STATEMENT OF GUY CARUSO

ADMINISTRATOR

ENERGY INFORMATION ADMINISTRATION

U.S. DEPARTMENT OF ENERGY

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Mr. Chairman and Members of the Committee:

I appreciate the opportunity to appear before you today. As requested in your letter of invitation, my testimony will address two main areas: the U.S. energy outlook and the recent experience with energy price volatility.

The Energy Information Administration (EIA) is an independent statistical and analytical agency within the Department of Energy. We are charged with providing objective, timely, and relevant data, analysis, and projections for the use of the Congress, the Administration, and the public. We do not take positions on policy issues, but we do produce data, analysis, and forecasts that are meant to help policy makers in their energy policy deliberations. Because we have an element of statutory independence with respect to the analyses, our views are strictly those of EIA and should not be construed as representing those of the Department of Energy or the Administration. However, EIA's baseline projections on energy trends are widely used by Government agencies, the private sector, and academia for their own energy analyses.

The *Annual Energy Outlook* provides projections and analysis of domestic energy consumption, supply, prices, and energy-related carbon dioxide emissions through 2025. *Annual Energy Outlook 2005* (*AEO2005*) is based on Federal and State laws and regulations in effect on October 31, 2004. The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require funds or implementing regulations that have not been provided or specified—are not reflected in the projections. *AEO2005* explicitly includes the impact of the recently enacted American Jobs Creation Act of 2004, the Military Construction Appropriations Act for Fiscal Year 2005, and the Working Families Tax Relief Act of 2004. *AEO2005* does not include the potential impact of proposed regulations such as the Environmental Protection Agency's (EPA) Clean Air Interstate and Clean Air Mercury rules.

The U.S. projections in this testimony are based on the *AEO2005*, which was released on the EIA website on February 11, 2005. The *AEO2005* is not meant to be an exact prediction of the future but represents a likely energy future, given technological and demographic trends, current laws and regulations, and consumer behavior as derived from known data. EIA recognizes that projections of energy markets are highly uncertain and subject to many random events that cannot be foreseen such as weather, political disruptions, and technological breakthroughs. In addition to these phenomena, long-term trends in technology development, demographics, economic growth, and energy resources may evolve along a different path than expected in the projections. The *AEO2005* includes a large number of alternative cases intended to examine these uncertainties. The *AEO2005* provides integrated projections of U.S. and world energy market trends for roughly the next two decades. The following discussion summarizes the highlights from *AEO2005* for the major categories of U.S. energy prices, demand, and supply and also includes the findings from some alternative cases.

U.S. Energy Outlook

U.S. Energy Prices

In the *AEO2005* reference case, the annual average world oil price[1] increases from $27.73 per barrel (2003 dollars) in 2003 ($4.64 per million Btu) to $35.00 per barrel in 2004 ($5.86 per million Btu) and then declines to $25.00 per barrel in 2010 ($4.18 per million Btu) as new supplies enter the market. It then rises slowly to $30.31 per barrel in 2025 ($5.07 per million Btu) (**Figure 1**). In nominal dollars, the average world oil price is about $52 per barrel in 2025 ($8.70 per million Btu).

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. For example, the *AEO2005* reference case assumes that world crude oil prices will decline as growth in consumption slows and producers increase their productive capacity and output in response to current high prices; however, the October 2004 oil futures prices for West Texas Intermediate crude oil (WTI) on the New York Mercantile Exchange (NYMEX) implies that the average annual oil price in 2005 will exceed its 2004 level before declining to levels that still would be above those projected in the reference case. To evaluate this uncertainty about world crude oil prices, the *AEO2005* includes other cases based on alternative world crude oil price paths, which are designed to address the uncertainty about the market behavior of the Organization of Petroleum Exporting Countries (OPEC). They are not intended to span the full range of possible outcomes.

The alternative world oil price cases examined include:

- High A world oil price case. Prices are projected to remain at about $34 per barrel (2003 dollars) 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 dollars per barrel (2003 dollars), fall to $37 in 2010, and rise to $48 dollars per barrel in 2025.

- Low world oil price case. Prices are projected to decline from their high in 2004 to $21 per barrel (2003 dollars) in 2009 and to remain at that level out to 2025.

Figure 2 provides a comparison of the reference case and the high B world oil price case. The implications of these alternative cases will be discussed later.

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1 World oil prices in *AEO2005* are defined based on the 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 has been as much as six dollars per barrel lower than the WTI in recent months. For the first 11 months of 2004, WTI averaged $41.31 per barrel ($7.12 per million Btu), while IRAC averaged $36.94 per barrel (nominal dollars) ($6.37 per million Btu).

In the *AEO2005*, average wellhead prices for natural gas in the United States are projected to decrease from $4.98 per thousand cubic feet (2003 dollars) in 2003 ($4.84 per million Btu) to $3.64 per thousand cubic feet in 2010 ($3.54 per million Btu) as the availability of new import sources and increased drilling expand available supply. After 2010, wellhead prices are projected to increase gradually, reaching $4.79 per thousand cubic feet in 2025 ($4.67 per million Btu) (about $8.20 per thousand cubic feet or $7.95 per million Btu in nominal dollars). Growth in liquefied natural gas (LNG) imports, Alaska production, and lower-48 production from nonconventional sources is not expected to increase sufficiently to offset the impacts of resource depletion and increased demand in the lower-48 States.

In *AEO2005*, the combination of more moderate increases in coal production, expected improvements in mine productivity, and a continuing shift to low-cost coal from the Powder River Basin in Wyoming leads to a gradual decline in the average minemouth price, to approximately $17 per ton (2003 dollars) shortly after 2010 ($0.86 per million Btu). The price is projected to remain nearly constant between 2010 and 2020, increasing after 2020 as rising natural gas prices and the need for baseload generating capacity lead to the construction of many new coal-fired generating plants. By 2025, the average minemouth price is projected to be $18.26 per ton ($0.91 per million Btu). The *AEO2005* projection is equivalent to an average minemouth coal price of $31.25 per ton in nominal dollars in 2025 ($1.56 per million Btu).

Average delivered electricity prices are projected to decline from 7.4 cents per kilowatthour (2003 dollars) in 2003 ($21.68 per million Btu) to a low of 6.6 cents per kilowatthour in 2011 ($19.34 per million Btu) as a result of an increasingly competitive generation market and a decline in natural gas prices. After 2011, average real electricity prices are projected to increase, reaching 7.3 cents per kilowatthour in 2025 ($21.38 per million Btu) (equivalent to 12.5 cents per kilowatthour or $36.61 per million Btu in nominal dollars).

U.S. Energy Consumption

<u>Total energy consumption</u> is projected to grow at about one-half the rate (1.4 percent per year) of gross domestic product (GDP) with the strongest growth in energy consumption for electricity generation (discussed later) and transportation and commercial uses. Transportation energy demand is expected to increase from 27.1 quadrillion Btu in 2003 to 40.0 quadrillion Btu in 2025, a growth rate of 1.8 percent per year (**Figure 3**). The largest demand growth occurs in light-duty vehicles and accounts for about 60 percent of the total increase in transportation energy demand by 2025, followed by heavy truck travel (20 percent of total growth) and air travel (12 percent of total growth). Delivered commercial energy consumption is projected to grow at a more rapid average annual rate of 1.9 percent between 2003 and 2025, reaching 12.5 quadrillion Btu in 2025, consistent with growth in commercial floorspace. The most rapid increase in commercial energy demand is projected for electricity used for computers, office equipment, telecommunications, and miscellaneous small appliances.

Delivered industrial energy consumption in *AEO2005* is projected to reach 30.8 quadrillion Btu in 2025, growing at an average rate of 1.0 percent per year between 2003 and 2025, as efficiency improvements in the use of energy only partially offset the impact of growth in manufacturing output. Delivered residential energy consumption is projected to grow from 11.6 quadrillion British thermal units (Btu) in 2003 to 14.3 quadrillion Btu in 2025 (0.9 percent per year). This growth is consistent with population growth and household formation. The most rapid growth in residential energy demand in *AEO2005* is projected to be in the demand for electricity used to power computers, electronic equipment, and appliances.

The reference case includes the effects of several policies aimed at increasing energy efficiency in both end-use technologies and supply technologies, including minimum efficiency standards and voluntary energy savings programs. However, as noted previously, the projections in *AEO2005* are based on existing Federal and State laws and regulations in effect on October 31, 2004. The impact on energy consumption of efficiency improvement could be different than what is shown in the reference case. **Figure 4** compares energy consumption in three cases to illustrate this point. The 2005 technology case assumes no increase in efficiency beyond that available in 2005. By 2025, 5 percent more energy (7.6 quadrillion Btu) is required than in the reference case. The high technology case assumes that the most-energy efficiency technologies are available earlier with lower costs and higher efficiencies. By 2025, total energy consumption is 7 quadrillion Btu lower in the high technology case when compared with the reference case.

Total petroleum demand is projected to grow at an average annual rate of 1.5 percent in the *AEO2005* reference case forecast, from 20.0 million barrels per day in 2003 to 27.9 million barrels per day in 2025 (**Figure 5**) led by growth in transportation uses, which account for 67 percent of total petroleum demand in 2003, increasing to 71 percent in 2025. Improvements in the efficiency of vehicles, planes, and ships are more than offset by growth in travel.

Total demand for natural gas is also projected to increase at an average annual rate of 1.5 percent from 2003 to 2025. About 75 percent of the growth in gas demand from 2003 to 2025 results from increased use in power generation and in industrial applications.

Total coal consumption is projected to increase from 1,095 million short tons in 2003 to 1,508 million short tons in 2025, growing by 1.5 percent per year. About 90 percent of the coal is currently used for electricity generation. Coal remains the primary fuel for generation and its share of generation is expected to remain about 50 percent between 2003 and 2025. Total coal consumption for electricity generation is projected to increase by an average of 1.6 percent per year, from 1,004 million short tons in 2003 to 1,425 million short tons in 2025.

Total electricity consumption, including both purchases from electric power producers and on-site generation, is projected to grow from 3,657 billion kilowatthours in 2003 to 5,467 billion kilowatthours in 2025, increasing at an average rate of 1.8 percent per year. Rapid growth in electricity use for computers, office equipment, and a variety of electrical appliances in the end-use sectors is partially offset in the *AEO2005* forecast by improved efficiency in these and other, more traditional electrical applications and by slower growth in electricity demand in the industrial sector.

Total marketed renewable fuel consumption, including ethanol for gasoline blending, is projected to grow by 1.5 percent per year in *AEO2005*, from 6.1 quadrillion Btu in 2003 to 8.5 quadrillion Btu in 2025, largely as a result of State mandates for renewable electricity generation and the effect of production tax credits. About 60 percent of the projected demand for renewables in 2025 is for grid-related electricity generation (including combined heat and power), and the rest is for dispersed heating and cooling, industrial uses, and fuel blending.

U.S. Energy Intensity

Energy intensity, as measured by primary energy use per dollar of GDP (2000 dollars), is projected to decline at an average annual rate of 1.6 percent in the *AEO2005*, with efficiency gains and structural shifts in the economy offsetting growth in demand for energy services (**Figure 6**). The projected rate of energy intensity decline in *AEO2005* falls between the historical averages of 2.3 percent per year from 1970 to 1986, when energy prices increased in real terms, and 0.7 percent per year from 1986 to 1992, when energy prices were generally falling. Between 1992 and 2003, energy intensity has declined on average by 1.9 percent per year. During this period, the role of energy-intensive industries in the U.S. economy fell sharply. Energy-intensive industries' share of industrial output declined 1.3 percent per year from 1992 to 2003. In the *AEO2005* forecast, the energy-intensive industries' share of total industrial output is projected to continue declining but at a slower rate of 0.8 percent per year, which leads to the projected slower annual rate of reduction in energy intensity.

Historically, energy use per person has varied over time with the level of economic growth, weather conditions, and energy prices, among many other factors. During the late 1970s and early 1980s, energy consumption per capita fell in response to high energy prices and weak economic growth. Starting in the late 1980s and lasting through the mid-1990s, energy consumption per capita increased with declining energy prices and strong economic growth. Per capita energy use is projected to increase in *AEO2005*, with growth in demand for energy services only partially offset by efficiency gains. Per capita energy use is expected to increase by an average of 0.5 percent per year between 2003 and 2025 in *AEO2005*.

U.S. Energy Production and Imports

Total energy consumption is expected to increase more rapidly than domestic energy supply through 2025. As a result, net imports of energy are projected to meet a growing share of energy demand. Net imports are expected to constitute 38 percent of total U.S. energy consumption in 2025, up from 27 percent in 2003 (**Figure 7**).

Petroleum. Projected U.S. crude oil production increases from 5.7 million barrels per day in 2003 to a peak of 6.2 million barrels per day in 2009 as a result of increased production offshore, predominantly in the deep waters of the Gulf of Mexico. Beginning in 2010, U.S. crude oil production is expected to start declining, falling to 4.7 million barrels per day in 2025. Total domestic petroleum supply (crude oil, natural gas plant liquids, refinery processing gains, and other refinery inputs) follows the same pattern as crude oil production in the *AEO2005* forecast, increasing from 9.1 million barrels per day in 2003 to a peak of 9.8 million barrels per day in 2009, then declining to 8.8 million barrels per day in 2025 (**Figure 8**).

In 2025, net petroleum imports, including both crude oil and refined products (on the basis of barrels per day), are expected to account for 68 percent of demand, up from 56 percent in 2003. Despite an expected increase in domestic refinery distillation capacity, net refined petroleum product imports account for a growing proportion of total net imports, increasing from 14 percent in 2003 to 16 percent in 2025.

