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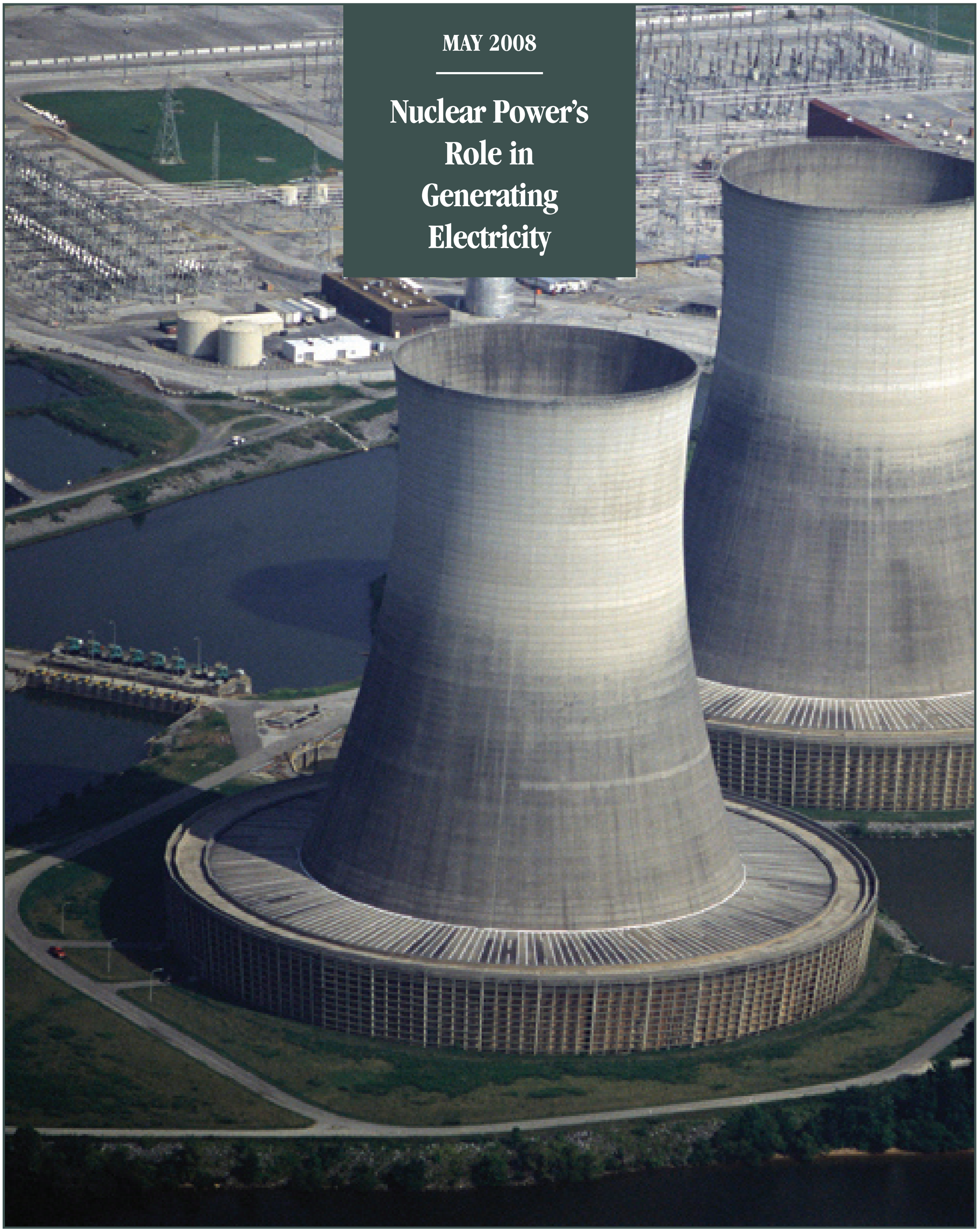
MAY 2008

Nuclear Power's Role in Generating Electricity



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CBO

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May 2008

The Congress of the United States ■ Congressional Budget Office

Notes

Unless otherwise indicated, costs are expressed in 2006 dollars.

A detailed description of the approach used to estimate levelized costs in this study can be found in CBO's Web supplement, *The Methodology Behind the Levelized Cost Analysis.*

The cover photo (©JupiterImages Corp.) is of the Sequoyah Nuclear Power plant in Tennessee.

Preface

Concerns about the adequacy of electricity supply and the impact of greenhouse-gas emissions on the environment have prompted policymakers to reevaluate the role that nuclear power might play in the future in meeting the nation's demand for electricity. The Energy Policy Act of 2005 (EPAct) offers incentives for expanding utilities' capacity to generate electricity using innovative fossil-fuel technologies and a new generation of nuclear reactors that are designed to decrease costs and enhance safety. In addition, policymakers are considering various proposals that would impose charges on entities that emit carbon dioxide, the most common greenhouse gas. Such policies could further encourage the use of nuclear power, which emits no such gases, by increasing the cost of generating electricity with competing fossil-fuel technologies.

At the request of the Chairman and Ranking Member of the Senate Committee on Energy and Natural Resources, the Congressional Budget Office (CBO) assessed the competitiveness of nuclear power when compared with other sources of new capacity to generate electricity, focusing on the possible effects of constraints on carbon dioxide emissions and the impact of EPAct incentives. In accordance with CBO's mandate to provide objective, impartial analysis, this study makes no recommendations.

Justin Falk of CBO's Microeconomic Studies Division wrote the study, under the supervision of Joseph Kile and David Moore. Michael Bennett, Kathy Gramp, and Wendy Kiska commented on drafts, as did Steven Gehl of the Energy Policy Research Institute, Jim Hewlett of the Energy Information Administration, and Paul Joskow of the Massachusetts Institute of Technology. (The assistance of external reviewers implies no responsibility for the final product, which rests solely with CBO.)

Loretta Lettner edited the study, with the assistance of John Skeen. Maureen Costantino designed the cover and prepared the report for publication. Angela McCollough prepared early drafts of the study. Lenny Skutnik printed the initial copies, Linda Schimmel coordinated the print distribution, and Simone Thomas prepared the electronic version for CBO's Web site (www.cbo.gov).

Peter R. Orszag
Director

May 2008

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Summary and Introduction

By the end of the next decade, demand for electricity in the United States is expected to increase by about 20 percent, according to the Energy Information Administration (EIA). That projected increase—coupled with concerns about the effects of greenhouse-gas emissions on the environment—has encouraged policymakers to reassess the role that nuclear power might play both in expanding the capacity to generate electricity and in limiting the amount of greenhouse gases produced by the combustion of fossil fuels. Because nuclear power uses an abundant fuel source to generate electricity without emitting such gases, prospects that new nuclear power plants will be planned and financed in the next decade are greater than at any time since the 1970s, when cost overruns and concerns about public safety halted investment in such facilities.

This reappraisal of nuclear power is motivated in large part by the expectation that market-based approaches to limit greenhouse-gas emissions could be put in place in the near future. Several options currently being considered by the Congress—including "cap-and-trade" programs—would impose a price on emissions of carbon dioxide, the most common greenhouse gas.[1] If implemented, such limits would encourage the use of nuclear technology by increasing the cost of generating electricity with conventional fossil-fuel technologies. The prospect that such legislation will be enacted is probably already reducing investment in conventional coal-fired power plants.

Current energy policy, especially as established and expanded under the Energy Policy Act of 2005 (EPAct), provides incentives for building additional capacity to generate electricity using innovative fossil-fuel technologies and an advanced generation of nuclear reactor designs that are intended to decrease costs and improve safety.[2] Among the provisions of EPAct that specifically apply to newly built nuclear power plants are funding for research and development; investment incentives, such as loan guarantees and insurance against regulatory delays; and production incentives, including a tax credit. Since the enactment of EPAct, about a dozen utilities have announced their intention to license about 30 nuclear plants.

This study assesses the commercial viability of advanced nuclear technology as a means of meeting future demand for electricity by comparing the costs of producing electricity from different sources under varying circumstances. The Congressional Budget Office (CBO) estimated the cost of producing electricity using a new generation of nuclear reactors and other base-load technologies under a variety of assumptions about prospective carbon dioxide charges, EPAct incentives, and future market conditions.[3] This study compares the cost of advanced nuclear technology with that of other major sources of base-load capacity that are available throughout the country—including both conventional and innovative fossil-fuel technologies. Because the study focuses only on technologies that can be used as base-load capacity in most parts of the country, it does not address renewable energy technologies that are intermittent (such

1. A cap-and-trade program would require utilities or other entities to hold permits, or allowances, to emit carbon dioxide. Because the permits would be tradable, a utility could buy them if it exceeded the emission cap or sell them if it emitted less than the cap allowed. The price at which those allowances traded would be the price of emitting carbon dioxide.

2. The Energy Policy Act (Public Law 109-58) was signed into law on August 8, 2005. The Energy Independence and Security Act (P.L. 110-140), which was enacted in December 2007, did not provide additional incentives for nuclear technology or alter the EPAct incentives analyzed in this study.

3. Electricity-generating capacity is commonly distinguished as base-load (that which is operated continuously, unless a plant is undergoing maintenance or repairs) or peak (that which is operated only during periods of high demand).

as wind and solar power) or technologies that use resources readily available only in certain areas (such as geothermal or hydroelectric power).

In the long run, carbon dioxide charges would increase the competitiveness of nuclear technology and could make it the least expensive source of new base-load capacity. More immediately, EPAct incentives by themselves could make advanced nuclear reactors a competitive technology for limited additions to base-load capacity. However, under some plausible assumptions that differ from those CBO adopted for its reference scenario—in particular, those that project higher future construction costs for nuclear plants or lower natural gas prices—nuclear technology would be a relatively expensive source of capacity, regardless of EPAct incentives. CBO's analysis yields the following conclusions:

- In the absence of both carbon dioxide charges and EPAct incentives, conventional fossil-fuel technologies would most likely be the least expensive source of new electricity-generating capacity.

- Carbon dioxide charges of about $45 per metric ton would probably make nuclear generation competitive with conventional fossil-fuel technologies as a source of new capacity, even without EPAct incentives. At charges below that threshold, conventional gas technology would probably be a more economic source of base-load capacity than coal technology. Below about $5 per metric ton, conventional coal technology would probably be the lowest cost source of new capacity.

- Also at roughly $45 per metric ton, carbon dioxide charges would probably make nuclear generation competitive with existing coal power plants and could lead utilities in a position to do so to build new nuclear plants that would eventually replace existing coal power plants.

- EPAct incentives would probably make nuclear generation a competitive technology for limited additions to base-load capacity, even in the absence of carbon dioxide charges. However, because some of those incentives are backed by a fixed amount of funding, they would be diluted as the number of nuclear projects increased; consequently, CBO anticipates that only a few of the 30 plants currently being proposed would be built if utilities did not expect carbon dioxide charges to be imposed.

- Uncertainties about future construction costs or natural gas prices could deter investment in nuclear power. In particular, if construction costs for new nuclear power plants proved to be as high as the average cost of nuclear plants built in the 1970s and 1980s or if natural gas prices fell back to the levels seen in the 1990s, then new nuclear capacity would not be competitive, regardless of the incentives provided by EPAct. Such variations in construction or fuel costs would be less likely to deter investment in new nuclear capacity if investors anticipated a carbon dioxide charge, but those charges would probably have to exceed $80 per metric ton in order for nuclear technology to remain competitive under either of those circumstances.

Background on Electricity-Generating Technologies

Electricity is produced using a variety of technologies powered by different sources of fuel, but the sources that predominate are coal, natural gas, and uranium. Coal-burning technologies emit the most carbon dioxide per unit of electricity; natural gas technologies emit carbon dioxide at about half that rate; and nuclear power, a "zero emissions technology," emits no carbon dioxide at all.[4] (See Box 1-1 for details on power plant technologies.)

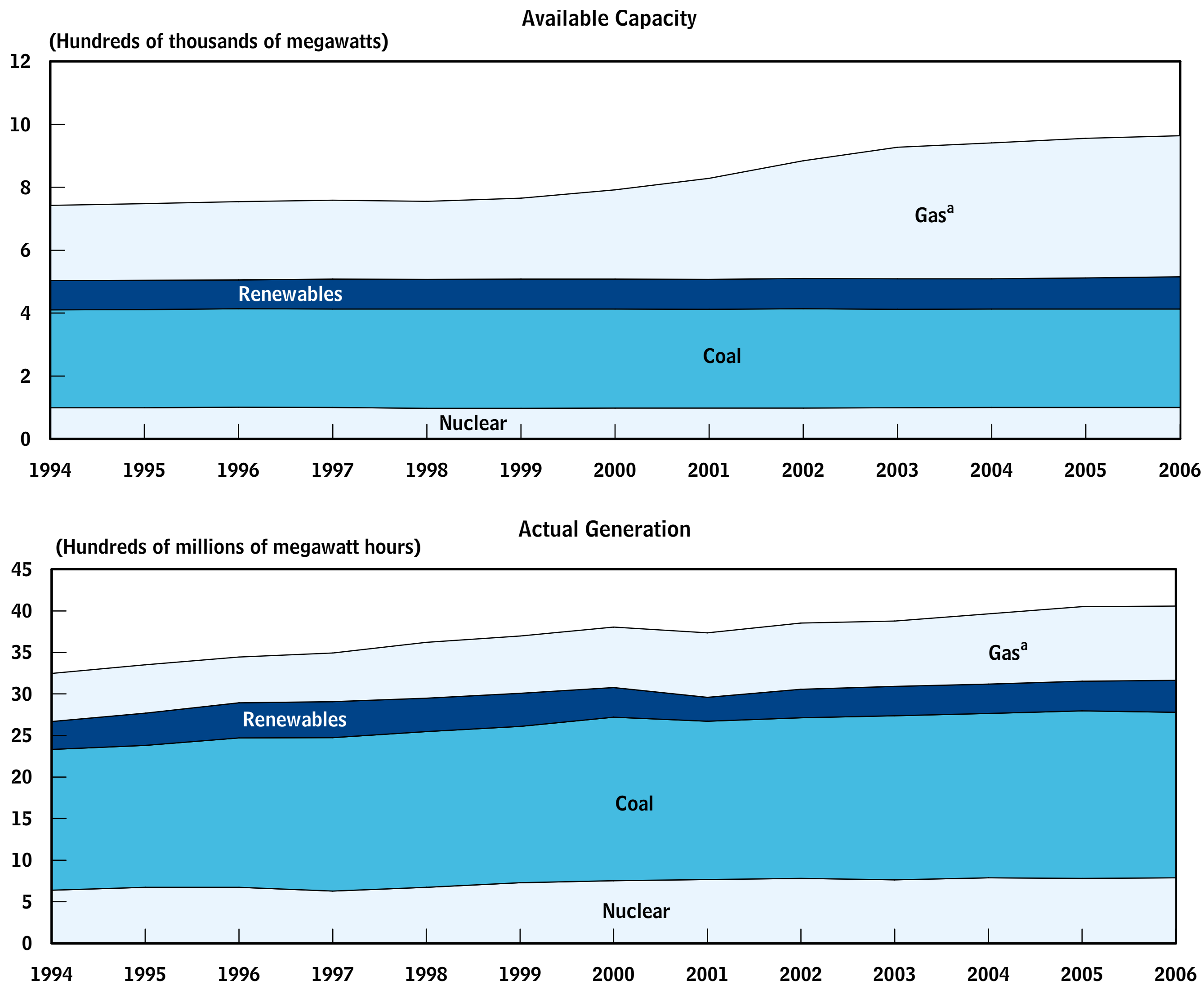
Historically, most base-load capacity has been provided using coal or nuclear technologies because, once the plants have been built, low fuel costs make them relatively cheap to operate continuously. Even though natural gas prices have increased significantly in recent years, natural gas remains the dominant source of peak capacity because power plants using that fuel are less expensive to build than coal-fired plants or nuclear reactors and easier to start up and shut down.

From 1994 to 2006, a period when the total amount of electricity generated rose by 25 percent, utilities appear to have increased base-load generation primarily by stepping

4. This study considers only stack emissions of carbon dioxide—emissions resulting directly from the operation of the power plant. All technologies cause additional emissions from the construction and decommissioning of a power plant, as well as from the production of fuel.

Figure 1-1.

Available Capacity to Generate Electricity and Actual Generation, by Technology Type, 1994 to 2006



Source: Congressional Budget Office based on data from the Energy Information Administration.

Notes: Electricity-generating capacity is measured in megawatts; the electrical power generated by that capacity is measured in megawatt hours. During a full hour of operation, 1 megawatt of capacity produces 1 megawatt hour of electricity, which can power roughly 800 average households.

a. Natural gas capacity represents about 85 percent of total gas capacity, with the remainder using petroleum-based or other gases.

up production at existing coal and nuclear plants, while using natural gas technology to expand overall capacity. During that time, the amount of electricity generated by nuclear and coal power plants expanded by about 20 percent as those facilities operated at closer to maximum capacity. (See Figure 1-1.) However, coal and nuclear capacity remained roughly constant because utilities increasingly chose to construct new natural gas power plants. By 2006, natural gas capacity had doubled, accounting for 75 percent more electricity generation than in 1994. Because of the extensive investment in natural gas capacity, the amount of excess capacity—which is used to meet surges in demand or to compensate

Box 1-1.

