Issues in Focus

Introduction

This section of the *Annual Energy Outlook* provides in-depth discussions of topics related to specific assumptions underlying the reference case forecast. In particular, the discussions focus on new methods or data that have led to significant changes in modeling approaches for the reference case. In addition, this section provides a more detailed examination of alternative cases.

World Oil Price Cases

World oil prices in *AEO2005* are set in an environment where the members of OPEC are assumed to act as the dominant producers, with lower production costs than other supply regions or countries. Non-OPEC oil producers are assumed to behave competitively, producing as much oil as they can profitability extract at the market price for oil. As a result, the OPEC member countries will be able effectively to set the price of oil when they can act in concert by varying their aggregate production. Alternatively, OPEC members could target a fixed level of production and let the world market determine the price.

The behavior and ability of OPEC member countries to set the price of oil will be influenced by many factors about which there is considerable uncertainty. These factors include the forces that will drive world oil demand, such as the rate of economic growth in the developed and developing world and the degree to which oil demand is linked to economic growth. The behavior of each major non-OPEC producer and changes in technologies that use or find and extract oil also will be important. Each of these factors will also be influenced by the market strategy that the OPEC members choose for OPEC in the aggregate or for themselves. For example, a strategy targeting relatively low prices and high market share would reduce the risk that new oil conservation or development technologies might be developed. It also would reduce the incentive for individual OPEC members to exceed their output quotas and reduce the risk that world economic growth might be slowed. With such a strategy, OPEC members would face little risk of losing market power, but their revenues and profits would be relatively low.

Conversely, if OPEC members jointly limited production to maintain high prices and low market share, new oil conservation or exploration and production technologies might be developed. Such a strategy would also increase the incentive for individual OPEC members to exceed their output quotas, cause importing countries to enact oil consumption reduction policies, and increase the likelihood that world economic growth would be slowed. While this strategy could result in relatively high revenues and profits in the short term, it would also be a relatively high-risk strategy.

World Oil Prices in AEO2005

World oil prices in *AEO2005* are defined on the basis of "average refiner acquisition cost" of imported oil to the United States (IRAC). The IRAC price tends to be a few dollars less than the widely cited West Texas Intermediate (WTI) spot price, and in recent months it has been as much as 6 dollars a barrel lower than the WTI**.** For the first 11 months of 2004, WTI averaged $41.31 per barrel and IRAC averaged $36.28 per barrel (in nominal dollars).

Approach

The *AEO* develops world oil price scenarios through an iterative process that examines the reasonableness of candidate oil price paths and their impacts on world oil supply and demand. The *AEO* process also considers the stated OPEC basket price target range, as well as ongoing discussions among OPEC members regarding possible changes to it.

The *AEO2005* reference case assumes a moderate market strategy between low-price, low-risk market share maximization and high-price, high-risk profit maximization. Alternative cases, in which different oil market behaviors are assumed, are also considered in *AEO2005*, including the October oil futures case, high A and B world oil price cases, and a low world oil price case. As with all of the projections in *AEO2005*, the oil price forecasts do not represent an assessment of what will happen, but rather, an assessment of what might happen under various scenarios. Higher or lower price paths are possible, and short-term price volatility in oil markets, which *AEO* scenarios do not attempt to model, is likely to continue.

World Oil Demand. Key inputs for projecting world oil demand—for example, the worldwide demand for various energy services (heating, cooling, transportation, etc.)—are estimated using EIA's System for Analysis of Global Energy Markets (SAGE) [*74*]. SAGE is an integrated set of regional models that provides a technology-rich basis for estimating regional energy supply and demand. For each region, estimates of end-use energy service demands (e.g., car, commercial truck, and heavy truck road travel; residential lighting; steam heat requirements in the paper industry; etc.) are developed on the basis of economic and demographic projections. Projections of energy demand are estimated on the basis of each region's existing energy use patterns, the existing stock of energy-using equipment, and the characteristics of available new technologies, as well as new sources of primary energy supply.

While oil products are used for many energy services (i.e., heating, steam generation, electricity generation, etc.) and as industrial feedstocks, the major use of petroleum products is for transportation. As a result, the worldwide demand for transportation services is the key driver for oil demand. In turn, the demand for transportation services in the various regions and countries represented in SAGE is driven by the projected level of income per capita, complemented by other important region-specific factors, such as the state of the transportation infrastructure. For the industrialized countries with well-developed transportation networks, demand for transportation services is influenced primarily by projected income levels and lifestyles; for developing countries, the lack of transportation infrastructure can be a significant constraint.

Table 16 summarizes by region and country the projected average annual growth rates for real GDP and oil demand, and the resulting oil intensity, in the *AEO2005* reference case from 2003 to 2025 [*75*]. The table also shows region and country shares of world GDP and oil demand in 2003 and 2025. As shown, total world GDP is projected to grow at an average annual rate of 3.1 percent, with the developing and former Soviet Union (FSU) countries generally projected to grow at higher rates, while the industrialized countries generally grow at slower rates. Total world oil demand is projected to grow more slowly, at 1.9 percent annually. World oil intensity declines by 1.2 percent per year.

Because of the differences in projected growth rates for GDP and oil demand, the developing countries are expected to play a growing role in the world economy and oil markets. In 2003, the industrialized countries accounted for 77 percent of world GDP and 57 percent of total world oil consumption. It is projected that in 2025 real GDP in industrialized countries will account for 68 percent of world GDP and 48 percent of total oil demand. In contrast, developing countries are projected to account for 28 percent of world GDP in 2025, up from 20 percent in 2003. Similarly, oil demand in developing countries is projected to account for 45 percent of world oil demand in 2025, up from 36 percent in 2003.

Table 16. Projected growth in world gross domestic product, oil consumption, and oil intensity in the AEO2005 reference case, 2003-2025

	Real GDP			Oil consumption			Oil intensity		
	Percent of world GDP		Annual growth, 2003-2025 (percent)	Percent of world oil use		Annual growth, 2003-2025 (percent)	Oil use (thousand Btu) per 1997 U.S. dollar of GDP		Annual growth, 2003-2025 (percent)
Country/region	2003	2025		2003	2025		2003	2025	
Industrialized countries									
United States	29.3	29.3	3.1	25.6	23.6	1.5	4.0	2.9	-1.5
Canada	2.3	2.2	2.7	2.7	2.3	1.2	5.3	3.8	-1.5
Mexico	1.4	1.7	4.1	2.5	2.9	2.5	8.3	5.9	-1.5
Western Europe	28.6	23.3	2.1	17.9	13.0	0.5	2.9	2.0	-1.7
Japan	13.4	9.9	1.7	7.0	4.8	0.2	2.4	1.7	-1.5
Australia/New Zealand	1.7	1.7	3.0	1.3	1.4	2.2	3.5	3.0	-0.7
Total	**76.8**	**68.2**	**2.5**	**57.0**	**48.1**	**1.1**	**3.4**	**2.5**	**-1.4**
Former Soviet Union and Eastern Europe									
Former Soviet Union	2.1	2.6	4.1	5.2	5.4	2.0	11.5	7.3	-2.0
Eastern Europe	1.2	1.5	4.0	1.8	1.7	1.8	6.7	4.2	-2.1
Total	**3.3**	**4.1**	**4.1**	**7.0**	**7.1**	**1.9**	**9.7**	**6.2**	**-2.0**
Developing Countries									
China	4.1	7.5	5.9	7.0	10.6	3.9	7.7	5.0	-1.9
India	1.7	2.7	5.2	2.8	4.4	4.1	7.4	5.9	-1.1
South Korea	1.8	2.3	4.2	2.7	2.4	1.4	6.9	3.8	-2.7
Other Asia	4.0	5.3	4.4	7.2	8.8	2.9	8.3	6.0	-1.5
Middle East	1.9	2.1	3.7	7.0	7.5	2.2	17.3	12.7	-1.4
Africa	2.0	2.4	4.1	3.4	3.9	2.5	7.9	5.7	-1.5
South/Central America	4.5	5.5	4.1	5.9	7.1	2.8	6.0	4.6	-1.2
Total	**19.9**	**27.8**	**4.7**	**36.0**	**44.8**	**2.9**	**8.3**	**5.7**	**-1.7**
Total World	**100.0**	**100.0**	**3.1**	**100.0**	**100.0**	**1.9**	**4.6**	**3.5**	**-1.2**

The projected growing role of the developing countries in the world economy and oil markets makes understanding the impact of economic growth on oil demand critically important. The sensitivity of oil demand to income is often characterized by what economists refer to as the income elasticity of demand, defined as the percentage change in oil demand with respect to the percentage change in real income. A rough approximation of the relative sizes of income elasticities for the different countries and regions represented in SAGE can be calculated from Table 16 by dividing the 2003 to 2025 average annual growth in oil demand by the average annual growth in real GDP. This calculation yields an income elasticity of demand of approximately 0.6 for the developing countries, compared with 0.4 for the industrialized countries [*76*].

The implication that oil demand in developing countries will be more responsive to changes in economic and income growth is consistent with research, but there is a great deal of uncertainty about the level of response. The response of oil demand to income growth and changes in oil prices has been examined in a number of empirical studies. The estimates of income elasticities in those studies vary widely, depending on the time period under study, the groups of countries considered, and the econometric specifications used [*77*]. Although the empirical evidence is not conclusive, and the magnitude of income elasticity estimates varies widely, most studies have found that developing countries generally have higher income elasticities than the industrialized economies.

Studies have shown both greater and smaller responses in developing countries than is reflected in SAGE. For example, Gately and Huntington found that the income elasticity of demand for oil in developing countries ranged from 0.5 to 1.0, depending on the groups of developing countries being considered [*78*]. The Gately and Huntington study, as well as most other empirical studies, used historical data and employed a single-equation reduced-form framework relating oil demand changes to changes in income, or income per capita, and oil prices in various lag formulations.

Such formulations may not fully capture the changes that have occurred in world economies or technologies in recent years, nor reflect how these changes might affect the future. For example, in an era of increased globalization and rapid technology transfer across countries, empirical estimates derived from historical data and simplified model formulations may not fully capture the more rapid transfer of new, efficient technologies from the industrialized countries to the developing countries that is likely to occur in the future. In contrast, the inferred income elasticities approximated in this report are based on projections coming from a structural model that explicitly incorporates the technical and cost relationships projected to exist between energy service demands by end-use sectors and the supply of energy. The model also represents region-specific factors that may encourage or inhibit demand for oil, such as transportation infrastructure constraints that are likely to arise as developing economies grow. One key assumption is that vehicles sold in both developing and industrialized countries in the future will be more fuel efficient than they were in the past.

World Oil Supply. Once oil demand has been estimated by region and country, the levels of regional non-OPEC conventional and nonconventional oil production are developed to be consistent with the assumed world oil price path and assumptions regarding proved oil reserves, undiscovered oil, and reserve growth. The gap between projected world oil consumption and non-OPEC oil production determines the call on OPEC producers. Production from individual OPEC suppliers is estimated based on information regarding proved reserves, project development schedules, long-term development plans, and production economics in each country or region. Production capacity estimates reflect both projected levels of supply and historical utilization rates. Several Persian Gulf OPEC producers, including Saudi Arabia, Kuwait, and the United Arab Emirates, are assumed to have production capacity utilization rates of 90 to 95 percent, while non-OPEC producers are assumed to use all of their capacity. Other OPEC producers are assumed to fall between these extremes.

The growth in non-OPEC oil supplies has played a significant role in the erosion of OPEC's market share over the past three decades, as non-OPEC supply has become increasingly diverse. North America dominated growth in non-OPEC supply in the early 1970s, the North Sea and Mexico evolved as major producers in the 1980s, and much of the new production since the 1990s has come from Latin America, West Africa, and the former Soviet Union. Non-OPEC supply from proved reserves is expected to increase steadily from 48.8 million barrels per day in 2003 to 65.0 million barrels per day in 2025 in the reference case.

The expectation in the late 1980s and early 1990s was that non-OPEC production in the longer term would stagnate or decline gradually in response to resource constraints. The relatively low cost of developing oil resources in OPEC countries (especially those in the Persian Gulf region) was considered such an overwhelming advantage that non-OPEC production potential was viewed with considerable pessimism. In actuality, however, despite several periods of relatively low prices, non-OPEC production has risen every year since 1993, growing by more than 8.2 million barrels per day between 1993 and 2003. Three factors are generally given credit for the impressive resiliency of non-OPEC production: development of new exploration and production technologies, efforts by the oil industry to reduce costs, and efforts by governments in non-OPEC countries to promote exploration and development by encouraging outside investors with attractive financial terms.

It is expected that oil prices will remain high enough that non-OPEC producers will be able to continue to increase output profitably, producing an additional 6.8 million barrels per day by 2010 in the reference case when compared with 2003. Much of the increased non-OPEC production is expected to come from Africa and Central and South America.

No one doubts that fossil fuels are subject to depletion and that depletion leads to scarcity, which in turn leads to higher prices; however, there are many resources that are not heavily exploited because they cannot be produced economically at low prices and with existing technologies. With higher prices, the development of such resources could become profitable. Ultimately, a combination of escalating prices and technological enhancements can make more resources economical. Much of the pessimism about oil resources has been focused entirely on conventional resources. However, there are substantial nonconventional resources, including production from oil sands, ultra-heavy oils, gas-to-liquids technologies, coal-to-liquids technologies, biofuel technologies, and shale oil, which can serve as a buffer against prolonged periods of very high oil prices. Total nonconventional liquids production in 2025 is projected to be 5.7 million barrels per day in the reference case, up from 1.8 million barrels per day in 2003.

Comparison of Projections

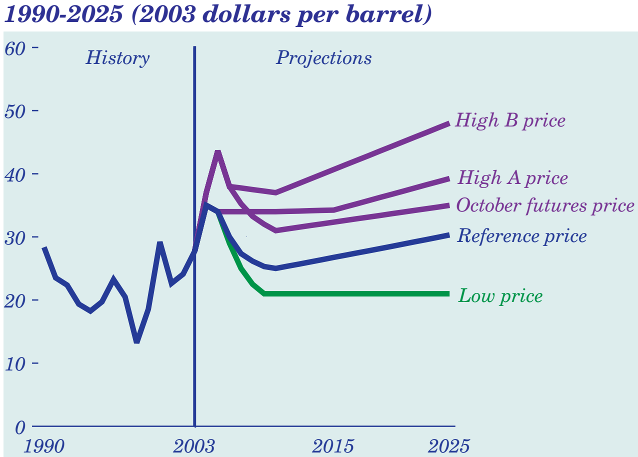
The world oil price cases in *AEO2005* are designed to address the uncertainty about the market behavior of OPEC. They are not intended to span the full range of possible outcomes. The cases are defined as follows:

- *Reference case.* Prices in 2010 are projected to be about $10 per barrel lower than current prices (2003 dollars) as both OPEC and non-OPEC producers add new production capacity over the next 5 years. After 2010, oil prices are projected to rise by about 1.3 percent per year, to more than $30 per barrel in 2025.
- *October oil futures case*. Prices in the near term rise through 2005, and then resume a growth trend similar to the reference case. The results of this case, which are similar to the reference case in the long term, are compared with the reference case results in the text box on page 44.
- *High A world oil price case*. Prices are projected to remain at about $34 per barrel through 2015 and then increase on average by 1.4 percent per year, to more than $39 per barrel in 2025.
- *High B world oil price case*. Projected prices continue to increase through 2005 to $44 per barrel, fall to $37 in 2010, and rise to $48 per barrel in 2025.
- *Low world oil price case*. Prices are projected to decline from their high in 2004 to $21 per barrel in 2009 and to remain at that level out to 2025.

World oil price projections in the five cases are shown in Figure 12. A detailed tabular summary and comparison of each of the oil price cases with the reference case is provided in Appendixes C and D.

