4. Fuel Market and Macroeconomic Impacts

Introduction

Efforts to reduce multiple emissions from electric power plants are expected to affect fuel choice decisions in the electricity generation sector, with significant impacts on supply patterns, prices, and employment in the coal, natural gas, and renewable fuels markets. This chapter discusses the projected impacts of new emission caps on nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon dioxide (CO_2), and mercury (Hg) and the adoption of a renewable portfolio standard (RPS) on the U.S. markets for those fuels, including industry employment levels. The chapter concludes with a discussion of the projected impacts on the U.S. economy as a whole resulting from the changes in energy prices that would be expected in various scenarios.

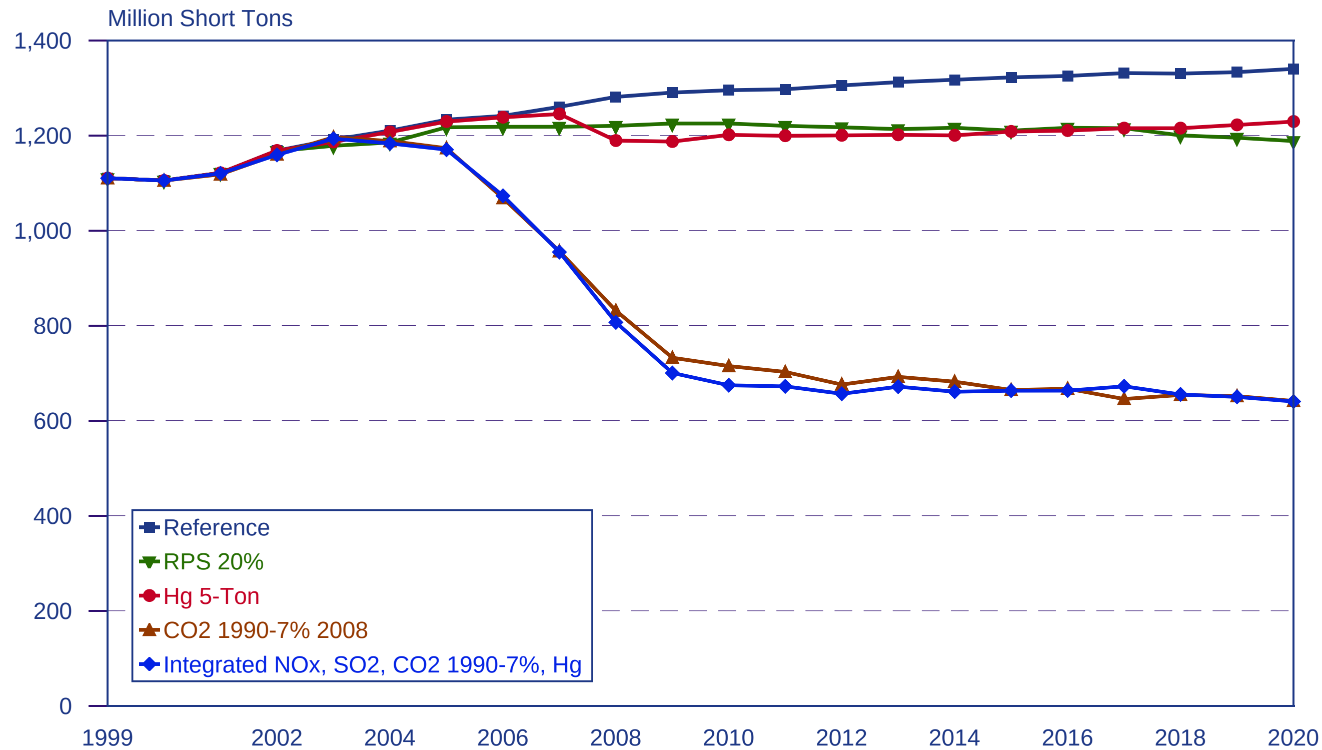
Coal Markets

The imposition of new, more stringent emission caps on electricity power plants would affect coal consumption, national and regional production, and prices (Figure 22). In general, the revised caps and the consequent need for introducing control technologies and other measures necessary to achieve compliance with the caps would raise the cost of electricity from coal-fired power plants relative to those using other fuels, encourage fuel switching, and cause the level of coal-fired generation to be reduced. The impacts on national coal industry production levels are projected to be negative relative to the reference case. The overall impacts on coal production depend on both the extent of the projected decline in coal demand and the types of coal expected to be used in the future mix of coal-burning capacity.

NO_x 2008 and SO_2 2008 Cases

In the NO_x 2008 case, the additional cost of adding and operating post-combustion emission control equipment is projected to increase electricity prices slightly and reduce electricity sales by a small amount. The projected coal share of the generation market and total projected coal-fired generation in the NO_x 2008 case are essentially unchanged from the reference case projections for 2020. Minemouth coal prices in the NO_x 2008 case range from 9 to 32 cents per ton higher than prices in the reference case for most of the 2008-2020 period (Table 13).

Figure 22. Projected U.S. Coal Production, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_X.D070601A, M2M9008.D060801A, M2C7B08.D060801A, and M2P7B08.D060801A.

Sustained growth in electricity demand over the forecast period is projected in the SO_2 2008 case. Although some additional coal-fired plants are projected to be retired, highly efficient, low-emitting advanced coal technology units are projected to be placed into service. In the SO_2 2008 case, the more stringent SO_2 emission caps are expected to lead to approximately 139 gigawatts of scrubber retrofits, compared with about 15 gigawatts in the reference case. Coal production east of the Mississippi River is projected to decline slowly but gain market share relative to the reference case. Eastern coal has a relatively high energy content, which permits greater generation of electricity per ton of coal burned.

Hg Emission Reduction Cases

The Hg emission reduction cases examine the impacts of reducing power plant emissions of Hg substantially below the 1997 emission level. Virtually all Hg emissions in the electricity generation sector originate from coal-fired boilers. Three general options are available to current coal-burning electricity generators to reduce Hg emissions: switch to coal containing lower quantities of Hg per unit of delivered energy input; install and utilize technologies that reduce Hg emissions; and dispatch coal-fired units at reduced levels or retire them from service, replacing the loss in output with power generation from other fuels. For a given Hg emission target, the extent to which each approach is expected to be utilized depends on the degree to which greater use of low-Hg coal types will increase their delivered costs, the cost and effectiveness of available Hg removal technologies, and the costs associated with replacement of coal-fired generation by other generation sources.

In the Hg 5-ton case and the Hg 20-ton case, both cap and trade cases, there is a projected shift to coal sources (such as the Rocky Mountain region) that contain lower levels of Hg and a move away from sources (such as lignite in the Gulf region) that have higher Hg content. Scrubber retrofits are expected to be made at a rapid pace in the Hg 5-ton case, reaching 18 gigawatts in 2010 and 52 gigawatts in 2020, compared with 15 gigawatts in 2020 for the reference case (Table 14). Scrubbers are introduced at a rapid pace through 2010 in the Hg 20-ton case, and activated carbon injection (ACI) controls, spray cooling, and fabric filters are also added, in order to meet the 20-ton target for Hg emissions. Because of the scrubbers, the Hg 20-ton case in 2010 makes greater use of eastern coal, which has a higher minemouth price. After 2010, Hg emissions are projected to be kept under the cap by employing additional ACI Hg removal, as coal-fired generation increases. In the Hg 5-ton case, ACI controls are heavily employed through 2010, along with scrubbers. After 2010, additional requirements for Hg removal are expected to be met by adding scrubbers. The steps taken to reduce Hg emissions, including switching to coals with lower Hg content, add to the cost of coal-fired generation and reduce coal consumption in the generation sector by a projected 116 million tons in 2020 in the Hg 5-ton case, relative to the reference case.

In the Hg MACT 90% case, each coal-burning generating unit is required to install a set of emission control technologies that will achieve (at a minimum) a 90-percent reduction in Hg emissions from the coal used at the plant. In this case, coal-fired generation drops by 1 percent in 2020 relative to the reference case. Generators are projected to meet the MACT requirements by installing control technologies rather than switching to coals with lower Hg content.

Most of the raw coal produced in the United States undergoes some degree of processing or coal preparation before it is shipped to generators, in order to remove associated rock and clay from the coal and make it a more marketable product. Generally, such processing will remove some of the Hg and sulfur in the raw coal as

Table 13. Coal Market Projections in the NO_x 2008 and SO_2 2008 Cases, 2010 and 2020

Projection	1999	2010			2020		
		Reference Case	NO_x 2008 Case	SO_2 2008 Case	Reference Case	NO_x 2008 Case	SO_2 2008 Case
Electricity Sector Coal Consumption (Million Tons)	923	1,145	1,129	1,117	1,196	1,181	1,185
Total Coal Production (Million Tons)	1,110	1,295	1,279	1,265	1,340	1,325	1,329
Minemouth Coal Price (1999 Dollars per Ton)	16.98	14.08	14.18	14.81	12.87	13.02	13.00
Delivered Coal Price to Generators (1999 Dollars per Million Btu)	1.22	1.06	1.07	1.04	0.98	0.98	0.96
Scrubber Retrofits (Cumulative Gigawatts of Generating Capability with Scrubbers Added)[a]	0	7	6	125	15	19	139

[a]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2NOX08.D060801A, and M2SO208P.D061201A.

well. In 2000, there were approximately 212 coal preparation plants in the United States.[30] About two-thirds of the bituminous coal mined in the East for electric power plants is cleaned, whereas the subbituminous coal and lignite shipped from western mines to coal-fired generating plants is generally only crushed and screened to facilitate handling and to remove extraneous material introduced during mining.[31] One estimate of the reductions in Hg provided by coal cleaning indicates a range of 0 to 64 percent removal, with an average of 21 percent, depending on the cleaning process, Hg concentration in the raw coal, and the technique used to measure Hg concentration.[32] The coal characteristics data that are used for this report are based on receipts at generators and therefore reflect the effects of quality improvements resulting from coal preparation.

RPS Cases

In the RPS cases, all the nonhydroelectric renewable generation technologies are projected to increase their market share of total generation, and the electricity generation shares of both coal and natural gas are projected to be lower than in the reference case. The effective price premium associated with using renewable fuels declines over time relative to nonrenewable sources, because the cost of the RPS credits that nonrenewable electricity generators must hold increases as the renewable share target becomes more stringent. In the RPS 10% case, the projected impacts on coal markets fall roughly midway between the results in the reference and RPS 20% cases.

In the reference case, coal consumption by electricity generators is expected to increase steadily from 2000, reaching 1,196 million tons in 2020. In the RPS 20% case, coal consumption by electricity generators increases at a slower rate over the period—to 1,043 million tons—13 percent lower than the reference case, as the share of total generation provided by renewable energy increases linearly on a year-by-year basis over the period and displaces fossil fuel demand (Table 15). Higher electricity prices, which decrease total electricity sales, also contribute to the reduced coal demand. Coal production in the RPS 20% case is projected to increase from 1,110 million tons in 1999 to 1,188 million tons in 2020, compared with 1,340 million tons in 2020 in the reference case. A larger share of the coal production decline relative to the reference case is projected to occur in the western States for three reasons: (1) wider availability and greater penetration of renewable energy (particularly wind and geothermal) in electricity generation markets in the West; (2) continued demand for industrial, metallurgical, and export coal—markets that are not affected by the RPS and are expected to continue to draw heavily on eastern coal; and (3) lower SO_2 allowance prices resulting from the reduction in coal demand permitting greater use of higher sulfur coal from mines east of the Mississippi River.

Existing coal-fired units are assumed to be able to co-fire biomass along with coal up to a maximum of 5 percent of the energy input to the boilers, if the delivered cost of biomass to the plant is competitive with coal and no

Table 14. Coal Market Projections in Mercury Emission Reduction Cases, 2010 and 2020

Projection	1999	2010				2020			
		Reference Case	Hg 20-Ton Case	Hg 5-Ton Case	Hg MACT 90% Case	Reference Case	Hg 20-Ton Case	Hg 5-Ton Case	Hg MACT 90% Case
Electricity Sector Coal Consumption (Million Tons)	923	1,145	1,091	1,051	1,132	1,196	1,144	1,080	1,176
Total Coal Production (Million Tons)	1,110	1,295	1,238	1,201	1,282	1,340	1,289	1,229	1,320
Minemouth Coal Price (1999 Dollars per Ton)	16.98	14.08	15.37	14.83	14.25	12.87	14.10	14.52	13.32
Delivered Coal Price to Generators (1999 Dollars per Million Btu)	1.22	1.06	1.06	1.09	1.04	0.98	0.98	1.01	0.97
Scrubber Retrofits (Cumulative Gigawatts of Generating Capability with Scrubbers Added)[a]	0	7	43	18	27	15	43	52	27
Average Hg Content of Coal (Pounds per Trillion Btu)[b]	7.7	7.2	6.7	6.1	7.1	7.0	6.5	6.3	7.0

[a]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
[b]Model estimate, calculated by weighting Hg content for each coal supply curve (see Table 6 in Chapter 2) by model estimates of shipments.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2M6008.D060801A, M2M9008.D060801A, and M2M9008M.D060801A.

[30]*Coal Age* (October 2000).

[31]Energy Information Administration, *Coal Data: A Reference*, DOE/EIA-0064(93) (Washington, DC, February 1995), p. 25.

