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before the

COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS

U. S. SENATE

HEARING ON S. 556, “THE CLEAN POWER ACT OF 2001"

November 1, 2001

Mr. Chairman and Members of the Committee:

I appreciate the opportunity to appear before you today to discuss the Energy Information Administration's analysis of multiple emission targets based on the provisions of S. 556, "The Clean Power Act of 2001."

The Energy Information Administration (EIA) is an autonomous statistical and analytical agency within the Department of Energy. We are charged with providing objective, timely, and relevant data, analysis, and projections for the use of the Department of Energy, other government agencies, the U.S. Congress and the public. We do not take positions on policy issues, but we do produce data and analysis reports that are meant to help policy makers determine energy policy. Because we have an element of statutory independence with respect to the analyses that we publish, our views are strictly those of EIA. We do not speak for the Department, nor for any particular point of view with respect to energy policy, and our views should not be construed as representing those of the Department or the Administration. However, EIA's baseline projections on energy trends are widely used by government agencies, the private sector, and academia for their own energy analyses.

The projections in this testimony are taken from the two reports we recently released entitled *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants With Advanced Technology Scenarios*, prepared at the request of Senators Jeffords and Lieberman; and *Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides, and Mercury from Electric Power Plants*, prepared at the request of Senators Smith, Voinovich, and Brownback. These reports analyzed the impacts on electricity producers and consumers of constraints on the emission of sulfur dioxide, nitrogen oxides, carbon dioxide, and/or mercury at electric power plants. The assumptions used in the analysis cases prepared for these reports, as described below, were specified by the requesters for each report. This includes the emission limits specified, and, in the case of the report requested by Senators Jeffords and Lieberman, the technology assumptions used in each case.

The projections in these reports are not meant to be exact predictions of the future, but represent possible alternative energy futures, given technological and demographic trends, current laws and regulations, and consumer behavior as derived from known data. EIA recognizes that projections of energy markets are highly uncertain, subject to many random events that cannot be foreseen, such as weather, political disruptions, strikes, and technological breakthroughs. In addition to these short-term phenomena, long-term trends in technology development, demographics, economic growth, and energy resources may evolve along a different path than projected in the reference case used in these reports. The costs to consumers and the impacts on the economy that are presented here are subject to considerable uncertainty, depending upon how the complex inter-relationships among many variables evolve.

S. 556 includes a provision that requires that all existing power plants must meet the most recent new source performance standards within 5 years of the enactment of the legislation, or on the plant's 30th birthday, whichever date is later. In effect, this would likely require all existing coal plants to retrofit with scrubbers and NOx reduction equipment if they have not done so already, or retire. Since this provision was not included in the letter from Senators Jeffords and

Lieberman requesting the study cited here, it was not included in EIA's analysis. Inclusion of this provision in the analysis would likely have changed the results of the study; in particular, the projected share of coal in electricity generation would likely have been lower, with consequent impacts on electricity prices and the cost of emission allowances.

Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants With Advanced Technology Scenarios

In the request from Senators Jeffords and Lieberman, the Energy Information Administration (EIA) was asked to analyze the impacts of emissions limits on nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon dioxide (CO_2), and mercury (Hg) from electricity generators against four cases with different assumptions concerning technology development and policies to reduce energy consumption and promote the use of cleaner technologies. The first case used the reference case technology characteristics in the *Annual Energy Outlook 2001 (AEO2001*). The second case assumed the high technology assumptions for energy demand, electricity generation, and fuel supply in *AEO2001*. The other two cases were based on the moderate and advanced cases from *Scenarios for a Clean Energy Future*. In all four cases, the same emissions limits were imposed on all electricity generators, excluding cogenerators. The start date for the reductions was assumed to be 2002. By 2007, NO_x emissions are reduced to 75 percent below 1997 levels, SO_2 emissions to 75 percent below the full implementation of the Phase II requirements under Title IV of the Clean Air Act Amendments of 1990, Hg emissions to 90 percent below 1999 levels, and CO_2 emissions to 1990 levels, exactly as specified in S.556 (Figure 1).

In this testimony, we focus on the reference case shown in the report, with and without emissions limits, in order to simplify the discussion and also because we believe this is the most likely future outcome. In general, the higher the assumed level of technology improvement in producing and consuming energy in a given case without more stringent emission targets, the lower will be the impact on electricity prices and electricity production resource costs[1] as a result of imposing emission limits in that case. However, in all cases the additional electricity production resource costs for meeting emission targets range from 8 to 9 percent of the corresponding costs in the cases with no additional emission controls. Also, the additional costs of developing and installing advanced technologies in the end-use and electricity sectors are not always explicitly considered in the advanced technology cases. Although the cost impacts of reducing emissions in these cases would be lower, the total cost including that of purchasing more efficient energy-consuming and producing equipment would likely be considerably higher than the impacts of controls in the reference case.

