Issues in Focus

The Economic Decline in East Asia

Recent Developments

Although this *Annual Energy Outlook 1999* (*AEO99*) focuses on the determinants of growth for the United States in a midterm (20-year) setting, it is also important to consider how near-term events may play out over the long run. The recent economic crisis in East Asia illustrates the need to reconcile volatility in the short run with the long-run determinants of growth for the world and the U.S. economy.

The economic crisis in East Asia began in the summer of 1997 and continued to deepen throughout 1998. Currency markets in Southeast Asia became extremely volatile, with Thailand, Malaysia, and Indonesia experiencing sharp depreciations first, followed by the Philippines and South Korea. Between the end of May 1997 and September 1998, the U.S. dollar rose by 67 percent against the Thai baht, nearly 53 percent against the Malaysian ringgit, and more than 61 percent against the South Korean won. For most of the East Asian countries, however, the exchange rate fluctuations occurred between August 1997 and the end of March 1998, with currency values relatively stable during the summer of 1998 (although at much higher levels against the dollar than in January 1997). Indonesia's currency did continue to show volatility, as the country tried to accommodate increased financing needs for both economic investment and social costs.

The Asian economies affected by the crisis share many characteristics: relatively rapid economic growth over the past 3 to 6 years; high domestic savings rates; economic expansion sustained by exports rather than domestic demand growth; high current account deficits; high inflows of foreign capital before the currencies became volatile; and relatively lax financial regulations. Early in 1997 their currencies were pegged to the U.S. dollar, and they became overvalued when the countries experienced large current account trade deficits. In addition, credit was allocated in their financial sectors on non-business criteria, and excessive investments were made in real estate, leading to inefficient uses of the available capital. When the exchange rates rose loans could not be repaid, foreign portfolio capital fled, and Asian firms found it difficult to finance needed imports of essential intermediate products.

Current events have exposed significant vulnerabilities in Asian and other developing economies, raising questions about the timing and extent of short- and long-term recovery. Developing economies need to devote much of their economic resources to improving infrastructure (education, transportation, and communication as well as energy resources) and tend to rely on international capital flows to finance much of their investment. But international capital flows, especially portfolio investment, are volatile and may have substantial impacts on short-term growth. Whether long-run growth is also affected depends on the reasons for the financial instability, the underlying economic characteristics of the country (such as the skill of the labor force), the domestic savings rate, the prospects for traded goods in global competition, and the infrastructure that supports the economy.

In Thailand, Indonesia, and South Korea, the International Monetary Fund (IMF) has agreed to supply capital in exchange for agreement to a set of fiscal and monetary policies designed to reduce volatility in financial markets. The policies are aimed at decreasing government expenditures, removing some government controls over the financial sector, allowing insolvent financial institutions and businesses to fail, and allowing more foreign ownership to encourage foreign direct investment. The short-run impacts of such policies are likely to be higher inflation, lower imports, and reductions in sectors of the economy that are sensitive to interest rates (such as construction and investment). One result is projected lower economic growth for the next several years.

The Asian recession is proving to be more severe than anticipated last year when *AEO98* was being prepared. At that time, most analysts thought that the Asian crisis would follow the course of the Mexican crisis of 1994, when the Mexican economy saw a severe drop in GDP growth in 1995 (6.2 percent), followed by positive growth (5.2 percent) in 1996.

A number of factors have contributed to a deeper recession in Asia than originally expected. First, with import demand plunging in many Asian countries, intraregional trade, which fueled growth in the early 1990s, has collapsed. The Japanese economy—weak at the beginning of the Asian crisis—has not yet recovered. In contrast, during Mexico's rapid economic recovery after its 1994 currency crisis, its main trading partner, the United States, was experiencing strong economic growth. Second, high interest rates and weak currencies have made it difficult for Asian countries to obtain financing for essential intermediate inputs. Without the necessary inputs, many export products cannot be produced. Finally, with the collapse of many Asian countries and the absence of a Japanese recovery, world export demand has not been sufficient to offset the drop in intra-Asian trade. Domestic demand in the Asian countries must recover before the intraregional trade can resume its impetus for growth.

High interest rates, prescribed by the IMF, were expected to cut wasteful spending while attracting more capital to the East Asia region. In fact, however, investors have been unwilling to channel their money to countries where there is a risk of further currency devaluations. Tighter credit has substantially reduced domestic demand in the affected countries, but the region's exchange rates are still volatile.

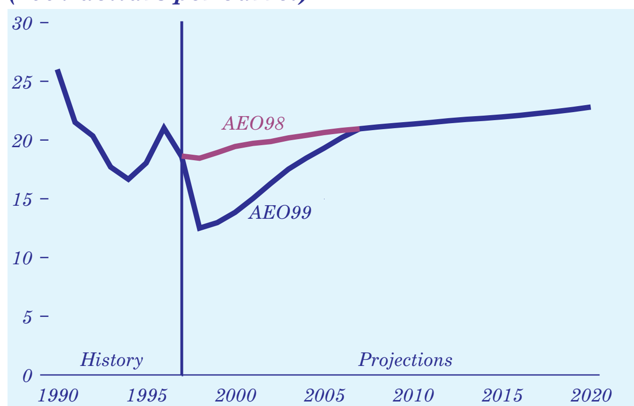
Whether the sharp currency devaluations in East Asia will lead to lower growth rates over the next 25 years will depend in large part on the policies enacted in response to short-run developments. If the financial reforms enacted make financial transactions more transparent, then market conditions will judge the efficacy of new investments. Making investment decisions more market-driven could lead to potentially higher long-run economic growth, especially given the relatively high education levels and savings rates of the labor force.

Impacts on the World Oil Market

Over the past 2 years, crude oil prices have dropped by more than 40 percent, reflecting a significant world oil surplus. Abundant supply and weak worldwide demand, especially among the struggling economies of the Pacific Rim, have combined to produce the lowest world oil prices since the early 1970s.

The timing and magnitude of an expected rebound in demand for oil and in world oil prices are the source of much uncertainty in *AEO99*. The reference case forecast assumes that real prices for oil rise at an annual rate of almost 6 percent from 1999 to 2007. After 2007, the reference case oil prices are similar to those in the *Annual Energy Outlook 1998* (*AEO98*), rising at an annual rate of less than 1 percent (Figure 8). Developments that could contribute to delaying the return until 2007, as opposed to a more rapid rebound, include the following.

Figure 8. World oil price projections in the AEO98 and AEO99 reference cases, 1990-2020 (1997 dollars per barrel)

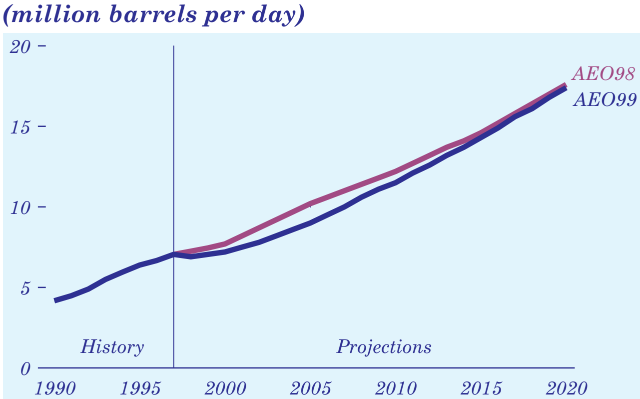


The Organization of Petroleum Exporting Countries (OPEC) has agreed on production cutbacks of about 2.6 million barrels a day in 1998 to counter the slow growth in world oil demand and the drop in oil prices. There is much skepticism, however, as to whether member nations will strictly adhere to such quotas. Prior excursions into quota-setting have resulted in temporary impacts on world oil prices, but cutbacks have been difficult to maintain and verify over the long term. Many OPEC countries are almost totally dependent on oil export revenues for their national income, and production cutbacks are especially painful. An additional factor of critical importance to OPEC supply potential is the reemergence of Iraq as an oil exporter. The United Nations Security Council has agreed to allow Iraq to export oil (for humanitarian reasons) at a rate of 1.6 million barrels a day. When Iraqi export sanctions are eventually lifted (assumed to be after 2000 in the reference case), Iraq could easily expand its production capacity to more than 3 million barrels a day by 2005. In addition, several non-Persian Gulf OPEC members (Algeria, Nigeria, and Venezuela) have active plans to expand their production capacities over the next half-dozen years.

Non-OPEC production potential continues to grow despite the low price environment. North Sea production is expected to peak by the middle of the next decade at levels that are at least 1 million barrels a day greater than current output. Other countries within the Organization for Economic Cooperation and Development (OECD) that are expected to register production increases within the next decade include Australia, Canada, and Mexico. In Latin America, Argentina, Brazil, and Colombia are showing accelerated growth in oil production due in part to privatization efforts. Deepwater projects off the coast of western Africa and in the South China Sea are not expected to be delayed and will start producing significant volumes early in the next century. Because subsea oil platforms have to be scheduled so far in advance, most of the world-wide deepwater projects are proceeding on schedule even at today's prices.

The bleak economic outlook for several Southeast Asian economies has significantly dampened the growth in oil demand for the region, which in recent years has accounted for about one-half of the growth in Asia's oil demand. In 1998 demand is expected to decline, and the timing of its recovery has become increasingly uncertain. Other regions whose near-term GDP growth is less optimistic than that assumed in *AEO98* include China, the Former Soviet Union, and Japan. Even with lower oil prices, near-term oil demand is expected to increase at only about half the rate of the past 5 years (Figure 9).

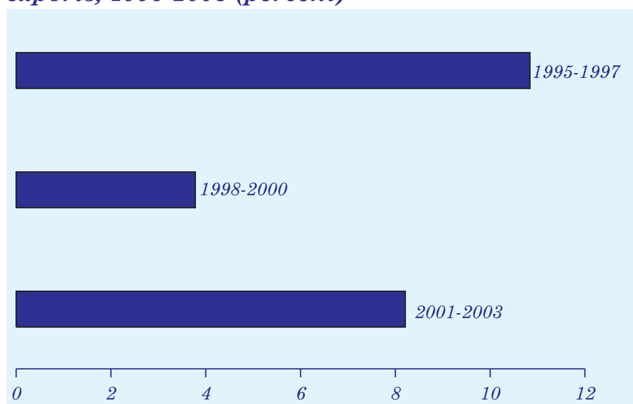
Figure 9. Oil demand projections for developing Asia in AEO98 and AEO99, 1990-2020 (million barrels per day)



Impacts on the Demand for U.S. Exports

In the near term, export demand for U.S. goods and services will suffer as world activity slows in response to these near-term volatile events (Figure 10). After expansive growth from 1995 through 1997, averaging over 11 percent a year, the growth in demand for U.S. exports slowed to less than 1 percent in 1998 and is expected to average less than 4 percent from 1998 through 2000. Export demand is expected to rebound by the year 2000 and sustain a growth rate of 8 percent a year from 2001 through 2003.

Figure 10. Projected annual growth in real U.S. exports, 1995-2003 (percent)



Because only a relatively small portion of U.S. exports goes to those countries where current economic disruptions are greatest, current Asian events are not expected to have as lasting an effect on the U.S. economy as on the world oil market. Nonetheless, compared with *AEO98*, slower growth in exports is expected from 1997 through 2010 in the *AEO99* reference case. The expected reduction in export demand is expected to reduce real GDP growth by as much as a tenth of a percentage point. The relatively lower growth in exports in the first 10 years of the forecast results in slower growth in domestic U.S. manufacturing relative to last year's expectations. Manufactured goods are affected more by export and import trends in the economy than are either services or wholesale and retail trade. As exports recover, so does the growth rate of manufactured output.