Technologies for Adding to Base-Load Capacity over the Next Decade

An advanced generation of nuclear reactors is one of several options currently under consideration for providing additional base-load capacity to produce electricity. Utilities will weigh the cost of new nuclear power plants against that of both conventional and innovative fossil-fuel alternatives. Among the conventional alternatives are pulverized coal technology and combined-cycle turbines that rely on natural gas. Among the innovative alternatives are technologies that capture and store most of the carbon dioxide emitted when coal and natural gas are burned. Utilities use several other technologies to generate electricity, but they are not widespread and are not likely to be commercially viable base-load alternatives in most areas.

Nuclear Power Plants

Advanced, or third-generation, nuclear reactors were developed by enhancing the designs of existing nuclear power plants, which use first- and second-generation reactors developed before the 1980s, before major advances in digital control systems. Interest in those older designs disappeared in the 1970s for a variety of reasons, including construction cost overruns, poor operational performance, and concerns about the safety of the nuclear technology. Beginning in the 1990s, industry and government participated in a variety of cost-sharing programs to develop the third generation of nuclear reactors, which are designed to be safer to operate and less expensive to build and maintain.[1]

Fossil-Fuel Power Plants

Coal and natural gas can be burned to create electricity through several different technologies. Pulverized coal power plants, which burn solid coal ignited by injected air, are by far the most common option for generating base-load electricity. Combined-cycle technology, which harnesses residual steam heat from the combustion cycle, has become, over the past 20 years, the most efficient method of generating electricity from natural gas. However, those conventional coal and natural gas technologies emit carbon dioxide and are therefore susceptible to the pricing of such emissions, so innovative technologies with "carbon capture and storage" (CCS) may become the most commercially viable option for using those fossil fuels.

1. The incentives provided by the Energy Policy Act of 2005 that are addressed in this study promote the research, design, and deployment of third-generation reactors. Additional incentives under that law promote the research and development of designs for a fourth generation, but those technologies are not expected to be deployable until around 2030.

Continued

for shutdowns at power plants—remained roughly the same.[5]

Investors may have preferred new natural gas power plants as a source of additional base-load and peak capacity because "combined-cycle" technology became an affordable and efficient technique for generating electricity.[6] As recently as 2000, EIA forecast that combined-cycle natural gas technology would be the least expensive means of generating base-load electricity until at least 2020. The expansion of natural gas capacity since 1994,

5. The electrical power industry's ability to continue to meet demand is conventionally measured by comparing peak usage—the amount of capacity used when electricity demand is greatest—to the amount of capacity available during the periods of peak usage. Both peak usage and the amount of capacity available to meet it increased by roughly 30 percent between 1994 and 2006, indicating the amount of excess capacity has, for the most part, stayed stable. (Peak usage data are available from EIA at www.eia.doe.gov/cneaf/electricity/epa/epat3p2.html under the label "net internal demand.") However, the infrastructure for transmitting electricity between certain areas of the country is limited; accordingly, excess capacity in one region may not be available to all other regions.

6. Combined-cycle gas turbines generate electricity in two sequential processes, first using the energy produced by burning natural gas and then harnessing residual steam heat. The single-cycle process is generally considered an inefficient method of generating base-load power because it produces less electricity from a given amount of fuel.

Box 1-1. Continued

Technologies for Adding to Base-Load Capacity over the Next Decade

Although CCS technologies have not yet been deployed commercially at power plants, many observers expect them to be available over the upcoming decade. Those technologies would capture carbon dioxide emitted by power plants fueled by either coal or natural gas and store it underground in geologic formations, such as deep saline formations, oil and gas fields, and coal beds that cannot be mined economically. For coal power plants with CCS, the coal would first be gasified and then the resulting gas ignited. Such integrated-gasification combined-cycle (IGCC) technology, which is already in use at a few power plants that do not capture carbon dioxide, allows for capturing it before combustion, when it is more concentrated.[2] Natural gas power plants with CCS use the same combined-cycle process as conventional natural gas plants but filter the carbon dioxide from the natural gas before combustion.[3]

2. In its analysis, the Congressional Budget Office also estimated the cost of electricity from new IGCC plants without CCS. Those results are not presented because they are roughly similar to the results for pulverized coal power plants.

Technologies Not Included in the Congressional Budget Office's Analysis

Oil and renewable energy technologies are not expected to compete with nuclear technology as a source of new base-load capacity nationwide. Because of high fuel costs, oil-fired generators are commercially competitive only in a few areas that have limited access to coal and natural gas, most notably, Hawaii. Intermittent technologies such as wind and solar power, which cannot operate much of the day, are not a source of base-load capacity. Other renewable technologies, like geothermal and hydroelectric power, can provide a more consistent flow of electricity but use resources that are mostly available in the West. Biomass technology can generate base-load electricity in certain parts of the country but is typically limited to small applications because fuel costs become prohibitive at large facilities.

3. For a more detailed discussion of technologies to capture and store carbon dioxide, see Congressional Budget Office, *The Potential for Carbon Sequestration in the United States* (September 2007), pp. 8–17.

rather than nuclear or coal capacity, could indicate that investors had similar expectations. However, EIA now projects that some of the recent increase in the price of natural gas will persist. (Figure 1-2 charts actual and projected natural gas prices.) If that assessment proves to be the case, natural gas capacity could be a relatively expensive source of base-load power.

Over the past few years, most likely in response to both the prospect of carbon dioxide charges and the incentives offered in EPAct, several utilities have begun planning new nuclear projects, which may signal the end of a 30-year hiatus in financing the construction of nuclear power plants. As of 2007, over a dozen utilities had announced their intention to file construction and operating licenses (COLs), which are obtained through the Nuclear Regulatory Commission (NRC), for roughly 30 nuclear plants.[7] Those plants would provide about 40,000 megawatts of new capacity.[8] For perspective, the roughly 100,000 megawatts of existing nuclear capacity currently provides about 20 percent of all electrical power in the United States.

Although the announcements reflect renewed interest in building new nuclear power plants, they do not indicate how much capacity utilities will ultimately build. Completing the revised design and licensing process is

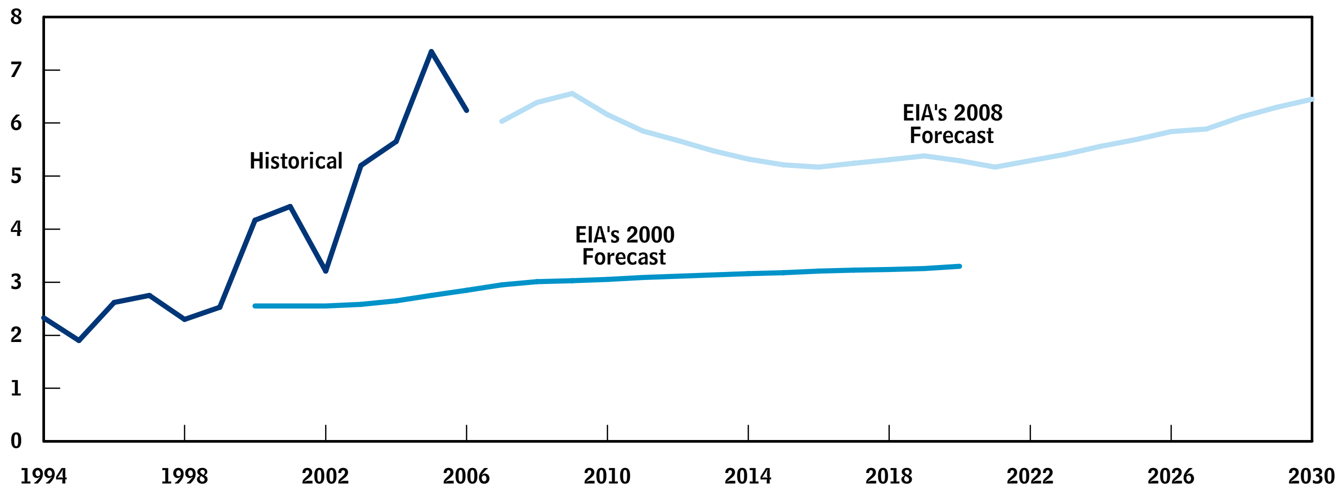
7. In this study, a nuclear power plant is defined as having one reactor; for example, if a utility built two reactors at the same site, that configuration would be considered two additional power plants.

8. See Energy Information Administration, *U.S. Household Electricity Report* (July 2005). Electricity-generating capacity is measured in megawatts; the electrical power generated by that capacity is measured in megawatt hours. During a full hour of operation, 1 megawatt of capacity generates 1 megawatt hour of electricity, which can power roughly 800 average households.

Figure 1-2.

Actual and Projected Natural Gas Prices, 1994 to 2030

(2006 dollars per million Btu)



Source: Congressional Budget Office based on data from the Energy Information Administration (EIA).

Notes: Btu = British thermal unit.

Prices are expressed in real (inflation-adjusted) dollars using the gross domestic product price index; they represent average prices received by natural gas producers (in the lower 48 states) and, therefore, do not include the cost of delivering natural gas from the wellhead to the power plant. EIA provides the average price of natural gas delivered to power plants for the years from 1997 to 2006. On average, those prices exceed the reported prices by $0.70 per million Btu.

expected to cost about $100 million per plant, less than 5 percent of the anticipated cost for constructing a nuclear plant. Filing a COL application by the end of 2008 may be necessary for those projects to remain eligible for a share of the $7.5 billion (in nominal dollars) in production tax credits, but filing does not obligate an applicant to build the proposed plant.

Considerations Underlying Future Investment in Power Plants

New base-load capacity requires years to plan and build—roughly a decade in the case of nuclear technology. Because power plants can operate for many years (numerous power stations built in the first half of the previous century are still in use), new capacity is expected to replace existing capacity slowly in the absence of a cost advantage.

Utilities typically invest in new electricity-generating capacity to meet increases in demand or to replace facilities that have become too expensive to operate. When planning new power plants, both traditional regulated utilities (whose return on investment is largely determined by public utility commissions) and merchant generators (whose return is dictated by market outcomes) consider which technology generates electricity at the lowest cost. The cost of electricity from new capacity depends on the cost of building a plant, the cost of financing that construction, and the recurring cost of operating the plant (including the cost of fuel).

For the purposes of CBO's analysis, conventional coal plants are assumed to use pulverized coal technology, which produces energy by burning a crushed form of solid coal, and conventional natural gas plants are assumed to convert gas into electricity using combined-cycle turbines. The advanced nuclear technology considered in the analysis is confined to reactor designs that would be available in the next decade. At the same time, development continues on innovative fossil-fuel technologies that are designed to capture and store almost all of the carbon dioxide emitted while generating electricity. Over the next decade, investors will also consider those carbon capture-and-storage, or CCS, technologies as an alternative for new generation capacity.[9]

To compare the cost of alternatives for new generating capacity, CBO developed a reference scenario to serve as a benchmark against which the effects of both existing and prospective policy initiatives and future market conditions could be measured. Specifically, the reference scenario excludes the possible effects of carbon dioxide charges and EPAct incentives. On the basis of the assumptions underlying that scenario, CBO estimated the levelized costs of five technological alternatives. Levelized cost, a construct frequently used in analyzing investment in electricity generation, is the minimum price of electricity at which a technology generates enough revenue to pay all of the utilities' costs, including a sufficient return to investors.[10] Federal, state, and local policies can change the costs incurred by utilities by providing incentives, which shift costs or financial risk to the public, or by levying taxes on the utilities, which increases their costs.

Among federal laws and programs that influence investors' decisions about which technology to choose for new electricity-generating capacity are standard corporate tax laws, programs that support specific technologies by altering tax laws or providing other incentives, and taxes on specific goods whose production or consumption affects others. Carbon dioxide charges in particular could significantly increase the utilities' costs of generating electricity, which could reduce the amount of investment in new capacity if customers reduced their usage in reaction to higher prices. This analysis, however, focuses on how potential carbon dioxide charges and the provisions of EPAct would change the relative cost of alternatives for generating electricity and does not address the total quantity of base-load capacity that might be built once investors accounted for future demand. However, there is general agreement that demand will continue to grow with the population; accordingly, investing in additional capacity will be commercially viable unless the costs of supplying electricity rise significantly.

How Might Carbon Dioxide Charges Affect the Prospects of Investment in New Nuclear Plants?

Measuring the utilities' costs across a range of potential carbon dioxide charges indicates which technologies might be competitive, given certain assumptions about future legislative action and market outcomes. In general, the higher the costs to utilities of emitting carbon dioxide, the more competitive nuclear power would be because it is the only zero-emissions base-load technology.

In the absence of both emission charges and EPAct incentives, conventional fossil-fuel technology would dominate nuclear technology. But, even without EPAct incentives, if lawmakers enacted legislation that resulted in a carbon dioxide charge of about $45 per metric ton, nuclear generation would most likely become a more attractive investment for new capacity than conventional fossil-fuel generation (see the left panel of Figure 1-3). If the cost of emitting carbon dioxide was between $20 and $45 per metric ton, nuclear generation as an option for new capacity would probably be preferred over coal but not natural gas.

Most of CBO's analysis focuses on technology choices for new power plants, but electricity from new capacity would still compete in the same market as that from existing capacity and could eventually begin to displace that capacity if the price of emitting carbon dioxide was sufficiently high. For instance, because utilities have already incurred construction costs for existing facilities, existing coal-fired power plants could be a less expensive source of electricity than new power plants under the range of carbon dioxide charges considered (see the right panel of Figure 1-3). If building new nuclear power plants proved to be less expensive than building new coal-fired plants but more expensive than using existing coal capacity, additions to nuclear capacity would be limited to meeting increases in electricity usage. Despite the high carbon intensity of conventional coal technology,

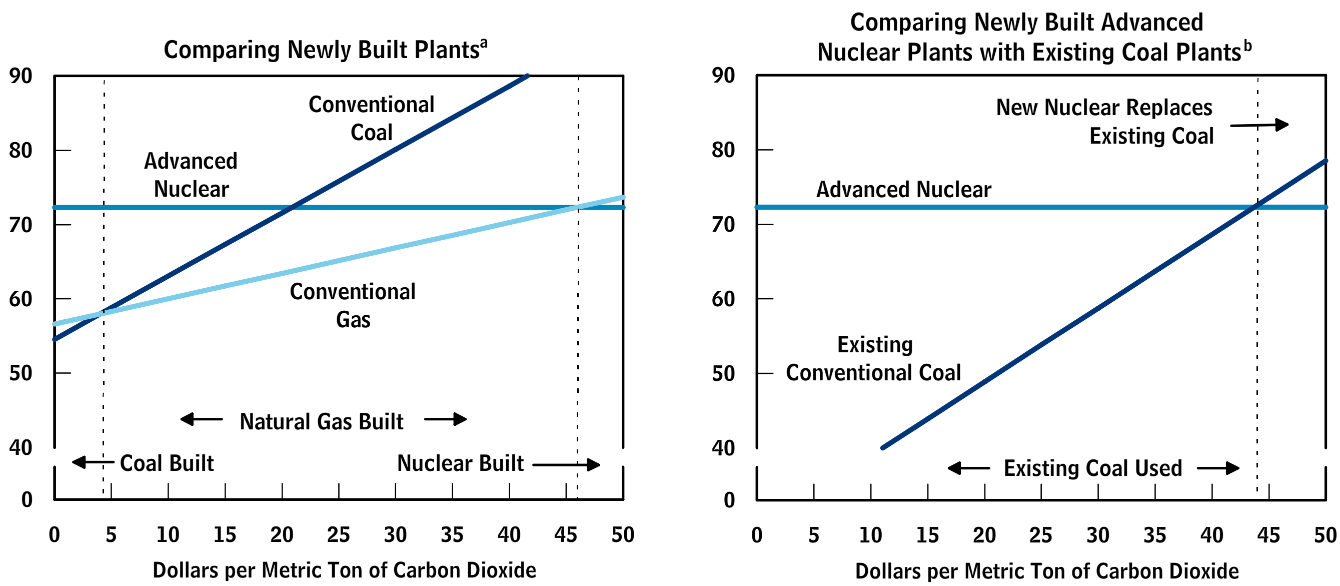
9. Prospects for CCS technologies and other forms of carbon sequestration are discussed in Congressional Budget Office, *The Potential for Carbon Sequestration in the United States* (September 2007).

10. The levelized cost estimates calculated in this study do not include the cost of distributing electricity so the relevant price against which costs are compared is the wholesale price of electricity. Nor do the calculations include any impediments, incentives, or rate regulation provided by state or local governments. Several states have official or de facto prohibitions against the construction of additional nuclear power plants or additional conventional coal-fired power plants. Other states and localities encourage additional nuclear capacity through tax incentives or regulations that allow higher returns.

Figure 1-3.

Levelized Cost of Electricity Under Carbon Dioxide Charges

(2006 dollars per megawatt hour)



Source: Congressional Budget Office.