[1]The total cost of producing electric power, including the cost of fuels to generate electricity, operations and maintenance costs, investments in plants and equipment, and costs to purchase power from other generators.

Summary Results

Prices: With the imposition of emissions limits identical to those specified in S. 556 on the reference case, the average delivered price of electricity in 2020 is projected to be 33 percent higher than in the reference case due to the cost to electricity generators of meeting the limits (Table 1). Projected wellhead natural gas prices are also higher by 20 percent as a result of higher natural gas consumption by electricity generators.

Consumption: Due to the higher energy prices that result from the assumed emissions limits, total energy consumption is projected to be reduced by 7 quadrillion British thermal units (Btu) in 2020, or 5 percent, and projected energy expenditures are higher. The primary energy intensity of the economy—defined as total energy consumption per dollar of gross domestic product (GDP)—is projected to decline at an average annual rate of 1.9 percent between 1999 and 2020, compared to 1.6 percent in the reference case. Projected consumption of coal and electricity is lower with the emissions limits than in the reference case without the limits; however, as electricity generators reduce the use of coal, the projected use of existing nuclear power plants and natural gas and renewable generating technologies is higher, raising the consumption of these energy sources, relative to the reference case.

Emissions: Because of reduced energy consumption and the shift in the fuel mix to more natural gas, renewables, and nuclear power, projected CO_2 emissions in 2020 are reduced by 287 million metric tons carbon equivalent, or 14 percent, relative to the reference case, and emissions of SO_2, NOx, and Hg are also reduced consistent with the assumed targets.

Emission Controls: In order to meet the emissions caps, electricity generators must retrofit existing generators with equipment that reduces emissions of SO_2, NOx, and Hg. By 2020, an additional 19 gigawatts of scrubbers are projected to be added above the reference case level, while 6 gigawatts of NOx combustion retrofits, and 11 gigawatts of selective catalytic reduction post-combustion units, the most expensive of the NOx-reduction retrofits, are added above reference case levels. Selective non-catalytic reduction post-combustion retrofits are about 9 gigawatts lower than in the reference case, mainly because the case with emissions controls reduces coal consumption enough to make those retrofits unnecessary. Hg controls added include 49 gigawatts of spray coolers, and 88 gigawatts retrofitting with fabric filters, neither of which is needed in the reference case since no Hg emission targets are assumed in that case.

Resource Costs and GDP: Total resource costs to meet the cap are $177 billion[2] higher than in the reference case over the 2001-2020 forecast horizon. Real GDP is 0.8 percent, or nearly $100 billion, lower in 2007 in the case with emissions compared to the reference case, falling to 0.3 percent, or just over $50 billion, lower by 2020.

[2] All prices and expenditures are in real 1999 dollars.

Electricity and Renewables

The introduction of emissions limits in the reference case results in substantially higher projected average delivered electricity prices relative to the reference case. Projected prices are 31 percent higher in 2010 and 33 percent higher in 2020 even as consumers reduce their consumption of electricity by 6 and 9 percent in 2010 and 2020, respectively (Figure 2). Annual expenditures are expected to be $158 more per household in 2010 and $154 more in 2020 as revenue to electricity providers is $58 billion and $59 billion higher in 2010 and 2020, respectively, some of which goes to pay for the higher costs of electricity production as described below.

Prices are expected to increase because the cost of producing power with emissions limits is more expensive than without limits. There are additional costs associated with the installation of emission control equipment, the purchase of emissions permits, and costs for fuels used to generate electricity. For example, in the case with emissions limits, 37 gigawatts of flue gas desulfurization equipment are expected to be constructed in 2020 compared with 17 gigawatts in the reference case. Combustion controls for NOx are installed at 52 gigawatts of generating capacity, compared to 47 gigawatts in the reference case, with additional retrofits of selective catalytic reduction post-combustion units for NOx control as well. There are also additional investments for fabric filters and spray coolers to reduce emissions of Hg, as well as use of activated carbon. Prices for fossil fuels are also expected to be higher. Natural gas prices to electricity generators are projected to be $4.52 per thousand cubic feet in 2020 in the reference case with limits compared with $3.68 in the reference case without limits. The effective price of natural gas to electricity generators, which includes the cost of a CO_2 allowance[3], reaches $6.31 per thousand cubic feet when the emissions limits are imposed. The higher projected price for natural gas also results from the higher costs associated with producing additional quantities of natural gas in the case with limits, which raises the average wellhead price of natural gas. Although the price of coal delivered to electricity generators is lower in 2020 when emissions limits are imposed, $17.28 per short ton compared to $19.34 per short ton in the case without limits, the effective price is projected to reach $81.28 per short ton, after including the CO_2 allowance cost.

