THE ECONOMIC FUTURE OF NUCLEAR POWER

A Study Conducted at The University of Chicago

August 2004

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Part One: Economic Competitiveness of Nuclear Energy

Any policies concerned with the future of nuclear power must funnel through the price at which nuclear power will enter the marketplace, if nuclear power is to be viable. The levelized cost of electricity (LCOE), as the price at the busbar needed to cover the operating plus annualized capital costs of nuclear power, must be competitive with prices of other baseload electricity. Part One attempts to develop the most reliable estimates possible of the future busbar cost of nuclear electricity.

A starting point is estimates of nuclear generator costs from previous studies. These estimates for the United States are reviewed in Chapter 1. Chapter 2 is a parallel international review.

In light of the importance of capital costs and the role they have played in contributing to differences in LCOE estimates, Chapter 3 is devoted to the anatomy of the estimation of capital costs. An aim is to narrow the range of uncertainty in estimates of future capital costs. Chapter 4 proceeds to another major reason for uncertainty about nuclear costs, which is learning from experience in constructing facilities. Drawing on analyses of earlier nuclear experience and innovations in manufacturing more generally, estimates are developed of the extent to which costs can be expected to fall between the building of the first and n^{th} plants of a given technology.

Chapter 5 develops the financial model used in this study to evaluate the prospects for nuclear power. The complications of the tax system and of private sector financing as influenced by risk are introduced. No-policy estimates of nuclear LCOEs are estimated to set the stage for the later policy analysis.

Chapter 1. LEVELIZED COSTS OF BASELOAD ALTERNATIVES

Summary

In Chapter 1, differences in the magnitude of levelized cost of electricity (LCOE) estimates from previous studies are compared. These differences illustrate the challenge of estimating a reasonable range on future LCOEs.

Reasons for differences in LCOE estimates include differences in assumptions about nuclear technology chosen, differences in the degree of experience with a technology, differences in equity and debt financing terms, differences in construction time, and less well defined differences in the degree of optimism or pessimism about costs.

Delaying the complication of taxes until Chapter 5, the present chapter develops a pre-tax LCOE model and uses it to calculate LCOEs of nuclear, coal and gas turbine combined cycle generation based on values from recent plant models. The models compared are GenSim, the SAIC industry model, the Scully Capital financial model, and an Energy Information Administration (EIA) model. The results illustrate how differences in assumptions influence estimated LCOEs.

GenSim does not specify a particular nuclear technology, but rather takes EIA's specifications from the agency's 2001 *Annual Energy Outlook* (AEO 2001). At a base capital cost of $1,853 per kW, increasing the discount rate from 10 to 15 percent raises the GenSim busbar nuclear cost from $51 to $83 per megawatt-hour (MWh). GenSim estimates for competitors to nuclear are: $37 to $48 per MWh for coal, $35 to $40 per MWh for gas combined cycle, and $56 to $68 per MWh for gas combustion turbines. Solar photovoltaic and solar thermal are far more costly, while wind's cost, in some areas, is comparable to gas combustion turbine.

The SAIC model considers several nuclear technologies, with cost estimates ranging from $39 per MWh for the Gas Turbine Modular Helium Reactor (GT-MHR) to $77 per MWh for existing nuclear technology. Coal-fired costs are on a par with Pebble Bed cost, at $43 to $49 per MWh. Gas combined cycle with lower capital costs is $38 to $40 per MWh.

The Scully model compares alternative financing plans for a technology that broadly corresponds to the AP1000. The busbar cost range is $36 to $44 per MWh.

EIA's AEO 2004 nuclear capital cost and interest rate assumptions keep previously built nuclear generation's busbar cost relatively high among these estimates at $63 to $68 per MWh and considerably lower for coal generation at $38 per MWh.

Outline

1.1. Introduction

Direct comparison of busbar costs frequently is hampered by different assumptions used in their calculation: discount rates, borrowing and equity shares and interest rates, construction time, plant life, treatment of taxes and depreciation, and quite importantly, the magnitude of overnight capital cost. This chapter reports on recent estimates of LCOE for baseload generation technologies. The estimates differ considerably among sources, despite the basic uniformity in the methodology of LCOE calculation. Accounting for these differences is the primary goal of this chapter.

Section 1.2 identifies several estimates of LCOE for nuclear, coal, and gas baseload generation. Section 1.3 describes a pre-tax LCOE model developed to provide a common calculation framework for comparing estimates. Section 1.4 reports the LCOE calculations made with the model of Section 1.3.

1.2. Representative Studies of Baseload Generation Costs

This chapter focuses on studies by Science Applications International Corporation (SAIC) (Reis and Crozat 2002), Scully Capital (Scully Capital 2003), a LCOE simulation model developed at Sandia National Laboratory (Drennan et al. 2002), and calculations using values from EIA's *Annual Energy Outlook 2004* (AEO 2004), which itself does not report LCOE estimates but which is an influential source of cost component estimates for others and provides the cost inputs for the National Energy Modeling System (NEMS).

Each of the calculations uses the basic LCOE methodology which amortizes capital costs and adds current operating costs to calculate a price in cents per kilowatt hour (kWh) or dollars per megawatt hour (MWh) that will cover costs. Stated alternatively, the calculation solves for the constant electricity price, in real terms, which if charged over the life of the plant, would give investors the rate of return they require on their capital in the plant.

1.3. The LCOE Concept

The LCOE, or busbar cost, is used for comparing the cost of energy production by different generation methods. As introduced in Chapter 2, a problem solved by the LCOE is the annualization of the up-front capital costs of a power plant so the total cost per kWh of generating electricity, including both fixed and variable costs, can be identified.

Capital costs are incurred during the construction period, when the actual outlays for equipment and construction and engineering labor are expended. Overnight costs are exclusive of interest and include engineer-procure-construct (EPC) costs, owner's costs, and contingencies, as explained in more detail in Chapter 3 on capital costs. These expenditures accrue interest charges during the construction period. Once electricity sales begin, the plant's owner begins to repay the sum of the overnight and interest costs. The price charged for electricity generated by the plant must cover these costs as well as yearly recurring fuel and operation and maintenance (O&M) costs.

While there are many variants in implementing LCOE calculations, the basic framework remains largely the same. The greatest differences in the many applications lie in their treatments of financing costs, inflation, and taxes, although additional cost considerations can be implemented as well. Accounting for taxes in an LCOE model introduces a number of complications which are dealt with in Chapter 5 on financing. Inflation affects the nominal value of taxable income, as does the allocation of financing between debt and equity, since debt repayments are expenses deductible against taxable income. Furthermore, without consideration of taxes, depreciation is immaterial.

1.4. A Pre-Tax LCOE Model

The LCOE model developed for this chapter contains five LCOE cost components: annuitized capital cost (A), insurance (I), fixed O&M costs (M_f), variable O&M costs (M_v), and fuel costs (F). The LCOE is such that a charge per kWh of this amount over the life of the plant will give present value of revenues just equal to the present value of the cost of constructing the plant and operating it over its life.

The revenue in any year is $LCOE \cdot W \cdot 8760 \cdot CF_t$, where W is the kW capacity of the plant, 8,760 is the number of hours in a year, and CF_t is the fraction of capacity at which the plant is operated during the year (capacity factor). The present value of the revenues is the discounted series of yearly revenues over the plant life:

$$PV(revenue) = \sum_t (LCOE \cdot W \cdot 8760 \cdot CF_t)/(1+r)^t,$$

where r is the debt-and-equity-weighted average discount rate. The present value of costs is

$$K = \sum_t (I + M_f + M_v + F)/(1+r)^t,$$

where K is the present value of the capital stock. Equating the present value of revenues and costs and solving for the LCOE that brings about equality gives

$$LCOE = A + I + M_f + M_v + F,$$

where

$$A = K/[8760W \sum_t CF_t/(1+r)^t].$$

1.4.1. Capital Cost, K

To obtain *K*, the total capital cost including financing is calculated by compounding the cost plus interest from the beginning of the construction until the plant is completed, using

$$K = \sum_{t}^{n} P_t C(1+r)^{n-t+1},$$

where

n = years required for construction
C = total overnight cost before financing
P_t = percentage of overnight cost outlay in year t
r = weighted average of debt and equity interest rates.

1.4.2. Insurance Cost, I

Insurance cost is entered as an insurance rate that is a fraction of the capital cost.

$$I = C \bullet \text{Insurance rate.}$$

1.4.3. Fixed O&M Cost, M_f

Fixed O&M cost includes items from rent to workers' wages. This cost is dependent on the size, rather than the output, of the plant. It is given as $ per kW. Fixed O&M cost is calculated as

$$M_f = \text{Fixed cost in \$ per kW} \bullet \text{plant size in kW} \bullet \text{plant life.}$$

1.4.4. Variable O&M Cost, M_v

Variable O&M is given in the form $ per kWh and is entered directly into the LCOE formula as M_v.