Reference World Oil Price Case. In the reference case, the assumption is that the OPEC members will continue to demonstrate a disciplined production approach that reflects a strategy of price defense in which the larger producers are willing to increase or decrease production levels to maintain fairly stable prices (in real dollar terms) to discourage the development of alternative crude oil supplies or energy

Figure 12. World oil prices in the reference, October oil futures, high A, high B, and low oil price cases, 1990-2025 (2003 dollars per barrel)



The October oil futures case

The *AEO2005* reference case assumes that world crude oil prices will decline as consumption slows and producers increase their productive capacity and output in response to current prices. In October 2004, however, NYMEX oil futures prices implied that the average annual oil price in 2005 will exceed its 2004 level before falling back somewhat, to levels that still would be above those projected in the reference case. To evaluate the likely effects of that possible price path on the U.S. energy economy, *AEO2005* includes an October oil futures case, which is based on an extrapolation of oil prices loosely corresponding to the recent mid-term profile of prices on the NYMEX futures market.

In the October oil futures case, world crude oil prices are assumed to average $44 per barrel in 2005 (in 2003 dollars) before falling to about $31 per barrel in 2010—about $6 per barrel higher than the reference case projection. Prices are assumed to remain above those in the reference case over the entire projection and to be about $5 per barrel higher than the reference case projection in 2025, at $35 per barrel.

The *AEO2005* reference case and October oil futures case are based on different assumptions about oil production by the members of OPEC—higher in the reference case and lower in the October oil futures case—reflecting uncertainty about future levels of production from the Persian Gulf region. OPEC members are assumed to be the principal source of the marginal supply needed to meet increases in demand; consequently, OPEC member country production varies more than non-OPEC production in response to changes in demand requirements. OPEC member country production in 2025 is projected to be about 55 million barrels per day in the reference case and about 50 million barrels per day in the October oil futures case.

U.S. domestic consumption of petroleum in 2025 is projected to be slightly lower in the October oil futures case than in the reference case (27.3 million and 27.9 million barrels per day, respectively). Most of the difference is the result of lower projected demand for transportation fuels in the October oil futures case. In 2025, total demand for petroleum in the U.S. transportation sector is projected to be 19.5 million barrels per day in the October oil futures case, compared with 19.8 million barrels per day in the reference case.

Higher oil prices in the October oil futures case are projected to have a small impact on U.S. economic activity, primarily in the first 5 years of the forecast. From 2005 to 2010, U.S. GDP is a cumulative $194 billion (about 0.3 percent) lower in the October oil futures case than in the reference case. By 2025, however, the GDP projections are nearly identical in the reference and October oil futures cases. The projections for electricity and natural gas prices are not appreciably different in the two cases, which differ primarily in their projections for the delivered price of petroleum products, with impacts mainly in the transportation sector.

In response to higher oil prices, total domestic petroleum supply in 2025 is projected to be higher in the October oil futures case (9.3 million barrels per day) than in the reference case (8.8 million barrels per day), which in combination with the lower demand projection leads to a lower projected level of total petroleum imports in the October oil futures case. Including crude oil and refined products, total net imports in the October oil futures case (18.0 million barrels per day) are 1.1 million barrels per day lower than in the reference case (19.1 million barrels per day in 2025). As a result, the import share of total U.S. petroleum demand is 66 percent in the October oil futures case, compared with 68 percent in the reference case. In 2003, the import share of U.S. demand was 56 percent.

In the U.S. energy market, the transportation sector consumes about two-thirds of all petroleum products and the industrial sector about one-quarter. The remaining 10 percent is divided among the residential, commercial, and electric power sectors. With limited opportunities for fuel switching in the transportation and industrial sectors, large price-induced changes in U.S. petroleum consumption are unlikely, unless changes in petroleum prices are very large or there are significant changes in the efficiencies of petroleum-using equipment. The results of the October oil futures case indicate that sustained increases in world oil prices would have to be significantly greater than those assumed for this case in order to have a major impact on projected U.S. energy use.

sources, allow for continued robust worldwide economic growth, and maintain compliance with quotas, particularly by smaller OPEC producers. It is also assumed that OPEC producers will achieve sufficient oil revenues to expand production capacity enough to keep prices in a range of $27 to $30 per barrel in 2003 dollars, near the high end of the current OPEC price target range. Their current level of proven reserves (870 billion barrels) is sufficient to meet the implied production levels.

In the medium term, there is enough resource potential in non-OPEC countries to allow non-OPEC oil production to continue growing. Over the longer term, it is estimated that it will be harder for non-OPEC producers to continue to increase production. Assuming reference case prices, the search for alternatives and unconventional liquids will be limited, while demand will continue to grow. Therefore, OPEC members will have to make up the production difference (Figure 13). To satisfy the remaining global demand for oil at the given reference case prices, OPEC production will have to increase from 30.6 million barrels per day to 55.1 million barrels per day, an average annual increase in production of 2.7 percent. This is projected to result in an increase in OPEC's market share from 39 percent in 2003 to 46 percent in 2025, as cheaper sources of non-OPEC oil are depleted.

Table 17 summarizes the main features of the reference case in terms of cumulative production volumes, cumulative revenues, and the sum of the discounted cumulative revenues (at a 5-percent discount rate) from 2003 to 2025 [*79*]. The OPEC and non-OPEC countries are aggregated by major regions.

The reasoning behind the assumed prices and production patterns in the reference case can be questioned. If OPEC members have sufficient market power and cohesiveness to set world prices, why would they not try to set higher oil prices? If OPEC comprised a group of producer countries with similar oil reserves, resource depletion time horizons, geopolitical concerns, and no fear of alternatives to oil at higher prices, then a more limited production strategy that maximizes economic profits in the short to medium term would appear more plausible. In the absence of these conditions, however, and given the difficulty of enforcing tight production goals to limit output, a reasonable strategy is to maintain stable prices that discourage oil alternatives while limiting the risk that member countries will exceed their quotas.

Another issue is whether OPEC members will be able to finance the investments needed to expand their output as projected in the reference case. While some OPEC producer countries are currently closed to foreign involvement in the exploration and development of oil resources, it is expected that they will be able to attract foreign capital, if needed, while retaining

Figure 13. OPEC oil production in four world oil price cases, 1990-2025 (million barrels per day)

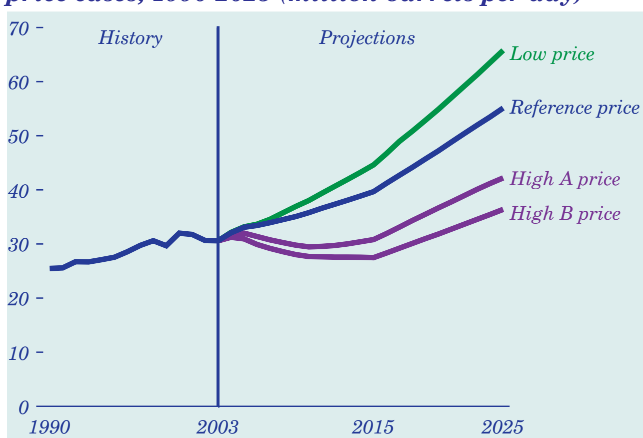


Table 17. Key projections in the reference case, 2003-2025

	World oil production (billion barrels)				World oil revenues (trillion 2003 dollars)	
Country/region	2003	2025	Cumulative, 2003-2025	Average annual growth, 2003-2025 (percent)	Cumulative, 2003-2025	Cumulative discounted value (at 5%), 2003-2025
Non-OPEC						
Industrialized countries	8.6	9.0	208.3	0.2	5.9	3.4
Former Soviet Union and Eastern Europe	3.8	6.5	123.2	2.5	3.5	1.9
Developing countries	5.4	8.2	157.5	2.0	4.4	2.5
Total	**17.8**	**23.7**	**489.0**	**1.3**	**13.8**	**7.9**
OPEC						
Middle East	7.6	14.0	235.4	2.8	6.6	3.7
Other OPEC	3.5	6.1	107.6	2.5	3.0	1.7
Total	**11.2**	**20.1**	**343.1**	**2.7**	**9.7**	**5.4**
Total World	**29.0**	**43.9**	**832.1**	**1.9**	**23.4**	**13.2**

sovereignty over their energy resources. The markets for financial capital have provided sufficient resources in similar situations in the past, especially when there are strong incentives from both the demand and supply sides. The current experience of China, which did not attract much financial capital in the past, is an example of what can happen with the appropriate economic incentives or when the motivations are strong. Other historical examples include the flow of foreign capital to Latin America in the 1980s and East Asia in the 1990s.

There are also factors that may encourage countries in the Middle East to open up their energy sectors to foreign participation in one form or another. For example, Saudi Arabia, for some time now, has been lobbying to gain admission to the World Trade Organization. One of the conditions that Saudi Arabia needs to fulfill to gain entry is to open up its economy, especially its financial markets. The opening up of the United Arab Emirates to foreign financial capital and its creation of an export trade zone provide another example of how the economic environment can change.

High A World Oil Price Case. In the high A world oil price case, the OPEC countries in aggregate are assumed to maintain a relatively constant share of the world oil market. There are a number of ways that a constant market share for the OPEC countries might result over the projection period. First, more cohesion among OPEC members could begin to place greater emphasis on short-term profit maximization, with more control on member output, as might occur if a mechanism were devised to enable stricter enforcement of quotas. This cohesion might be reinforced by a perception that the incremental non-OPEC oil resource development costs are quite high and that the resource base is limited, and thus that there is less risk from non-OPEC producers in the long term. Second, some large producer countries in OPEC might not be able to finance sufficient development and enlargement of productive capacity because of competing social infrastructure demands on government budgets.

In this case, the world oil price would tend to reflect the projected incremental cost of non-OPEC oil and rise faster than in the reference case—from about $28 per barrel in 2003 to more than $39 per barrel in 2025 in real terms, an average annual increase of 1.6 percent from 2003 to 2025. As a result of higher world oil prices, world oil demand in 2025 is projected to be lower in the high A world oil price case than in the reference case (115 million barrels per day and 120 million barrels per day, respectively). Table 18 summarizes the main features of the high A world oil price case.

For OPEC members, cumulative production of almost 280 billion barrels in the high A world oil price case is projected to bring in $9.9 trillion (in 2003 dollars), as compared with cumulative production of 343 billion barrels and revenues of $9.7 trillion in the reference case. Although the high A world oil price case appears to be more attractive to OPEC producers than the reference case in terms of economic profits, the sustainability of the higher prices over the projection period is uncertain. Higher prices would create greater incentive for OPEC countries to exceed quotas, greater likelihood of increased conventional and unconventional oil production in non-OPEC countries, and greater possibility of increased conservation measures in oil-consuming countries, induced both by higher prices and by public policy measures.

Table 18. Key projections in the high A world oil price case, 2003-2025

	World oil production (billion barrels)				World oil revenues (trillion 2003 dollars)	
Country/region	2003	2025	Cumulative, 2003-2025	Average annual growth, 2003-2025 (percent)	Cumulative, 2003-2025	Cumulative discounted value (at 5%), 2003-2025
Non-OPEC						
Industrialized countries	8.6	10.0	221.1	0.7	7.8	4.6
Former Soviet Union and Eastern Europe	3.8	7.1	132.2	2.9	4.7	2.7
Developing countries	5.4	9.2	170.4	2.4	6.0	3.5
Total	**17.9**	**26.3**	**523.7**	**1.8**	**18.5**	**10.8**
OPEC						
Middle East	7.6	10.5	189.8	1.5	6.7	3.9
Other OPEC	3.5	4.9	90.6	1.5	3.2	1.9
Total	**11.1**	**15.4**	**280.4**	**1.5**	**9.9**	**5.8**
Total World	**29.0**	**41.7**	**804.1**	**1.7**	**28.4**	**16.6**

While the *AEO* cases are developed under the assumption of unchanged policy in consuming countries, major oil exporters may expect that higher prices would spur policy responses in oil-importing nations. Based on these considerations, economically rational producers would be likely to apply higher discount rates when evaluating the revenue stream associated with the high A world oil price case than that associated with the reference case. Taking this difference into account, key OPEC producers might accept the reference price case.

High B World Oil Price Case. There is a great deal of uncertainty about the size and availability of crude oil resources, particularly conventional resources, the adequacy of investment capital, and geopolitical trends. While the high A world oil price case tries to reflect the uncertainty in some of these variables, some analysts argue that the higher prices seen in recent years will be sustained and represent a fundamental change in the market. The high B world oil price case was completed to evaluate the impact of world oil prices that remain close to current levels for the foreseeable future.

The high B world oil price case assumes a continued rise in prices through 2005, followed by a gradual decline to 2010 and then strong increases through 2025. The near-term prices reflect the trends observed in oil futures on the NYMEX for WTI during October 2004, where crude oil futures prices exceeded 2004 levels in 2005 before falling back somewhat, but to levels well above those projected in the *AEO2005* reference case. The world oil price in the high B case is assumed to be $2 higher than in the reference case in 2004, or $37 per barrel, to grow to about $44 per barrel in 2005 before falling to $37 in 2010, and then to rise to $48 per barrel in 2025, compared with $30 in the reference case and $39 in the high A world oil price case.

The high B world oil price case reflects an assumption that OPEC producers will be less able or willing to expand their productive capacity and that their output growth will be constrained considerably (Table 19). As a result, the OPEC members are projected to lose market share over time, in contrast to the high A world oil price case, where their market share remains constant over time. OPEC member country production is projected to grow from 30.6 million barrels per day in 2003 to 36.6 million barrels per day in 2025, compared with 55.1 million barrels per day in the reference case and 42.4 million barrels per day in the high A world oil price case. The worldwide impacts on energy supply in the high B case are more uncertain because of limited experience with sustained periods of high world oil prices. Nevertheless, roughly one-half of the difference between OPEC member country production in the reference and high B world oil price cases is projected to be made up for by non-OPEC countries (Figure 14). The remaining difference reflects the reduction in oil demand resulting from higher prices, as well as increased production of synthetic oil from coal and natural gas and nonconventional liquids.

Undiscounted cumulative revenues from OPEC member country production in the high B world oil price case exceed those in the reference and high A world oil price cases, despite lower production; however, the high B case is projected to result in significant impacts on world energy demand and alternative sources of supply, including increased production from synthetic fuels. In addition, strong cohesiveness among OPEC members would be required to maintain the strict production quotas implicit in the high

Table 19. Key projections in the high B world oil price case, 2003-2025

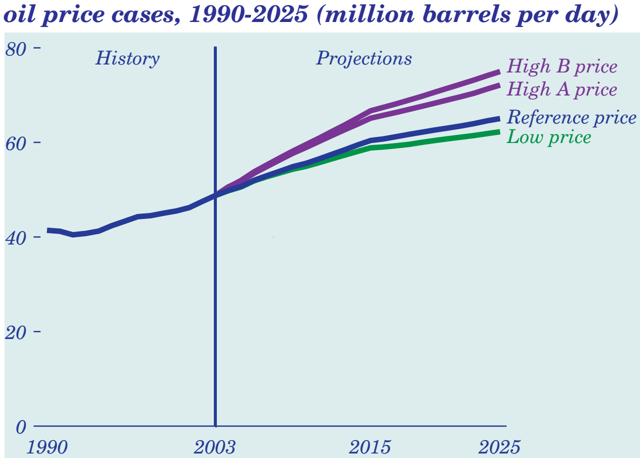
	World oil production (billion barrels)				World oil revenues (trillion 2003 dollars)	
Country/region	2003	2025	Cumulative, 2003-2025	Average annual growth, 2003-2025 (percent)	Cumulative, 2003-2025	Cumulative discounted value (at 5%), 2003-2025
Non-OPEC						
Industrialized countries	8.6	10.2	225.0	0.8	9.2	5.4
Former Soviet Union and Eastern Europe	3.8	7.2	133.4	2.9	5.5	3.1
Developing countries	5.4	9.5	173.1	2.6	7.2	4.1
Total	**17.9**	**26.9**	**531.5**	**1.9**	**21.9**	**12.6**
OPEC						
Middle East	7.6	9.0	171.9	0.8	7.1	4.2
Other OPEC	3.5	4.3	83.3	1.0	3.4	2.0
Total	**11.1**	**13.4**	**255.2**	**0.9**	**10.5**	**6.2**
Total World	**29.0**	**40.3**	**786.7**	**1.5**	**32.4**	**18.8**

B case. As a result, the uncertainty and risk associated with this case for individual OPEC members suggest that a higher rate is appropriate for discounting the projected revenue stream.