The projected higher electricity prices cause consumers to reduce their use of electricity, although higher projected natural gas prices dampen the impact of the higher electricity prices. Sales of electricity are expected to be lower by 261 billion kilowatthours in 2010 and by 443 billion kilowatthours in 2020 (Figure 3). These lower levels of consumption, combined with fuel switching by electricity generators, are reflected in the levels and types of generation. Projected coal-fired generation is reduced by 962 billion kilowatthours in 2010 and by 1,261 billion kilowatthours in 2020, 43 percent and 55 percent, respectively (Figure 4). The lower levels of coal-fired generation are expected to occur because emissions limits on controlled gases and Hg discourage the use of coal more than other fuels. Compared with coal, natural gas has lower emissions per unit, resulting in higher projected consumption levels for natural gas compared

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[3]It is assumed in this analysis that electricity generators would need to purchase an allowance for each ton of CO_2 emitted, similar to the SO_2 control provisions of the Clean Air Act Amendments of 1990.

with the reference case without limits. The use of renewable sources and nuclear power is also expected to be higher in the case with limits because the costs of coal- and petroleum-fired generation are relatively more expensive. By 2010, nonhydropower renewable technologies, including geothermal, wind, biomass, municipal solid waste and landfill gas, and solar, are expected to produce 94 billion kilowatthours more than the 95 billion kilowatthours generated in the reference case without limits. In 2020, these renewable technologies are expected to generate 217 billion kilowatthours in the reference case with emissions limits, compared to 99 billion kilowatthours in the case without limits. Projected nuclear generation is higher by 21 billion kilowatthours in 2010 and by 59 billion kilowatthours in 2020, 3 percent and 10 percent, respectively, compared to the case without limits.

The higher projected price for electricity is due, in part, to the costs of obtaining emission permits. CO_2 emissions permit costs are included in the price of the fossil fuel to electricity generators. For the other three emissions, the permit costs are effectively included in the electricity price based on the cost incurred by the marginal generator.

The costs for SO_2 permits (allowances) are projected to be \$46 per ton in 2010 and \$221 per ton in 2020 in the reference case with emissions limits (Figure 5). The current price level for SO_2 permits is approximately \$175 per ton. In 2020, the cost of SO_2 permits is projected to be \$21 per ton higher than in the reference case without emissions limits, reflecting lower emissions limits and additional investments in emissions control equipment. The price for CO_2 permits is expected to be \$93 per metric ton carbon equivalent in 2010, increasing to \$122 per metric ton carbon equivalent in 2020 (Figure 6). This cost for CO_2 permits reflects the need to retire existing coal-fired capacity and switch to less carbon-intensive fuels, primarily natural gas. Currently, there are no economical technologies to sequester CO_2 emissions from coal plants. The cost for NO_x emission allowances is expected to decline to zero by 2010 because the actions taken to meet the CO_2 limits result in NO_x emissions being within the specified limit (Figure 7). The Hg allowance costs are expected to be \$482 million per ton in 2010 and \$306 million per ton in 2020 (Figure 8). Although the unit cost of Hg removal is high, the total cost for reducing Hg emissions is small when compared with costs to reduce CO_2 emissions.

To put the various allowance prices on comparable terms, Figure 9 converts the 2010 projected allowance prices for the four emission types to a cents per kilowatthour basis for two typical coal plants – one relatively uncontrolled and one equipped to remove 75-80 percent of NOx emissions and 95 percent of SO_2 emissions. As shown, for both plants the carbon allowance price would be expected to have the greatest impact on the operating costs of the plant. In the relatively uncontrolled plant carbon allowances would account for over two thirds of the total allowance cost, while in the more controlled plant, it would account for over 90 percent of the total. In reality, the impacts would vary from plant-to-plant depending on each plant's configuration and the quantity of coal consumed. However, this figure illustrates the relative importance of each of the allowance costs. For the industry as a whole, the cost of carbon allowances is by far the largest of the four emissions considered. The total value of carbon allowances in 2010 is about \$44 billion, rising to \$58 billion in 2020. This compares with the total value of allowances for the other emissions in 2010 of just over \$2 billion, falling to under \$2 billion by 2020.

