the 2013 Start Case.

The introduction of Alaska natural gas to the lower-48 States results in reduced domestic production in the lower-48 States, reduced imports, and increased consumption. Of the additional 11.2 tcf of cumulative production in Alaska from 2013 to 2025 that results from the earlier introduction of the pipeline in 2013, 16 percent represents increased consumption, 54 percent displaces lower-48 production, 30 percent displaces imports. Cumulative natural gas production from unconventional sources[44] absorbs about 60 percent of the lower 48 reduction, although it represents only about 40 percent of the cumulative lower-48 production over the period. This can be attributed to the typically higher costs associated with unconventional natural gas production (most of which is located in the Rocky Mountain region), identifying it as a marginal supply source. LNG imports into the United States, and into Mexico that are targeted for the United States, represent 86 percent of the net import reduction, with the remainder attributable to Canada. The differences between the two cases are greatest between 2014 and 2017.

[44] Unconventional natural gas is produced from tight sands, Devonian/Antrim shale, and coalbed methane formations.

Large-volume supply projects, such as an Alaska natural gas pipeline, are expected to place downward pressure on prices, particularly when initially brought online. Under the 2020 Start Case, an Alaska pipeline results in an annual price reduction in the overall lower-48 wellhead price in 2020 of 4 cents (in 2001 dollars) compared to the price in the previous year. The 2013 introduction of the pipeline reduces the average wellhead price by 9 cents in 2014 compared to 2012. When comparing the price differences between the two cases, the greatest difference occurs in 2015, when the wellhead price is 25 cents lower (in 2001 dollars) in the 2013 Start Case, relative to the \$3.67-per-mcf price in the 2020 Start Case in 2015. Prices are generally higher throughout the forecast in the 2020 Start Case, relative to the earlier start case, except between 2020 and 2022 when the pipeline first comes on line.

From 2013 to 2025, U.S. natural gas consumers, while cumulatively consuming more natural gas, would be expected to save almost \$20 billion (in 2001 dollars) on natural gas purchases, because of generally lower delivered prices in the 2013 Start Case. The impact in lost revenues to lower-48 producers would be even more dramatic at \$48 billion (in 2001 dollars). Table 11 summarizes the cumulative impact of the earlier start of an Alaska gas pipeline as a result of the H.R.6.EAS tax credit proposal.

Table 11. Net Impact of 2013 Start of the Alaska Natural Gas Pipeline, Cumulative Difference from 2020 Start Case in 2013 through 2025 (billion 2001 dollars)

	Early Start
U.S. Consumer Savings	19.7
Lower-48 Producer Revenue Loss	48.3

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs bsangts3.d100703b and angts3.d100603a.

A net present value calculation can provide a slightly different perspective from using cumulative revenues to summarize the impact of an earlier start of an Alaska gas pipeline. In general, consumer savings and producer revenue losses are greater in the initial years after the pipeline begins to operate, in the latter part of 2013. A net present value calculation places greater weight on the changes that occur in the earlier years over those occurring later. Table 12 provides the revenue impact in net present value terms using an assumed 7-percent rate of return.

U.S. Treasury Implications as a Result of the Tax Credit

The more difficult assessment is the potential impact of a tax credit on the U.S. Treasury. Here, we consider the impact on the U.S. Treasury as a direct result of the tax credit as well as the impact of an earlier (2013) pipeline start on federal royalty receipts from natural gas production in the lower 48 States.

Table 12. Net Impact of 2013 Start of the Alaska Natural Gas Pipeline, Net Present Value in the Year 2001 of Difference from 2020 Start Case in 2002 through 2025 (assuming a 7-percent rate of return) (billion 2001 dollars)

	Early Start
U.S. Consumer Savings	9.9
Lower-48 Producer Revenue Loss	23.4

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs bsangts3.d100703b and angts3.d100603a.

The Treasury impacts of the tax credit will depend on monthly natural gas prices at the AECO-C hub. EIA projects annual price trends for all U.S. lower-48 production at the wellhead, but these projections do not reflect short-term price volatility affecting particular months or particular trading hubs. Using EIA's annual average lower-48 wellhead price projections and assuming a $0.60 per mcf (in 2001 dollars) differential[45] between the lower-48 price and the AECO-C Hub price, the AECO-C Hub price would not be expected to fall below the $3.25 per million btu in 2013 dollars (or $2.59 per mcf in 2001 dollars) floor on an annual basis for the tax credit to take effect. Under these assumptions the lower-48 wellhead price would have to be below $3.19 per mcf in 2001 dollars for the credit to be triggered.

Given the wide variability of natural gas prices, this result should not be construed as a definitive estimate of tax credit costs. Natural gas prices are expected to continually be volatile in the future, as they have in the past, and even more so with spot prices, such as at the AECO-C Hub. The AECO-C Hub price in particular has experienced relatively low periods in the past when the flow of gas from Canada into the United States was constrained by pipeline capacity. While the general belief is that prices over the next two decades will be higher than they have been in the past decade, average U.S. wellhead prices under $3.19 were the norm in the 1990s. On the other hand, realized prices could actually be higher than those projected by EIA, if historic trends in technological progress are not sustained into the future, resource estimates prove to be too optimistic, or the amount recoverable per well prove to be lower than estimated.

Federal royalty receipts from natural gas production in Federal onshore and offshore areas would be impacted by an earlier pipeline start that reduced either the volume or value of production. EIA does not project the share of total U.S. natural gas production subject to Federal royalties. However, information on the Minerals Management Service (MMS) website indicates that in 2000, production from Federal onshore and offshore

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[45] This $0.60 per mcf differential is based on an historical average differential between the annual average wellhead price in Alberta and the lower-48 wellhead price, discounting for years when the differential was elevated when pipeline constraints impeded imports from Canada to the United States. A differential between the AECO-C Hub and the lower-48 price is much more variable, given the variability of the AECO-C Hub price, making projecting the differential difficult. The average from 1990 to 2001 of the Alberta wellhead price was essentially equal to the average AECO-C hub price in real terms over the same period.

resources accounted for 36 percent of total U.S. natural gas production (onshore at 11 percent and offshore at 25 percent). MMS reports that royalty rates in 2000 were 12.27 percent for onshore production and approximately 15.5 percent for offshore production – the standard rate for offshore royalties is 16.67 percent, but some production gets significant royalty relief. Assuming a constant 36 percent of production on federal lands, entry-into service of the Alaska pipeline would reduce Federal royalty receipts by $2.5 billion (cumulative undiscounted year 2001 dollars) over the first 15 years of operation.

Finally, it should be noted that additional indirect Federal budget impacts may also result from changes in the level of economic activity and tax revenue collections, which should be positively affected by the pipeline project itself and negatively affected by any displacement of gas development activities in the lower-48 States. Increased natural gas supply and lower prices projected as a result of the earlier availability of North Slope gas should also provide economic benefits to gas consumers that may be reflected in increased economic activity. Consideration of these impacts is beyond the scope of the present analysis.

4. Variations Under S.1149 and S.14

A variation of the tax credit and the loan guarantee were proposed in S.1149 and S.14, and a provision for accelerating the depreciation of Alaska pipeline assets for tax purposes was proposed in S.1149. These three provisions are:

1) A 15-year production tax credit for Alaska North Slope gas equal to $0.52 per million Btu (in 2002 dollars), that is reduced equally for every cent a to-be-determined monthly reference wellhead price for gas in Alaska exceeds $0.83 per million Btu [Sec. 511 of S.1149];
2) A pipeline loan guarantee on 80 percent of the capital costs, including interest during construction, not to exceed $18 billion dollars for a pipeline running from the North Slope of Alaska to the continental United States. [Sec. 144 of S.14];
3) A shortened accelerated cost recovery period for assets when calculating taxable income related to the Alaskan portion of the Alaska natural gas pipeline [Sec. 512 of S.1149].

These variations of the tax credit and loan guarantee should not appreciably change the start date of the pipeline compared to the similar provisions in the recently-passed Senate bill (Sec. 2503 and 710 of H.R.6.EAS). Including the Canadian portion of the pipeline within the loan guarantee could increase the interest of the Canadians in the project. However, the primary difference is expected to be the impact on the U.S. Treasury, as the tax credit under S.1149, unlike the one under H.R.6.EAS, is estimated to result in a direct impact on the U.S. Treasury, when based on an approximate calculation using annual average forecasted prices. A more rapid depreciation of pipeline assets for tax purposes is not expected to notably alter the tariff charges for the pipeline or affect the start date, but should allow the pipeline to more readily secure financing.

a. Rapid Depreciation of Pipeline Assets

S.1149 (Section 512) allows the portion of an Alaska natural gas pipeline that is within the State of Alaska to be depreciated on an accelerated basis over 7 years, rather than the current 15 years, for tax purposes. This provision holds for a pipeline that is placed in service after December 31, 2014.[46] In general, a company benefits by accelerating the depreciation of an asset when calculating taxable income by reducing tax payments in the early years of the project, when additional cash flow can be more important (e.g., in securing bonds), and deferring these taxes to later years. A shorter depreciation period allows the pipeline to more readily secure financing for a project and successfully begin operations.