Responding to Growth in Demand for Natural Gas

In the *AEO99* reference case projections, natural gas consumption in 2020 is nearly 50 percent higher than the 1997 level of 22.0 trillion cubic feet. In order to satisfy the demand projected for 2020, a number of changes will be needed in the U.S. natural gas industry, including a significant increase in production and considerable expansion of infrastructure. Onshore and offshore production are projected to increase by 57 and 14 percent, respectively, and pipeline capacity to increase by 32 percent over 1997 levels. Although today's market differs from the markets that existed in past periods of significant growth, increases well above those projected in *AEO99* have been realized in the past, and the industry's past performance gives reason for confidence that the projected increases can be accommodated.

Interregional pipeline capacity increased by 6.9 trillion cubic feet (21 percent) over the 7-year period from 1990 (the first year EIA began compiling capacity data) to 1997. The driving force behind the expansion was not to meet an overall increase in demand *per se*—the 1997 market of 22.0 trillion cubic feet is roughly equivalent in size to the 1972 historical peak of 22.1 trillion cubic feet—but instead to provide new access corridors as supply and demand centers shifted in a changing market. Similarly, the need for additional pipeline capacity projected in *AEO99* primarily reflects the demand for greater customer access to new and expanding supply sources and for supplemental capacity into areas of growing demand where peak period utilization is approaching maximum available capacity.

As an example, proposed additional capacity from Canada will bring significantly greater volumes of gas to the midwestern marketplace. At the same time, several existing pipelines already have the capacity to move large volumes of gas from the South Central region to the same area. As capacity expansion projects proceed over the next several years, there is a strong potential for surplus supply to develop in the Chicago area. As a result, pipelines exiting the South Central region that compete with Canadian gas could become underutilized. To alleviate the situation, and to address the growing demand for natural gas in the Northeast, a number of projects have been proposed that would tap into the expanding Chicago hub and redirect some of its supplies eastward.

Much of the new capacity that has been added since 1990 or is to be completed by 2000 consists of long-haul pipelines from growing supply areas. By 2000, much of the projected new capacity will be able to link with nearby major long-haul pipelines already in operation, so that the primary short-term requirements will be for feeder lines to tap into the existing pipelines or compression and looping along existing routes where capacity needs to be augmented. Compression and looping are much less expensive than laying pipe along new routes and usually require less lead time.

Much of the expansion projected in *AEO99* before 2001 already is either under construction or planned, and more than half the pipeline expansion expected by 2020 is likely to occur between now and 2000. A number of projects have been proposed (although not all of them will actually be built), and substantial investment has been made in pipeline expansion. The added capacity will provide access to new and expanding production areas, such as Canada and the deep offshore, and will accommodate shifts in demand patterns, such as new demand for natural gas to replace electricity generation capacity lost as a result of nuclear retirements.

Government policy supports an optimistic outlook for the post-2000 pipeline expansion forecast. FERC policy allows the pipelines to assume more risk rather than requiring firm contracts to be in place before approving an expansion, and the Council on Environmental Quality has recently allocated funding to promote interagency cooperation in the review of pipeline permits, with the primary intention of speeding up the process. The FERC has responded positively to issues raised by the pipeline industry regarding its method of determining allowed rates of return by evaluating possible changes in the method it uses to calculate returns. Pipelines have claimed that they face considerable risk because of increased competition and the threat of capacity turnback, and that the 12- to 13-percent average rate of return for pipelines in 1996 was far lower than the 20-percent rate earned by most public companies [*17*].

Another issue that the industry will face in meeting the production forecast is supply availability. Uncertainty in estimates of the Nation's natural gas resources, both onshore and offshore, has always been an issue in projecting production [*18*]. Despite the fact that offshore production levels in the *AEO99* forecast do not exceed current levels until 2003—suggesting that offshore production will not be a problem—there are a number of potential problems related to the recovery of natural gas from offshore areas.

One issue is a potential shortage of offshore rigs and skilled personnel. Although the short-term situation has changed with the recent downturn in oil prices, every available offshore rig was in use throughout 1997, and the construction of new rigs has been limited by uncertainty surrounding their demand for the longer term. The lead time for construction of new rigs is 2 to 3 years, and costs range from $115 million for a 350-foot jack up to $325 million for a deepwater semisubmersible [*19*]. Training is needed to develop a work force for offshore production, and because of its cyclical history many people are reluctant to enter this work force.

An additional issue is the need for infrastructure expansion. Infrastructure to move natural gas from offshore drilling platforms to the shore will need to expand as production grows, and gathering systems for offshore production, the costs of which are not known with certainty, need to be developed. Despite the problems these issues may present, however, continuing developments in offshore technology have improved the prospects for offshore gas production. Although there have been some spending cutbacks as a result of current low oil prices, investments are being made in all these areas, and technology advances are cutting lead times and improving the economics of smaller fields.

Because of expected growth in natural gas demand, several studies are being undertaken to assess what steps the natural gas industry needs to take to be able to respond. Former Secretary of Energy Federico Peña commissioned the National Petroleum Council (NPC) to undertake a study of what is needed for the industry to be able to respond to demand increases. In addition, the Natural Gas Supply Association (NGSA) is working on a report that will analyze whether the industry can meet increased demand projections without increasing wellhead prices, and the Interstate Natural Gas Association of America (INGAA) is working on a study to determine what needs to be done for the pipeline industry to meet the needs of a market of 30 trillion cubic feet by 2010 (2 trillion cubic feet above the *AEO99* forecast). The key uncertainties in satisfying a market of that size are where the demand will occur and whether there is enough pipeline capacity to move the gas into growing demand centers.

The INGAA study addresses the question of whether the pipeline industry can provide the expanded infrastructure needed to get the gas to market. One of the problems with rapid expansions is the lead time necessary for a pipeline project. Barring unforeseen delays, capacity expansion requires a lead time of 2.5 to 3 years. If an environmental impact statement is required, it can add another 3 months to the completion time [*20*].

The pipeline capacity expansion currently underway reflects the industry's anticipation of an expanding market. Positive steps are also being taken in other parts of the industry. Again, despite recent cutbacks resulting from low oil prices, investments still are being made in exploration and production, and they are expected to continue, largely independent of lower oil prices, as higher gas prices provide a positive incentive for investment. In fact, spending on natural gas projects increased in the first quarter of 1998 and was unchanged in the second quarter [*21*].

The rising levels of demand and prices for natural gas projected in *AEO99* will provide additional economic incentives for the investments in infrastructure, rigs, drilling, and manpower development needed to meet the necessary increases in gas production. As a result, it is expected that the natural gas industry will be in a position to meet the challenge of satisfying the demand increases projected.

Renewable Portfolio Standards

Federal legislation proposed by Senator Jeffords, Senator Bumpers, and Congressman Schaefer include renewable portfolio standard (RPS) provisions that are similar to those included in State restructuring plans. Each of the Federal bills proposes a renewable credit system as described in "Legislation and Regulations" (see page 15). The key differences in the respective RPS provisions are the required renewable share and the renewable technologies that would receive credits. The share required by 2020 varies from 4 percent in H.R. 655 (Schaefer) to 20 percent in S. 687 (Jeffords). Each of the bills allows all nonhydroelectric renewable resources to receive credits. S. 237 (Bumpers) also provides partial credits to large hydroelectric facilities, greater than 80 megawatts.

In March 1998, the Clinton Administration released its Comprehensive Electricity Competition Plan [*22*], and in June 1998 the Secretary of Energy submitted the Administration's proposed legislation to implement the plan. Section 302 of the proposed Comprehensive Electricity Competition Act [*23*] calls for the establishment of a Federal RPS. Beginning in 2000, each retail electricity supplier would be required to submit to the Secretary of Energy renewable energy credits in an amount equal to the required percentage. Credits would be earned for each kilowatthour generated from solar, wind, geothermal, or biomass plants. The proposed percentage reaches 5.5 percent in 2010 and remains there through 2015. Between 2000 and 2010 the required percentage is to be determined by the Secretary of Energy, but it would be less than 5.5 percent. The following analysis illustrates the potential effects of the proposed RPS. For purposes of the analysis, it is assumed that the required share would grow linearly from 0 to 5.5 percent between 2000 and 2010 and remain at 5.5 percent through 2015, at which time the requirement would be eliminated [*24*].

The RPS would have an impact on the types of plants built to meet the growing demand for electricity. New wind and biomass plants, and geothermal to a lesser extent, are expected to make key contributions in meeting the RPS (Figure 11). In the reference case, only 9 gigawatts of new renewable plants are expected to be built, because in most situations they are not competitive with fossil alternatives. Under the proposed Federal RPS, however, renewable technologies would play a larger role. In the Federal RPS sensitivity case, more new wind plants are expected to be built in some regions of the country, particularly in the Northwest, Southwest, and Upper Midwest.

The United States has vast wind resources in some areas, but many are in regions of low demand, and there is some uncertainty about the costs of developing them and delivering their power. For example, some of the best wind resources are located far from transmission lines and load centers, in environmentally sensitive areas, or on terrain that it is not suitable for economical construction.

In terms of biomass, there are significant supplies of relatively low-cost biomass that, for the most part, are not currently being used for energy production. The low cost of fossil fuels, particularly coal, makes them unattractive. For example, there are large amounts of urban wood waste, tree trimmings, construction and demolition debris, and discards such as crates and pallets that could be burned to produce energy, rather than disposed of in landfills. These materials can be burned in standalone facilities, but a less expensive alternative may be to use them as a secondary fuel in existing coal-fired plants. Many existing coal plants may be able to consume up to 5 percent of their total fuel input as biomass with relatively minor modifications, and even higher levels are possible with more significant modifications. In this analysis, coal-fired plants are permitted to meet up to 5 percent of their fuel needs with biomass if it is economical; however, use of the biomass option is limited by the projected low cost of coal.