The projections in the high B world oil price and reference cases are compared in the text box on page 49. It is important to stress the uncertainties and limitations of this case. The market conditions in the high B world oil price case fall outside the range of experience best represented in NEMS. In particular, some of the modeling uncertainties and limitations about the case are as follows:

- The level of economic production of oil from both conventional sources and unconventional sources (such as oil sands) is subject to considerable uncertainty, particularly with sustained oil prices at much higher levels than in the reference case.
- The effects of global competition for natural gas through pipelines, LNG, and gas-to-liquids (GTL) are highly uncertain in an environment of high sustained oil prices. For example, stranded gas (gas production at sites without access to pipelines) that might otherwise be economical to export as LNG could potentially become economical to process as GTL. These impacts on world natural gas supply cannot be evaluated endogenously with the present versions of EIA's U.S. and global energy models; however, an adjustment to the assumed cost profile of LNG imports to the United States has been incorporated to reflect the potential market impact. As model development is able to continue, additional analytical capability in this area would be a high priority.
- Prospects for synthetic petroleum—GTL and coal-to-liquids (CTL) may be constrained by plant siting issues that have not been investigated, such as waste disposal and limited water supplies.
- The worldwide economic and political response to a regime of prolonged high oil prices is uncertain, as is the long-term effect on domestic economic growth.
- EIA's modeling of petroleum consumption reflects observed patterns of use and consumer preferences, as well as existing and foreseeable technologies. Consumer and manufacturer behavior in the face of sustained high oil prices may depart from the patterns on which the model is based. For example, there could be shifts to smaller, more efficient vehicles, more penetration of alternative-fuel vehicles, and a shift in the demand for vehicular travel to other travel modes, such as from truck to rail freight.
- High world oil prices and high natural gas prices may spur unforeseen technological innovation and adoption, but quantifying these possibilities remains a challenge.

Figure 14. Non-OPEC oil production in four world oil price cases, 1990-2025 (million barrels per day)



Low World Oil Price Case. The low world oil price case reflects a future market where all oil production becomes more competitive and plentiful. There are several ways in which this could come about. First, the OPEC countries could become less cohesive, with each producer attempting to sell as much of its productive capacity as the market will allow. In this sense, the low world oil price case is exactly the opposite of the high A world oil price case. Another possibility would be a decline in the costs of non-OPEC oil production or the viable development of competitive alternatives. To forestall the penetration of alternatives and other sources of competition, OPEC would lower its price band and increase production.

The world oil price (in 2003 dollars) is projected to decline from about $28 per barrel in 2003 to $21 per barrel in 2009 in the low world oil price case, and to stay at that level through 2025. As a result of increased competition between OPEC members or a conscious attempt to increase market share, the market share of OPEC's member countries increases from 39 percent in 2003 to 51 percent in 2025. Within OPEC, nearly all producers, except for Indonesia, which has limited remaining resources, are projected to increase production at an average annual rate of 3 percent or higher over the 2003 to 2025 period. The average annual growth in production by OPEC members over the same period is 3.5 percent. The low world oil prices in this case cause world oil demand to increase from 80 million barrels per day in 2003 to

Comparison of projections in the reference and high B world oil price cases

Higher crude oil prices spur greater exploration and development of domestic oil supplies, reduce demand for petroleum, and slow the growth of oil imports in the high B world oil price case compared to the reference case. Total domestic petroleum supply in 2025 is projected to be 2.2 million barrels a day (25 percent) higher in the high B case than in the reference case. Production in the high B case includes 1.2 million barrels a day in 2025 from synthetic petroleum fuel produced from coal and natural gas. Total net imports in 2025, including crude oil and refined products, are reduced from 19.1 million barrels a day in the reference case to 15.2 in the high B case. As a result, the projected import share of total U.S. petroleum demand in 2025 is 58 percent in the high B world oil price case, compared with 68 percent in the reference case. In 2003, the import share of U.S. petroleum demand was 56 percent.

With the steep, prolonged rise in crude oil prices in the high B world oil price case, the worldwide potential for natural gas and coal-based synthetic fuels would become viable, with implications for imported U.S. supplies of LNG. In the reference case, the United States is expected to become increasingly dependent on LNG, with imports projected to increase from 0.4 trillion cubic feet in 2003 to 6.4 trillion cubic feet in 2025. In the high B case, GTL conversion of stranded natural gas could compete favorably with liquefaction, thus reducing the potential supply of LNG worldwide. As a result, LNG supplied to the United States is projected to be priced higher in the high B world oil price case, leading to higher average end-use natural gas prices than in the reference case and to a 51-percent reduction in projected imports of LNG in 2025. The projected average *delivered* price of natural gas in 2025 (in 2003 dollars) is $7.35 per thousand cubic feet in the high B world oil price case, compared with $6.77 in the reference case.

The higher oil and natural gas prices in the high B world oil price case result in a greater reliance on domestic gas supply, along with a reduction in the projected growth of natural gas consumption. Domestic dry gas production in 2025 in the high B case increases to 23.5 trillion cubic feet, 8 percent higher than the reference case projection of 21.8 trillion cubic feet. In addition, the high price of oil in the high B case results in favorable economics for GTL domestically, leading to an additional 0.7 trillion cubic feet of natural gas consumption for GTL in 2025, offsetting some of the reduction in end-use demand that would result from higher natural gas prices.

The higher natural gas prices in the high B world oil price case would promote greater use of coal technologies for new electricity generation plants, leading to an increase in projected coal consumption of 69 million short tons in 2025 compared to the reference case. In addition, CTL technology to produce petroleum fuels is expected to become economical in the high B world oil price case, resulting in additional coal consumption of 209 million short tons in 2025.

CTL plants are assumed to employ integrated gasification and combined-cycle power generation to produce synthesis gas, process steam, and electric power. CTL plants are considered to be combined heat and power plants, supplying surplus electricity as well as power for on-site use. As a result, an increase of 25 gigawatts of generating capacity from CTL plants is projected in the high B world oil price case. In aggregate, CTL plants are estimated to produce 1 million barrels a day of synthetic liquid fuel in 2025 in the high B world oil price case.

U.S. petroleum demand is reduced in the high B world oil price case, but the modest response to the price changes reflects the limited opportunities for fuel switching in the transportation and industrial sectors, which account for about 90 percent of U.S. oil consumption. Total petroleum consumption is projected to change by only 3 percent in 2010, compared to the reference case, despite a 22-percent higher average price of refined petroleum in 2010. In 2025, petroleum demand is 6 percent lower in the high B world oil price case, and average refined petroleum prices are 32 percent higher.

About two-thirds of the difference in projected petroleum consumption between the reference and high B world oil price cases in 2025 is represented by gasoline. There is very little difference between the projections of demand for transportation uses of diesel and jet fuel, which together accounted for one-third of the petroleum used in the transport sector in 2003. The demand for diesel fuel to move freight in trucks, rail, and shipping is relatively insensitive to price changes, as the equipment used is long-lived and the prospects of efficiency improvements for freight carriers are more limited than

(continued on page 50)

Comparison of projections in the reference and high B world oil price cases (continued)

those for passenger transportation. In addition, there is some projected increase in rail and shipping in the high B world oil price case as a result of increased coal use in the electricity sector, offsetting some of the fuel saved by efficiency improvements in the freight truck fleet. Potential energy savings beyond those projected in the high B world oil price case would be possible if there were greater shifts among modes of travel, such as increased use of rail in place of trucking.

The demand for jet fuel is expected to be insensitive to price increases through 2025, as air travel growth is constrained by the availability of airport capacity in that time frame. The changes in fuel costs are unlikely to bring air travel demand down below the limits imposed by available airport capacity, eliminating much of the expected price response. The reduction in jet fuel between the reference and the high B world oil price cases, 1.6 percent in 2025, occurs primarily due to adoption of technology to increase aircraft efficiency.

Growth in projected gasoline demand in the high B world oil price case is lower than the reference case, as consumers respond to higher increased fuel costs by reducing the number of vehicle miles traveled and by purchasing more efficient automobiles. The projected price of gasoline in 2025 in the high B world oil price case is $2.01 a gallon (2003 dollars), compared to $1.59 in the reference case. As a result, average fuel economy of new, light-duty vehicles in 2025 increases from 26.9 miles per gallon in the reference case to 28.2 in the high B world oil price case. Even greater fuel economy improvements might occur under a high price scenario if consumers and manufacturers departed from recent trends and shifted to smaller, less powerful vehicles, or if there was a greater penetration rate of hybrid and diesel vehicles than is projected. However, at gasoline prices at or below $2.00 a gallon, significant changes in consumer behavior are not expected.

The U.S. economy is sensitive to oil price spikes, and several recessions have followed supply disruptions in recent decades; however, gradual changes in oil prices are less damaging to long-term economic growth, because the economy has more time to adjust. The projected impact on real GDP in the high B world oil price case, compared to the reference case, is $53 billion (2000 dollars) in 2010 (0.4 percent) and $32 billion in 2025 (0.2 percent). The macroeconomic results suggest that the U.S. economy would continue to fare well in the face of rising oil prices, provided that prices rose gradually over a long period of time; however, this analysis does not consider the potential impacts on the United States of worldwide economic disruption that might occur as a result of sustained high oil prices.

128 million barrels per day in 2025, an average annual increase of 2.2 percent.

Given the projected state of technology, projected reserves, and their relatively higher cost structures, non-OPEC producers would be expected to increase output at a slower rate in the low world oil price case than in the reference case (Figure 14). Starting from a production level of 49 million barrels per day in 2003, non-OPEC oil output is projected to grow at an average annual rate of 1.1 percent in the low price case, to 62 million barrels per day in 2025. Table 20 summarizes the main features of the low world oil price case.

The low oil price case is the most favorable of the *AEO2005* oil price cases in terms of economic welfare, because the world oil price is projected to be closer to its marginal cost. It is less favorable, however, from the producers' point of view. Relative to the reference case, OPEC members would end up producing 11 percent more oil over the 2003 to 2025 period and earning roughly 11 percent less in cumulative revenues. Further, with a decline in oil prices there would be less exploration activity at the margin, a tendency for more cohesion in OPEC, and lower penetration of alternative fuels.

Changing Trends in the Bulk Chemicals and Pulp and Paper Industries

Compared with the experience of the 1990s, rising energy prices in recent years have led to questions about expectations of growth in industrial output, particularly in energy-intensive industries. Given the higher price trends, a review of expected growth trends in selected industries was undertaken as part of the production of *AEO2005*. In addition, projections for the industrial value of shipments, which were based on the Standard Industrial Classification (SIC) system in *AEO2004*, are based on the North American Industry Classification System (NAICS) in *AEO2005*. The change in industrial classification leads to lower historical growth rates for many industrial sectors. The impacts of these two changes are

Table 20. Key projections in the low world oil price case, 2003-2025

Country/region	World oil production (billion barrels) 2003	2025	Cumulative, 2003-2025	Average annual growth, 2003-2025 (percent)	World oil revenues (trillion 2003 dollars) Cumulative, 2003-2025	Cumulative discounted value (at 5%), 2003-2025
Non-OPEC						
Industrialized countries	8.6	8.5	202.8	0.0	4.7	2.9
Former Soviet Union and Eastern Europe	3.8	6.3	121.1	2.3	2.7	1.6
Developing countries	5.4	7.9	153.8	1.8	3.5	2.1
Total	**17.8**	**22.7**	**477.8**	**1.1**	**10.9**	**6.5**
OPEC						
Middle East	7.6	16.9	264.0	3.7	5.9	3.4
Other OPEC	3.5	7.1	117.7	3.2	2.6	1.5
Total	**11.2**	**24.0**	**381.7**	**3.5**	**8.6**	**4.9**
Total World	**29.0**	**46.7**	**859.5**	**2.2**	**19.5**	**11.4**

highlighted in this section for two of the largest energy-consuming industries in the U.S. industrial sector—bulk chemicals and pulp and paper.

Output growth rates for the pulp and paper industry and the bulk chemical industry have been revised downward in *AEO2005* to align better with historical trends. Models for both industries in NEMS have also been revised to reflect recent trends in their specific production processes. In combination, these changes have had an important impact on the *AEO2005* forecast for industrial energy consumption.

The scope of activities included in the industrial sector (which includes agriculture, mining, construction, and manufacturing) and how they are defined have changed with the move to NAICS. For example, publishing, logging, and manufacturers' administrative and auxiliary services that are not co-located with manufacturing establishments are no longer covered in the manufacturing sector but are now included in the commercial sector. Under NAICS, the manufacturing sector is about 3 percent smaller in terms of value and 4 percent smaller in terms of employment than under SIC in 1997, the only year for which economic census data are available for both classification systems.

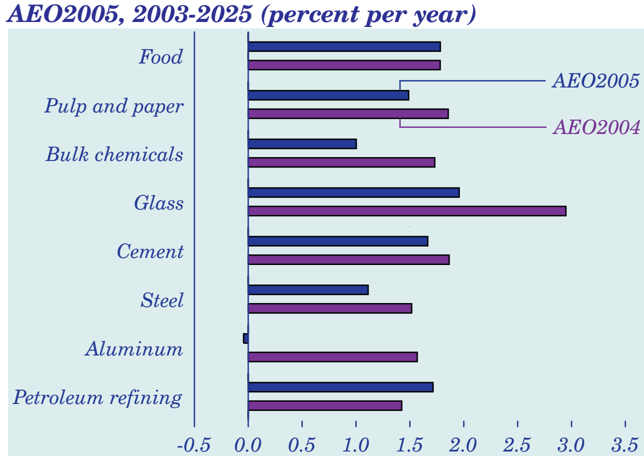
The *AEO2005* industrial forecast reflects both changes in economic conditions and changes in historical growth rates as a result of the move from SIC to NAICS. The projected growth rates for most energy-intensive industries are lower in *AEO2005* than in *AEO2004*, in part because the historical growth rates have been revised downward. Figure 15 compares the growth rates projected for selected energy-intensive industries in *AEO2005* and *AEO2004*.

Pulp and Paper

AEO2004 projected that paper final product would grow by an average of 1.9 percent annually from 2003 to 2025; however, the intermediate steps in the industry, and the energy use associated with them, were expected to grow at different rates as the mix of technologies changed and costs shifted. For example, between 2003 and 2025, kraft pulping was projected to grow by 2.1 percent per year while semi-chemical pulping grew by 0.9 percent per year. Mechanical pulping was projected to decline by 0.5 percent per year over the same period.

From 1983 to 2000, paper and board production grew by 2.1 percent per year while total pulping grew by only 1.1 percent per year. Although long-term data for the individual pulping steps is limited, kraft pulping, because of its superior technology [*80*], is the primary pulping method, accounting for 86 percent of

Figure 15. Projected growth in output for energy-intensive industries in AEO2004 and AEO2005, 2003-2025 (percent per year)



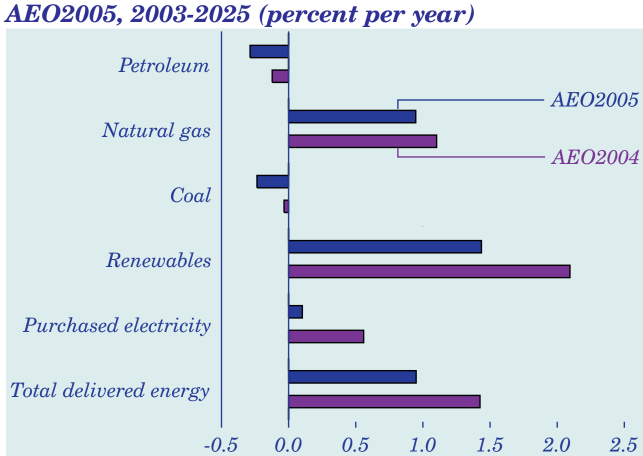
virgin pulping in 2002. Between 1996 and 2002, kraft pulping increased while semi-chemical pulping declined, and mechanical pulping dropped by more than 20 percent [*81*].