Notes: Electricity-generating capacity is measured in megawatts; the electrical power generated by that capacity is measured in megawatt hours. During a full hour of operation, 1 megawatt of capacity produces 1 megawatt hour of electricity, which can power roughly 800 average households.

Advanced nuclear technology refers to third-generation reactors. Conventional coal power plants are assumed to use pulverized coal technology, which produces energy by burning a crushed form of solid coal. Conventional natural gas power plants are assumed to convert gas into electricity using combined-cycle turbines.

These comparisons exclude the impacts of incentives provided under the Energy Policy Act of 2005.

a. The levelized cost of new capacity using fossil-fuel technologies is not included in the figure, but those technologies generally have a higher levelized cost than nuclear technology.

b. The levelized cost of new capacity using conventional natural gas technology is not included in the figure, but electricity produced using new natural gas capacity would be cheaper than continuing to operate existing coal capacity at carbon dioxide charges above $45 per metric ton.

continuing to operate existing coal-fired plants would remain a relatively inexpensive source of electricity until carbon dioxide charges reached about $45 per metric ton.

How Does the Energy Policy Act of 2005 Affect the Prospects of Investment in New Nuclear Plants?

During the next several years, the incentives put in place or extended by EPAct could significantly improve the relative cost of at least the first few nuclear plants built. (See Table 1-1 for an overview of EPAct incentives.) In contrast to carbon dioxide charges, which make nuclear alternatives attractive by increasing the cost of fossil-fuel alternatives, subsidies for new nuclear projects directly reduce the cost of nuclear plants in comparison to fossil-fuel options.

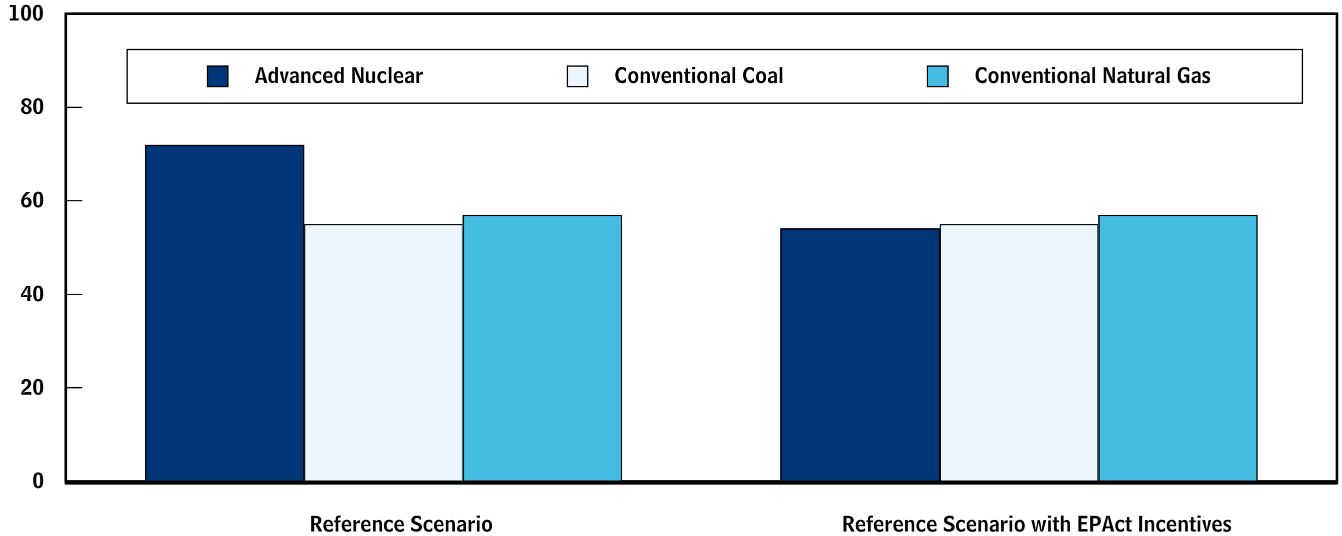
The largest incentives available under EPAct are a production tax credit and a loan guarantee program. The tax credit provides up to $18 in tax relief per megawatt hour of electricity produced at qualifying power plants during the first eight years of operation. (For comparison, the average wholesale price of electricity in 2005 was about $50 per megawatt, on average.)[11] The loan guarantee

11. See Energy Information Administration, *Annual Electric Power Industry Report* (2005), available at www.eia.doe.gov/cneaf/electricity/wholesale/wholesalet2.xls.

Figure 1-4.

Levelized Cost of Electricity With and Without EPAct Incentives

(2006 dollars per megawatt hour)



Source: Congressional Budget Office (CBO).

Notes: EPAct = Energy Policy Act of 2005.

CBO's reference scenario excludes both the effects of prospective carbon dioxide constraints and the impact of EPAct incentives.

Electricity-generating capacity is measured in megawatts; the electrical power generated by that capacity is measured in megawatt hours. During a full hour of operation, 1 megawatt of capacity produces 1 megawatt hour of electricity, which can power roughly 800 average households.

The estimate of the effect of EPAct incentives assumes that advanced nuclear technology receives the maximum production tax credits and loan guarantees. The production tax credits are shared among 6,000 megawatts or less of advanced nuclear capacity, and loan guarantees cover 80 percent of construction costs.

Advanced nuclear technology refers to third-generation reactors. Conventional coal power plants are assumed to use pulverized coal technology, which produces energy by burning a crushed form of solid coal. Conventional natural gas power plants are assumed to convert gas into electricity using combined-cycle turbines.

program provides a federal guarantee on debt that covers as much as 80 percent of construction costs. (Debt for building capacity has been financed at roughly 1 percentage point to 5 percentage points above the Treasury-bill rate.)[12] The loan guarantee program also applies to utilities employing innovative fossil-fuel or renewable technologies.

Without the incentives offered to investors who chose nuclear and other innovative generating technologies, conventional coal technology would be the least expensive means of generating electricity (see Figure 1-4). Generating electricity with nuclear technology would be roughly 35 percent more expensive than using conventional coal technology and 30 percent more expensive than using natural gas capacity. Accordingly, investment in nuclear capacity would be unlikely in the absence of carbon dioxide charges and EPAct incentives.

Nuclear power would be a competitive technology for a few new power plants, however, if those plants received the maximum benefits that could be provided under EPAct. Most of the reductions in the cost for those plants would come from the production tax credit and loan guarantees. Other incentives—such as preferential tax treatment for decommissioning funds and limited liability protection—would have a relatively small effect on the

12. That range is based on the 10-year average of historical spreads for debt rated from B to BBB.

Table 1-1.

Incentives Provided by the Energy Policy Act of 2005

Program	Technology	Incentives	Federal Cost
		Research and Development	
Nuclear Power 2010	Advanced nuclear	DOE covers one-half of FOAK costs for licensing and design	$281 million (nominal dollars through 2007)
FutureGen	Innovative coal	DOE shares the cost of developing new facilities	$97 million (nominal dollars through 2007)
		Investment	
Loan Guarantee	Eligible technologies (including advanced nuclear and innovative coal)	Provides low-cost debt financing on up to 80 percent of construction costs (the Treasury reimburses the lender in cases of default)	The utility pays the Treasury for administrative and subsidy costs, but tax revenues diminish under debt financing[a,b]
Delay Insurance[c]	Advanced nuclear	Applies to the first six nuclear plants covered by DOE. Compensates for certain delays in operation, providing up to $500 million apiece for the first two plants and $250 million each for the next four	Utility pays subsidy cost[a]
Investment Tax Credit	Innovative coal[d]	Provides tax credits for up to 20 percent of a project's construction costs	Less than the dollar value of the credits[e]

Continued

cost of nuclear capacity.[13] Incentives covering first-of-a-kind (FOAK) costs could be crucial for attracting financing for the first nuclear plants of each advanced reactor design, although those incentives might not directly affect the cost of subsequent plants. The investment tax credit and loan guarantees for innovative coal plants with CCS and loan guarantees for innovative natural gas power plants with CCS reduce the utilities' costs for those technologies but not by enough to make them less expensive than nuclear power plants that qualify for EPAct incentives or conventional fossil-fuel power plants.

The cost of new nuclear capacity would probably be higher if utilities attempted to build a large number of power plants over the next decade. For instance, building all of the 30 proposed nuclear plants over the next 10 to 15 years—roughly the period of availability for the production tax credit—could significantly increase construction costs for nuclear power plants by increasing demand for scarce components that are necessary to build reactors (for example, specialized steel forgings).

A large wave of additions could also lead to higher costs by reducing the value of the production tax credits or by exhausting coverage under the loan guarantee program. EPAct limits production tax credits for nuclear power plants to a total of $7.5 billion, which means that each eligible plant's allotment of credits would decrease if more than 6,000 megawatts of capacity (roughly the capacity

13. Nuclear plant operators are required to set aside funds to cover the cost of decommissioning—that is, safely shutting down a nuclear reactor at the end of its useful life.

Table 1-1. Continued

Incentives Provided by the Energy Policy Act of 2005

Program	Technology	Incentives	Federal Cost
		Production	
Production Tax Credit	Advanced nuclear	Up to $18/MWh over the first eight years of operation for new nuclear plants[f, g]	A reduction in tax revenues up to the value of the credits issued[h]
Limited Liability[i]	Nuclear	Applies to plants built through 2025. The nuclear industry would not be responsible for damage exceeding $10.6 billion from a nuclear accident[j]	Probably small in terms of expected costs (see Box 3-1 in Chapter 3)
Tax Treatment of Decommissioning Funds	Nuclear	Extends to plants owned by merchant generators. Funds taxed at a reduced rate (20 percent)[k]	A reduction in tax revenues

Source: Congressional Budget Office.

Notes: CCS = carbon capture and storage; DOE = Department of Energy; EPAct = Energy Policy Act of 2005; FOAK = first-of-a-kind costs; MW = megawatt; MWh = megawatt hour.

Electricity-generating capacity is measured in MW; the electrical power generated by that capacity is measured in MWh. During a full hour of operation, 1 MW of capacity produces 1 MWh of electricity, which can power roughly 800 average households.

Advanced nuclear technology refers to third-generation reactors; nuclear technology not designated "advanced" may use first- and second-generation reactors. Innovative coal and natural gas technologies are assumed to capture and store most carbon dioxide emissions.

a. The subsidy cost is the cost the government is expected to incur by guaranteeing debt or insuring against certain delays. In the absence of appropriations for that purpose, the utility must pay the cost; to date, the Congress has not made such appropriations.

b. By making debt financing cheaper, the loan guarantee program increases the amount of financing for which interest payments are tax deductible.

c. Delay insurance is authorized by EPAct under the title "Standby Support for Certain Nuclear Plant Delays."

d. Credits have been available for both innovative coal technology and conventional (pulverized) coal technology that meet specific efficiency and environmental criteria. This study considers only the investment tax credit for innovative coal technology because the credits for conventional coal technology have been awarded already. An investment tax credit is also provided for new solar capacity.

e. The net reduction in tax payments for an investment tax credit is less because applying the credit reduces the amount of capital cost that may be deducted through standard corporate tax law. For the percentage of capital cost on which a credit is claimed, 50 percent of the standard tax deduction may be taken.

f. Production tax credits are also available for technologies that use renewable energy sources.

g. The production tax credit for advanced nuclear technology is not adjusted for inflation; consequently, the maximum value of the credit is likely to decrease substantially by the time advanced nuclear power plants begin operating. In addition, if more than 6,000 MW of capacity qualified, the credit would then be divided proportionally among all qualified capacity. For example, if 12,000 MW of capacity qualified, then the owners of each plant would receive a maximum credit of $9/MWh. The per-MWh value of the credit would also be reduced if the nuclear power plant operated at 80 percent above capacity.

h. The value of credits used cannot exceed the utility's alternative minimum tax liability.

i. Limited liability is provided by the Price-Anderson Nuclear Industries Indemnity Act, which was extended under EPAct.

j. The $10.6 billion figure assumes that the 104 operating commercial reactors will remain operational. The industry's liability per accident equals roughly $300 million plus $96 million multiplied by the number of operating commercial reactors.

k. A utility may deduct the cost of decommissioning as payments are made to the funds, although deductions typically are not made until the service (decommissioning) is performed.

of five plants) qualified for the credit.[14] CBO's analysis incorporates the assumption that no more than 6,000 megawatts of capacity would qualify. Thus, the comparison of costs is intended to indicate only whether nuclear technology would be a commercially viable choice for up to a few nuclear power plants. For gauging the long-run competitiveness of nuclear generation, potential carbon dioxide charges are more likely to influence the development of new nuclear capacity than EPAct incentives.

Uncertainties Posed by Future Market Conditions and the Possibility of Carbon Dioxide Constraints

The commercial viability of nuclear capacity depends both on generators' perceptions of future market conditions at the point they consider committing to the construction of a plant—which might not occur for a few years—and the return that investors would require if confronted with carbon dioxide charges. An array of factors—recent volatility in natural gas prices and construction costs, nuclear power's history of construction cost overruns, and uncertainty about future policy on carbon dioxide emissions—suggests that a wide range of costs are plausible for each of the base-load technologies. Those ranges in costs for new power plants demonstrate that each technology faces considerable uncertainty.

Costs Under Alternative Market Conditions

The assumptions used in the reference scenario are intended to represent investors' perceptions, but even if those base-case assumptions accurately portray the current outlook, unanticipated events may alter those perceptions before investors make binding commitments to nuclear capacity. CBO compared levelized costs under several plausible future scenarios for fuel, construction, and financing costs to identify which technology utilities would probably choose for new capacity under a broad range of circumstances.

Cost of Fuel. In the reference scenario, CBO assumed that natural gas prices in the future would be similar to average prices observed since 2000. However, if natural gas prices fell to levels seen in the 1990s and carbon dioxide emissions remained unconstrained, conventional natural gas technology would be the cheapest source of base-load capacity, even if nuclear technology benefited from EPAct incentives. Conversely, if natural gas prices continued to rise, as they have since the 1990s, natural gas technology would be unlikely to be a competitive alternative for base-load electricity generation. (Table 1-2 shows the cost of generating electricity using each technology under the reference scenario and under alternative market conditions that involve substantial deviations from the base-case assumptions about costs for fuel and construction.)

Although uranium prices have fluctuated widely over the past few years, fuel costs have historically accounted for a small share of the cost of nuclear capacity. EIA projects that the price of nuclear fuel will increase by about 40 percent over the next decade—a trend that CBO incorporates in its base-case assumptions—but if nuclear fuel prices stay at the relatively low 2006 level, the overall cost of nuclear technology would decrease by only 3 percent. (Table 1-2 shows that the cost of nuclear technology is largely insensitive to changes in fuel prices.) Utilities investing in new nuclear power plants would incur most of the cost of that technology during construction.

Cost of Construction. Historically, construction costs for nuclear facilities have been roughly double initial estimates. NRC's revised licensing process for nuclear power plants is expected to reduce midconstruction modifications, which were blamed for many cost overruns in the past. Moreover, vendors argue that advanced reactors will have lower construction costs because they have fewer parts than older reactors. As a result, CBO's base-case assumption for construction costs is about 25 percent lower than the historical average—a figure that reflects recent experience in the construction of advanced reactors in Japan. If those factors turned out not to reduce construction costs in the United States, nuclear capacity would probably be an unattractive investment even with EPAct incentives, unless substantial carbon dioxide charges were imposed.

Cost of Financing. The cost of financing construction is substantial for all technologies but particularly so for capital-intense technologies. In CBO's base-case assumptions, the cost incurred to finance commercially viable projects did not depend on which technology was used for a given project. That assumption would be justified if volatility in natural gas prices and the prospect of

14. Under Internal Revenue Service guidelines for the production tax credit, once the amount of qualified nuclear capacity exceeded 6,000 megawatts, a fixed amount of total credits would be divided among all eligible capacity.

Table 1-2.

Levelized Cost of Electricity Under Alternative Market and Policy Conditions

(2006 dollars per megawatt hour)

	Reference Scenario	Variations in Future Market Conditions: Fuel Costs, High (+100%)	Fuel Costs, Low (-50%)	Construction Costs, High (+100%)	Construction Costs, Low (-50%)	Variations in Future Carbon Dioxide Policy: Emissions Capped at 2008 Level	Emissions Capped at About 85% Below 2008 Level by 2050
Advanced Nuclear	72	80	68	121	48	72	72
Conventional Coal	55	70	47	83	40	80	128
Conventional Natural Gas	57	97	36	69	51	67	86

Source: Congressional Budget Office.

Notes: Electricity-generating capacity is measured in megawatts; the electrical power generated by that capacity is measured in megawatt hours. During a full hour of operation, 1 megawatt of capacity produces 1 megawatt hour of electricity, which can power roughly 800 average households.

Advanced nuclear technology refers to third-generation reactors. Conventional coal power plants are assumed to use pulverized coal technology, which produces energy by burning a crushed form of solid coal. Conventional natural gas power plants are assumed to convert gas into electricity using combined-cycle turbines.