Although the required share for renewables is relatively low in the Federal RPS sensitivity case, it would nevertheless have an impact on electricity prices (Figure 12), which are projected to be almost 2 percent higher in 2010 and 2015 than they are in

Figure 11. Renewable electricity generation in two cases, 2020 (billion kilowatthours)

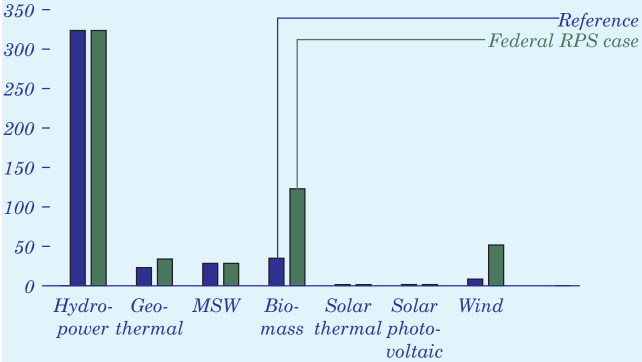
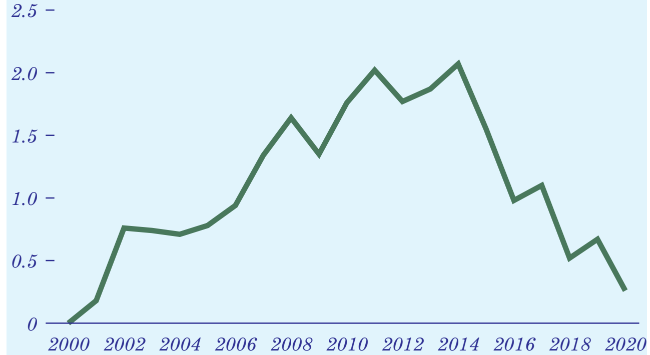
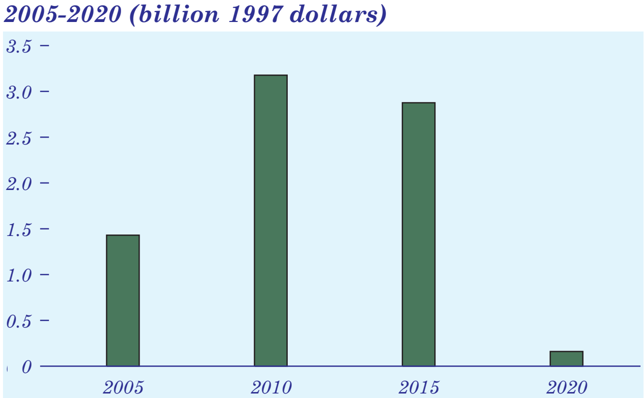


Figure 12. Change in average U.S. electricity prices in the Federal RPS sensitivity case from the reference case, 2000-2020 (percent)



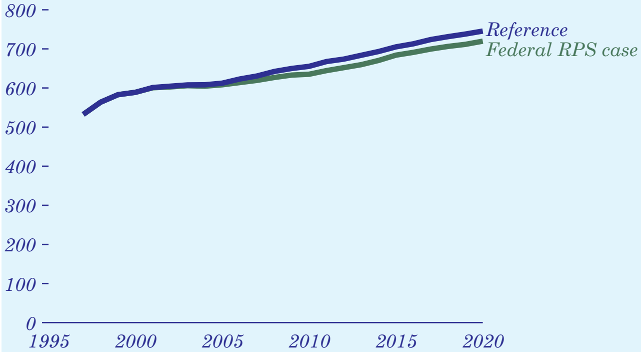
the reference case. The impact is less in the later years because renewable technologies are expected to become more economical over time, with costs declining once they begin to penetrate the market. The price impact almost disappears in 2020, when the RPS has ended. The projected price differences are relatively small, but they do amount to an added cost to consumers. The annual impact varies between $1.4 billion and $3.7 billion a year between 2005 and 2015, with the average residential electricity bill projected to be about $1 a month higher than in the reference case in 2010 (Figure 13). After 2015 the impact declines sharply.

Figure 13. Variation from reference case national electricity costs in the Federal RPS sensitivity case, 2005-2020 (billion 1997 dollars)



The imposition of the RPS would have a positive effect in reducing emissions. Because the new renewable facilities built to comply with the RPS would displace output from fossil plants, total emissions would be lower. For example, the 5.5 percent RPS reduces electricity sector carbon emissions by approximately 23 million metric tons a year between 2010 and 2020 (Figure 14). Emissions of nitrogen oxides (NO_x) and sulfur dioxide (SO_2) are

Figure 14. Projected U.S. electricity-related carbon emissions in two cases, 1996-2020 (million metric tons)



not significantly reduced, because their levels are explicitly capped, and implementing the RPS would not lead to further reductions. The imposition of the RPS is projected to reduce slightly the incremental cost of meeting the NO_x and SO_2 caps.

Electricity Pricing in a Competitive Environment

Electricity markets in many parts of the United States are being restructured to increase competition. Competitive pressures are affecting the operations of electricity generators, even in areas where no formal restructuring legislation has been introduced. For example, operating and maintenance costs for existing power plants have been falling in recent years, and further reductions are anticipated. To reflect this trend, the *AEO99* reference case assumes a 25-percent reduction in current nonfuel operating costs in all regions over the next 10 years. Capital costs and operating efficiencies for new plants are also assumed to improve over time in all regions.

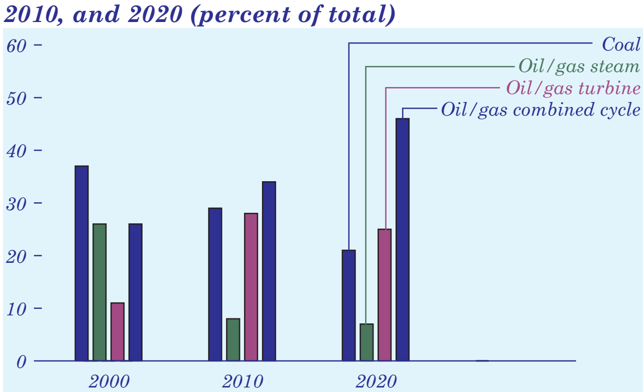
Future investment decisions may also be affected by increasing competition. Accordingly, the *AEO99* reference case assumes higher costs of capital and shorter recovery periods. Thus, the reference case forecast incorporates many of the expected effects of industry restructuring in all regions, including those where competitive pricing legislation or other binding rules have not been passed.

Historically, prices have been set administratively as the average embedded costs of producing electricity, including all fuel and operating and maintenance costs, as well as recovery of construction costs and a regulated profit. In a competitive market, generation prices will vary over time (even hour to hour), and will be set in each time period by the operating costs of the most expensive plant needed to meet demand at that point in time—the “marginal cost” of production. The marginal cost typically includes the fuel and variable operating and maintenance costs for the generator.

During periods of high demand in a competitive market, when the demand for electricity approaches the available generating capacity, prices might rise over the operating costs of the most expensive generator operating. Such occasional price spikes can encourage consumers to reduce their usage so that supply and demand are kept in balance. Similarly, prices consistently over the marginal operating costs will provide incentives for the construction of new generating capacity.

In *AEO99*, a full competitive pricing sensitivity case assumes that competitive pricing will be phased in throughout the United States over 10 years, with full competitive pricing based entirely on marginal costs occurring by 2008. Currently, marginal operating costs are generally lower than average embedded costs, which include the recovery of construction costs on plants that are not competitive in today's market. With a gradual shift to full competitive pricing, it is assumed that a portion of such costs will be recovered in the competitive price. When the uneconomical generators have either been paid for or retired, average costs are expected to approach, and possibly fall below, marginal costs. In the early years of the forecast, coal-fired units are projected to be used most often to set the marginal cost (Figure 15). In the later years, as demand increases and most new capacity is gas-fired, the projected marginal unit is more often a combined-cycle or turbine unit, and the marginal costs are dependent on gas prices. As a result, by 2020, marginal costs are projected to be slightly higher than average costs.

Figure 15. Percentage of time that different plant types set national marginal electricity prices, 2000, 2010, and 2020 (percent of total)



It is worth noting that the areas with the highest electricity prices under regulation (New York, New England, and California) were among the first to pass legislation allowing competition between electricity suppliers. Because the *AEO99* reference case assumes marginal cost pricing for electricity generation in those regions that have enacted restructuring legislation, the regions that would expect the largest price declines as a result of competitive pricing are assumed to have competitive electricity prices in both the reference and full competitive pricing cases. (The reference case assumes a transition to competitive pricing in California, New York, the New England States, the Mid-Atlantic States, and the Mid-America Interconnected Network—Illinois and parts of Wisconsin and Missouri.) As a result, the projected differences in national average electricity prices between the two cases are relatively modest, ranging from 5 percent lower in 2005 to 4 percent higher in 2020 in the full competitive pricing case than in the reference case. In 2020, the electricity price in the full competitive pricing case is higher than in the reference case because of increasing natural gas prices, which affect marginal electricity prices more directly than average prices. Detailed results from the full competitive pricing case are presented in Appendix F, Table F9.

The full competitive pricing case also assumes that some consumers will be able to respond to time-of-use pricing by altering their demand patterns. Through "load-shifting," consumers can reduce usage during a peak period, when prices are high and supply is tight, and shift that usage to an off-peak period. The net effect is lower peak demand and a flatter demand pattern for the year, with less variation between the lowest and highest points. Load shifting could also reduce the need for new capacity, because peak demand would be lower, so that different types of capacity would be built. In the full competitive pricing case, 28 gigawatts less new capacity is projected to be built by 2020 than in the reference case. Some of the difference results from lower reserve margins overall under full competitive pricing (reserve margins are projected to be as much as 3 percentage points lower nationally), but a portion is also due to the flatter load pattern.

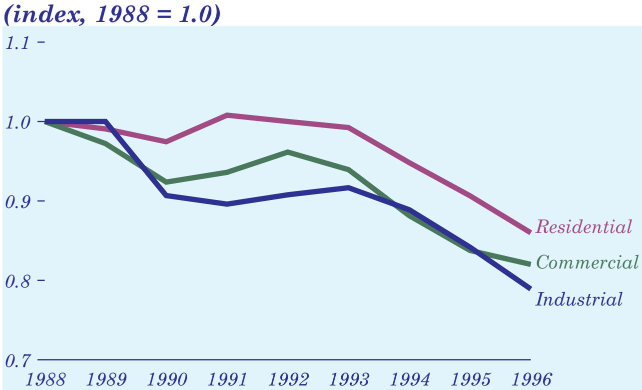
Sectoral Pricing of Electricity in Competitive Markets

The emergence of competitive markets for generation in the electricity industry has created the potential for a new distribution of costs and benefits among classes of utility customers. Traditionally, rates were set by regulators on the basis of "embedded costs"—the average cost of producing electricity and serving the customer, including both short-run costs such as fuel and long-run costs such as plant and capital recovery. Because rates were set to cover all costs, including return on capital invested, this was referred to as “rate-of return regulation.” Rates were generally set to reflect average costs rather than the more volatile fluctuations in marginal costs.

Historically, given the large transaction costs associated with real-time pricing, average cost pricing was seen as ensuring that revenues would cover total costs. Because some activities or investments, such as maintenance of a substation, serve multiple customer classes, regulators developed various methods of allocating the costs to different customer classes. Typically, both fairness and efficiency [*25*] played a role in setting customer class tariffs [*26*].

The changing nature of the electric utility industry will undoubtedly modify the pattern of allocations of costs among customer classes, with market forces having a greater role. Although all customers are expected to benefit eventually from the introduction of competition in the generation function, the rate and degree of such benefits may vary by customer class. Figure 16 shows sectoral prices of electricity in the United Kingdom during the period 1988-1996—when the electricity industry was privatized and competition was introduced in the generation sector—indexed to 1988 prices. Profitability in the regulated market was allowed to rise for 2 years before the introduction of competition in 1990. Savings from the introduction of competition were realized more quickly by the larger customers first.

Figure 16. Real electricity prices in the United Kingdom after deregulation, 1988-1996 (index, 1988 = 1.0)

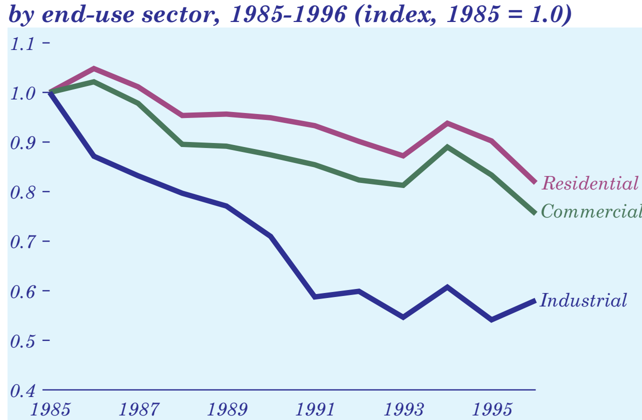


Initially only the largest customers in the United Kingdom, those with peak loads of more than 1 megawatt (approximately the size of 500 households), had a choice of suppliers. These customers were referred to as non-franchise customers, and they had the choice of any of the 12 Regional Electricity Companies (RECs), or other independent generating companies. Franchise customers, primarily residential and small commercial, were required to purchase electricity through their local RECs. The franchise threshold was lowered to 100 kilowatts in 1994, and all customers were to have choice of suppliers by the end of 1998.