1.4.5. Fuel Cost, F

Fuel cost is calculated using the formula $F \bullet HR$, where

F = Fuel cost in $ per MMBtu
HR = Heat Rate in MMBtu.

1.4.6. Additional Factors

While this model incorporates the basic components of LCOE, it is not all encompassing, as it omits taxes and decommissioning and decontamination (D&D) cost.

Many LCOE estimates are calculated before taxes, so omitting taxes permits comparison. The LCOE model of Chapter 5, used for the later analysis in this study, does deal with taxes.

Given that the D&D cost is a small percentage of the capital cost and it is only payable at the end of the plant life, which is 40 to 60 years in the future for new nuclear plants, the amount is negligible after it is discounted into present dollars, and is thus not included in these LCOE calculations. D&D costs are included in the post-tax LCOE model of Chapter 5.

1.5. Before-Tax Comparisons of Busbar Costs of Nuclear, Coal, and Gas Generation in the United States

Table 1-1 reports a number of cost comparisons. Capital costs are identified below busbar costs for the baseload technologies and models for which those costs are available. The financing costs assumed in the original models are used in this set of calculations, and for several technologies, the table reports busbar costs calculated with alternative financing assumptions.

GenSim does not specify a particular nuclear technology, but rather takes EIA's specifications and conducts sensitivity analyses on capital and fuel costs. At a base capital cost of $1,853 per kW, increasing the discount rate from 10 to 15 percent raises the busbar cost from $51 to $83 per MWh. GenSim uses the same interest rates on nuclear and conventional technologies and, with lower capital costs for coal- and gas-fired generation, obtains lower busbar costs for the latter: from $37 to $48 per MWh for coal, $35 to $40 per MWh for gas turbine combined cycle, and $56 to $68 per MWh for gas combustion turbines. While combined cycle plants were originally intended for peaking, they have been used as baseload power sources as well. Solar photovoltaic and solar thermal are far more costly, while wind's cost, in some locations, is comparable to gas combustion turbine.

The Scully model compares alternative financing plans for a technology that broadly corresponds to the AP1000. At a borrowing rate of 8 percent and an overnight capital cost of $1,247 per kW, it calculates a busbar cost of $36 per MWh; with a 10 percent rate and the same capital cost, its busbar cost rises to $40 per MWh. At the higher overnight capital cost of $1,454 per kW, and an interest rate of 10 percent, the busbar cost rises to $44 per MWh. Allowing for the modest differences in Scully's higher capital cost and GenSim's capital cost, and the similar interest rates used in the two models, the busbar cost calculations appear comparable.

The SAIC model offers cost input parameters on several nuclear technologies, at a considerable range of capital costs, but with a single set of interest rate and discount parameters. This model also calculates busbar costs for coal and gas combined cycle generation. Their cost parameters yield nuclear busbar costs as low as $39 per MWh for the Gas Turbine Modular Helium Reactor (GT-MHR) with a capital cost of $1,365 per kW, to $77 per MWh for existing nuclear technology at a $2,000 per kW capital cost and higher interest rates. SAIC's coal-fired capital costs are on a par with Pebble Bed Modular Reactor (PBMR) capital cost, giving similar busbar costs, $43 to $49 per MWh. Gas turbine combined cycle capital costs are projected much lower, and busbar costs are correspondingly lower, at $38 to $40 per MWh.

The latest *Annual Energy Outlook* (EIA 2004, pp. 5-58) reduces nuclear capital cost assumptions below those in previous *AEO*s (EIA 2003, p. 73, Table 40). The two right-hand columns of Table 1-1 use the new EIA nuclear capital cost estimates. The nuclear base case capital cost estimate makes new nuclear generation's busbar cost relatively high among the estimates in this table, at $63 to $68 per MWh for the nuclear base case, but lower for the advanced nuclear case, at $43 to $53 per MWh. EIA's estimate is considerably lower for coal generation, at $38, and for gas generation, at $41.

Table 1-1: Summary Worksheet for Busbar Cost Comparisons, $ per MWh, with Capital Costs in $ per kW, 2003 Prices

Technology	Sandia Model GenSim		SAIC Model Power Choice			Scully Capital Report			EIA – AEO 2004	
	r=10%	r=15%	Debt r = 8%; Disc r = 8%	Debt r =10%; Disc r = 8%	Debt r =10%; Disc r = 10%	r = 8%	r = 10%	r = 10%	Debt r =10%; Eq = 15%; Disc r = 10%	Debt r =8%; Eq = 10%; Disc r = 10%
Nuclear	51	83								
(capital cost)	(1,853)	(1,853)								
Legacy Nuclear			65	70	77					
(capital cost)			(2,000)	(2,000)	(2,000)					
EIA Reference Case, New Nuclear									63 to 68	
(capital cost)									(1,752 to 1,928)	
EIA Advanced Technology Case, New Nuclear									43 to 53	
(capital cost)									(1,080 to 1,555)	
ABWR			53	50	55					
(capital cost)			(1,600)	(1,600)	(1,600)					
AP 1000			49	46	51	36	40	44		
(capital cost)			(1,365)	(1,365)	(1,365)	(1,247)	(1,247)	(1,455)		
Pebble Bed Modular Reactor (PBMR)			40	41	45					
(capital cost)			(1,365)	(1,365)	(1,365)					
Gas-Turbine Modular Helium Reactor (GT-MHR)			39	39	43					
(capital cost)			(1,126)	(1,126)	(1,126)					
Advanced Fast Reactor (AFR)			57	57	64					
(capital cost)			(1,126)	(1,126)	(1,126)					
Coal	37	48	43	44	49					38
(capital cost)	(1,094)	(1,094)	(1,350)	(1,350)	(1,350)					(1,169)
Gas Turbine Combined Cycle	35	40	38	38	40					41
(capital cost)	(472)	(472)	(590)	(590)	(590)					(466)
Gas Combustion Turbine	56	68								
(capital cost)	(571)	(571)								
Solar-Photovoltaic	202	308								
Solar-Thermal	158	235								
Wind	55	77								

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Chapter 2. INTERNATIONAL COMPARISONS

Summary

Chapter 2 extends the analysis of Chapter 1 to other countries' energy systems and electricity costs to broaden the understanding of what factors may be particular to the U.S. electricity system and what factors are more general.

Due to its relatively low coal and natural gas prices, the United States has larger shares of electricity from coal and gas than many other countries. On the other hand, India and China stand out as coal users, with coal share of power generation at around 75 percent versus 52 percent in the United States. Also, Russia is a natural gas generator, with natural gas share of power generation at 43 percent versus 15 percent in the United States. The U.S. nuclear share of power generation is very close to the world average, 19 percent versus the world average of 17 percent. France has the world's largest nuclear generation share, 76 percent, while Japan and Korea have 32 and 37 percent shares, respectively. Italy stands alone in the world with its oil generation share of 41 percent, compared to the world average of 9 percent.

Busbar cost estimates are quite variable across countries, depending on assumptions about discount rate, plant life, and capacity factor, in addition to differences in underlying fuel prices and construction costs. Nonetheless, several studies permitting inter-country cost comparisons are available. These place U.S. natural gas combined cycle costs near the low end of a worldwide range of $30 to $101 per MWh. Similarly for coal, U.S. costs are near the low end of a worldwide range of $31 to $84 per MWh.

U.S. nuclear busbar costs are estimated somewhat below the middle of the worldwide range for countries not reprocessing spent fuel, of $36 to $65 per MWh. LCOEs on new nuclear plants in the United States are not projected to be higher than those elsewhere in the world, comparing favorably even with the prospective French costs. Nuclear power's large share of electricity generation in France appears to be due at least partially to the fact that generation costs from alternative sources in France are higher than for nuclear power. Total capital cost shares of LCOEs for new nuclear plants projected in the United States and France are similar.

Historically, France has experienced shorter and less variable construction times for its nuclear plants than has the United States. Meanwhile, nuclear plants built around the world since 1993, mostly in Asia, have been built in shorter times, and with lesser variability, than even the French experience, offering some basis for optimism regarding future nuclear construction in the United States.

Outline

2.1. Introduction

This chapter places the U.S. electric power industry in an international perspective. What similarities and differences are there between the U.S. sector's characteristics and those of other countries? How do U.S. LCOEs, or busbar costs, compare with those of other countries, and what can account for differences? How does the distribution of capacity and generation compare across countries, and again, what can account for the differences? Of particular interest are comparisons with the Organization for Economic Cooperation and Development (OECD) countries and other large power-producing countries such as Russia and China. The two primary areas of discussion are the distribution of generation types and busbar costs for different plant types. Busbar cost information for the U.K. and Germany has been omitted for lack of data stemming from the recent privatization of the power industry in those two countries.