In the U.S. energy markets, 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. **Figure 9** compares the impact of the *AEO2005* reference and high B world oil price cases on U.S. oil production, consumption, and imports.

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 per day (24 percent) higher in the high B case than in the reference case. Production in the high B case includes 1.2 million barrels per day in 2025 of synthetic petroleum fuel produced from coal and natural gas (**Figure 10**). Total net imports in 2025, including crude oil and refined products, are reduced from 19.1 million barrels per day in the reference case to 15.2 million barrels per day 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.

Natural Gas. Domestic natural gas production is projected to increase from 19.1 trillion cubic feet in 2003 to 21.8 trillion cubic feet in 2025 in *AEO2005* (**Figure 11**). Lower 48 onshore natural gas production is projected to increase from 13.9 trillion cubic feet in 2003 to a peak of 15.7 trillion cubic feet in 2012 before falling to 14.7 trillion cubic feet in 2025. Lower 48 offshore production, which was 4.7 trillion cubic feet in 2003, is projected to increase in the near term to 5.3 trillion cubic feet by 2014 because of the expected development of some large deepwater fields, including Mad Dog, Entrada, and Thunder Horse. After 2014, offshore production is projected to decline to about 4.9 trillion cubic feet in 2025.

Growth in U.S. natural gas supplies will depend on unconventional domestic production, natural gas from Alaska, and imports of LNG. Total nonassociated unconventional natural gas production is projected to grow from 6.6 trillion cubic feet in 2003 to 8.6 trillion cubic feet in 2025. With completion of an Alaskan natural gas pipeline in 2016, total Alaskan production is projected to increase from 0.4 trillion cubic feet in 2003 to 2.2 trillion cubic feet in 2025.

Three of the four existing U.S. LNG terminals (Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana) are all expected to expand by 2007, and additional facilities are expected to be built in the lower-48 States, serving the Gulf, Mid-Atlantic, and South Atlantic States, including a new facility in the Bahamas serving Florida via a pipeline. Another facility is projected to be built in Baja California, Mexico, serving a portion of the California market. Total net LNG imports in the United States and the Bahamas are projected to increase from 0.4 trillion cubic feet in 2003 to 6.4 trillion cubic feet in 2025.

Net Canadian imports are expected to decline from 2003 levels of 3.1 trillion cubic feet to about 2.5 trillion cubic feet by 2009. After 2010, Canadian natural gas imports in *AEO2005* increase to 3.0 trillion cubic feet in 2015 as a result of rising natural gas prices, the introduction of gas from the Mackenzie Delta, and increased production from coalbeds. After 2015, because of reserve depletion effects and growing domestic demand in Canada, net U.S. imports are projected to decline to 2.6 trillion cubic feet in 2025.

Coal. As domestic coal demand grows in *AEO2005*, U.S. coal production is projected to increase at an average rate of 1.5 percent per year, from 1,083 million short tons in 2003 to 1,488 million short tons in 2025. Production from mines west of the Mississippi River is expected to provide the largest share of the incremental coal production. In 2025, nearly two-thirds of coal production is projected to originate from the western States (**Figure 12**).

U.S. Electricity Generation

In *AEO2005*, generation from both natural gas and coal is projected to increase through 2025 to meet growing demand for electricity. *AEO2005* projects that 1,406 billion kilowatthours of electricity (including generation in the end-use sectors) will be generated from natural gas in 2025, more than twice the 2003 level of about 630 billion kilowatthours (**Figure 13**). The natural gas share of electricity generation is projected to increase from 16 percent in 2003 to 24 percent in 2025. Generation from coal is projected to grow from about 1,970 billion kilowatthours in 2003 to 2,890 billion kilowatthours in 2025, with the share decreasing slightly from 51 percent in 2003 to 50 percent in 2025. Between 2004 and 2025, *AEO2005* projects that 87 gigawatts of new coal-fired generating capacity will be constructed.

Nuclear generating capacity in the *AEO2005* is projected to increase from 99.2 gigawatts in 2003 to 102.7 gigawatts in 2025 as a result of uprates of existing plants between 2003 and 2025. All existing nuclear plants are projected to continue to operate, but EIA projects that no new plants will become operational between 2003 and 2025. Total nuclear generation is projected to grow from 764 billion kilowatthours in 2003 to 830 billion kilowatthours in 2025 in *AEO2005*. The share of electricity generated from nuclear is projected to decline from 20 percent in 2003 to 14 percent in 2025.

The *AEO2005* reference case assumptions for the cost and performance characteristics of new nuclear technologies are based on cost estimates by Government and industry analysts, allowing for uncertainties about new, unproven designs. Two advanced nuclear cost cases analyze the sensitivity of the projections to lower costs for new nuclear power plants. The advanced nuclear cost case assumes capital and operating costs 20 percent below the reference case in 2025, reflecting a 28-percent reduction in overnight capital costs from 2005 to 2025. The vendor estimates case assumes reductions relative to the reference case of 18 percent initially and 38 percent by 2025. These costs are consistent with estimates from British Nuclear Fuels Limited for the manufacture of its advanced pressurized-water reactor (AP1000). Cost and performance characteristics for all other technologies are assumed to be the same as those in the reference case.

Projected nuclear generating costs in the advanced nuclear cost cases are competitive with the generating costs projected for new coal- and natural-gas-fired units toward the end of the projection period. In the advanced nuclear case, 7 gigawatts of new nuclear capacity are added by 2025, while the greater cost reductions in the vendor estimates case bring on 25 gigawatts by 2025 (**Figure 14**). The additional nuclear capacity displaces primarily new coal capacity.

Renewable technologies are projected to grow slowly in the *AEO2005* reference case because they are relatively capital intensive and they do not compete broadly with traditional fossil-fired generation. Where enacted, State renewable portfolio standards, which specify a minimum share of generation or sales from renewable sources, are included in the forecast. *AEO2005* includes the extension of the Federal production tax credit (PTC) for wind and biomass through December 31, 2005, as indicated in H.R. 1308, the Working Families Tax Relief Act of 2004. Total renewable generation in *AEO2005*, including combined heat and power generation, is projected to increase from 359 billion kilowatthours in 2003 to 489 billion kilowatthours in 2025, increasing 1.4 percent per year.

Current law has the PTC expiring at the end of 2005; however, since the enactment of the PTC in 1992, several previously established sunset dates have come and gone. In each instance, the credit has been extended, generally several months after expiration, with retroactive application. Thus, extension beyond the current 2005 expiration 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. This 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 forecast, which assumes no extension of the PTC beyond 2005. This case is based on an "as-is" extension of the renewable electricity PTC program, as expanded by American Jobs Creation Act of 2004, to facilities placed in service by the end of 2015.

Figure 15 summarizes the impact of the extension of the PTC to 2015 in this alternative case. Wind power sees 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).

U.S. Carbon Dioxide Emissions

Carbon dioxide emissions from energy use are projected to increase from 5,789 million metric tons in 2003 to 8,062 million metric tons in 2025 in *AEO2005*, an average annual increase of 1.5 percent (**Figure 16**). The carbon dioxide emissions intensity of the U.S. economy is projected to fall from 558 metric tons per million dollars of GDP in 2003 to 397 metric tons per million dollars of GDP in 2025, an average decline of 1.5 percent per year. Projected increases in carbon dioxide emissions primarily result from continued reliance on coal for electricity generation and on petroleum fuels in the transportation sector.

Petroleum and Natural Gas Price Volatility

In your letter of invitation, Mr. Chairman, you also asked that we address energy price volatility. The *AEO2005*, a 20-year forecast, does not address daily or monthly swings in energy prices due to changes in the rate of economic growth, weather variation, or temporary supply disruptions. However, EIA has data as well as expertise that can be used to examine recent historical crude oil and natural gas price volatility and its most likely causes.

Petroleum Prices and Price Volatility

Recently, WTI crude oil on the NYMEX has traded at over $50 per barrel. The main reason behind the crude oil price increases seen since early 2004 is unexpected strong demand growth worldwide, which not only outstripped supply growth to tighten the world balance, but also reduced world excess crude oil production capacity to very low levels. A 2.7-million-barrel-per-day increase in global oil demand, largely due to significant growth in China and the United States, combined with only a 0.9-million-barrel increase in non-OPEC production, forced OPEC to produce very close to its capacity towards the end of 2004. This situation leaves little flexibility in the crude oil supply system. This tighter balance explains why prices have moved from the $30s to the $40s and $50s, with concerns about future supplies pushing prices higher.

While crude oil prices have more than doubled over the $20-per-barrel prices experienced in the 1990s, volatility, which is a measure of short-term price fluctuations on a percentage basis, also clearly has increased in the last 5-year period compared with the early-to-mid 1990s (**Figure 17**). Volatility, because of the way it is defined, may stay relatively constant when overall prices are increasing even though absolute price fluctuations are increasing sharply (**Figure 18**). For consumers, the magnitude of absolute price changes is of most concern. For example, 5-cent-per-gallon gasoline price fluctuations on a base price of $1.00 are equivalent in the traditional volatility sense to 10-cent-per-gallon fluctuations on a $2.00-per-gallon base price. However, in the second case, the consumer is not only paying more for the gasoline, but is also having to deal with larger price variations. **Figure 19** shows that consumers rarely saw weekly changes above 2 cents per gallon during the 1990s, but since 2000, fluctuations have increased, with occasional weekly changes over 6 cents per gallon, which were not seen during the 1990s.

Crude oil price volatility normally passes through to the markets for petroleum products, such as gasoline, diesel fuel, and heating oil. Because crude oil costs are by far the largest component of product costs, product and crude oil prices tend to move together. In addition, product markets have their own volatility over and above crude oil. As a result, gasoline price volatility is higher than crude price volatility. The tighter world petroleum market since 2000 has resulted in low product inventories as well as low crude oil inventories. When an unexpected loss of product supply or an increase in demand occurs, product prices will rise over and above crude oil prices until new supply enters the market, The longer the time for re-supply, the larger the price increase.

U.S. product markets have evolved in a way that adds to the potential for product price volatility apart from crude oil. The continued growth in domestic petroleum demand has increased U.S. refinery capacity utilization to the point that little excess refinery production capacity is available during peak demand months to help cover unexpected needs. At the same time, the delivery system has been strained both by growing demand and an increasing number of distinct fuel types being used to provide cleaner-burning fuels to consumers. Such fragmentation of the market can slow down the supply system's ability to re-supply areas that experience unexpected supply problems, such as a refinery of pipeline outage. However, to date, this does not seem to have resulted in major regional price spikes outside of California and the Midwest. The move to cleaner-burning fuels may also affect imports in a way that could add to volatility. For example, the sulfur reductions in gasoline and diesel and some States' bans on methyl tertiary butyl ether (MTBE) use in gasoline limit the number of import sources that can serve U.S. markets. While the remaining sources have been able to meet our needs, the U.S. has fewer places to turn when unexpected supply-demand imbalances occur, which can delay supply response and create larger price swings. While the import situation will likely improve as the world continues to move to cleaner-burning fuels, today, U.S. import supply for petroleum products is more constrained than during the 1990s.

Natural Gas Prices and Price Volatility

Natural gas spot prices at the Henry Hub recently have been around $7 per thousand cubic feet, which exceeds the levels for all but a few periods since the beginning of 2000. The average monthly wellhead price for the first 2 months of 2005 has been above $5.50 per thousand cubic feet. This is almost three times the average price during the 1990s. Factors contributing to the recent relatively high prices include flat or declining U.S. natural gas production, limited growth in net imports, high petroleum prices, increasing industrial demand driven by the economic recovery, and expanding stocks of gas burning equipment in households and electric power generation. Approximately 84 percent of U.S. supplies come from domestic production. The declining productivity of new gas wells means that any need for additional supplies can be met primarily with higher cost production, if at all. This supply tightness contributes to higher prices and price volatility.

Natural gas supply has been tight since mid-2002, exhibiting a higher overall price level with periods of significant volatility (**Figure 20**). A severe cold spell and low levels of working gas in storage during the first quarter of 2003 resulted in severe price volatility. In 2003, natural gas wellhead prices rose, peaking at $6.96 per thousand cubic feet for the month of March. Since then, although prices have declined somewhat, they remain at historically high levels. Price volatility has not been as severe since. The mild summer and winter in 2004 resulted in a decline in volatility from the relatively high level experienced in 2003. However, during this time, increasing industrial demand for natural gas, shut-in natural gas production in the Gulf of Mexico, and increasing world crude oil and heating oil prices have put upward pressure on natural gas prices. With a tight natural gas demand and supply balance and limited short-term substitutability in the natural gas market, fluctuations in supply or demand owing to weather, transmission congestion, or supply disruptions create the potential for large swings in prices.

Owing to the short-run relative inelasticity of supply and demand, levels of natural gas in storage are a critical element in managing short-term fluctuations in demand and supply. During the period since 1993, natural gas prices have become most volatile as the level of natural gas in storage falls. As of the end of February 2005, working gas in storage was more than 25 percent above the 5-year average. This should help mitigate natural gas price volatility during the remainder of 2005. However, weather and its relation to gas-fired power generation could jeopardize the stability of gas markets during the upcoming summer months. The dependence on gas-fired power generation is heightened because of a prolonged drought in the West, which has reduced available electricity from hydroelectric generation.