Growth in final paper and board production, coupled with slower growth or a decline in the intermediate pulping steps, is made possible by increases in recovered paper and imports of market pulp. Consumption of recovered paper at paper and board mills increased by 5 percent annually from 1983 to 2002, and the United States has gone from being a net exporter of market pulp in 1997 to a net importer in 2002, importing about 15 percent more than it exports [*82*].

The *AEO2004* results were reviewed relative to the trends outlined above, and revisions were made as necessary. As a result of the changes made and a lower forecast of growth in final industrial production in *AEO2005*, waste pulping, which consists of recovered paper and market pulp, is projected to grow by 2.0 percent per year from 2003 to 2025; mechanical pulping is projected to decline by 0.8 percent per year; and semi-chemical and kraft pulping are projected to grow by 0.7 percent per year and 1.4 percent per year, respectively. Pulp and paper output is projected to grow by 1.5 percent per year.

The most notable impact of these revisions and updates is that the projected growth of purchased electricity for the pulp and paper sector falls to only 0.1 percent per year in *AEO2005*, from 0.6 percent per year in *AEO2004* (Figure 16). The use of all fuels in the pulp and paper industry is projected to grow more slowly (or decline faster) in *AEO2005* than in *AEO2004*. Total energy consumption for the pulp and paper industry is projected to grow at an annual rate of 0.9 percent per year from 2003 to 2025 in *AEO2005*, compared with 1.4 percent per year in *AEO2004*.

Figure 16. Projected growth in energy consumption for the pulp and paper industry in AEO2004 and AEO2005, 2003-2025 (percent per year)

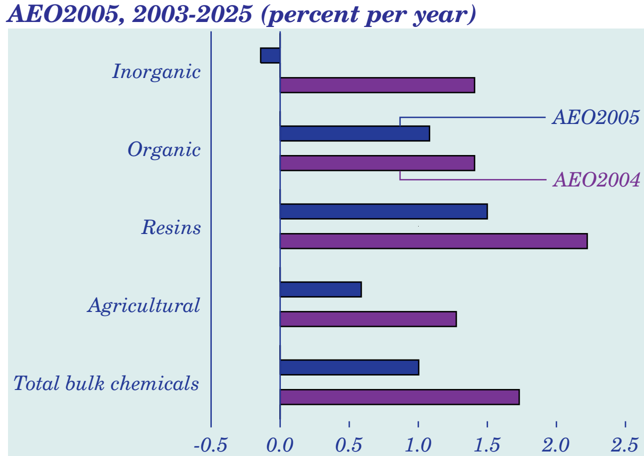


Bulk Chemicals

The bulk chemical industry is dependent on natural gas and petroleum as material inputs (feedstocks) and as fuels for heat and power. The bulk chemical industry model used for *AEO2005* was revised to address separately the four subsectors of the bulk chemical industry: inorganic, organic, resins, and agricultural chemicals [*83*]. Figure 17 compares the projected output growth rates for each component of the bulk chemical industry in *AEO2004* and *AEO2005*.

The growth rate for the total bulk chemical industry is projected to be 1.0 percent per year in *AEO2005*, compared with 1.7 percent per year in *AEO2004*. The largest changes are for the inorganic and agricultural chemicals components of the bulk chemical industry. The inorganic chemicals industry is a mature industry [*84*] that has grown slowly over the past several years. Its limited growth prospects are better represented in *AEO2005*, where the projected growth rate for inorganic chemicals is close to zero as compared with 1.4 percent per year in *AEO2004*. The agricultural chemicals subsector, which includes the production of nitrogenous fertilizers, has faced increased competition from foreign suppliers due to relatively high U.S. natural gas prices [*85*]. The *AEO2005* forecast reflects the current competitive situation. This update reduced projected growth from 1.3 percent per year in *AEO2004* to 0.6 percent per year in *AEO2005*. The organic and resins components have exhibited a tendency toward increasing use of imports of energy-intensive intermediate products in preference to domestically manufactured products [*86*], and that tendency is reflected in a lower assumed energy intensity for new or replacement plant.

Figure 17. Projected output growth for components of the bulk chemicals industry in AEO2004 and AEO2005, 2003-2025 (percent per year)



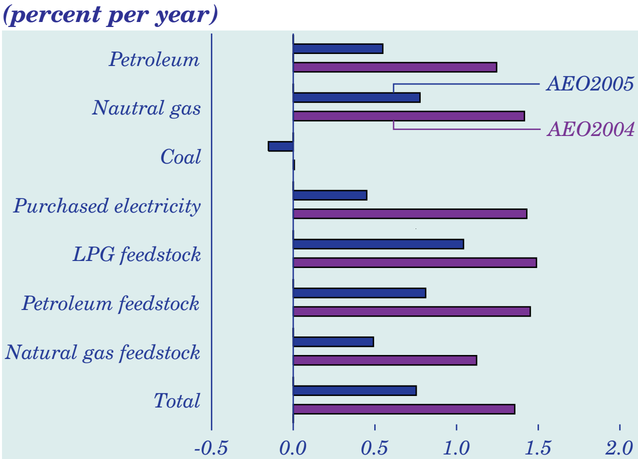
The combination of lower projected output growth and a shift to less energy-intensive production processes leads to lower projected growth in energy consumption for the bulk chemical industry in *AEO2005* than was projected in *AEO2004* (Figure 18). Despite these changes, however, the bulk chemical industry remains the largest energy-consuming industry in the industrial sector. In 2003, the bulk chemical industry consumed 6.3 quadrillion Btu of energy (including feedstocks), and that total is projected to grow to 7.5 quadrillion Btu in 2025, about 1 quadrillion Btu less than was projected in *AEO2004*. Feedstock consumption is projected to increase from 3.5 quadrillion Btu in 2003 to 4.3 quadrillion Btu in 2025 in the *AEO2005* forecast, 0.4 quadrillion Btu less than was projected in *AEO2004*.

In summary, the transition from SIC to NAICS, reduced rates of output growth, and revised modeling have reduced the *AEO2005* projection of industrial energy consumption in 2025 by 2.6 quadrillion Btu (8 percent) from the *AEO2004* projection. Lower natural gas consumption accounts for about two-thirds of the difference between the two projections.

Fuel Economy of the Light-Duty Vehicle Fleet

The U.S. fleet of light-duty vehicles consists of cars and light trucks, including minivans, sport utility vehicles (SUVs) and trucks with gross vehicle weight less than 8,500 pounds. The fuel economy of light-duty vehicles is regulated by the CAFE standards set by NHTSA. Currently, the CAFE standard is 27.5 miles per gallon (mpg) for cars and 20.7 mpg for light trucks. The most recent increase in the CAFE standard for cars was in 1990, and the most recent increase in the CAFE standard for light trucks was in 1996.

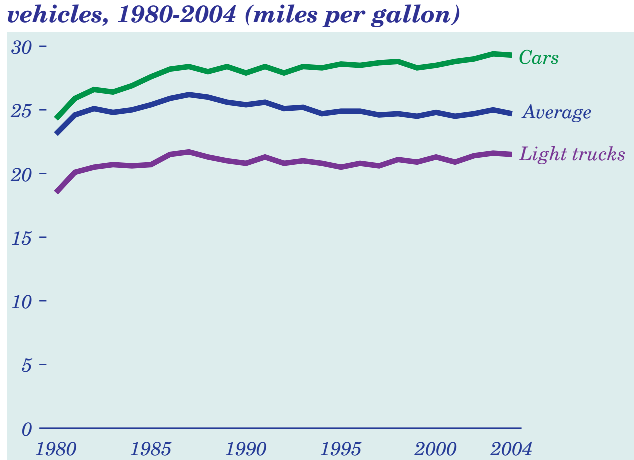
Figure 18. Projected growth in energy consumption for the bulk chemicals industry by energy source in AEO2004 and AEO2005, 2003-2025 (percent per year)



There has been little improvement in the average fuel economy of new cars and light trucks sold in the United States over the past 15 years (Figure 19), but the combined average fuel economy for all new light-duty vehicles has declined steadily because of an increase in sales of light trucks. Since 1987, the average fuel economy of new light-duty vehicles sold has remained relatively constant, averaging 28.5 mpg for cars and 21.1 mpg for light trucks. For model year 2003, cars achieved the highest measured CAFE to date, averaging 29.4 mpg. The highest light truck CAFE was achieved in 1987 at 21.7 mpg, but light truck CAFE has been increasing in recent years, to 21.6 mpg for model year 2003 [*87*]. The fuel economy of light trucks is expected to improve over the next 3 years, because NHTSA announced new standards in April 2003 that increased the requirements to 21.0 mpg for model year 2005, 21.6 mpg for model year 2006, and 22.2 mpg for model years 2007 and beyond.

Although the relatively flat fuel economy for cars and light trucks over the past 15 years may suggest little technological improvement, this is not the case. Instead, technological advances have led to significant improvements in vehicle performance and increases in vehicle size, while generally maintaining or slightly increasing fuel economy. Based on NHTSA data, the average new car in 1990 achieved 28.0 mpg, had a curb weight of 2,906 pounds, and produced 132 horsepower. In 2002, average new car fuel economy was 3.2 percent higher at 28.9 mpg, curb weight was 8.7 percent higher at 3,159 pounds, and engine size was 30.0 percent higher at 171 horsepower [*88*]. Thus, although fuel economy improvements have been minimal, the introduction of advanced

Figure 19. Average fuel economy for new light-duty vehicles, 1980-2004 (miles per gallon)



technologies (including variable valve timing and lift, electronic engine and transmission controls, lock-up torque converters, and five-speed automatic transmissions) have produced significant improvement in engine and transmission efficiency, allowing substantial increases in new car size and performance. Data from the EPA show similar performance trends. For example, from 1990 to 2002, average new car horsepower per cubic inch displacement, a measure of engine efficiency, increased by 28.6 percent, from 0.83 to 1.07, as a result of implementation of advanced technologies and improved engine designs [*89*].

Similar improvements in vehicle attributes have also occurred for light trucks. In 1990, the average new light truck achieved 20.8 mpg, had a curb weight of 4,005 pounds, and produced 151 horsepower. In 2002, the average fuel economy for new light trucks was 4.8 percent higher at 21.8 mpg, curb weight was 13.5 percent higher at 4,547 pounds, and engine size was 45.7 percent higher at 220 horsepower. As in the case of cars, manufacturers have provided improved fuel economy for light trucks while increasing vehicle size and performance by implementing advanced technologies. From 1990 to 2002, light truck horsepower per cubic inch displacement increased by 37.4 percent, from 0.67 to 0.92.

In addition to increases in weight and performance, the mix of new vehicles sold has changed dramatically over the past 20 years. In 1983, cars accounted for 76.5 percent of new light-duty vehicles sold; in 2003, they accounted for only 47.2 percent. In addition, sales of subcompact cars, as a percent of total new vehicles sold, decreased from 20.5 percent in 1983 to 2.8 percent in 2003. Compact, midsize, and large car sales as a percent of total new light-duty vehicle sales have also declined.

Since 1983, sales of new light trucks, including SUVs, have increased significantly. In 2002, light trucks made up the majority of new light-duty vehicle sales. Increases in light truck sales over the past 20 years can be attributed to increased consumer demand for vehicle utility, seating capacity, ride height, and perceived safety. Coupled with low fuel prices, this trend has provided a favorable market for new light trucks, with sales of SUVs and minivans accounting for most of the increase in light truck sales. In 1983, SUVs accounted for 2.9 percent of new light-duty vehicle sales; in 2003, SUVs accounted for 27.0 percent of new light-duty vehicle sales and represented the largest segment of the light-duty vehicle market. Similarly, sales of minivans have grown dramatically. In 1983, minivans accounted for 0.1 percent of new light-duty vehicle sales; in 1994, they reached a peak share of 9.2 percent; and in 2003 their share was 6.5 percent of new light-duty vehicle sales [*90*].

Although significant improvements have been made in light-duty vehicle engine and transmission efficiency, consumer demand for increased performance and vehicle size, coupled with the growth of the light truck market, has resulted in an average new light-duty vehicle fuel economy that peaked at 26.2 mpg in 1987. New light-duty vehicle fuel economy declined steadily throughout the 1990s, to a low of 24.5 mpg in 1999, followed by an increase to 25.0 mpg for model year 2003 vehicles.

The *AEO2005* reference case projects that, in addition to increases in market penetration of advanced technologies, sales of hybrid and diesel vehicles will continue to increase. As a result, new car fuel economy in 2025 is projected to average 31.0 mpg, and new light truck fuel economy is projected to average 24.6 mpg—increases of 5.4 percent for cars and 14.1 percent for light trucks over the respective model year 2003 CAFE levels. Similar to historic trends, average engine power output is projected to increase to 215 horsepower for new cars sold in 2025 (26.3 percent higher than model year 2003) and 243 horsepower for new light trucks sold in 2025 (18.0 percent higher than model year 2003). Light truck sales are projected to account for 58.6 percent of new light-duty vehicle sales in 2025, and as a result the average fuel economy for all new light-duty vehicles sold is projected to increase by 7.2 percent, to 26.9 mpg in 2025.

Recent introductions of more efficient crossover vehicles (SUVs with design features more similar to those of cars than trucks), increasing consumer interest in environmentally friendly vehicles, the possibility of sustained high fuel prices, and increasing consumer demand for improvements in vehicle performance and luxury all will influence the future of light-duty vehicle sales and fuel economy. In addition, carbon emission regulations for light-duty vehicles that have been issued in eight U.S. States and Canada would require improvements in vehicle fuel economy starting in 2009 that go beyond those required by current U.S. CAFE standards. (*AEO2005* does not include the impact of these carbon emission regulations, because their future is uncertain. The auto industry has filed suit against the regulations established in California, contending that only the Federal Government has the authority to set vehicle fuel economy standards. See “Legislation and Regulations,” page 27.) NHTSA is also considering modification of light truck CAFE standards, which could result in the redefinition of a light truck as well as a restructuring of the standards to be based on vehicle weight and/or size.

In summary, considerable uncertainty surrounds the future of light-duty vehicle fuel economy. Fuel prices, the market success of hybrid and diesel vehicles, continued increases in consumer demand for light trucks and better vehicle performance, potential new fuel economy standards, and future regulation of carbon dioxide emissions all have potentially significant impacts on the automobile industry and the vehicles that will be manufactured and sold in the future.

U.S. Greenhouse Gas Intensity and the Global Climate Change Initiative

On February 14, 2002, President Bush announced the Administration's Global Climate Change Initiative [*91*]. A key goal of the Climate Change Initiative is to reduce U.S. greenhouse gas intensity by 18 percent over the 2002 to 2012 time frame. For the purposes of the initiative, greenhouse gas intensity is defined as the ratio of total U.S. greenhouse gas emissions to economic output.

AEO2005 projects energy-related carbon dioxide emissions, which represented approximately 84 percent of total U.S. greenhouse gas emissions in 2002. Projections for the other greenhouse gases are based on an EPA "Business-as-Usual" (BAU) case cited in the Addendum to the *Global Climate Change Policy Book* [*92*] released with the Global Climate Change Initiative. Those projections are based on several EPA-sponsored studies conducted in the preparation of the U.S. Department of State's *Climate Action Report 2002* [*93*, *94*, *95*, *96*]. Table 21 combines the *AEO2005* reference case projections for energy-related carbon dioxide emissions with the projections for other greenhouse gases.

According to the combined emissions projections in Table 21, the greenhouse gas intensity of the U.S. economy is expected to decline by 14 percent from 2002 to 2012 and by 30 percent from 2002 to 2025 in the reference case. The Administration's goal of reducing greenhouse gas intensity by 18 percent by 2012 would require an emissions reduction of about 366 million metric tons carbon dioxide equivalent from the projected level in the reference case.