The remainder of the introduction covers similar previous studies and the data sources used in this study. Section 2.2 discusses the distribution of generation sources. Section 2.3 discusses the busbar cost figures for each country. Section 2.4 takes a closer look at nuclear power. Section 2.5 summarizes the results of this study and presents an overall picture of the U.S. power industry in comparison with the rest of the world. Section 2.6 is an appendix which details the methodology used in the LCOE calculations in this chapter.

2.1.1. Previous Studies

Although reliable data for an international comparison of the power industry are often hard to come by, there have been a number of previous studies that are useful for orientation and comparison. OECD (1998) is an update of a 1992 study. It uses a levelized cost methodology to project busbar costs for new power plants in fourteen OECD countries and five other nations. The original cost information for this study was gathered by a group of experts drawn from the relevant countries. The recent study by MIT (2003) calculates costs for several generation technologies in a number of countries. Although the focus is on nuclear power, other technologies are mentioned for purposes of comparison.

Tarjanne and Kari Luostarinen (2002), discuss the economics of nuclear power in Finland. This study includes LCOEs for new plants as well as historical data on plants operated by Teollisuuden Voima Oy. Although the study focuses on nuclear power, it reports cost information for other technologies as well.

Feretic and Tomsic (2003) estimate busbar costs for new power plants in Croatia. The study provides a slightly different approach to levelized cost calculations. Instead of point estimates for costs and other model inputs, each parameter is given a probability distribution, and busbar costs are then calculated as a probability distribution as well.

Smith and Hove's (2003) Deutsche Bank report covers coal, gas, and nuclear power generation, discussing busbar costs as well as new technology options. That study's audience of potential investors in the power industry gives it a focus on prospects under what the authors consider most likely events in the near future.

2.1.2. Data Sources

Data used in this chapter are drawn from a number of sources. Information concerning the distribution of generation sources comes exclusively from *Electricity Information* (IEA 2000). Information specific to nuclear power plants is taken from *Country Nuclear Power Profiles* (IAEA 2002).

Capital, operation, maintenance, and fuel costs come from three of the studies noted above, OECD (1998), Smith and Hove (2003), and Tarjanne and Luostarinen (2002). The OECD study obtained its data directly from the governments of the nations under study. The exact source of the data in the other two studies is unclear; the Finnish data come from a Finnish language paper by the same author, while the Deutsche Bank cost estimates cite the proprietary "Deutsche Bank Securities, Inc. Estimates." The costs included in these sources vary somewhat between the three studies and even within the OECD study itself. A description of what the cost figures include can be found in Section 2.6.3.

Cost information from the Croatian study (Feretic 2003) is not used here because of its probabilistic cost estimates, but one of its conclusions is noteworthy by virtue of its contrast with the other studies. It projects natural gas to be significantly more expensive than either coal or nuclear power, principally because of its assumption of rapidly escalating gas prices, an assumption not made by any of the other studies.

2.2. Distribution of the World's Electricity Generation Sources

The International Energy Agency (IEA) collects data on the distribution of generation sources for most countries in the world. Table 2-1 presents 1998 figures for the countries covered in this study. With regard to predominant generation source, Belgium, Finland, France, Hungary, and Japan receive the largest share of their electricity from nuclear power. Hydroelectric power supplies the greatest share of electricity in Brazil, Canada, Portugal, Romania, and Turkey. Italy is the single country for which oil plants generate the most power. Natural gas is predominant in the Netherlands and Russia. Coal is most often the most prevalent power source, being so in China, Denmark, Germany, India, Korea, Spain, the U.K., and the United States.

Table 2-1: Percent Distribution of 1998 Electricity Generation Capacity by Country

Country	Nuclear	Coal	Natural Gas	Oil	Hydro	Renew & Waste	Solar & Wind	Geothermal	Peat
Belgium	55.5	20.3	18.1	3.1	1.8	1.3	0.0	0.0	0.0
Brazil	1.0	2.2	0.0	3.9	90.6	2.3	0.0	0.0	0.0
Canada	12.7	19.1	4.6	3.3	59.1	1.1	0.0	0.0	0.0
China	1.2	75.9	0.6	4.5	17.8	0.0	0.0	0.0	0.0
Denmark	0.0	57.5	19.9	12.1	0.1	3.6	6.9	0.0	0.0
Finland	31.1	12.3	12.6	1.6	21.4	13.9	0.0	0.0	7.0
France	75.9	7.3	1.0	2.3	12.9	0.5	0.1	0.0	0.0
Germany	29.1	53.8	9.8	1.1	3.8	1.6	0.8	0.0	0.0
Hungary	37.5	26.1	20.0	16.0	0.4	0.0	0.0	0.0	0.0
India	0.3	76.9	4.8	0.8	17.2	0.0	0.0	0.0	0.0
Italy	0.0	10.7	27.3	41.3	18.2	0.5	0.4	1.6	0.0
Japan	31.8	18.9	20.9	16.2	9.8	2.1	0.0	0.3	0.0
Korea	37.0	43.0	11.2	6.1	2.6	0.0	0.0	0.0	0.0
Netherlands	4.2	29.9	57.0	3.9	0.1	4.0	0.9	0.0	0.0
Portugal	0.0	30.9	5.2	27.4	33.5	2.6	0.2	0.2	0.0
Romania	9.9	28.0	19.0	7.7	35.3	0.0	0.0	0.0	0.0
Russia	12.5	19.3	42.7	6.1	19.3	0.0	0.0	0.0	0.1
Spain	30.2	32.3	8.3	9.0	18.3	1.2	0.7	0.0	0.0
Turkey	0.0	32.1	22.4	7.1	38.0	0.2	0.0	0.1	0.0
U.K	28.0	34.3	32.4	1.6	1.9	1.6	0.2	0.0	0.0
U.S	18.6	52.3	14.6	3.8	8.4	1.7	0.1	0.4	0.0

Source: IEA (2000)

With regard to the degree of diversity of generation sources within a country, Table 2-2 shows the number of generation sources in each nation providing over 5 percent of that country's electricity in 1998. Finland, Japan, Romania, Russia, and Spain are the most diverse, each with five sources above 5 percent, while Brazil is the least diverse, relying almost exclusively on hydroelectric power.

Table 2-2: Number of Generation Sources Providing over 5 Percent of Total Electricity in 1998

Country	Number of Sources
Finland	5
Japan	5
Romania	5
Russia	5
Spain	5
Denmark	4
Hungary	4
Italy	4
Korea	4
Portugal	4
Turkey	4
United States	4
Belgium	3
Canada	3
France	3
Germany	3
United Kingdom	3
China	2
India	2
Netherlands	2
Brazil	1

Source: IEA (2000)

Table 2-3 shows IEA projections of future distributions of capacity by type, in 2010, for most of the countries of Table 2-1. Comparing Table 2-3 with Table 2-1, these countries all show a projected increased reliance on natural gas. Some countries show projected decreases in shares of nuclear power, but Japan shows a substantial increase.

Table 2-3: Projected Percent Distribution of 2010 Electricity Generation by Country

Country	Nuclear	Coal	Natural Gas	Oil	Hydro	Renew & Waste	Solar & Wind	Geothermal
Belgium	55.5	8.7	29.6	2.3	0.4	3.5	0.0	0.0
Canada	11.2	13.6	15.8	0.7	58.3	0.2	0.0	0.1
Denmark	0.0	42.3	26.2	8.8	0.1	7.7	14.9	0.0
Finland	22.4	39.7	13.5	1.5	14.3	8.6	0.1	0.0
France	69.8	1.5	16.3	0.2	12.3	0.0	0.0	0.0
Germany	25.1	50.5	14.5	0.8	3.6	2.7	2.9	0.0
Hungary	35.8	19.9	33.7	9.5	0.5	0.6	0.0	0.0
Italy	0.0	9.2	43.6	22.0	12.2	7.6	4.3	1.1
Japan	40.7	15.2	20.2	11.2	8.9	2.3	0.5	1.1
Netherlands	0.0	14.9	70.5	8.1	0.2	4.6	1.7	0.0
Portugal	0.0	23.0	41.0	11.1	20.4	2.9	1.5	0.1
Spain	24.4	11.0	27.0	8.0	14.7	6.4	8.6	0.0
Turkey	4.7	35.3	35.9	0.3	23.7	0.0	0.0	0.0
U.K	13.7	19.7	49.3	15.2	1.1	0.9	0.1	0.0
U.S.	15.2	48.6	24.4	1.3	7.0	2.8	0.3	0.4

Source: IEA (2000).