There are costs to power producers associated with electricity generation resulting from the emissions limits. The total cost of producing electric power includes the cost of fuels to generate electricity, operations and maintenance costs, investments in plants and equipment, and costs to purchase power from other generators. The sum of all these costs is called the resource cost. This resource cost is different from the marginal cost of generating electricity because it includes fixed costs, such as investments and portions of operations and maintenance costs, that do not vary based on production levels. Producers may not recover these fixed costs in competitive markets when the market price of electricity is at the same level as their marginal production costs, which only include fuel and certain other costs that vary with output levels. However, over time, producers need to recover their resource costs in order to remain in business. In the competitive marketplace which is assumed in these projections, a power producer would recover these costs during periods when the market price of power is higher than its production cost, for example, when a high-production-cost combustion turbine sets the market price while a low-production-cost pulverized coal unit is producing electricity.

For all the cases with emissions limits analyzed in this study, the resource costs are projected to be higher relative to the resource costs in the comparable cases without emissions limits. The largest increase is for fuels used to generate electricity. There are also costs associated with purchases of power from other generators and investment costs for new generation facilities or for retrofitting plants with emission control equipment.

From 2001 through 2020, the cumulative resource costs to generate electricity are expected to be $2,208 billion (undiscounted 1999 dollars) in the reference case with emissions limits, compared to $2,031 billion in the same case without the limits. Thus, the projected incremental cumulative expenditures attributable to emission limits that would be incurred by electricity generators is $177 billion, a 9-percent increase (Figure 10). These costs exclude the costs of emission permits that must be purchased by electricity generators because they are funds that are transferred among industry participants and do not represent actual resource consumption. The costs of the emissions permits are included in the delivered price of electricity, to the extent that they can be passed through to consumers.

In the reference case with emissions limits, the annualized resource costs in 2007 (the year the limits are fully imposed), which include financing and capital recovery costs, are $19.9 billion higher than projected in the reference case without limits. These incremental costs due to emissions limits are expected to be reduced to $19.1 billion and $18.1 billion in 2010 and 2020, respectively.

Resource costs are computed for the projected levels of consumption for each case. Since consumption is lower in the case with emissions limits (due to higher prices) there is also a loss in consumer surplus as a result of the reduced consumption.[4]

[4]Consumer surplus is a measure of the benefit accruing to consumers who would be willing to pay more than the market price of electricity. For example, when the price of electricity is 6 cents per kilowatt-hour, a consumer who would have been willing to pay 8 cents gains a benefit of 2 cents per kilowatt-hour. By raising the market price to 8 cents, that surplus is lost. A rough estimate of the loss in this analysis is $2.5 billion in 2010,

Natural Gas

In the reference case, natural gas consumption is expected to increase at an average annual rate of 2.3 percent over the forecast horizon. By 2020, total natural gas consumption is expected to reach 35.0 trillion cubic feet, an increase of 61 percent from 1999 levels. One of the fastest growing sectors for natural gas consumption is electricity generation. By 2020, the amount of natural gas consumed by electricity generators, excluding cogenerators, is expected to reach 11.2 trillion cubic feet, three times the volume used in 1999. In the next few years, natural gas prices are expected to decline from their record-high levels reached over the winter of 2001, dropping to $2.84 per thousand cubic feet at the wellhead by 2006. Although increased domestic production and imports keep pace with consumption, prices in the longer term rise as total demand grows, and wellhead prices are projected to reach $3.10 per thousand cubic feet by 2020 in the reference case.

Imposing emissions limits on electricity generators is expected to increase the demand for natural gas, during a period when the demand is already expected to be growing quickly. Because CO_2 emissions from natural gas are relatively low compared with other fossil fuels and natural gas is virtually free of SO_2 and Hg, electricity generators can help meet their emissions requirements by switching to natural gas. Imposing the limits on the reference case leads to higher natural gas demand by electricity generators. By 2020, the demand for natural gas by electricity generators is expected to reach 13.9 trillion cubic feet, 24 percent higher than the level of 11.2 trillion cubic feet projected in the case without emissions limits. Also, projected natural gas consumption in the commercial and industrial sectors is higher, primarily for cogeneration, which is not assumed to be subject to the emission limits imposed on other electricity generation, providing a stimulus for additional generation for self-use in these sectors. As a result, total natural gas consumption in 2020 is projected to increase to 38.4 trillion cubic feet, compared to 35.0 trillion cubic feet in the reference case without emissions limits.