Although *AEO2005* does not include cases that specifically address alternative assumptions about greenhouse gas intensity, the integrated high technology case does give some indication of the feasibility of meeting the 18-percent intensity reduction target. In the integrated high technology case, which combines the high technology cases for the residential, commercial, industrial, transportation, and electric power sectors, carbon dioxide emissions in 2012 are projected to be 129 million metric tons less than the reference case projection. As a result, U.S. greenhouse gas intensity would fall by 15.5 percent from 2002 to 2012, still somewhat short of the Administration's goal of 18 percent (Figure 20). An 18-percent decline in intensity is projected to occur by 2014 in the integrated high technology case, as compared with 2015 in the reference case.

Impacts of Temperature Variation on Energy Demand in Buildings

In the residential and commercial sectors, heating and cooling account for more than 40 percent of

Table 21. Projected changes in U.S. greenhouse gas emissions, gross domestic product, and greenhouse gas intensity, 2002-2025

	Projection			Percent Change	
Measure	**2002**	**2012**	**2025**	**2002-2012**	**2002-2025**
Greenhouse gas emissions (million metric tons carbon dioxide equivalent)					
Energy-related carbon dioxide	5,750	6,812	8,062	18.5	40.2
Methane	599	609	606	1.7	1.1
Nitrous oxide	323	342	382	5.7	18.3
Gases with high global warming potential	144	284	624	97.5	334.0
Other carbon dioxide and adjustments for military and international bunker fuel	60	82	93	37.2	56.9
Total greenhouse gases	**6,876**	**8,128**	**9,767**	**18.2**	**42.1**
Gross domestic product (billion 2000 dollars)	10,075	13,869	20,292	37.7	101.4
Greenhouse gas intensity (thousand metric tons carbon dioxide equivalent per billion 2000 dollars of gross domestic product)	682	586	481	-14.1	-29.5

end-use energy demand. As a result, energy consumption in those sectors can vary significantly from year to year, depending on yearly average temperatures.

In long-term energy forecasting, an average of the heating and cooling degree-days data for the previous 30 years is ordinarily used as a proxy for "normal" weather [*97*]. Both heating and cooling degree-days have shown a slight warming trend since 1973 (Figure 21), although no warming trend is evident from an examination of the long-term data since 1930. The direction of year-to-year fluctuations in U.S. average heating degree-days and in U.S. average cooling-degree days do not appear to be correlated; however, both the lowest yearly average for heating degree-days and the highest yearly average for cooling degree-days were recorded in 1998. The coldest winter over the 1973-2003 period (1978) was 11 percent colder than the average, and the warmest winter (1998) was 12 percent warmer than the average. The coolest summer (1976) was 16 percent cooler than the average, and the warmest summer (1998) was 15 percent warmer than the average.

The *AEO2005* reference case uses the 30-year average of heating and cooling degree-days from the National Oceanic and Atmospheric Administration at the State level, adjusted for State population forecasts through 2025, to represent future temperatures (previous *AEO*s used Census division forecasts). As a result of State population shifts, population-weighted heating degree-days are projected to decline by 3.2 percent, and population-weighted cooling degree-days are projected to increase by 4.1 percent from 2003 to 2025, relative to the weather normal average assumed in 2005, because the population is projected to shift to States with warmer climates.

To estimate the possible impact of warmer or colder weather on energy use in the residential and commercial sectors, two alternative cases were examined: a warmer case assuming above-average temperatures and a cooler case assuming below-average temperatures throughout the projection period. For this analysis, it was assumed that State-level heating and cooling degree-days would reach the average of the five warmest or coolest levels that have occurred over the past 30 years by 2025. It was also assumed that warmer winters would coincide with warmer summers, and vice versa. Figures 22 and 23 show the projected trends in heating and cooling degree-days from 2005 to 2025 in the reference, warmer, and cooler cases. Compared with the reference case forecast, heating degree-days are projected to be 11 percent higher in the cooler case and 12 percent lower in the warmer case by 2025, and cooling degree-days are projected to be 17 percent higher in the warmer case and 16 percent lower in the cooler case.

The impacts of the assumptions in the warmer and cooler weather cases on projected energy consumption in the residential and commercial sectors are mixed, because warmer winters reduce demand for space heating (generally fossil fuels) and warmer summers increase demand for space cooling (generally electricity), whereas colder winters and summers do the opposite. Figure 24 shows the impacts of the two cases on electricity consumption (including conversion losses) and direct fossil fuel consumption.

Given that fossil-fuel-fired space heating is the largest use of energy in the two buildings sectors, it is not surprising that the cumulative change in the two weather cases is greatest for fossil fuels. The cumulative change in fossil fuel consumption in the buildings

Figure 20. Projected change in U.S. greenhouse gas intensity in three cases, 2002-2025 (percent)

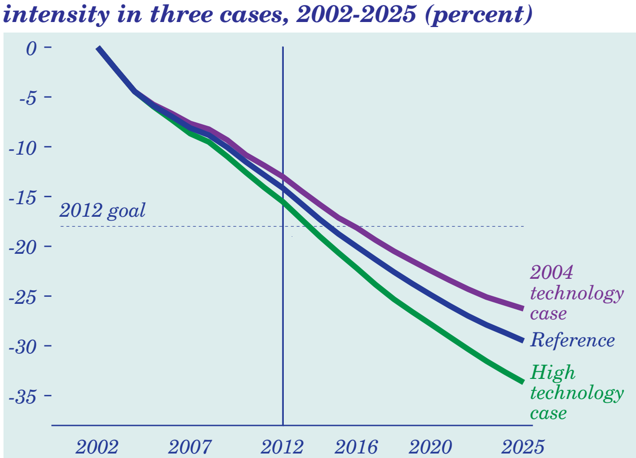
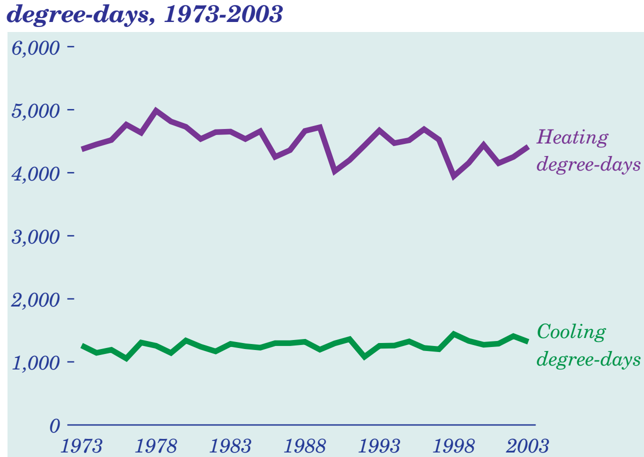


Figure 21. U.S. average heating and cooling degree-days, 1973-2003



sector in the warmer and colder cases represents 2.4 and 1.9 percent, respectively, of the cumulative amount of fossil fuels used in the buildings sector from 2006 through 2025. For electricity, the cumulative change is 0.2 percent of the cumulative amount of electricity (including conversion losses) used in the buildings sector in both cases between 2006 and 2025. The much lower change for electricity is due to the fact that much less of the electricity load is temperature dependent—only 16 percent, compared with 62 percent for fossil fuels. For example, many of the major end-use services that are not temperature dependent, such as lighting, refrigeration, and office equipment, are powered almost exclusively by electricity.

Changes in projected energy demand in the warmer and cooler cases also affect the projections of energy prices. Relative to the *AEO2005* reference case, average residential and commercial electricity prices in the cooler case are 0.7 percent and 0.5 percent lower over the projection period, respectively, as summer peak demand is reduced by decreases in air conditioning use. In the warmer case, average electricity prices to residential and commercial customers over the period from 2006 to 2025 are 0.8 percent and 0.9 percent higher, respectively, as summer peak load is increased.

Figure 22. Projected U.S. average heating degree-days in three cases, 2000-2025

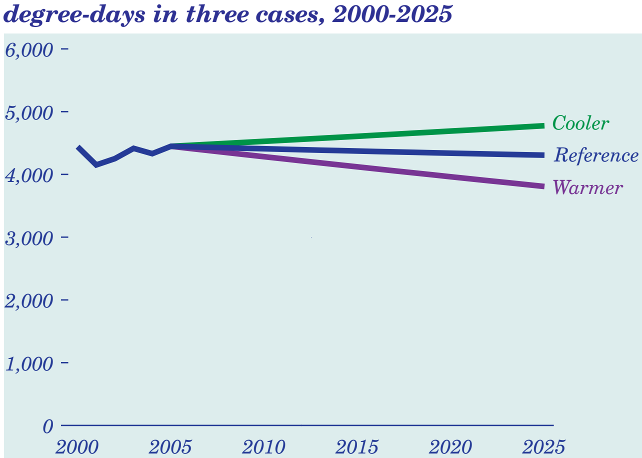
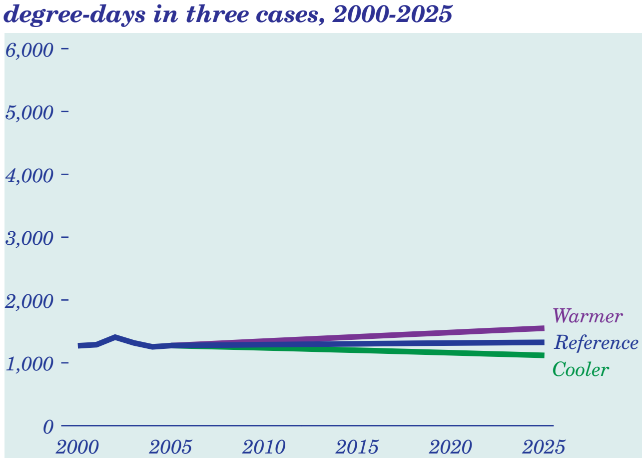


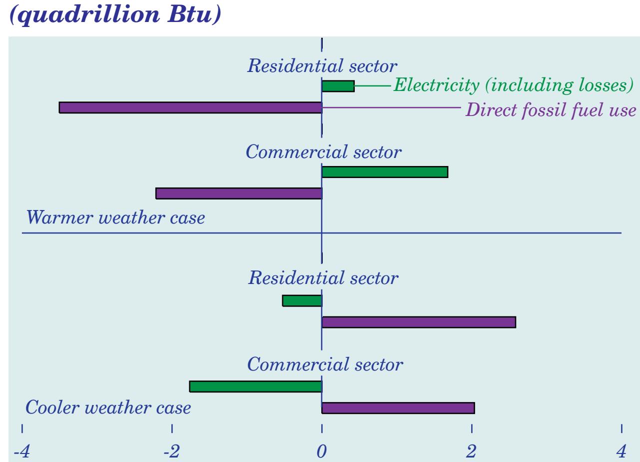
Figure 23. Projected U.S. average cooling degree-days in three cases, 2000-2025



The changes in electricity demand are not evenly distributed throughout the year; there is a much greater change in peak demand than there is in total demand. This also affects the amount of electric generating capacity needed, which is based on an assumed reserve over the peak demand. In the warmer case, peak demand in 2025 is 4.8 percent higher than in the reference case, resulting in a 3.5-percent increase in overall electricity generation capacity, although total demand in 2025 is only 0.5 percent higher than in the reference case. As a result, higher average electricity prices are projected, due to the increased costs of capacity without an equal increase in generation. The incremental cost is spread over relatively few additional kilowatthours. In the colder case, projected peak demand in 2025 is 4.4 percent lower than in the reference case, and total capacity is 3.2 percent lower, although total demand is only 0.7 percent lower. In this case, total costs are lower due to fewer new capacity additions, but total demand is again almost the same, and average prices are lower.

Because changes in annual energy demand vary depending on season and fuel type in the two weather cases, it follows that changes in energy expenditures will vary as well. As shown in Figure 24, demand for fossil fuel and electricity change in opposite directions relative to the reference case in the two temperature

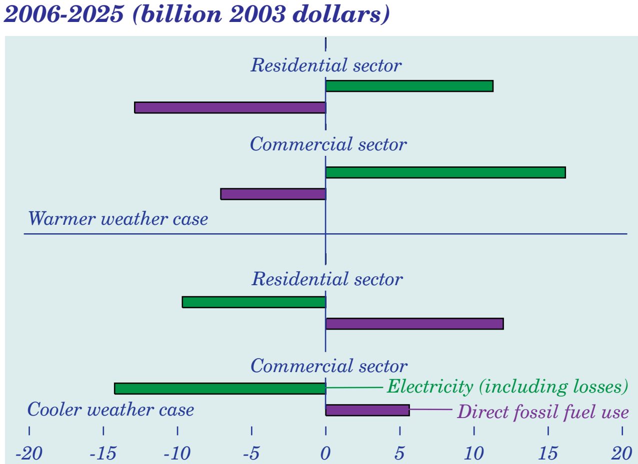
Figure 24. Cumulative projected change from the reference case in buildings sector electricity and fossil fuel use in two cases, 2006-2025 (quadrillion Btu)



sensitivity cases. Figure 25 shows the changes in projected present value of expenditures for electricity and fossil fuels in the residential and commercial sectors in the warmer and colder cases. The present value of commercial electricity expenditures changes the most, but the difference, as a percentage of current commercial electricity expenditures, reaches only 1.3 percent over the present value of all future expenditures on electricity in the sector. The present value of residential energy expenditures increases by $2.3 billion in the cooler case, meaning that consumers could expect to pay more money for their household energy use over the projection period. In the warmer case, the present value of residential energy expenditures decreases by $1.6 billion, reflecting the larger heating requirements relative to cooling requirements in the sector.

In summary, average yearly temperatures that are warmer or cooler than expected would have mixed impacts on energy consumption and expenditures in the residential and commercial sectors if the changes were directionally the same in the heating and cooling seasons. Warmer summer temperatures would increase demand for air conditioning, and warmer winter temperatures would decrease demand for heating. Because space heating accounts for more energy use than air conditioning on the basis of sales volumes, heating fuels tend to be more affected by changes in temperature than do cooling fuels; however, given the relatively high delivered price of electricity compared to fossil fuels, changes in energy consumption tend to affect electricity more on the basis of total expenditures.

Figure 25. Present value of projected change from the reference case in buildings sector expenditures for electricity and fossil fuel use in two cases, 2006-2025 (billion 2003 dollars)



The projections in the warmer and cooler weather cases show that energy consumption and expenditures are sensitive to changes in temperature. It should be noted, however, that the changes projected are relatively small relative to the sector totals. Accordingly, in the colder case, cumulative carbon dioxide emissions from 2003 to 2025 are projected to be only 0.1 percent higher than in the reference case, and in the warmer case they are projected to be only 0.2 percent lower than in the reference case.

Production Tax Credit for Renewable Electricity Generation

In the late 1970s and early 1980s, environmental and energy security concerns were addressed at the Federal level by several key pieces of energy legislation. Among them, the Public Utility Regulatory Policies Act of 1978 (PURPA), P.L. 95-617, required regulated power utilities to purchase alternative electricity generation from qualified generating facilities, including small-scale renewable generators; and the Investment Tax Credit (ITC), P.L. 95-618, part of the Energy Tax Act of 1978, provided a 10-percent Federal tax credit on new investment in capital-intensive wind and solar generation technologies [*98*].

EPACT included a provision that addresses problems with the ITC—specifically, the lack of incentives for operation of wind facilities. EPACT introduced the renewable electricity PTC, a credit based on annual production of electricity from wind and some biomass resources. The initial tax credit of 1.5 cents per kilowatthour (1992 dollars) for the first 10 years of output from plants entering service by December 31, 1999, has been adjusted for inflation and is currently valued at 1.8 cents per kilowatthour (2003 dollars) [*99*, *100*].

The original PTC applied to generation from tax-paying owners of new wind plants and biomass power plants using fuel grown in a "closed-loop" arrangement (crops grown specifically for energy production, as opposed to byproducts of agriculture, forestry, urban landscaping, and other activities). In its early years, the PTC had little discernable effect on the wind and biomass industries it was designed to support (Figure 26). Although there have not been any commercial closed-loop generators, by 1999, when the provision was originally set to expire, U.S. wind capacity had begun growing again, and the PTC supported the development of more than 500 megawatts of new wind capacity in California, Iowa, Minnesota, and other States. Wind power development was also encouraged by State-level programs, such as the mandate in Minnesota for 425 megawatts of wind power by 2003 as part of a settlement with Northern States Power (now Xcel Energy) to extend on-site storage of nuclear waste at its nuclear facility [*101*].