Imports have continued to play a crucial role in balancing U.S. natural gas supply and demand, with net imports contributing almost 16 percent of U.S. consumption in 2004. However, continued growth of natural gas demand in Canada and maturing producing fields has dimmed prospects for growth in imports from Canada. After 16 years of steady growth, Canadian sales to the United States declined in 2003 with only a partial recovery last year. However, imports of LNG to the continental United States have expanded dramatically in recent years, reaching 652 billion cubic feet in 2004, which is a new annual record. LNG imports to the continental United States in 2004 represented about 3.5 percent of U.S. dry production and 16 percent of total natural gas imports.

Substantial demand reductions seem unlikely in the near future as demand growth continues in the residential, commercial, and electric power sectors. Demand for natural gas traditionally has been highly seasonal, depending strongly on the weather changes. The seasonal character of natural gas demand is driven by its principal use in the residential and commercial sectors for space and water heating, causing demand peaks and price spikes during the cold weather months of the year. When severe winter weather strikes, residential and much of commercial consumption tends to be unresponsive to price increases. This demand inelasticity, in conjunction with the capacity constrained supply, often results in relatively large price changes as weather varies during the heating season.

Price volatility in the natural gas market does not appear to have changed appreciably since 1993. During this time, there have been several occasions of extreme price volatility. These periods of high volatility in the natural gas market typically occur during the heating season months when demand peaks and supplies are most constrained. Natural gas prices remain significantly volatile compared with most other commodities. Moreover, in terms of absolute price changes, variability in the natural gas market has increased since 2000 (**Figure 21**). These higher absolute price swings could pose significant challenges for consumers of natural gas in the future.

Conclusions

Continuing economic growth in the United States is expected to stimulate more energy demand, with fossil fuels remaining the dominant source of energy. Dependence on foreign sources of oil is expected to increase significantly in the United States. Petroleum imports that accounted for 56 percent of total U.S. petroleum demand in 2003 are expected to account for 68 percent of total demand by 2025 and the United States alone is expected to account for about 20 percent of the world increase in projected oil demand through 2025, with most of the increase resulting from increased consumption for transportation. This strong growth in oil consumption adds to pressure on world oil prices and can lead to increased price volatility.

Furthermore, although natural gas production in the United States is expected to increase, natural gas imports, particularly LNG, is expected to grow rapidly. Total net LNG imports in the United States and the Bahamas are projected to increase from 0.4 trillion cubic feet in 2003 to 6.4 trillion cubic feet in 2025. In the United States, reliance on domestic natural gas supply to meet demand is projected to fall from 86 percent in 2003 to 72 percent in 2025. The growing dependence on imports in the United States occurs despite efficiency improvements in both the consumption and the production of natural gas. Uncertainty about the adequacy and timing of the investment capital needed to put the infrastructure in place to allow for this level of imports adds to the uncertainty about future energy prices. Again, this can lead to increased price volatility.

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

Figure 1. U.S. Energy Prices, 1970-2025

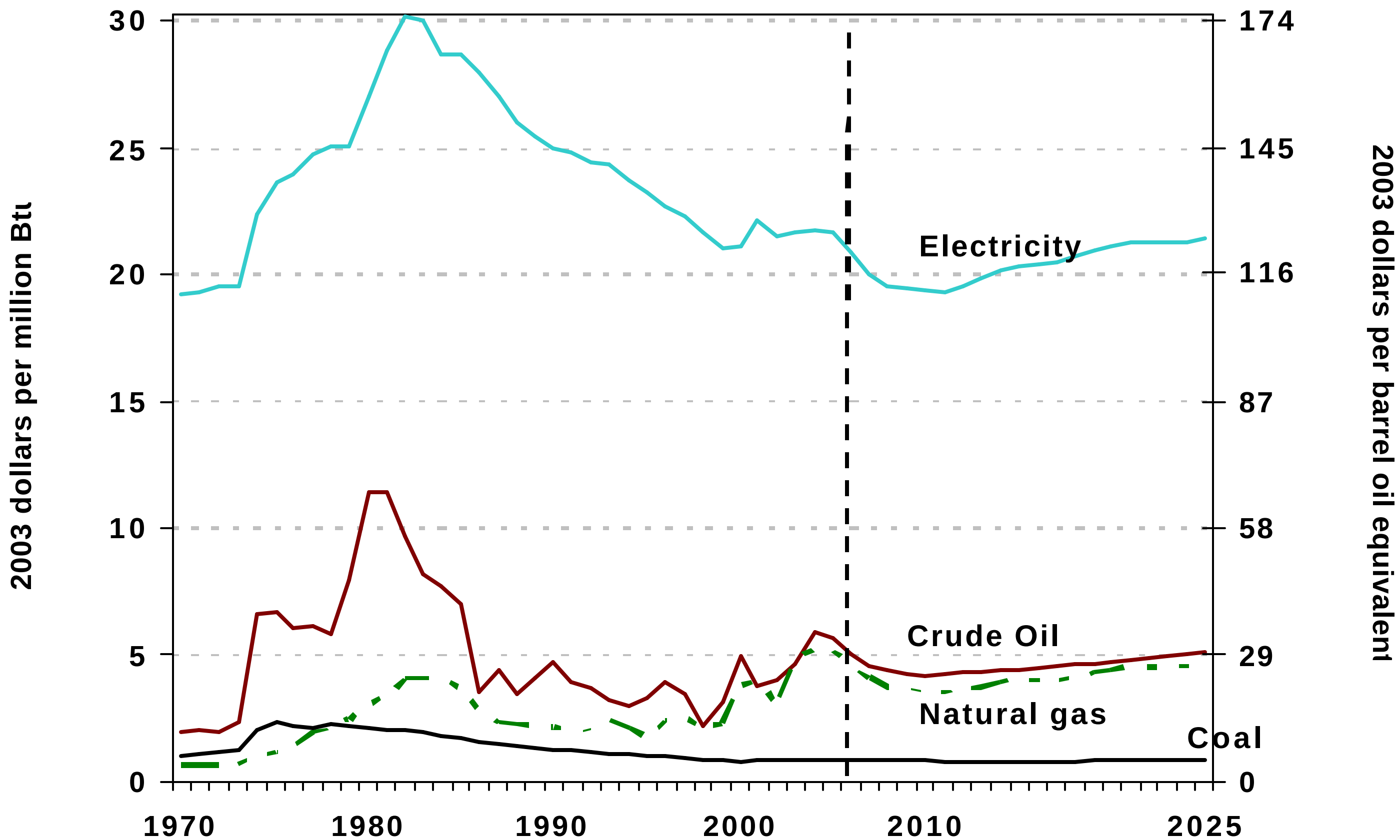

Figure 2. World Oil Price in two cases, 1970-2025
(2003 dollars per barrel)

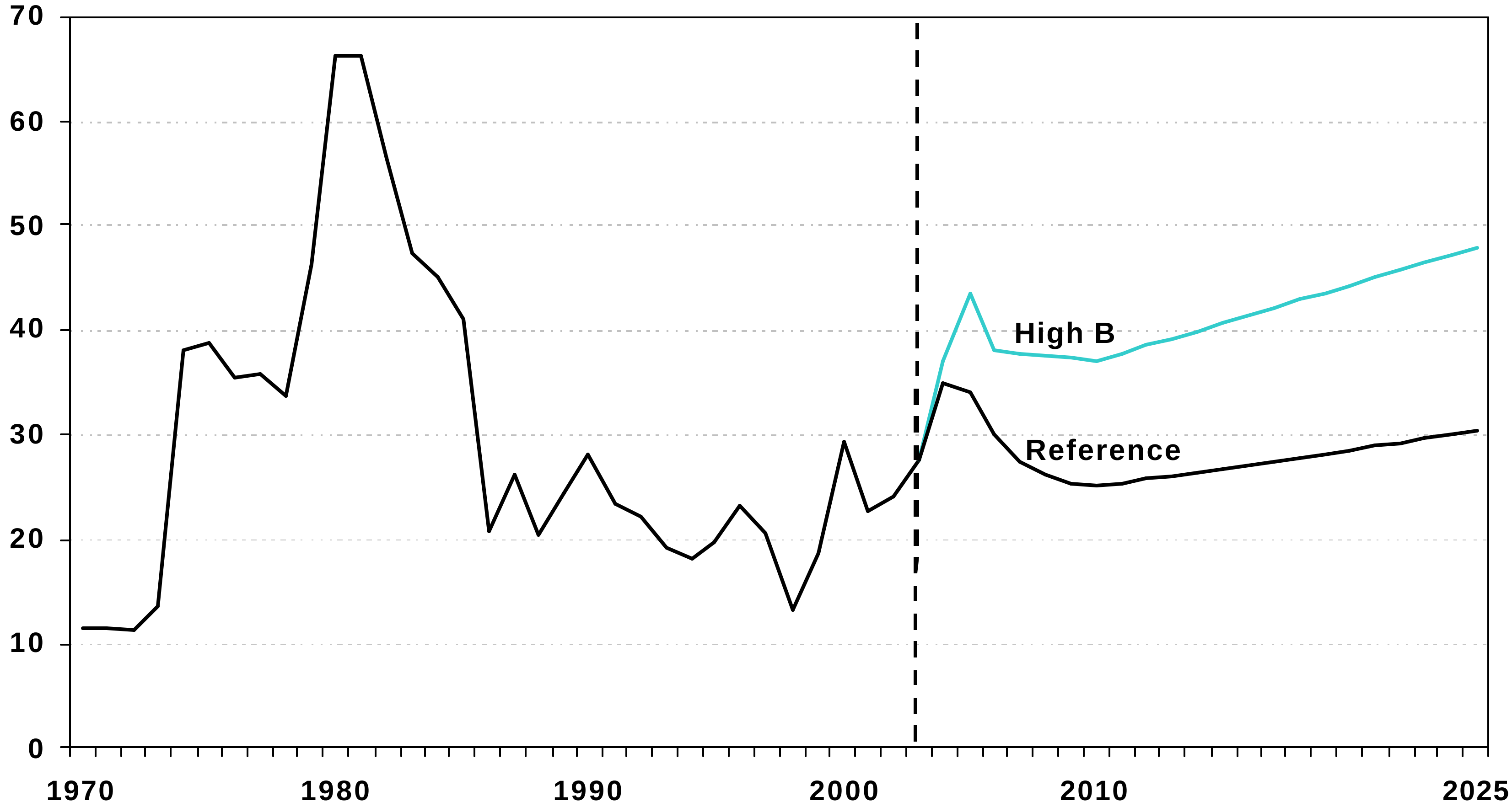

Figure 3. U.S. Delivered Energy Consumption by Sector, 2003 and 2025 (quadrillion Btu)

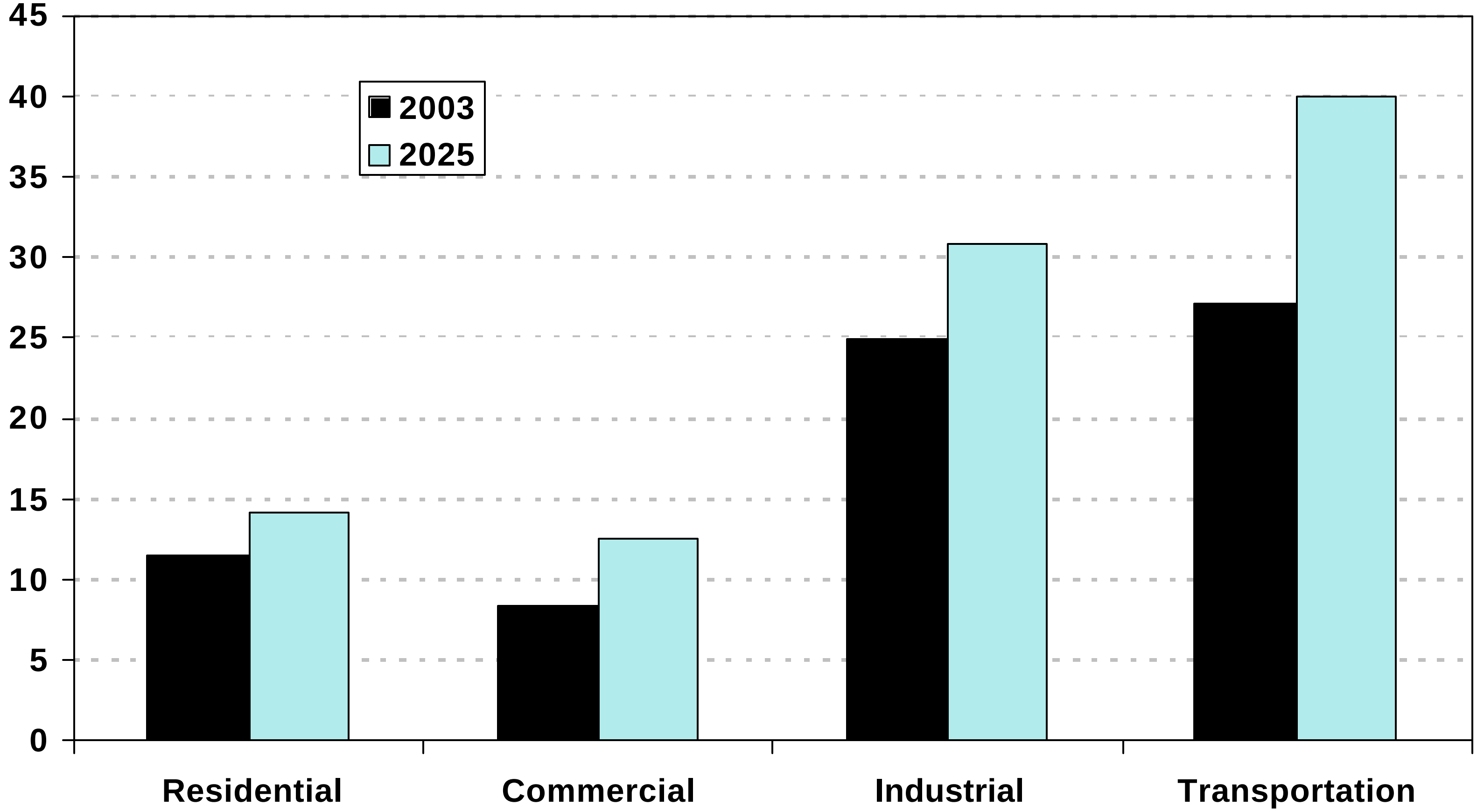

Figure 4. U.S. Energy Consumption in Three Cases, 1960-2025 (quadrillion Btu)