Higher natural gas demand results in higher prices. By 2020, the projected wellhead price reaches $3.72 per thousand cubic feet in the case with the emissions limits, compared to $3.10 per thousand cubic feet in the case without the limits (Figure 11). This results in higher natural gas prices for end users. Industrial prices, which are more closely tied to the wellhead price, are higher by 16 percent in 2020 compared to the reference case, while residential prices, which include more distribution costs, are higher by 8 percent.

Coal

Primarily due to the CO_2 limits, projected coal consumption is sharply reduced from the level in the reference case when emissions limits are imposed. When the costs associated with acquiring CO_2 allowances are added to the delivered price of coal, the effective delivered price to generators is projected to triple relative to that in the reference case by 2010 and reaches $3.97

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rising to about $4.5 billion in 2020. Over the period from 2001 to 2020, the total (undiscounted) loss to consumers is about $45 billion.

per million Btu in 2020, approximately four times the reference case price. Due to CO_2 emissions reductions and measures taken to meet the Hg limit, coal-fired electricity generation is projected to lose a substantial share of the market to natural gas-fired generation, compared with the share of coal-fired generation in the reference case. In addition, higher projected electricity prices cause total electricity sales to decline, reducing overall generation requirements.

Because of lower installed coal-fired generation capacity and lower utilization of the remaining coal-fired capacity, projected coal consumption for electricity generation in 2020 is reduced to a level that is 43 percent of that in the reference case. Total coal production is projected to decline at a slower rate than the demand for coal in the electricity generation sector because, as a result of lower coal prices, consumption is projected to increase in other sectors not subject to the CO_2 limits, including industrial and coking coal and coal exports, assuming other countries do not impose new limits on coal consumption (Figure 12).

Although CO_2 limits have the greatest impact on coal consumption, both SO_2 and Hg emissions limits are projected to add to the cost of using coal and contribute to further reductions in coal-fired generation. In 2020, an additional 20 gigawatts of scrubber retrofits are projected to be added to meet the more stringent emissions limits on SO_2 and Hg. The assumed technology costs for emissions removal are based on current estimates. Coal production is projected to be reduced in all regions and shift to sources with lower Hg content, such as mines located in the Rocky Mountains, and away from lignite and waste coal, which have relatively high Hg content.

Residential End-Use Demand

Relative to the reference case, average residential energy prices from all sources (electricity, natural gas, and petroleum) are projected to be 17 percent higher in both 2010 and 2020. However, projected residential prices of electricity are 25 and 26 percent higher in 2010 and 2020, respectively. The higher prices in the case with emissions limits are projected to reduce residential energy demand, as consumers react to the higher prices by purchasing more efficient appliances and reducing their demand for energy services (Figure 13).

Since residential electricity prices are projected to increase more than the other fuels as a result of the emissions limits, the projected demand for electricity shows the largest decrease, as consumers switch to other fuels for their heating needs and overall appliance efficiency increases for electric equipment, such as air conditioners. The projected reduction in electricity demand is reflected in reduced CO_2 emissions attributed to energy use in the residential sector. Of the projected CO_2 reduction of 76 million metric tons carbon equivalent in the residential sector in the case with emissions limits in 2010, virtually all is attributed to the projected decrease in electricity demand. In 2020, the projected residential CO_2 emissions are reduced by 102 million metric tons carbon equivalent, or 27 percent, relative to the reference case.

Commercial End-Use Demand

The imposition of emissions limits in the reference case results in a 4-percent reduction in projected commercial delivered energy use in 2010, with electricity accounting for 83 percent of the projected decrease. In 2020, commercial energy demand is projected to be reduced by 2 percent, relative to the reference case. The cost of complying with emissions limits causes projected commercial electricity prices to be 33 percent higher in 2010 and 34 percent higher in 2020, compared to the reference case, while average natural gas prices to the sector are projected to be higher by 9 percent and 10 percent in 2010 and 2020, respectively, as electricity generators turn to natural gas to minimize their compliance costs. Commercial consumers are expected to minimize their own energy costs in the case with emissions limits through measures such as shutting off lights and equipment while not in use and by purchasing more efficient equipment.

Industrial End-Use Demand

Imposing emissions limits on the electric generation sector has essentially no impact on total delivered industrial energy consumption in the reference case because the industrial sector chooses to generate more of its own electricity (which is assumed to be exempt from the emissions limits), primarily from natural gas, accounting for a slight increase in total industrial energy consumption. While total delivered energy consumption is not significantly affected by the emissions limits, the fuel mix is altered. The projected industrial electricity price in 2010 is 40 percent higher than in the reference case due to the emissions limits and 43 percent higher in 2020. As a result, purchased electricity consumption is projected to be lower by 7 percent, or 0.3 quadrillion Btu, relative to the reference case in 2010 and by 13 percent, or 0.6 quadrillion Btu in 2020. At the same time, consumption of both petroleum products and natural gas is projected to be higher. Projected cogeneration from natural gas is higher by 61 percent in 2010 and 128 percent in 2020 compared to the reference case without emissions limits.