When a pipeline sets rates for transportation services, taxes are calculated on a straight-line basis and, in a given year, are not equal to the actual taxes paid to the Federal Government. Therefore, a change in the depreciation period for tax purposes does not directly change the calculation of taxes used for ratemaking purposes. However, the rate base is adjusted by the accumulated level of the deferred taxes, which ultimately results in a potential change in the regulated rate charged by the pipeline company and an insignificant change in taxes owed. Overall, the impact on pipeline tariffs is expected to be negligible.

On a cumulative basis over the 15-year period after the pipeline goes into service, the taxes paid to the Federal Government on a nominal basis can be expected to be nearly equal under a 7-year accelerated depreciation schedule versus a 15-year schedule. The relative budgetary impacts are related to the impacts of inflation and the general time value of money. For the purposes of this analysis, EIA assumed that the portion of an Alaska natural gas pipeline in the State of Alaska would cost $4.6 billion (in 2001 dollars), or 40 percent of the $11.6 billion dollar estimate from the producer consortium for the pipeline taken further to Alberta. On a present value basis, assuming a discount rate of 7 percent, the Federal Government would expect to receive $260 million (in 2001 dollars) less in tax revenue as a direct result of moving from a 15-year to a 7-year depreciation schedule.

b. Tax Credit Provision

With the tax credit provision proposed under S.1149, suppliers of natural gas to the pipeline will receive $1.35 per million Btu in total from gas purchasers and from the tax credit, as long as the reference price in Alaska is between $0.83 and $1.35 per million Btu. When the reference price exceeds $1.35, no production tax credit is allowed, and the producer receives just the market price. When the reference price falls below $0.83, the production tax credit stays at $0.52, and the effective recovered price for the suppliers of gas to the pipeline is the reference price in Alaska plus $0.52 per million Btu ($0.53

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46 According to staff members on the Senate Finance Committee, this date was not selected to delay the project and will be modified to align more closely with estimates of the earliest the pipeline could potentially be brought into service. Therefore, for the purposes of this analysis this date was assumed to align with the year of the initial flow of gas on an Alaska pipeline.

per mcf in 2001 dollars). Since EIA assumes that producers of gas in Alaska will supply sufficient gas to fill the pipeline in the initial years of operation at $0.80 per mcf at the wellhead, a total return of $1.35 ($1.37 per mcf in 2001 dollars), as called for under the bill, should be more than sufficient for producers to be willing to supply the gas and provide the necessary incentive for the pipeline to be built as soon as possible.

The reference price in Alaska is to be established by a National regulatory body based on a monthly published market price for natural gas, presumably in the lower-48 States or Alberta, minus any transportation and processing costs (including gas treatment costs). An estimate of the cost of a production tax credit to the Federal Government depends on the projected natural gas prices for the selected market, as well as the toll for the transportation of the gas and the processing costs. Lower natural gas prices or higher transportation tolls than estimated could increase the amount of tax credits. Since EIA has the capability to project the average lower-48 wellhead price, that market was selected for this analysis. The historical differential between lower-48 and Alberta wellhead prices was used to represent Alberta-to-market transportation costs,[47] while a regulated based tariff calculation was used to estimate the pipeline tariff from Alaska to Alberta. Gas treatment costs were assumed at $0.41 per mcf in (2001 dollars).

The remainder of this section discusses issues related to the calculation of transportation costs and the selection of a published market price, all of which can affect the amount of available tax credits. The section concludes with estimates of available tax credits under several alternative assumptions.

The Published Market Price

The S.1149 tax credit is specified in relation to “the applicable reference price.” Although the language in the bill is not explicit, the implication is that this is a reference price on the North Slope. The bill indicates that this reference price will be established using “a published market price…(reduced by any gas transportation costs and gas processing costs as determined by the appropriate national regulatory body for natural gas transportation)….” One plausible, but not explicitly required, implementation of this methodology would use “transportation costs” that represent the regulated transportation rates associated with moving the gas along natural gas pipelines from the North Slope to a point associated with the “published market price.” EIA did not consider the potential of transportation costs which do not reflect the cost of moving gas from the North Slope to a geographical location associated with the selected “published market price.”

For points in North America beyond the Alberta hub with “published market prices,” there are multiple routes to move gas from the Alberta hub. In addition, regulated rates on pipelines can vary depending on the provided level of service – notably, service is

[47] The Alberta-to-lower-48 differential was established by averaging recent historical differences in the wellhead prices in real terms at the two locations. Selected years were removed when there were indications that the price differential had spiked in response to restricted flow of gas into the U.S. because of pipeline capacity constraints. The assumed differential for this analysis was set at $0.60 per mcf in 2001 dollars.

typically provided with varying degrees of "firmness" and under different commitment periods. This suggests that the "national regulatory body" would presumably have a degree of latitude in setting the specific rates that would be applied, unless the language in the bill is made more specific. Based on an assumption that Alberta and U.S. gas compete at common U.S. market points based on transportation differentials, EIA's analysis uses the difference between the lower-48 average wellhead price and the Alberta wellhead price as the Alberta-to-lower-48 component of the transportation differential to be subtracted from a lower-48 average wellhead "published price."

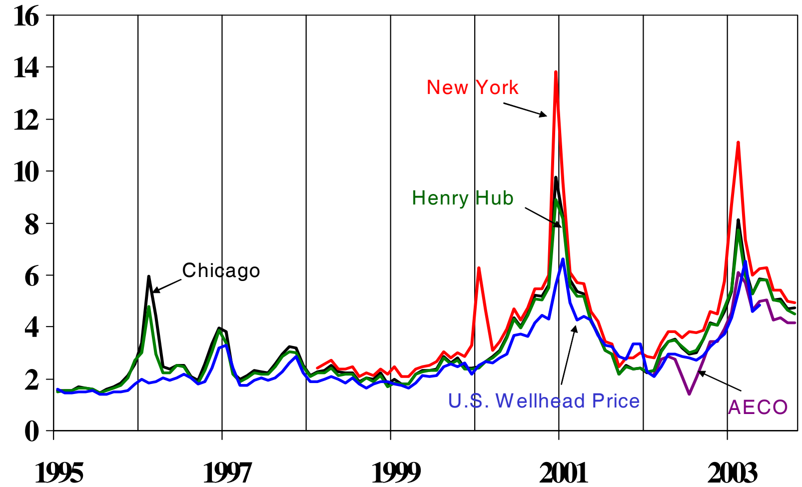
In actuality, there are a couple of implications for selecting one published market price over another. Although the language is vague in the bill, EIA assumes that the intention is to select a price reported at a primary natural gas market hub (a spot price) that is associated with a particular geographical area. Spot prices are generally much more responsive to changes in market conditions (particularly on the high end) than what would be reflected in an average wellhead price and are typically higher on average.[48] Some market hub prices are more volatile than others because of their location on the pipeline network (Figure 1). When the pipelines servicing an area at the end of the network (e.g., in California or New York) reach maximum utilization levels, the rise in prices can be expected to exceed any rise experienced at other more central hubs (e.g., the Henry Hub). Conversely, prices at the AECO-C Hub and wellhead prices in Alberta have been depressed when pipeline constraints have restricted the flow of gas out of Canada. At such times the AECO-C Hub price can be expected to fall below the average wellhead in Alberta. In practice, using a spot price rather than an average wellhead price as a "published market price" will tend to result in instances of more wild swings in the resulting monthly reference price in Alaska when the U.S. gas market is stressed. Such short-term market responses are not captured in EIA's annual forecast. Excluding the short-term fluctuations, the average lower-48 wellhead price generally tracks reasonably well with the Henry Hub price.

Transportation Costs

Estimates of available tax credits are also sensitive to uncertainty in the toll for transporting the gas. EIA employs a simple representation of the calculations used to establish regulated natural gas pipeline rates, based on assumptions provided by the Alaska producer group (e.g., a debt/equity ratio of 70/30) and others assumptions based on averages from financial reports by major U.S. pipeline companies. In the end, the actual tariff will depend on the rate case filed at the Federal Energy Regulatory Commission (FERC) and what FERC finally approves. It also will depend on the accuracy of the cost estimates -- the Alaska producer group has indicated an uncertainty range of plus or minus 20 percent on the capital costs. Higher transportation costs than those calculated by EIA, including estimates made by the producer group, would increase tax credits available under S.1149.

[48] EIA examined the historical relationship between the average U.S. wellhead price and the Henry Hub price from 1996 to 2000 and determined that the Henry Hub was 10.8 percent higher on average, with a median difference of $0.236 per mcf in 2000 dollars. (www.eia.doe.gov/oiaf/analysispaper/henryhub/index.html.)

Figure 1. Natural Gas Spot Prices at Selected Locations and Average Lower-48 Wellhead Prices (dollars per million Btu)



Sources: Spot prices—Natural Gas Intelligence's Daily Gas Price Index (AECO C Hub price converted from Canadian dollars per gigajoule by EIA); U.S. wellhead price—EIA's Natural Gas Monthly.