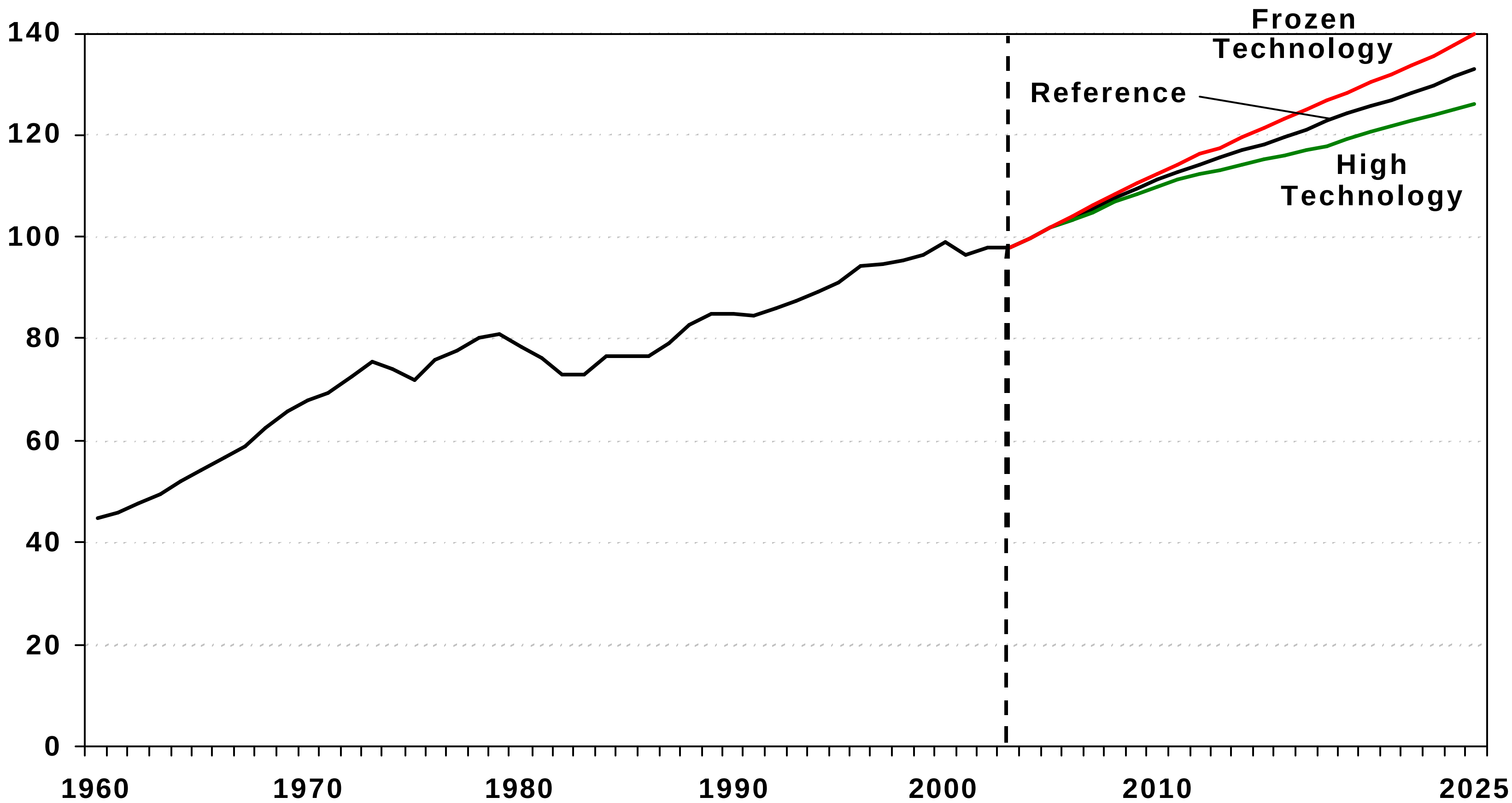

Figure 5. U.S. Energy Consumption by Fuel, 1970-2025 (quadrillion Btu)

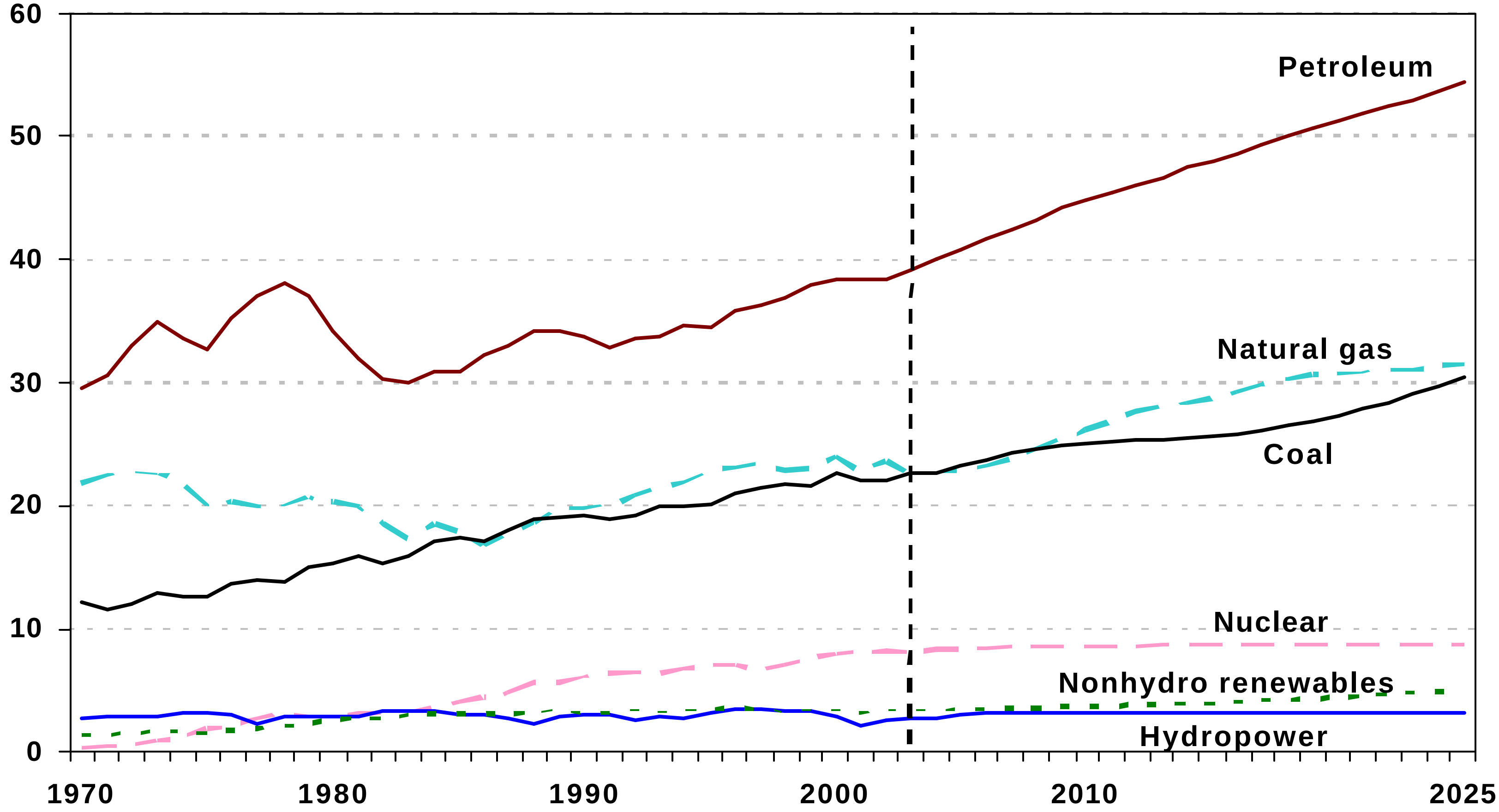

Figure 6. U.S. Energy Use per Capita and per Dollar of Gross Domestic Product, 1970-2025 (index, 1970 = 1)

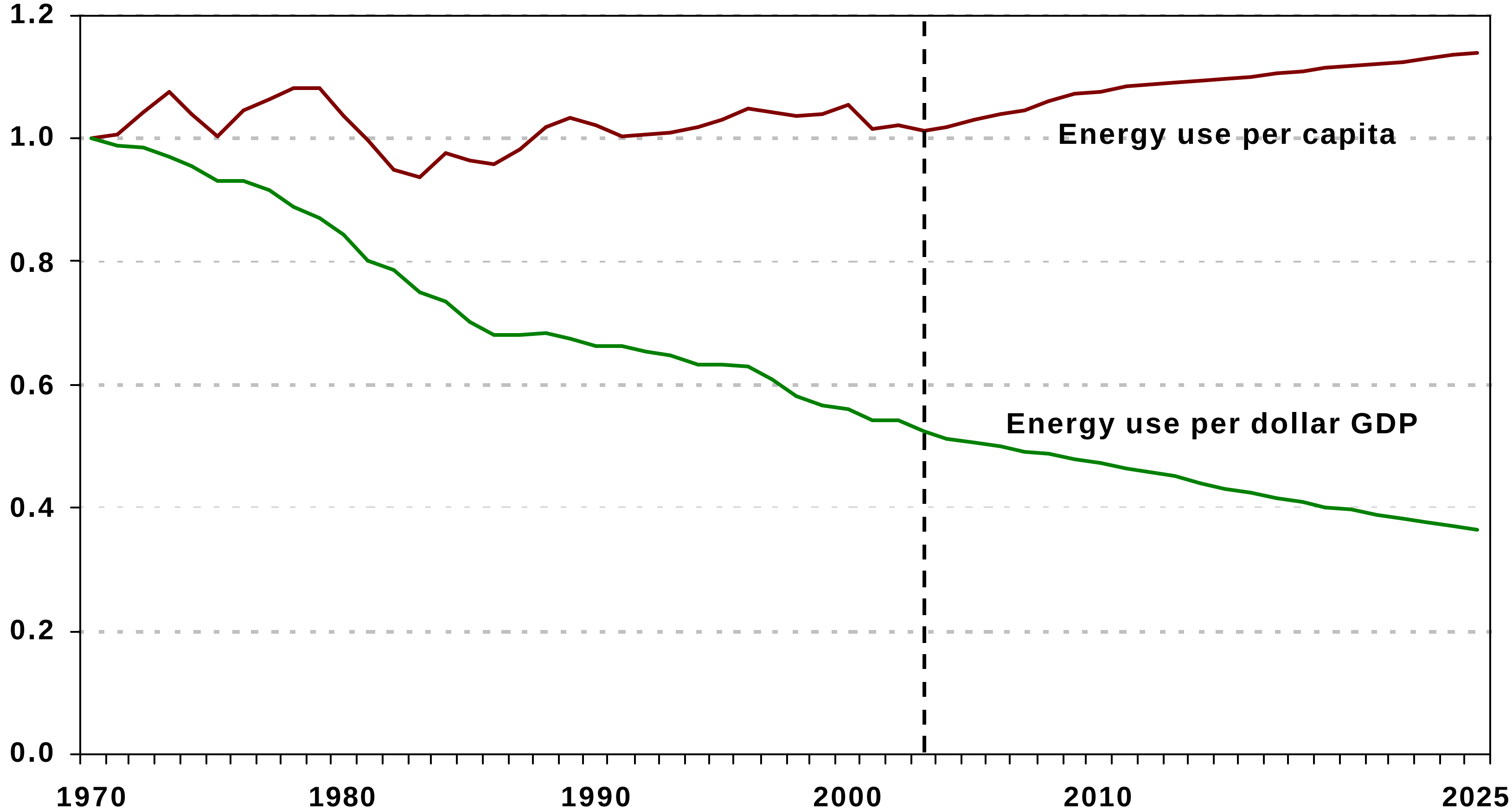

Figure 7. U.S. Energy Production, Consumption, and Net Imports, 1960-2025 (quadrillion Btu)