In 1999, the PTC was allowed to expire as scheduled, but within a few months it was retroactively extended through the end of 2001 [*102*], and poultry litter was added to the list of eligible biomass fuels. Although wind power development slowed significantly in 2000, 2001 was a record year with as much as 1,700 megawatts installed [*103*]. Again, State and local programs, including a significant renewable energy mandate program in Texas, also supported new wind installations.

The PTC was allowed to expire again on December 31, 2001, while Congress worked on a comprehensive new energy policy bill. It was retroactively extended a second time to December 31, 2003, as part of an omnibus package of extended tax credits passed in response to the economic downturn and terrorist attacks of 2001 [*104*].

Like the 1999 expiration and extension, the extension of the PTC in 2002 was followed by a lull in wind power development; however, in 2003, the year leading up to the expiration, the wind industry saw significant growth of almost 1,700 megawatts [*105*], approaching the record set in 2001. Significantly, while many 2003 builds still relied on multiple incentives (for example, the PTC plus a State program) to achieve economic viability, some (in Oklahoma and other States) were developed with little government support beyond the PTC [*106*].

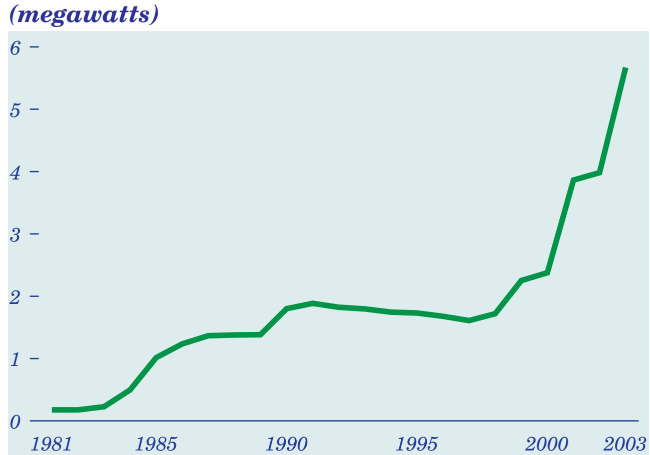
An extension of the PTC program to eligible plants entering service on or before December 31, 2005, was passed as part of the Working Families Tax Relief Act of 2004 (P.L. 108-311). In addition, the American Jobs Creation Act of 2004 (P.L. 108-357) expanded the credit to other renewable resources, such as open-loop biomass, geothermal, and solar electricity, as detailed below.

With reductions in capital costs and increases in capacity factors [*107*], wind power technology has improved since the introduction of the ITC and PTC. It is likely that the installations spurred by those incentives allowed the industry to "learn by doing" and thus contributed to improvement of the technology. There were, however, other factors that contributed to cost reductions during the period, including government-funded research and development and large markets for wind power technology that were created by subsidy programs in other countries, especially, Denmark and Germany.

The *AEO2005* reference case, assuming no extension of the PTC beyond 2005 (as provided for in current law as of October 31, 2004), projects that the levelized cost of electricity generated by wind plants coming on line within the next few years would range from approximately 4.5 cents per kilowatthour at a site with excellent wind resources [*108*] to 6.0 cents per kilowatthour at less favorable sites. To incorporate the effect of the current 1.8-cent tax credit over the 10-year eligibility period for those wind plants, the projections account for both the tax implications and the time value of the subsidy. As a tax credit, the PTC represents 1.8 cents per kilowatthour of tax-free money to a project owner. If the owner did not receive the tax credit and wanted to recoup that 1.8 cents with taxable revenue from electricity sales, 2.8 cents would have to be added to the sales price of each kilowatthour, assuming a 38-percent marginal tax rate.

Applying the same assumptions used to derive the 4.8-cent total levelized cost of wind energy over a 20-year project life, the levelized value of the PTC to a wind project owner is approximately 2.1 cents per kilowatthour. Similarly, the lower value of the PTC for other resources could be expected to reduce the levelized cost of prime geothermal sites from 4.4 to 3.6 cents per kilowatthour, and to reduce the levelized cost of a new dedicated biomass plant burning low-cost eligible urban or agricultural waste from 5.1 to 4.5 cents per kilowatthour. Solar projects with high capital costs and relatively low capacity factors probably would benefit more from the available 10-percent investment tax credit than from the PTC (Table 22).

Figure 26. U.S. installed wind capacity, 1981-2003 (megawatts)



In the reference case, the projected levelized cost for electricity from new natural gas combined-cycle plants is 4.7 cents per kilowatthour, and for new coal-fired plants the projected cost in 2010 is 4.3 cents per kilowatthour [*109*]. The value of the incremental fuel and capacity displaced by wind power in 2010 is 4.3 cents per kilowatthour in the reference case. Thus, it is easy to see how the PTC could make wind plants an attractive investment in the mid-term electricity market.

In view of the history of past PTC extensions, another extension beyond the current 2005 expiration date seems well within the realm of possibility. Given the uncertainty regarding the long-term fate of the PTC, EIA examined one possible outcome for an extension of the PTC. The PTC extension case is not meant to represent any expectation about future policy decisions regarding the PTC, but rather to provide a useful indication of the impacts of the PTC program on future energy markets relative to the reference case forecast, which assumes no extension of the PTC beyond 2005. This case is based on an "as-is" extension to 2015 of the expanded renewable electricity PTC program, as expanded by the American Jobs Creation Act of 2004 to facilities placed in service by the end of 2015.

The current PTC law provides a tax credit of 1.8 cents per kilowatthour for the first 10 years of operation to new wind plants, dedicated biomass plants burning closed-loop fuel or poultry litter, and certain approved fossil fuel plants co-firing with closed-loop renewable fuels. A credit of 1.8 cents per kilowatthour is provided for the first 5 years of operation to new geothermal and solar plants [*110*], and a credit of 0.9 cent per kilowatthour is provided for the first 5 years of operation to new dedicated biomass plants burning a wide variety of "open-loop" fuels, such as urban wood wastes, landscaping wastes, agricultural residues, and forestry residues. Landfill gas and municipal solid waste mass-burn facilities are eligible for the "open-loop" credit as well, although this would preclude taking advantage of other tax credits offered to some of those facilities.

Table 22. Levelized costs of new conventional and renewable generation in two cases, 2010 (2003 cents per kilowatthour)

Generation source	Reference case	PTC extension case
Combined cycle	4.7	4.5
Combustion turbine	7.0	6.8
Coal	4.3	4.3
Geothermal	4.4	3.6
Photovoltaic	21.0	21.0
Solar thermal	12.6	12.6
Open-loop biomass	5.1	4.5
Wind	4.8	2.9
Avoided cost of geothermal or biomass	4.4	4.0
Avoided cost of wind	4.3	4.0

Each of the credits is modeled as specified in the law, with the exception of the "closed-loop" credits for dedicated biomass plants and approved co-firing applications, the tax credit for photovoltaics, and the credit for refined coal. Because of the long establishment times and relative expense of energy crops, it is assumed that there will be no dedicated, closed-loop biomass plants able to take advantage of an extension of the PTC to 2015. Furthermore, the eligibility of co-firing plants to take advantage of the credit is to be determined on a case-by-case basis by the Department of Energy, and determining which or how many plants will be able to qualify is beyond the scope of this analysis. This analysis assumes that no PTC is given for co-firing. Geothermal, utility-owned photovoltaics, and solar thermal power applications are all eligible for *either* the PTC or the ITC. In the case of photovoltaics, which has very high investment costs and relatively low annual output per unit capacity, the ITC is estimated to be the more valuable of the two tax credits, and it is assumed that it will be preferred over the PTC. EIA does not currently provide projections for refined coal markets.

The PTC extension case assumes an uninterrupted extension of the PTC through 2015. As indicated above, the PTC has historically been subject to a series of expirations with retroactive extension for short periods (typically, 2 years per extension). The resulting uncertainty for the relatively long-term cycle of electricity market investment may have a significant impact on the ability of the industry to exploit the subsidy. The observed "packing" of construction in the last 6 months or so of each new eligibility window may serve to increase investment cost. In addition, uncertainty about the future availability of the PTC may affect infrastructure investment decisions that could lead to fuller realization of cost-reduction opportunities [*111*].

In the PTC extension case, wind power has the largest projected gains, although landfill gas, geothermal, and dedicated, open-loop biomass resources all are projected to see some capacity expansion. Installed wind capacity in 2015 is almost 63 gigawatts in the PTC extension case, compared to 9.3 gigawatts in the reference case. This 580-percent increase in capacity results in a 650-percent increase in generation from the reference case projection for 2015 (206 billion kilowatthours in the PTC extension case compared to 27 billion kilowatthours in the reference case).

In 2015, geothermal capacity in the PTC extension case (3.23 gigawatts) is more than 20 percent greater than in the reference case (2.66 gigawatts), resulting in 30 percent more electricity generation from geothermal resources in 2015 (Table 23). With limited availability of new sites, new landfill gas capacity in 2015 is only 50 megawatts greater in the PTC extension case than the reference case projection of 3,630 megawatts. Although new dedicated biomass capacity in 2015 is almost 65 percent greater in the PTC extension case than in the reference case (3.39 gigawatts compared to 2.06 gigawatts), total biomass generation in the electric power sector in 2015 is only 10 percent higher than in the reference case (33.13 billion kilowatthours compared to 30.01 billion kilowatthours). This is largely a result of a significant decline in the use of biomass for co-firing applications, as the dedicated plants receiving the tax credit generally are expected to have a competitive advantage over co-firing plants in obtaining open-loop fuel.

Although geothermal capacity and dedicated biomass capacity in the PTC extension case continue to grow after the assumed 2015 expiration of the PTC, wind capacity expansion all but stops when the PTC expires. Because geothermal and biomass compete as baseload resources, their relative economics in the 2015 to 2025 time frame are similar in the reference and PTC extension cases; however, both benefit from reduced technology costs as a result of "learning-by-doing." Wind, on the other hand, competes as an intermittent resource, with much of its generation displacing intermediate-load energy rather than peak or baseload energy. Initially, the displaced load consists of a significant amount of natural-gas-fired generation, with a relatively high fuel cost; however, after significant gas-fired generation is displaced, more coal-fired generation (with lower fuel costs) is displaced. In the PTC extension case, the avoided cost of wind generation is reduced by as much as 15 percent in 2020 from the reference case projection.

The total incremental cost to the U.S. Treasury of extending the PTC from 2005 to 2015 is estimated at $17 billion in lost tax revenue (all cumulative money calculations are in 2003 dollars, discounted at 7

Table 23. Renewable electricity capacity and generation in two cases, 2005, 2015, and 2025

Projection	2005 Reference case	2005 PTC extension case	2015 Reference case	2015 PTC extension case	2025 Reference case	2025 PTC extension case
Electric power sector net summer capacity (gigawatts)						
Conventional hydropower	78.1	78.1	78.2	78.2	78.2	78.2
Geothermal	2.2	2.2	2.7	3.2	4.6	5.3
Municipal solid waste	3.4	3.4	3.6	3.7	3.7	3.7
Wood and other biomass	1.8	1.8	2.1	3.4	4.5	5.6
Solar thermal	0.4	0.4	0.5	0.5	0.5	0.5
Solar photovoltaic	0.1	0.1	0.2	0.2	0.4	0.4
Wind	8.2	8.2	9.3	63.0	11.3	63.0
Total renewable	94.1	94.1	96.5	152.1	103.1	156.6
Total electric power industry	945	945	967	1,014	1,145	1,186
Electric power sector generation (billion kilowatthours)						
Conventional hydropower	288.4	288.4	300.5	300.6	301.1	301.1
Geothermal	12.1	12.1	16.1	21.0	32.8	38.3
Municipal solid waste	24.3	24.3	26.1	26.5	26.5	26.9
Wood and other biomass	20.6	20.7	30.0	33.1	37.4	44.5
Dedicated plants	10.1	10.1	11.7	19.8	27.3	35.4
Co-firing	10.6	10.6	18.3	13.3	10.1	9.1
Solar thermal	0.7	0.7	0.9	0.9	1.0	1.0
Solar photovoltaic	0.1	0.1	0.5	0.5	1.0	1.0
Wind	23.6	23.6	27.3	205.7	34.5	205.7
Total renewable	369.8	369.8	401.4	588.3	434.2	618.5
Coal	2,054	2,054	2,305	2,275	2,890	2,802
Natural gas	699	699	1,172	1,054	1,403	1,331
Total net generation to the grid	3,890	3,890	4,676	4,708	5,522	5,545

percent per year unless otherwise noted). The electric power industry incurs $12 billion in cumulative additional costs through 2025 in the PTC extension case compared to the reference case; however, this additional expense is more than compensated for by the subsidy. Because the net effect of the PTC extension is a slight reduction in end-use electric power prices, electricity consumers save about $37 billion in end-use electricity expenditures through 2025 in the PTC extension case compared to reference case. In addition, the assumed PTC extension significantly reduces demand for natural gas in the electric power sector, lowering natural gas prices for all consumers. Total natural gas expenditures by consumers other than electric utilities are reduced by $13 billion through 2025 in the PTC extension case compared to the reference case. About $16 billion of the $17 billion in taxpayer cost is allocated to wind energy resources as a result of both the significantly higher level of PTC-induced wind generation and the higher PTC value and claim period for wind projects than for geothermal or open-loop biomass projects.

Distributed Generation in Buildings

Distributed generators installed by residential and commercial customers may supply electricity alone (generation) or electricity as well as heat or steam (CHP). On-site generators can have several advantages for electricity customers:

- If redundant capability is installed, reliability can be much higher than for grid-supplied electricity.
- Although electricity from distributed generation is generally more costly than grid-supplied power, the waste heat from on-site generation can be captured and used to offset energy requirements and costs for other end uses, such as space heating and water heating.
- Distributed generation can reduce the need for energy purchases during periods of peak demand, which can lower both current energy bills and, presumably, energy bills in future competitive markets, when peak prices will be set by the most expensive generator supplying power to the grid.

Currently, distributed generation provides a very small share of residential and commercial electricity requirements in the United States. The *AEO2005* reference case projects a significant increase in electricity generation in the buildings sector, but distributed generation is expected to remain a small contributor to the sector's energy needs. Although the advent of higher energy prices or more rapid improvement in technology could increase the use of distributed generation relative to the reference case projection, the vast majority of electricity used in buildings is projected to continue to be purchased from the grid.

The *AEO2005* buildings models represent several grid-connected distributed generation technologies either as simple generation or as CHP, including conventional technologies such as oil or gas engines and combustion turbines and new technologies such as solar photovoltaics (PV), fuel cells, and microturbines. PV systems are the most costly of the distributed technologies for buildings on the basis of installed capital costs; however, once the systems are installed, no fuel costs are incurred. Petroleum-based generation is often used for emergency power backup in the commercial sector, but potential issues related to localized emissions make it less appropriate than natural-gas-based generation for continuous operation.

The projected adoption of distributed generation technologies in the buildings sector is based on forecasts of the economic returns from their purchase to meet baseload electricity needs (also thermal needs in the case of CHP) and on estimated participation in programs aimed at fostering distributed generation [*112*]. A detailed cash flow analysis is used to estimate the number of years needed to achieve a positive cumulative cash flow. The calculations include the annual costs (down payments, loan payments, maintenance costs, and fuel costs) and returns (tax deductions, tax credits, and energy cost savings) from the investment over a 30-year period from the time of the investment decision. The analysis includes the assumption that if more electricity is generated than needed, the excess can be sold to the grid [*113*].

Economic penetration of these technologies is a function of how quickly an investment in a technology is estimated to recoup its flow of costs. Program-related purchases are based on estimates from the Department of Energy's Million Solar Roofs program, the Department of Defense fuel cell demonstration program, State RPS and other renewable energy programs and goals, and locally targeted initiatives, such as the Spire Solar Chicago program.