Under standard pipeline rate calculations, tariffs can be expected to decline in real terms, and potentially in nominal terms, over time as a pipeline is depreciated. As the pipeline ages, refurbishments and operation and maintenance expenses can be expected to increase and offset some of this decline. The tolls that were released by the Alaska producer group reflect their estimates of the actual tariff that will be charged the first year of operation. ConocoPhillips, one of the potential Alaska North Slope producers, indicated that they believe that the rate will remain constant in nominal terms over the life of the pipeline – levelized nominal rates. For the purpose of this analysis, EIA calculated the expected Alaska-to-Alberta tariff in nominal terms, which decline over time as the pipeline is depreciated. Then, a "levelized" nominal tariff was established as the average of this series over 15 years. This rate was assumed to be constant in nominal terms over the life of the project. The expected tax credit will be assessed for both levelized and nonlevelized rates.

It is EIA's understanding that the potential pipeline owners can propose either levelized or non-levelized rates to their new customers and ultimately to FERC. The regulator usually agrees if the customers are agreeable. It is possible that the availability of tax credits may favor the use of non-levelized (in nominal terms) rates, which could increase the likelihood that tax credits could be collected in early years with higher transportation rates that would not have to be repaid when rates fall. The language in the bill does not preclude this possibility.

Estimated Applied Tax Credit

EIA estimates that the initial total transportation and fuel cost to move natural gas from Alaska to the lower-48 States starting in 2013 is $2.20 per mcf in 2001 dollars (assuming levelized transportation and processing rates in nominal terms thereafter). This includes: 1) $0.41 for gas treatment, 2) $1.19 for transportation from Alaska to Alberta, including pipeline fuel, and 3) $0.60 (in 2001 dollars) for transportation to the lower 48 wellhead equivalent. If the average U.S. wellhead price were used as the "published market price," and the $2.20 per mcf average transportation rate were used to establish the "reference price" in Alaska, then EIA estimates that the tax credit would take effect in 2013 if the average monthly U.S. wellhead price falls below $3.57 per mcf in 2001 dollars. However, over the life of the pipeline, the transportation costs are assumed to fall in real terms, causing this $3.57 threshold to fall.

Assuming the Alaska pipeline starts operations in 2013 with a delivery volume of 3.9 Bcfd, the average annual lower-48 wellhead price projection falls below the tax credit threshold in the first 3 years of the pipeline's operation (by an annual average of 15 cents), when the additional supplies in the market cause downward pressure on the price. This amounts to a $396 million (2001 dollars) impact on the U.S. Treasury directly attributable to the tax credit under S.1149. This calculation does not take account of month-to-month fluctuations, which -- given the difference in the payment and repayment triggers -- are likely to increase costs to the Treasury, possibly by a substantial amount.

As noted in the earlier discussion of ratemaking, tariff calculations are affected by numerous factors and assumptions. The actual tariffs may differ significantly from any estimate and could substantially affect Treasury costs. Using an alternative rate structure in which nominal rates are not levelized, the cumulative undiscounted impact on the U.S. Treasury would be $1.71 billion 2001 dollars.[49] Using the toll in 2013 for the Alaska-to-Alberta pipeline estimated by the Alaska producers group at $1.47 per mcf (2001 dollars, but held constant in nominal terms thereafter) for transportation ($1.13 per mcf) and processing ($0.34 per mcf), the cumulative undiscounted impact on the U.S. Treasury as a direct result of the tax credit is estimated to be $17 million 2001 dollars.

Again, these calculations do not take account of month-to-month fluctuations, which given the difference in the payment and repayment triggers, are likely to increase costs to the Treasury, possibly by a substantial amount. An extreme upper bound on the budgetary impact of the tax credit can be calculated under the assumption that all North Slope gas receives the full credit in each month. Over a 15-year period, the maximum cumulative undiscounted impact on the Federal budget as a direct result of the tax credit would be $13 billion 2001 dollars, assuming no expansion on the Alaska pipeline. Actual costs are unlikely to approach this extreme upper bound. For illustrative purposes, Tables 13 and 14 display the production tax credit and the associated reductions in Federal tax receipts for ranges of lower-48 wellhead prices and transportation tolls.

[49] In 2001 dollars per mcf these transportation rates range from $1.52 in 2013, to $0.99 in 2020, to $0.64 in 2025.

As outlined in the earlier discussion of the tax credit provision in H.R.6.EAS, the total net impact on the U.S. Treasury (i.e., not just from the tax credit specifically) will also reflect impacts on federal royalty collections as well as any changes in the level of economic activity that affect revenues or outlays.

Table 13. Production Tax Credit Under S.1149 (2001 dollars per mcf)

Alaska to Lower 48 Toll (2001$/mcf) \ Average Lower 48 Wellhead Price (2001$/mcf)	2.30	2.40	2.50	2.60	2.70	2.80	2.90	3.00	3.10	3.20	3.30	3.40	3.50	3.60	3.70	3.80	3.90
2.50												0.47	0.37	0.27	0.17	0.07	
2.40											0.47	0.37	0.27	0.17	0.07		
2.30										0.47	0.37	0.27	0.17	0.07			
2.20		0.53							0.47	0.37	0.27	0.17	0.07				
2.10								0.47	0.37	0.27	0.17	0.07					
2.00							0.47	0.37	0.27	0.17	0.07				0.00		
1.90						0.47	0.37	0.27	0.17	0.07							
1.80					0.47	0.37	0.27	0.17	0.07								
1.70				0.47	0.37	0.27	0.17	0.07									
1.60			0.47	0.37	0.27	0.17	0.07										
1.50		0.47	0.37	0.27	0.17	0.07											

Table 14. Reduction in Federal Tax Receipts Under S.1149 for 4.3 Bcf/d Entering Alaska Pipeline Under S.1149 (billion 2001 dollars per year)

Alaska to Lower 48 Toll (2001$/mcf) \ Average Lower 48 Wellhead Price (2001$/mcf)	2.30	2.40	2.50	2.60	2.70	2.80	2.90	3.00	3.10	3.20	3.30	3.40	3.50	3.60	3.70	3.80	3.90
2.50												0.74	0.58	0.42	0.27	0.11	
2.40											0.74	0.58	0.42	0.27	0.11		
2.30										0.74	0.58	0.42	0.27	0.11			
2.20		0.83							0.74	0.58	0.42	0.27	0.11				
2.10								0.74	0.58	0.42	0.27	0.11					
2.00							0.74	0.58	0.42	0.27	0.11						
1.90						0.74	0.58	0.42	0.27	0.11					0.00		
1.80					0.74	0.58	0.42	0.27	0.11								
1.70				0.74	0.58	0.42	0.27	0.11									
1.60			0.74	0.58	0.42	0.27	0.11										
1.50		0.74	0.58	0.42	0.27	0.11											

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting

4. Electricity Supply

A. Renewable Portfolio Standard (Senate 264)

Both the House and Senate bills contain provisions to stimulate renewable fuel use in the electricity generation sector. Both bills extend the existing Production Tax Credit (PTC) for electric generation from certain renewable resources for three years and the Senate bill establishes a Renewable Portfolio Standard (RPS) and credit trading system that would apply to all retail electric suppliers beginning in 2005. The RPS in the Senate bill requires that a set percentage of the electricity provided by a retail supplier be generated from qualifying renewable sources.[50] The RPS percentages required in the Senate bill from 2005 through 2020 are shown in Table 15.

Table 15. Renewable Portfolio Shares

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013
Percentage	1.0	1.0	2.2	2.2	3.4	3.4	4.6	4.6	5.8

Year	2014	2015	2016	2017	2018	2019	2020
Percentage	5.8	7.0	7.0	8.5	8.5	10.0	10.0

The Secretary of Energy is charged with establishing the RPS percentages to be used between 2020 and 2030 by January 1, 2015, but it must be at least 10 percent, so it is assumed that the program will continue through 2030 with at least a 10-percent requirement. The Secretary of Energy is also charged with establishing the renewable energy credit program no later than one year after enactment of the bill. The program would be charged with issuing credits, monitoring the sale or exchange of credits, and tracking credits. Credits would be issued to an electric supplier that generated electricity through the use of renewable energy. One credit would be issued for each kilowatthour of electric energy generated with renewables. However, the number of credits would vary to some extent depending on the location of generation (e.g., two credits per kilowatthour issued for generation on Indian lands) and type of renewables (e.g., two credits issued per kilowatthour for generation offsets). Credits could be sold and exchanged, but they could only be carried forward for a period of four years. Relatively small retail electricity suppliers, those with sales below one million megawatthours, do not have to hold credits, and the credit price is limited to 1.5 cents per kilowatthour.[51]

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[50] Renewables is defined to include solar, wind, ocean, geothermal, biomass (excluding solid waste and paper that is commonly recycles), landfill gas, a generation offset (a metered reduction in electricity usage at a site where a customer consumes energy from a renewable energy technology), or incremental hydropower.

[51] Section 264 actually specifies a 3.0-cent per kilowatthour credit price limit, but Section 271 changes it to 1.5 cents per kilowatthour.