In general, over this time, small consumers have seen only modest price reductions. As the franchise limitations were removed, first large and then medium industrial customers received greater benefits, although there was a good deal of variation in the experience of industrial customers. Some very large industrial customers, participants in the “qualifying industrial customer scheme” (QUICS) program before privatization, initially saw price increases and have received relatively little benefit from the competitive market [*27*]. As shown in Figure 16, even after a transition period, it is likely that the effect of deregulation will vary by customer class.

As markets are restructured, firms have incentives to change their pricing to meet specialized demands. An example is the U.S. natural gas market for transmission services, where restructuring resulted in a wider array of options for some customers. In particular, those customers with more flexibility in their transmission and distribution requirements were in a position to reduce their overall price of service. Those users, primarily large industrial consumers, benefited most from the restructured natural gas market [*28*]. Figure 17 shows the transmission and distribution markup (the difference

Figure 17. Index of real U.S. natural gas transmission and distribution markups by end-use sector, 1985-1996 (index, 1985 = 1.0)



between the wellhead and end-use prices of natural gas) by sector from 1985 to 1996, indexed to 1985. As shown, the average price of transmission and distribution for industrial users declined significantly more (on a percentage basis) than that for residential users.

Traditionally, an electric utility was granted an exclusive franchise over its territory and served as a regulated monopoly. Because customers are easily identified by demand level and have different price elasticities of demand, a utility can charge different prices to different customers. In a regulated monopoly, there is no inherent requirement that prices equal long-run average costs. In order for the revenue requirements of the utility to be met, some price differentials must be established. That is, if every customer class were charged its incremental cost of service, a utility might not cover its total costs. Allocation of such costs over and above the incremental costs are decided by regulators. Such allocations, translated into rates, result in different prices per kilowatthour for different customers. Such differences are inherent in traditional rate development [*29*].

Given the traditional market structure of a regulated monopoly, efficiency considerations encourage the adoption of a pricing approach whereby classes of customers with inelastic demands pay a higher markup over marginal cost than those with more elastic demands [*30*]. However, the goal of equity leads policymakers to set prices that are seen as fair and reasonable. This goal can lead regulators to deviate from the economically optimal pricing methodology so as to avoid imposing "unreasonably" high prices on groups with inelastic demands. Thus, regulated sectoral pricing deviates from economically optimal pricing, because both equity and efficiency are important in setting rates.

Figure 18 compares actual prices of electricity by customer class in 1996 with an estimate of what such prices would look like if the costs were allocated in an economically optimal (market-based) manner. The results indicate that current industrial and commercial prices are largely higher and current residential prices are lower than the prices associated with the economically optimal solution. Significant changes may occur when there is a restructured electricity generation market. Figure 19 compares the generation price by customer class in the full competition case, in which generation is assumed to be priced on a marginal cost basis. It is also assumed that, through the function of an independent system operator (ISO) or other market structure, the generation component of price at any one time will be equal for all customers. That is, the difference between the average yearly price of the generation component of electricity for different customer classes depends only on the fraction of annual electricity requirements purchased during high-priced periods. With these assumptions, the average annual generation prices are nearly equal for the different customer classes.

Figure 18. Actual 1997 electricity prices by sector and calculated prices with optimal pricing (1997 mills per kilowatthour)

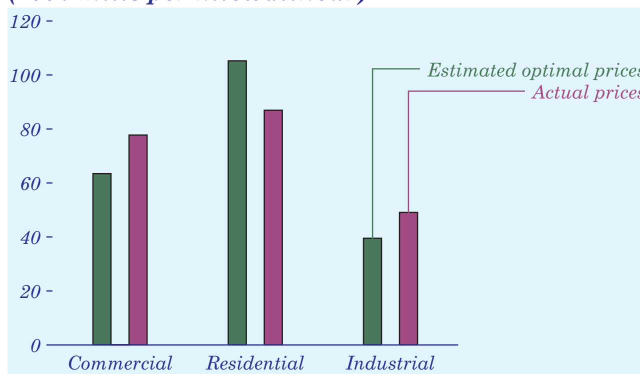
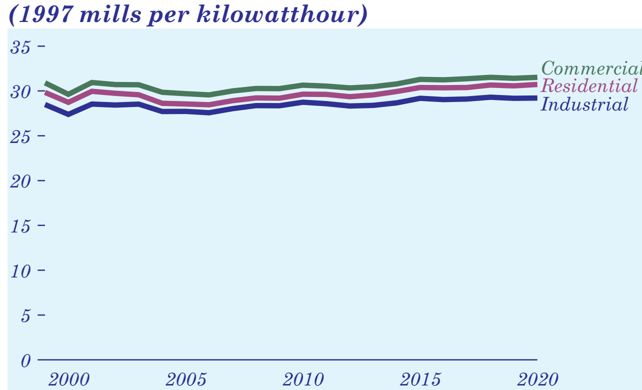
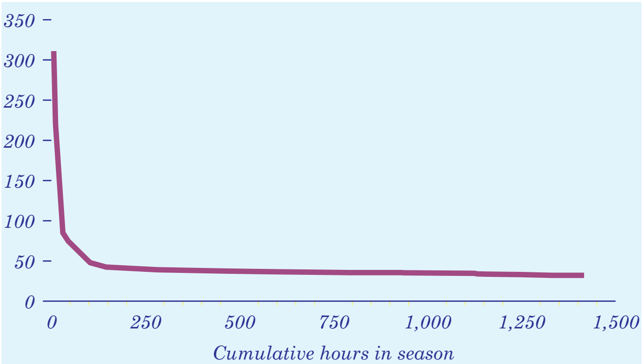


Figure 19. Generation component of electricity prices by end-use sector, 1999-2020 (1997 mills per kilowatthour)



The reason that sectoral generation prices are nearly equivalent is illustrated by the representative price-duration curve shown in Figure 20, depicting the ranked hourly price of electricity from the most expensive to the least expensive hour. The key feature of the graph is that the price-duration curve is relatively flat on a per-kilowatthour basis. A flat

Figure 20. Electricity generation price duration curve for the New England region (1997 mills per kilowatthour)



curve shows that, except for a limited number of peak hours, the price of generating electricity is relatively constant. Therefore, in a fully competitive market, the generation price is similar for all customer classes.

Although both transmission and distribution are assumed to be regulated, there is reason to believe that the unbundling of generation from transmission and distribution may provide medium and large consumers with a greater ability to obtain price concessions from the operator of the distribution system. Specifically, under the new market structure, some consumers may have the ability to bypass the distribution system at relatively low cost by connecting directly to the transmission system or building an on-site generator. Concessionary pricing, i.e., changes in the allocation of fixed costs among the customer classes, may be necessary to retain such customers.

Figure 21 compares the industrial price in the reference case with that in the fully competitive case, including concessionary pricing of transmission and distribution. As a counterpoint, another projection is shown, based on the assumption that industrial customers would be unable to obtain any additional concessions from the operators of the transmission and distribution system (no concessionary pricing). If average generation prices by customer class tend to converge, it is possible that industrial prices could rise significantly above the reference case price without reallocation of costs within the regulated transmission and distribution sector. Prices would be modestly higher than those in the reference case if such reallocation occurred.

Figure 21. U.S. industrial electricity prices under three fixed cost allocation options, 1999-2020 (1997 mills per kilowatthour)

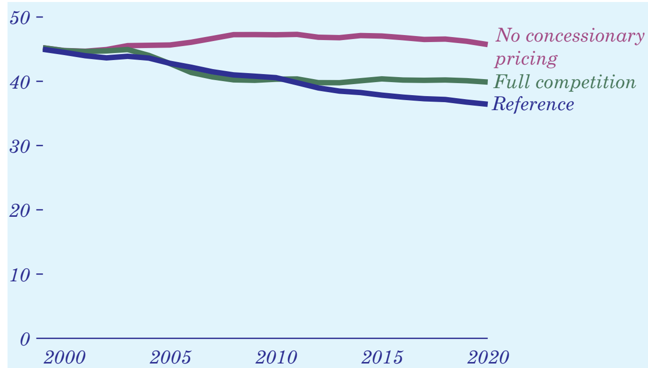
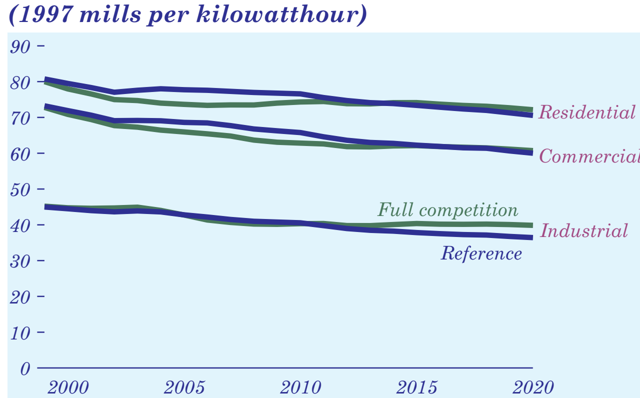


Figure 22 compares national sectoral prices in the fully competitive market case with those in the reference case. Given that similar efficiency improvements are assumed in the reference and full competition cases, it is not surprising that the price paths are similar. However, this analysis assumes that, if pricing is nondiscriminatory in the generation market, larger customers will nonetheless maintain their ability to achieve lower rates through market pressures on the remaining regulated portions of the industry.

Figure 22. U.S. electricity prices by end-use sector in the reference and full competition cases, 1999-2020 (1997 mills per kilowatthour)



Although the approach toward analyzing sectoral prices represents an advance over previous EIA analyses, a great deal of uncertainty remains. Clearly, the precise market structures that evolve will have a significant effect on price, as will the extent and speed at which new technologies, as well as market forces, influence the ratemaking process. Moreover, the validity of these projections depends on the consistency between EIA's assumptions about market structures and their actual performance. Finally, any assumptions about regulators' behavior are subject to changes in the overall regulatory environment.

Gasoline Sulfur Reduction

In early 1999, the U.S. Environmental Protection Agency (EPA) is expected to propose tighter restrictions on the amount of sulfur allowed in gasoline. Because gasoline sulfur and automotive emissions are linked, the proposal will be issued in conjunction with the new "Tier 2" vehicle exhaust emissions standards that would take effect between model years 2004 and 2007 (see "Legislation and Regulations," page 11). Sulfur reduces the effectiveness of the catalyst used in the emissions control systems of advanced technology engines, increasing their emissions of hydrocarbons, carbon monoxide, and NO_x. As a result, gasoline with significantly reduced sulfur levels will be required for the control systems to work properly and meet the new Tier 2 standards.

The EPA has been considering lowering the average annual sulfur content of gasoline to between 150 and 30 parts per million (ppm), from the existing standard of 1,000 ppm. The current national average gasoline sulfur content is 340 ppm [*31*]. The existing limit for all gasoline in California is an annual average of 30 ppm, with a cap of 80 ppm, or a flat (unaveraged) limit of 40 ppm. Discussions of California-like sulfur limits may be framed in terms of a "30 ppm" or a "40 ppm" limit, but for all intents and purposes, the two are the same.