Alternative market and policy conditions are overlaid on the reference scenario, which excludes both the effects of prospective carbon dioxide constraints and the impact of incentives provided under the Energy Policy Act of 2005.

constraints on carbon dioxide emissions created cost uncertainties for conventional fossil-fuel technologies that were similar in magnitude to the uncertainties facing investment in nuclear technology.[15]

Costs Under Carbon Dioxide Constraints

Utilities that invest in coal capacity face substantial cost uncertainties because of the prospect of future carbon dioxide constraints and the unknown stringency of such constraints. (The last two columns of Table 1-2 show the cost for new power plants by technology associated with two proposed carbon dioxide constraints.) A policy that constrained carbon dioxide emissions to 2008 levels is projected to increase the cost of electricity from conventional coal-fired plants by roughly one-half and a more stringent constraint would more than double the cost.[16] The projected cost of electricity from conventional natural gas capacity is about half as sensitive to such constraints. Because nuclear plants do not emit carbon dioxide, their levelized costs would be unaffected by the stringency of carbon charges.

15. The results of alternative financing assumptions are given in Chapter 2.

16. CBO based carbon dioxide charges under the two hypothetical cap-and-trade policies on allowance prices in Sergey Paltsev and others, *Assessment of U.S. Cap-and-Trade Proposals*, Working Paper No. 13176 (Cambridge, Mass.: National Bureau of Economic Research, June 2007).

CHAPTER

2

Framing the Analysis: Base-Case Assumptions and the Effects of Policy

To assess the competitiveness of advanced nuclear technology in comparison with other base-load options, the Congressional Budget Office estimated the levelized cost of alternatives under a reference scenario reflecting the agency's best judgment about future market conditions and the policy environment before the enactment of the Energy Policy Act of 2005, and under alternatives that consider the effects of both carbon dioxide charges and EPAct incentives. To calculate those costs, CBO adopted base-case assumptions about an array of technical and economic choices confronting investors in new electricity-generating capacity.[1]

Some of the assumptions underlying this analysis are very uncertain. For instance, large power plants using carbon capture-and-storage technologies exist only as blueprints, which makes predicting their costs difficult. Also subject to uncertainty and controversy are the costs of building a new nuclear plant in the United States, where no reactor has been ordered since the 1970s, when substantial cost overruns were the rule. Even the risks of investing in conventional coal power plants are heightened because utilities cannot anticipate with certainty whether charges on carbon dioxide emissions will be imposed in the future and, if so, at what level. For those and other reasons, financial markets may require a higher rate of return for any investment in new base-load capacity. To account for those uncertainties, CBO assessed the levelized cost of alternatives over a range of values for critical assumptions about plant costs, fuel costs, and the rates of return required by investors to finance new capacity. The results of such calculations indicate the potentially significant impact of those uncertainties on CBO's estimates of the levelized costs of the various technologies.

1. For the most part, the assumptions that CBO adopted are drawn from analysis prepared by the Energy Information Administration.

Levelized Cost Analysis

Levelized cost is the minimum price at which a technology option produces electricity and generates enough revenue to pay all of a utility's costs and still provide a sufficient return to investors. In its analysis, CBO projected expected cash flows in order to find the minimum real (inflation-adjusted) price of electricity at which revenue exceeded costs by enough to encourage investment in the construction of new capacity based on each technology. (A detailed description of the approach used to estimate levelized costs in this study can be found in CBO's Web supplement, *The Methodology Behind the Levelized Cost Analysis.*)

Levelized costs affect investment decisions made by both merchant generators and regulated utilities. If the levelized cost of a technology exceeded anticipated prices for electricity, merchant generators would be unlikely to invest in new capacity based on that technology because the expected return would not justify the amount of risk they would have to incur. State utility commissions commonly direct regulated utilities to meet anticipated demand for new capacity using the technology with the lowest levelized cost.

Both types of utilities typically fund costs that are incurred before a plant begins operating through a combination of debt and equity financing. The revenue that results from the sale of electrical power is first used to pay the plant's operating costs, including the purchase of fuel. After deductions are made for corporate income taxes and debt payments, the remaining revenue is paid to equity-holders. CBO estimated the lowest constant real price of electricity at which the return to equity was adequate to attract the investment for up-front costs.

Whereas utilities' decisions are made on a site-by-site basis, the levelized costs estimated by CBO are intended to give a representative cost for each technology. One technology would probably not have the lowest cost in all parts of the country and other factors could be considered, but a technology with the lowest representative levelized cost would most likely be a common choice for new capacity.

Another consideration is that levelized costs do not indicate which technology produces electricity most efficiently because they capture the utility's cost of generating electricity rather than the actual cost. Government incentives that directly subsidize electricity generation or transfer financial risk from investors to the public decrease levelized costs in comparison to actual costs. Because corporate income taxes increase utilities' costs relative to actual costs, they could make efficient, capital-intense technologies relatively costly. Last, levelized costs include only those costs that markets and current laws require utilities to pay. For example, a carbon-emitting technology might have the lowest levelized cost in the absence of a carbon dioxide charge but not be the most efficient technology because the levelized cost would not account for the damage caused by carbon dioxide emissions.

Base-Case Assumptions

The base-case assumptions necessary to estimate the levelized cost of plants that employ alternative technologies include the cost of building a plant as if it was built and paid for immediately (so-called overnight costs); the return that investors require to finance that construction and subsequent operations; and the cost of operating the plant (largely composed of fuel costs). As a first approximation, CBO relied on the Energy Information Administration's most recent projections for its base-case assumptions and compared those with assumptions adopted in two prominent studies of generation alternatives, one conducted by researchers at the Massachusetts Institute of Technology (MIT) and the other by analysts at the International Energy Agency.[2]

Construction Costs

CBO's base-case assumptions include overnight costs of about $2.4 million for each megawatt of capacity for new nuclear plants and innovative coal plants but lower costs for conventional coal, conventional natural gas, and innovative natural gas technologies. For nuclear and innovative coal and natural gas technologies, the assumptions are intended to represent plants built over the next decade but do not incorporate the first-of-a-kind costs that are assumed to be covered by federal research and development programs. The estimate for nuclear plants, taken from the EIA's most recent analysis, is roughly 10 percent above the estimate of overnight costs used in MIT's study, which was published in 2003, before construction costs for most types of power plants surged. CBO also calculated construction costs for each technology using alternative assumptions designed to capture plausible variations in those costs. For nuclear and innovative coal technologies, CBO considered construction costs ranging from about $1.2 million per megawatt of capacity to roughly $4.8 million per megawatt of capacity. The breadth of that range reflects the uncertainty associated with the cost of building new nuclear plants in the United States and is wide enough to capture plausible further increases in construction costs, which could affect conventional fossil-fuel plants as well.

CBO's assumption about the cost of building new nuclear power plants in the United States is particularly uncertain because of the industry's history of construction cost overruns. For the 75 nuclear power plants built in the United States between 1966 and 1986, the average actual cost of construction exceeded the initial estimates by over 200 percent (see Table 2-1). Although no new nuclear power plants were proposed after the partial core meltdown at Three Mile Island in 1979, utilities attempted to complete more than 40 nuclear power projects already under way. For those plants, construction

2. See John Deutch and others, *The Future of Nuclear Power: An Interdisciplinary MIT Study* (July 2003); and International Energy Agency, *World Energy Outlook* (2006).

Table 2-1.

Projected and Actual Construction Costs for Nuclear Power Plants

Construction Starts		Average Overnight Costs[a]		
Year Initiated	Number of Plants[b]	Utilities' Projections (Thousands of dollars per MW)	Actual (Thousands of dollars per MW)	Overrun (Percent)
1966 to 1967	11	612	1,279	109
1968 to 1969	26	741	2,180	194
1970 to 1971	12	829	2,889	248
1972 to 1973	7	1,220	3,882	218
1974 to 1975	14	1,263	4,817	281
1976 to 1977	5	1,630	4,377	169
Overall Average	**13**	**938**	**2,959**	**207**

Source: Congressional Budget Office (CBO) based on data from Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs,* Technical Report DOE/EIA-0485 (January 1, 1986).

Notes: Electricity-generating capacity is measured in megawatts (MW); the electrical power generated by that capacity is measured in megawatt hours (MWh). During a full hour of operation, 1 MW of capacity produces 1 MWh of electricity, which can power roughly 800 average households.

The data underlying CBO's analysis include only plants on which construction was begun after 1965 and completed by 1986.

Data are expressed in 1982 dollars and adjusted to 2006 dollars using the Bureau of Economic Analysis's price index for private fixed investment in electricity-generating structures. Averages are weighted by the number of plants.

a. Overnight construction costs do not include financing charges.

b. In this study, a nuclear power plant is defined as having one reactor. (For example, if a utility built two reactors at the same site, that configuration would be considered two additional power plants.)

cost overruns exceeded 250 percent.[3] (An average of 12 years elapsed between the start of construction and the point at which the plants began commercial operation. The overruns in overnight costs did not include additional financing costs that were attributable to post-accident construction delays.)[4]

The base-case assumption adopted in this analysis for nuclear power plants' overnight costs recognizes that history but also allows for countervailing factors, such as changes in the U.S. regulatory process and other countries' recent experience with new reactor designs. In 1989, the Nuclear Regulatory Commission developed an alternative process for obtaining the licensing necessary to operate a nuclear power plant. That revised process is intended to reduce cost uncertainties by allowing utilities to fulfill more regulatory requirements before beginning construction, thereby reducing midconstruction design changes that contributed to overruns in the past.

The experience of a Japanese utility, the Tokyo Electric Power Company (TEPCO), in the mid-1990s also appears to support CBO's base-case assumption about construction costs. According to the 2003 MIT study, verifiable data indicate that TEPCO constructed two advanced boiling-water reactors at costs and schedules close to manufacturers' estimates.[5] However, a Finnish utility that is building a reactor based on a different design, an advanced pressurized-water reactor, continues to have difficulty adhering to original cost estimates. By

3. The calculation is based on data from Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs*, DOE/EIA-0485 (1986). Those data include only plants on which construction was begun after 1965 and completed by 1986.

4. See Pietro S. Nivola, "The Political Economy of Nuclear Energy in the United States," *Brookings Policy Brief No. 138* (September 2004).

5. See Deutch and others, *The Future of Nuclear Power,* p. 142.

Table 2-2.

Financial Risk Assumptions in Comparable Studies

Study	Real Rate of Return (Percent)	Capital Recovery Period[a] (Years)
CBO	8-3/4 – 12-1/2	40
EIA	9-1/4	20
IEA	8 – 11	40 – 25
MIT	8 – 11-1/4	25 – 40

Source: Congressional Budget Office (CBO).

Notes: EIA = Energy Information Administration; IEA = International Energy Agency; MIT = Massachusetts Institute of Technology.

Real rates of return are rounded to the nearest quarter of a percentage point. CBO calculated those rates on the basis of the inflation rates and nominal rates of return used in each study. The underlying nominal rates of return for the studies conducted by EIA and IEA represent the weighted average cost of capital assumed in those studies. The nominal rates of return for the MIT study were constructed by taking the ratio of financing charges to balances in CBO's replication of the MIT model.

a. The capital recovery period represents the number of years over which revenue from the sale of electricity is used to repay debt or equityholders.

2007, that project, initially estimated to cost €3 billion, had fallen at least 18 months behind schedule, causing costs to increase by €700 million.[6]

Financing Costs

Even if construction proceeds on schedule, utilities still incur substantial financing costs because power plants take years to build, and financing costs for construction extend over the decades that a plant generates electricity. CBO's assumptions about financing costs are a synthesis of the financial analyses presented in the studies by EIA and MIT. Those assumptions are encapsulated by the real rate of return that investors require to assume the risk of paying up-front construction costs.[7] CBO used a real rate of return of 10 percent, which falls within the range of rates of return given in the other studies (see Table 2-2).[8] The 10 percent rate of return was used for each technology, reflecting that the level of financial risk is similar across commercially viable projects. The MIT study assumed that a higher rate of return would be required for nuclear technology than for conventional fossil-fuel technologies; however, that 2003 study was published before much of the volatility in natural gas prices and when future federal carbon dioxide constraints may have appeared less likely.[9] But nuclear plants could still be a riskier investment than competing alternatives, or the rate of return could vary for all technologies. In addition to the base-case assumption of a 10 percent rate of return, CBO considered the competitiveness of nuclear power under lower and higher rates (as shown in Table 2-2).

Fuel Costs

The cost of fuel is one of the most significant operating costs included in CBO's estimates of the levelized cost of options for generating electricity. The base-case assumption for nuclear power is that $8 (in 2006 dollars) in fuel costs are incurred for each megawatt hour of electricity generated (see Table 2-3). That contrasts with $16 for conventional coal-fired plants and $40 for conventional natural gas plants.[10] Those assumptions are based on long-term projections by EIA. In the past, fuel costs have proved difficult to predict, particularly the price of natural gas. (See Figure 2-1 for fluctuations in fuel prices between 1995 and 2006.) In addition to those base-case assumptions, CBO also estimated levelized costs using alternative assumptions intended to capture most plausible variations in fuel costs.

6. See David Gauthier-Villars, "Trials of Nuclear Rebuilding: Problems at Finland Reactor Highlight Global Expertise Shortage," *Wall Street Journal*, March 3, 2007, p. A6.

7. Financing costs are also influenced by the period of capital recovery—the number of years over which the plant generates revenue for equityholders. As the recovery period increases, so do the financing costs.

8. The 10 percent rate of return is based on 45 percent debt financing and 55 percent equity financing. Debt is assumed to be repaid at a rate of return of 8 percent over 20 years, and equity is assumed to be repaid at an average rate of return of 14 percent over the 40 years the plant is assumed to operate.

9. See "Coal Utilities Say They Do Not Fear Risk to Credit, Despite Moody's Warning on Carbon Burdens," *Platts Electric Utility Week* (March 3, 2008), p. 1. According to that report, Moody's Investors Services has warned that the prospect of future carbon dioxide charges may adversely affect the credit rating of utilities and thus raise the cost of capital for investment in conventional coal-fired generation.

10. Fuel costs at innovative fossil-fuel plants are expected to be 10 percent to 30 percent higher because additional energy is needed to capture carbon dioxide.

Table 2-3.

Key Assumptions Underlying CBO's Reference Scenario

	Advanced Nuclear	Conventional Coal	Conventional Natural Gas	Innovative Coal	Innovative Natural Gas
Construction					
Time (Years)	6	4	3	4	3
Overnight costs (Thousands of dollars per MW)[a]	2,358	1,499	685	2,471	1,388
Operating Costs					
Fuel (Dollars per MWh)	8	16	40	17	52
Fixed operation and maintenance (Dollars per MWh)	8	4	1	6	3

Source: Congressional Budget Office based on data from the Energy Information Administration.

Notes: Electricity-generating capacity is measured in megawatts; the electrical power generated by that capacity is measured in megawatt hours. During a full hour of operation, 1 megawatt of capacity produces 1 megawatt hour of electricity, which can power roughly 800 average households.

The reference scenario excludes both the effects of prospective carbon dioxide charges and the impact of incentives provided under the Energy Policy Act of 2005.

Advanced nuclear technology refers to third-generation reactors. Conventional coal power plants are assumed to use pulverized coal technology, which produces energy by burning a crushed form of solid coal. Conventional natural gas power plants are assumed to convert gas into electricity using combined-cycle turbines.

Values are expressed in 2006 dollars.

a. Overnight construction costs do not include financing charges. Financing charges are addressed separately in Table 2-2.

The cost of disposing of the used (spent) fuel generated by nuclear fission is currently unique to that fuel source. (However, if carbon dioxide charges were imposed in the future, they could be seen as similar because utilities could have to assume the full cost of their fuel choice—that is, they would have to pay for the damage inflicted by emitting carbon dioxide.) CBO's levelized cost estimate for nuclear power includes a $1 per megawatt hour charge to cover the cost of such disposal.[11]

Additional Assumptions

Other important considerations in CBO's analysis include the fixed cost of operating and maintaining a power plant (that is, the costs that do not vary with the amount of electricity produced) and the percentage of maximum electricity production achieved by the plant (the "capacity factor"). For nuclear plants, fixed operating and maintenance expenses include the cost of providing security and monitoring safety systems. On the basis of EIA's analysis, the combination of such costs is assumed to be five times those incurred by a conventional natural gas coal plant and twice those incurred by a conventional coal plant. The fixed operating costs of innovative coal and natural gas plants are assumed to be higher than those of conventional fossil-fuel alternatives but lower than those of nuclear power plants.