CO_2 emissions attributable to the industrial sector are reduced by 62 million metric tons carbon equivalent, or 12 percent, in 2010 and by 83 million metric tons carbon equivalent, or 14 percent, in 2020. The CO_2 reductions result from the reduction in purchased electricity.

Macroeconomic Impacts

The imposition of emission limits on electricity generators is expected to affect the U.S. economy primarily through higher delivered energy prices. Higher energy costs would reduce the use of energy by shifting production toward less energy-intensive sectors, by replacing energy with labor and capital in specific production processes, and by encouraging energy conservation. Although reflecting a more efficient use of higher cost energy, the change would also tend to lower the productivity of other factors in the production process because of a shift in the prices of capital and labor relative to energy. Moreover, an increase in energy prices would raise non-energy intermediate and final product prices and introduce cyclical fluctuations in the economy, resulting in output and employment losses in the short term. In the long term, however, the economy can be expected to recover and move back to a more stable growth path.

Relative to a reference case projection for energy markets, a case with emissions limits has impacts on the aggregate economy. However, with alternative projections for energy markets, the same emissions limits will have different impacts on energy markets and subsequently different impacts on the economy. The macroeconomic assessment in this testimony evaluates the impacts of emissions limits on the reference case.

The macroeconomic analysis assumes a marketable emissions permit system, with a no-cost (grandfathered) allocation of permits. In meeting the targets, power suppliers are free to buy and sell allowances at a market-determined price for the permits, which represents the marginal cost of abatement of any given emission.

The introduction of emissions limits in the reference case results in a substantial increase in energy prices and subsequently in aggregate prices for the economy. The wholesale price index for fuel and power (WPI-Fuel and Power) gives an indication of the overall change in energy prices across all fuels. The WPI-Fuel and Power is projected to rise rapidly above the reference case without emissions limits by 14.6 percent in 2007, the target year for emissions reduction. Thereafter, this index remains approximately 15 percent above the reference case without limits through 2020. Higher projected electricity and natural gas prices initially affect only the energy portion of the consumer price index (CPI). The higher projected energy prices are expected to be accompanied by general price effects as they are incorporated in the prices of other goods and services. In this case, the level of the CPI is projected to be about 0.7 percent above the reference case without limits by 2007 and to moderate only slightly to approximately 0.6 percent above the reference case level through 2020.

How would the projected changes in energy prices affect the general economy? Capital, labor, and production processes in the economy would need to adjust to accommodate the new, higher set of energy and non-energy prices. Higher energy prices would affect both consumers and businesses. Households would face higher prices for energy and the need to adjust spending patterns. Rising expenditures for energy would take a larger share of the family budget for consumption of goods and services, leaving less for savings. Energy services also represent a key input in the production of goods and services. As energy prices increase, the costs of production rise, placing upward pressure on the prices of all intermediate goods and final goods and services in the economy. These transition effects tend to dominate in the short run, but dissipate over time. The unemployment rate is projected to rise by 0.4 percentage points above the reference case with no limits in 2007. Along with the projected increase in inflation and unemployment, real output of the economy is projected to be lower. Real GDP is projected to be 0.8 percent, or about $100 billion, lower relative to the reference case with no limits in 2007, and employment in non-agricultural establishments is projected to be lower by one million jobs. Similarly, real disposable income is expected to be reduced by 1.0 percent.

As the economy adjusts to higher energy prices, projected inflation begins to subside after 2007. At the same time, the economy begins to return to its long-run growth path. By 2020, the projected unemployment rate is 0.1 percentage points above the reference case, and real GDP is projected to be 0.3 percent, or about $50 billion, below the reference case projection. The impact on non-agricultural employment is projected to moderate to just over 400,000 jobs relative to the reference case in 2020.

Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides, and Mercury from Electric Power Plants

This analysis responded to a request from Senators Smith, Voinovich, and Brownback to examine the costs of specific multi-emission reduction strategies in the electricity generation sector. In their request, Senators Smith, Voinovich, and Brownback asked EIA to analyze the impacts of three scenarios with alternative power sector emission caps on NO_x, SO_2, and Hg:

Scenario 1: Reduce NO_x emissions by 75 percent below 1997 levels, SO_2 emissions by 75 percent below full implementation of Title IV of the Clean Air Act Amendments of 1990 (CAAA90), and Hg emissions by 75 percent below 1999 levels by 2012, with half the reductions for each of the emissions occurring by 2007.