A joint study by the EPA and the U.S. Department of Energy (DOE) put preliminary sulfur reduction costs for East Coast and Gulf Coast refiners at 5.1 to 8.0 cents a gallon for 40 ppm gasoline and 1.1 to 1.8 cents a gallon for 150 ppm gasoline. A study sponsored by the American Automobile Manufacturers Association estimated the cost of reducing sulfur to 40 ppm at 5.5 cents a gallon for refiners in the eastern half of the country. Another study sponsored by the American Petroleum Institute (API) estimated the costs of sulfur reduction at 5.1 cents a gallon for 40 ppm gasoline and 2.7 cents a gallon for 150 ppm gasoline [*32*].

Although there is a broad consensus that gasoline sulfur must be reduced, the level of reduction and the application of the requirement have been intensely debated. In addition to determining the appropriate sulfur level, the EPA is considering whether to make sulfur reduction a national or regional requirement. The range of sulfur reduction options under consideration by the EPA is bounded by proposals from two groups: automakers—the American Automobile Manufacturers Association and the Association of International Automobile Manufacturers—and gasoline producers—the American Petroleum Institute (API) and the National Petrochemical and Refiners Association (NPRA). *AEO99* includes the two proposals as alternative cases to explore their potential impacts on the long-term projections of gasoline supply and prices.

The automakers propose to reduce the average allowable sulfur content of gasoline in the United States to 40 ppm, which is equivalent to the current standard in the State of California. The API/NPRA submitted a less stringent regional proposal in which all gasoline in Federal reformulated gasoline areas, in 23 States, and in East Texas would meet an annual average of 150 ppm [*33*]; gasoline in California would continue to meet the State's gasoline requirements, including the 40 ppm annual average sulfur limit; and gasoline in all other parts of the country would have an annual average of 300 ppm. API/NPRA proposes further sulfur reductions by 2010 in areas that require year-round NO_x control. The areas of coverage and the level of sulfur reductions would be determined by an EPA study. In the API/NPRA analysis case, all the areas required to use 150 ppm gasoline in 2004 were assumed to require further reductions to 40 ppm by 2010.

As expected, the price impact is greater in the case based on the automakers' proposal (which is a more severe, nationwide plan) than in the API/NPRA case. Both cases assume that the additional costs associated with sulfur reductions would be passed on to consumers. Relative to the *AEO99* reference case, the API/NPRA scenario increases the average price of gasoline by 1.3 cents a gallon in 2004 and by 4.9 cents a gallon in 2010. The automakers' scenario increases the price by 8.3 cents a gallon in 2004 and 6.8 cents in 2010. The API/NPRA scenario increases total consumer spending for gasoline by $1.8 billion in 2004 relative to the *AEO99* reference case and by $7.6 billion in 2010. In the automakers' scenario, the corresponding increases are $11.7 billion in 2004 and $10.5 billion in 2010. In both cases, the price increases reflect investments in sulfur reduction processes at refineries, as well as changes in the selection of refinery inputs.

Before 2010, the cost of sulfur reduction is lower in the API/NPRA scenario because sulfur reduction to the 300 and 150 ppm levels can be achieved largely by adjustments in refinery processes. On the other hand, sulfur reduction to the 40 ppm level, reflected in the automakers' scenario and after 2010 in the API/NPRA scenario, can only be achieved by more costly refinery upgrades, including naphtha hydrotreating, gas oil desulfurization, alkylation, and hydrogen units.

An interesting feature of both scenarios is that they lead to a projected increase in domestic production of gasoline and blending components relative to the reference case projections, with a corresponding reduction in projected imports. On the other hand, the reductions in imports of gasoline and blending components are more than offset by increased requirements for crude oil imports. The net result is that imports represent the same share of total projected petroleum requirements in the API/NPRA scenario as in the *AEO99* reference case and a slightly higher percentage in the automakers' scenario.

The Kyoto Protocol and Carbon Emissions

Greenhouse Gas Emissions and the Framework Convention

The greenhouse effect is a natural process by which some of the radiant heat from the sun is captured in the lower atmosphere of the Earth, thus maintaining the temperature of the Earth's surface. The gases that help capture the heat, called "greenhouse gases," include water vapor, carbon dioxide, methane, nitrous oxide, and a variety of manufactured chemicals. Some are emitted from natural sources; others result from anthropogenic, or human, activities. Over the past several decades, rising concentrations of greenhouse gases have been detected in the Earth's atmosphere, and it has been suggested that this may lead to an increase in the average temperature of the Earth's surface and consequently to detrimental effects.

In 1988, the Intergovernmental Panel on Climate Change (IPCC) was established by the World Meteorological Organization and the United Nations Environment Programme to assess the scientific, technical, and socioeconomic information in the field of climate change. The most recent report of the IPCC concluded that: "Our ability to quantify the human influence on global climate is currently limited because the expected signal is still emerging from the noise of natural variability, and because there are uncertainties in key factors. These include the magnitude and patterns of long term natural variability and the time-evolving pattern of forcing by, and response to, changes in concentrations of greenhouse gases and aerosols, and land surface changes. Nevertheless, the balance of evidence suggests that there is a discernible human influence on global climate" [*34*].

Following a series of negotiating sessions, the text of the Framework Convention on Climate Change was adopted at the United Nations on May 9, 1992, and opened for signature at Rio de Janeiro, Brazil, on June 4. The objective of the Framework Convention was to ". . . achieve . . . stabilization of the greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." The signatories agreed to formulate programs to mitigate climate change. Furthermore, the developed country signatories agreed to adopt national policies to return anthropogenic emissions of greenhouse gases to their 1990 levels. The Convention excludes chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs), greenhouse gases that are deemed to cause damage to the Earth's stratospheric ozone and are controlled by the 1987 Montreal Protocol on Substances that Deplete the Ozone Layer.

Responding to the Framework Convention, on April 21, 1993, President Clinton called upon the United States to stabilize greenhouse gas emissions by 2000 at 1990 levels. Specific steps to achieve U.S. stabilization were enumerated in the Climate Change Action Plan (CCAP) [*35*], published in October 1993, which consists of a series of 44 actions to reduce greenhouse gas emissions. These actions include voluntary programs, industry partnerships, government incentives, research and development, regulatory programs, including energy efficiency standards, and forestry actions. Greenhouse gases affected by these actions include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs). At the time CCAP was developed, the Administration estimated that the actions in CCAP would reduce the total net emissions [*36*] of these greenhouse gases to 1990 levels by 2000.

In addition to the climate-related actions of CCAP, the Energy Policy Act of 1992 (EPACT), Section 1605(a), provided for an annual inventory of U.S. greenhouse gas emissions, which is contained in the EIA publication series, *Emissions of Greenhouse Gases in the United States* [*37*]. Also, Section 1605(b) of EPACT established the Voluntary Reporting Program, permitting corporations, government agencies, households, and voluntary organizations to report to EIA on actions that have reduced or avoided emissions of greenhouse gases. The results of the Voluntary Reporting Program are reported annually by EIA, most recently in *Mitigating Greenhouse Gas Emissions: Voluntary Reporting 1996* [*38*]. Entities providing data to the Voluntary Reporting Program include some participants in government-sponsored voluntary programs, such as the Climate Wise and Climate Challenge programs, which are cosponsored by the EPA and DOE to foster reductions in greenhouse gas emissions by industry and electricity generators.

The Kyoto Protocol

The Framework Convention established the Conference of the Parties to "review the implementation of the Convention and . . . make, within its mandate, the decisions necessary to promote the effective implementation." The first and second Conference of the Parties in 1995 and 1996 agreed to address the issue of greenhouse gas emissions for the period beyond 2000 and negotiate quantified emission limitations and reductions for the third Conference of the Parties. On December 1 through 11, 1997, representatives from more than 160 countries met in Kyoto, Japan, to negotiate binding limits for greenhouse gas emissions for developed nations. In the resulting Kyoto Protocol, emissions targets were established for these nations, the Annex I countries [*39*], relative to their emissions in 1990, to achieve an overall reduction of about 5.2 percent [*40*].

The individual targets for the Annex I countries range from an 8-percent reduction for the European Union (EU) (or its individual member states) to a 10-percent increase allowed for Iceland. Australia and Norway are also allowed increases of 8 and 1 percent, respectively, while New Zealand, the Russian Federation, and the Ukraine are held to their 1990 levels. Other Eastern European countries undergoing transition to a market economy have reduction targets of between 5 and 8 percent. The reduction targets for Canada and Japan are 6 percent and for the United States 7 percent. Non-Annex I countries have no targets under the Protocol, although the Protocol reaffirms the commitments of the Framework Convention by all parties to formulate and implement climate change mitigation and adaptation programs.

The greenhouse gases covered by the Protocol are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride [*41*]. The aggregate target is established using the carbon dioxide equivalent of each of the greenhouse gases. For the three synthetic greenhouse gases, countries have the option of using 1995 as the base year. Sources of emissions include energy combustion, fugitive emissions from fuels, industrial processes, solvents, agriculture, and waste management and disposal. The Protocol does not prescribe specific actions to be taken but lists a number of potential actions, including energy efficiency improvements, enhancement of carbon-absorbing sinks, such as forests and other vegetation, research and development of sequestration technologies, phasing out of fiscal incentives and subsidies that may inhibit the goal of emissions reductions, and reduction of methane emissions in waste management and in energy production, distribution, and transportation.

The targets must be achieved on average over the commitment period 2008 to 2012, the first commitment period. Each country can average its emissions over that 5-year period to establish compliance, smoothing out short-term fluctuations that might occur due to economic cycles or extreme weather patterns. Countries must have made demonstrable progress by 2005, but no targets are established for the period after 2012 (although lower targets may be set by future Conferences of the Parties). Banking—carrying over of unused allowances from one commitment period to the next—is allowed; however, the borrowing of emissions allowances from a future commitment period is not permitted.

Several provisions of the Protocol allow for some flexibility in meeting the emissions targets. Net changes in emissions by direct anthropogenic land-use changes and forestry activities will also be used in meeting the commitment; however, they are limited to afforestation, reforestation, and deforestation since 1990. Emissions trading among the Annex I countries is permitted. According to EIA's *International Energy Outlook 1998* (*IEO98*) [*42*], the amount of carbon that may be available for trade from the Annex I countries of the former Soviet Union as a result of the economic decline in those countries in the 1990s is estimated at 165 million metric tons in 2010. Also, additional carbon permits may be available. Joint implementation projects are allowed among the Annex I countries, allowing a nation to take emissions credits for projects that reduce emissions or enhance emissions-absorbing sinks, such as forests and other vegetation, in other Annex I countries. It is specifically indicated that trading and joint implementation are supplemental to domestic actions.

The Protocol also establishes a Clean Development Mechanism (CDM), under which Annex I countries can earn credits for projects that reduce emissions in non-Annex I countries provided that the projects lead to measurable, long-term benefits. Reductions from such projects undertaken from 2000 until the first commitment period can be used to assist with compliance in the first commitment period. This provision calls for the establishment of an executive board to oversee the projects. In addition, an unspecified share of the proceeds from the project activities must be used to cover administrative expenses and to assist with adaptation in countries that are particularly vulnerable to climate change.

Annex I countries, such as the EU, may create a bubble or umbrella to meet the total commitment of all the member nations. In a bubble, countries agree to meet the total commitment jointly by allocating a share to each member. In an umbrella arrangement, the total reduction of all member nations is met collectively through the trading of emissions rights. There is potential interest in the United States entering into an umbrella trading arrangement.

The Protocol became open for signature on March 16, 1998, for a one-year period. It enters into force 90 days following the acceptance by 55 Parties, including Annex I countries accounting for at least 55 percent of the 1990 carbon dioxide emissions from Annex I nations. Signature by the United States would need to be followed by Senate ratification. As of September 29, 1998, 57 countries had signed the Protocol, including 26 Annex I nations that accounted for about 38 percent of Annex I carbon emissions in 1990.