2.3. Cost Comparisons of New Plants

International comparison of costs is subject to several difficulties. In many cases, accurate cost information for various countries and technologies is not available. When cost information is available, it is not always clear what factors are included in the quoted figures. Deregulation in the U.K. and Germany complicated the comparability for those countries so greatly that cost figures are omitted for them.

Busbar cost data are taken from OECD (1998), Tarjanne and Luostarinen (2002), and Smith and Hove (2003). An effort has been made to keep costs used in calculations consistent across sources. For example, overnight capital costs for OECD countries are calculated with and without contingency costs, the largest difference being 5.6 percent. Thus, an actual quantitative comparison of costs between the sources has the potential to be misleading, although discrepancies in costs included should change the total busbar cost less than 10 percent.

The model used to calculate the costs is comparable to the LCOE model of Chapter 1, with some differences to accommodate the structure of the international data. Ilten (2003) reports the equations of the model used in this chapter. All costs are expressed in 2003 U.S. dollars per MWh. Foreign exchange rates used to convert euros to dollars are from Federal Reserve (2001), and the dollar costs were adjusted to 2003 prices using the urban consumer price index (CPI-U) (BLS 2003).

LCOEs are reported for uniform cost and performance assumptions, across countries and plant types, for a 40-year plant life and 75 percent capacity factor, for discount rates of 8 and 10 percent. Sensitivity analyses were conducted and are reported in Ilten (2003, Tables 12-3, 12-5). In general, technologies with high capital costs, such as coal-fired plants and nuclear plants, are less costly at lower discount rates, longer plant lives, and higher capacity factors. At the same time, the low capital costs of natural gas make them less costly at higher discount rates, lower capacity factors, and shorter plant lives.

2.3.1. Deutsche Bank Busbar Costs

Deutsche Bank reports cost information for new baseload gas turbine combined cycle (GTCC), circulating fluidized bed (CFB), integrated gasification combined cycle (IGCC), nuclear, and pulverized coal combustion plants in China, Japan, the United States, and Western Europe. These costs have been used in the pre-tax LCOE model developed for this study to calculate comparable busbar costs across countries, shown in Table 2-4.

For the three countries identified individually in Table 2-4, nuclear power is not competitive. For China, a pulverized coal plant is least expensive except at high discount rates, where the lower capital costs of gas turbine combined cycle (GTCC) plants give them an advantage. For the other three countries, the least-cost plant types are integrated gasification combined cycle (IGCC) at lower discount rates and GTCC at higher discount rates. Costs for the United States and Western Europe are similar, in that IGCC is only least expensive at discount rates of 5 percent. IGCC is more attractive in Japan, being least-cost at discount rates of up to 10 percent.

Table 2-4: Deutsche Bank Busbar Costs, 75 Percent Capacity Factor, 40-Year Plant Life, $ per MWh, 2003 Prices

		Discount Rate	
		8 Percent	10 Percent
Country	Plant Type	$ per MWh	
China	Gas Turbine Combined Cycle	33 to 45	34 to 48
China	Coal Circulating Fluidized Bed	37 to 38	42 to 43
China	Coal, IGCC	33 to 36	38 to 41
China	Pulverized Coal	31 to 33	34 to 37
China	Nuclear	49	60
Japan	Gas Turbine Combined Cycle	36 to 47	38 to 49
Japan	Coal Circulating Fluidized Bed	38 to 40	42 to 45
Japan	Coal, IGCC	33 to 38	38 to 44
Japan	Pulverized Coal	39	44
Japan	Nuclear	105[a]	118[a]
Western Europe	Gas Turbine Combined Cycle	29 to 32	31 to 34
Western Europe	Coal Circulating Fluidized Bed	37 to 42	4 to 47
Western Europe	Coal, IGCC	32 to 38	37 to 44
Western Europe	Pulverized Coal	38 to 40	43 to 45
Western Europe	Nuclear	56	69
United States	Gas Turbine Combined Cycle	30 to 36	32 to 39
United States	Coal Circulating Fluidized Bed	37 to 40	41 to 45
United States	Coal, IGCC	32 to 37	37 to 43
United States	Pulverized Coal	38 to 39	43
United States	Nuclear	51	63

Source: Smith and Hove (2003).

[a]Japan's higher busbar costs are the result of higher parameter values including higher risk premiums, fuel cycle costs, and other factors.

2.3.2. OECD Busbar Costs

The OECD data, shown in Table 2-5, include cost information for new plants in Belgium, Canada, China, Denmark, Finland, France, Hungary, India, Italy, Japan, Korea, the Netherlands, Portugal, Romania, Russia, Spain, Turkey, and the United States. The plant types for which cost figures are available depend on the country, so some caution should be taken when discussing the lowest-cost plant type for a country. However, the inclusion of a coal-fired plant and at least one other plant type for every nation except Romania allows some discussion of least-cost plant types. Table 2-5 reports estimates for 8 and 10 percent interest rates.

Table 2-5: OECD Busbar Costs, 75 Percent Capacity Factor, 40-Year Plant Life, $ per MWh, 2003 Prices

		Discount Rate	
		8 Percent	10 Percent
Country	Plant Type	$ per MWh	
Belgium	Gas Turbine Combined Cycle	47	51
Belgium	Pulverized Coal Combustion	56	63
Canada	Gas Turbine Combined Cycle	35	38
Canada	Coal Circulating Fluidized Bed	56	63
Canada	Pulverized Coal Combustion	38	43
Canada	Nuclear, Spent Fuel Disposal	39 to 45	48 to 53
China	Pulverized Coal Combustion	43	48
China	Nuclear with Reprocessing	39 to 50	47 to 61
China	Nuclear, Spent Fuel Disposal	44	54
Finland	Gas Turbine Combined Cycle	46	49
Finland	Pulverized Coal Combustion	43	47
Finland	Nuclear, Spent Fuel Disposal	58	68
France	Gas Turbine Combined Cycle	59	63
France	Pulverized Coal Combustion	66	74
France	Nuclear with Reprocessing	50	60
Hungary	Gas Turbine Combined Cycle	45	48
Hungary	Pulverized Coal Combustion	49 to 52	55 to 57
India	Pulverized Coal Combustion	49	55
India	Nuclear, Spent Fuel Disposal	52	64
Italy	Gas Turbine Combined Cycle	58	61
Italy	Pulverized Coal Combustion	56	62
Japan	Gas Turbine Combined Cycle & Liquified Natural Gas	94	101
Japan	Pulverized Coal Combustion	78	88
Japan	Nuclear with Reprocessing	83	97
Korea	Gas Turbine Combined Cycle & Liquified Natural Gas	53	56
Korea	Pulverized Coal Combustion	48	54
Korea	Nuclear, Spent Fuel Disposal	49	59
Netherlands	Gas Turbine Combined Cycle	49 to 54	52 to 57
Netherlands	Coal IGCC	66	74
Netherlands	Pulverized Coal Combustion	61 to 63	67 to 71
Portugal	Gas Turbine Combined Cycle	55 to 56	58 to 59
Portugal	Pulverized Coal Combustion	71 to 74	81 to 84
Romania	Nuclear, Spent Fuel Disposal	49	59
Russia	Gas Turbine Combined Cycle	42	46
Russia	Pulverized Coal Combustion	57	64
Russia	Nuclear, Spent Fuel Disposal	45	55
Spain	Gas Turbine Combined Cycle	61	65
Spain	Pulverized Coal Combustion	59	66
Spain	Nuclear, Spent Fuel Disposal	65	78
Turkey	Boiler & Fuel Oil	51	55
Turkey	Gas Turbine Combined Cycle	38	40
Turkey	Pulverized Coal Combustion	53 to 76	58 to 84
Turkey	Nuclear, Spent Fuel Disposal	53	64
United States	Advanced Gas Turbine Combined Cycle	26	27
United States	Gas Turbine Combined Cycle	30	32
United States	Coal IGCC	36	42
United States	Pulverized Coal Combustion	36	41
United States	Nuclear, Spent Fuel Disposal	45	53

Source: OECD (1998).

Given configurations of plant life, capacity factor and discount rate in Table 2-5, nuclear power is the least-cost generating alternative for two countries, although it is close to its nearest competitor in several countries. In France, nuclear power is less costly than either coal- or gas-fired power, and the low range of once-through nuclear costs in China is below the Chinese pulverized cost. In Canada, nuclear is close in cost to the low end of pulverized coal and well below the cost of circulating fluidized bed coal combustion. In Russia, the once-through nuclear cost is close to the cost of gas-fired generation and well below that of pulverized coal. In Turkey, nuclear power is competitive with pulverized coal, but considerably more costly than natural gas-fired generation. France is the country where nuclear power has by far the greatest advantage over other plant types; only at the highest discount rate is nuclear power not the least-cost option. For most other countries, the high capital costs of nuclear power prohibit it from being cost-competitive with coal and natural gas-fired technologies.