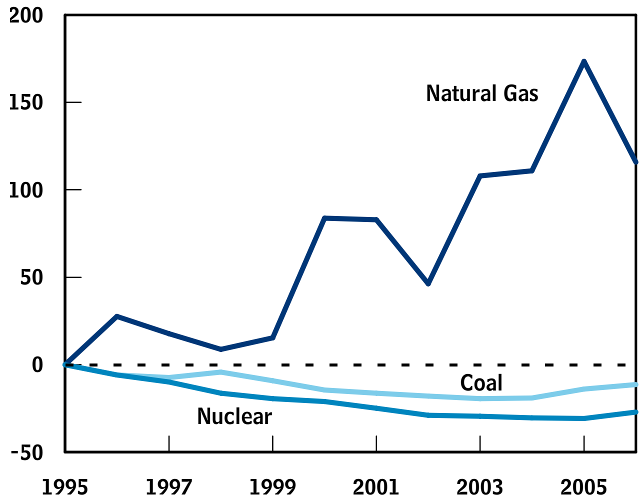
Capacity factors range from about 80 percent to 90 percent, depending on the technology. Those factors represent the maximum rate at which each technology could physically operate, as determined by EIA. Historically, utilities have utilized natural gas capacity at much lower rates because, in comparison with coal-fired and nuclear technologies, natural gas has typically been an expensive source of base-load power. But because this study evaluates the competitiveness of natural gas as a base-load alternative, CBO assumed that options using that fuel would operate at their maximum capacity factor.

11. See Department of Energy, *Nuclear Waste Fund Fee Adequacy: An Assessment*, DOE/RW-0534 (May 2001), p. 1.

Figure 2-1.

Historical Volatility in Fuel Prices

(Percentage change)



Source: Congressional Budget Office based on data from the Energy Information Administration (EIA).

Note: The percentage changes are based on prices in 2006 dollars, with adjustments for inflation made using the gross domestic product price index. Prices for all fuels equal the average cost at which those fuels are delivered to power plants, as measured by EIA.

Accounting for the Effects of Policy

Expanding the reference scenario to include the effects of carbon dioxide charges and EPAct incentives changes CBO's estimates of the levelized cost—and potential competitiveness—of each technological option. Carbon dioxide charges would raise the levelized cost of fossil-fuel alternatives but not the cost of nuclear power. Conversely, EPAct incentives reduce the levelized cost of nuclear power and innovative fossil-fuel options in comparison with that of conventional fossil-fuel technologies.

In addition to the uncertainty inherent in the base-case assumptions, some of the assumptions linking policy to levelized cost are subject to uncertainty. In particular, when estimating levelized cost, CBO assumed that the full benefits of EPAct incentives would be available to both nuclear and innovative fossil-fuel options. In some instances, CBO also used simplifying assumptions to incorporate policy into levelized cost. For example, carbon dioxide charges were assumed to be levied only on smoke-stack emissions (those resulting directly from the operation of a power plant). In reality, all technologies have the potential to produce additional emissions from the construction and decommissioning of a facility, as well as from the processing of fuel. Such additional life-cycle emissions are not included in this analysis because they are difficult to measure precisely and are probably an order of magnitude smaller than the stack emissions from coal or natural gas power plants.[12]

Accounting for the Effects of Carbon Dioxide Charges

Carbon dioxide constraints could encourage the use of nuclear technology by increasing the cost of generating electricity with fossil fuels. The effect is most pronounced for coal, which emits nearly a metric ton of carbon dioxide for every megawatt hour of electricity produced. The effect on conventional generators fueled by natural gas would be less because they emit carbon dioxide at roughly half the rate of the average coal plant.

Because competing base-load alternatives emit carbon dioxide, the attractiveness of financing a new nuclear power plant depends on investors' expectations about the costs of emitting carbon dioxide over the operating life of that plant. To the extent that carbon dioxide charges are expected, investment in new nuclear capacity would be more attractive relative to both the construction of new fossil-fuel capacity and the continued use of existing fossil-fuel capacity. Many investors appear to anticipate some form of carbon dioxide charge in the near future; a survey conducted by Cambridge Energy Research Associates in 2006 found that about 80 percent of utility executives expected a carbon dioxide charge to be implemented within the next 10 years.[13]

Although the imposition of carbon dioxide constraints would not directly decrease the cost of operating nuclear power plants, such a policy would increase the cost of operating fossil-fuel power plants, which in all their variants emit at least some carbon dioxide, and consequently make new nuclear capacity a more attractive source of base-load generation. Newly built power plants based on conventional fossil-fuel technology are designed to burn

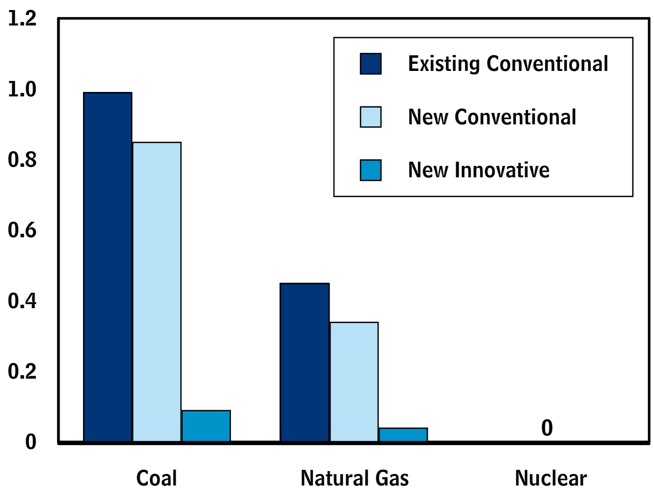
12. See Joseph V. Spadaro, Lucille Langlois, and Bruce Hamilton, *Greenhouse Gas Emissions of Electricity Generation Chains: Assessing the Difference* (International Atomic Energy Agency, February 2000), p. 21.

13. See Kathy Carolin Larsen, "Carbon Leads Long List of Electricity Market Risks," *Platts Insight* (November 2006).

Figure 2-2.

Carbon Dioxide Emissions of Base-Load Technologies for Generating Electricity

(Metric tons per megawatt hour)



Source: Congressional Budget Office (CBO).

Note: Electricity-generating capacity is measured in megawatts (MW); the electrical power generated by that capacity is measured in megawatt hours (MWh). During a full hour of operation, 1 MW of capacity produces 1 MWh of electricity, which can power roughly 800 average households.

Conventional coal power plants are assumed to use pulverized coal technology, which produces energy by burning a crushed form of solid coal. Conventional natural gas power plants are assumed to convert gas into electricity using combined-cycle turbines. Both innovative coal and innovative natural gas technologies are assumed to capture and store most carbon dioxide (CO_2) emissions.

CBO's analysis assumes that coal contains approximately 0.095 metric tons per million British thermal units (Btu) of CO_2 and that natural gas contains 0.054 metric tons per million Btu. It also assumes that existing conventional coal technology burns 10.463 million Btu of coal per MWh of electricity and that existing conventional natural gas technology burns 8.401 million Btu of natural gas per MWh of electricity. See CBO's Web supplement for assumptions underlying the analysis.

fuel more efficiently than plants built in the past, but their emissions would still be substantial enough for the cost of producing electricity to be sensitive to carbon dioxide charges. Innovative fossil-fuel power plants that capture and store carbon dioxide are assumed to emit only about 10 percent of the carbon dioxide discharged into the atmosphere by the lowest emitting conventional plants that burn fossil fuel—but they still emit carbon dioxide. As of 2007, such carbon dioxide capture-and-storage technologies had not been used at commercial power plants, but those technologies could be an option for new base-load capacity by the time new nuclear plants were deployed and might be the most competitive alternative to nuclear technology under carbon dioxide charges.[14]

CBO estimated the cost of emitting carbon dioxide using hypothetical charges based on the levels of carbon intensity for coal and natural gas reported in the MIT study. Those hypothetical charges were assumed to be proportional to the amount of carbon dioxide emitted by each technology (see Figure 2-2).

Accounting for the Effects of Energy Policy Act Incentives

EPAct provides or extends numerous incentives for generating electricity using nuclear, renewable, and innovative fossil-fuel technologies. In general, the incentives lower the cost of nuclear and other innovative technologies in comparison to conventional fossil-fuel alternatives. Among the programs reauthorized under EPAct were the Nuclear Power 2010 program and FutureGen (originally authorized in 2002 and 2003, respectively).[15] Under those programs, the federal government shares with industry the cost of researching, developing, and deploying advanced nuclear power plants and innovative coal-fired plants that incorporate CCS technology. Other incentives—in particular, loan guarantees, investment tax credits, and insurance against regulatory delays—are intended to encourage investment in nuclear power and innovative fossil-fuel technologies. Another set of EPAct policies provides production incentives for operating advanced nuclear power plants once construction is complete. (Table 1-1 on page 10 lists and describes in more detail the incentives provided by EPAct.)

14. For more information, see Congressional Budget Office, *The Potential for Carbon Sequestration in the United States*.

15. After canceling the original FutureGen program—which would have funded the construction of a single coal plant with CCS technology that also would have generated hydrogen for commercial purposes—the Department of Energy now plans to fund research and development for multiple innovative coal plants that use CCS technology.

Research and Development Incentives

The lessons learned in developing and implementing a particular design for a new power plant could reduce the cost of building additional power plants with similar designs. First-of-a-kind costs could be especially large in the nuclear industry because the technology is complex, and utilities have little experience in navigating the revised regulatory process for obtaining a construction and operating license. To the extent that the original utility does not have exclusive rights to build any additional plants, part of the gains in knowledge and experience arising from the initial investment could be captured by other utilities that build plants later. As a result, utilities might underinvest in new technologies because they would not retain enough of the benefit such investment produced.[16]

The Nuclear Power 2010 pays a share of FOAK costs for advanced nuclear technology—to increase the amount of investment in its development.[17] To estimate the reduction in costs attained by plants benefiting from that program, CBO included FOAK costs for licensing and design in supplementary analysis.

Investment Incentives

A second set of incentives encourages investment in the construction of power plants that use advanced nuclear and innovative fossil-fuel technologies. They include a loan guarantee program that insures the debt for such technologies, another insurance program that provides advanced nuclear technologies protection against the cost of certain delays in the start of operation, and tax incentives for investment in innovative coal technologies.

Such incentives could be viewed as countering negative effects on investment caused by taxes on capital income. For instance, corporate income taxes, as well as taxes on capital gains, dividends, and interest income, act as proportional surcharges on investing in the construction of power plants. Such taxes could cause utilities to prefer technologies that were less capital-intensive. In particular, capital costs make up a relatively large portion of the cost of producing electricity using nuclear or innovative coal power plants because those plants are relatively expensive to build. As a result, taxes on capital income might encourage utilities to build conventional fossil-fuel power plants, which have lower capital costs. Investment incentives could counter potential bias against capital-intensive technologies caused by taxes on capital income.

Loan guarantees and insurance against delays reduce the financial risk of investing in advanced nuclear power plants by transferring risk to the public. The reduced risk means investors would incur lower costs for financing construction and other activities before a plant began operating. However, economic theory suggests that such incentives cause recipients to invest in excessively risky projects because they do not bear all the cost of a project's failure. The federal government also provides investment subsidies through investment tax credits, which reduce tax liability in proportion to construction expenditures.

Production Incentives

A third set of incentives encourages not only the construction of nuclear plants but also their continued operation. Those incentives indirectly encourage investment by making operation more profitable. Incentives supporting operation include a production tax credit, a limit on liability for nuclear accidents, and a tax incentive to reduce the cost of disposing of radioactive waste, which is a byproduct of operating nuclear plants.[18]

Such subsidies could be viewed as compensating utilities that choose zero-emissions technologies, such as nuclear, for the potential public benefits of mitigating carbon dioxide emissions; however, such subsidies are inefficient and counterproductive in comparison to charges for emitting carbon dioxide.[19] Because production tax credits reduce the price of electricity, consumers might use electrical power less efficiently and expand the gap

16. For a detailed review of the role of research and development in promoting technologies that reduce carbon dioxide emissions, see the Congressional Budget Office report, *Evaluating the Role of Prices and R&D in Reducing Carbon Dioxide Emissions* (September 2006).

17. Although Nuclear Power 2010 and FutureGen have been two of the largest EPAct research and development incentives for the electricity industry, other cost-sharing programs exist for innovative coal technologies, renewable energy technologies, and fourth-generation nuclear reactors.

18. The EPAct expansion of the preferential tax treatment of decommissioning funds reduces the private cost of cleaning and securing a nuclear facility once it is retired, which primarily involves the disposal of low-level radioactive waste. The federal government also plays a role in the long-term disposal of spent fuel, but that program is not addressed by EPAct.

19. The production tax credit is also available to investors in some zero-emissions renewable technologies.

between the price of electricity and its cost to society at the expense of the general taxpayer. Alternatively, a charge on carbon dioxide emissions that was representative of the damage those emissions cause would equate the price of electricity to its social cost. Such a price would lead to more-efficient use of electricity, because the utility and consumer, rather than the general taxpayer, would pay for the cost of carbon dioxide emissions.

CHAPTER

3

Results and Implications of the Analysis

Under the provisions of the Energy Policy Act of 2005, it is probable that at least a few nuclear power plants will be built over the next decade, most likely in markets where electricity usage and the corresponding demand for additional base-load capacity are expected to grow significantly. Ultimately, however, the longer-term competitiveness of nuclear technology as a source of electricity is likely to depend on policymakers' decisions regarding carbon dioxide constraints. If such constraints are implemented, nuclear power will probably enjoy a cost advantage over conventional fossil-fuel alternatives as a source of electricity-generating capacity. Today, even the anticipation that carbon dioxide emissions will be priced is a factor being weighed in investors' decisions about new base-load capacity. Those conclusions are tentative, though, because the electricity industry faces numerous uncertainties. If expectations related to future market conditions—especially those pertaining to construction costs or fuel prices—shift before investors commit to the construction of new base-load capacity, the prospects for new nuclear capacity could change dramatically.

The Outlook for Investment in the Absence of Carbon Dioxide Charges and EPAct Incentives

In the Congressional Budget Office's reference scenario, the estimated levelized costs of new capacity based on conventional coal or conventional natural gas technology are roughly equivalent. By comparison, the levelized costs of the other options under consideration are much higher. Specifically, the levelized costs for building and operating a new nuclear power plant are estimated to be about 30 percent more than the cost of either a conventional coal or natural gas plant. The costs for innovative coal and natural gas plants that capture and store carbon dioxide are even greater, exceeding those of the lowest-cost conventional fossil-fuel options by 50 percent. Accordingly, in the absence of carbon dioxide constraints and without the incentives of EPAct, utilities would probably continue to build power plants relying on conventional fossil-fuel technologies to meet increases in base-load electricity demand.

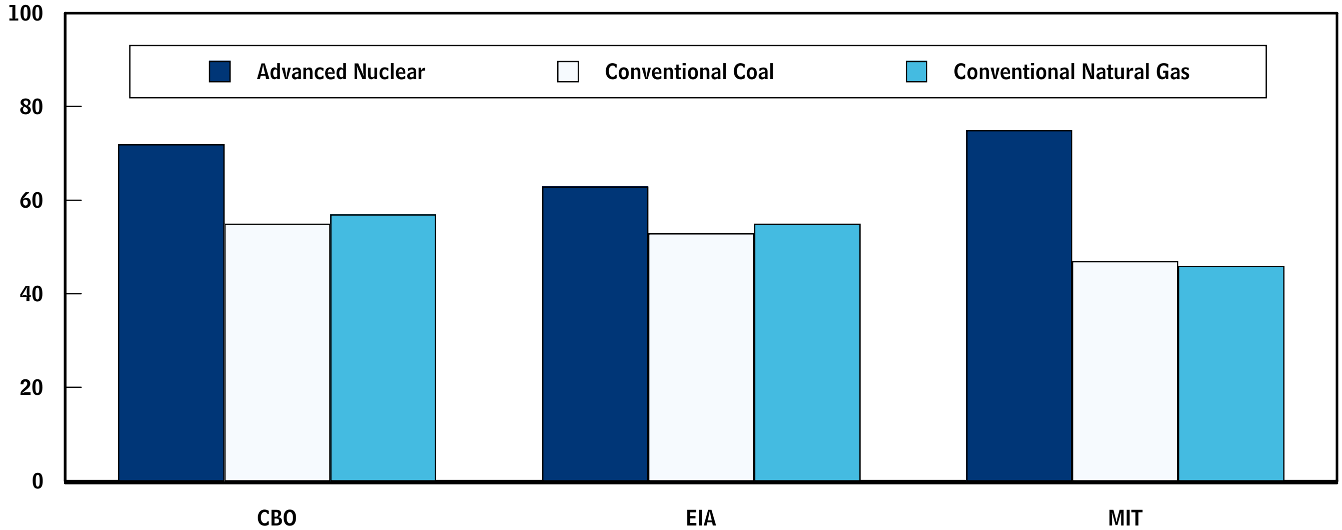
Differences in construction and fuel costs explain the differences between the levelized costs of conventional fossil-fuel technologies and nuclear technology. In the reference scenario, the cost of building a new coal plant is about two-thirds the cost of building a nuclear plant, and the cost of building a natural gas plant is even less (about a third of that required to build a nuclear plant). The levelized costs for conventional coal and natural gas technologies converge because the higher cost of building a coal plant is offset by the higher cost of using natural gas as a fuel. The highest-cost alternatives considered in the reference scenario, innovative fossil-fuel plants that capture and store carbon dioxide, are encumbered by the fact that they are more costly to build and fuel than their conventional counterparts. In the reference scenario, the levelized cost of a nuclear plant is about 15 percent below that of an innovative coal-fired facility with CCS (the least expensive of the two innovative fossil-fuel technologies).