In 1990, total greenhouse gas emissions in the United States were 1,633 million metric tons carbon equivalent. Of this total, 1,346 million metric tons, or 82 percent, was due to carbon emissions from the combustion of energy fuels. By 1997, total U.S. greenhouse gas emissions had risen to 1,791 million metric tons carbon equivalent, of which 83 percent, or 1,480 million metric tons, were carbon emissions from energy combustion. EIA now projects that energy-related carbon emissions will reach 1,790 million metric tons in 2010, 33 percent above the 1990 level, increasing to 1,975 million metric tons in 2020. Because energy-related carbon emissions constitute such a large percentage of the total greenhouse gas emissions, any action or policy to reduce emissions will affect U.S. energy markets; however, there are a number of factors outside the domestic energy market that influence emissions and may offset the impacts on domestic energy.

To put U.S. emissions in a global perspective, the United States produced about 24 percent of the worldwide energy-related carbon emissions in 1996, which totaled 6.0 billion metric tons, according to *IEO98*. Although carbon emissions continue to increase in the United States and other industrialized countries, they are increasing at a much more rapid rate in the developing countries of Asia, the Middle East, Africa, and Central and South America. As a result, global carbon emissions from energy are expected to increase at an average annual rate of 2.4 percent from 1996 through 2010, reaching 8.3 billion metric tons, to which the United States is expected to contribute about 22 percent.

EIA Analysis of the Kyoto Protocol

At the request of the U.S. House of Representatives Committee on Science, EIA performed an analysis of the Kyoto Protocol in the summer of 1998, focusing on the impacts of the Protocol on U.S. energy prices, energy use, and the economy in the 2008 to 2012 time frame. The analysis was published in *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* [*43*]. The request specified that the analysis use the same methodologies and assumptions as the *AEO98* [*44*], with no changes in policy, regulatory actions, or funding for energy and environmental programs. The Committee indicated that no new nuclear plants should be allowed, although economic life extensions of nuclear plants should be permitted. Construction of new nuclear plants, variations in economic growth, and different assumptions concerning technology characteristics were all to be analyzed as sensitivities to the target cases.

The EIA analysis assumes that the Government would hold an auction of carbon permits. The cost of the permits is reflected in energy prices, and the revenues collected from the permits are recycled either to individuals by means of an income tax rebate or to individuals and businesses through a social security tax rebate.

The Protocol includes a number of international provisions, including international emissions trading, joint implementation projects, and CDM, which may reduce the cost of compliance; however, guidelines for the provisions must be resolved at future meetings of the Conferences of the Parties. (The fourth Conference was underway in Buenos Aires, Argentina, at the time *AEO99* went to press.) In addition, rules and guidelines for the accounting of emissions and sinks from activities related to agriculture, land use, and forestry activities must be developed. The specific guidelines may have a significant impact on the level of reductions from other sources that a country must undertake. Reductions in the other greenhouse gases may also offset the reductions required from carbon dioxide. A fact sheet issued by the U.S. Department of State on January 15, 1998, discussing the Protocol, estimated that the method of accounting for sinks and the flexibility to use 1995 as the base year for the synthetic greenhouse gases may reduce the U.S. target for energy-related carbon emissions to 3 percent below 1990 levels [*45*].

Because of these uncertainties concerning the final implementation of the Protocol, EIA's analysis includes cases with a range of reductions for energy-related carbon emissions within the United States in order to analyze the energy and economic impacts of achieving those reductions on the U.S. energy system and the economy. The cases assume that the reductions needed to meet the target of 7 percent below the 1990 emissions level that are not obtained from domestic energy-related reductions would come from some combination of forestry and agricultural sinks, offsets from other greenhouse gases, international trading, and other international activities. For example, the cases with the least stringent reductions in energy-related carbon emissions implicitly assume considerable international actions.

The analysis includes six carbon emissions reduction cases, plus a reference case, defined as follows:

Reference Case (33 Percent above 1990 Levels). This case represents the reference projections of energy markets and carbon emissions without any enforced reductions, in order to compare the energy market impacts in the reduction cases with a reference case. Although this case is based on the reference case from *AEO98*, there are small differences in order to permit additional flexibility in response to higher energy prices or to include certain analyses previously done offline directly within the modeling framework, such as nuclear plant life extension and generating plant retirements. Also, some assumptions are modified to reflect more recent assessments of technological improvements and costs. As a result of these modifications, energy-related carbon emissions in 2010 are slightly reduced from the *AEO98* reference case level of 1,803 million metric tons to 1,791 million metric tons.

24 Percent above 1990 Levels (1990+24%). This case assumes that carbon emissions can increase to an average of 1,670 million metric tons between 2008 and 2012, 24 percent above the 1990 levels. Compared to the average emissions in the reference case, carbon emissions are reduced by an average of 122 million metric tons during the commitment period.

14 Percent Above 1990 Levels (1990+14%). This case assumes that carbon emissions average 1,539 between 2008 and 2012, approximately at the level estimated for 1998 in *AEO98*, 1,533 million metric tons. This target is 14 percent above 1990 levels and represents an average annual reduction of 253 million metric tons from the reference case.

9 Percent Above 1990 Levels (1990+9%). This case assumes that energy-related carbon emissions can increase to an average of 1,467 million metric tons between 2008 and 2012, 9 percent above 1990 levels, an average annual reduction of 325 million metric tons from the reference case.

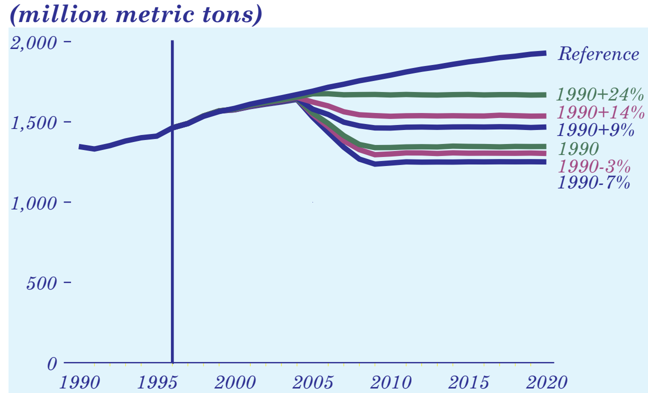
Stabilization at 1990 Levels (1990). This case assumes that carbon emissions reach an average of 1,345 million metric tons during the commitment period of 2008 through 2012, stabilizing approximately at the 1990 level of 1,346 million metric tons. This is an average annual reduction of 447 million metric tons from the reference case.

3 Percent Below 1990 Levels (1990-3%). This case assumes that energy-related carbon emissions are reduced to an average of 1,307 million metric tons between 2008 and 2012, an average annual reduction of 485 million metric tons from the reference case projections.

7 Percent Below 1990 Levels (1990-7%). Energy-related carbon emissions are reduced from the level of 1,346 million metric tons in 1990 to an average of 1,250 million metric tons in the commitment period, 2008 to 2012. Compared to the reference case, this is an average annual reduction of 542 million metric tons of energy-related carbon emissions during that period. This case essentially assumes that the 7-percent target in the Kyoto Protocol must be shared evenly by all emitting sources, with no net offsets for energy-related carbon emissions from sinks, other greenhouse gases, or international activities.

In each of the carbon reduction cases, the target is achieved on average for each of the years in the first commitment period, 2008 through 2012 (Figure 23). Because the Protocol does not specify any targets beyond the first commitment period, the target is assumed to hold constant from 2013 through 2020, the end of the forecast horizon, although more stringent requirements may be set by future Conferences of the Parties. The target is assumed to be phased in over a 3-year period, beginning in 2005, because the Protocol indicates that demonstrable progress toward reducing emissions must be shown by 2005. This allows energy markets to begin adjustments to meet the reduction targets in the absence of complete foresight. In the analysis, some carbon reductions occur before 2005 because of capacity expansion decisions by electricity generators that incorporate the future increases in energy prices.

Figure 23. U.S. carbon emissions in seven Kyoto Protocol analysis cases, 1990-2020 (million metric tons)



There are three ways to reduce energy-related carbon emissions: reducing the demand for energy services, adopting more energy-efficient equipment, and shifting to noncarbon or less carbon-intensive fuels. To reduce emissions, the price of carbon permits is applied to each of the fuels at its point of consumption relative to its carbon content. Electricity does not directly receive a carbon price; however, the fossil fuels used for generation receive the price, and this cost, as well as the increased cost of investment in generation plants, is reflected in the delivered price of electricity.

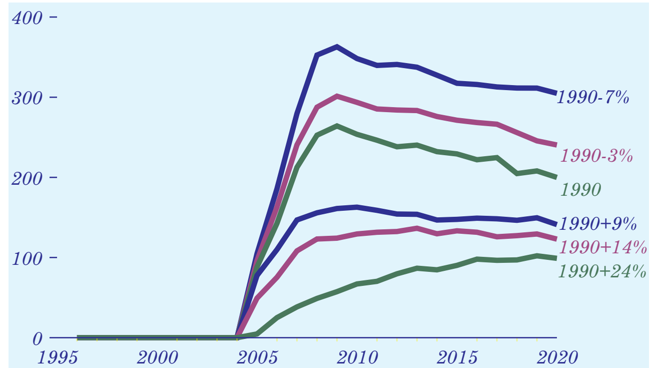
In the analysis, the carbon prices represent the marginal cost of reducing carbon emissions to the specified level, reflecting the price the United States would be willing to pay in order to purchase carbon permits domestically. Because the study does not include an analysis of trade and other flexible mechanisms to reduce carbon emissions internationally, the carbon prices do not represent the international market-clearing price of carbon permits or the price other countries would be willing to pay for permits.

Because of its representation of technology, NEMS captures the most significant factors that influence the turnover of energy-using and producing equipment and the choice of new technologies. Thus, it is well-suited for the analysis of the transitional impacts of policies designed to influence the choice of energy-consuming technologies, as new equipment is needed to meet growing demand for energy services or to replace retired equipment. Many sectors of NEMS include explicit treatment of individual technologies and their characteristics, such as initial cost, operating cost, date of commercial availability, efficiency, and other characteristics specific to the sector. Higher energy prices induce more rapid adoption of more efficient or advanced technologies because consumers have more incentive to purchase them. In addition, for new generating technologies, the electricity sector accounts for technological optimism in the capital costs of first-of-a-kind plants; and several sectors, including the generation sector, account for a decline in the costs as experience with the technologies is gained.

Energy Market and Macroeconomic Analysis. The analysis indicates that significant changes in the mix of energy fuels, as well as higher energy efficiency and lower consumption, will be needed for the required reductions. To induce the changes, the price of energy will increase. Some of the most significant results from the analysis are as follows:

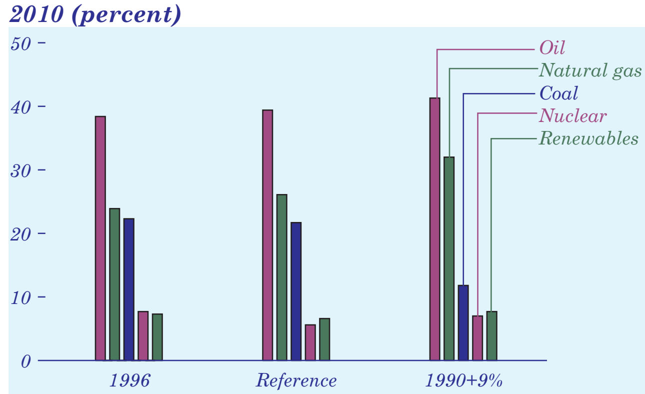
- The cost of the Kyoto Protocol will depend on the amount of permits that can be purchased on the international market and on cost-effective projects to reduce emissions or develop carbon-absorbing sinks in other countries. Domestic actions to reduce other greenhouse gases covered by the Protocol and to develop sinks may also serve to reduce the costs.
- The carbon price necessary to reduce U.S. energy-related carbon emissions to the required level ranges from $67 to $348 per metric ton (1996 dollars) in 2010. In the more stringent reduction cases, the carbon price falls by 2020 as more efficient and lower-carbon technologies become economically available and penetrate later in the forecast horizon (Figure 24).
- Higher energy prices and their impact on the broader U.S. economy will encourage consumers to reduce energy consumption by reducing the demand for energy services and purchasing more efficient equipment. However, consumption will increase later with a growing economy and lower carbon prices. Shifts from more to less carbon-intensive fuels also occur.