Gas-fired power is most often the least-cost option. In addition to its competitiveness at the higher discount rate, gas-fired power is the least-cost option for a number of countries at lower discount rates as well. In Canada, Hungary, Russia, and Turkey, gas is least-cost at discount rates as low as 8 percent. For Belgium, the Netherlands, Portugal, and the United States, gas-fired power is the least-cost option with both discount rates.

Coal is most often the least-cost plant type at lower discount rates, although for a number of countries with higher natural gas prices, coal is competitive at the higher discount rate as well. In China, Denmark, Finland, India, and Japan, coal is the least-cost option at high discount rates. It is the least-cost option at lower discount rates in Denmark, Finland, Hungary, Italy, Japan, and Spain.

2.3.3. Other Recent European Assessments

Several European assessments of the busbar costs of new nuclear plants have been conducted recently, in addition to the 1998 OECD study reported above: the 1997 Direction du gaz, de l'électricité et du charbon (DIGEC) study, of the French Ministry of Energy; a French Parliament report of 1999; a report requested by the French Prime Minister, prepared by Charpin et al. (2000); a 2000 report from the Belgian AMPERE commission; and a 2003 report by the French Ministry of Industry. These studies have calculated LCOEs in the range of $26 to $38 per MWh for nuclear and $31 to $69 for the combined cycle gas turbine (CCGT), to which are added $7 to $42 for costs of environmental impacts, using discount rates between 5 and 10 percent, as summarized in Bouchard (2003, Attachment 1, p. 5). The reactor designs assumed are the European Pressurized Reactor (EPR), available immediately; the RHR1 which is similar to the GT-MHR, available after 2015; and the RHR2, a second generation high-temperature reactor available after 2040. The overnight costs range from $1,620 to $2,040 per kW (Charpin et al. 2000, pp. 111-114). The range of gas generation costs of these studies is wider than that calculated in the previous sections, but that for the new nuclear plants is considerably lower.

The discount rates used in the LCOE calculations of these studies are low for risky investments. French authors writing on private financing of new nuclear plants have expressed concern about the high risk premiums that capital markets will assign to investments in these facilities (Lescoeur and Penz 1999).

2.3.4. Finnish Busbar Costs

The Finnish data include cost information for new GTCC, nuclear, and pulverized coal plants, shown in Table 2-6. Nuclear power is the highest-cost option at 8 and 10 percent discount rates, but it is the least-cost option at a 5 percent discount rate. GTCC is the least-cost option at both 8 and 10 percent discount. Pulverized coal combustion is always the intermediate-cost technology.

Table 2-6: Finnish Busbar Costs, 75 Percent Capacity Factor, 40-Year Plant Life, $ per MWh, 2003 Prices

PLANT TYPE	Discount Rate		
	5 Percent	**8 Percent**	**10 Percent**
	$ per MWh		
Gas Turbine Combined Cycle	29	31	33
Pulverized Coal Combustion	31	35	37
Nuclear	28	36	42

Source: Tarjanne and Luostarinen (2002).

The reversal of nuclear power's relative cost, from highest to lowest, does not occur for other countries even at the 5 percent discount rate. Although conditions in Finland may differ from those in other countries, it is nonetheless helpful to have a concrete example of what it takes for nuclear power to be cost-competitive.

2.4. Nuclear Power Around the World

Nuclear power in the United States has been characterized by lengthy construction periods and high shares of capital costs. Comparison with those characteristics in other countries shows some similarities as well as differences.

2.4.1. Existing Nuclear Plant Construction Times and Costs

The costs assessed above have been for new plants. This section reports information on existing plants. Table 2-7 shows the construction times for nuclear power plants in the United States, France, and plants in other countries begun later than 1993. France has had a more predictable construction experience than the United States, but the newly-built reactors show the shortest average construction times. The U.S. construction time has been both lengthier and more variable than the French experience. The U.S. average has been 9.3 years against 6.7 for the French; and the relative variability of U.S. construction time (the standard deviation as a percent of the mean) has been 40 percent of the average, while the French relative variability has been 30 percent.

Table 2-7: Years Elapsed from Construction Start to Commercial Operation as of December 31, 2001

	Average	Minimum	Maximum	Standard Deviation	Last Plant Begun
U.S nuclear plants connected to grid	9.3	3.4	23.4	3.8	1977
French nuclear plants connected to grid	6.7	4.3	16.3	2.0	1985
Plants under construction beginning later than 1993[a]	5.3	4.5	7.2	0.75	2001

Source: IAEA (2002).
[a]China, India, Japan, and Korea.

The U.S. construction period in Table 2-7 was achieved under regulatory conditions that have been revised, and the French construction period may be a better estimate of future U.S. construction times, but the recent Asian experience, an average of 5.3 years with a variability of only 14 percent, may suggest that even further reductions are possible.

Total capital costs are strongly influenced by the length of construction period. While construction time may be influenced by the size of plant, there is no clear relationship between overnight cost per kW and construction time. Table 2-8 shows the recent record in overnight cost for some of the plants included in Table 2-7 as built after 1993, although the sample of plants in the former table is broader than that in the latter table. The costs in Table 2-8 have been converted to 2003 prices with the CPI-U (BLS 2003).

Table 2-8: Estimated Construction Costs for Recently Built Nuclear Power Plants, $ per kW, 2003 Prices

Country	Name of Plant	Start of Commercial Operation	Overnight Cost
Japan	Onagawa 3	January 2002	2,417
Japan	Genkai 3	March 1994	2,827
Japan	Genkai 4	July 1997	2,296
Japan	Kariwa 6	NA	2,027
Japan	Kariwa 7	NA	1,796
South Korea	Yongwang 5 & 6	2004/2005	2,308

Source: MIT (2003, pp. 141-142).

While the construction times for the plants in Table 2-8 are not available, some of these plants are included in the post-1993 plants of Table 2-7. The lowest construction cost estimate in Table 2-8, that for Kashiwazaki-Kariwa 7, is $1,796 per kW. Each of the other costs is as high as EIA estimates of near-term overnight costs of a new advanced nuclear plant in the United States. While construction time appears to be falling in new Asian plants, overnight costs associated with these more recent construction times are not particularly low compared to the costs expected by vendors of advanced reactor designs for new construction in North America and Europe, as reported in Chapter 3.

2.4.2. Composition of Nuclear Busbar Cost

The share of annuitized capital costs in the projected LCOE of new French nuclear plants is roughly the same as that in U.S. projections. The projected capital cost shares in Table 2-9 are around 70 percent, compared to the 61 to 64 percent estimated for the AP1000 and the advanced boiling water reactor (ABWR) in Chapter 3, but OECD's overnight cost assumptions are higher than those used in Chapter 3, and the capacity factors are lower.

The U.S. nuclear fuel cost share is slightly lower than that in France, probably because of the difference in fuel cycles, and the U.S. O&M cost share is correspondingly higher. The small share of French generating capacity in gas and coal plants may somewhat reduce the interest of the cost composition of those alternatives in France, but the differences between French and U.S. cost structure is illuminating for the U.S. distribution of generation types. The fuel cost share of new gas plants in France is somewhat higher than that projected for new U.S. gas plants, reflecting higher gas prices in France. The capital and O&M shares for the U.S. gas plants are correspondingly higher. The greatest differences in cost structure exist in coal plants, in which the French fuel cost share is half as large as the U.S. share. With nearly identical O&M cost shares, the capital cost share of U.S. coal plants is correspondingly about one-third higher than that of the French coal plants. The cost composition of coal-fired generation reflects the U.S. advantage in coal costs, which has been a major impetus to the French concentration in nuclear generation capacity.

Table 2-9: Comparison of French and U.S. Busbar Costs, 25-Year Plant Life, Technology-Specific Capacity Factors, 10 Percent Discount Rate, $ per MWh, 2003 Prices

Country	Plant Type	Capacity Factor, Percent	Shares of Busbar Cost, Percent			Busbar Cost
			Capital	O&M	Fuel	
France	Nuclear Closed-Cycle	70	71	13	16	55
United States	Nuclear Once-Through	70	68	19	13	53
France	Gas Turbine Combined Cycle	80	25	7	68	60
United States	Gas Turbine Combined Cycle	80	28	9	63	32
France	Pulverized Coal Combustion	80	46	15	40	67
United States	Pulverized Coal Combustion	80	60	14	26	42

Source: OECD (1998), Ilten (2003, Table 39).
Source: MIT (2003, pp. 141-142).