[32]U.S. Environmental Protection Agency, *Mercury Study Report to Congress, Volume 2: An Inventory of Anthropogenic Mercury Emissions in the United States* (Washington, DC, December 1997).

extensive modifications to the plant are required. Generation based on biomass co-firing with coal is projected to increase from 0.9 billion kilowatthours in 1999 to 79 billion kilowatthours in 2020 in the RPS 20% case, compared with 6 billion kilowatthours in 2020 in the reference case.

CO_2 1990-7% 2008 Case

In the CO_2 1990-7% 2008 case, substantial reductions in coal consumption are projected, with corresponding drops in coal production (Table 16). To continue using coal under the CO_2 cap, a power plant operator would have to pay for both the coal and the CO_2 allowances needed to cover the emissions that would result from burning it. In the CO_2 1990-7% 2008 case, the delivered price of coal to electricity generators in 2020 is projected to average $0.84 per million Btu, but the costs of CO_2 allowances are projected to add a penalty of $3.87 per million Btu. Thus, the effective cost of using coal is projected to be $4.71 per million Btu in 2020. The corresponding effective cost to electricity generators in the reference case is projected to be $0.98 per million Btu in 2020.

In the CO_2 cap case, the use of coal is projected to decline sharply at many electric power plants. Although the effective price for coal on a Btu basis is still projected to be below that for natural gas (which incurs a lower requirement for carbon allowances), the price differential between the two fuels is expected to narrow slightly, and the higher efficiency of natural gas generation is expected to tip the generation share away from coal in many regional markets.

Because CO_2 allowance requirements are projected to increase operating costs for generators, many existing coal-fired power plants are projected to become uneconomical in the CO_2 1990-7% 2008 case, causing large blocks of capacity to be retired and replaced by natural

Table 15. Coal Market Projections in Two RPS Cases, 2010 and 2020

Projection	1999	2010 Reference Case	2010 RPS 10% Case	2010 RPS 20% Case	2020 Reference Case	2020 RPS 10% Case	2020 RPS 20% Case
Electricity Sector Coal Consumption (Million Tons)	923	1,145	1,122	1,074	1,196	1,131	1,043
Total Coal Production (Million Tons)	1,110	1,295	1,273	1,225	1,340	1,275	1,188
Minemouth Coal Price (1999 Dollars per Ton)	16.98	14.08	14.05	14.19	12.87	12.99	13.28
Delivered Coal Price to Generators (1999 Dollars per Million Btu)	1.22	1.06	1.06	1.07	0.98	0.98	0.97
Electricity Generation with Biomass Co-firing (Billion Kilowatthours)	0.9	10	49	40	6	92	79
Scrubber Retrofits (Cumulative Gigawatts of Generating Capability with Scrubbers Added)[a]	0	7	6	6	15	10	10

[a]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20H_X.D070601A, and M2RPS20_X.D070601A.

Table 16. Coal Market Projections in the CO_2 1990-7% 2008 Case, 2010 and 2020

Projection	1999	2010 Reference Case	2010 CO_2 1990-7% 2008 Case	2020 Reference Case	2020 CO_2 1990-7% 2008 Case
Electricity Sector Coal Consumption (Million Tons)	923	1,145	559	1,196	491
Total Coal Production (Million Tons)	1,110	1,295	715	1,340	641
Minemouth Coal Price (1999 Dollars per Ton)	16.98	14.08	14.22	12.87	12.77
Delivered Coal Price to Generators (1999 Dollars per Million Btu)	1.22	1.06	0.93	0.98	0.84
Effective Delivered Coal Price to Generators[a] (1999 Dollars per Million Btu)	1.22	1.06	4.93	0.98	4.71
Scrubber Retrofits (Cumulative Gigawatts of Generating Capability with Scrubbers Added)[b]	0	7	0	15	0

[a]Effective delivered price reflects the cost impact of CO_2 emission allowances in cases that include a CO_2 cap.
[b]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
Source: National Energy Modeling System, runs M2BASE.D060801A and M2C7B08.D060801A.

gas capacity. The combined effects of lower in-service coal capacity and lower utilization of the remaining coal capacity are projected to reduce coal consumption for electricity generation to levels that are approximately 41 percent of those in the reference case projections. With large reductions in coal-fired generation projected as a result of the CO_2 allowance requirements, SO_2 emissions are projected to be well below the CAAA90 caps, eliminating the need for additional scrubber retrofits. Total coal production is projected to decline at a slower rate than demand from the electricity generation sector, because consumption in other sectors (including industrial and coking coal and coal exports, which are not subject to CO_2 allowance fees) remains essentially unchanged from reference case values.

Integrated Cases With No RPS

In the integrated cases with CO_2 caps, coal consumption is projected to be reduced sharply. When the costs associated with acquiring CO_2 allowances are added to the delivered price of coal (and no RPS requirement exists), the effective delivered price is quadrupled relative to that in the reference case by 2010. As in the CO_2 1990-7% 2008 case, coal-fired electricity generation loses substantial market share to natural-gas-fired generation, as compared with its share of total electricity generation in the reference case. In addition, total electricity sales decline, reducing overall generation requirements.

The integrated cases that assume a cap on power sector CO_2 emissions at 7 percent below the 1990 level have the most severe impacts on coal markets and are projected to reduce coal consumption by electricity generators by an additional 49 to 81 million tons relative to the integrated cases that cap CO_2 emissions at the 1990 level (Table 17). In all the cases with CO_2 caps, the combined effects of lower installed coal-fired generation capacity and lower utilization of the remaining coal-fired capacity are projected to reduce coal consumption for electricity generation in 2020 to levels that range from 40 to 46 percent of those projected in the reference case. In the integrated cases that add an Hg emission cap, additional reductions in coal consumption are projected. Total coal production is projected to decline at a slower rate than demand for coal in the electricity generation sector, however, because consumption in other sectors (including industrial and coking coal and coal exports, which are not subject to the CO_2 caps) remains essentially unchanged from reference case values. With large reductions in coal-fired generation projected as a result of the cost impacts of CO_2 allowances and the cost of meeting the Hg cap, SO_2 emissions are projected to fall well below the tightened SO_2 cap.

Integrated Cases With an RPS

When an RPS is included in the set of integrated scenario requirements, both coal-fired electricity generation and

Table 17. Coal Market Projections in Selected Integrated Cases With No RPS, 2010 and 2020

Projection	1999	2010				2020			
			Integrated Cases				Integrated Cases		
		Reference Case	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	NO_x, SO_2, CO_2 1990-7%, Hg	Reference Case	NO_x, SO_2, CO_2 1990	NO_x, SO_2, CO_2 1990-7%	NO_x, SO_2, CO_2 1990-7%, Hg
Electricity Sector Coal Consumption (Million Tons)	923	1,145	694	567	518	1,196	554	485	478
Total Coal Production (Million Tons)	1,110	1,295	853	724	674	1,340	721	641	640
Minemouth Coal Price (1999 Dollars per Ton)	16.98	14.08	13.42	13.43	14.38	12.87	11.90	12.16	13.41
Delivered Coal Price to Generators (1999 Dollars per Million Btu)	1.22	1.06	0.95	0.91	0.93	0.98	0.85	0.82	0.85
Effective Delivered Coal Price to Generators[a] (1999 Dollars per Million Btu)	1.22	1.06	3.83	4.54	3.99	0.98	4.52	4.77	4.68
Scrubber Retrofits (Cumulative Gigawatts of Generating Capability with Scrubbers Added)[b]	0	7	14	19	21	15	14	19	21
Average Hg Content of Coal (Pounds per Trillion Btu)[c]	7.7	7.2	6.8	7.2	6.4	7.0	6.8	7.1	6.4

[a]Effective delivered price reflects the cost impact of CO_2 emission allowances in cases that include a CO_2 cap.
[b]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
[c]Model estimate, calculated by weighting Hg content for each coal supply curve (see Table 6 in Chapter 2) by model estimates of shipments.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM9008.D060801A, M2NM7B08.D060901A, and M2P7B08.D060801A.

coal production are higher than projected in the integrated cases with no RPS, and the effective delivered price of coal to electricity generators is lower (Table 18). With an RPS, the resulting increase in electricity generation from renewable fuels, which produce no net CO_2 emissions, lessens the need to reduce coal-fired generation to comply with the CO_2 cap.

In the integrated moderate targets case, in which all emission caps and the RPS are assumed to be less stringent than those in the integrated all CO_2 1990-7% case, electricity sector coal consumption in 2020 is 106 million tons higher than projected in the integrated all case. The effective delivered price of coal to electricity generators is higher in the integrated moderate targets case than in the integrated all case, because the CO_2 reductions projected to result from the use of renewable fuels are reduced to only one-half those in the integrated case with more stringent caps and RPS requirements, resulting in a higher cost impact from acquiring CO_2 emission allowances.

Regional Impacts on Coal

In all the cases examined in this analysis, coal production is projected to be lower than projected in the reference case, because the cost impacts of the various emission caps make the delivered price of coal higher relative to other fuels and reduce demand for electricity. There are also impacts on regional shares of coal production. Caps on Hg emissions lead to a shift away from coal types with high Hg content (such as Gulf lignite) and their replacement by coal with lower Hg content (from regions such as the Rocky Mountains). Scrubber retrofits that are required to meet an SO_2 cap are expected to lower production from regions producing low-sulfur coal. Table 6 in Chapter 2 lists coal quality data (heat content, sulfur content, and Hg content) for coals from the major supply regions.

The ability of the coal industry to adapt quickly to the requirements imposed by emission caps is subject to several infrastructure issues. The early closing of existing mines (such as those producing high-Hg coals) could result in substantial financial penalties, such as severance pay, unrecovered equipment costs, and reclamation charges, that could hamper the ability of some companies to secure funding for new mines. In the transportation sector, it would be necessary to establish new transportation patterns, which could create bottlenecks and raise costs. Increased use of low-sulfur and low-Hg coals could create near-term issues of licensing, siting, and staffing new mines that might otherwise not be needed.

Natural Gas Markets

Reference Case

The reference case is based on *AEO2001* but incorporates more recent data on natural gas markets. Wellhead prices for natural gas are expected to fall from recent highs to $3.22 (constant 1999 dollars) per thousand cubic feet by 2020. Natural gas consumption in the reference case is expected to grow more quickly over the next two decades than total energy use. By 2020, the share of energy provided by natural gas is expected to increase to

Table 18. Coal Market Projections in the Integrated Moderate Targets and Integrated All CO_2 1990-7% Cases, 2010 and 2020

Projection	1999	2010 Reference Case	2010 Integrated Moderate Targets Case	2010 Integrated All CO_2 1990-7% Case	2020 Reference Case	2020 Integrated Moderate Targets Case	2020 Integrated All CO_2 1990-7% Case
Electricity Sector Coal Consumption (Million Tons)	923	1,145	738	587	1,196	680	574
Total Coal Production (Million Tons)	1,110	1,295	895	749	1,340	836	731
Minemouth Coal Price (1999 Dollars per Ton)	16.98	14.08	14.14	15.43	12.87	12.68	14.08
Delivered Coal Price to Generators (1999 Dollars per Million Btu)	1.22	1.06	0.98	0.98	0.98	0.88	0.91
Effective Delivered Coal Price to Generators (1999 Dollars per Million Btu)[a]	1.22	1.06	3.83	4.15	0.98	3.94	3.19
Scrubber Retrofits (Cumulative Gigawatts of Generating Capability with Scrubbers Added)[b]	0	7	4	28	15	4	32
Average Hg Content of Coal (Pounds per Trillion Btu)[a]	7.7	7.2	6.6	6.4	7.0	6.6	6.4

[a]Effective delivered price reflects the cost impact of CO_2 emission allowances in cases that include a CO_2 cap.
[b]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
[c]Model estimate, calculated by weighting Hg content for each coal supply curve (see Table 6 in Chapter 2) by model estimates of shipments.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2PHF08R_X.D070901A, and M2P7B08R_X.D070601A.

28 percent from 23 percent in 1999, and the total volume of natural gas used is expected to grow to 35.2 trillion cubic feet from 21.7 trillion cubic feet in 1999. Natural gas use for electricity generation is projected to grow by 5.2 percent per year, faster than in the other demand sectors, reaching 11.2 trillion cubic feet per year by 2020. The projected growth in electricity generation consumption of natural gas accounts for 7.3 trillion cubic feet out of the 13.5 trillion cubic feet projected increase in total consumption between 1999 and 2020. The rate of growth of natural gas use in other sectors of the economy is more modest.

Domestic production is expected to grow to meet increased demand. Production of natural gas in 2020 is projected to be 10.8 trillion cubic feet per year higher than it was in 1999. Natural gas produced offshore is expected to account for 26 percent of total domestic production, with unconventional gas accounting for an additional 30 percent. Imports are also expected to grow. By 2020, net natural gas imports from Canada are projected to be 5.4 trillion cubic feet per year, 2.1 trillion cubic feet higher than they were in 1999. Additional net imports of liquefied natural gas (LNG) are expected to grow from 97 billion cubic feet in 1999 to 792 billion cubic feet in 2020, adding 695 billion cubic feet to total U.S. supplies. The additional projected LNG imports are assumed to enter the U.S. market through existing facilities that expand their capacity (see box below).