CBO's results echo those of other studies. Researchers at the Energy Information Administration and Massachusetts Institute of Technology found that, in the absence of carbon dioxide charges and EPAct incentives, new nuclear technology would have a higher levelized cost than conventional fossil-fuel technologies. Some disagree-

Figure 3-1.

Levelized Cost of Electricity in Comparable Studies

(2006 dollars per megawatt hour)



Source: Congressional Budget Office (CBO).

Notes: EIA = Energy Information Administration; MIT = Massachusetts Institute of Technology.

Electricity-generating capacity is measured in megawatts; the electrical power generated by that capacity is measured in megawatt hours. During a full hour of operation, 1 megawatt of capacity produces 1 megawatt hour of electricity, which can power roughly 800 average households.

Advanced nuclear technology refers to third-generation reactors. Conventional coal power plants are assumed to use pulverized coal technology, which produces energy by burning a crushed form of solid coal. Conventional natural gas power plants are assumed to convert gas into electricity using combined-cycle turbines.

CBO's estimates of levelized costs presented here are based on a reference scenario that excludes both the effects of prospective carbon dioxide constraints and the impact of incentives provided by the Energy Policy Act of 2005. EIA's levelized costs are based on its reference case, which includes the assumption that power plants will be built in 2015. MIT's levelized costs derive from its base case, which assumes a 40-year capital recovery period and an 85 percent capacity factor. MIT's results were converted to 2006 dollars using the gross domestic product price index and do not include the cost of delivering electricity.

ment exists about the size of the gap, however (see Figure 3-1).[1] The researchers at MIT predicted a larger cost gap because they concluded that an investment in new nuclear capacity would be riskier than an investment in conventional fossil-fuel technologies; consequently, they projected higher financing costs for nuclear technology.

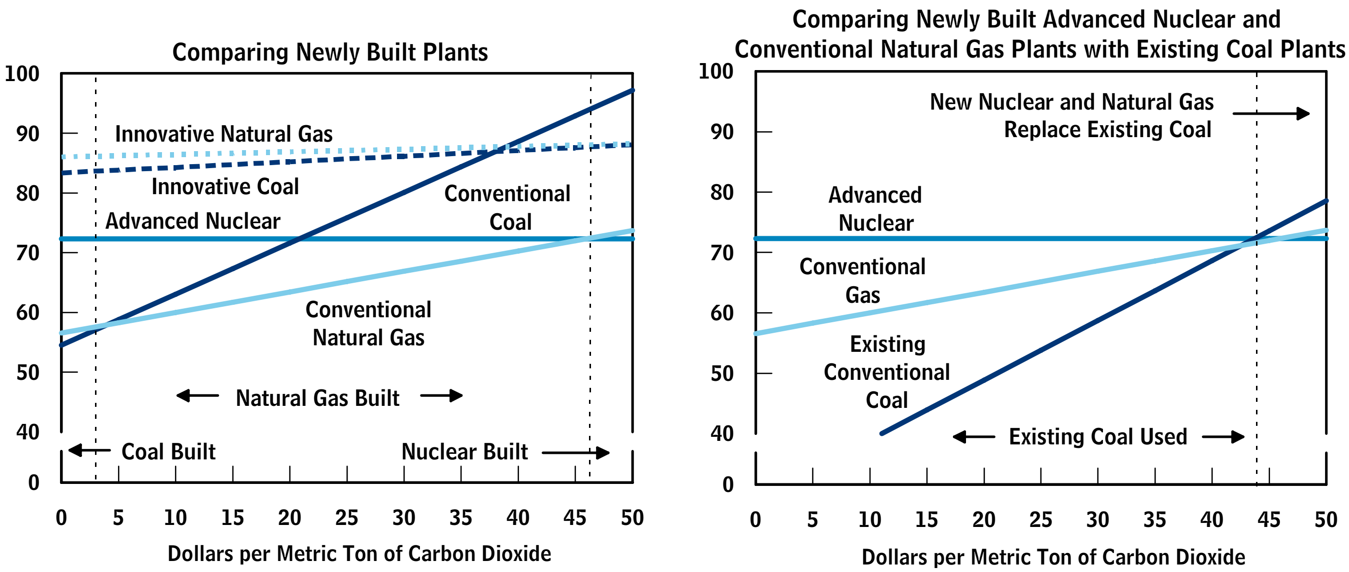
Neither the assumptions underlying that study nor CBO's base-case assumptions explicitly included the additional costs that utilities would have to pay if not for the limited liability protection offered under the Price-Anderson Nuclear Industries Indemnity Act, a policy long in effect (and extended by EPAct) that is implicitly captured in the reference scenario's assumptions. Supplementary analysis that expands on the reference scenario by exploring the likelihood that a catastrophic nuclear accident might occur suggests that removing that insurance subsidy would probably increase the levelized cost of nuclear generation by no more than 1 percent (see Box 3-1).

1. Levelized costs for CCS technologies are not reflected in Figure 3-1 because those estimates were not available in all of the reports. In particular, the MIT study group did not analyze CCS technologies in *The Future of Nuclear Power* (2003). That study group estimated the cost of coal-fired power plants with CCS technology in a later report, *The Future of Coal* (2007), but changes in the methodology obscure whether the levelized cost for CCS technology in that report can be compared with the levelized cost of nuclear power in the earlier analysis. EIA found that the cost of generating electricity from coal-fired power plants with CCS would exceed the cost of power generated by nuclear power plants by about 15 percent.

Figure 3-2.

Levelized Cost of Alternative Technologies to Generate Electricity Under Carbon Dioxide Charges

(2006 dollars per megawatt hour)



Source: Congressional Budget Office.

Notes: Electricity-generating capacity is measured in megawatts; the electrical power generated by that capacity is measured in megawatt hours. During a full hour of operation, 1 megawatt of capacity produces 1 megawatt hour of electricity, which can power roughly 800 average households.

Advanced nuclear technology refers to third-generation reactors. Conventional coal power plants are assumed to use pulverized coal technology, which produces energy by burning a crushed form of solid coal. Conventional natural gas power plants are assumed to convert gas into electricity using combined-cycle turbines. Innovative coal and natural gas technologies are assumed to capture and store most carbon dioxide emissions.

The Outlook for Investment Under Carbon Dioxide Charges

Putting in place a cap-and-trade system that limited the amount of carbon dioxide power plants could emit or levying a tax on such emissions would encourage the construction of new nuclear capacity by increasing the cost of generating electricity with competing fossil-fuel technologies. Carbon dioxide constraints would have no direct effect on the levelized cost of nuclear plants and would have only a small effect on innovative fossil-fuel plants with CCS technology (which are assumed to capture 90 percent of carbon dioxide emissions). In general, under the assumptions incorporated in CBO's analysis, nuclear technology would become a more competitive source of new base-load capacity as the cost of emitting carbon dioxide increased. Eventually, if carbon dioxide charges became high enough, it would be economical for utilities to construct new nuclear or new conventional natural gas plants to replace conventional coal plants that were still operational. Regardless of the magnitude of the charges that might be imposed, however, it is unlikely that nuclear plants could be built quickly enough at any point in the near future to replace existing coal power plants, which currently account for half of the electricity generated in the United States.

Would Nuclear Technology Be the Choice for Expanding Capacity?

Adding a carbon dioxide charge of about $45 per metric ton to the levelized cost estimates in the reference scenario would make nuclear power the least expensive source of additional base-load capacity (see the left panel of Figure 3-2). Up to that threshold, at all but the lowest level of charges, conventional natural gas technology

Box 3-1.

The Cost of Liability for Nuclear Accidents

Among its various provisions, the Energy Policy Act of 2005 extended the Price-Anderson Nuclear Industries Indemnity Act, which limits the industry's liability for accidents at nuclear power plants. In practice, Price-Anderson subsidizes utilities by reducing their cost of carrying liability insurance. Instead of purchasing full coverage, operators of nuclear power plants are required to obtain coverage only up to the liability limit, which is currently set at about $10 billion per accident.[1] The value of the subsidy is the difference between the premium for full coverage and the premium for $10 billion in coverage. On the basis of data obtained from two studies—one conducted by the Nuclear Regulatory Commission (NRC) and the other by the Department of Energy (DOE)—the Congressional Budget Office (CBO) estimates that the subsidy probably amounts to less than 1 percent of the levelized cost for new nuclear capacity.[2]

To assess the health hazards that existing nuclear power plants could pose, analysts at the NRC estimated the probability of radioactive releases occurring at several nuclear facilities, including the Surry power station in Virginia, and the consequence of such an event.[3] Damage to property and possible injury or loss of life caused by a hypothetical accident at that facility could be pertinent to assessing the liability of proposed nuclear plants because several of them would be located in areas of the Southeast with roughly similar population densities. For the Surry power station, the NRC study provides assessments of both internally initiated accidents (which could be

1. That $10 billion in coverage has two layers: The owner of a nuclear plant is required to purchase primary insurance covering liability up to $300 million. In the event of an accident, liability for damages assessed at between $300 million and $10 billion would then be shared among the owners of all U.S. nuclear plants, who would pay a "retroactive premium."

2. See Nuclear Regulatory Commission, *Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants*, NUREG-1150 (December 1990); and Department of Energy, *Technical Guidance for Siting Criteria Development*, SAND-81-1549 (December 1982). CBO's estimate was derived to evaluate the sensitivity of levelized costs (or the minimum price of electricity at which a technology generates enough revenue to be economically viable) to limits on liability but should not be interpreted as a precise estimate of the expected cost of liability.

3. A description and evaluation of the NRC's probabilistic risk assessment models is provided in *Nuclear Power Joint Fact-Finding* (Keystone Center, June 2007).

Continued

would probably be the least costly option. Because coal is more carbon-intense than natural gas, the cost advantage of new capacity based on natural gas technology would grow in relation to coal technology as carbon dioxide charges increased; but the advantage that natural gas technology enjoyed over nuclear technology would shrink and eventually disappear as emission charges reached about $45 per metric ton. Thereafter, the levelized cost advantage of nuclear technology over conventional gas technology would grow. Although carbon dioxide charges would not change the cost of nuclear power plants at all, they would increase the cost of innovative fossil-fuel alternatives; as a result, the cost advantage that nuclear technology held over those technologies would increase with carbon dioxide charges but at a slower rate than that observed with conventional fossil-fuel technologies.

Variations in the base-case assumptions about the costs for construction, fuel, or financing could increase the levelized cost of meeting base-load demand with nuclear technology relative to that for alternative technologies. For example, if the construction costs of all generation technologies doubled, carbon dioxide charges would have to be set at $150 per metric ton for nuclear technology to be preferred over conventional natural gas technology. (The concluding section of this chapter provides a more comprehensive assessment of the sensitivity of various technologies to variations in the base-case assumptions.)

Box 3-1. Continued

The Cost of Liability for Nuclear Accidents

caused by malfunctioning equipment or human error) and externally initiated accidents (which could result from a fire or earthquake). According to the study, an internally initiated accident at such a facility that on average caused more than 10 deaths would occur, at most, once every million years. A fire-related accident causing more than 1,000 deaths on average would occur, at most, once every million years. CBO's analysis adopted those probabilities and results for the sake of determining liability from fatalities. To that, CBO added estimates of injuries and property damage to provide a more complete estimate of liability.

CBO based its assessment of liability from injuries and property damage on the DOE report, which modeled a radioactive release at the Limerick facility near Philadelphia. That scenario includes, in addition to the number of fatalities, estimates of injury and property damage, from which CBO inferred potential liability resulting from an accident at the Surry plant.

On the basis of the probability of fatal accidents estimated in the NRC report and the estimates of damage from such accidents in the DOE report, it appears that catastrophic accidents are possible but likely to be rare; CBO estimates that an accident causing about $500 billion in damages will occur an average of 3 out of every 100 million years.[4] Because such potential damages are spread over a long period, the long-run average of damages per year (the expected cost) would be only about $600,000. That figure does not include the cost of nonfatal accidents, which might already be covered by the $10 billion in damages for which the nuclear power industry is held liable under the Price-Anderson Act. If so, the projected annual subsidy is about $600,000 per reactor as well.

Insurance premiums represent a small portion of the levelized cost for a nuclear power plant. Even if the analysis based on the Surry facility understates the expected cost of fatal nuclear accidents by a factor of 10, paying a fair premium would not lead to large changes in the levelized cost. In CBO's reference scenario, increasing the insurance premium by $6 million per year increases the levelized costs by 1 percent.

4. Each fatality is assumed to lead to $5,000,000 in liability, and each injury is assumed to cause $2,500,000 in liability.

Would New Nuclear Plants Replace Any Existing Coal Capacity?

When carbon dioxide charges are added to the levelized costs estimated in the reference scenario, they fall most heavily on coal technologies. The effect is so significant that, at a carbon dioxide charge of about $45 per metric ton of emissions, this analysis suggests that utilities could build and operate new nuclear or conventional natural gas plants at a lower levelized cost than continuing to operate existing coal plants. But whether such a switch would occur would depend on other factors as well—including the markets for the components and labor necessary to build new reactors and the market for natural gas.

Even if carbon dioxide charges over $45 per metric ton were implemented, it would take decades for sufficient nuclear capacity to be put in place before most utilities could consider substituting new nuclear capacity for existing coal plants. Replacing the 300,000 megawatts of existing coal capacity would require hundreds of new nuclear plants. The capacity of the industry that builds nuclear plants and its suppliers of components is currently constrained and unlikely to expand rapidly enough for even tens of plants to be built in the next decade. For example, the Brattle Group (a consulting firm) has pointed out that the skilled labor necessary to erect power plants is in short supply and could be slow to expand if a surge in the demand for nuclear plants occurred.[2] Also, the supply of steel forgings necessary to build a reactor's containment vessel—a structure that prevents radiation from leaking into the atmosphere—is limited.[3]

Although the trend toward natural gas technology that was evident in the 1990s could always recur, it is not likely that natural gas technology would completely replace coal technology as a source of electrical power. The primary reason is that increased demand for natural gas would exert upward pressure on the price of that fuel, perhaps pushing costs above the levels included in the reference scenario. To illustrate, at the highest prices for natural gas considered in CBO's analysis of market and policy uncertainties, utilities would be extremely unlikely to prefer natural gas to either existing coal plants or new nuclear plants.

The Outlook for Investment Under the Energy Policy Act of 2005

The maximum allocation of benefits currently available under EPAct would most likely lead to the planning and construction of at least a few new nuclear plants in the next decade, even in the absence of carbon dioxide charges. (Table 1-1 on page 10 provides a complete list of incentives created or extended by EPAct.) If just a few nuclear plants qualified for the incentives, the most substantial one—the production tax credit—would lead to sizable reductions in those plants' corporate income tax liability during the first several years of operation. Nuclear projects eligible for federal loan guarantees, which cover up to 80 percent of construction costs, would benefit from reductions in financing costs. The preferential tax treatment of decommissioning funds—funds that utilities are required to set aside to cover the cost of safely shutting down and securing a nuclear plant at the end of its useful life—would provide far less financial incentive because the discounted present value of the cost of decommissioning is small. (Although the decommissioning of a 1,350-megawatt plant costs nearly $500 million, by CBO's estimate, the present value of that cost would be much smaller because that sum would be spent 40 years after the power plant was constructed. In the absence of the preferential income tax rate, decommissioning costs would still account for less than 1 percent of the levelized cost of generating electricity with new nuclear capacity.)

The value of other EPAct incentives—including cost-sharing for the licensing and design of advanced reactors, which is offered by the Nuclear Power 2010 program, and the protection afforded by delay insurance, which insures investors in new nuclear plants for the financial risk caused by litigation or licensing delays, is not reflected in CBO's analysis of EPAct incentives because those subsidies directly reduce the cost of only the first plants built of any new type. Those first-of-a-kind costs are not projected to have large effects on the levelized cost estimates. (The value of both the Nuclear Power 2010 program and delay insurance is discussed further in Box 3-2.)

Projects Receiving the Maximum Benefits Under EPAct

When the levelized costs estimated under the reference scenario are changed to account for the benefits provided by EPAct, nuclear technology emerges as a competitive source for a limited amount of new capacity, with costs roughly comparable to those of additional capacity based on conventional fossil-fuel technologies. Accounting for the EPAct incentives also reduces the levelized cost of both innovative fossil-fuel options. The levelized cost of innovative natural gas plants falls by about 5 percent, and that of innovative coal plants decreases by 20 percent. However, those technologies are still more costly than conventional fossil-fuel alternatives or nuclear technology. (See Figure 3-3 for an illustration of the cost of each technology under the full provision of EPAct incentives.) After those first few new nuclear plants qualified for EPAct incentives, the cost of new nuclear capacity would exceed the cost of new conventional coal capacity.

Production Tax Credits

Production tax credits provided under EPAct reduce by almost 15 percent the levelized cost of nuclear technology estimated in the reference scenario, making them the incentive with the greatest potential value to investors.