2.5. Conclusion

The United States is in many ways typical when it comes to electricity. The abundance of both natural gas and coal resources in the United States is reflected in the relatively low cost of coal-fired and gas-fired power, yielding some of the lowest busbar costs in the world, despite the fact that U.S. nuclear busbar costs are comparable to or lower than nuclear busbar costs in most other nations. The one country where nuclear power is both least-cost and highly utilized, France, does so not because of the absolutely low cost of its nuclear power but because of the high costs of gas and coal.

When it comes to distribution of generation shares, the United States is in the mainstream of countries around the world. Its reliance on nuclear power is close to the world's average. Its high reliance on coal is also in no way unusual. The diversity of its generation sources is also a common experience. Thus the United States is in fact rather typical, with the usual reliance on fossil fuels and additional generation provided by nuclear and hydroelectric.

LCOEs on new nuclear plants in the United States are not projected to be higher than those elsewhere in the world, comparing favorably even with the prospective French costs. Nuclear power's large share of electricity generation in France appears to be due at least partially to the fact that generation costs from alternative sources in France are higher than for nuclear power. Total capital cost shares of LCOEs for new nuclear plants projected in the United States and France are similar.

Historically, France has experienced shorter and less variable construction times for its nuclear plants than has the United States. Meanwhile, nuclear plants built since 1993, mostly in Asia, have been built in shorter times, and with lesser variability, than even the French experience, offering some basis for optimism regarding future nuclear construction in the United States. However, the overnight costs of a sample of these recently built plants remain high.

2.6. Appendix: LCOE Methodology

This appendix reports the formulations used in the calculations of the international LCOE comparison and discusses the cost and performance data used. The structure of this model is essentially the same as the pre-tax LCOE model of Chapter 1. Some minor specification differences, which are implemented in the model of this chapter to accommodate the structure of OECD data, are noted below.

2.6.1. Levelized Cost Formula

The following levelized cost formula was used to calculate the total busbar cost for each plant.

$$EGC = I/(E \sum_{t=1}^{n} (1+r)^{-t}) + \frac{M}{E} + F$$

where:

EGC = Average lifetime levelized electricity generation cost per kWh
I = Total capital expenditures discounted to year 1
M = Yearly operation and maintenance expenditures
F = Fuel cost
E = Yearly electricity generation
r = Discount rate
n = Plant life.

I, the total capital expenditures discounted to year 1, is calculated as follows:

$$I = C + \sum_{t=1}^{c} S_t K (1+i)^{c-t+1}$$

where:

I = Total capital expenditures discounted to year 1
C = Contingency costs
K = Overnight capital cost (excluding contingency costs)
S_t = Percentage of overnight capital costs incurred in the t^{th} year of construction
c = Length of construction period.

K, overnight capital cost (less contingency costs), is the dollar amount that would be paid out if all capital expenses occurred simultaneously; no interest payments are included. OECD (1998) reports contingency costs separately from overnight costs, although the U.S. definition of overnight cost includes contingency costs and owner's costs, as described in greater detail in Chapter 3. This data reporting difference is responsible for the separate accounting of contingency costs in the equation for capital costs above, which treats contingencies as being expended in the final year of construction. *E*, yearly electricity generation is simply total nameplate capacity times capacity factor. *F*, the fuel cost, and *M*, the yearly operation and maintenance expenditures, were taken directly from each of the data sources.

All costs are reported in June 2003 U.S. mills per kWh. Costs from each data source were first converted to dollars with the Federal Reserve exchange rates (Federal Reserve Board 2001) if necessary, and then converted to June 2003 mills using the CPI-U (BLS 2003).

2.6.2. Relationship to OECD Cost Formula

A significant portion of the cost data used in this study was drawn from OECD (1998). Thus it may be helpful to see the relationship between the cost formula used here and the formula used in that study.

The OECD formula is a standard levelized cost formula, looking at the ratio between the total sum of discounted costs and the total sum of discounted generation:

$$EGC = \left(\sum_t \left[(I_t+M_t+F_t)(1+r)^{-t}\right]\right)/\mathrm{G}$$

$$\mathrm{G} = \sum_t \left[E_t(1+r)^{-t}\right]$$

where:

EGC = Average lifetime levelized electricity generation cost per kWh
I_t = Capital expenditures in the year t

M_t = Operation and maintenance expenditures in the year t
F_t = Fuel expenditures in the year t
E_t = Electricity generation in the year t
r = Discount rate.

The summation is carried out over the entire life of the plant, beginning with planning and construction and lasting until decommissioning is over.

By assuming constant operation, maintenance, and fuel costs and a constant amount of electricity generation, the formula becomes:

$$EGC = \sum_t I_t(1+r)^{-t}/E \sum_{t=1}^{n} (1+r)^{-t}) + \frac{M}{E} + F$$

where:

M = Yearly operation and maintenance expenditures
F = Busbar fuel cost
E = Yearly electricity generation.

This is equivalent to the formula described in Section 2.6.1.

Because of the similarity between the OECD formula and the formula used in this study, one would hope for similar results. This is in fact the case. Comparing cost results with a uniform capacity factor of 75 percent, plant life of 40 years, and discount rate of 10 percent, the OECD busbar cost was on average only 1 mill per kWh less than the estimate obtained using this study's formula, with a standard deviation of 1.9.

2.6.3. Notes Concerning Cost Data

The Deutsche Bank cost data come from Smith and Hove (2003, Figures 65–70). Plant size, capital cost, fixed and variable O&M costs, and fuel costs are taken directly from the given data. Although it is not explicitly stated what is meant by "capital cost," the formulas in Figure 64 appear to imply that it does not include financing; thus "capital cost" is equivalent to the overnight capital cost used in Section 2.6.1. No construction cost schedule is provided, so overnight capital cost is allocated evenly over the number of years specified by the lead time prior to the first year of operation. The given depreciation term is used as the plant life; capacity factor is taken directly from the data. The source includes little annotation of what the cost figures include, although it is implied that they do not include taxes.

The Finnish cost data come from Tarjanne and Luostarinen (2002, Table 1 and p. 3). Plant size, busbar fuel cost, plant life, variable O&M costs, and discount rate come directly from the table. Capacity factor is calculated using the hours of full-load operation given at

Tarjanne and Luostarinen (2002, p. 5). Fixed O&M costs are calculated by multiplying the given cost percentage by the given investment cost. However, these investment costs are not used as the overnight capital costs. No construction cost schedules are given, so OECD schedules are used. Finland's OECD schedules are used for coal, gas and nuclear. Overnight capital costs are calculated by solving for the cost figure yielding the total investment discounted to year 1, given the construction schedules and a 5 percent discount rate. That is, the following equation is solved for *K*:

$$I = \sum_{t=1}^{c} S_t K (1.05)^{c-t+1}$$

where:

I = Total capital expenditures discounted to year 1
K = Overnight capital cost
S_t = Percentage of overnight capital costs incurred in the tth year of construction
c = Length of construction period.

No mention is made of contingency costs, so they are omitted. Costs include initial fuel loading for the nuclear plant, but do not include value-added-tax.

The OECD cost data come from OECD (1998, Tables 1–17). Plant size, contingency cost, overnight capital cost, construction schedules, total O&M costs, capacity factor, and discount rate are taken directly from the given data. No construction schedules are provided for the fuel oil plant in Turkey, so all costs occur in the year previous to operation. Factors covered in the costs vary by country and are detailed in Annex 7 of that report. In general, taxes are not included in the costs.

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Chapter 3. CAPITAL COSTS

Summary

Capital costs are the single most important component of the costs of providing nuclear power, as is illustrated by figures from one of the major technologies considered in detail in this chapter. For the Advanced Boiling Water Reactor (ABWR), already built in Asia, the overnight capital costs, or undiscounted capital outlays, account for over one-third of LCOE, and the interest costs on the overnight costs account for another quarter of the LCOE.

Overnight Costs

Overnight cost estimates from different sources have ranged from less than $1,000 per kW to as much as $2,300 per kW. This chapter examines reasons for differences in estimates, with the aim of reaching a smaller range.

The first major component of overnight costs consists of engineer-procure-construct, or EPC, costs, amounting to around 85 percent of total overnight costs paid. EPC costs are in turn separated into direct and indirect costs. The direct costs are for physical plant equipment and the labor and materials to assemble them, while the indirect costs involve supervisory engineering and support labor costs, with some materials. Direct costs account for roughly 70 percent of EPC costs. About 60 percent of EPC costs are for factory equipment, 25 percent for labor, and 15 percent for materials. About 50 percent of EPC costs are for reactor plant and turbine equipment. These figures include equipment, labor, and materials costs of installing them. R&D targeted at these components could have a substantial impact on overnight cost.