<u>*Impact of Renewable Portfolio Standard*</u>

EIA has not analyzed the specific provisions in Senate bill Section 264. However, EIA recently analyzed proposals for a 10-percent RPS that are similar. For example, in 2002, at the request of Senator Murkowski, EIA analyzed the RPS provision of Senate bill 517 from the 107th Congress in a study, *Impacts of a 10-Percent Renewable Portfolio Standard*.[52] In the spring of this year, EIA analyzed a similar RPS proposal at the request of Senator Bingaman in a study, *Analysis of a 10-Percent Renewable Portfolio Standard*,[53] with additional analyses of the same proposed legislation performed at the request of Senator Domenici.[54] The bill S.517, analyzed for Senator Murkowski, reflected an early draft of the current legislation, but there have been some changes since the report was released. The current legislation contains a 2030 sunset provision and a 1.5 cent per kilowatthour credit cost cap, while the version EIA analyzed for Senator Murkowski contained a 2020 sunset and a 3.0 cent credit cost cap. The proposal analyzed for Senator Bingaman also differs from the Senate bill in the size of the standard used to exempt small utilities from the requirement (less than one million megawatt hours of sales for the current legislation compared to four million megawatthours of sales analyzed with Senator Bingaman's request). The schedule of required renewable generation also differs, although both set a 10-percent target by 2020, as shown in Table 16.

Both analyses reached similar conclusions, however, several key assumptions of the more recent analyses for Senators Bingaman and Domenici are closer to the final language passed in the Senate bill:

- The imposition of program sunset provisions, credit price caps (or penalty mechanisms that effectively function as price caps), and exemption of small utilities and certain types of renewable generation from program requirements results in legislatively specified targets not being met, especially in the latter years of the forecast. In the *Addendum to Analysis of a 10-Percent RPS*, part of the analyses conducted for Senator Bingaman and examining the provisions closest to those in the Senate bill, total renewable generation achieved by 2025 is 6.5 percent of U.S. sales, compared to the 8.8-percent effective target based on eligible renewable generation and non-exempt sales.[55]

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[52] Energy Information Administration, *Impact of a 10-Percent Renewable Portfolio Standard,* SR/OIAF/2002-03, (Washington, DC, February 2002), web site http://www.eia.doe.gov/oiaf/servicerpt/rps/pdf/sroiaf(2002)03.pdf.

[53] Energy Information Administration, *Analysis of a 10-Percent Renewable Portfolio Standard,* SR/OIAF/2003-01, (Washington, DC, May 2003), web site http://www.eia.doe.gov/oiaf/servicerpt/rps2/pdf/sroiaf(2003)01.pdf.

[54] Energy Information Administration, *Supplement to Analysis of a 10 Percent Renewable Portfolio Standard,* (Washington, DC, June 2003), web site http://www.eia.doe.gov/oiaf/servicerpt/rps2/pdf/supplement.pdf

[55] The 8.8 percent is total renewable generation as a fraction of total U.S. sales, which is equivalent to the legislative target of 10 percent of eligible renewable generation as a fraction of non-exempt sales.

Table 16. Legislative Targets for Eligible Renewable Generation as a Percent of Non-Exempt Electricity Sales

Year	S. 517	Bingaman Amendment (June 2003)	Senate bill (August 2003)
2003	0.5[1]	0.0	0.0
2004	1.5[1]	0.0	0.0
2005	2.5	0.0	1.0
2006	3.0	0.0	1.0
2007	3.5	0.0	2.2
2008	4.0	2.5	2.2
2009	4.5	2.5	3.4
2010	5.0	2.5	3.4
2011	5.5	2.5	4.6
2012	6.0	5.0	4.6
2013	6.5	5.0	5.8
2014	7.0	5.0	5.8
2015	7.5	5.0	7.0
2016	8.0	7.5	7.0
2017	8.5	7.5	8.5
2018	9.0	7.5	8.5
2019	9.5	7.5	10.0
2020	10.0	10.0	10.0
2021	0	10.0	10.0[2]
2022	0	10.0	10.0[2]
2023	0	10.0	10.0[2]
2024	0	10.0	10.0[2]
2025	0	10.0	10.0[2]

1 Legislative language as analyzed by EIA left the target for 2003 and 2004 to the discretion of the Secretary of Energy, these targets are EIA assumptions as analyzed for the request.
2 Legislative language leaves targets for 2020 through 2030 to the discretion of the Secretary of Energy, but requires a 10-percent minimum.

- The cost to the power industry of the program is small relative to overall industry revenue. In the *Addendum* report referenced above, the program would add $4.9 billion (2001 dollars, discounted at 7 percent), or about six-tenths of one percent, to cumulative net industry costs over the forecast horizon to 2025.[56]
- The cost to consumers is small relative to total consumer expenditures on electricity. Consumer electricity expenditures in residential, commercial, and industrial categories, totaling $1.8 billion in 2025 (2001 dollars), are all well under 1 percent over Reference Case expenditures in the *Addendum* analysis (0.4 percent for residential, 0.5 percent for commercial, 0.4 percent for industrial).
- Reduced natural gas prices, which result from a decline in natural gas demand, provide savings to both the power industry and end-use consumers that partially offset higher electricity costs. Reduced fuel costs to the power industry are reflected in the net industry costs cited above. In the residential, commercial, and

56 Comparisons are to the mlbase.d050303a Reference Case as published in the cited Addendum report.

industrial sectors, natural gas expenditures are reduced by $1.1 billion in 2025 (0.5 percent for residential, 0.6 percent for commercial, and 0.4 percent for industrial).

- In the *Addendum* report, the incremental renewable capacity resulting from the RPS is primarily wind. By 2025, an additional 36 gigawatts of wind capacity generating 129 billion kilowatthours is added when compared with the Reference Case. Although no other renewable technology contributes to significant capacity expansion, biomass co-firing produces an additional 31 billion kilowatt-hour generation increment in 2025 over the Reference Case utilizing existing coal-fired capacity

The *Supplement* analysis conducted at the request of Senator Domenici considered the compliance cost of the RPS analyzed in the *Addendum* if all credits were purchased from the government for 1.5 cents per kilowatthour. The cumulative cost over the life of the program (in 2001 dollars, using a 7-percent discount rate) would be $37 billion (1.1 percent of total industry revenue). Since there would be no additional renewable generation if all compliance were achieved through purchase of government allowances, there would be no offsetting decrease in natural gas prices. Furthermore, the total amount ($37 billion) would represent a net power industry outlay, rather than primarily an intra-industry transfer payment. However, the EIA analysis indicates that there is significant potential for renewable generation with a credit value of less than 1.5 cents per kilowatthour.

B. Extension of Production Tax Incentive (House 41002, Senate 1901-1906)

The production tax credit (PTC), originally enacted as part of the 1992 Energy Policy Act (EPACT), has been extended twice, in 1999 and 2002, and is currently slated to expire December 31, 2003. It provides a 1.8 cent (2001 dollars) Federal tax credit for every kilowatthour of electricity generated during the first ten years of operation for plants using wind, closed loop (dedicated to energy production) biomass, or poultry waste (added to program in 1999) if they entered or will enter service between January 1, 1994 and December 31, 2003. To date, only new wind plants have taken advantage of the PTC.

Both the House and Senate bills extend the PTC three-years, covering facilities that are brought into service by December 31, 2006. The Senate bill also expands the coverage of the credit to cover landfill gas, geothermal, and solar, in addition to wind and biomass. However, it is very difficult to project the amount of U.S. capacity that will be built with or without a three-year extension of the PTC. Projects now under development may be affected by the extension of the PTC. Current information available to EIA indicates that of the 2,357 megawatts of currently planned wind capacity construction from 2004 through 2007, 1,535 megawatts are dependent on PTC extension. Such an extension may also stimulate additional wind projects that have not been publicly announced at this time. Recent experience with the expiration and short-term extension of the PTC suggests that this pattern leads to a substantial "lull" in construction shortly after the extension is authorized, with a substantial "crunch" of project announcements and construction activity in the final year before expiration.

C. Clean Coal Incentives (House 3117, Senate 2201-2221)

Both the House and Senate bills contain provisions providing power plant developers with an incentive to invest in new, innovative, clean coal technologies. The hope is that these incentives will lead to the early commercialization of these cleaner, more efficient technologies. The bills provide both investment tax credits and production tax incentives. For example, the House bill, Section 3117, provides a 10-percent investment tax credit for up to 7,500 megawatts of qualifying clean coal capacity. The tax credits are to be spread among various clean coal technologies that meet specified development timetables, efficiency, and emission removal targets.

Section 2211 of the Senate bill includes a similar program to the House bill with slightly different timetables and more stringent efficiency targets, and it limits the credit to a maximum of 4,000 megawatts of new qualifying clean coal capacity. Sections 2201 and 2221 of the Senate bill, also includes a production tax incentive for clean coal technologies that are applied to existing plants through retrofitting, repowering, or replacement. The incentive is limited to plants that are no larger than 300 megawatts and the maximum amount of capacity that can receive it is 4,000 megawatts. Eligible facilities will receive a 0.34 cent payment for each kilowatthour generated for the first ten-years of its operation after retrofitting. Therefore, under the Senate bill, incentives are limited to 8,000 megawatts (4,000 megawatts of new and 4,000 megawatts of existing capacity).