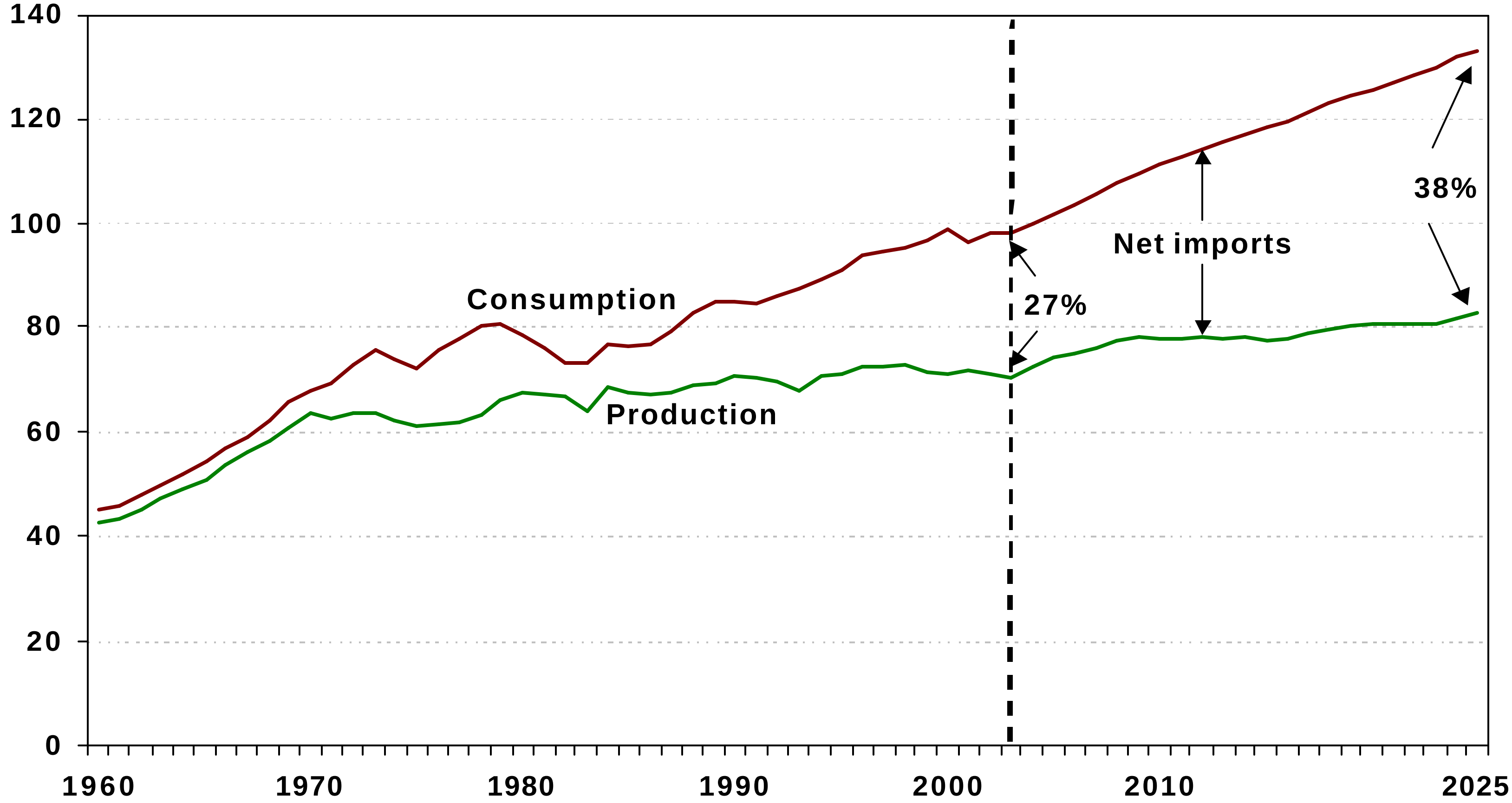

Figure 8. U.S. Petroleum Supply, Consumption, and Imports, 1970-2025 (million barrels per day)

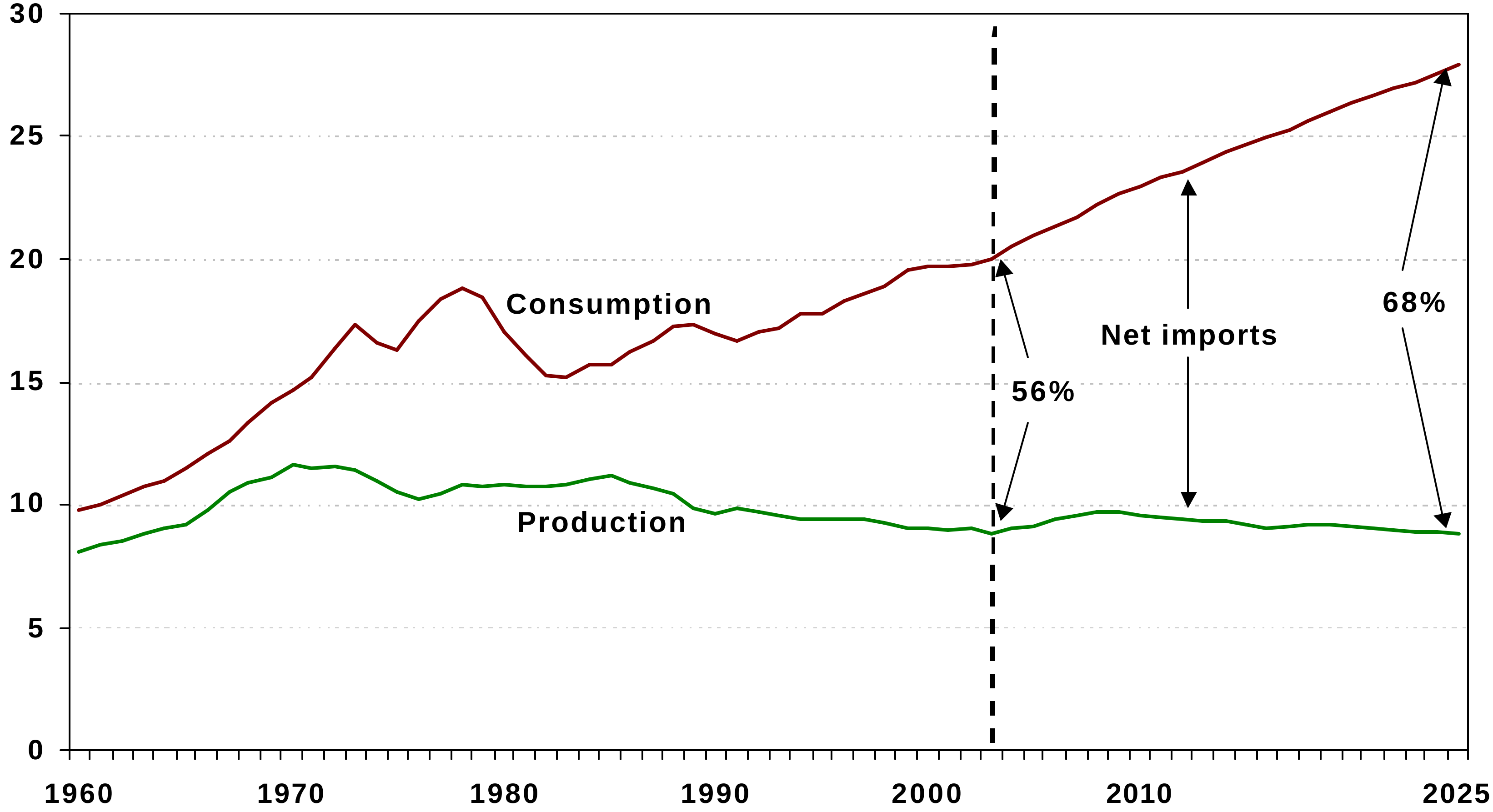

Figure 9. Petroleum Supply, Consumption, and Imports, in Two Cases 1970-2025 (million barrels per day)

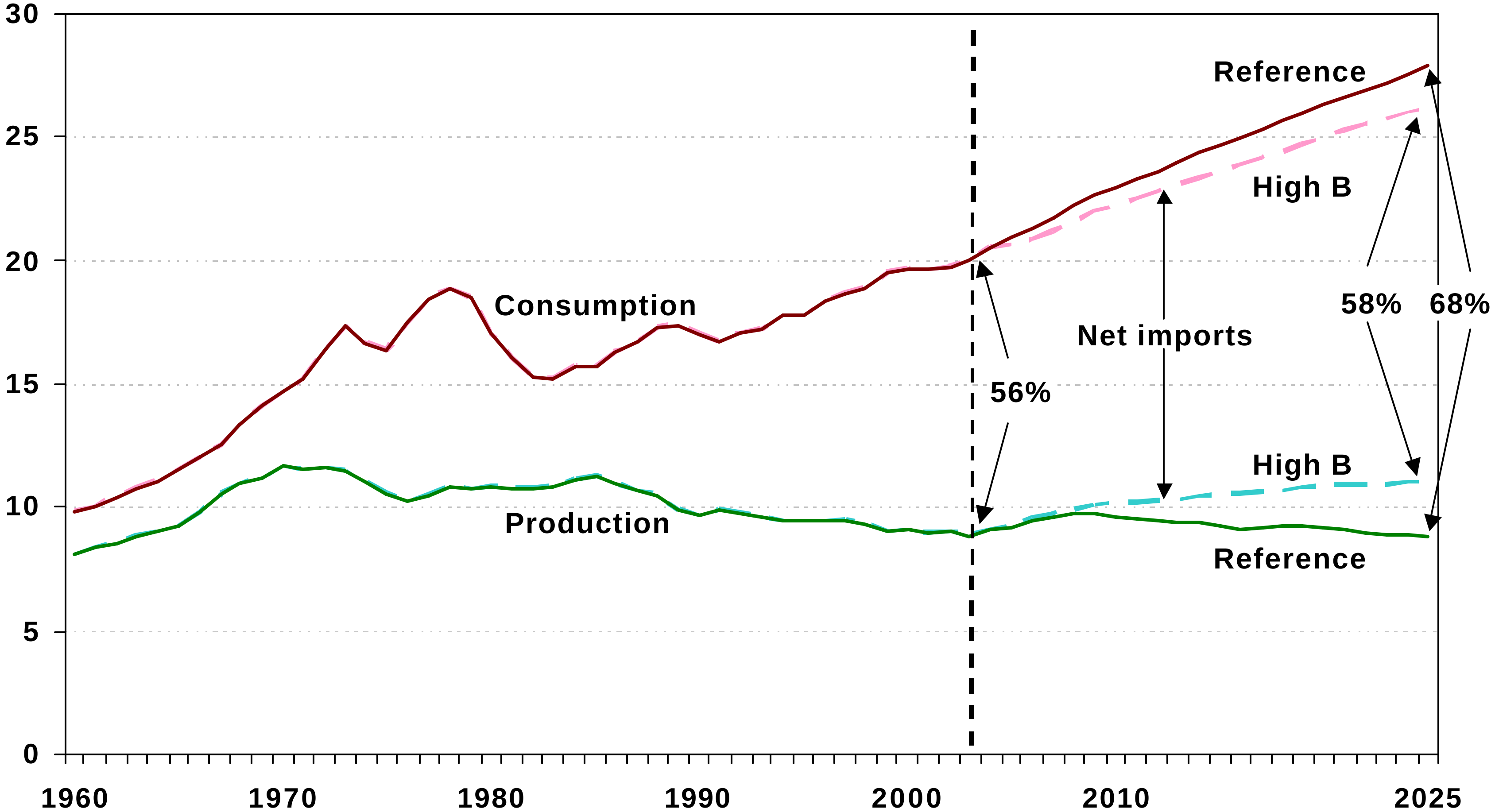

Figure 10. Petroleum Liquids Supply from Coal and Natural Gas in the High B Case, 2003-2025 (thousand barrels per day)

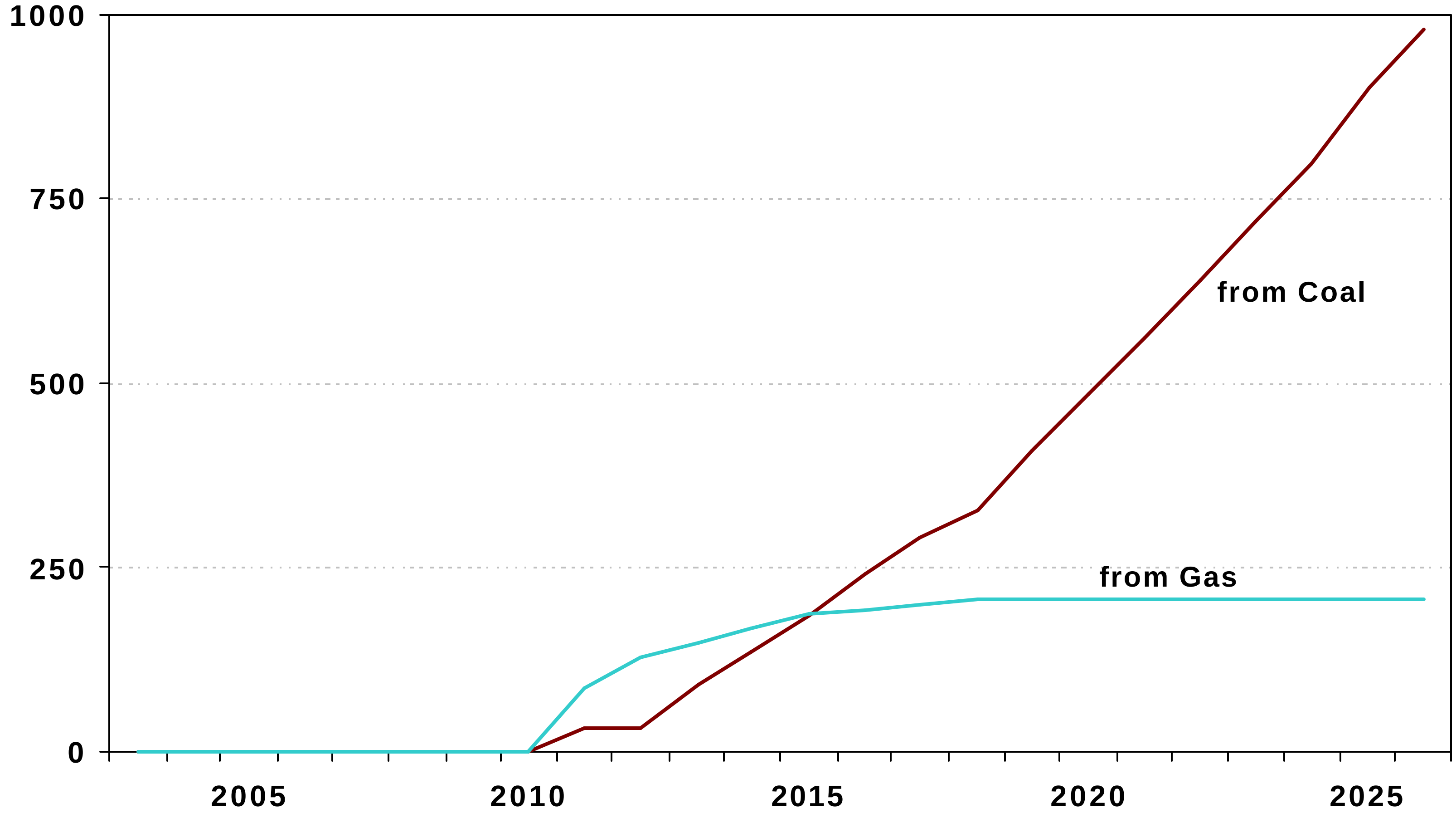

Figure 11. U.S. Natural Gas Production, Consumption, and Imports, 1970-2025 (trillion cubic feet)