Overnight costs include three additional categories of costs, one for contingencies, one for the owner's costs of infrastructure and training incurred to get the plant running safely when it is built, and one for first-of-a-kind engineering, or FOAKE, costs.

Contingencies and owner's costs can add 15 to 20 percent to overnight costs. Before a reactor of a particular design has been built, several hundred million dollars must be expended to complete its engineering design specifications. These are FOAKE costs. They are incurred only once for any type of reactor—although building a reactor of a particular design in one country may not transfer all the preliminary engineering necessary to satisfy safety regulations in another country, so some FOAKE costs may still be incurred for the first construction in any given country. Nonetheless, when a U.S. firm builds a new design overseas, much of the engineering experience may be transferable to the home country, making it possible for routine engineering and home office services to cover those remaining costs.

FOAKE costs are a fixed cost of a particular reactor design. How a vendor allocates FOAKE costs across all the reactors it sells can affect the overnight cost of early reactors

considerably. A vendor may be concerned about ability to sell multiple reactors and want to recover all FOAKE costs on its first plant. That could raise the overnight cost of the first plant by 35 percent.

FOAKE costs are to be distinguished from n^{th}-of-a-kind capital costs, which are the consequence of learning by doing beyond the first-of-a kind construction and are considered in the next chapter.

Interest Costs

Meanwhile, interest costs accrued during construction greatly affect total capital costs. By the time a new plant comes on line, total capital cost that electricity sales must cover to repay investors can be 25 to 80 percent greater than the overnight costs, depending on the interest rates and the length of the construction period.

How to deal with the sensitivity of nuclear capital costs to interest rates, as dependent on risk premium and length of construction periods, is dealt with in Chapter 5.

Overnight Cost Sensitivity Scenarios for the Present Study

In addition, much is accomplished in narrowing the range of uncertainty in capital costs by realistic specifications of reactors likely to be used and by attention to FOAKE cost assumptions. The ABWR, the CANDU ACR-700, the AP1000, and Framatome's SWR 1000 appear to be reasonable candidates for deployment in the United States within the coming decade.

The ABWR is a mature design, having been built recently in Japan by a U.S. firm teaming with a Japanese firm, so its FOAKE costs may be considered already paid. An overnight cost of $1,246 per kW is justifiable for it. The CANDU ACR-700 has had units of a closely related model, the CANDU 6, built recently in China and Romania. Construction times have been short, and vendor estimates of overnight costs are quite low, around $1,000 per kW, although EIA estimates $1,100 to $1,200 per kW for a third-of-a-kind twin unit. Its cost characteristics would appear to overlap those of the ABWR, despite their size differences (1,350 MW versus 753 MW), so the first reactor design chosen for analysis may be considered as representing either the ABWR or the ACR-700.

The AP1000 is closely related in design to the already certified AP600, but neither design has been built yet, so its FOAKE costs remain to be paid. Assuming its entire FOAKE costs are paid on the first plant, $1,500 per kW is a justifiable overnight cost. The SWR 1000 is based on design features proven in the European market. In meetings with the U.S. Nuclear Regulatory Commission (NRC), Framatome has expressed its intent to apply for certification to enter the U.S. market with the design. Framatome's European Pressurized Water Reactor (EPR) has been selected for construction in Finland. Estimates for the EPR in Finland suggest an overnight cost of $1,800 per kW for that reactor design, which would roughly parallel those of the SWR 1000.

Consideration of the foregoing reactor types contributes to the choice of $1,200, $1,500, and $1,800 per kW overnight costs in the sensitivity scenarios used in the economic viability analysis in Chapters 5 and 9. The range is consistent with allowance for uncertainty in the cost estimates in view of the scope for variation in overnight costs due to the other factors reviewed in this chapter.

Outline

3.1. Introduction

Capital costs are especially important to the competitiveness of nuclear power, since they account for a major share of the levelized cost of electricity (LCOE). The literature on nuclear power plant costs reports a wide array of capital costs. In analyzing why the estimates differ, Section 3.2 of this chapter deals with the overnight cost component of capital costs. Section 3.3 deals with the interest component. Section 3.4 uses the results of the chapter to narrow the range of capital costs to be used in the economic analysis of the present study, proposing to limit the analysis to three near-term reactors as the most realistic possibility and to allow for remaining uncertainty based on analysis of the individual components of capital costs.

3.2. Overnight Costs

3.2.1. Why Overnight Costs Differ

Estimates of overnight capital costs of nuclear plants have ranged from as high as \$2,300 per kW and to as low as \$1,100 per kW. The reasons for the differences are diverse. At the simplest explanation, the numbers refer to different reactor technologies. Estimates for the same technology can differ as well, however. At different times, the cost estimates for reactor components may differ, and of course, different price levels prevail at different dates, so cost estimates produced at different dates should be adjusted for price-level differences for comparability.

A further important source of cost difference, for identical as well as different technologies is the allowance for contingencies. Reactor cost quotes are firm-fixed-price offers (even if they may be subject to negotiation between vendor and buyer), and vendors include allowances for construction costing more than their most optimistic estimate. These costs are included in an account explicitly referred to as contingencies and are charged to the buyer whether the contingent events occur or not. Depending on how much of the contingency costs actually get expended—which can be more or less than 100 percent—a vendor's profits on a project will vary.

Cost numbers sometimes refer to expected costs in different countries, and market costs of inputs may differ across countries, for which purchasing power parity adjustments are imperfect. When considering cost numbers of technologies of firms from different countries, the possibility should be considered that governments are offering subventions for some proportion of costs.

Some cost numbers refer to actual construction costs where others are expected costs of plants not yet built. For reactors that have not been built, some estimates may include FOAKE costs while others may exclude them. Frequently costs are expressed in terms of n^{th}-of-a-kind and possibly combined with twin plant assumptions. The n^{th}-of-a-kind cost has reduced the first-plant cost by some presumed learning efficiency in construction, often assumed to be 5 percent for each doubling of the number of plants built of the specified type. With twin plants, greater cost reductions are expected. If two reactors are built at the same site at the same time, some experience suggests that both can be built for 5 to 7 percent less than if they were built separately, either at different sites at the same time or at the same site at different times. The cost reduction derives from the ability to schedule work crews and construction equipment more expeditiously, with less down-time, as well as economies in procurement and related support costs. This phenomenon will be considered more fully in the next chapter.

When a publication gives an overnight capital cost number for a nuclear power plant, some of these qualifications may appear in footnotes, but most often, some will be omitted.

3.2.2. Categories of Overnight Capital Costs

Capital costs are customarily separated into three principal types of expenditure which are allocated across ten or eleven accounts. Table 3-1 identifies the accounts and reports a typical structure of capital cost accounts for a nuclear power plant for a boiling water reactor of mature design. Table 3-2 disaggregates the expenditures by account for the mature boiling water reactor into their three principal components, equipment, labor, and materials, reporting the structure of costs in more detail. The cost structure of Table 3-2 is similar to the cost structures reported for a variety of reactors in Nuclear Energy Agency (NEA), 2000, Table 5, p. 29.

Table 3-1: Capital Cost Distribution for 1,144 MW Advanced Boiling Water Reactor (ABWR), Mature Design, Including Contingencies and Owner's Costs

Account	Description[a]	As Percent of Total Costs[b]
21	Structures & improvements	13.9
22	Reactor plant equip.	20.4
23	Turbine plant equip.	14.7
24	Electric plant equip.	4.4
25	Misc. plant equip.	3.1
26	Main cond. heat rej. system	3.4
	Total Direct Costs	**59.8**
91	Construction services	13
92	Engineering & home office services	6.4
93	Field supervision & field office services	5.6
	Total Indirect Costs	**24.9**
94	Owner's cost	5.1
96	Contingency	10.2
	Total	**100**
95	FOAKE	Already paid

[a]Source of description of accounting system structure, Delene and Hudson (1993, passim).
[b]Source of numbers, DOE (1988, passim).

Table 3-2: Percentage Distribution of Overnight Capital Costs by Account, for Advanced Boiling Water Reactor (ABWR), Mature Design

Account	Description	(1) Factory Equipment Cost	(2) Site Labor Cost	(3) Site Material Cost	(4) Account Costs as Percent of Total Costs Including Contingencies and Owner's Costs (Sum of Columns 1-3)
21	Structures & improvements	1.6	7.7	4.5	13.9
22	Reactor plant equip.	17.0	2.5	0.9	20.4
23	Turbine plant equip.	12.5	1.7	0.5	14.7
24	Electric plant equip.	2.5	1.3	0.6	4.4
25	Misc. plant equip.	1.5	1.3	0.4	3.1
26	Main cond. heat rej. system	2.2	1.0	0.2	3.4
	Total Direct Costs	**37.3**	**15.4**	**7.0**	**59.8**
91	Construction services	3.5	5.0	4.5	13.0
92	Engineering & home office services	6.4			6.4
93	Field supervision & field office services	4.3	0.6	0.6	5.6
	Total Indirect Costs	**14.2**	**5.6**	**5.2**	**24.9**
94	Owner's cost	-	-	-	5.1
96	Contingency	-	-	-	10.2
95	FOAKE				Already paid for this plant
	Total				**100.0**

Source: DOE (2001, Tables 1-4, pp. 4-20—4-23).