Scenario 2: Reduce NO_x emissions by 50 percent below 1997 levels, SO_2 emissions by 65 percent below full implementation of Title IV of the Clean Air Act Amendments of 1990 (CAAA90), and Hg emissions by 65 percent below 1999 levels by 2012, with half the reductions for each of the emissions occurring by 2007.

Scenario 3: Reduce NO_x emissions by 50 percent below 1997 levels, SO_2 emissions by 50 percent below full implementation of Title IV of the Clean Air Act Amendments of 1990 (CAAA90), and Hg emissions by 50 percent below 1999 levels by 2012, with half the reductions for each of the emissions occurring by 2007.

The key results included:

• Adding emissions control equipment to reduce NO_x, SO_2, and Hg is projected to be the dominant compliance option. Emissions control equipment is expected to be added to many of the existing U.S. coal-fired electric power plants, which currently total just over 300 gigawatts of capacity.
• Decreased use of coal and increased use of natural gas in the electricity sector is projected to result when emission reduction efforts of these levels are required. By 2020, coal-fired electricity generation is projected to be between 4 percent and 10 percent below the reference case level, and natural gas-fired generation is projected to be between 4 percent and 10 percent above the reference case level.
•Emission allowance costs and electricity prices are projected to increase as the caps on NO_x ,SO_2, and Hg are tightened across the cases. The price of electricity is projected to be between 1 percent and 6 percent higher in 2020 than in the reference case. The Nation’s total electricity bill (in 1999 dollars) is projected to be between $3 billion and $13 billion (1 to 5 percent) higher in 2020 than projected in the reference case.
• Over the 2001 to 2020 forecast period, power supplier resource costs (in 1999 dollars) are projected to be between $28 billion and $89 billion higher than in the reference case.

A key difference between this study and the one done for Senators Jeffords and Lieberman relates to the treatment of CO_2 emissions. In the Jeffords-Lieberman report, CO_2 emissions were specified to reach 1990 levels by 2007. In this report, there were no specific emissions limits for CO_2 in the main cases.[5] Therefore, the results of the two reports can be compared to show how limits on CO_2 affect the costs of mitigating SO_2 and NOx; and how the costs of Hg mitigation rise as the target becomes more stringent.

Figure 14 shows the allowance costs for SO_2, NOx, and Hg based on the three scenarios described above. The 75 percent reduction case has the same targets for SO_2 and NOx as in the Jeffords-Lieberman report. Comparing these allowance costs to those shown in Figures 5 and 7, it is clear that the addition of CO_2 emission targets helps to reduce the costs of meeting the targets on SO_2 and NOx. For example, in 2020, the cost of reducing NOx emissions to 75 percent below 1997 levels without a CO_2 cap is $2825 per ton; when CO_2 emissions at 1990 levels are included, the cost drops to zero, because coal generation is reduced sufficiently to enable NOx emission targets to be met without further incentives to reduce coal use or add NOx reduction equipment. Similarly, the cost of reducing SO_2 emissions to 75 percent below the CAAA90 Phase II limits is $1737 per ton in 2020 without limits on CO_2 emissions, dropping to $221 per ton when CO_2 emissions must meet 1990 levels. As with NOx emissions, the reduction in coal use allows generators to meet the targeted SO_2 levels at a much lower marginal cost when CO_2 emissions are capped.

A comparison of Hg targets between the two reports indicates that the cost of mitigation rises more than proportionately with the amount of Hg to be reduced. Under Scenario 1 above, the costs of reducing Hg by 75 percent from 1997 levels is $85,000 per pound in 2020. In the Jeffords-Lieberman analysis, reducing the cap such that emissions would be 90 percent below 1997 levels yields an Hg allowance cost of $153,000 per pound in 2020, 80 percent above the 75-percent case when the mitigation is only 20 percent higher. The more stringent the cap, the more such expensive options as activated carbon to remove the Hg must be used, greatly increasing the marginal cost compared to less stringent targets.