Low oil prices in 1998 cut revenues to the combined oil and natural gas industry and reduced exploration for natural gas. This, coupled with higher demand driven by strong economic growth during the first three quarters of 2000 and unusually cold weather in the last quarter of 2000, led to higher prices in 2000 than were seen throughout the 1990s. During 2000, the average annual wellhead price was $3.52 per thousand cubic feet (1999 dollars). The average wellhead price is expected to be even higher in 2001, but prices are projected to decline from these high levels as markets move back into equilibrium. In the reference case, the projected price of natural gas is $2.96 per thousand cubic feet in 2005 and $2.87 per thousand cubic feet in 2010. In the later years of the projections, continued strong demand for natural gas and increasingly costly new reserves (see box on page 50) lead to higher prices. By 2020, the projected wellhead price of natural gas reaches $3.22 per thousand cubic feet in the reference case.

Hg Emission Reduction Cases

Reducing Hg emissions is expected to lead to faster growth in natural gas use as some electric power generators switch from coal to natural gas in order to lower their Hg emissions. This leads to greater consumption by electricity generators, over and above the strong growth in consumption of natural gas that is already expected in the reference case. Stronger demand leads to higher natural gas prices than those projected in the reference case. Domestic production and imports are also higher. A higher Hg emissions cap of 20 tons has much less effect on U.S. natural gas prices and production. The projected effects on natural gas prices are also estimated to be lower if MACT standards are used rather than a cap and trade system, because without tradable allowances there is less incentive to switch to natural gas.

By 2010, electricity generation use is projected to be 7.6 trillion cubic feet in the Hg 5-ton case, compared with 6.8 trillion cubic feet in the reference case (Table 19). By 2020, the volume of natural gas used by electricity generators increases to 11.9 trillion cubic feet in the Hg 5-ton case, about 0.7 trillion cubic feet higher than projected in the reference case. In the Hg 20-ton case, raising the Hg cap reduces the incremental natural gas use for

Potential New Sources of Natural Gas Supply

The projected growth in U.S. natural gas supplies in the reference case is accomplished by expanding domestic production and current sources of imports. However, there are other new potential sources of supply that could make more natural gas available to U.S. consumers and therefore lower prices. They are available in cases where natural gas demand and thus natural gas prices are high enough to support these new potential sources.

One example is natural gas from Alaska, brought to consumers either as liquefied natural gas (LNG) or through a proposed pipeline connecting the Alaskan North Slope to Alberta, Canada, and then to the lower 48 States. A pipeline was discussed in the early 1980s but never built. As of this writing, ExxonMobil Production, BP Exploration Alaska, and Phillips Alaska are working jointly to assess the viability of a pipeline for Alaskan gas, with a potential capacity of up to 4 billion cubic feet per day, or 1.4 trillion cubic feet per year. Implementing a pipeline is estimated to take 5 to 7 years.

A second possibility is expanding U.S. LNG import capacity. In the reference case for this analysis, growth in LNG imports occurs through expansion of existing facilities. Other possible sites for new LNG facilities that are currently being explored include Florida; Baja California, Mexico; the Bahamas with a pipeline connection to Florida; offshore in the Gulf of Mexico; the U.S. West Coast; and the DelMarva Peninsula and North Carolina on the U.S. East Coast. As of this point, none of these proposed projects has moved beyond the planning stage.

electricity generation, although it is still above the projected levels in the reference case. Industrial, commercial, and residential use of natural gas is roughly the same as in the reference case.

The increased demand for natural gas resulting from Hg emissions reductions leads to higher prices (Figure 23). By 2010, the projected wellhead price in the Hg 5-ton case reaches $3.06 per thousand cubic feet, compared with $2.87 in the reference case. The projected price difference fluctuates but is still $0.19 per thousand cubic feet in 2020, when the wellhead price is projected to be $3.22 in the reference case and $3.41 in the Hg 5-ton case. While the Hg emissions requirements in the Hg 5-ton case cause more natural-gas-fired capacity to be adopted earlier, much of the additional capacity is ultimately brought on line toward the end of the forecast period in the reference case.

When the Hg requirements are implemented, projected domestic natural gas production in the Hg 5-ton case is higher than in the reference case (Figure 24). In 2010, domestic production in the Hg 5-ton case is projected to be 24.1 trillion cubic feet, compared with 23.4 trillion cubic feet in the reference case. The difference in the volume of production is split roughly equally among offshore production, onshore conventional production, and unconventional production. By 2020, the difference

Table 19. Natural Gas Market Projections in Three Mercury Emission Reduction Cases, 2010 and 2020

Projection	1999	2010				2020			
		Reference Case	Hg 20-Ton Case	Hg 5-Ton Case	Hg MACT 90% Case	Reference Case	Hg 20-Ton Case	Hg 5-Ton Case	Hg MACT 90% Case
Average Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.17	2.87	2.90	3.06	2.89	3.22	3.33	3.41	3.24
Total Domestic Production (Trillion Cubic Feet)	18.62	23.43	23.76	24.09	23.57	29.47	29.58	30.12	29.54
Net Imports (Trillion Cubic Feet)	3.42	5.00	5.05	5.12	5.02	5.82	5.85	5.92	5.84
Consumption for Electricity Generation (Trillion Cubic Feet)	3.86	6.81	7.13	7.59	6.98	11.19	11.33	11.92	11.29

Source: National Energy Modeling System, runs M2BASE.D060801A, M2M6008.D060801A, M2M9008.D060801A, and M2M9008M.D060801A.

Depletion of Natural Gas Resources

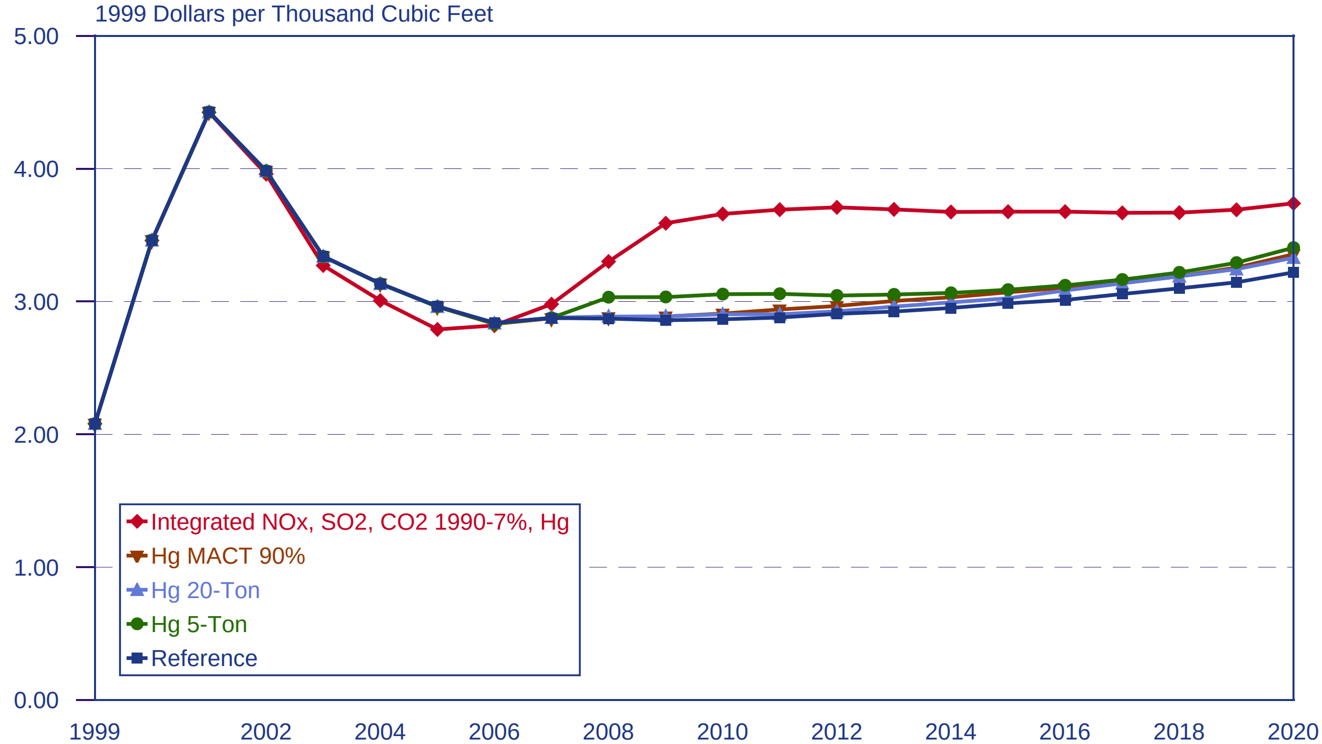
Natural gas is a finite resource. As discovered natural gas reserves are developed and produced, additional reserves must be discovered in order to maintain production levels. Over time, replacing depleted reserves is increasingly difficult. The largest and most easily developed resources tend to be developed first, and subsequent reserve additions are, on average, smaller and more expensive to develop. The increased difficulty of adding new reserves due to the cumulative effects of depletion are offset by improvements in technology, which lowers exploration costs, the number of dry holes, and drilling and production costs.

The cases developed for this study use the Oil and Gas Supply Model (OGSM) of the National Energy Modeling System to project future natural gas production. The OGSM specifically incorporates the effects of cumulative depletion on projected future natural gas discoveries, based on historical patterns. Some industry observers have suggested, however, that current natural gas discoveries per successful well are considerably lower than they have been in the past. They are concerned that the effects of cumulative depletion are more severe than indicated by historical trends. Stronger than expected depletion effects could make future natural gas production more difficult and lead to higher prices than are projected in this study.

Additional discussion of the possible adverse effects of cumulative depletion can be found in a recent EIA Service Report, *Accelerated Depletion: Assessing Its Impacts on Domestic Oil and Natural Gas Prices and Production* (Sept. 2000, DOE/FE-0424). In that study, future reserve additions were assumed to be only two-thirds of the size suggested by long-term historical trends. The expected production schedule of new wells was also assumed to have a higher percentage of each well's total output coming in the first years of production. Under the accelerated depletion assumptions, the projected wellhead price of natural gas in 2020 was 48 percent higher than projected in the study's reference case used (which differed from the reference case for the current analysis). Assumptions of faster technological progress and increased access to reserves mitigated the higher price projections.

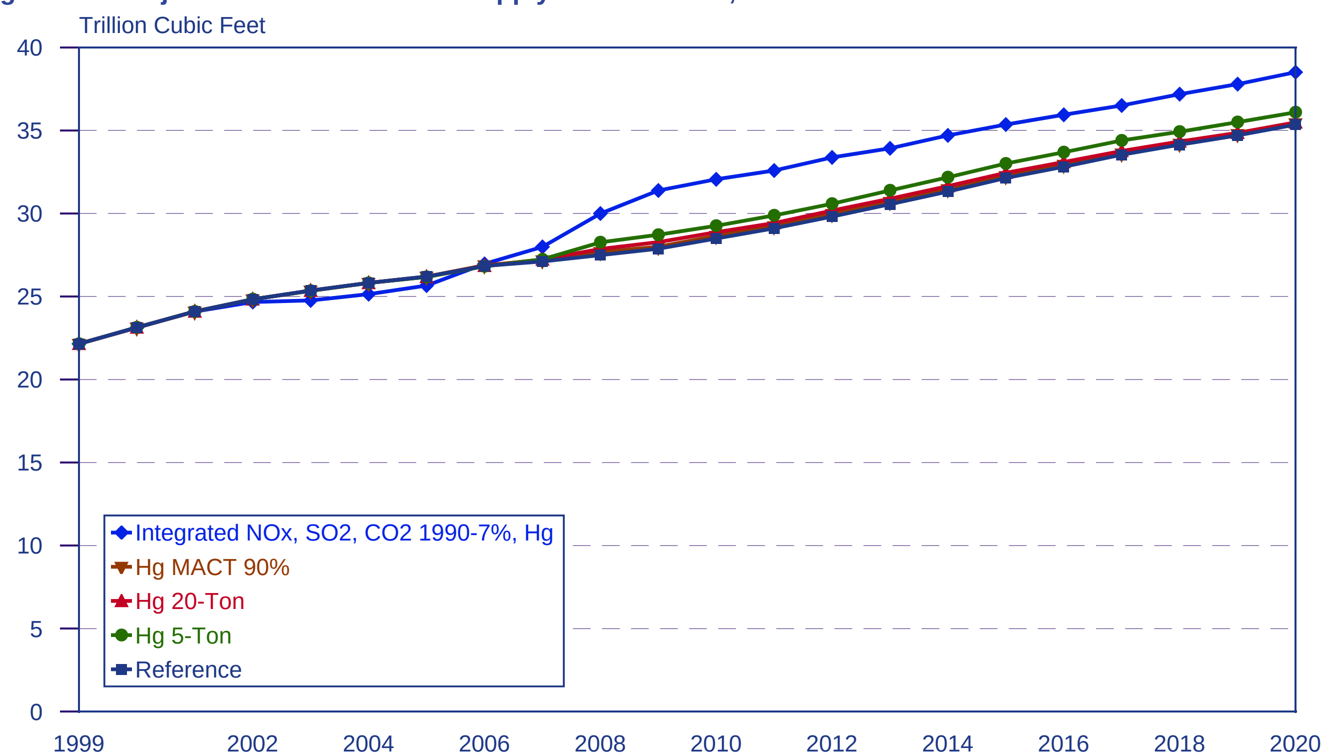
The assumptions used in the *Accelerated Depletion* study were designed to explore the potential adverse effects of greater than expected reductions in domestic natural gas supply. The assumptions for the cases in this analysis are based on the historical trend, which indicates much less dramatic effects of depletion on potential supply.

Figure 23. Projected U.S. Natural Gas Wellhead Prices in Five Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A, M2M9008M.D060801A, and M2P7B08.D060801A.