Impacts of Clean Coal Incentives

While a detailed analysis of each of these provisions was not made, rough estimates of the cost of the programs and the potential amount of new clean coal technology stimulated by these provisions can be developed and compared to the projected coal capacity additions in the Reference Case, a mid-term revision to *AEO2003*[57] that was completed for the study, *Analysis of S.485, the Clear Skies Act of 2003, and S.843, the Clean Air Planning Act of 2003.*[58]

If fully successful, at a maximum, the House bill could lead to 7,500 megawatts of new clean coal capacity, the limit under the House bill that can receive incentives, while the Senate bill could lead to 8,000 megawatts (4,000 megawatts of new capacity and 4,000 megawatts of retrofitted, refurbished and/or replaced capacity), the limit under the Senate

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

58 Energy Information Administration, *Analysis of S.485, the Clear Skies Act of 2003, and S.843, the Clean Air Planning Act of 2003,* SR/OIAF/2003-03, (Washington, DC, September 2003). The mid-term Reference Case is imbase.d080503a.

bill that can receive incentives. Assuming that these new plants will generally cost between $1,000 and $1,500 per kilowatt (all dollars are shown in 2001 dollars) and using $1,250 as an average, over the life of the program, the investment tax credit provisions in the House bill would reduce tax revenue by $938 million, while those in the Senate bill would reduce them by $500 million. Assuming that plants stimulated by the production tax incentive in the Senate bill would operate at a 75-percent utilization rate, when fully implemented the annual payment could reach $89 million.

The total potential new clean coal technology stimulated by the bills, 7,500 to 8,000 megawatts (the limits of the House and Senate bills), is lower than the total new coal capacity projected in the Reference Case. In the Reference Case, nearly 77,000 megawatts of new coal capacity (17 percent of total new capacity) is projected between 2005 and 2025, with 8,000 megawatts on-line by 2010 and 20,000 megawatts on-line by 2015. Of the projected 77,000 megawatts in the Reference Case, roughly 4,000 megawatts are advanced clean coal technologies that are expected to come online after 2010. The House and Senate bills would likely accelerate the development of these advanced technologies and cause a small amount of the projected new conventional coal capacity to switch over to one of the advanced technologies. The overall new coal capacity would probably remain near the 77,000 megawatts projected without the bills.

5. Ethanol and Biodiesel Provisions

A. Renewable Fuels Standards and Elimination of MTBE

Both Senate and House energy bills require a renewable fuels standard (RFS) of 5 billion gallons by 2012 in the Senate bill and by 2015 in the House bill. In addition, the Senate energy bill requires the phase-out of MTBE in four years. The Senate version of this provision is discussed below, followed by the House version.

1. Senate RFS/MTBE Ban (Senate 820, 833, 834)

Sections 820, 833, and 834 of the Senate bill contain provisions essentially identical to the Senate Energy Bill as amended (H.R.4) in the Fall of 2002. Highlights of the Senate provisions regarding the RFS and a nation-wide MTBE phase-out are listed below:

1) Create a renewable fuels program requiring the use of the following volumes in the total gasoline pool:

Year	Amount
2004	2.3 billion gallons per year
2005	2.6
2006	2.9
2007	3.2
2008	3.5
2009	3.9
2010	4.3
2011	4.7
2012	5.0

   and for every one gallon of cellulosic biomass ethanol[59] used provide a 1.5-gallon credit
2) Eliminate the RFG oxygen requirement and require southern-grade RFG standards nation-wide (Section 834)
3) Create a renewable fuels credit trading program (Section 820)
4) Phase out the use of MTBE in four years (Section 833), but:
   - Allow States to "authorize the use of" MTBE if they want to continue using MTBE;
   - Provide assistance to merchant MTBE producers to convert their facilities to other gasoline blending components.[60]

[59] For 2013 and beyond, renewable fuel volumes in each year would be equal to the share of renewable fuels relative to the total gasoline consumed in 2012.

[60] The Senate bill would provide up to $250,000,000 per year for three years of Federal assistance to merchant MTBE plant conversions to produce other gasoline blending components.

Impact of Senate RFS/MTBE Ban

In 2002, EIA performed a study, *Renewable Motor Fuel Production Capacity Under H.R.4*, of Senate bill H.R.4 on the impact of an RFS and MTBE phase-out.[61] The study used the *AEO2002* as a Reference Case.[62] In the analysis, it was assumed that the Nation would use 5 billion gallons per year of renewables (mostly ethanol) in transportation fuels by 2012. Texas was assumed to seek and receive a waiver on MTBE phase-out, resulting in 87 percent of the Nation's MTBE being phased out in four years. All other major H.R.4 provisions were also considered, including the elimination of the oxygen requirement in RFG and providing financial assistance for merchant MTBE plant conversions. The ethanol credit trading provision was not modeled;[63] and the tax credit for blending ethanol into gasoline was assumed to continue at $0.51 (nominal) per gallon after 2007. Because the Senate bill is essentially the same as H.R.4, the 2002 EIA study is used for this analysis, with the understanding that the phase-out of MTBE would be delayed by two years (assuming an energy bill is passed in 2004).

Figure 2 shows the projected impact of the Senate bill on renewables consumption, compared to a case when MTBE is banned in 17 States.[64] For 2004 and 2005, refiners are likely to provide RFG blended with ethanol for those States banning MTBE. In 2006 and 2007, the RFS volume requirements would drive the demand for renewables (mostly ethanol). In 2008, the phase-out of MTBE would briefly require more renewables than specified by the RFS. After 2008, the RFS is projected to be the driving factor for renewables demand in the Nation.

Figures 3 and 4 show the projected price impacts on RFG and average gasoline, respectively. The average RFG price increase under the Senate bill is expected to be about 3.6 cents per gallon when compared to the 17-State MTBE ban case in which about 45 percent of the MTBE would be phased out by 2004 by State legislatures. All gasoline prices are expected to be less than 1 cent per gallon higher than the 17-State MTBE ban case. The impact on RFG prices would be mainly from blending ethanol into the RFG. Because in doing so**,** relatively cheap gasoline blending components such as butanes and pentanes (highly volatile, yet also high in octane) must be removed to make room for

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61 Energy Information Administration, *Renewable Motor Fuel Production Capacity Under H.R.*4, (Washington, DC, September 2002), web site http://www.eia.doe.gov/oiaf/servicerpt/fuel/pdf/question2.pdf.

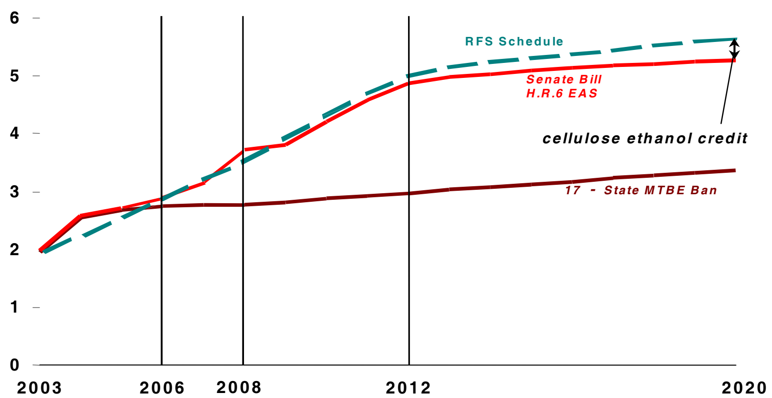
62 Energy Information Administration, *Annual Energy Outlook 2002,* DOE/EIA-0383(2002) (Washington, DC, September 2002), web site http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2002).pdf.

63 The impact of an ethanol credit-trading program on the RFG price would likely be lower than the ethanol transportation costs from the Midwest to the California or Northeast markets. An effective ethanol credit-trading program could reduce the RFG price increases in those markets, at most 0.7 cents per gallon for California and at most 0.6 cents per gallon for the Northeast.

64 California, Colorado, Connecticut, Iowa, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, New York, Ohio, South Dakota, Washington, and Wisconsin. Of these States, only five currently rely on MTBE (California, Connecticut, Kentucky, Missouri, and New York); together, they account for approximately 45 percent of the Nation's MTBE consumption.

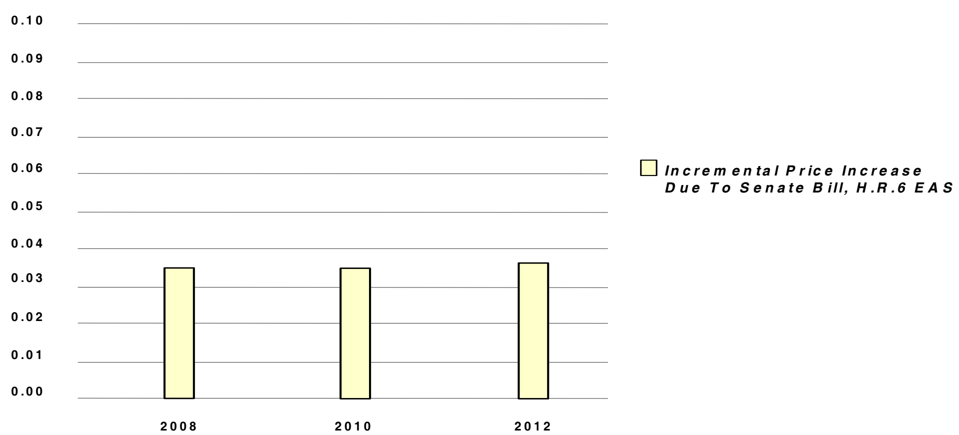
ethanol (because of ethanol's tendency to increase the gasoline vapor pressure). In addition, to make up for the volume loss due to an MTBE ban, more alkylate and reformate (petroleum-based gasoline blending components high in octane, but more expensive than either MTBE or ethanol) would need to be produced.