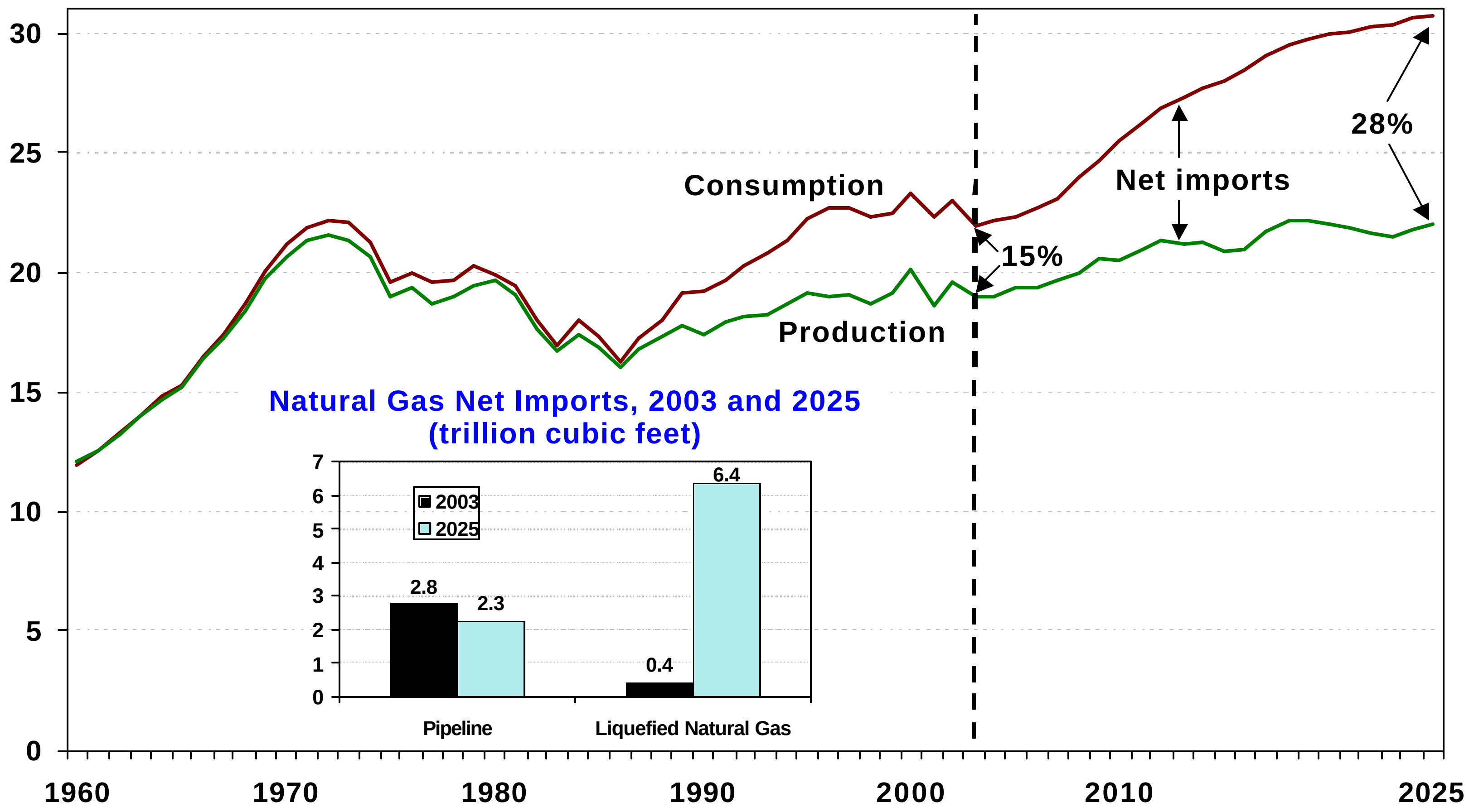

Figure 12. U.S. Coal Production by Region, 1970-2025 (million short tons)

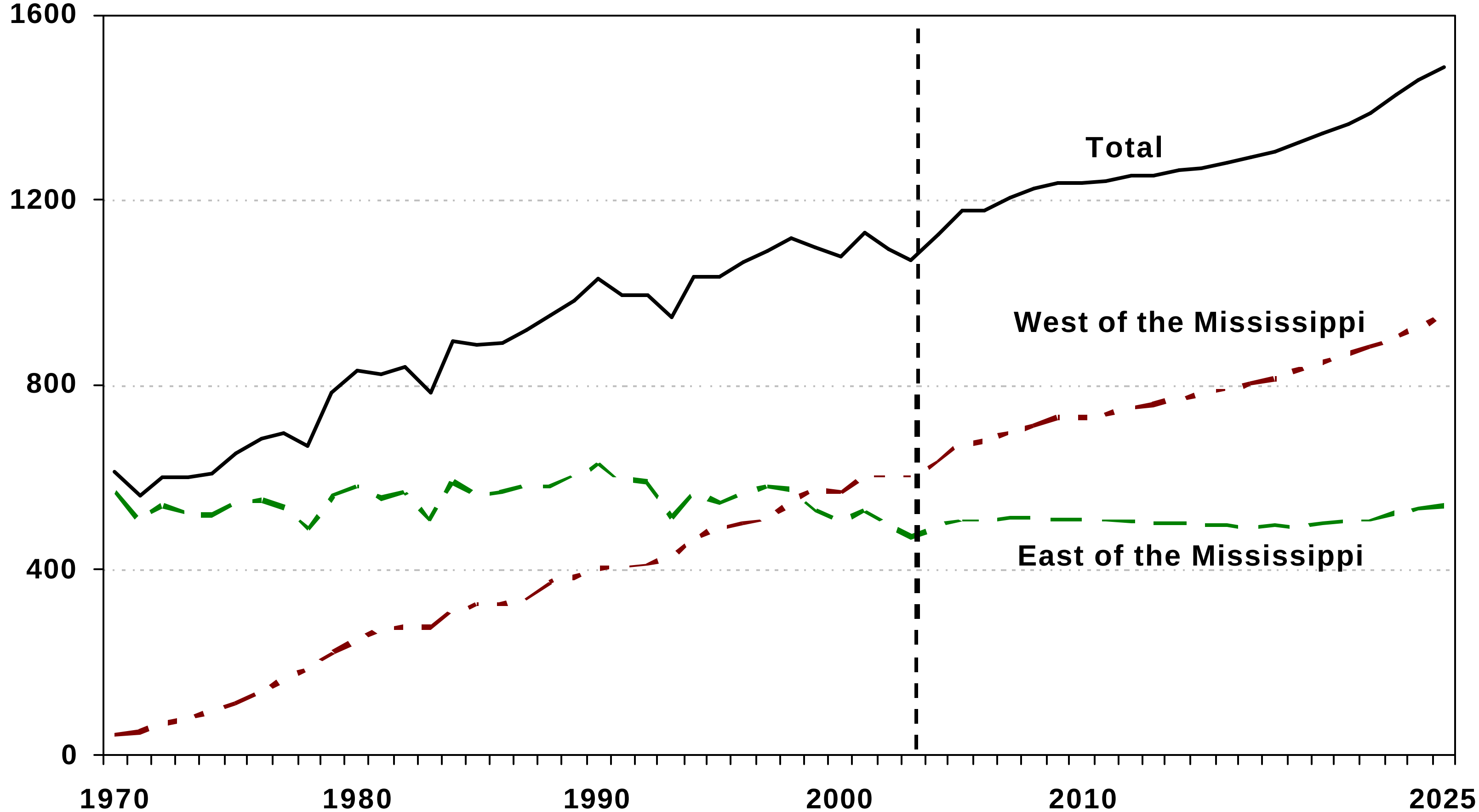

Figure 13. U.S. Electricity Generation by Fuel, 1970-2025 (billion kilowatthours)

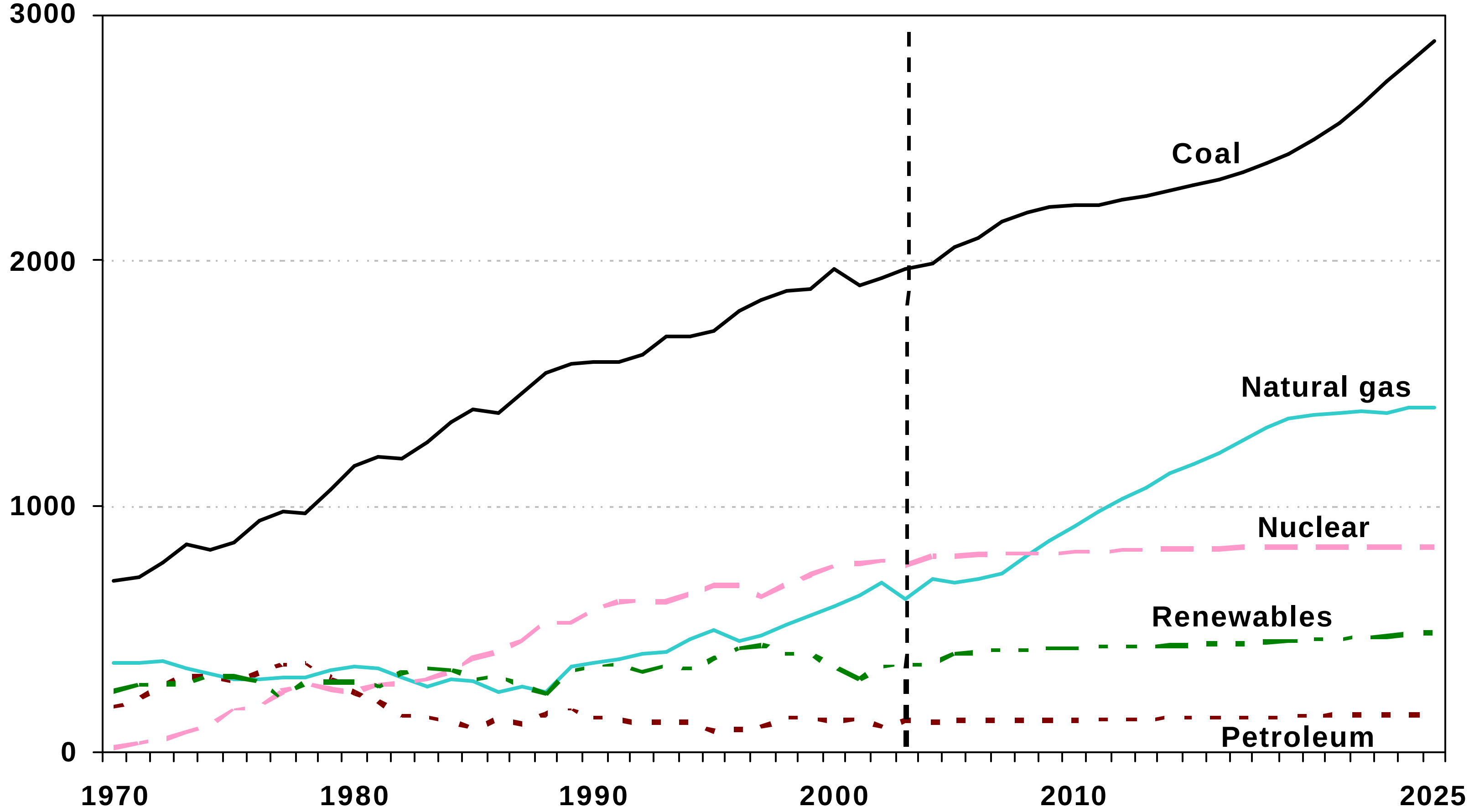

Figure 14. Electricity Generation Capacity by Nuclear Power in Three Cases, 1970-2025 (gigawatts)