Figure 24. Projected U.S. Natural Gas Supply in Five Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A, M2M9008M.D060801A, and M2P7B08.D060801A.

in projected production between the Hg 5-ton case and the reference case is 650 billion cubic feet, or roughly the same as expected in 2010. Approximately two-thirds of the difference in production is provided by higher unconventional production. The stronger reliance on unconventional production in the Hg 5-ton case is one of the reasons why prices remain higher than in the reference case.

Increased net imports account for only a small part of the difference in supply between the reference case and the Hg 5-ton case. By 2020, Canadian net imports are projected to be 5.5 trillion cubic feet per year in the Hg 5-ton case compared with 5.4 trillion cubic feet in the reference case. Projected net imports from other sources, including LNG imports and pipeline imports from Mexico, are the same in the two cases.

Higher wellhead prices for natural gas result in not only higher electricity prices, but also higher direct costs to residential natural gas consumers. In the Hg 5-ton case, the average price paid by residential customers in 2020 is estimated to be $7.01 per thousand cubic feet, 2.6 percent higher than the reference case price of $6.83 per thousand cubic feet. The average household residential cost of natural gas in 2020 is 2 percent higher in the Hg 5-ton case than in the reference case.

Under a cap and trade system, such as that assumed in the Hg 5-ton case, producers who reduce their emissions below their allowances can sell credits to other electricity generators. In the Hg MACT 90% case, each facility is assumed to meet its target without a credit trading option. Because mitigation costs are proportional to a percentage rather than an absolute reduction, the incentives for the electricity generation sector to meet its emission reduction requirements by switching fuels is greatly reduced. Consequently, the projected increase in demand for natural gas for electricity generation is lower than in the cap and trade cases. The Hg MACT 90% case shows lower demand from electricity generators (11.29 trillion cubic feet in 2020), leading to lower prices than are projected in the comparable cap and trade cases. The natural gas wellhead price projected for 2020 in the Hg MACT 90% case is $3.24 per thousand cubic feet, 5 percent lower than the 2020 price in the Hg 5-ton case and only $0.02 feet higher than in the reference case.

RPS Cases

The inclusion of a renewable portfolio standard reduces the projected rate of growth in natural gas consumption by U.S. power generators. Under an RPS, total demand for natural gas is expected to be lower than in the reference case. Projected prices and production are also lower.

The introduction of an RPS leads to changes in natural gas markets by slowing the projected rate of increase in electricity generation demand (Table 20). In the RPS 20% case, the differences in projected prices, consumption, and production steadily increase through 2020, as the required share generated by nonhydroelectric renewable resources grows to 20 percent in 2020. The volume of natural gas used by electricity generators in 2020 is projected to be 7.0 trillion cubic feet, compared with 11.2 trillion cubic feet in the reference case.

The sharply lower projected demand from electricity generators results in lower natural gas prices. By 2010, the wellhead price of natural gas is projected to be $2.65 per thousand cubic feet, 7.7 percent lower than projected in the reference case. The projected price of natural gas in the RPS 20% case is $2.66 per thousand cubic feet in 2020, $0.56 (17 percent) lower than in the reference case.

Lower prices for natural gas lead to slightly higher projected consumption in the industrial, commercial, and residential sectors, but not enough to offset the projected difference in electricity generator use. In 2020, consumption from these sectors together is 21.6 trillion cubic feet, compared with 20.9 trillion cubic feet in the reference case. Total natural gas consumption in the RPS case is projected to be 31.4 trillion cubic feet in 2020, compared with 35.2 trillion cubic feet in the reference case.

Lower projected consumption and prices in the RPS 20% case lead to lower projected domestic production and net imports. By 2020, projected U.S. production is 26.1 trillion cubic feet in the RPS 20% case, compared with

Table 20. Natural Gas Market Projections in Two RPS Cases, 2010 and 2020

Projection	1999	2010			2020		
		Reference Case	RPS 10% Case	RPS 20% Case	Reference Case	RPS 10% Case	RPS 20% Case
Average Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.17	2.87	2.81	2.65	3.22	2.95	2.66
Total Domestic Production (Trillion Cubic Feet)	18.62	23.43	23.21	22.45	29.47	28.22	26.09
Net Imports (Trillion Cubic Feet)	3.42	5.00	5.02	4.86	5.82	5.67	5.38
Consumption for Electricity Generation (Trillion Cubic Feet)	3.86	6.81	6.59	5.59	11.19	9.65	7.00

Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20H_X.D070601A, and M2RPS20_X.D070601A.

29.5 trillion cubic feet in the reference case. Net imports are also lower. Canadian net imports in 2020 are estimated to be 5.0 trillion cubic feet, compared with 5.4 trillion cubic feet in the reference case.

Lower prices lead to lower expenditures by consumers. By 2020, the average household expenditure on natural gas is 5 percent lower in the RPS 20% case than projected in the reference case. The industrial price for natural gas drops to $3.39 per thousand cubic feet, about 14 percent lower than projected in the reference case.

In the RPS 10% case, reducing the required amount of generation from nonhydroelectric renewable energy sources raises the projected consumption of natural gas as compared with a more stringent RPS, but consumption still remains below the reference case level. By 2010, natural gas use for electricity generation in the RPS 10% case is 220 billion cubic feet lower than in the reference case, leading to projected wellhead prices that are $0.06 per thousand cubic feet lower than in the reference case. The difference in electricity generator use increases to 1.54 trillion cubic feet by 2020, resulting in a projected wellhead price $0.27 lower than in the reference case but still $0.29 higher than in the RPS 20% case. Although the RPS 10% case leads to lower natural gas prices than are projected in the reference case, the differences are small through 2010 and considerably smaller than the differences between the reference case and the RPS 20% case.

Integrated Emission Reduction Cases

Integrated NO_x, SO_2, CO_2 1990-7%, Hg Case

An integrated emission control strategy that includes CO_2 emission reductions greatly increases the demand for natural gas by electricity generators. While end-of-pipe emission controls can reduce many types of emissions, reducing CO_2 emissions to the required level—7 percent below 1990 emissions—requires much more intensive fuel switching from coal to natural gas, which has lower CO_2 emissions per Btu.

The sustained higher demand for natural gas that is caused by CO_2 emissions reductions are assumed to lead to new sources of natural gas supply that are not expected to become available in the cases that do not include CO_2 emission caps. First, due to the sustained higher prices in the United States, Mexico is assumed to become a net exporter to the United States instead of a net importer. By 2020, net imports from Mexico are assumed to be 360 billion cubic feet in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, rather than the net exports to Mexico of 400 billion cubic feet assumed in the reference case. Second, strong sustained demand and higher prices are assumed to lead to an additional 1 trillion cubic feet from other sources of supply, including LNG imports and Alaskan production through Canada. The additional supply becomes available starting in 2008, as the restrictions on CO_2 emissions are implemented and wellhead prices rise. The net effect of these assumptions is that imports are projected to be 2.3 trillion cubic feet higher in 2020 than projected in the reference case (Table 21).

By 2010, the projected volume of natural gas used to generate electricity is 10.6 trillion cubic feet in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, 3.8 trillion cubic feet higher than the projected level in the reference case. By 2020, total electricity generation use is projected to grow to 13.4 trillion cubic feet, compared to 11.2 trillion cubic feet in the reference case. Although higher prices lead to slightly lower consumption in other sectors of the economy, total natural gas consumption in all sectors in 2020 is projected to be 38.3 trillion cubic feet, 3.1 trillion cubic feet higher than in the reference case.

In the early years of the forecast, demand from electricity generators is slightly lower as new, more efficient natural-gas-fired capacity is brought on line in anticipation of the 2008 emissions targets. By 2010, however, the wellhead price of natural gas reaches $3.66 per thousand cubic feet in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, $0.79 higher per thousand cubic feet than in the reference case. In 2020, the projected price of natural gas is $3.74 in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, compared with $3.22 in the reference case. Higher prices are passed through to consumers, and in 2020 the average household expenditure in the integrated case is

Table 21. Natural Gas Market Projections in Two Integrated Cases, 2010 and 2020

Projection	1999	2010			2020		
		Reference Case	Integrated Cases: NO_x, SO_2, CO_2 1990-7%	Integrated Cases: NO_x, SO_2, CO_2 1990-7%, Hg	Reference Case	Integrated Cases: NO_x, SO_2, CO_2 1990-7%	Integrated Cases: NO_x, SO_2, CO_2 1990-7%, Hg
Average Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.17	2.87	3.50	3.66	3.22	3.80	3.74
Total Domestic Production (Trillion Cubic Feet)	18.62	23.43	24.90	25.31	29.47	30.44	30.29
Net Imports (Trillion Cubic Feet)	3.42	5.00	6.60	6.69	5.82	7.97	8.16
Consumption for Electricity Generation (Trillion Cubic Feet)	3.86	6.81	9.93	10.63	11.19	13.12	13.43

Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM7B08.D060901A, and M2P7B08.D060801A.

projected to be 6 percent higher than in the reference case.

U.S. production of dry gas reaches 30.3 trillion cubic feet in 2020 in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, compared with 29.5 trillion cubic feet in the reference case. Unconventional natural gas production in 2020 is projected to be 900 billion cubic feet, or 10 percent, higher in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case than in the reference case, and cumulative total gas production in 2020 is nearly 16 trillion cubic feet higher. These factors underlie the persistent higher prices in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, despite more imports than assumed in the reference case. About 74 percent of the additional projected supply in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case is met through increased imports, the least-cost source of supply. Increased Canadian imports are 300 billion cubic feet higher in 2020 than projected in the reference case.

Integrated NO_x, SO_2, CO_2 1990-7% Case

Although this case does not include Hg emissions, the effects on the natural gas markets are similar to the effects of the integrated NO_x, SO_2, CO_2 1990-7%, Hg case but less pronounced (Table 21). Natural gas use for electricity generation is lower than projected in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, because the absence of Hg emissions reductions causes less projected fuel switching to natural gas. By 2010, projected natural gas use in the electric power sector is 0.7 trillion cubic feet lower than in the corresponding case with Hg reductions. At $3.50 per thousand cubic feet, the projected wellhead price in 2010 is $0.16 lower than in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. The difference between the two cases in projected natural gas use for electricity generation falls to 0.3 trillion cubic feet by 2020.

Integrated All CO_2 1990-7% Case

Imposing an RPS in conjunction with an integrated emission control program has a dramatic effect on projected natural gas demand and prices. In this case, projections of future supply do not include the higher levels of imports assumed in most of the other cases that include CO_2 emissions reduction, because prices are not projected to be high enough to make those additional supplies feasible. In the integrated all CO_2 1990-7% case, consumption grows more slowly than in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, reaching 34.1 trillion cubic feet by 2020, compared with 38.3 trillion cubic feet in the corresponding case without the RPS. As a result, the wellhead price of natural gas in 2020 is $0.43 per thousand cubic feet lower, and the average residential bill is 4 percent lower than in the same case without an RPS (Table 22).

The projected level of drilling and the total cumulative production (measured from 2000) diverge strongly between the integrated all CO_2 1990-7% case and the corresponding case without the RPS (Table 23). In 2010, both total number of wells drilled and cumulative production are fairly similar between cases. By 2020, however, the higher production required to meet growing demand by electricity generators increases cumulative production to 519.8 trillion cubic feet in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, compared with 506.6 trillion cubic feet in the corresponding RPS case. The difference in cumulative natural gas production between the two cases is equivalent to about 9 months total production at current levels. The total number of wells required to meet projected production is 46.3 thousand in 2020 in the integrated NO_x, SO_2, CO_2 1990-7% and Hg, 35 percent higher than it is in the corresponding case with an RPS. Including the RPS reduces the quantity of reserves that must be replaced and the amount of drilling required to meet production, dramatically lowering the projected wellhead price.

Integrated High Gas Price Case

The integrated high gas price case considers the effects of less optimistic assumptions about natural gas supply in an integrated case that includes a cap on power sector CO_2 emissions but no RPS. This case is intended to show how natural gas and electricity markets might react if the additional supplies that are projected in the other

Table 22. Natural Gas Market Projections in Three Integrated Cases, 2010 and 2020

Projection	1999	2010 Integrated Cases: NO_x, SO_2, CO_2 1990-7%, Hg	2010: High Gas Price	2010: All CO_2 1990-7%	2020 Integrated Cases: NO_x, SO_2, CO_2 1990-7%, Hg	2020: High Gas Price	2020: All CO_2 1990-7%
Average Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.17	3.66	4.08	3.13	3.74	5.05	3.31
Total Domestic Production (Trillion Cubic Feet)	18.62	25.31	25.89	24.84	30.29	26.93	28.40
Net Imports (Trillion Cubic Feet)	3.42	6.69	5.57	5.33	8.16	6.40	5.85
Consumption for Electricity Generation (Trillion Cubic Feet)	3.86	10.63	10.25	8.35	13.43	10.04	8.97

Source: National Energy Modeling System, runs M2P7B08.D060801A, M2P7B08L.D060901A, and M2P7B08R_X.D070601A.

cases that limit CO_2 emissions prove to be unavailable, despite higher prices due to slower technological progress. First, the additional sources of supply—including Alaskan production and imports from Mexico or as LNG—that are included in other cases that limit CO_2 emissions (but are not projected in the reference case) are not allowed in the integrated high gas price case. Although the higher prices associated with this case would normally be expected to make these additional supplies available, there is more uncertainty concerning them than there is for the domestic production and imports projected in the reference case. Second, the projected rate of technological improvement in natural gas production is also reduced by 25 percent, making the cost of drilling in the long term higher and reducing the success rate and the volume of reserves added per well.[33]

Slower technology growth reduces the number of productive wells that can be drilled domestically, even as prices are higher. By 2020, successful well completions projected in the integrated high gas price case are approximately 42,000, compared with more than 46,000 in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. Domestic production is 3.4 trillion cubic feet, or 11 percent, lower than projected in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. Coupled with the changes in the assumed level of available imports, the resulting supplies are more than 5 trillion cubic feet lower than the supplies in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case.