Finally, Figure 15 shows the resource costs for meeting the targets in the scenarios described at the beginning of this section. Over the 2001-2020 time period, total resources would range from $28 billion to $89 billion (1999 dollars) above reference case levels in order to meet the three-pollutant targets specified for this report. This compares with Figure 10 from the Jeffords-Lieberman analysis, which shows increased resource costs of $177 billion to reach the levels specified in that report, including CO_2, relative to the reference case. Both the more stringent Hg limits, and the cap on CO_2 emissions, have a significant impact on the cost to the industry of meeting the increased mitigation required by the Jeffords-Lieberman assumptions. The difference between the two sets of cases–the Jeffords-Lieberman case and the Scenario 1 (75 percent emission reduction) Smith-Voinovich-Brownback case--could be even higher, for

[5] A second set of cases with CO_2 emissions held at 2008 levels was run in order to examine the costs of purchasing offsets for any further increases in CO_2 emissions, as requested by Senators Smith, Voinovich, and Brownback.

several reasons. The loss of consumer surplus as a result of the lower electricity consumption is greater in the Jeffords-Lieberman case. Also, changes in resource costs in the Jeffords-Lieberman analysis are higher in the earlier years of the forecast horizon due to the earlier assumed compliance dates, the more stringent cap on mercury, and the cap on carbon dioxide. If the costs were discounted over time to reflect a higher value in the earlier years, this result would also raise the difference between the two analyses.

Conclusion

Based on the Jeffords-Lieberman analysis of the emission caps required by S. 556, electricity prices would be expected to be about 2 cents per kilowatt-hour higher (33 percent) in 2020 than in a case assuming current laws and regulations and assuming reference case technology assumptions. Consumption of coal would be greatly reduced, by about 50 percent in the case with emission controls compared to the case without controls. Additional use of natural gas, renewables, and existing nuclear units, as well as lower electricity consumption, is projected to offset the reduced coal usage. Resources for producing electricity would be about $177 billion higher under emission targets than in the reference case without targets (based on annual changes from 2001 through 2020 with no discounting). This does not include the loss of consumer surplus as a result of the reduction in consumption due to higher prices, which would represent an additional economic cost.

Thank you, Mr. Chairman and members of the Committee. I will be happy to answer any questions you may have.

Table 1. Energy Market Data and Projections, 1999 and 2020

Projections	1999	2020 Without Emissions Limits	2020 With Emissions Limits
Primary Energy Consumption (Quadrillion Btu)			
Petroleum	37.9	50.4	50.3
Natural Gas	22.3	35.9	39.3
Coal	21.4	26.3	13.3
Nuclear Power	7.8	6.5	7.2
Renewable Energy	6.5	8.4	10.5
Total	**96.3**	**127.7**	**120.9**
Change in Primary Energy Intensity (Annual Percent Change, 1999-2020)	**—**	**-1.6**	**-1.9**
Electricity Sales (Billion Kilowatthours)	3,294	4,763	4,320
Electricity Generation, Excluding Cogenerators (Billion Kilowatthours)			
Coal	1,830	2,302	1,041
Petroleum	85	23	11
Natural Gas	370	1,488	2,072
Nuclear Power	730	610	669
Renewables	355	399	519
Total	**3,369**	**4,821**	**4,311**
Electricity Generation by Cogenerators (Billion Kilowatthours)	**303**	**440**	**664**
Prices			
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.08	3.1	3.72
Coal Minemouth Price (1999 Dollars per Short Ton)	17.13	12.93	12.61
Average Delivered Electricity Price (1999 Cents per Kilowatthour)	6.7	6.1	8.1
Cumulative Resource Cost for Electricity Generation, 2001-2020 (Billion 1999 Dollars)	**—**	**2,031**	**2,208**
Emissions[a]			
CO_2 (Million Metric Tons Carbon Equivalent)[b]	1,511	2,044	1,757
SO_2 (Million Tons)	13.5	9	2.2
NO_x (Million Tons)	5.4	4.5	1.4
Hg (Tons)	43.4	45.2	4.3
Allowance Prices			
CO_2 (1999 Dollars per Metric Ton Carbon Equivalent)	0	0	122
SO_2 (1999 Dollars per Ton)	0	200	221
NO_x (1999 Dollars per Ton)[c]	0	0	0
Hg (Million 1999 Dollars per Ton)	0	0	306
Gross Domestic Product (Percent Change from Case Without Limits)	N/A	N/A	-0.3

[a]CO_2 emissions are from all energy sectors. Other emissions are from electricity generators, excluding cogenerators.
[b]CO_2 emissions are from energy combustion only and do not include emissions from energy production or industrial processes.
[c]Regional NO_x limits are included in the reference case, but the corresponding allowance costs are not included in the table because they are not comparable to a national NO_x limit.
Note: N/A = Not applicable
Source: National Energy Modeling System, runs SCENABS.D080301A, SCENAEM.D081601A, SCENBBS.D080301A, and SCENBEM.D081701A.