Figure 24. Carbon prices in six Kyoto Protocol analysis cases, 1996-2020 (1996 dollars per metric ton)



- Because coal is the most carbon-intensive of the fossil fuels, the price of coal will rise dramatically, and coal use will be sharply curtailed, particularly for electricity generation. If the carbon price increases to its highest level, the use of coal for generation may nearly disappear by 2020 in the more stringent reduction cases. Shrinking domestic and international markets will lead to sharply reduced coal production and employment.
- Coal-fired electricity generation will be replaced by generation from natural gas and renewables and also by the continued operation of many existing nuclear plants. Increases in natural gas generation will more than offset reductions in natural gas use by residential, commercial, and industrial consumers. As a result, the natural gas industry will expand production and distribution services (Figure 25).

Figure 25. Projected fuel shares of U.S. energy consumption in two Kyoto Protocol analysis cases, 2010 (percent)



- Renewable generation will also increase as more of the technologies become economical in light of higher fossil fuel prices. Renewables could capture as much as a 22-percent share of the generation market by 2020, with more than half supplied by nonhydroelectric renewable generation in the more stringent cases. Within the energy industry, increased employment in the natural gas and renewables industries could offset some reductions in coal employment.
- Nuclear generation's decline will slow as it becomes economical under higher carbon prices to extend the operating lives of existing plants rather than retire them.
- Petroleum consumption will be lower than expected in the reference case but will likely remain above current levels. Although petroleum consumption is lower, the petroleum share of total energy consumption is higher than in the reference case, because the total is lower. The majority of petroleum is used for transportation, where there are limited economically attractive options for shifting to less carbon-intensive fuels.
- Recycling carbon revenues back to consumers will offset some of the negative impacts on the economy. The economy will continue to grow; however, the growth in the gross domestic product (GDP) could be lower than reference case levels during the transition period. As carbon prices decline and the economy adjusts, GDP will rebound by 2020 to about the level it would have been in the absence of a carbon reduction program (Figures 26 and 27).
- The loss in GDP, plus the funds used to purchase permits internationally, represents the total cost to the economy. Over the first compliance period, from 2008 to 2012, the total cost ranges from an annual average of $77 billion (1992 dollars) to almost four times that amount, depending on the required carbon reductions and how the revenues are recycled to the economy. This is relative to a total economy of $7 trillion in 1996, which is expected to grow to $9.5 trillion in 2010 and $11 trillion in 2020.

Sensitivity Cases. The analysis includes several sensitivity cases to examine factors that may affect energy demand and carbon emissions over the next 20 years, including economic growth, the rate of improvement of technology, and nuclear power. With the exception of the nuclear sensitivity case, the sensitivity cases were analyzed relative to the 1990+9% case. Because each of the sensitivity cases is constrained to the same level of carbon emissions as the case to which it is compared, the primary impact is on the carbon price required to meet the emissions target.

- *Macroeconomic Growth.* The assumed rate of economic growth has a significant impact on projected energy demand and carbon emissions. The reference and carbon reduction cases in the analysis assume an average growth rate of 1.9 percent a year between 1996 and 2020, and higher and lower growth rates of 2.4 and 1.3 percent a year are analyzed as sensitivities. Higher growth results in higher manufacturing output and income, increasing the demand for energy services and resulting in higher energy demand

Figure 26. Annual GDP growth rates in four Kyoto Protocol analysis cases, 2005-2010 (percent)

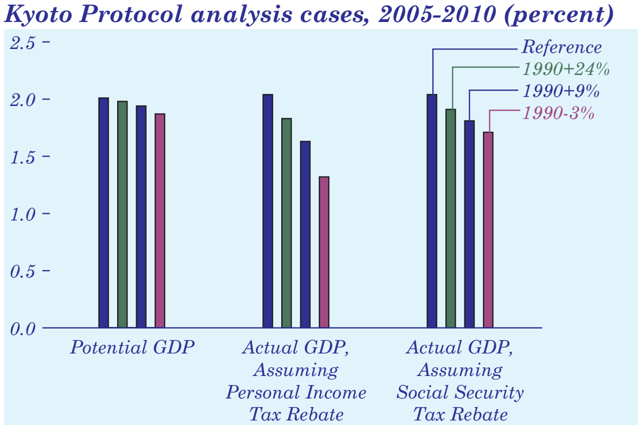
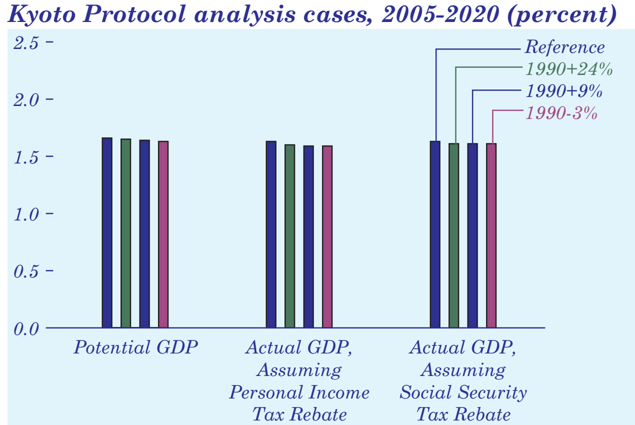


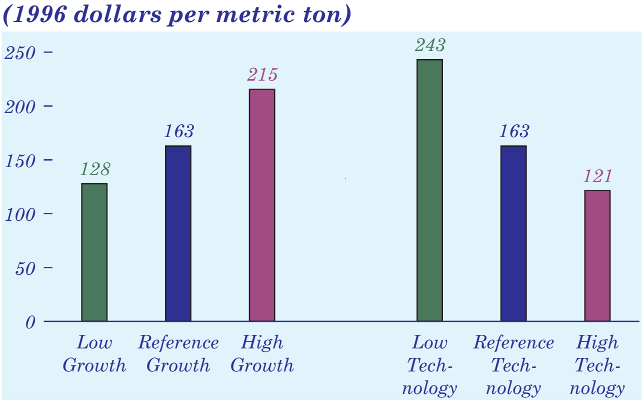
Figure 27. Annual GDP growth rates in four Kyoto Protocol analysis cases, 2005-2020 (percent)



and carbon emissions. Converse trends hold for the lower economic growth case.

Because higher growth increases energy consumption, carbon prices must be higher to attain a given carbon emissions target. In the high growth case, the carbon price in 2010 is $215 per metric ton, $52 per metric ton higher than the reference case carbon price of $163 per metric ton (Figure 28). In the low growth case, the carbon price in 2010 is $128 per metric ton. Total energy consumption in 2010 is higher and lower by 2.2 quadrillion Btu with higher and lower growth, relative to the 1990+9% case with reference economic growth.

Figure 28. Projected carbon prices in four Kyoto Protocol sensitivity analysis cases, 2010 (1996 dollars per metric ton)



- *Technological Progress*. High technology assumptions were developed by technology experts for the end-use sectors—residential, commercial, industrial, and transportation—considering the potential impacts of increased research and development for more advanced technologies [*46*]. The revised assumptions include earlier years of introduction, lower costs, high maximum market potential, and higher efficiencies than assumed in the reference case. For the electricity generation sector, the cost and efficiencies of advanced fossil-fired and renewable generating technologies are assumed to improve from reference case values. The low technology case assumes that all future equipment choices are made from the end-use equipment available in 1998, with building shell and industrial plant efficiencies frozen at 1998 levels, and no new advanced fossil-fired generating technologies are assumed.

Because faster technology development makes advanced energy-efficient and low-carbon technologies more economically attractive, the carbon prices required to meet carbon reduction levels are significantly reduced. Conversely, slower technology improvement requires higher carbon prices. With high technology assumptions, the carbon price in 2010 is $121 per metric ton, compared to the carbon price of $163 per metric ton with the reference technology assumptions. With the low technology assumptions, the carbon price increases to $243 per metric ton in 2010.

- *Nuclear Power*. In the reference case, nuclear generation declines because 52 percent of the total nuclear capacity available in 1996 is retired by 2020. A number of units are retired before the end of their 40-year operating licenses, based on industry announcements and analysis of the age and operating costs of the units. In the carbon reduction cases, life extension of the plants can occur, if economical, and there is an increasing incentive to invest in nuclear plant refurbishment with higher carbon prices; however, these cases do not allow the construction of new nuclear power plants. A nuclear power sensitivity case examines the effects of allowing new plants to be constructed if they are economical. Because nuclear plants still are not competitive with fossil and renewable plants in the 1990+9% case, this sensitivity case is analyzed against the 1990-3% case. In addition to allowing new nuclear plants, the higher costs assumed in the reference case for the first few advanced nuclear plants are reduced in this case.

Relative to the 1990-3% case, 1 gigawatt of new nuclear capacity is added by 2010 in the nuclear power sensitivity case, and 41 gigawatts, representing about 68 new plants of 600 megawatts each, are added by 2020. Because most of the impact from the new nuclear plants comes after the commitment period of 2008 through 2012, there is little impact on carbon prices and energy markets in 2010. By 2020, however, carbon prices are $199 per metric ton with the assumption of new nuclear plants, compared to $240 per metric ton in the 1990-3% case with the reference nuclear assumptions.

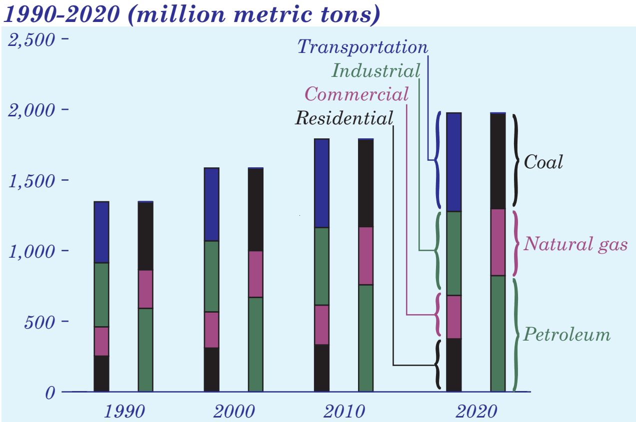
Carbon Emissions in *AEO99*

Reference Case

In the *AEO99* reference case, carbon emissions from energy consumption are expected to reach 1,585 million metric tons in 2000, 18 percent above the 1990 level of 1,346 million metric tons. The projected emissions continue to rise to 1,790 million metric tons in 2010 and 1,975 million metric tons in 2020, 33 percent and 47 percent above the 1990 levels, respectively (Figure 29). Total emissions increase at an average annual rate of 1.3 percent between 1997 and 2020, and per capita emissions also increase at an average rate of 0.4 percent. Throughout the projection period, carbon emissions rise, because continued economic growth and moderate increases in energy prices are expected to lead to increasing energy consumption. Emissions rise at a faster rate than total energy consumption, which increases at an average annual rate of 1.1 percent, for two primary reasons. First, approximately 51 percent of nuclear generating capacity, which is carbon free, is retired by 2020 and no new nuclear plants are constructed. Second, moderate increases in the price of natural gas and decreases in the price of coal lead to slow growth in renewables.