Limiting potential supply pushes expected prices even higher than they are in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. By 2020, the average wellhead price of natural gas in the high gas price case reaches $5.05 per thousand cubic feet (Table 22). The higher price of natural gas in the integrated high gas price case causes residential expenditures for natural gas to be 10 percent higher than projected in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. High prices also cause commercial, residential, and industrial customers, as well as electricity generators, to limit their use of natural gas. By 2020, total projected natural gas consumption in the integrated high gas price case is 33.2 trillion cubic feet, 13 percent lower than projected in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case.

The sharp differences in projected prices and total consumption illustrate the sensitivity of natural gas market projections to assumptions about available supply. However, this is an extreme case. The increases in demand for natural gas that accompany CO_2 emission reductions are generally expected to sustain the prices that make additional supply feasible, including LNG imports. In addition, the lower rate of technological improvement assumed in this case does not reflect historical trends. The rate of technology improvement in costs and finding rates that are used in the other cases in this report are projected econometrically from historical production trends, and they are considered to be more likely estimates of future trends.

The high levels of demand for natural gas in the electric power sector that are projected in the CO_2 cap cases for this analysis would constitute a serious challenge for the U.S. natural gas market, during a period when the industry already is expecting strong demand growth. U.S. natural gas production is projected to grow at near record rates between 2005 and 2010 in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case and in the integrated high gas price case. Several consecutive years of growth at the projected rates could prove to be difficult to achieve, due to limitations on available trained workers, drilling rigs, and other production capital. The pipeline infrastructure would also have to be expanded at record rates.[34]

Table 23. Projections for Natural Gas Wells Drilled and Cumulative Production in Two Integrated Cases, 2010 and 2020

Projection	Reference Case	Integrated NO_x, $S0_2$, CO_2 1990-7%, Hg Case	Integrated All CO_2 1990-7% Case
2010			
Thousand Natural Gas Wells Drilled	29.9	34.4	30.8
Cumulative Natural Gas Production, 2000-2010 (Trillion Cubic Feet)	236.1	240.7	238.4
2020			
Thousand Natural Gas Wells Drilled	39.4	46.3	34.3
Cumulative Natural Gas Production, 2000-2020 (Trillion Cubic Feet)	504.1	519.8	506.6

Source: National Energy Modeling System, runs M2BASE.D060801A, M2P7B08.D060801A and M2P7B08R_X.D070601A.

[33]The changes in the projected rate of technological advancement made in the integrated high gas price case are the same changes that were made in the slow technology case in the *AEO2001*.

[34]For a discussion of the challenges faced in meeting the production required in a CO_2 emission reduction case, see the earlier EIA report, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, SR / OIAF-2000-05 (Washington, DC, December 2000).

Renewable Fuels Markets

EIA's earlier report on multiple emission reductions included projections of renewable energy use for electricity generation in cases with caps on emissions of SO_2, NO_x, and CO_2.[35] In constructing the assumptions for the analysis cases in the earlier study, EIA reviewed the status of nonhydroelectric renewable generating capacity in the United States as of mid-2000, as well as State RPS and other mandates, green power programs, and other voluntary programs designed to encourage renewable electricity generation. On the basis of that review, it was assumed in the reference case and in all the analysis cases that 5.4 gigawatts of new nonhydroelectric renewable generating capacity would be built in the United States from 2000 to 2020, including 3.1 gigawatts of new wind capacity.

A similar review conducted for the current study resulted in substantial increases in the estimates for additions of wind and geothermal generating capacity, based on recent developments in California, Texas, and Washington State. As a result, the reference and analysis cases for this study assume that 7.5 gigawatts of new nonhydroelectric renewable generating capacity will be built in the United States from 2000 to 2020, including 5.1 gigawatts of new wind capacity and 0.3 gigawatts of new geothermal capacity.[36]

Reference Case

Because they cost more than fossil alternatives, renewable energy technologies are projected to account for very little new generating capacity through 2020 in the reference case, other than near-term builds in response to State RPS or other requirements. Generation from nonhydroelectric renewables is projected to increase from 87 billion kilowatthours in 1999 to 149 billion kilowatthours in 2020 (Table 24), and the nonhydroelectric renewable share of total U.S. electricity supply is projected to increase to 2.8 percent of net generation and 3.1 percent of retail electricity sales in 2020. Only biomass (including cogeneration) is projected to provide more than 1 percent of U.S. electricity sales by 2020 in the reference case. Geothermal energy is projected to provide about 0.6 percent of total generation in 2020, municipal solid waste/landfill gas about 0.6 percent, wind about 0.4 percent, and solar thermal and photovoltaics less than 0.1 percent each. Generation from conventional hydroelectric capacity is expected to remain essentially unchanged.

NO_x, SO_2, and Hg Emission Reduction Cases

The emission caps in the NO_x and SO_2 2008 cases are projected to have little or no effect on renewable energy use, with the exception of a small increase in co-firing of

Table 24. Renewable Fuels Market Projections in Two RPS Cases, 2010 and 2020
(Billion Kilowatthours)

Projection	1999	2010			2020		
		Reference Case	RPS 20% Case	RPS 10% Case	Reference Case	RPS 20% Case	RPS 10% Case
Total Electricity Generation	3,706	4,597	4,573	4,591	5,294	5,252	5,285
Total Electricity Sales	3,312	4,147	4,117	4,141	4,788	4,707	4,771
Electricity Generation Using Renewables							
Conventional Hydroelectric Power	319	306	306	306	304	304	305
Geothermal	17	31	104	63	31	114	76
Municipal Solid Waste and Landfill Gas	27	28	35	32	32	40	37
Wood and Other Biomass	38	56	190	96	63	527	251
Dedicated Biomass	36	46	149	47	57	447	160
Biomass Co-firing	1	10	40	49	6	79	92
Solar (Thermal and Photovoltaic)	1	2	2	2	3	3	3
Wind	5	18	96	22	19	264	116
Total Renewables	406	441	732	521	453	1,253	788
Total Nonhydroelectric Renewables	87	136	426	215	149	948	483
Average End-Use Electricity Price (1999 Cents per Kilowatthour)	6.7	6.1	6.3	6.2	6.2	6.5	6.2

Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_X.D070601A, and M2RPS20H_X.D070601A.

[35] For discussion of the renewable energy sources included, see pages 46-48 of the earlier EIA report.

[36] Small additions of new solar thermal capacity (107 megawatts) and central-station photovoltaic generating capacity (500 megawatts) are also assumed from 2000 to 2020. It is assumed that experience gained from solar and wind technology applications in foreign countries will contribute to reducing domestic capital costs through a learning effect. Based on a review of international renewable energy developments, it is assumed that 5 megawatts of photovoltaic capacity additions and 50 megawatts of wind capacity additions will contribute to the international learning effect in each year from 2000 through 2020. Other revisions from the earlier analysis include updated historical data and updated baseline projections for other renewable energy technologies.

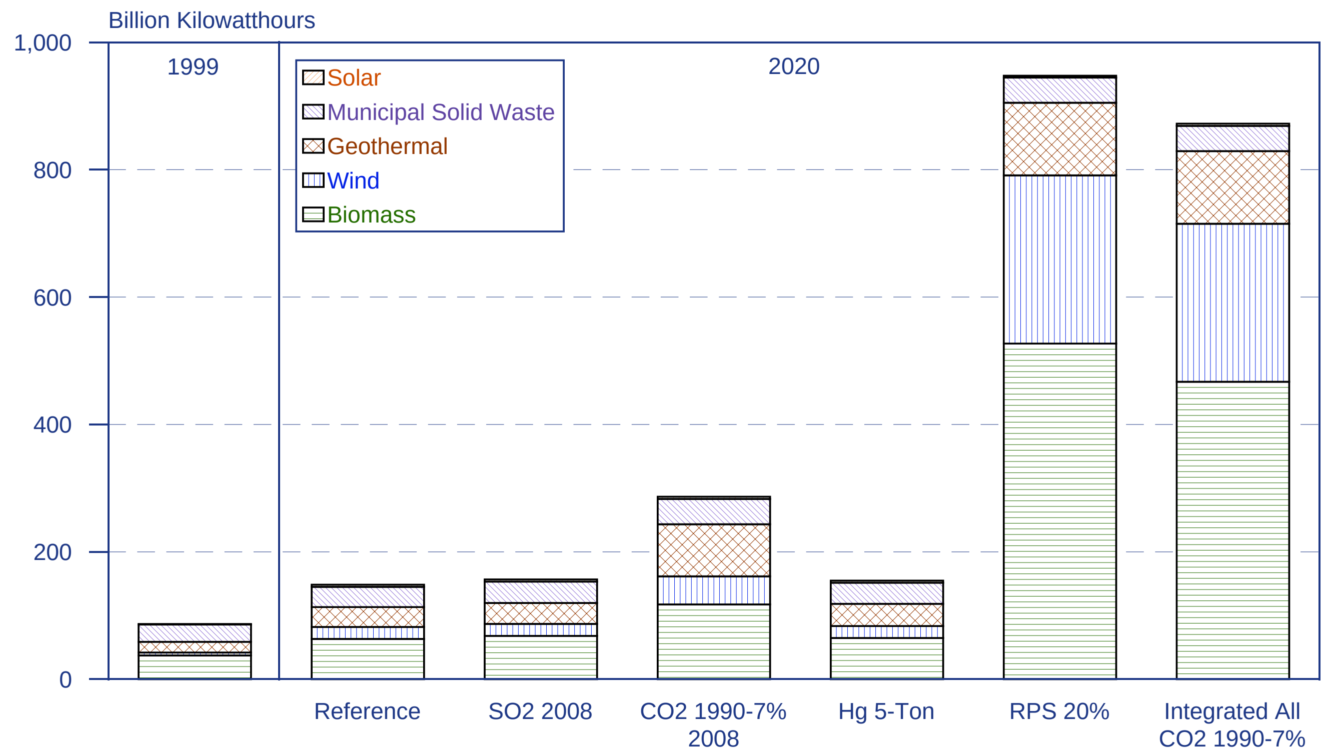
biomass with coal in the SO_2 2008 case in response to higher projected prices for low-sulfur coal (Figure 25). In the Hg 5-ton case, less than 1 gigawatt more new renewable energy generating capacity is projected to be added by 2020 than in the reference case, because the Hg cap can be met more cost-effectively by retrofitting and switching from coal to natural gas than by switching to more costly renewable energy technologies.

RPS Cases

Imposition of a 20-percent RPS is expected to lead to large increases in electricity generation from the least costly nonhydroelectric renewable fuels—biomass, wind, and geothermal. In the RPS 20% case, which requires that 10 percent of all U.S. electricity sales be provided by renewables other than conventional hydroelectricity by 2010, 15 percent by 2015, and 20 percent by 2020, total electricity generation from nonhydroelectric renewable energy sources is projected to increase to 948 billion kilowatthours in 2020. Because renewable generation is more expensive than coal- or natural-gas-fired generation, retail electricity prices are projected to reach 6.5 cents per kilowatthour by 2020, compared with 6.2 cents per kilowatthour in the reference case (Table 24). As a result, total electricity consumption in 2020 is projected to be 81 billion kilowatthours lower in the RPS 20% case than the 4,788 billion kilowatthours projected in the reference case. The natural gas share of total electricity sales in 2020 is projected to be 27 percent in the RPS 20% case, compared with 38 percent in the reference case, and the coal share of total sales in 2020 is projected to be 44 percent, compared with 49 percent in the reference case.

The total projected increase in nonhydroelectric renewable generation from 1999 through 2020 in the RPS 20% case is 861 billion kilowatthours. In contrast to the reference case, additions to renewable generating capacity are expected throughout the forecast period, consisting primarily of lower cost geothermal resources before 2010 (with little growth in geothermal capacity after 2010) and higher cost but more plentiful biomass and wind resources after 2010. Of the total increase in nonhydroelectric renewable generation over the forecast, 57 percent is expected to come from biomass, 30 percent from wind, 11 percent from geothermal, and 2 percent from landfill gas. Biomass (including cogeneration and co-firing with coal) is thus projected to become the primary renewable energy source for grid-connected U.S. electric power generation, providing 11 percent of all U.S. electricity sales in 2020 in the RPS 20% case. Biomass capacity in the electricity generation sector (excluding cogenerators) is projected to reach 61 gigawatts by 2020 in the RPS 20% case, compared with 2.4 gigawatts in the reference case, and generation from

Figure 25. Projected Electricity Generation from Nonhydroelectric Renewable Energy Sources, 2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2SO208P.D061201A, M2C7B08.D060801A, M2M9008.D060801A, M2RPS20_X.D070601A, and M2P7B08R_X.D070601A.

biomass co-fired with coal is projected to total 79 billion kilowatthours in 2020, compared with 6 billion kilowatthours in the reference case.[37]

Wind power adds the greatest amount of new renewable energy capacity in the RPS 20% case compared with the reference case and ranks second, after biomass, in increased generation.[38] Like biomass, wind capacity grows rapidly over the entire forecast period, increasing to 94 gigawatts by 2020 in the RPS 20% case, compared with about 8 gigawatts in the reference case.