Table 24 shows projected installed capital costs [*114*] and electrical conversion efficiencies [*115*] for several of the distributed generation technologies represented in the buildings sector models. All fossil-fuel-fired systems are assumed to be used in CHP applications to take advantage of waste heat produced in the generation process. The costs and performance of fossil-fuel-fired CHP and PV systems are assumed to improve over time in the *AEO2005* projections, with emerging technologies (fuel cells, microturbines, and PV) showing the most improvement. Technology learning is also expected to occur for the emerging technologies, allowing for additional cost declines if cumulative shipments increase sufficiently [*116*].

Market Factors

The availability of technologies does not guarantee their widespread adoption. Many factors enter into the decision whether to purchase grid-supplied electricity to meet all of a building's power needs or to invest in a distributed generation system. Some of the issues that affect the market for distributed generation are discussed below.

Economics, Technology, and Suitability. In most instances, purchasing electricity is currently more economical for residential and commercial consumers than investing in distributed generation systems. On average, buildings sector sites are much smaller than industrial sites, and they are limited to technologies that have been more expensive and less efficient than larger CHP. Commercial firms generally have fewer operating hours per year and lower load factors than industrial firms, limiting the annual hours of system operation in which the higher first costs can be recouped. In addition, few types of buildings applications involve the steady thermal requirements that maximize the efficiency and economics of CHP systems.

Recent increases in fuel prices have further dampened enthusiasm for new CHP systems in buildings. Although fuel costs are not an issue with PV systems, their high installed capital cost limits economic viability to areas with high electricity prices and/or program-based incentives that offset a significant portion of the added investment costs. To the extent that deregulated retail electricity markets may pass along hourly or seasonal variation in the cost of producing electricity, such as time-of-day or real-time pricing, distributed generation applications may see further economic opportunities to offset higher energy costs; however, the adoption of such rate structures on a widespread basis in the residential and commercial sectors is currently highly uncertain.

All the fossil-fuel-fired distributed generation technologies represented in the reference case are assumed to be CHP systems; however, based on a January 2000 report prepared by ONSITE SYCOM Energy Corporation, only about 5 percent of existing commercial buildings in the United States have technically adequate electric demand and thermal loads to meet the criteria for CHP [*117*]. Considering the possibility of cost-effective CHP systems in smaller sizes and the advent of systems that include heat-activated cooling [*118*] increases the potential market for CHP adoption, but conditions would need to change from those represented in the reference case to encompass a much larger share of the commercial sector, let alone to make CHP systems economically attractive to meet residential consumers' everyday power and heating needs.

The amount of electricity a PV system can produce depends on the quality of the solar resource, as well as the size and efficiency of the system. On an annual basis, a PV system in Alaska would, in general, produce less electricity than an identical system in Arizona. The suitability of PV also depends on the ability to site the system to take advantage of the sunlight available. In addition, although PV systems tend to generate power during some of the peak electricity demand hours, their value in offsetting peak power costs may be somewhat less than that of fossil-fueled systems, because their output cannot be controlled with sufficient precision to follow real-time pricing signals or match a time-of-day tariff structure.

Regulation. Another factor to be considered when an investment in distributed generation technology is being made is the regulatory environment. Requirements for permits and approvals for distributed generation systems vary widely by State, technology,

Table 24. Projected installed costs (2003 dollars per kilowatt) and electrical conversion efficiencies (percent) for distributed generation technologies by year and technology, 2004, 2010, 2020, 2025

	2004		2010		2020		2025	
Technology	Cost	Efficiency	Cost	Efficiency	Cost	Efficiency	Cost	Efficiency
Residential photovoltaic	8,600	14	6,200	18	3,814	22	3,180	22
Commercial photovoltaic	6,250	14	4,750	18	3,178	22	2,650	22
Commercial fuel cell	5,200	36	2,500	49	1,800	51	1,450	52
Natural gas turbine	1,860	22	1,679	24	1,567	27	1,539	28
Natural gas engine	1,130	32	1,030	33	930	34	915	34
Natural gas microturbine	1,773	28	1,415	36	870	38	818	39

fuel, and project size. Researching and responding to a wide range of requirements is a hurdle for project development, adding expense to an already capital-intensive endeavor. Requirements can range from emissions and siting regulations to local building, zoning, and fire codes to local utility interconnection policies, exit fees, and standby rates [*119*].

Interconnection. The electric grid was not designed for two-way energy flow or storing energy at the distribution level. Consequently, utilities have implemented interconnection policies for the safe and reliable operation of the local grid when distributed generation units are interconnected to it. Some States are proposing to follow the requirements recently set forth by the Institute of Electrical and Electronics Engineers in IEEE 1547, "Standard for Distributed Resource Interconnects with Electric Power Systems" [*120*]. Others are developing their own interconnection standards. Still others have no standards, and procedures in those States are defined by individual electric utilities. Although some utilities have simplified the processes for small distributed generation projects (below 30 to 40 kilowatts), utilities generally require an interconnection study to be completed as part of the planning process for an installation.

Emissions. Restrictions may also be imposed on emissions from fossil-fuel-fired on-site generation that could contribute to smog and acid rain. Basic permitting and emission control requirements vary by State and whether a site falls within an emissions nonattainment zone with significant air quality problems [*121*]. Most States do not require permits for small units or units with small amounts of emissions. The threshold for such exemptions varies by State. In addition, distributed generation equipment that requires a permit is likely to require some emission limitations or controls. Systems that use fuel oil typically have higher "fuel-based" emissions than those that run on natural gas, making permitting and control costs a larger issue for those systems.

Reference Case Projections

The *AEO2005* reference case includes residential and commercial distributed generation projections at the national level and for the nine Census divisions [*122*], using the assumptions and methodology described above. At the national level, there is currently little residential capacity for electricity generation from fossil fuels. Existing capacity consists primarily of emergency backup generators to provide electricity for minimum basic needs in the event of power outages. Generating capacity in the commercial sector is also primarily for emergency backup; however, some electricity supply and peak generation is reported. EIA's 1999 Commercial Buildings Energy Consumption Survey (CBECS) estimated that about 0.7 percent of all commercial buildings (1.6 percent of all commercial floorspace) use generators for purposes other than emergency backup.

Fossil-fuel-fired commercial generating facilities larger than 1 megawatt reported generating 7.0 billion kilowatthours of electricity in 2002 and 6.3 billion kilowatthours in 2003, about 0.5 percent of the sector's electricity needs [*123*]. The reference case projects an 80-percent increase in electricity supplied annually by fossil-fuel-fired distributed generation in the buildings sector, to 11.3 billion kilowatthours in 2025, but distributed generation still is expected to meet less than 1 percent of the electricity requirements for buildings nationally.

Generation from natural gas turbines at commercial facilities is projected to remain essentially constant throughout the forecast. Gas turbines are viewed as a "mature" technology that is expected to show only modest improvement over the forecast, and, in addition, few commercial facilities have power and thermal needs or operating hours that would warrant investment in a large CHP system such as a gas turbine. Although engines are expected to remain a popular choice for commercial CHP, the adoption of microturbines and fuel cells is projected to increase later in the forecast period, reflecting projected cost declines and technological progress for these emerging technologies. With reference case electricity and fossil fuel prices, the vast majority of residential consumers are not expected to purchase fossil-fuel-fired distributed generation systems to meet their daily electricity requirements.

The reference case projections for grid-connected PV incorporate current national incentives for commercial sector systems, including an Investment Energy Tax Credit and favorable depreciation treatment [*124*]. The effects of regional and local incentives are estimated through projections for program-related purchases of PV systems. Although *AEO2005* projections are limited to grid-connected systems, EIA estimates that remote PV applications (off-grid power systems) representing as much as 134 megawatts of electricity generation capacity were in service in 2002, in addition to another 362 megawatts of PV generating capacity in specialized applications, such as communications and transportation [*125*].

In the reference case, electricity generation from PV systems in the buildings sector is projected to increase at an average annual rate of 17 percent, to 3.7 billion kilowatthours in 2025 (Figure 27). New installations through 2010 are expected to result from program-related purchases that generally include incentives to help defray the high capital costs associated with the technology. Later in the forecast, as a result of projected cost declines combined with favorable tax treatment, PV systems are projected to become economically attractive without additional subsidies in regions where electricity costs are relatively high.

Delivered energy prices vary by geographical region in the United States and are expected to continue to differ by region throughout the forecast horizon. Variations in electricity prices, fossil fuel prices, and the relative difference between electricity and fossil fuel prices result in significant differences in the projected adoption of distributed generation technologies by region. Public policies and incentive programs differ by State and region as well, adding to the expected regional variation in distributed generation.

The use of fossil-fuel-fired distributed generation technologies in CHP applications is projected to grow fastest in regions with high electricity prices and relatively moderate natural gas prices (Figure 28). Although the Mountain Census division is projected to show the fastest rate of growth in the reference case, 5.0 percent per year between 2003 and 2025, the Pacific Census division is projected to show the greatest increase in generation, 1.6 billion kilowatthours. Census divisions with relatively low electricity prices, such as the East South Central division, show little growth.

Near-term adoption of PV systems in the buildings sector is expected to be concentrated in regions that exhibit some combination of the following: active programs to foster the development of PV, high electricity rates, and sufficient periods of sunlight to maintain PV electricity production. For example, in addition to abundant sunshine in many parts of California, the California Energy Commission's rebate program, funded by a System Benefits Charge, refunds up to one-half of the installed cost of PV systems. States with RPS programs that require a percentage of electricity generation to be provided from renewable energy sources often offer "extra credit" for PV that increases its attractiveness [*126*]. The Pacific Census division, the current leader in PV electricity generation, is expected to show the greatest increase in the *AEO2005* reference case, with projected PV generation of more than 1 billion kilowatthours in 2025 (Figure 28). In the New England and Middle Atlantic Census divisions, where high electricity prices are projected, the use of distributed PV systems is projected to increase by more than 20 percent from 2003 to 2025.

Alternative Cases

Technology Improvement. The buildings sector 2005 technology and high technology cases included in *AEO2005* examine the sensitivity of the projections to different technology assumptions in combination with reference case energy prices and economic assumptions [*127*]. These cases alter residential and commercial assumptions for distributed generation technologies, end-use equipment, and building shell measures, focusing only on technological progress in the buildings sector. In the 2005 technology case,

Figure 27. Projected buildings sector electricity generation by selected distributed resources in the reference case, 2003-2025 (billion kilowatthours)

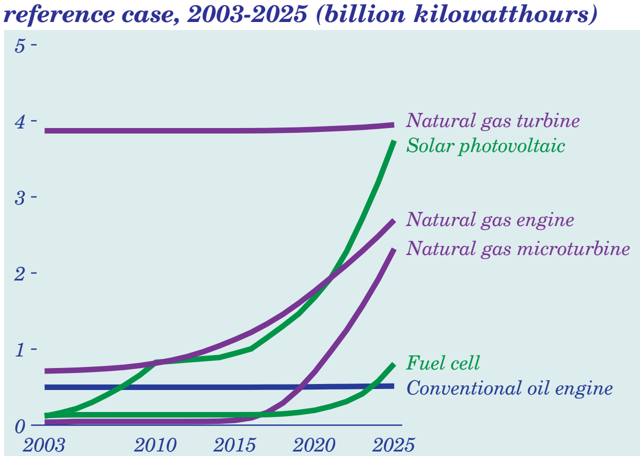
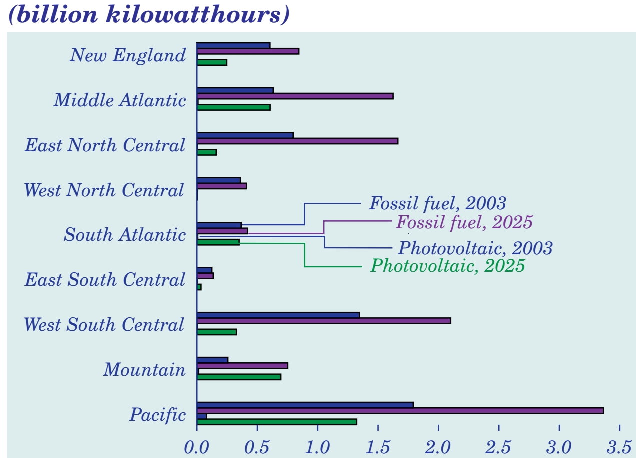


Figure 28. Projected buildings sector generation by fossil fuel-fired and photovoltaic systems by Census division in the reference case, 2003 and 2025 (billion kilowatthours)



which assumes no further technological improvements, fossil-fuel-fired CHP is projected to total 7.2 billion kilowatthours in 2025, a 14-percent increase from 2003 but 37 percent (4.2 billion kilowatthours) lower than the reference case projection (Table 25). Similarly, PV generation is projected to total 1.4 billion kilowatthours in 2025, 62 percent (2.3 billion kilowatthours) lower than reference case projection.

The buildings high technology case is based on more optimistic assumptions for emerging distributed generation technologies, allowing greater cost declines as shipments increase [*128*]. The high technology assumptions result in projected generation of 11.8 billion kilowatthours from fossil-fuel-fired CHP in 2025, 4 percent higher than the reference case projection. PV generation is projected to total 4.7 billion kilowatthours in 2025 in the high technology case, 25 percent higher that the reference case projection.

Energy Prices. In the *AEO2005* low world oil price case, lower prices for petroleum lead to lower projected electricity prices. As a result, more consumers are expected to purchase electricity rather than invest in distributed generation systems. In the low world oil price case, generation from fossil-fuel-fired CHP in buildings is projected to total 10.9 billion kilowatthours in 2025 (400 million kilowatthours less than in the reference case), and PV generation is projected to total 3.6 billion kilowatthours (100 million kilowatthours less than in the reference case)—both 4 percent lower than the corresponding reference case projections (Table 25). In the high world oil price case, projected electricity and natural gas prices are slightly higher than in the reference case for most of the forecast period. As a result, in 2025, generation from fossil-fuel-fired CHP in buildings is projected to total 11.8 billion kilowatthours, 4 percent (500 million kilowatthours) higher than the reference case projection, and PV generation is projected to total 3.9 billion kilowatthours, 4 percent (100 million kilowatthours) more than in the reference case.

Restricted Natural Gas Supply Case

The restricted natural gas supply case provides an analysis of the energy-economic implications of a scenario in which future gas supply is significantly more constrained than assumed in the reference case. Future natural gas supply conditions could be constrained because of problems with the construction and operation of large new energy projects, and because the future rate of technological progress could be significantly lower than the historical rate. Although the restricted natural gas supply case represents a plausible set of constraints on future natural gas supply, it is *not* intended to represent what is likely to happen in the future.

The restricted natural gas supply case assumes the following constraints on natural gas supply:

- The Alaska natural gas pipeline is not built and put into operation by 2025.
- No new U.S. regasification terminals for LNG are built during the forecast, but the proposed expansions of existing U.S. terminals are permitted to go into operation as currently scheduled, along with any new LNG terminals already under construction.
- The future rates of technological progress for oil and gas exploration and development for both conventional and unconventional gas are one-half of the historical rates assumed in the reference case.

The restricted supply case assumes that the Alaska natural gas pipeline is not built during the forecast period either because of public opposition to this project and/or a perception by potential project sponsors that there are significant risks associated with such a project that more than outweigh the potential rewards. Potential risks include the possibilities that pipeline construction costs could be significantly higher than currently estimated, and that future lower 48 natural gas prices could be considerably lower than either current prices or expected future prices.

The restricted supply case assumes that public opposition to the construction of new U.S. LNG regasification terminals would preclude their construction. Existing terminals are assumed to proceed with their expansion plans, based on the assumption that LNG operations at existing terminals have lower financial risk and are more acceptable to the public. Any new LNG terminals already under construction are assumed to be completed in the restricted supply

Table 25. Buildings sector distributed electricity generation in alternative cases: difference from the reference case in 2025 (billion kilowatthours)

Projection	Fossil-fuel-fired generation	Photovoltaic generation
Buildings 2005 technology case	-4.2	-2.3
Buildings high technology case	0.5	0.9
Low world oil price case	-0.4	-0.1
High world oil price case	0.5	0.1

case. In particular, Excelerate's EnergyBridge project in the Gulf of Mexico is under construction, in the sense that the LNG tankers are under construction, along with the docking buoy, which attaches the tanker to the pipeline. The Excelerate EnergyBridge project, the only new terminal represented in the restricted supply case, is assumed to become operational in 2006. The volume of LNG imported into Canada and Mexico is assumed to be identical in the restricted supply and reference cases.