2. Marc Chupka and Gregory Basheda, *Rising Utility Construction Costs: Sources and Impacts* (report submitted by the Brattle Group to The Edison Foundation, September 2007), available at www.edisonfoundation.net/Rising_Utility_Construction_Costs.pdf.

3. "Samurai-Sword Maker's Reactor Monopoly May Cool Nuclear Revial," *Bloomberg.com*, at http://bloomberg.com/apps/news?pid=20670001&refer=home&sid+aaVMzCTMz3ms.

Box 3-2.

The Value of the Nuclear Power 2010 Program and Delay Insurance

The Energy Policy Act of 2005 (EPAct) includes provisions authorizing the Nuclear Power 2010 program and Standby Support, a program offering insurance against regulatory delays. Both are intended to encourage investment in advanced nuclear technology by covering a share of "first-of-a-kind" (FOAK) costs. Specifically, the Nuclear Power 2010 program shares the cost of licensing and designing new nuclear power plants, and the delay insurance helps mitigate risks that are particular to the first plants to test the Nuclear Regulatory Commission's revised licensing process.

Through fiscal year 2007, the Nuclear Power 2010 program contributed roughly $280 million to funds spent by three industry consortia that were attempting to design and obtain certification for the first power plants using advanced nuclear technology.[1] Such design and licensing costs for each new plant are estimated to be $300 million to $500 million. However, because utilities that decided to build subsequent plants using the same design would benefit from the knowledge and experience gained during the construction of the first few plants, their costs would be less, roughly $100 million.[2] The costs for subsequent plants are the basis of the design and licensing costs used in CBO's reference scenario, where they account for 5 percent of a nuclear power plant's levelized cost.

If the additional $200 million to $400 million in first-of-a-kind design and licensing costs was added to a single plant in CBO's reference scenario, the levelized cost of that initial nuclear plant would increase by roughly 15 percent. But the first utilities to build plants might be able to share some FOAK costs by forming consortia, even in the absence of the federal program. Accordingly, in the absence of federal support for design and licensing costs, levelized costs for the first plants might increase by only a fraction of the 15 percent.

Even if utilities pay the Department of Energy's (DOE's) estimated subsidy costs for the delay insurance, the program would reduce utilities' cost of generating electricity by the transferring financial risk from private investors to taxpayers. However, according to an assessment by DOE, the amount of financial risk transferred is small in comparison to that of the department's program providing guarantees for construction loans.[3] For the delay insurance, DOE estimates a hypothetical subsidy cost of $14 million for a reactor with a capacity of 1,090 megawatts. Under the terms of the insurance, the Treasury would reimburse a utility for up to $500 million in costs in the event of a covered delay.[4] For the loan guarantee program, the maximum reimbursement is roughly 10 times as much.

1. Each consortium is developing a standard nuclear power plant blueprint based on a different third-generation reactor design. One of the three reactor designs, the advanced boiling water reactor, received final approval before the Nuclear Power 2010 program was initiated, but the program supports the design and licensing of a power plant's components surrounding such a reactor.

2. See Louis Long and others, *A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010* (prepared for the Department of Energy, October 2001).

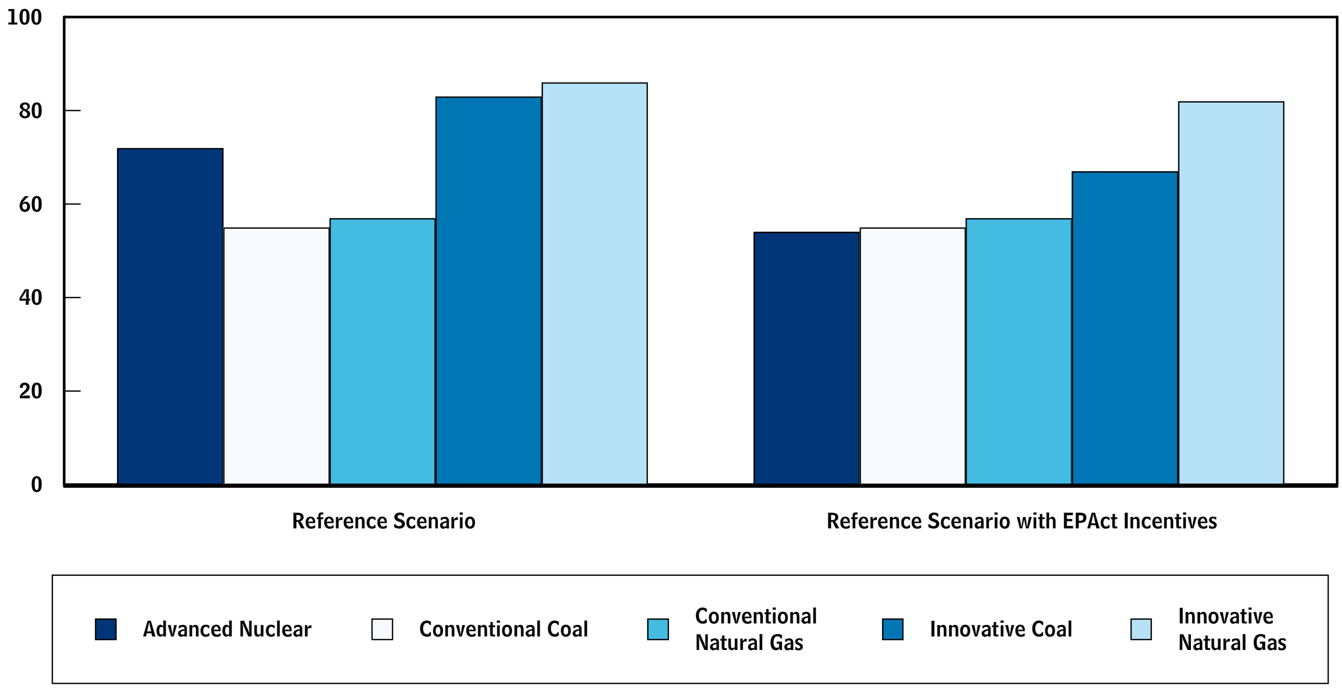
3. See Department of Energy, "Standby Support for Certain Nuclear Plant Delays; Final Rule," *Federal Register*, vol. 71, no. 155 (August 2006), p. 46324.

4. The $500 million in coverage is available only to the first two reactors. The next four reactors are eligible for reduced coverage. DOE estimates that the subsidy cost for the reduced coverage is roughly half of the $14 million subsidy cost for the first two reactors.

Figure 3-3.

Levelized Cost of Alternative Technologies to Generate Electricity With and Without EPAct Incentives

(2006 dollars per megawatt hour)



Source: Congressional Budget Office (CBO).

Notes: CBO's reference scenario excludes both the effects of prospective carbon dioxide constraints and the impact of incentives provided by the Energy Policy Act of 2005 (EPAct). The estimate of the effect of EPAct incentives assumes the maximum production tax credits, loan guarantees, and investment tax credits. The production tax credits are shared among 6,000 megawatts or less of advanced nuclear capacity. Advanced nuclear and innovative fossil fuel technologies receive loan guarantees covering 80 percent of construction costs. Innovative coal technology receives investment tax credits for 20 percent of construction costs.

Electricity-generating capacity is measured in megawatts; the electrical power generated by that capacity is measured in megawatt hours. During a full hour of operation, 1 megawatt of capacity produces 1 megawatt hour of electricity, which can power roughly 800 average households.

Advanced nuclear technology refers to third-generation reactors. Conventional coal power plants are assumed to use pulverized coal technology, which produces energy by burning a crushed form of solid coal. Conventional natural gas power plants are assumed to convert gas into electricity using combined-cycle turbines. Both innovative coal and innovative natural gas technologies are assumed to capture and store most carbon dioxide emissions.

The effect of the production tax credits on levelized costs would be smaller if more than 6,000 megawatts of qualified nuclear capacity (equivalent to the output of three to five plants) was constructed; but construction of more capacity would indicate that nuclear technology did not require the full allotment of credits to be commercially viable.

Because the credits would not be used until after a plant began operating—in other words, once electricity had been sold and the utility had incurred sufficient tax liability—the reduction in the levelized cost of generating electricity for qualifying nuclear plants would necessarily be less than the nominal value of the credits awarded to each project. Thus, even though credits of $18 per megawatt hour of generated electricity are equal to about one-quarter of the levelized cost estimated in the reference scenario, after discounting, the credits would reduce the cost of nuclear capacity by only about 15 percent if they were used within three years of being awarded.

Loan Guarantees

The maximum coverage available under the loan guarantee program—a guarantee on debt covering 80 percent of a plant's construction costs, which implies that investors' equity would cover the remaining 20 percent—would most likely reduce the levelized cost of new nuclear capacity by about 10 percent. But not all prospective nuclear plants would necessarily receive a guarantee of debt covering 80 percent of construction costs because the criteria for qualifying are restrictive. The Department of Energy has indicated that it will deny a utility's application for a loan guarantee if the project is not deemed to be both innovative (essentially, in the case of nuclear technology, a plant design that has not been built in the United States) and commercially viable, and that no more than three plants based on each advanced reactor design can be considered innovative. The 30 plants currently being proposed use five reactor designs, so at most, 15 of those plants would qualify as innovative. In addition, just because a plant is considered both innovative and commercially viable does not mean it will receive the maximum guarantee of 80 percent. Under the base-case assumptions, covering 80 percent of construction costs would require guaranteeing debt with a face value of $4.5 billion to $7.5 billion for each plant (depending on the size of the reactor). Providing the maximum coverage to three plants based on each of the five reactor designs would result in roughly $100 billion in loan guarantees, a commitment that has not been proposed, let alone funded. (The President's budget proposed a limit of $18.5 billion [in nominal dollars] on the cumulative amount of loan guarantees for new nuclear plants over the 2008–2011 period.)[4] The loan guarantee program could encourage investors to choose relatively risky projects over more certain alternatives because they would be responsible for only about 20 percent of a project's costs but would receive 100 percent of the returns that exceeded costs.[5]

Incentives and Impediments at the State and Local Levels

Because some states and localities regulate the rates that consumers pay for electricity or offer incentives for specific technologies, the levelized cost of nuclear technology in certain areas of the country could be lower than the estimates in this analysis. Other states have policies that deter investment in new nuclear or coal capacity altogether, which renders the levelized cost of the prohibited technology moot.

States and localities encourage investment in new nuclear capacity through a variety of policies. Over half of the currently proposed new nuclear plants are sited in southeastern states, where most electricity-generation capacity is owned by utilities that charge regulated rates. To the extent that rate regulation guarantees that customers will reimburse utilities for the cost of building a new plant, financial risk is transferred from investors to customers, which leads to larger reductions in the cost of capital-intense technologies such as nuclear. In several of those states, additional incentives that could further reduce the cost of nuclear power are under consideration. Those provisions include allowing higher rates of return for nuclear power than for other technologies, allowing utilities to recover some construction costs before plants begin operations, and tax incentives. State incentives for new nuclear power plants are not limited to states with traditional regulation in place. For instance, Texas, a state that allows markets a large role in setting electricity prices, has expanded a tax incentive initially designed to encourage investment in renewable energy technologies to apply to new nuclear capacity. Last, California and a number of eastern states are considering legislation that would limit carbon dioxide emissions, which could increase the competitiveness of nuclear and innovative fossil-fuel technologies. As of 2007, however, the only states in that group that had proposed sites for new nuclear power plants were Maryland, Pennsylvania, and New York.

At least 11 states have prohibitions against the construction of new nuclear facilities until certain provisions governing the long-term disposal of spent nuclear fuel are put in place.[6] Minnesota completely bans the construction of new nuclear power plants.

Other prohibitions apply to conventional coal technology. A California law essentially prohibits the

4. See *Budget of the United States Government, Fiscal Year 2009—Appendix*, p. 407, available at www.whitehouse.gov/omb/budget/fy2009/.

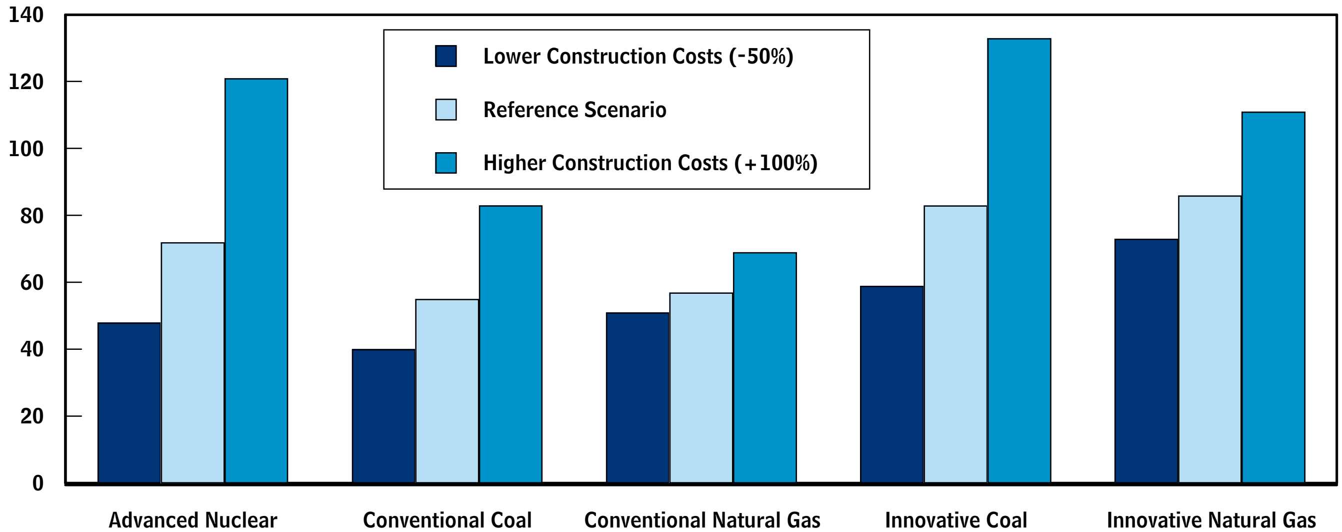
5. Those costs would include fixed payments for debt.

6. See Members of the Special Committee on Nuclear Power, Wisconsin Legislative Council, Staff Memorandum No. 2 (November 2006), available at www.legis.state.wi.us/lc/committees/study/2006/NPOWR/files/memo2_npowr.pdf.

Figure 3-4.

Sensitivity of Levelized Costs to Future Construction Costs

(2006 dollars per megawatt hour)



Source: Congressional Budget Office (CBO).

Notes: Electricity-generating capacity is measured in megawatts; the electrical power generated by that capacity is measured in megawatt hours. During a full hour of operation, 1 megawatt of capacity produces 1 megawatt hour of electricity, which can power roughly 800 average households.

CBO's reference scenario excludes both the effects of prospective carbon dioxide constraints and the impact of incentives provided by the Energy Policy Act of 2005.

CBO calculated levelized costs for the reference scenario using estimates of overnight construction costs from the Energy Information Administration (EIA). In the case of "Lower Construction Costs," CBO halved EIA's estimates and recalculated levelized costs on that basis. In the case of "Higher Construction Costs," CBO doubled EIA's estimates and recalculated the costs.

Advanced nuclear technology refers to third-generation reactors. Conventional coal power plants are assumed to use pulverized coal technology, which produces energy by burning a crushed form of solid coal. Conventional natural gas power plants are assumed to convert gas into electricity using combined-cycle turbines. Both innovative coal and innovative natural gas technologies are assumed to capture and store most carbon dioxide emissions.

construction of any new coal-fired power plant that does not employ CCS technology. In New England, utilities have been blocked from building new coal-fired plants for over a decade.

Future Market and Policy Uncertainties

The commercial viability of new nuclear capacity depends on investors' perceptions of future market conditions and carbon dioxide constraints when investment decisions are finalized. Licensing and regulatory approval for building new nuclear plants in the United States are expected to take about three years, so the construction of the first new nuclear plants would be unlikely to start until 2010 at the earliest. At that point, the commercial viability of a new plant would depend on anticipated market conditions and policy outcomes over the operating life of the plant, which may exceed 40 years. A combination of factors—recent volatility in construction costs and natural gas prices, nuclear power's history of construction cost overruns, and uncertainty about future policy on carbon dioxide emissions—indicates that a wide range of costs are plausible for each of the technologies considered. Those ranges demonstrate that the future competitiveness of each technology and thus the conclusions presented in this analysis are quite uncertain.

Costs Under Alternative Market Conditions

If the base-case assumptions incorporated in CBO's reference scenario did not hold—for instance, if construction costs for new nuclear power plants proved to be as high as the average cost of nuclear plants built in the 1970s and 1980s or if natural gas prices fell back to the average levels seen in the 1990s—new nuclear capacity would be an unattractive investment, regardless of the incentives provided by EPAct. Specifically, CBO compared the levelized cost of electricity from new capacity assuming that the overnight construction costs for nuclear technology would be 25 percent higher or that the fuel costs for natural gas capacity would be 50 percent lower than in the base case. Nuclear technology benefiting from EPAct incentives was about 15 percent more expensive than conventional fossil-fuel capacity in the first case and about 50 percent more expensive than conventional natural gas capacity in the second case. However, such variations in construction or fuel costs would be less likely to deter investment in new nuclear capacity if investors anticipated future charges for emitting carbon dioxide. New nuclear capacity could even compete at lower carbon dioxide charges if the price of natural gas continued to rise or if the construction cost reductions predicted by reactor designers were accurate (and thus below the costs assumed in the reference scenario).