U.S. geothermal capacity is projected to increase to 15 gigawatts by 2020 in the RPS 20% case, compared with 5 gigawatts in the reference case. However, there is considerable uncertainty about economically accessible supply of geothermal resources for sustained electric power production, and in the RPS 20% case, geothermal increases quickly, with most competitive geothermal resources developed by 2010. Only 1.3 gigawatts of new geothermal capacity is projected to be added after 2010.

Similarly, increased use of landfill gas provides additional relatively low-cost electric power in the RPS 20% case but is constrained by a limited number of landfills and the small size of individual landfill gas plants. As a result, compared with the reference case, additional new landfill gas capacity adds 1 gigawatt more generating capacity by 2020. Total municipal solid waste and landfill gas generating capacity in the electricity sector reaches 4.9 gigawatts by 2020 in the RPS 20% case.

Neither solar thermal nor photovoltaics is projected to add central-station generating capability in the RPS 20% case compared with the reference case. These technologies are both projected to remain more expensive than other alternatives through 2020. However, experience shows that some consumers and some utilities do select additional solar for reasons other than least-cost power supply; moreover, some jurisdictions may supplement the Federal RPS by offering rebates, tax credits, or other incentives not assumed here. As a result, additional residential and commercially installed solar units are possible. The projections in this report do not include off-grid photovoltaics. To the extent that off-grid markets are affected by increased costs of grid-supplied power or by other incentives, additional growth in off-grid photovoltaic generation growth could also occur.

In the RPS 10% case, which assumes an RPS half as stringent as in the RPS 20% case, projections for new renewable energy technologies are similar in overall direction to those in the RPS 20% case but show less new generating capacity powered by renewables. In the reference case 3.1 percent of U.S. electricity sales in 2020 are projected to be provided by nonhydroelectric renewables, meaning that an additional 7 percent is required in the RPS 10% case compared with 17 percent more in the RPS 20% case. In the RPS 10% case only 66 additional gigawatts are needed between 1999 and 2020 (excluding hydropower), or 39 percent of the total additions needed in the RPS 20% case. Because more coal-fired generating capacity is expected to be in service in 2020 in the RPS 10% case, biomass co-firing with coal is higher in 2020 in the RPS 10% case than in the RPS 20% case. In the RPS 10% case, electricity prices in 2020 are projected to average 6.2 cents per kilowatthour, the same as in the reference case (Table 24).

CO_2 1990-7% 2008 Case

The requirement to reduce CO_2 emissions alone results in increased renewable energy technology use compared with the reference case, including increased co-firing of biomass with coal in existing coal-fired plants and a slight increase in conventional hydroelectric power use. In the CO_2 1990-7% 2008 case, electricity prices in 2020 are projected to be 8.6 cents per kilowatthour, nearly 40 percent higher than projected in the reference case (Table 25). As a consequence, sales of electricity are projected to be 12 percent (nearly 600 billion kilowatthours) lower than in the reference case. Nonhydroelectric renewables (including cogeneration) are projected to provide almost 7 percent of U.S. electricity sales in 2020 in the CO_2 1990-7% 2008 case, and generation from conventional hydroelectric power is projected to be 5 billion kilowatthours higher than in the reference case in 2020, with 1.5 gigawatts of new hydroelectric capacity expected to be added by 2020.

Among renewable energy technologies, generation using biomass is projected to increase most in the CO_2 1990-7% 2008 case, to 118 billion kilowatthours in 2020 (Table 25), providing about 3 percent of total electricity sales. Generation from geothermal power increases to 82 billion kilowatthours in 2020, and generation from wind power increases to 44 billion kilowatthours in 2020.

Integrated All CO_2 1990-7% Case

The projections for renewable electricity generation in the integrated all CO_2 1990-7% case, which includes a 20-percent RPS, are generally similar to those in the RPS 20% case. However, because a 1990-7% cap on

[37]In an offline analysis using the assumptions of the RPS 20% case, EIA found that additional biomass co-firing beyond the 5-percent limit (up to 10 percent) could be economical as a fuel substitute for coal, assuming retrofit costs of $200 per kilowatt. Using the projected prices of coal, biomass, and renewable credits in 2015, approximately 100 billion kilowatthours of additional co-firing could be expected in 2015 beyond the level projected in the RPS 20% case. Because the RPS establishes a given level of renewable generation, however, the additional biomass co-firing would displace generation from other renewables rather than adding to the total.

[38]Because wind units generate electricity only when winds are sufficient, expected generation from a wind unit is less than for a comparably sized unit of biomass capacity.

power sector CO_2 emissions is also included, electricity prices are projected to be higher, total electricity sales are projected to be lower, and nonhydroelectric renewable energy use is projected to be lower than in the RPS 20% case. A slight increase in conventional hydroelectric power generation is also projected as a result of the CO2 cap (Table 26).

Integrated Sensitivity Cases

In the integrated moderate targets case, which assumes less stringent emissions caps than in the integrated all CO_2 1990-7% 2008 case and only a 10-percent RPS, nonhydroelectric renewables are projected to provide only about half as much electricity generation in 2020 as is projected in the integrated all CO_2 1990-7% 2008 case (Table 26). The 452 billion kilowatthours of nonhydroelectric renewable generation projected for 2020 in the integrated moderate targets case is similar to the level of 483 billion kilowatthours projected in the RPS 10% case.

In the integrated cost of service case, emissions allowances are assumed to have a zero cost basis in regions where electricity prices are based on cost of service. No RPS is assumed in this case. The projections for renewable generation in the integrated cost of service case (Table 26) are generally similar to those in the CO_2 1990-7% 2008 case (Table 25), but because overall

Table 25. Renewable Fuels Market Projections in the CO_2 1990-7% 2008 Case, 2010 and 2020
(Billion Kilowatthours)

Projection	1999	2010		2020	
		Reference Case	CO_2 1990-7% 2008 Case	Reference Case	CO_2 1990-7% 2008 Case
Total Electricity Generation	3,706	4,597	4,280	5,294	4,963
Total Electricity Sales	3,312	4,147	3,803	4,788	4,204
Electricity Generation Using Renewables					
Conventional Hydroelectric Power	319	306	311	304	309
Geothermal	17	31	78	31	82
Municipal Solid Waste and Landfill Gas	27	28	36	32	40
Wood and Other Biomass	38	56	108	63	118
Dedicated Biomass	36	46	51	57	68
Biomass Co-firing	1	10	57	6	50
Solar (Thermal and Photovoltaic)	1	2	2	3	4
Wind	5	18	24	19	44
Total Renewables	406	441	559	453	596
Total Nonhydroelectric Renewables	87	136	248	149	287
Average End-Use Electricity Price (1999 Cents per Kilowatthour)	6.7	6.1	8.8	6.2	8.6

Source: National Energy Modeling System, runs M2BASE.D060801A and M2C7B08.D060801A.

Table 26. Renewable Fuels Market Projections in Four Integrated Cases, 2010 and 2020
(Billion Kilowatthours)

Projection	1999	2010					2020				
			Integrated Cases					Integrated Cases			
		Reference Case	All CO_2 1990-7%	Moderate Targets	Cost of Service	High Gas Price	Reference Case	All CO_2 1990-7%	Moderate Targets	Cost of Service	High Gas Price
Total Electricity Generation	3,706	4,597	4,305	4,347	4,408	4,306	5,294	5,025	5,014	5,064	4,886
Total Electricity Sales	3,312	4,147	3,830	3,870	3,956	3,838	4,788	4,313	4,318	4,453	4,188
Electricity Generation Using Renewables											
Conventional Hydroelectric Power	319	306	310	310	311	311	304	309	309	310	310
Geothermal	17	31	99	63	81	78	31	114	73	85	86
Municipal Solid Waste and Landfill Gas	27	28	36	36	36	36	32	40	40	40	40
Wood and Other Biomass	38	56	211	127	104	105	63	467	257	198	207
Dedicated Biomass	36	46	161	53	63	62	57	421	188	161	163
Biomass Co-firing	1	10	50	74	41	43	6	46	68	37	44
Solar (Thermal and Photovoltaic)	1	2	2	2	2	2	3	3	3	3	4
Wind	5	18	93	39	26	26	19	248	78	74	94
Total Renewables	406	441	750	577	559	558	453	1,181	761	710	740
Total Nonhydroelectric Renewables	87	136	440	267	249	247	149	872	452	400	430
Average End-Use Electricity Price (1999 Cents per Kilowatthour)	6.7	6.1	8.6	8.2	7.7	8.6	6.2	8.0	8.2	7.9	9.3

Source: National Energy Modeling System, runs M2BASE.D060801A, M2P7B08R_X.D070601A, M2PHF08R_X.D070901A, M2P7B08C.D060901A, and M2P7B08L.D060901A.

electricity demand is projected to be somewhat higher, renewables penetrate to a greater degree.

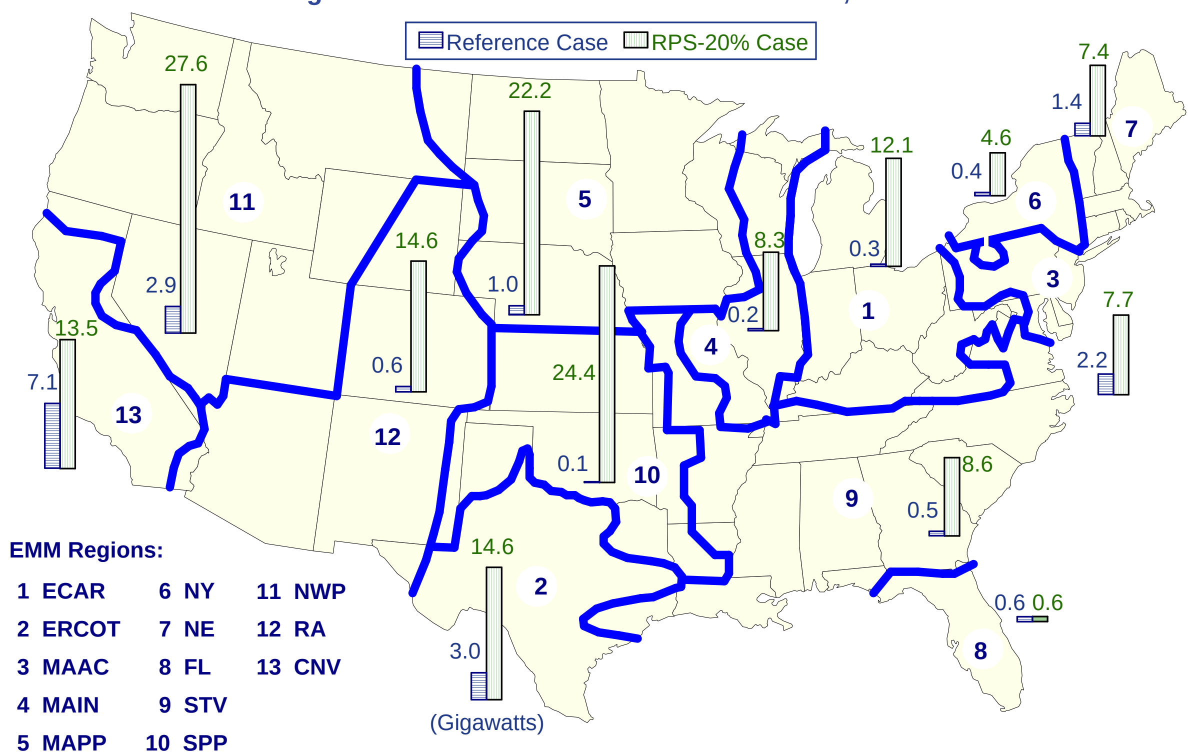
The integrated high gas price case assumes slower improvements in technologies for finding, developing, and delivering natural gas than are assumed for other cases in this analysis. It can be compared with the CO_2 1990-7% 2008 case, including the CO_2 reduction requirements but no RPS. Because of the higher natural gas prices, electricity generating costs are projected to rise more rapidly, and electricity prices in 2020 are projected to reach 9.3 cents per kilowatthour, higher than projected in any of the other analysis cases. As a result, renewables are projected to account for almost 18 percent of U.S. electricity sales by 2020, compared with 14 percent in the CO_2 1990-7% 2008 case, and nonhydroelectric renewables are projected to account for 10 percent of electricity sales by 2020.

Regional Impacts

Because opportunities for the development of new renewable energy supplies are not distributed evenly across the country, most of the projected increases in nonhydroelectric renewable electricity generation are expected in regions west of the Mississippi River (Figure 26). The West (EMM regions 11, 12, 13), which is projected to account for only about one-fifth of U.S. electricity sales in 2020 in the RPS 20% case, accounts for one-third of new qualifying renewable energy capacity. The Eastern Seaboard and Ohio Valley (regions 1, 3, 6, 7, 8, 9), which account for 56 percent of U.S. electricity sales, are expected to provide only one-fourth of new qualifying renewable energy capacity. The Midwest and Southwest from the Dakotas and Minnesota through Texas, which currently account for less than one-fourth of all U.S. electricity sales, are expected to account for more than 40 percent of new renewable energy electricity generating capacity in the RPS 20% case.