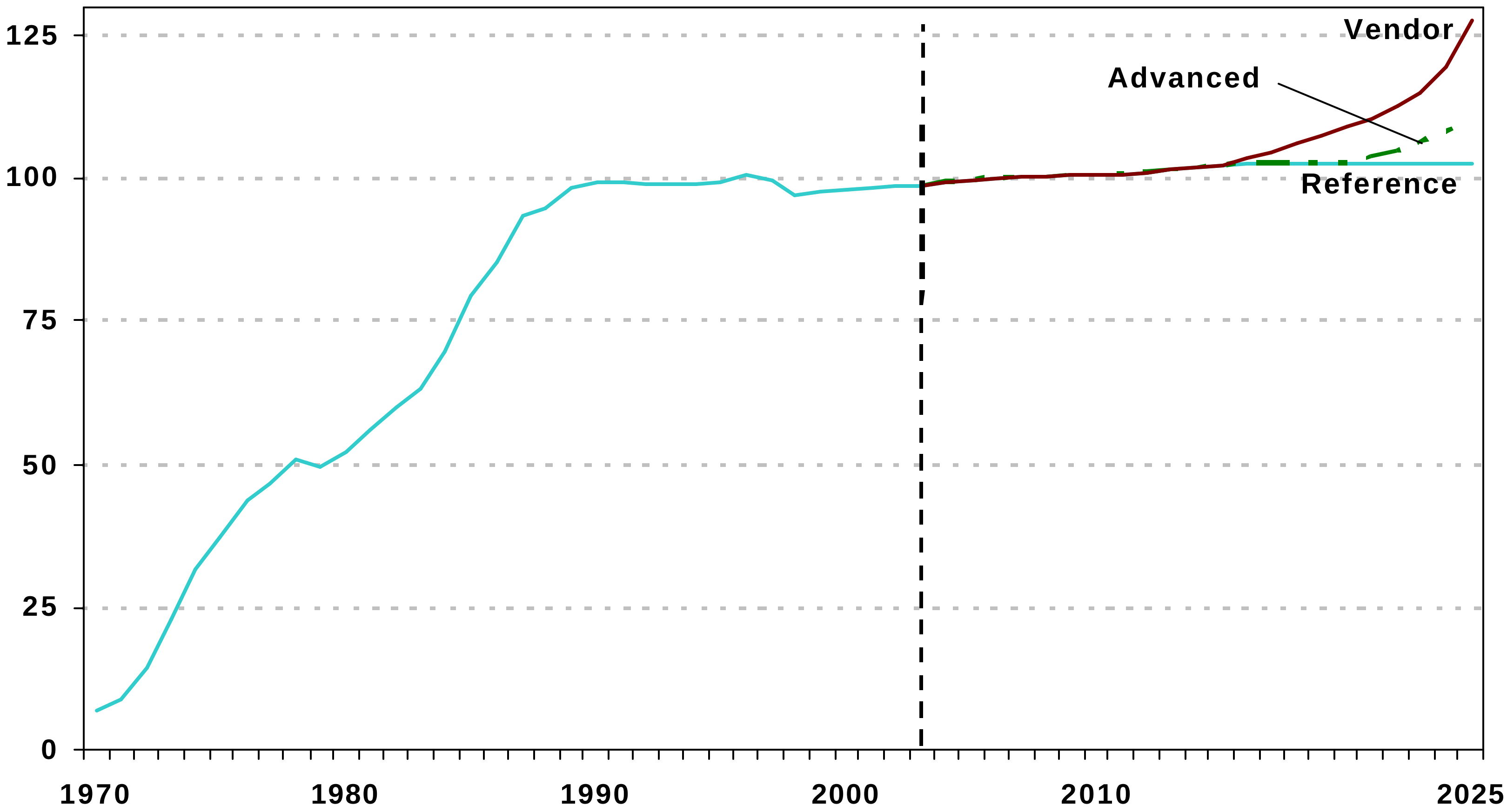

Figure 15. Renewable Electricity Generation Capacity in Two Cases, 2015 and 2025 (billion kwh)

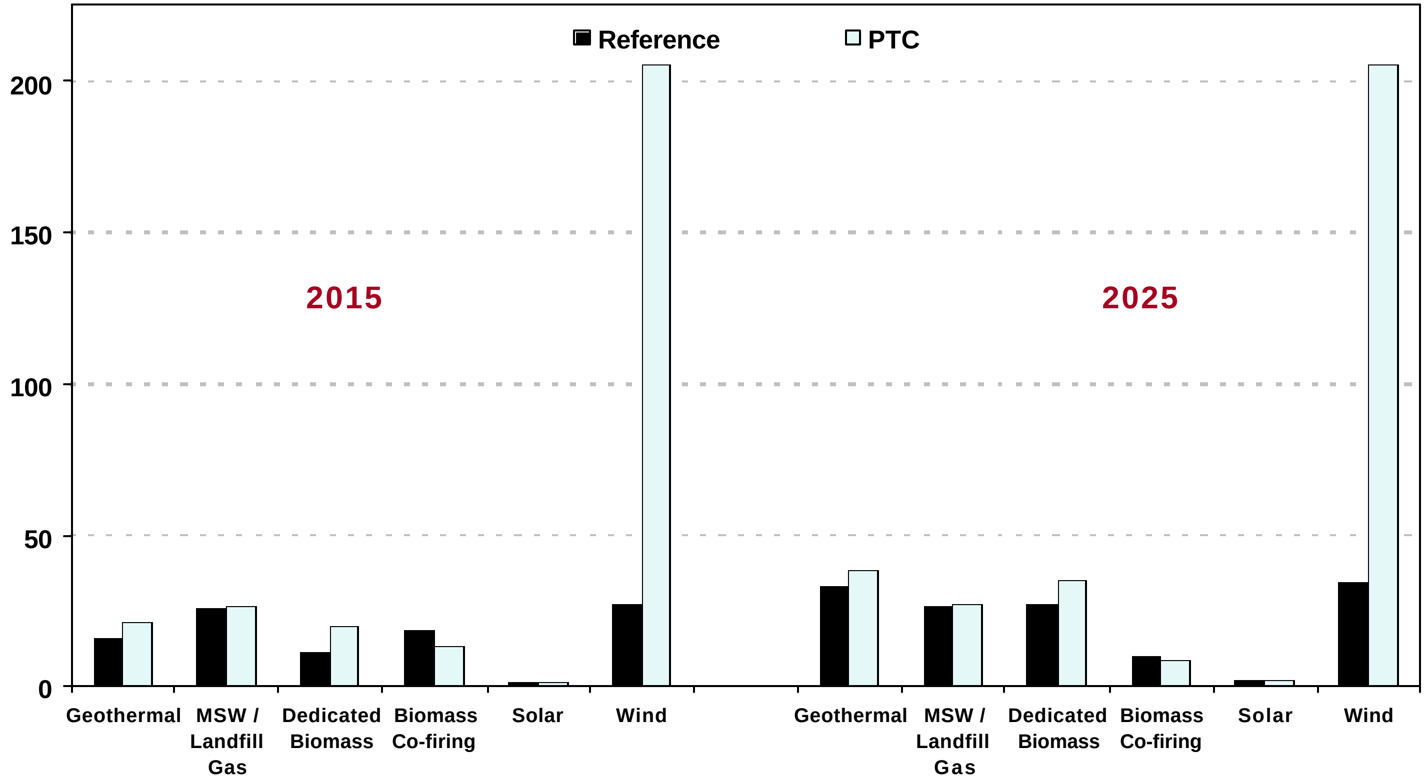

Figure 16. U.S. Carbon Dioxide Emissions by Fuel and Sector, 1970-2025 (million metric tons)

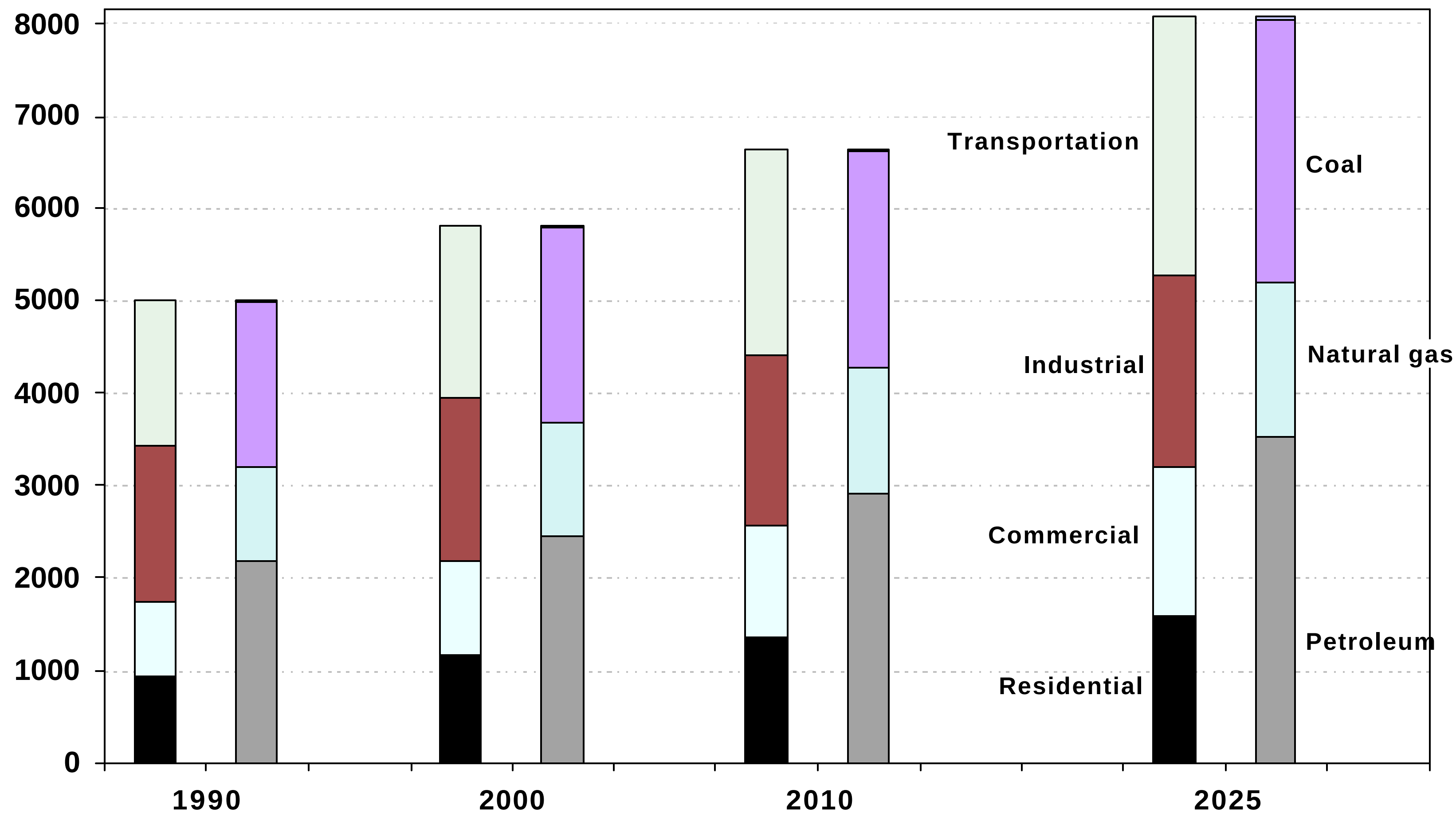

Figure 17. Monthly WTI Crude Oil Price and Volatility, January 1991 to January 2005

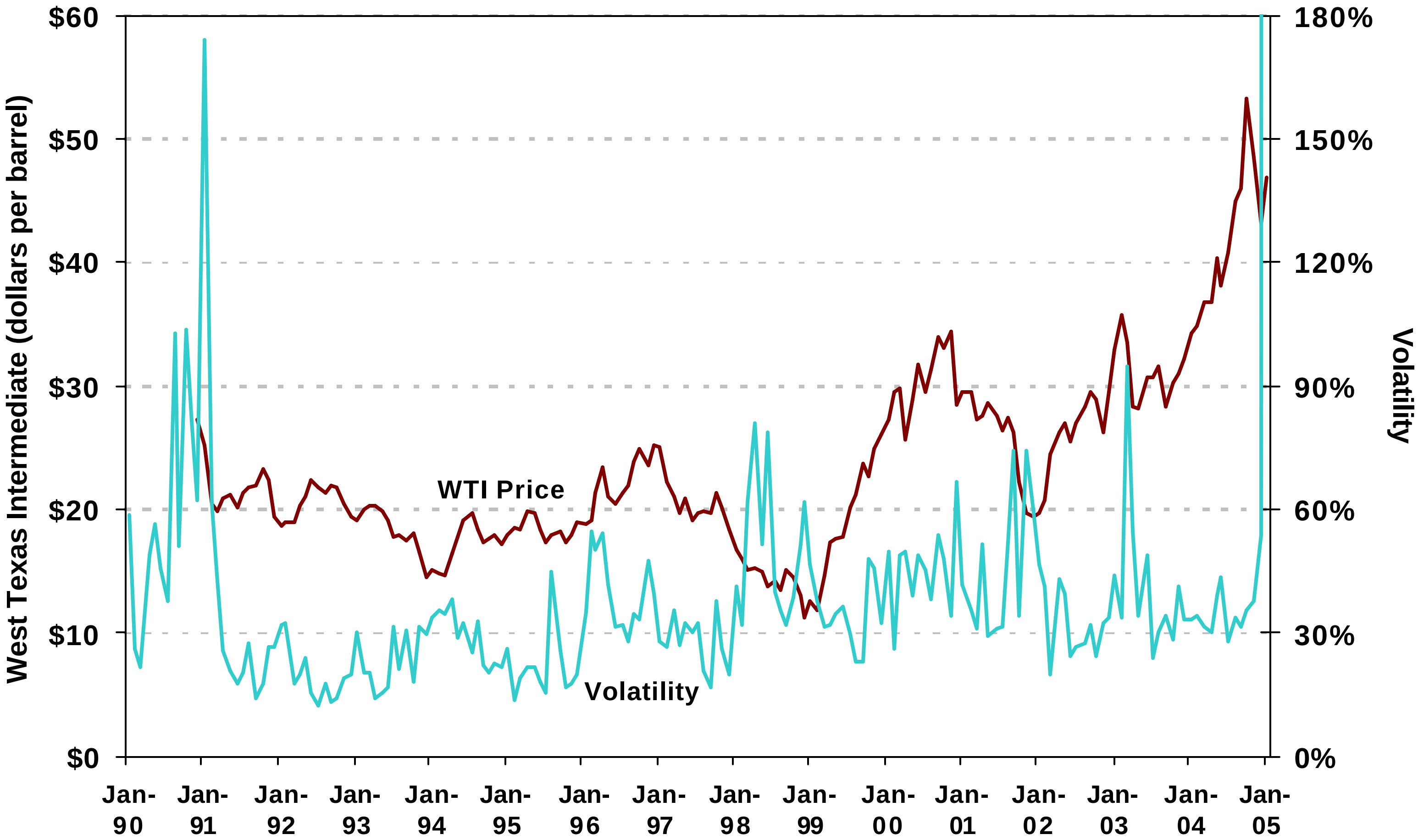

Figure 18. Spot WTI Crude Oil Price and Week-to-Week Change, August 1990 to February 2005 (dollars per barrel)