The restricted supply case assumes limits on the degree to which technology could enhance the productivity of future oil and natural gas supply operations. For example, current technology permits producers to recover between 75 and 85 percent of the in-place gas in conventional expansion gas reservoirs. Clearly, the highest theoretical recovery is 100 percent. Similarly, while seismic technology to access underground geologic formations can still be improved, there could be diminishing economic returns to such advances, because it is unlikely that, even with such advances, seismic technology would be able to determine, for example, whether an adequate reservoir seal existed at the appropriate point in geologic time to permit the capture and retention of hydrocarbons.

Although the future rate of oil and gas technological progress might be considerably less than the historical rate, it is unlikely that there would be no technological progress in the future, given the competitive nature of the oil and gas business and continued private and public investment in research and development. Consequently, the restricted supply case assumes a rate of technological progress that is 50 percent lower than the historical rate. It is also assumed that the oil and gas industry in Canada would operate in the same technology environment as U.S. oil and gas producers. Consequently, the lower rate of technological improvement has the same impact on oil and gas exploration and development in Canada as in the United States.

Wellhead Natural Gas Prices. The assumptions used in the restricted natural gas supply case result in significantly higher projections of lower 48 wellhead natural gas prices. In 2015 and 2025, projected wellhead gas prices are 23 percent and 31 percent higher, respectively, in the restricted supply case than in the reference case (Figure 29). In 2015, the restricted supply case projects a wellhead price of $5.13 per thousand cubic feet (2003 dollars), compared with the reference case price of $4.16 per thousand cubic feet. Similarly, in 2025, the restricted supply case projects a wellhead price of $6.29 per thousand cubic feet, compared with the reference case price of $4.79 per thousand cubic feet.

Natural Gas Consumption. The high wellhead prices projected in the restricted supply case significantly reduce projected natural gas consumption (Figure 30). In the reference case, total U.S. natural gas consumption increases throughout the forecast, from 22.0 trillion cubic feet in 2003 to 30.7 trillion cubic feet in 2025. In the restricted supply case, total U.S. gas consumption grows from 2003 levels to a peak of 26.0 trillion cubic feet in 2014, then declines in the remainder of the forecast, to 24.5 trillion cubic feet in 2025.

All end-use sectors are projected to consume less natural gas in the restricted supply case. The electric power sector shows the greatest reduction in consumption because of the availability of other

Figure 29. Lower 48 average wellhead natural gas price in two cases, 2000-2025 (2003 dollars per thousand cubic feet)

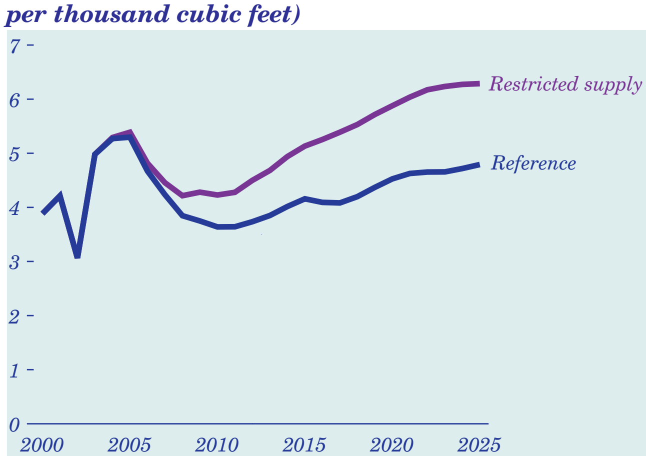
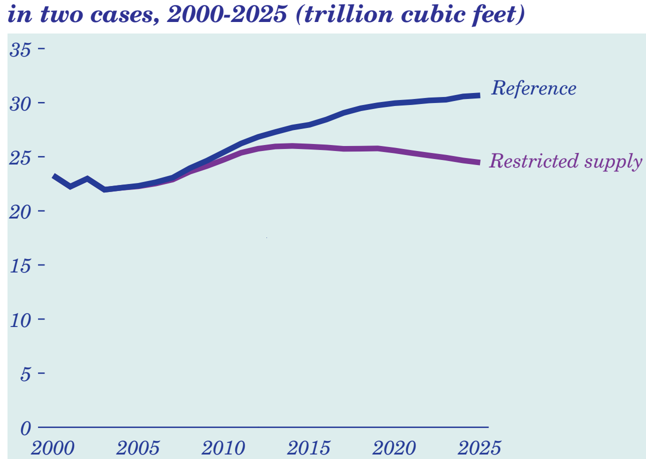


Figure 30. Total U.S. natural gas consumption in two cases, 2000-2025 (trillion cubic feet)



generating options. In 2025, projected natural gas consumption in the electric power sector is 4.3 trillion cubic feet lower in the restricted supply case than in the reference case (5.1 trillion cubic feet and 9.4 trillion cubic feet, respectively). The electric power sector accounts for almost 70 percent of the total reduction in projected gas consumption in 2025 in the restricted supply case and is largely responsible for the shape of the total gas consumption trend in that case (Figure 31). Specifically, natural gas consumption in the electric power sector is projected to peak in 2014 at 7.1 trillion cubic feet in the restricted supply case, then decline steadily to 5.1 trillion cubic feet in 2025.

The high natural gas prices in the restricted supply case both reduce the projected level of gas-fired electric generation capacity and reduce the use of the gas-fired generating plants already in operation. More coal-fired and renewable energy capacity is projected to be built as a result of the higher natural gas prices: 451 gigawatts of coal-fired capacity through 2025, as compared with 394 gigawatts in the reference case, and 114 gigawatts of renewable capacity in 2025, as compared with 103 gigawatts in the reference case.

The second largest decline in projected end-use natural gas consumption in the restricted supply case is in the industrial sector, with total projected consumption of 8.3 trillion cubic feet in 2025, as compared with 9.0 trillion cubic feet in the reference case. Industrial CHP production falls sharply as a result of the higher natural gas prices, from 123 billion kilowatthours in the reference case to 93 billion kilowatthours in the restricted supply case in 2025, which further reduces natural gas consumption.

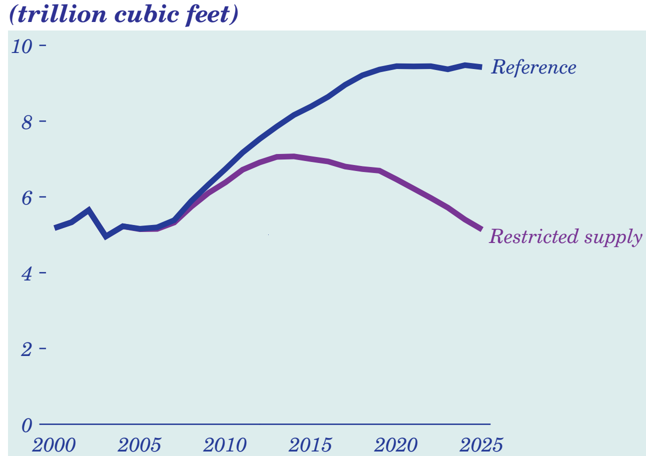
Projected natural gas consumption in the residential and commercial sectors is also reduced from reference case levels in the restricted supply case, again due to higher gas prices. Residential gas consumption in 2025 is projected to be 5.4 trillion cubic feet in the restricted supply case, compared with 6.0 trillion cubic feet in the reference case. Natural gas prices to residential consumers are 12 percent higher in the restricted supply case than in the reference case in 2015 and 19 percent higher in 2025, and residential electricity prices are 4 percent and 2 percent higher in 2015 and 2025, respectively.

Commercial gas consumption in 2025 is projected to be 3.8 trillion cubic feet in the restricted supply case, compared with 4.1 trillion cubic feet in the reference case. The higher natural gas prices in the restricted supply case prompt commercial consumers to invest in more efficient equipment or to switch to heating oil for their space heating and water heating needs, relative to the reference case. Commercial facilities also are expected to find natural-gas-fired CHP less attractive, with projected gas-fired electricity generation in the sector 17 percent (1.7 billion kilowatthours) lower in 2025 than projected in the reference case. Even with the actions described above, projected energy expenditures in the commercial sector in the restricted supply case are 5 percent higher than in the reference case in 2025, because the higher prices more than offset the reduced consumption volumes.

Natural Gas Supply. The supply of natural gas available to U.S. consumers comes from both domestic production and net imports. In the restricted natural gas supply case, the availability of future domestic gas production is constrained by the assumed absence of an Alaska natural gas pipeline and by rates of technological progress that are 50 percent lower than those observed historically. Natural gas imports are constrained by the assumption that only the currently scheduled proposed expansions of existing U.S. terminals are permitted to go into operation, along with new LNG terminals already under construction. Imports from Canada are constrained by the assumption of low rates progress in oil and gas exploration and recovery technologies.

The restricted supply case significantly reduces future LNG imports in comparison with the reference case projections (Figure 32). Net LNG imports in 2025 are projected to be 2.5 trillion cubic feet in the restricted supply case, compared with 6.4 trillion cubic feet in the reference case. Currently planned expansions at the four existing LNG terminals and

Figure 31. U.S. natural gas consumption for electric power generation in two cases, 2000-2025 (trillion cubic feet)



the construction and operation of the Excelerate EnergyBridge terminal are responsible for the increase in future LNG imports projected in the restricted supply case, relative to the 0.4 trillion cubic feet of net LNG imports in 2003. The restriction on new LNG terminals reduces LNG's share of total U.S. gas supply in 2025 from 21 percent in the reference case to 10 percent in the restricted supply case.

The higher natural gas prices projected in the restricted supply case have a mixed impact on net imports of natural gas from Canada. In the near term, the higher prices are projected to stimulate Canada's production, and from 2015 to 2020, U.S. imports of natural gas from Canada are projected to average about 340 billion cubic feet per year more in the restricted supply case than in the reference case. After 2020, a larger drop in net imports from Canada is projected in the restricted supply case than in the reference case, and projected net imports in 2025 are lower in the restricted supply case than in the reference case (2.3 trillion cubic feet and 2.5 trillion cubic, respectively).

With higher U.S. wellhead prices projected in the restricted supply case, Mexico is projected to become a net exporter of natural gas to the United States after 2019, rather than being a net importer as projected in the reference case. In 2025, net exports from Mexico to the United States are projected to be about 400 billion cubic feet of natural gas per year in the restricted supply case, compared with about 250 billion cubic feet per year of net imports from the United States in the reference case.

Total U.S. production of natural gas in 2025 is projected to be 19.1 trillion cubic feet in the restricted supply case, compared with 21.8 trillion cubic feet in the reference case (Figure 33). About 70 percent of the difference is directly attributable to the assumption that there would be no Alaska gas pipeline constructed in the restricted supply case.

In the lower 48 States, projected natural gas production is not significantly different in the restricted supply and reference cases, because the higher prices projected in the restricted supply case largely offset the lower assumed rate of technological progress. The restricted supply case projects total lower 48 gas production of 18.8 trillion cubic feet in 2025, 4 percent less than projected in the reference case. Most of the reduction in projected lower 48 conventional gas production—about 270 billion cubic feet in 2025 in the restricted supply case relative to the reference case—occurs offshore.

Unconventional gas production is sensitive to technological progress, because technological improvements could, for example, significantly improve the recovery rate of the unconventional gas in-place. Generally, there is more opportunity for technological progress to expand the economically recoverable unconventional resource base than the economically recoverable onshore conventional gas resource base. Offshore gas production is also sensitive to the future rate of technological progress, especially in the deepwater Gulf of Mexico. For example, technological improvements could reduce the development time necessary to bring oil and gas fields into operation and could make smaller oil and gas deposits profitable to produce.

Although projected lower 48 natural gas production in the restricted supply case is not significantly different from that in the reference case, the absence of an Alaska gas pipeline does reduce total U.S. gas

Figure 32. U.S. net imports of liquefied natural gas in two cases, 2000-2025 (trillion cubic feet)

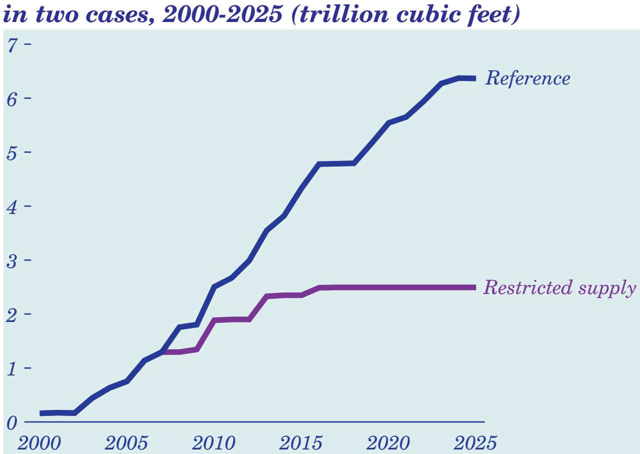
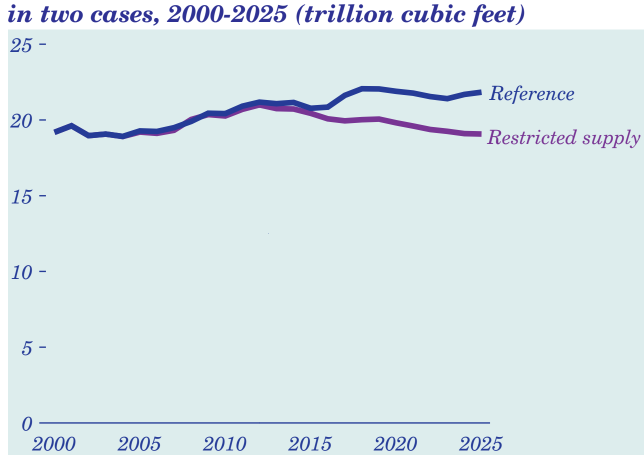


Figure 33. Total U.S. natural gas production in two cases, 2000-2025 (trillion cubic feet)



production throughout the forecast by 4 percent from 2003 through 2025. From an estimated technically recoverable natural gas resource base of 1,337 trillion cubic feet (as of January 1, 2003), 34 percent is projected to be produced in the restricted supply case, as compared with 36 percent in the reference case.

Electricity Prices and Consumption. In 2003, natural-gas-fired facilities provided 16 percent of the electricity generated in the United States. The reference case projects that gas-fired facilities will provide 25 percent of the electricity generated in 2025, compared with 14 percent in the restricted natural gas supply case. Because natural gas accounts for a significant portion of total electricity generation throughout the projections, higher natural gas prices increase future delivered electricity prices above those projected in the reference case. Although gas consumption in the electricity sector peaks in 2014 in the restricted supply case, the greatest difference in projections for the delivered price of electricity between the two cases is in 2018, when the price in the restricted supply case is 6 percent (0.4 cent per kilowatthour in 2003 dollars) higher than in the reference case.

Natural Gas Expenditures. The restricted natural gas supply case is projected to increase natural gas prices to a level that induces consumers to reduce their purchases of natural gas. Given the long lifetime of most gas-consuming equipment, the adjustment to higher gas prices would be relatively slow. Consequently, the negative impacts of high natural gas prices are more apparent in the nearer term than toward the end of the forecast. For example, the higher gas prices in the restricted supply case causes total projected U.S. end-use expenditures for natural gas to increase to $171 billion in 2015—equal to 1.1 percent of GDP—compared with $158 billion (1.0 percent of GDP) in the reference case (Figure 34). The greatest difference in gas consumption expenditures between the two cases, $13.4 billion, is projected in 2016. In 2025, when overall gas consumption is reduced in the restricted supply case, total end-use expenditures for natural gas are projected to be only $1.0 billion more than in the reference case.

Figure 34. Total end-use expenditures on natural gas in two cases, 2003-2025 (billion 2003 dollars)