The large volumes of wind power projected in the RPS 20% case suggest that U.S. wind opportunities could be strained in meeting such large demands, primarily by exhausting wind resources, straining existing transmission networks, and encountering environmental and other siting objections. Using EIA estimates, four regions with relatively plentiful wind resources, the Upper Midwest (region 5), South Central (region 10), Northwest (region 11), and Southwest (region 12) are generally expected to be able to meet demands for new wind capacity. However, in order to meet the 20-percent RPS requirement, every region would fairly quickly exhaust its least-cost wind sites, and by the middle years of the forecast period nearly half of the regions with useful wind resources are projected to resort to their highest cost wind resources. Based on 1993 work done by the National Renewable Energy Laboratory, more recent experience, and contacts with experts, EIA assumes as

Figure 26. Cumulative Additions to Nonhydroelectric Renewable Generating Capacity by NEMS Electricity Market Module Region in the Reference and RPS-20% Cases, 2000-2020



Note: Capacity projections exclude cogenerators.
Source: National Energy Modeling System, runs M2BASE.D060801A and M2RPS20_X.D070601A.

an intermittency constraint that 15 percent is the maximum percentage of any region's electricity sector generation that can be provided by wind and solar photovoltaic power without imposing notable additional costs on the system.[39] The far Southwest (region 12) is projected to be affected by such intermittency constraints, although the Upper Midwest (region 5), New England (region 7), South Central (region 10), and Northwest (region 11) approach them as well.

Uncertainties

There are significant uncertainties about the availability and quality of renewable energy resources, the future costs and performance of renewable energy technologies, and marketplace acceptance of the new technologies. National environmental concerns and renewables' perceived role in meeting those concerns add further uncertainty for renewable energy technology expectations. Also, the extent to which biomass can be efficiently co-fired with coal is still being tested.[40]

With little historical demand for large-scale use of renewables, resource availability, quality, accessibility, and sustainability are uncertain. Limited transmission capacity constrains geothermal and wind power located in remote areas. The extent to which large integrated electric power networks can incorporate intermittent power sources such as wind and solar photovoltaics is unclear. Cultural, environmental, and other market preference and acceptance issues could also affect renewable penetration.

Industry Employment Impacts

The analysis cases in this report can be expected to produce both broad macroeconomic and specific fuel sector impacts on employment. Macroeconomic impacts result from increased energy prices that will in turn affect industrial sectoral output, gross domestic product, overall productivity in the economy, and employment. In the primary fuel sectors, emission limits and higher prices are expected to alter the levels of overall and regional production of the fuels used for electricity generation and to change the levels of both direct employment and employment in associated industries and the surrounding infrastructure. In particular, the coal industry is expected to experience employment declines because of reduced coal production, and the natural gas and renewables industries are projected to show employment gains as electricity generators switch fuels. Relative to the reference case, projected employment gains in the oil and gas sectors in 2020 generally exceed projected employment losses in the coal sector in the Hg, NO_x, SO_2, and CO_2 cap cases.[41] In the RPS cases, increased activity and employment in the wind, biomass and geothermal industries lead to lower projected levels of production and employment in both the natural gas and coal industries.

Coal Industry

Between 1978 and 1999, the number of miners employed in the U.S. coal industry fell by 5.3 percent per year, from 246,000 to 79,000 (Figure 27). The decrease primarily reflected strong growth in labor productivity, which increased at an annual rate of 6.4 percent over the same period. An additional factor contributing to the employment decline was the increased output from large surface mines in the Powder River Basin, which require much less labor per ton of output than mines located in the Interior and Appalachian regions. With improvements in productivity continuing over the forecast period, further declines in employment of 1.5 and 0.8 percent per year are projected from 1999 through 2010 and from 2010 through 2020, respectively. In absolute terms, coal mine employment is projected to decline in the reference case from 79,000 in 1999 to 67,000 in 2010 and 62,000 in 2020 (Table 27).

In the Hg 5-ton case, lower projected growth in U.S. coal consumption and production relative to the reference case combined with shifts in regional production patterns, leads to an expected overall decline in coal mining employment similar to that in the reference case forecast. Negative employment impacts resulting from the projected decline in U.S. coal production in the Hg 5-ton case are partially offset by shifts in production from high-productivity regions to regions with lower mining productivity. Relative to the reference case forecast, projected changes in regional production patterns are attributable to: (1) additional retrofits of flue gas desulfurization equipment (scrubbers) to reduce Hg emissions, making coal from the low-sulfur, high-productivity Powder River Basin region (Wyoming and Montana) less valuable relative to the reference case; and (2) a stringent cap on Hg emissions that leads to shifts in production to regions with low-Hg coals. As a result of the regional production shifts, labor productivity is projected to increase at an average rate of 1.8 percent per year in the Hg 5-ton case between 1999 and 2020, compared with a rate of 2.2 percent per year in the reference case. Thus, although coal production is projected to be 8 percent less in 2020 than in the reference case forecast (1,229 million tons in the Hg 5-ton case

[39] Y.H. Wan and B.K. Parsons, *Factors Relevant to Utility Integration of Intermittent Renewable Technologies,* NREL/TP-463-4953 (Golden, CO: National Renewable Energy Laboratory, August 1993).

[40] It is assumed in this analysis that biomass could be co-fired in coal plants up to 5 percent of total capacity. Co-firing above that level would require additional expenditures, whose costs are too uncertain to model at this time.

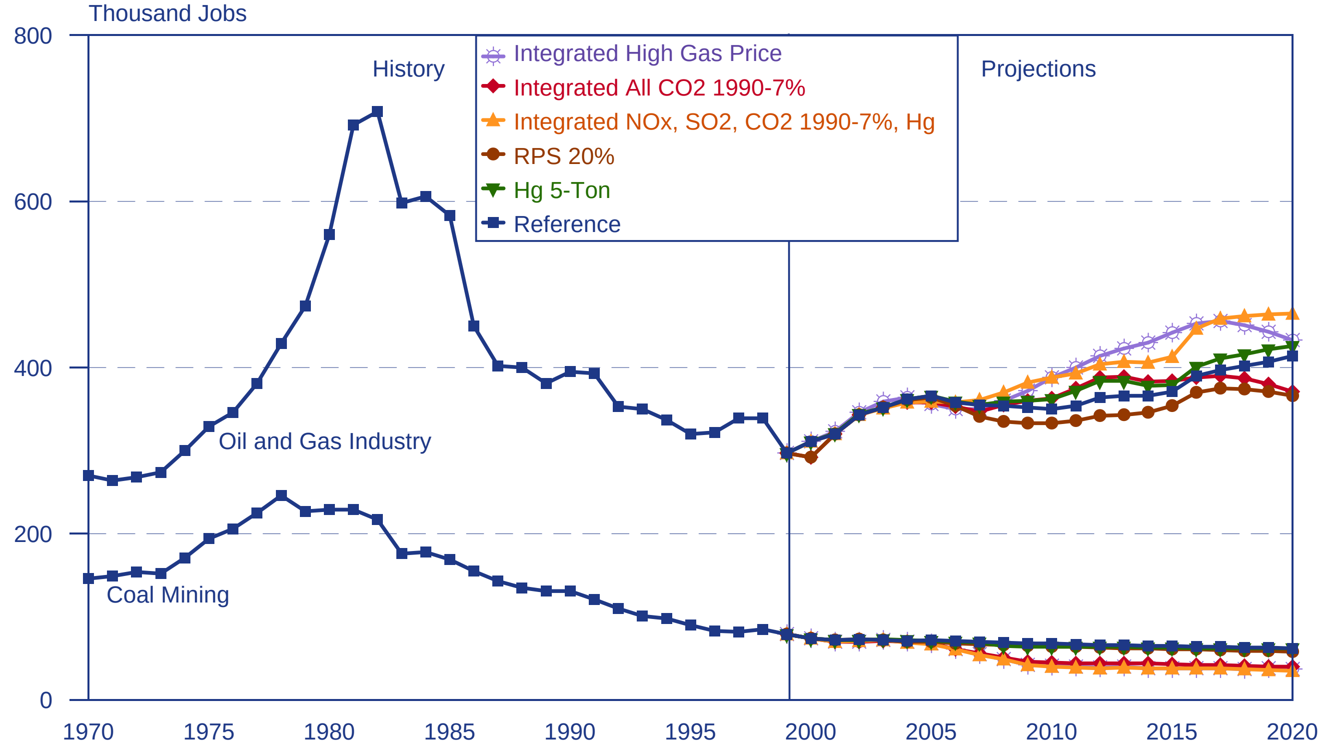
[41] For analysis of employment impacts in NO_x and SO_2 cap cases, see the results published in the earlier EIA report, pages 50-52.

compared with 1,340 million tons in the reference case), coal mine employment in 2020 is projected to be the same as in the reference case.

In the Hg 5-ton recycle case, it is assumed that 90 percent of the activated carbon used to remove Hg from power plant stack gases can be recycled and reused. Relative to the Hg 5-ton case, which assumes no recycling, the projected costs of removing Hg from the stack gas are substantially less, leading to less switching from high- to low-Hg coals and from coal to other fuels. U.S. coal production is projected to reach 1,261 million short tons by 2020, or 6 percent less than in the reference case, and coal industry employment is projected to fall to 61,000 by 2020, 2 percent less than the reference case forecast of 62,000 miners.

In the Hg MACT 90% case, it is assumed that all coal-fired generating units will be required to remove or capture 90 percent of the Hg from the coal received at the

Figure 27. Coal Mining and Oil and Gas Industry Employment, 1970-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, M2RPS20_X.D070601A, M2P7B08.D060801A, M2P7B08R_X.D070601A, and M2P7B08L.D060901A.

Table 27. Projected Impacts on Employment in the Coal Mining and Oil and Gas Industries, 2000-2020 (Thousand Jobs)

Industry	Analysis Case	1999	2005	2010	2020	Average Annual Growth, 2000-2020 (Percent)
Coal Mining.	Reference	79	71	67	62	-1.1
	Hg 5-Ton		71	64	62	-1.1
	RPS 20%		70	64	58	-1.5
	Integrated NO_x, SO_2, CO_2 1990-7%, Hg		67	40	35	-3.8
	Integrated All CO_2 1990-7%		68	45	40	-3.2
	Integrated High Gas Price		68	41	37	-3.5
Oil and Gas Extraction . . .	Reference	297	366	350	414	1.6
	Hg 5-Ton		366	362	426	1.7
	RPS 20%		364	333	366	1.0
	Integrated NO_x, SO_2, CO_2 1990-7%, Hg		359	388	465	2.2
	Integrated All CO_2 1990-7%		358	363	371	1.0
	Integrated High Gas Price		356	388	433	1.8

Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, M2RPS20_X.D070601A, M2P7B08.D060801A, M2P7B08R_X.D070601A, and M2P7B08L.D060901A.

plant, using maximum achievable control technology (MACT). Under this scenario, the incentive to switch to low-Hg coals is eliminated, because the costs of reduction are proportional to the percentage rather than the absolute amount of Hg removed. As a result, both coal production and employment patterns are not significantly different from those projected in the reference case.

In the RPS 20% case, projected U.S. coal consumption and production levels are slightly less than those in the reference case. In 2020, U.S. coal production is projected to reach 1,188 million short tons, 11 percent lower than in the reference case. As a result, U.S. coal mine employment is projected to decline from 79,000 miners in 1999 to 58,000 in 2020, 6 percent below the reference case projection for 2020.

In the integrated cases, lower levels of coal production in all supply regions relative to the reference case result in lower coal industry employment in all regions. In the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, coal mine employment is projected to decline by 3.8 percent per year, to 35,000 by 2020. In the integrated all CO_2 1990-7% case, which includes an RPS, coal mine employment is projected to decline at a slightly slower rate of 3.2 percent per year, to 40,000 by 2020. The lower carbon allowance fee in this case, due to increased generation from renewable energy sources, leads to higher production of coal relative to the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. Nevertheless, both of these cases show a considerably higher rate of decline in coal industry employment than does the reference case, where coal mine employment is projected to decline at a more moderate rate of 1.1 percent per year to 62,000 by 2020.

Although coal industry employment has declined substantially in recent years and is a relatively minor component of the current U.S. workforce, coal mines are typically in remote locations and provide a significant source of income and employment in rural areas of the country. According to data published by the U.S. Department of Labor, U.S. coal industry wages ranked in the top 20 of all major industries in 1999, with workers in the coal industry earning an average of $50,673 for the year, compared with an average of $33,244 for all U.S. industries taken as a whole.[42] In addition to the substantial contraction of the U.S. coal industry projected in the integrated cases, employment in the U.S. rail industry, which derives considerable revenues from coal shipments, also would be greatly affected.[43]

Oil and Gas Industry

Employment in the oil and gas industry has experienced a recent resurgence but is still lower than at its peak. In 2000, total industry employment in oil and gas production was 304,000 employees, up from 293,000 employees in 1999. Total oil and gas employment peaked in the U.S. in 1982, when employment reached 708,000 employees. Since 1982, employment has been generally falling, with minor upturns in 1990 (associated with the high oil prices accompanying the Gulf War) and in 2000, with a sharp resurgence in both world oil prices and domestic gas prices.

The oil and gas production industry comprises two segments: oil and gas production and oil and gas field services. Historically, most of the workers in the oil and gas industry have been employed in oil and gas field services rather than production. In 2000, oil and gas field service workers accounted for 172,000 employees, while production employment was 129,000. The year-to-year growth in oil and gas industry employment was entirely due to additional field service workers; employment in primary production actually fell by 4,000 jobs between 1999 and 2000.