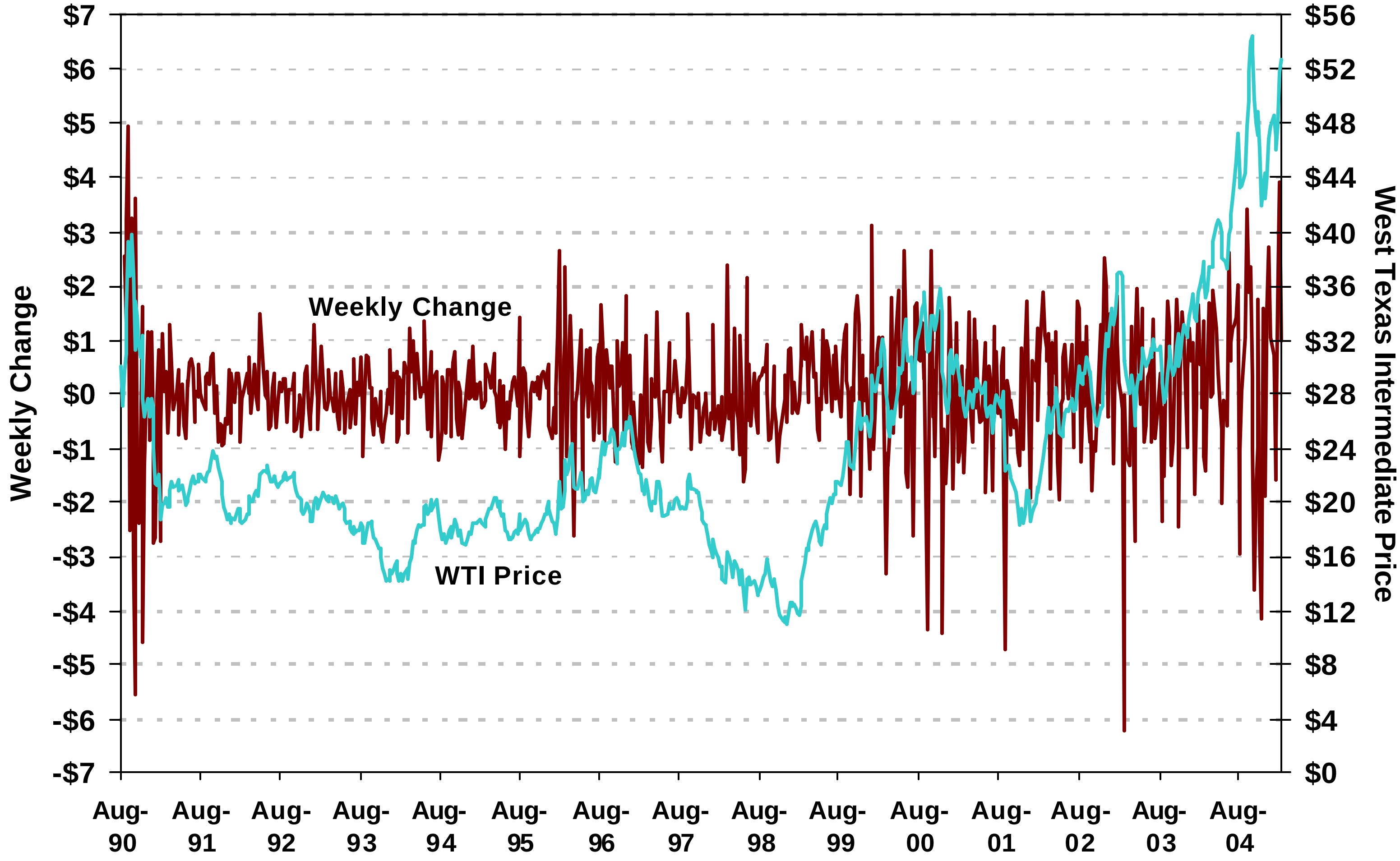

Figure 19. Retail Regular Gasoline Price and Week-to-Week Change, August 1990 to February 2005 (cents per gallon)

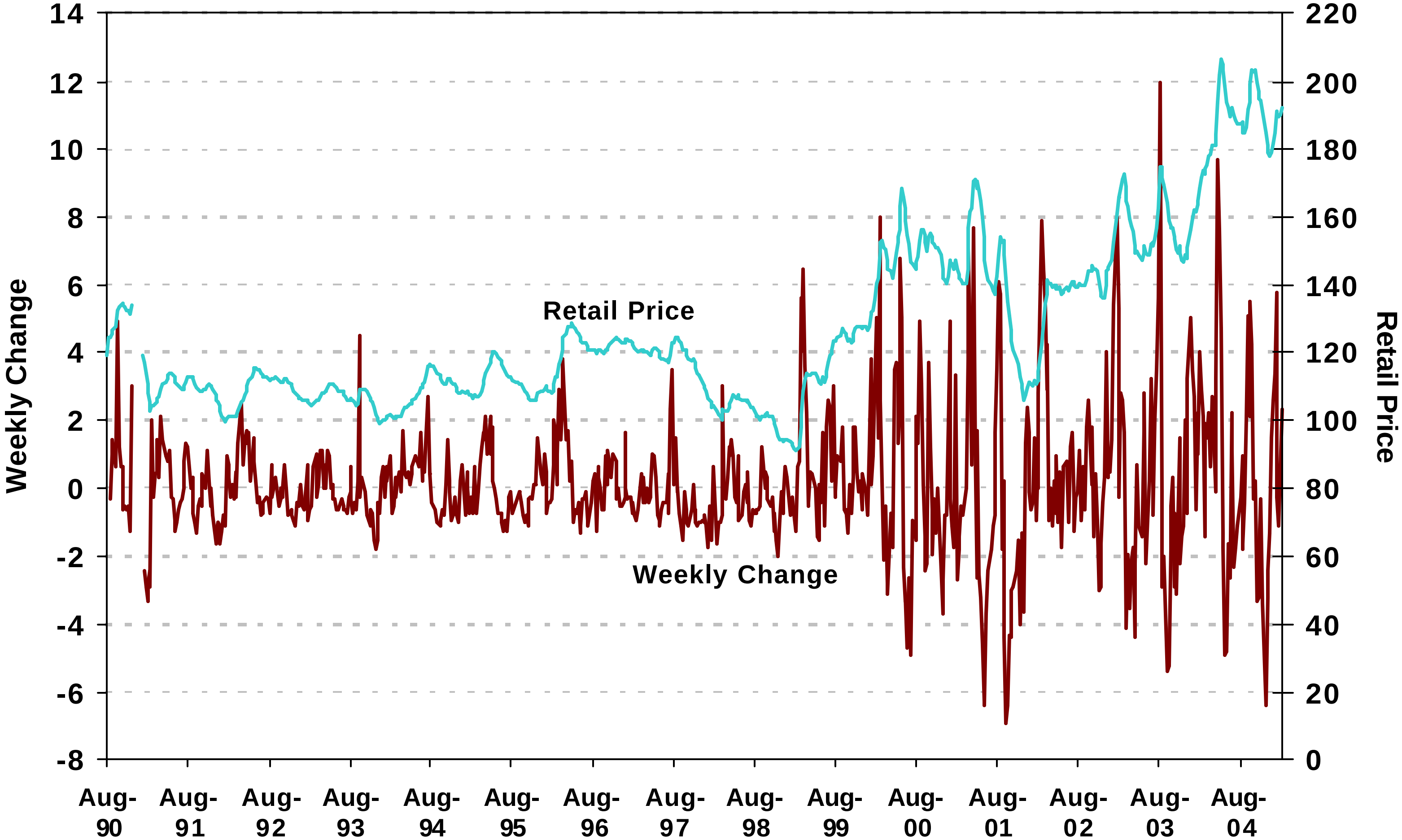

Figure 20. Monthly Natural Gas Spot Price Volatility and Wellhead Price, July 1993 to March 2005

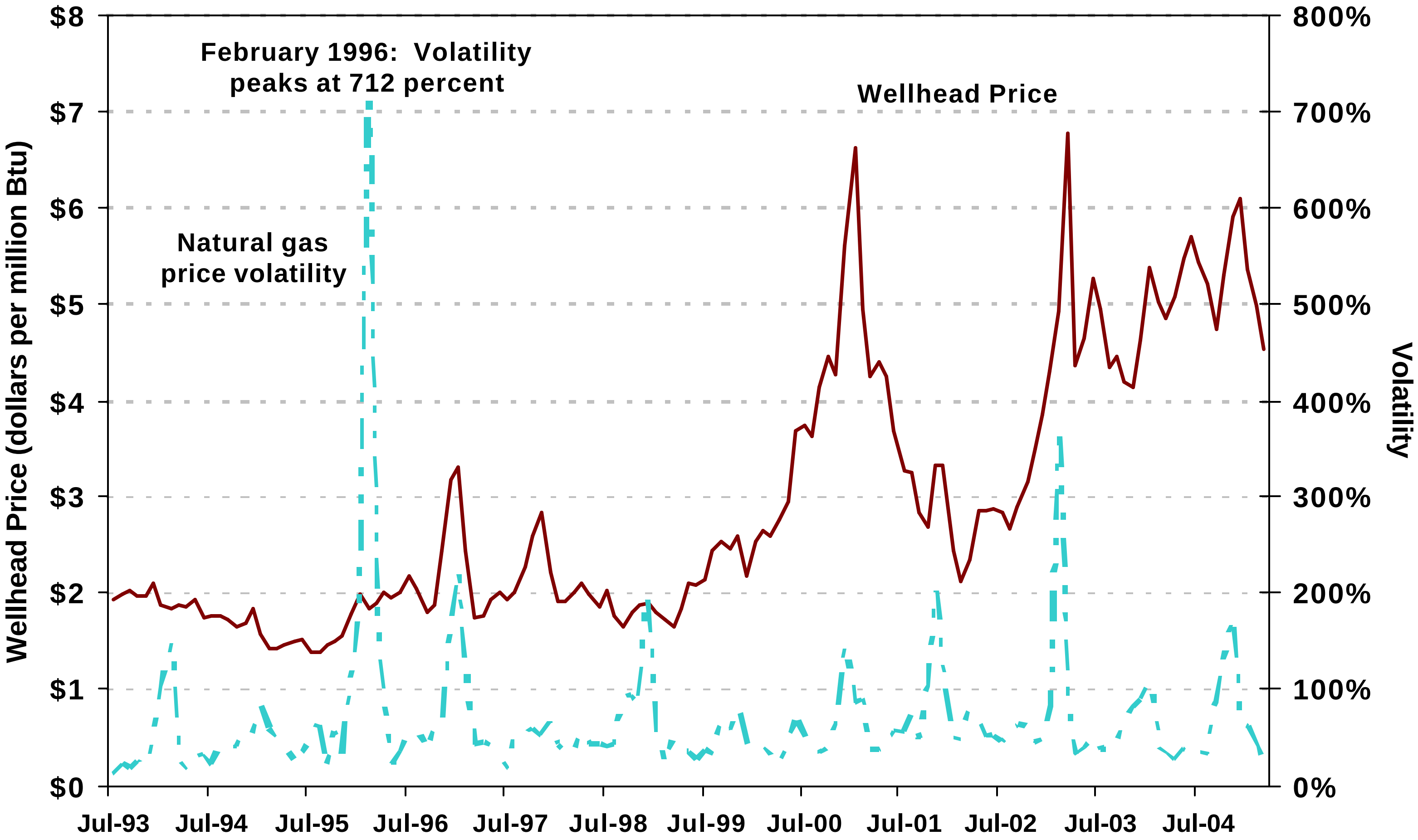

Figure 21. Henry Hub Spot Price and Week-to-Week Change, July 1993 to February 2005 (dollars per million Btu)