Figure 2. Total Renewable Consumption for Two Cases (billion gallons per day)



Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System date codes ENs1mXoX.d082302b, ENs1m087.d082302c.

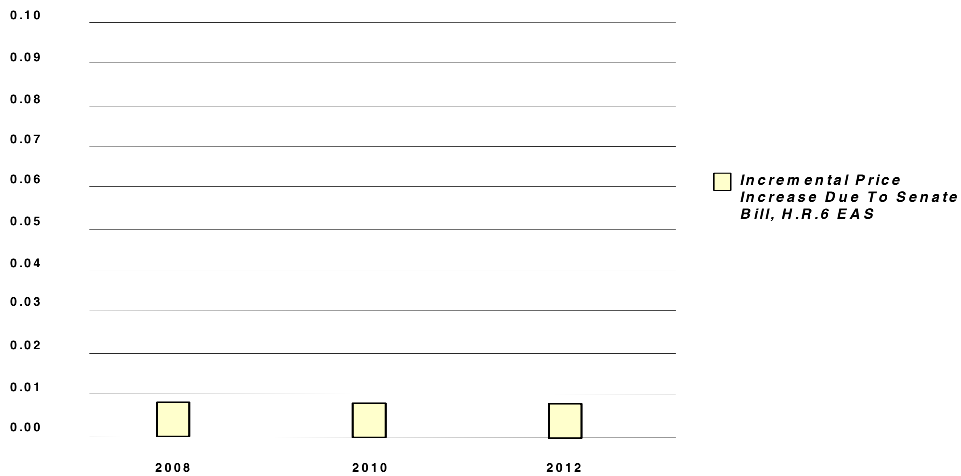
Figure 3. Average RFG Price Differentials Compared to 17-State MTBE Ban (2001 dollars per gallon)



Note: Assumes indefinite extension of ethanol tax credit.

Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, Derived from National Energy Modeling System date codes ENs1mXoX.d082302b, ENs1m087.d082302c.

Figure 4. Average National Gasoline Price Differentials Compared to 17-State MTBE Ban (2001 dollars per gallon)



Note: Assumes indefinite extension of ethanol tax credit.

Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, Derived from National Energy Modeling System date codes ENs1mXoX.d082302b, ENs1m087.d082302c.

The current excise tax credit for ethanol blending into gasoline is \$0.52 per gallon of ethanol, phased down to \$0.51 per gallon for 2005 and 2006, and discontinued after 2007. This ethanol tax credit has been extended many times in the past by the U.S. Congress. Thus, EIA assumes this tax credit will continue in the *Annual Energy Outlook*, as well as all relevant special studies. If the ethanol tax credit is discontinued, it is expected that the price of ethanol-blended gasoline would be higher by the amount of the tax credit itself. For example, a 10-percent (by volume) ethanol-blended RFG would cost about 5.1 cents per gallon more (10 percent times \$0.51 per gallon) without the tax credit than with the credit and a 5.7 percent (by volume) ethanol-blended RFG would cost 2.9 cents per gallon more (5.7 times \$0.51 per gallon). Because not all gasoline would be blended with ethanol, the above estimates would be applicable only to gasoline blended with ethanol.

Ethanol demand under the Senate bill is projected to be 3.5 billion gallons in 2006 and 3.6 billion gallons in 2007. According to the latest Renewable Fuels Association (RFA) data, the current ethanol production capacity in the Nation is 3.4 billion gallons, with an additional 0.5 billion gallons capacity under construction.[65] Additional capacity would be needed to reach the 5 billion gallons requirement assumed in this analysis, but since ethanol plants only take about two years to build, constructing them is not expected to be a problem. As a result, the supply of ethanol under the Senate bill is not expected to be an issue in terms of production capacity.

65 http://www.ethanolrfa.org/eth_prod_fac.html

2. House RFS (House 17101 – 17104)[66]

Sections 17101 to 17104 of the House bill require that 5 billion gallons of renewable transportation fuels be consumed by 2015. The House bill does not include a Federal MTBE ban, but would provide the same transition assistance for merchant MTBE plant conversions as the Senate bill. In addition, the House bill would waive the 2-percent oxygen requirement (by weight) for RFG. The following is a comparison of the main similarities and differences between the RFS/MTBE provisions of Senate bill and the House bill:

1. Create a renewable fuels program requiring:

YEAR	Amount (billion gallons per year)	
	House Energy Bill (H.R.6.EH, Section 17101)	**Senate Energy Policy Act of 2003 (H.R.6.EAS, Section 820)**
2004	-	2.3
2005	2.7	2.6
2006	2.7	2.9
2007	2.9	3.2
2008	2.9	3.5
2009	3.4	3.9
2010	3.4	4.3
2011	3.4	4.7
2012	4.2	5.0
2013	4.2	Renewable fuels as a fixed proportion of total annual gasoline consumption based on 2012 data.
2014	4.2	
2015	5.0	
2016 and beyond	Renewable fuels as a fixed proportion of total annual gasoline consumption based on 2015 data.	

Note: Both H.R.6.EH and H.R.6.EAS allow for a 1.5-gallon credit for every one-gallon of cellulosic biomass ethanol.

2. Eliminate the RFG oxygen requirement and require southern-grade RFG standards nationwide (Section 17104), essentially the same as the Senate bill.
3. Create a renewable fuels credit trading program (Section 17101), essentially the same as the Senate bill.

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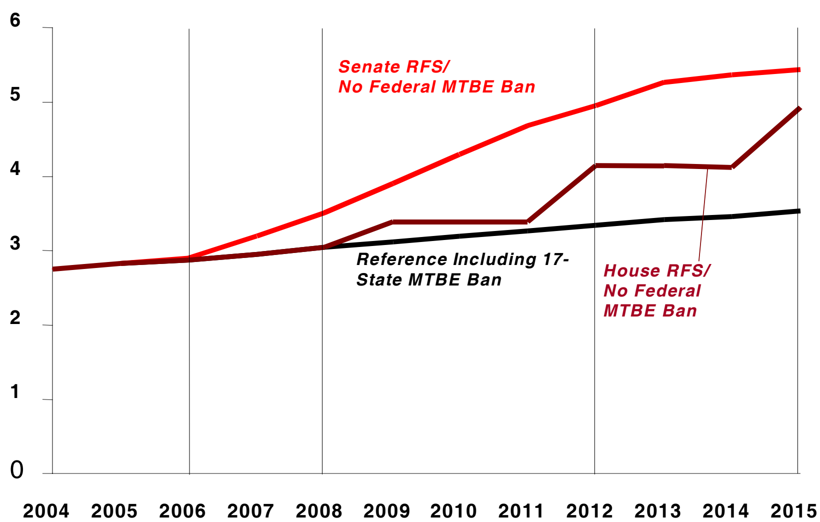
[66] The Reference Case used in this section is hbs1mxox.d030303a.

4. Provide assistance to merchant MTBE producers to convert their facilities to making other gasoline blending components (Section 17103).
5. Safe Harbor provision for both renewable fuels ***and*** MTBE (Section 17102) in the House bill; but only for renewable fuels in the Senate bill.[67]

<u>Impact of House RFS</u>

The discussion of the House RFS is based on the *AEO2003*[68] assumptions, in which 17 States would ban MTBE starting in 2004, with a 2-percent oxygen requirement for RFG remaining intact. Figure 5 shows the relative ethanol consumption of the two RFS schedules specified by the Senate and the House, respectively. Both RFS-only cases are compared to the Reference Case. In the Reference Case, the ethanol is blended into both RFG and oxygenated gasoline.[69] The total ethanol consumption in the Reference Case is expected to reach 3.30 billion gallons per year by 2012 and 3.48 billion gallons per year by 2015.

Figure 5. Total Renewable Fuels Consumption for Transportation Sector (billion gallons per year)



Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System date codes HBs1mXoX.d030303a, BNs1mXrf.d030303b, HBs1mXrf.d030303c.

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67 The Safe Harbor provision would provide for liability protection for renewable fuels and/or MTBE, when used as a motor fuel additive, concerning any defect claims against such product(s).

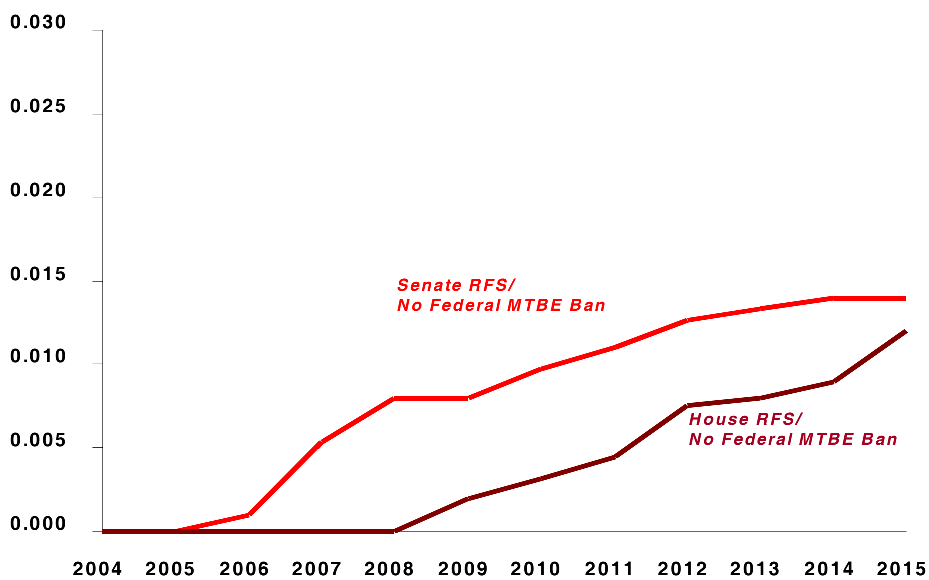
68 Energy Information Administration, *Annual Energy Outlook 2003,* DOE/EIA-0383(2003), (Washington, DC, January 2003), web site http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2003).pdf

69 Oxygenated gasoline is conventional gasoline, which contains 2.7 percent oxygen by weight for areas with winter carbon monoxide emission concerns.