Although oil production does not change dramatically in the reference case, total gas production is expected to increase rapidly, from 19.4 trillion cubic feet in 2000 to 29.5 trillion cubic feet by 2020. Producing more natural gas will require more employees, most of them employed in field services. In the reference case, total oil and gas employment is projected to reach 350,000 in 2010 and 414,000 in 2020. While the total number of oil and gas employees is projected to grow in the reference case, projected employment is 2020 is still less than the industry employment was as recently as 1986, when employment exceeded 450,000.

Controlling Hg emissions leads to greater use of natural gas and more jobs in the oil and gas industry. By 2020, industry employment is projected to be 426,000 in the Hg 5-ton case. Employment grows to as much as 465,000 in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, 12 percent higher than employment in the reference case. Employment increases much more quickly in the early years. By 2010, employment in the integrated case is already 38,000 higher than projected in the reference case.

The introduction of an RPS lowers the growth in natural gas use and therefore lowers employment. In 2020, total industry employment in the RPS case is projected to be 366,000, 48,000 lower than projected in the reference case. Incorporating an RPS standard as part of an integrated policy including CO_2 emission reductions also lowers employment. In 2020, total employment in the oil and gas industry is projected to be 371,000 in the integrated all CO_2 1990-7% case, 20 percent lower than in the corresponding integrated case without the RPS.

[42]U.S. Department of Labor, Bureau of Labor Statistics, ES-202 Program, "Covered Employment and Wages."

[43]See the earlier EIA report, pages 38 and 39, for a discussion of impacts on the rail industry.

Although controlling Hg either by itself or as part of an integrated policy is projected to stimulate oil and gas production to grow more quickly than it does in the reference case, the required growth in employment is not stronger than what has been experienced historically. Between 1980 and 1981, average oil and gas employment grew by more than 130,000 in a single year. This suggests that the projected expansion in oil and gas production workers is feasible across all scenarios, even those that projected strong increases in natural gas demand.

Renewable Fuels Industry

Depending on the emissions to be reduced, employment in U.S. renewable energy industries could either remain unaffected or be significantly increased by changes in U.S. emissions control policies. Renewable energy employment is not expected to increase under scenarios designed solely to reduce NO_x, SO_2, or Hg emissions from electric power plants because no notable increases in use of renewable energy resources are expected in those cases. In addition, most renewables—geothermal, hydroelectric, landfill gas, solar, and wind, for example—do not support separate renewable energy extraction industries. Only biomass involves notable labor in energy production, such as for energy crops or for separating, preparing, and transporting various agricultural and forest wastes.

Scenarios calling for significant reductions in CO_2 emissions or imposing a 10- or 20-percent national RPS could be expected to induce significant employment in manufacturing power plant equipment, for plant construction, and in ongoing operations and maintenance. Non-U.S. suppliers as well as domestic manufacturers would likely also provide significant shares of equipment for U.S. renewable energy installations, particularly for turbine generators.

Macroeconomic Impacts

The imposition of new, more stringent emissions caps on electricity generators is expected to affect the U.S. economy primarily through an increase in 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 the price of energy. Moreover, a rise in energy prices would raise non-energy intermediate and final product prices and introduce cyclical behavior in the economy, resulting in output and employment losses in the short run. In the long run, however, the economy can be expected to recover and move back to a more stable growth path.

The macroeconomic assessment presented in this section evaluates one of the integrated cases discussed in Chapter 2, the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, but from two different implementation viewpoints. The integrated NO_x, SO_2, CO_2 1990-7%, Hg case is discussed because it incorporates all of the stringent emission caps analyzed in this report. It requires that power sector emissions of NO_x and SO_2 be reduced to 75 percent below their 1997 level, that Hg emissions be capped at 5 tons per year (90 percent below their 1997 level), and that CO_2 emissions be reduced to 7 percent below their 1990 level. Two implementation systems are presented to indicate that the manner of implementation will affect the overall impacts on the economy:

- The first case assumes a marketable emission permit system, with a no-cost allocation of the 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 pollutant.
- An alternative form of permit system would auction the permits to power suppliers. The price paid for the auctioned permits would equal the price paid for traded permits under the no-cost allocation system used for this study. However, the two systems imply a different distribution of income. The funds collected through the auction are assumed to be recycled to consumers through a lump-sum transfer.

Table 28 summarizes the projected macroeconomic impacts under these two implementation strategies.

With a No-Cost Allocation of Permits to Power Suppliers

Energy prices are projected to continue increasing relative to the reference case projections through the target year (2008) of the emission reduction. The most rapid increases in energy prices are projected during the first 10 years of the forecast period, because the power sector is expected to turn from coal to natural gas to comply with the CO_2 emission caps. Energy prices are projected to continue rising after 2010, but the rate of increase is expected to be more gradual.

In the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, the aggregate prices for the economy are projected to rise steadily above the level projected in the reference case. 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 rise steadily through 2010, reaching 0.9 percent above the reference case. Between 2010 and 2020, the level of the CPI does not increase further, and it remains 0.9 percent above the reference case in 2020.

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 goods and service consumption, 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. Capital, labor, and production processes in the economy would need to be adjusted to accommodate the new, higher set of energy and non-energy prices. These transition effects tend to dominate in the short run but dissipate over time.

Expectations on the part of power suppliers and consumers of energy play a key role. On the part of the

Table 28. Projected Macroeconomic Impacts in the Reference and Integrated NO_x, SO_2, CO_2 1990-7%, Hg Cases Under Two Emission Permit Allocation Schemes, 2010 and 2020

Projection	1999	2010	2020
Real Gross Domestic Product (Billion 1996 Dollars)			
Reference	8,876	12,667	16,515
No-Cost Allocation of Permits		12,555	16,493
Auction of Permits with Recycling to Consumers		12,565	16,456
Real Gross Domestic Product (Percent Change from Reference Case)			
No-Cost Allocation of Permits		-0.9	-0.1
Auction of Permits with Recycling to Consumers		-0.8	-0.4
Consumer Price Index (Index, 1982-1984 = 100)			
Reference	167.0	220.0	295.0
No-Cost Allocation of Permits		221.9	297.5
Auction of Permits with Recycling to Consumers		221.9	298.3
Consumer Price Index (Percent Change from Reference Case)			
No-Cost Allocation of Permits		0.9	0.9
Auction of Permits with Recycling to Consumers		0.9	1.1
Unemployment Rate (Percent)			
Reference	4.22	4.94	4.28
No-Cost Allocation of Permits		5.34	4.23
Auction of Permits with Recycling to Consumers		5.28	4.26
Unemployment Rate (Change in Rate from Reference Case)			
No-Cost Allocation of Permits		0.40	-0.05
Auction of Permits with Recycling to Consumers		0.34	-0.02
Disposable Income (Billion 1996 Dollars)			
Reference	6,363	8,928	11,842
No-Cost Allocation of Permits		8,822	11,789
Auction of Permits with Recycling to Consumers		8,861	11,819
Disposable Income (Percent Change from Reference Case)			
No-Cost Allocation of Permits		-1.2	-0.4
Auction of Permits with Recycling to Consumers		-0.8	-0.2
Non-agricultural Employment (Million Employed)			
Reference	128.5	149.7	165.1
No-Cost Allocation of Permits		148.4	165.2
Auction of Permits with Recycling to Consumers		148.6	165.1
Non-agricultural Employment (Change from Reference Case, Million Employed)			
No-Cost Allocation of Permits		-1.3	0.1
Auction of Permits with Recycling to Consumers		-1.1	0.0

Note: All percent changes and changes from the reference case are rounded to one decimal point.
Source: Simulations of the Standard & Poor's DRI Macroeconomic Model of the U.S. Economy.

power suppliers, current investment decisions depend on expectations about future markets. They will make decisions by reviewing each technology's current and future capital, operations and maintenance, and fuel costs. Both current and expected future costs are considered because generating assets require considerable investment and last many years. These forward-looking decisions help to moderate the ultimate price effects passed on to the rest of the economy. The views of consumers and businesses are also influenced by expectations of future price changes. Inflationary expectations on the part of consumers and businesses are characterized as a function of recent rates of increase in prices and spending. Thus, although expectations are important, they are based in general on recent changes, not on forward-looking expectations in the absence of change.

In the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, the unemployment rate is projected to be 0.4 percentage points above the reference case in 2010. Along with the rise in inflation and unemployment, real output of the economy is projected to decline. Real gross domestic product (GDP) is projected to be 0.9 percent lower relative to the reference case in 2010, and employment in non-agricultural establishments is projected to be lower by 1.3 million jobs. Similarly, real disposable income is expected to be 1.2 percent lower than the reference case level. The economic impacts peak early in the forecast period, by 2010, in response to the rapid rise in energy prices as the target level of emissions is reached in 2008.

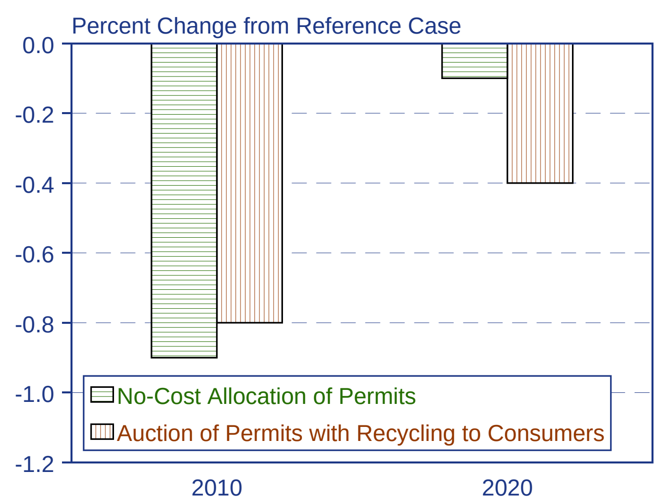
As the economy adjusts to higher energy prices, inflation begins to subside in the forecasts after 2010. At the same time, the economy begins to return to its long-run growth path. By 2020, real GDP is projected to be only 0.1 percent below the reference case level, and both employment and the unemployment rate are near reference case levels.

With an Auction of Permits with Recycling to Consumers

In the no-cost allocation system, there would be a redistribution of income flows between power suppliers in the form of purchases of emission permits. There would be no net burden on the power suppliers as a whole, only a transfer of funds among firms. While all firms are expected to benefit from trading, the burden would vary among firms. With a Federal auction system, in contrast, there would be a net transfer of income from power suppliers to the Federal Government. In the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, the magnitude of the transfer would be approximately $46 billion (1996 dollars) in 2010 and almost $60 billion in 2020. The key question at this juncture turns on the use of the funds by the Federal Government. If the funds were returned to the power suppliers, the effect would be the same as in the no-cost allocation scheme, but with the Federal Government establishing the permit market mechanism. Another use of the funds might be to return them to consumers either in the form of a lump-sum transfer or in the form of a personal income tax cut, partially compensating consumers for the higher prices paid for energy and non-energy goods and services.

Relative to the no-cost allocation of permits, an auction that transfers funds to consumers in a lump sum would help to maintain their level of overall consumption. With the transfer, however, total investment declines relative to the no-cost allocation system. The two effects tend to counterbalance each other, but not completely. Returning collected auction funds to the consumer has a slightly more positive effect than the negative effect on investment through 2010. In 2010, real GDP is projected to be 0.9 percent below the reference case under the no-cost allocation, but this is moderated to a difference of 0.8 percent when the funds are recycled to consumers (Figure 28). However, in the period between 2010 and 2020, investment rebounds faster in the no-cost allocation case, and this feature contributes significantly to the faster recovery back to the baseline. By 2020, real GDP under the no-cost allocation of permits is 0.1 percent below the reference case, but with the recycling of funds to consumers, real GDP is 0.4 percent below the reference case. There is a fundamental tradeoff in the time profile of the impacts in the two cases. Returning auctioned permit revenues to consumers ameliorates the near-term adverse impacts, but this case does not return

Figure 28. Changes in Projected U.S. Gross Domestic Product with Multiple Emissions Reduction Requirements, 2010 and 2020



Source: National Energy Modeling System, run M2P7B08.D060801A, and simulations of the Standard & Poor's DRI Macroeconomic Model of the U.S. Economy.

as quickly to the reference case as does the case with a no-cost allocation of permits.[44]

Other approaches would recycle the revenues from auctioned permits back to either consumers or business through a reduction in marginal tax rates on capital or labor.[45] Unlike the no-cost allocation or the lump-sum payment to consumers, this approach may lower the aggregate cost to the economy by shifting the tax burden away from taxes on labor and capital toward the taxation of an environmental pollutant. Most often research on this method is based on a general equilibrium approach, where all factors are assumed to be utilized fully, as in the work by Goulder, Parry, and Burtraw.[46]

[44]For further discussion of recycling issues for an economy in transition, see Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR / OIAF / 98-03 (Washington, DC, October 1998), Chapter 6, "Assessment of Economic Impacts."

[45]For a discussion of the relative merits of alternative policy instruments, see R. Perman, Y. Ma, and J. McGilvray, "Pollution Control Policy," in *Natural Resource and Environmental Economics* (Addison Wesley Longman, 1996).

[46]L.H. Goulder, I.W.H. Parry, and D. Burtraw, "Revenue-Raising Versus Other Approaches to Environmental Protection: The Critical Significance of Pre-existing Tax Distortions," *RAND Journal of Economics*, Vol. 28. No. 4 (Winter 1997), pp. 708-731.