In 2020, electricity generation accounts for 38 percent of all carbon emissions, increasing from 36 percent in 1997. The increasing share of carbon emissions from generation results, in part, from the 1.4-percent annual growth rate in electricity consumption. Of the new capacity required to meet electricity demand growth and to replace the loss of nuclear capacity, about 9 percent is fueled with coal and 88 percent with natural gas.

Figure 29. U.S. carbon emissions by sector and fuel, 1990-2020 (million metric tons)



Energy consumption and carbon emissions for transportation grow the fastest of all the end-use sectors because of increased travel and the slow improvement in fuel efficiency in the reference case. Between 1997 and 2020, both transportation demand and emissions grow at an average annual rate of 1.7 percent, and in 2020 the transportation sector accounts for 35 percent of all carbon emissions. The average efficiency of the light-duty vehicle fleet—cars, light trucks, vans, and sport-utility vehicles—increases at an average annual rate of only 0.2 percent between 1997 and 2020. Over the same period, vehicle-miles traveled by light-duty vehicles increase by 1.6 percent a year, faster than the growth rate for the over-age-16 population (0.9 percent a year). Growth in both air and freight travel, at average rates of 3.8 percent and 1.8 percent a year, also contribute to the increase in emissions from the transportation sector.

Emissions from both the residential and commercial sectors grow by 1.2 percent a year, contributing 19 percent and 16 percent of carbon emissions in 2020 (including emissions from the generation of electricity used in each sector). Continued growth in energy service demand, particularly in electricity-using equipment and appliances, results in the emissions increases, offset somewhat by efficiency improvements in both sectors. Industrial sector emissions increase by only 0.9 percent a year through 2020 and account for 30 percent of the emissions in 2020 (including emissions from electricity generation for the sector). The relatively low growth rate results from efficiency improvements and a shift to less energy-intensive industries.

By fuel, petroleum products are the leading source of energy-related carbon emissions because of the continuing growth of the transportation sector, which is heavily dependent on petroleum. About 42 percent of all emissions, or 823 million metric tons of the total of 1,975 million metric tons in 2020, are from petroleum products, and about 81 percent of the petroleum emissions are from transportation uses.

Coal is the second leading source of carbon emissions at about 34 percent, or 676 million metric tons, in 2020. Coal has the highest carbon content of all the fossil fuels and remains the predominant source of electricity generation. By 2020, the share of coal-fired generation, excluding cogeneration, declines slightly from its 1997 level of 56 percent but still accounts for 52 percent of all generation. About 90 percent of coal emissions in 2020 result from electricity generation.

Natural gas consumption for both electricity generation and direct end uses grows the fastest of all the fossil fuels—at a rate of 1.7 percent a year through 2020. Natural gas has a relatively low carbon content relative to other fossil fuels (only about half that of coal), and thus carbon emissions from natural gas use are projected to be just 475 million metric tons in 2020, about 24 percent of the total.

Macroeconomic Growth

The assumed rate of economic growth has a strong impact on the projection of energy consumption and, therefore, carbon emissions. In *AEO99*, the high economic growth case includes higher growth in population, the labor force, and labor productivity, resulting in higher industrial output, lower inflation, and lower interest rates. As a result, GDP increases at an average rate of 2.6 percent a year from 1997 to 2020, compared with a growth rate of 2.1 percent a year in the reference case.

With higher macroeconomic growth, energy demand grows faster, as higher manufacturing output and higher income increase the demand for energy services. Total energy consumption in the high economic growth case is 129.4 quadrillion Btu in 2020, compared with 119.9 quadrillion Btu in the reference case. As a result of the higher consumption, carbon emissions are 2,124 million metric tons, or 8 percent, higher than the reference case level of 1,975 million metric tons in 2020.

Assumptions of lower growth in population, the labor force, and labor productivity result in an average annual growth rate of 1.5 percent in the low economic growth case through 2020. With lower economic growth, energy consumption in 2020 is reduced from 119.9 quadrillion Btu to 110.5 quadrillion Btu, and carbon emissions are 1,826 million metric tons, or 8 percent, lower than in the reference case.

Total energy intensity, measured as primary energy consumption per dollar of GDP, improves at a faster rate in the higher economic growth case, partially offsetting the changes in energy consumption caused by the higher growth assumptions. With more rapid growth in energy consumption, there is greater opportunity to turn over and improve the stock of energy-using technologies, increasing the overall efficiency of the capital stock. Aggregate energy intensity in the high economic growth case decreases at a rate of 1.2 percent a year from 1997 through 2020, compared with 1.0 percent in the reference case and 0.8 percent in the low economic growth case.

Technology Improvement

The *AEO99* reference case includes continued improvements in technology for both energy consumption and production—improvements in building shell efficiencies for both new and existing buildings; efficiency improvements for new appliances and transportation vehicles; productivity improvements for coal production; and improvements in the exploration and development costs, finding rates, and success rates for oil and gas production. As a result of continued improvements in the efficiency of end-use and electricity generation technologies, total energy intensity in the reference case declines at an average annual rate of 1.0 percent between 1997 and 2020.

The projected decline in energy intensity is considerably less than that experienced during the 1970s and early 1980s. when energy intensity declined, on average, by 2.3 percent a year. Approximately half of that decline can be attributed to structural shifts in the economy—shifts to service industries and other less energy-intensive industries; however, the rest resulted from the use of more energy-efficient equipment. During those years there were periods of rapid escalation in energy prices, encouraging some of the efficiency improvements. Then, as energy prices moderated, the improvement in energy intensity moderated. Between 1986 and 1996, energy intensity was relatively flat.

Regulatory programs have contributed to some of the past improvements in energy efficiency, including the Corporate Average Fuel Economy standards for light-duty vehicles and standards for motors and energy-using equipment in buildings in the Energy Policy Act of 1992 and the National Appliance Energy Conservation Act of 1987. In keeping with the general practice of incorporating only current policy and regulations, the reference case of *AEO99* assumes no new efficiency standards. Only current standards or approved new standards with specified levels are included.

Technology improvements in energy-consuming equipment could reduce energy consumption and energy-related carbon emissions to levels below those in the reference case. Conversely, slower improvements could increase both consumption and emissions. *AEO99* presents a range of alternative cases that vary key assumptions about technology improvement and penetration.

In the end-use demand sectors, experts in technology engineering were consulted to derive high technology assumptions, considering the potential impacts of increased research and development for more advanced technologies. The revised assumptions included earlier years of introduction, lower costs, higher maximum market potential, and higher efficiencies than in the reference case. It is possible that further technology improvements could occur if there were a very aggressive research and development effort. For the electricity generation sector, the cost and efficiencies of advanced fossil-fired generating technologies were assumed to improve from reference case values [*47*].

The low technology case assumes that all future equipment choices are from the equipment and vehicles available in 1999, with new building shell and industrial plant efficiencies frozen at 1999 levels. New generating technologies are assumed not to improve over time. Aggregate efficiencies still improve over the forecast period as new equipment is chosen to replace older stock and the capital stock expands. Also, building shell efficiencies improve with price increases.

In the high technology case, with the high technology assumptions of all four end-use demand sectors and the electricity generation sector combined, aggregate energy intensity declines at an average of 1.3 percent a year from 1997 to 2020, compared with 1.0 percent a year in the reference case (Figure 30). In the 1999 technology case, the average decline is only 0.8 percent a year through 2020. Total energy consumption increases to 111.9 quadrillion Btu in 2020 in the high technology case, compared with 119.9 quadrillion Btu in the reference case (Figure 31), but increases to 126.6 quadrillion Btu in the 1999 technology case.

Figure 30. U.S. energy intensity in three cases, 1997-2020 (thousand Btu per dollar GDP)

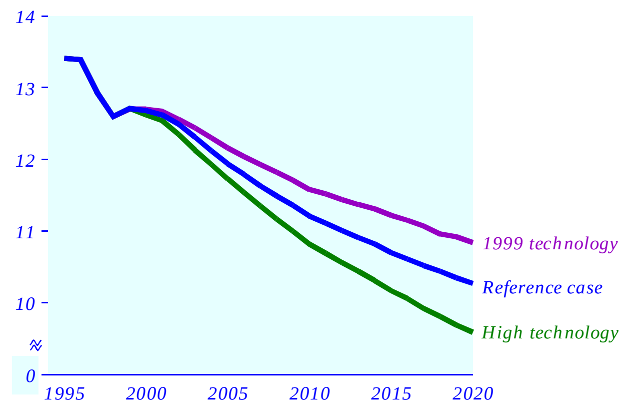
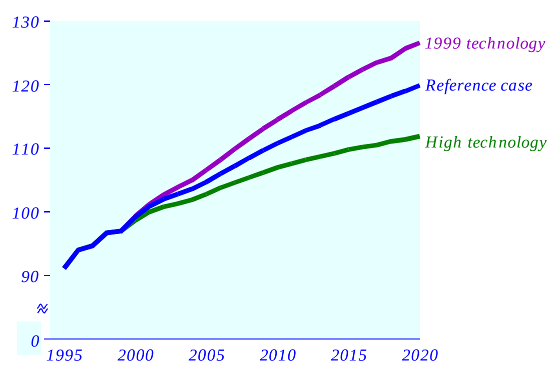
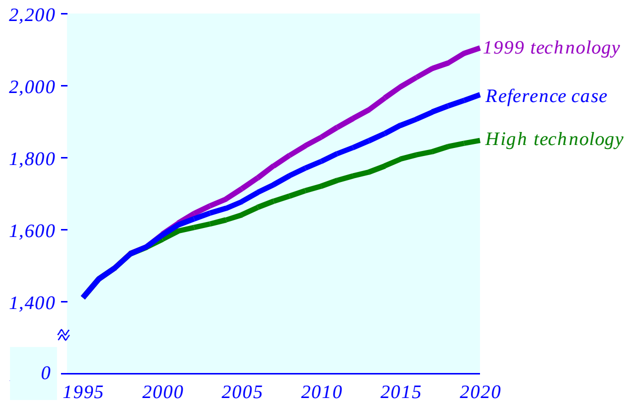


Figure 31. U.S. energy consumption in three cases, 1997-2020 (quadrillion Btu)



The lower energy consumption in the high technology case lowers carbon emissions from 1,975 million metric tons in the reference case in 2020 to 1,848 million metric tons (Figure 32). In the 1999 technology case, emissions increase to 2,105 million metric tons in 2020. About 30 percent, or 38 million metric tons, of the reduction in carbon emissions in the high technology case compared to the reference case results from lower electricity demand and generation. An additional 51 million metric tons of the reduction, or 40 percent, results from shifts to

Figure 32. U.S. carbon emissions in three cases, 1997-2020 (million metric tons)



more efficient or alternative-fueled vehicles in the transportation sector.

The high technology assumptions themselves do not guarantee acceptance and penetration in the market. Technologies must still be cost-effective as judged by the consumers, and penetration can be slowed by the relative turnover of the capital stock. In order to encourage more rapid penetration of advanced technologies, to reduce energy consumption or carbon emissions, it is likely that either market policies (for example, higher energy prices) or non-market policies (for example, new standards) may be required.