With the Senate RFS schedule, total ethanol consumption is projected to reach 4.90 billion gallons per year by 2012 and 5.40 billion gallons per year by 2015. Due to the 1.5-gallon credit for 1 gallon of cellulose-based ethanol, and some small amount of biodiesel supplied, the total renewable fuels consumption would be slightly less than the 5 billion gallons per year required in 2012. If the Senate bill only required an RFS without an MTBE ban, most of the additional ethanol beyond the Reference Case would be blended into conventional gasoline in the Midwest. By comparison, the House RFS requirement takes step-wise increments. In this case, the RFS would overtake the impact of 17-State MTBE bans after 2008. The difference from the Reference Case is relatively minimal before 2012; then the disparity grows larger with the total ethanol consumption reaching 4.88 billion gallons per year by 2015.

Figure 6 shows the price impact on RFG for these two RFS-only cases. Under an RFS, the average RFG price is not expected to increase more than 1.5 cents per gallon. The delay in RFS in the House version would moderate the increase in RFG prices. Between 2008 and 2014, this delay is projected to reduce the impact on RFG prices by an average of 0.5 cents per gallon. However, by 2015 the advantage of a delayed RFS schedule would be diminished and the price difference between the two cases would also become smaller (about 0.2 cents per gallon by 2015).

Figure 6. Average RFG Price Differential Compared to Reference (2001 dollars per gallon)



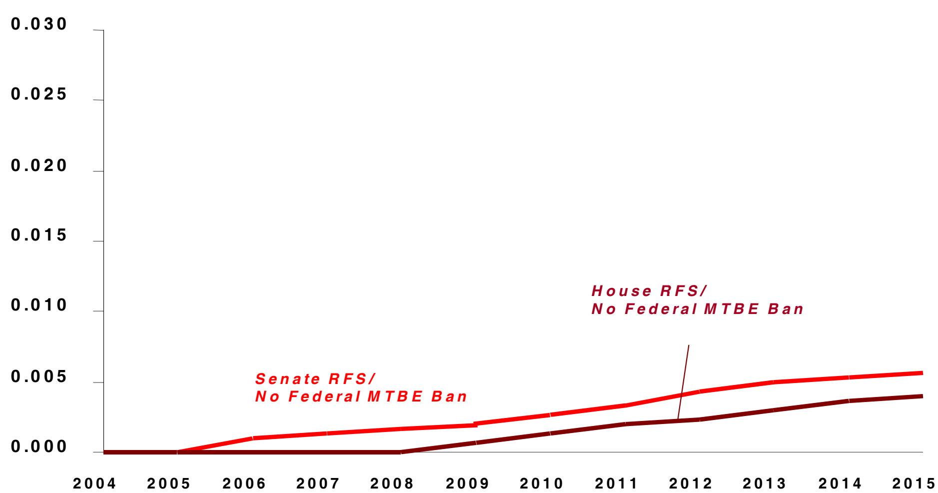
Note: Assumes indefinite extension of ethanol tax credit.

Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System date codes HBs1mXoX.d030303a, BNs1mXrf.d030303b, HBs1mXrf.d030303c.

If the ethanol tax credit is discontinued, it is expected that the price of ethanol-blended gasoline would be higher by the amount of the tax credit itself. For example, a 10-percent (by volume) ethanol-blended RFG would cost about 5.1 cents per gallon more (10 percent times $0.51 per gallon) without the tax credit than with the credit and a 5.7 percent (by volume) ethanol-blended RFG would cost 2.9 cents per gallon more (5.7 times $0.51 per gallon). Because not all gasoline would be blended with ethanol, the above estimates would be applicable only to gasoline blended with ethanol.

Figure 7 shows the price impact on average gasoline. An RFS is not expected to increase the average gasoline price by more than 0.5 cents per gallon. If the ethanol tax credit were not extended, the national average gasoline prices would be an additional 1 to 1.5 cents per gallon higher under an RFS. However, the increase in the national average price would be lower in magnitude then the RFG price increase. Again, the delay in RFS in the House version would moderate the increase in average gasoline prices. The difference remains relatively uniform after 2008 at about 0.1 to 0.2 cents per gallon. This is due largely to the fact that most of the additional ethanol required would be blended into the conventional gasoline, which accounts for about two-thirds of the market.

Figure 7. Average National Gasoline Price Differential Compared to Reference (2001 dollars per gallon)



Note: Assumes indefinite extension of ethanol tax credit.

Sources: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System date codes HBs1mXoX.d030303a, BNs1mXrf.d030303b, HBs1mXrf.d030303c.

B. Biodiesel Credits

1. Biodiesel Credit Expansion (Senate 817)

The Energy Policy Act of 1992 (EPAct) requires certain Federal, State, and alternative fuel provider-owned light-duty-vehicle fleets to gradually switch to alternative-fueled vehicles. Seventy-five percent of new light-duty vehicles purchased by Federal and State fleets must be capable of running on alternative fuels. Ninety percent of new light-duty vehicles purchased by alternative fuel providers must be capable of running on alternative fuels. The Energy Conservation and Reauthorization Act of 1998 gave fleet operators the option of using biodiesel credits to offset vehicle purchase requirements. A biodiesel credit is obtained by using 450 gallons of biodiesel blended into petroleum diesel at 20 percent or less of total volume. Previously, up to half of a fleet's alternative-fueled vehicle purchase requirement could be satisfied using biodiesel credits. Section 817 of the Senate bill allows EPAct fleets to use biodiesel credits to offset all required alternative-fueled vehicle purchases through 2005.

Impact of Biodiesel Credit Expansion

Federal fleets covered under EPAct purchased 20,799 light-duty vehicles in fiscal year 2000. Three-quarters of these vehicles, or 15,600, must be capable of running on alternative fuels. To offset this number of vehicle purchases with biodiesel credits, about seven million gallons of neat biodiesel would be required. Another 6.5 million gallons of neat biodiesel would be needed to fully offset 14,453 alternative-fueled vehicle purchases required of State and alternative fuel provider fleets in model year 2001. It is difficult to forecast incremental biodiesel demand under Section 817 of the Senate bill, because the vehicle purchases of such a small group are not likely to follow a smooth trend. For example, State fleets and fleets owned by alternative-fuel providers purchased 22 percent fewer light-duty vehicles in model year 2001 than in model year 2000.

Another consideration is that the EPAct's vehicle-purchase requirements have never been satisfied by all covered fleets. Most of the covered fleets belong to the Federal or State governments. Costs for alternative fuels and alternative-fueled vehicles are higher than costs for conventional fuels and vehicles, yet no funding is appropriated specifically to defray the added costs. Compliance with the EPAct would therefore reduce funding available to carry out the agencies' functions. In addition, the EPAct has never been rigorously enforced, so it is not surprising that many fleets are not in compliance.

C. Federal Purchasing Requirements

1. Federal Agency Purchasing Requirement for Ethanol and Biodiesel (Senate 820A)

Section 820A of the Senate bill requires Federal agencies to purchase gasoline with 10-percent ethanol, if supplies are "reasonably available" at a "generally competitive price".

This provision also requires Federal agencies to purchase biodiesel blends of at least 2 percent by volume for diesel vehicles that are centrally fueled, beginning five years after the bill is enacted. The required minimum volume percentage of biodiesel increases to 20 percent ten years after the bill is enacted.

Impact of Federal Agency Purchasing Requirements

The ethanol blend purchase requirement is not likely to have much of an effect, due to limited availability of 10-percent ethanol blend gasoline and due to the small size of the civilian Federal vehicle fleet. The choice between 10-percent ethanol blend and gasoline without ethanol is offered only in geographic areas that use conventional gasoline. Conventional gasolines with and without ethanol are fungible, and consumers are assumed to be indifferent between the two. If Federal agencies increase their consumption of gasoline with ethanol, other entities will decrease their consumption by a corresponding amount. In some geographic locations, all gasoline is required to contain ethanol, though not all at fractions of 10 percent by volume. RFG in the Midwest is blended with 10-percent ethanol. California Air Resource Board gasoline, however, is effectively limited to 5.8-percent ethanol, and RFG in the Northeast is expected to be 5.8-percent ethanol as well. There is obviously no gasoline choice for agency administrators to make in these regions.