Construction Costs. To examine the effect of uncertainties related to overnight construction costs, CBO calculated the levelized cost of each of the technological alternatives using values for construction costs that were 50 percent less than and 100 percent more than the assumptions in the reference scenario (see Figure 3-4). In the reference scenario, CBO assumed an overnight construction cost for new nuclear capacity of about $2.4 million per megawatt, so in the "lower" and "higher" cases, CBO used a cost of about $1.2 million and $4.8 million, respectively. Taking into consideration the history of very large construction cost overruns that have plagued the nuclear power industry in the past, the high end of the range encompasses costs well above those included in the reference scenario. Utilities would be unlikely to invest in new nuclear plants if construction costs for nuclear plants were twice those assumed in the reference scenario, as the levelized cost of a nuclear plant would be well over $100 per megawatt hour.

However, the construction costs for new capacity using the other technologies are subject to uncertainty as well. Adjusted for general inflation, construction costs for new power plants increased by 15 percent between 1994 to 2006, with most of that increase occurring over the past three years.[7] If that trend continued, the overnight costs assumed in the reference scenario for all of the technologies would be too low. If the construction costs of each technology increased by a similar percentage, the impact on the levelized cost of the technologies with the highest overnight costs in the reference scenario—nuclear and innovative coal—would be the greatest. Conventional natural gas technology would become less expensive by comparison because construction costs account for a smaller percentage of that technology's levelized cost. Conversely, reductions in construction costs would have a disproportionately large effect in reducing the relative cost of those technologies that had high construction costs in the reference scenario.

Fuel Costs. The price of the primary fuels used by each of the base-load technology options has increased in recent years. Contracted uranium prices (the prices that operators of nuclear plants pay for most of their fuel) increased by 40 percent between 2004 and 2006. Spot prices for uranium (the prices at which a relatively small amount of uranium trades on commodity exchanges) have climbed steeply and then fallen over the past year. Natural gas prices have increased dramatically (see Figure 2-1 on page 20), and even spot prices for coal have recently increased to levels that are well above long-run averages. To capture the effects of uncertainty surrounding fuel prices, CBO estimated the levelized cost of each of the five technology options on the basis of fuel prices set at levels 50 percent less than and 100 percent more than those assumed in the reference scenario. (The results are displayed in Figure 3-5.)

The analysis shows that assumptions about fuel prices have particularly large effects on the estimated levelized cost of natural gas technologies. For conventional natural gas, doubling the cost of fuel used in the reference scenario increases the levelized cost of that technology by over 70 percent. For innovative natural gas plants, the corresponding increase in levelized cost is just over 60 percent. By contrast, nuclear power has the lowest fuel cost of the technologies considered under the base-case assumptions. Doubling that cost would increase the levelized cost of new nuclear capacity by about 15 percent above that assumed in the reference scenario.

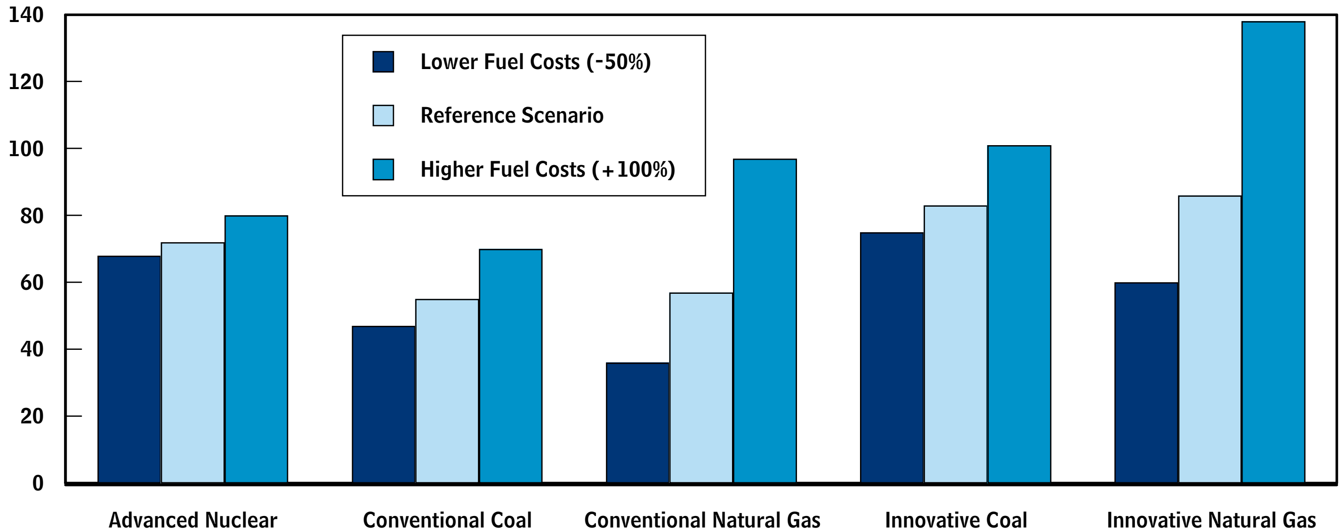
Financing Costs. A levelized cost analysis accounts for risk by assuming that investors will require a higher rate of

7. That increase is based on the Price Index for Fixed Investment in Power and Communication, produced by the Bureau of Economic Analysis. The data are adjusted for inflation using the price index for gross domestic product.

Figure 3-5.

Sensitivity of Levelized Costs to Future Fuel Costs

(2006 dollars per megawatt hour)



Source: Congressional Budget Office (CBO).

Notes: Electricity-generating capacity is measured in megawatts; the electrical power generated by that capacity is measured in megawatt hours. During a full hour of operation, 1 megawatt of capacity produces 1 megawatt hour of electricity, which can power roughly 800 average households.

CBO's reference scenario excludes both the effects of prospective carbon dioxide constraints and the impact of incentives provided by the Energy Policy Act of 2005.

CBO estimated levelized costs for the reference scenario using estimates of fuel costs from the Energy Information Administration (EIA). In the case of "Lower Fuel Costs," CBO halved EIA's estimates and recalculated levelized costs on that basis. In the case of "Higher Fuel Costs," CBO doubled EIA's estimates and recalculated the costs.

Advanced nuclear technology refers to third-generation reactors. Conventional coal power plants are assumed to use pulverized coal technology, which produces energy by burning a crushed form of solid coal. Conventional natural gas power plants are assumed to convert gas into electricity using combined-cycle turbines. Both innovative coal and innovative natural gas technologies are assumed to capture and store most carbon dioxide emissions.

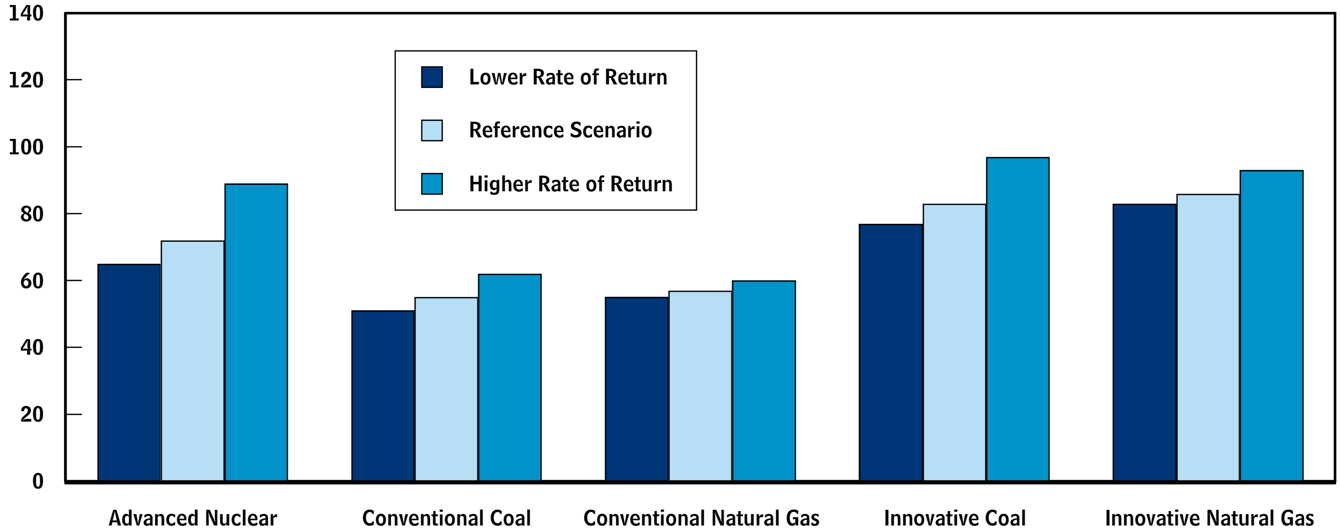
return for riskier projects. The effect of uncertainty on the return that investors will require to finance new base-load capacity can be shown for all of the options by calculating the levelized cost of each option at a lower rate of return (8-$^{3}/_{4}$ percent) and at a higher return (12-$^{1}/_{2}$ percent) and comparing those results with the rate of return (10 percent) used in the reference scenario. (The results of that analysis are presented in Figure 3-6.)

The changes in levelized costs follow the same pattern as that produced under higher construction costs. The levelized costs for nuclear and innovative fossil-fuel technologies increase by more than those for the conventional fossil-fuel options, which require smaller up-front investments. But some observers rate the level of risk attached to nuclear technology as somewhat higher than that of the other alternatives, independent of the technology's relatively high construction costs. The prospect that investors would require a higher rate of return relative to that of other options to compensate for a risk unique to nuclear power (for instance, an accident at an existing nuclear plant could significantly delay the construction of new plants, as was the case after the Three Mile Island accident) can be assessed by comparing the levelized cost of nuclear technology at the highest rate of return with the levelized cost of the other options calculated for the reference scenario. For example, the levelized cost of nuclear technology calculated at a 12-$^{1}/_{2}$ percent real rate of return is 65 percent higher than the levelized cost of conventional coal with a 10 percent real rate of return. With the same comparison applied to nuclear technology the least expensive innovative fossil-fuel technology—

Figure 3-6.

Sensitivity of Levelized Costs to Future Financing Risks

(2006 dollars per megawatt hour)



Source: Congressional Budget Office (CBO).

Notes: Electricity-generating capacity is measured in megawatts; the electrical power generated by that capacity is measured in megawatt hours. During a full hour of operation, 1 megawatt of capacity produces 1 megawatt hour of electricity, which can power roughly 800 average households.

CBO's reference scenario excludes both the effects of prospective carbon dioxide constraints and the impact of incentives provided by the Energy Policy Act of 2005.

CBO estimated levelized costs for the reference scenario using a financing rate of about 10 percent. For the category "Lower Rate of Return," CBO recalculated levelized costs using a financing rate of about 8-$^{3}/_{4}$ percent. For the category "Higher Rate of Return," CBO recalculated those costs using a rate of about 12-$^{1}/_{2}$ percent. In each case, financing rates were derived from CBO's assumptions for debt and equity financing (which are discussed in detail in the Web supplement to this paper) and rounded to the nearest quarter of a percentage point.

Advanced nuclear technology refers to third-generation reactors. Conventional coal power plants are assumed to use pulverized coal technology, which produces energy by burning a crushed form of solid coal. Conventional natural gas power plants are assumed to convert gas into electricity using combined-cycle turbines. Both innovative coal and innovative natural gas technologies are assumed to capture and store most carbon dioxide emissions.

coal with CCS—the levelized cost of nuclear technology exceeds that of innovative coal technology by about 5 percent. Such comparisons suggest that if financial markets required a substantially higher rate of return for new nuclear technology than for other base-load technologies, investment in new nuclear plants would not be commercially viable.

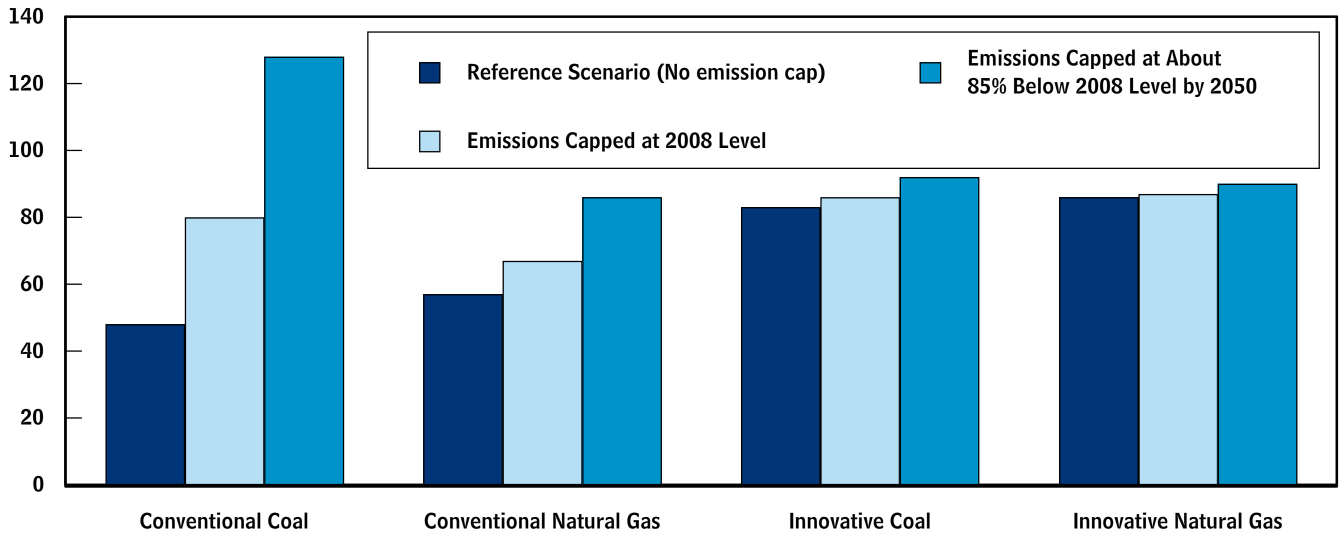
Costs Under Prospective Carbon Dioxide Constraints

It is less likely that the cost of building and fueling conventional coal plants will vary toward the extremes of the ranges included in this analysis than it would for the other generation options considered. Construction costs for coal plants have been less volatile than for nuclear plants, and the abundance of U.S. coal supplies has historically led to relatively stable prices for coal. Still, investors in new coal capacity face substantial uncertainty because of the prospect that carbon dioxide constraints will be implemented and the variability in the prospective stringency of such constraints. Although the implications of such stringency can be observed by adding specific carbon dioxide charges to the levelized costs estimated for the reference scenario, the effect is more clearly demonstrated by comparing the levelized cost of the technology alternatives at specific levels of carbon emissions that might be targeted by policymakers. CBO compared the levelized cost of the different base-load technologies under the reference scenario with the levelized cost at two different levels of stringency, one holding future

Figure 3-7.

Sensitivity of Levelized Costs to Potential Carbon Dioxide Constraints

(2006 dollars per megawatt hour)



Source: Congressional Budget Office.

Notes: Electricity-generating capacity is measured in megawatts; the electrical power generated by that capacity is measured in megawatt hours. During a full hour of operation, 1 megawatt of capacity produces 1 megawatt hour of electricity, which can power roughly 800 average households.

CBO's reference scenario excludes both the effects of prospective carbon dioxide constraints and the impact of incentives provided by the Energy Policy Act of 2005.

In the reference scenario, carbon dioxide emissions are not constrained, so they are not priced. In the second case, the number of allowances issued each year for emitting carbon dioxide would correspond to a cap at roughly the level of emissions in 2008. In the third case, the number of such allowances would correspond to a cap about 85 percent below that level by 2050. The allowance prices resulting from those hypothetical constraints are listed in the Web supplement to this paper.

Conventional coal power plants are assumed to use pulverized coal technology, which produces energy by burning a crushed form of solid coal. Conventional natural gas power plants are assumed to convert gas into electricity using combined-cycle turbines. Both innovative coal and innovative natural gas technologies are assumed to capture and store most carbon dioxide emissions.

emissions at their 2008 level and the other reducing future emissions even more, to about 85 percent below their 2008 level by 2050.[8] Under the less stringent cap, the costs for electricity from newly built conventional coal and natural gas capacity would increase by about 70 percent and 20 percent, respectively. Under the more stringent cap, those costs would increase by about 165 percent and 65 percent, respectively. (Figure 3-7 shows the levelized cost under the hypothetical cap-and-trade programs.)

8. The more stringent cap would reduce future emissions to 80 percent below 1990 emissions by 2050. CBO relates that cap to 2008 emissions for comparability with the less stringent cap.