The biodiesel purchase requirement would take effect in 2008, at the earliest. A 2-percent biodiesel blend currently sells for about 2 cents per gallon more than diesel; a 20-percent biodiesel blend sells for about 18 cents per gallon more than diesel. It is unlikely that an 18-cent-per-gallon premium would be considered "generally competitive." Some agencies might be willing to pay the premium for 2-percent biodiesel, but the more diesel that the agency consumes, the more price-conscious it is likely to be. And agencies might already plan to use 20-percent biodiesel blend to satisfy EPAct requirements. For these reasons, the biodiesel purchasing requirement is also not likely to have much effect.

D. Ethanol From MSW

1. Commercial Byproducts from Municipal Solid Waste Loan Guarantee Program (Senate 820B and House 17108)

Section 820B of the Senate bill and Section 17108 of the House bill direct the Secretary of Energy to establish loan guarantees for the construction of facilities to convert municipal solid waste into ethanol or other commercial products.

Impact of Loan Guarantee Program

A subsidiary of Masada Resource Group is awaiting final approval to construct such a facility in Orange County, New York. While the economics appear to be favorable, Masada has encountered local opposition to its permitted emissions levels that has successfully delayed construction for the past several years.[70] Construction is expected to finally begin this year, and the plant is expected to begin operation in 2005.[71]

The Federal loan guarantee serves to eliminate the risk premium that might be required to finance new technology. But this effect is only temporary. The risk of investment in municipal solid waste-to-ethanol technology will be reduced several years after Masada begins operating, in that the economics of the technology will be known to a much greater degree. Once the profitability of municipal solid waste-to-ethanol is known, there will be no risk premium assessed for new technology, and the loan guarantees will have little or no effect.

E. Biodiesel Incentives

1. Incentives for Biodiesel (Senate 2008)

Section 2008 of the Senate bill establishes income tax credits of $1.00 per gallon and $0.50 per gallon (nominal dollars), respectively, for producers of biodiesel from virgin oil and nonvirgin oil. Producers of biodiesel from virgin oil can take an excise tax exemption of $1 per gallon (nominal dollars) of biodiesel for blends up to 20 percent by volume instead of the income tax credit. These credits expire after 2005.

Impact of Biodiesel Incentives

The excise tax exemption in conjunction with the Department of Agriculture's Commodity Credit Corporation (CCC) grants (available through fiscal year 2006) could result in large increases in biodiesel production for the fiscal years 2004 to 2006. In May 2003, Agriculture issued revised rules for the CCC bioenergy program. Although the funding formula changed, the payments for increased virgin oil biodiesel production remained about the same as under the previous rules. The payment for nonvirgin oil biodiesel is new under the revised rules. Another new benefit from the bioenergy program is base payments for biodiesel production.

The National Biodiesel Board[72] claims that dedicated biodiesel plants with capacity of 60 to 80 million gallons have already been built.[73] In addition, 200 million gallons of capacity are available from oleochemical producers, such as Proctor and Gamble. These firms make methyl esters of fats and oils for use in consumer products such as soaps and detergents. The virgin feedstock of choice is soybean oil. The nonvirgin feedstock of choice is yellow grease, consisting mostly of used cooking oil and rendered animal fats. This analysis assumes that the competing uses for yellow grease limit output of biodiesel from this source to 100 million gallons per year.

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[70] http://www.masada.com/presshome.html
[71] http://www.fortune.com/fortune/smallbusiness/articles/0,15114,444690-2,00.html
[72] http://www.biodiesel.org/pdf_files/Capacity.PDF
[73] For more background on biodiesel, see Energy Information Administration, *Impact of Renewable Fuels Standard/MTBE Provisions of S. 1766*, SR/OIASF/2002-06, (Washington, DC, March 2002).

From fiscal years 2004 through 2006, soybean oil biodiesel receives an income tax credit or excise tax exemption of 90 to 94 cents per gallon; yellow grease biodiesel receives an income tax credit of 45 to 47 cents (2001 cents). In addition, the CCC payments for expansion of biodiesel production are $1.43 to $1.46 for soybean oil biodiesel and 88 to 90 cents for yellow grease biodiesel. The Commodity Credit Corporation payments and the proposed income tax credit or excise tax exemption effectively reduce the variable cost of additional soybean oil and yellow grease biodiesel to 21 and 30 cents per gallon, respectively, in fiscal year 2004 (see Tables 17 and 18). But additional units produced in fiscal 2004 become base units in fiscal 2005 and 2006 and, as such, are eligible only for much smaller, and declining, base production payments. Because the Commodity Credit Corporation subsidies and the tax exemptions under Section 2008 are temporary, they are likely to result in large but unsustainable increases in biodiesel production. In the absence of any further policy changes, EIA projects biodiesel production of about 33 million gallons in calendar year 2004.

Table 17. Soybean Oil Biodiesel Costs and Subsidies For Production Levels Under 65 Million Gallons Per Year (2001 dollars per gallon)

Fiscal Year	Variable Cost	Sec. 2008 Excise Tax Exemption/ Income Tax Credit	CCC Base Production Payment	Variable Cost of Base Production, Net	CCC Additional Production Payment	Variable Cost of Additional Production, Net
2004	2.58	0.94	0.43	1.21	1.43	0.21
2005	2.58	0.92	0.22	1.44	1.44	0.22
2006	2.54	0.90	0.00	1.64	1.46	0.18

Sources: Variable costs were estimated by EIA, assuming total annual output of 180 million gallons from soybean oil. Payments were estimated by EIA based on 7 CFR Part 1424 (Bioenergy Program; Final Rule). Soybean and soybean oil price projections are from USDA Baseline Projections, February 2003.

Table 18. Yellow Grease Biodiesel Costs and Subsidies For Production Levels Under 65 Million Gallons Per Year (2001 dollars per gallon)

Fiscal Year	Variable Cost	Sec. 2008 Excise Tax Exemption/ Income Tax Credit	CCC Base Production Payment	Variable Cost of Base Production, Net	CCC Additional Production Payment	Variable Cost of Additional Production, Net
2004	1.64	0.47	0.26	0.91	0.88	0.30
2005	1.65	0.46	0.13	1.06	0.89	0.30
2006	1.63	0.45	0.00	1.18	0.90	0.27

Sources: Variable costs were estimated by EIA, assuming total annual output of 100 million gallons from yellow grease. Payments were estimated by EIA based on 7 CFR Part 1424 (Bioenergy Program; Final Rule). Yellow grease prices are from econometric estimates by EIA.

Note: Additional production payments in a fiscal year are for production above the level of the prior fiscal year. Base production payments apply to production up to the level of the prior fiscal year.

Payments for output levels above 65 million gallons per year are approximately 30 percent lower than the values reported in the Tables 15 and 16.

Appendix A

Request Letter from Senator Byron L. Dorgan

AUG. 1.2003 1:36PM SENATOR DORGAN NO.636 P.2

BYRON L. DORGAN
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102 NORTH 4TH STREET, ROOM 108
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100 1ST STREET, S.W., ROOM 105
MINOT, ND 58701
701-852-0703

July 31, 2003

2003-010249

Guy F. Caruso
Administrator
Energy Information Administration
EI-1/Forrestal Building
100 Independence Avenue SW
Washington, DC 20585

Dear Mr. Caruso:

I am writing to request that that you conduct a title-by-title quantitative analysis of the energy consumption and oil savings that would result from the Senate energy bill, and the impact on energy imports. I would also like you to assess the differences between the House and Senate–passed bills, compared with the Annual Energy Outlook as a baseline. Your analysis could improve the eventual agreements made in conference between the House and Senate.

I would like EIA to undertake a broad review of the expected energy and economic impacts of the two bills, highlighting those key differences that you see in the areas of oil and gas imports, energy savings from improvements in efficiency, and evolution in the long term mix of renewables, coal, nuclear and hydrogen.

Important assumptions about the appropriate level of detail, the timing of the analysis and planning horizons could be resolved in discussions with my staff. Please contact Jerome Hinkle, at (202) 224-3700, with any questions.

I appreciate your guidance and assistance. The Energy Information Administration has often made key contributions to debate and understanding. I expect that the analysis I have described here will greatly help Congress in its pursuit of a national energy policy.

Sincerely,

Byron L. Dorgan
U.S. Senator

BLD:jh

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E-mail from Senator Dorgan's Staff

From: Hutzler, Mary
Sent: Wednesday, September 03, 2003 10:00 AM
To: Holtberg, Paul
Subject: FW: Energy Bills Analysis
Email from Hinkle
-----Original Message-----
From: Cynthia Roberts [mailto:fjhinklefamily@earthlink.net]
Sent: Sunday, August 17, 2003 10:29 PM
To: mary.hutzler@eia.doe.gov
Subject: Energy Bills Analysis

Mary--thanks for spending the time to discuss our analysis. I believe that it will make an important contribution to forming consensus in Conference. The key amendments on the Senate Floor, like ethanol, the million barrel a day savings, etc., are worth viewing as influential factors in the eventual debates if there are similar or related provisions in either the House or Senate bills. After the first round of reviews and summaries, it might even be worthwhile to meet occasionally during the Conference to discuss the evolution of agreements in shaping the final bill, and to get your team's judgements on their supply/demand/import implications. I'm looking forward to working with you.

Regards,
Jerry Hinkle

--- Cynthia Roberts
--- fjhinklefamily@earthlink.net
--- EarthLink: The #1 provider of the Real Internet.