3.2.2.1. The Accounts

3.2.2.1.1. Direct and Indirect Costs

The three principal expenditure categories are equipment, labor, and materials. The accounts in Table 3-1 describe the types of components used—such as reactor equipment (account 22), turbine equipment (account 23), and structures and improvements, which would include control rooms (account 21)—and types of services employed in the construction—such as construction services (account 91) and field supervision and field office services (account 93). The equipment and structures accounts are classified as direct costs, and the construction, engineering, and support services are classified as indirect costs. Direct and indirect costs account for about 80 percent of total overnight capital costs.

3.2.2.1.2. Contingencies

To these direct and indirect costs, vendors add a percentage referred to as contingencies (account 96). They will need to justify these contingency costs to a buyer, and they may be negotiated. Sometimes a government will agree to pay contingency costs. These may range from 9 to 12 percent of total direct and indirect costs, or be as low as zero.

3.2.2.1.3. Owner's Costs

Another category of costs, owner's cost (account 94), is paid directly by the buyer. These are costs of testing systems within the plant, training a staff (which may take several years while the plant is being built), various inspections, etc. These range from 5 to 10 percent of direct and indirect costs.

3.2.2.1.4. FOAKE Costs

Accounting practices for nuclear power plant costs have evolved in recent years, and the identification of the costs of working out the initial engineering design of a new type of reactor as a distinct type of cost is an important product of that development. When a new type of reactor is developed, taking that design from relatively simple conceptual stages to detailed engineering specifications that will make all the necessary components come together successfully is a massive undertaking. These costs can range from $300 million to $600 million, adding as much as 30 percent to the cost of a first reactor. However, once these design efforts are completed, they never have to be repeated for this reactor design. Further engineering design work will have to be undertaken to place this type of reactor into a particular site, with its particular geographical and geological setting, but those engineering costs are contained in account 92, engineering and home office services.

FOAKE costs are specific to each reactor design. For example, two new reactor designs, say the AP1000 and the ABWR would have completely separate FOAKE costs. However, if one of these designs were to be built in, say, China, a considerable portion, but not all, of the FOAKE costs of building it in the United States would be covered by the design work for the Chinese installation. This reduction, if not elimination, of FOAKE costs by building a new reactor in any particular country, is motivation for more aggressive initial pricing in overseas markets.

How a vendor accounts for these FOAKE costs can make a substantial difference in the capital cost estimate. The effects of accounting for FOAKE costs are discussed further in Section 3.4 below.

3.2.2.2. The Account Structure of Capital Costs

Table 3-1 shows the largest component of overnight capital costs to be the reactor equipment. This account amounts to 20 percent of total costs, including owner's costs and contingencies. Following the reactor equipment in cost share is the turbine equipment, followed closely in turn by structures and improvements. The turbine equipment accounts for 15 percent of the total. Structures and equipment account for 14 percent of the costs. Electric plant equipment, miscellaneous plant equipment, and main conditioning heat rejection systems each account for 3 to 4 percent of costs. Total direct costs amount to 60 percent of total costs.

Indirect costs are comprised of construction services, engineering and home office services, and field supervision and field office services. Construction services, which are the actual building and assembly of the components into a functioning plant, are the largest indirect cost component. Engineering and home office services include engineering design costs required to adapt a fully known reactor design into a particular site, as well as procurement and other administrative services required to support construction. It includes no FOAKE costs, as this may be considered a mature design. Field supervision and field office services involve the supervision of construction, including on-site engineering and administrative support activities. Indirect costs account for 25 percent of the costs.

Owner's cost accounts for an additional 5 percent of the costs. Contingencies are 10 percent of total costs.

3.2.2.3. The Composition of the Capital Cost Accounts

Table 3-2 disaggregates the overnight cost accounts of the mature design ABWR into equipment, labor, and materials cost components. Equipment costs dominate total costs accounting for 52 percent of total costs. Labor accounts for 21 percent of costs, and materials for the remaining 12 percent. In column 1, equipment costs for the reactor (account 22) and the turbine equipment (account 23) account for fully 30 percent of total costs. The most significant labor costs are in structures and improvements (account 21), at nearly 8 percent of total costs.

3.2.2.4. Cost Uncertainties

Excluding contingencies, labor costs may be the greatest source of cost uncertainty. Strikes or other sources of labor productivity variance can operate on a quarter of total direct and indirect costs. A 25 percent overrun in labor costs would add 5 percent to total costs.

Once a particular reactor design has been built, and its equipment components supplied, the factory equipment cost shares should be quite predictable, but the equipment costs of reactor and turbine components for a new design may well vary 20 percent around the base cost shares shown in Table 3-2 for this mature reactor design. If factory equipment costs in these two accounts (22 and 23) both were 20 percent higher than the estimates for which Table 3-2 presents cost shares, total costs would increase by 7 percent.

3.2.2.5. Possible Effect of Strategic Considerations

Several reasons exist why overnight cost estimates are not entirely hard engineering estimates. For example, if a vendor finds some indirect value to building a plant (especially a first plant or a first plant in a particular market), it may depress its contingency cost component, possibly eliminating it altogether, in order to obtain the sale. If some of the contingent events do occur, the vendor may well have to take the associated costs out of its profits. In some instances in which national governments have particularly close associations with their countries' nuclear vendors, the governments may agree to help with contingencies, although these actions may be limited by international trade agreements. A vendor might be able to get a variance agreement with the buyer to reimburse additional costs, particularly but not exclusively, in *force majeure* cases.

Cost estimates may be influenced by marketing goals. When comparing cost estimates for different types of reactors, produced by different vendors, it is even possible that one cost estimate is a strategic marketing reaction to another cost estimate. Account 96, contingencies, is available to assist a vendor in strategic marketing goals, with or without government subventions.

3.2.3. FOAKE Costs and Capital Cost Estimates

Section 3.2.1 introduced FOAKE costs, and noted that they can add 30 percent to total overnight costs. FOAKE costs are a fixed cost of a reactor design. If a lengthy production run reasonably could be assured, comparable to, say, a new model of automobile, the costs can be amortized over the anticipated future production and have little effect on the unit price. Conditions have not proven as simple for nuclear reactors.

How a vendor chooses to account for FOAKE costs may affect price and even its ability to sell a reactor. The preferred method, of course, is to have the vendor's government pay for these costs, but the practicality of that alternative depends on the priorities of different countries' governments. An agreement with a utility or consortium of utilities for the purchase of multiple reactors, possibly eight or ten, spread out over a relatively short time period, would be an alternative that would permit the spread of these fixed costs over multiple units. However, any utility or consortium accepting such a cost agreement would effectively subsidize subsequent buyers of this design, which reduces the likelihood of such an arrangement being reached in practice.

No a priori solution to this problem is apparent. Vendors may deal with the pricing problem by either (1) quoting n^{th}-of-a-kind costs, which exclude FOAKE costs and include cost reductions due to learning over the construction of the first n-1 reactors or (2) quoting capital cost for a first plant in $ per kW terms and placing the FOAKE cost alongside as a cover charge.

3.2.4. Learning by Doing

The n^{th}-of-a-kind costs were introduced above, in Section 3.2.2, as including the cost-reducing effects of learning from previous construction and manufacturing experience. This cost reduction excludes the FOAKE cost that might be associated with the first reactor built. The cost reductions derived from learning by doing and the elimination of sunk FOAKE costs are quite different conceptually, as this section emphasizes. The magnitude of learning effects is expressed as the percent reduction in cost associated with a doubling of the number of plants built. For example, an x percent learning rate means that the second plant will cost x percent less than the first plant, that the fourth plant will cost x percent less than the second plant, the eighth plant will cost x percent less than the fourth plant, and so on. The cost reductions decrease with continued construction although the learning rate is constant. The empirical evidence on the magnitudes of these effects is presented in Chapter 4.

Three principal sources of learning in nuclear construction may be distinguished. The first source of learning by doing cost reductions is in the factory, with vendors and their equipment. Engineers and skilled workers learn ways to produce components in less time and possibly fewer wasted materials. The second source of learning by doing in nuclear power plant construction is on-site replication—construction by the same contractor at the same site over a short time span. Engineering staffs and construction crews can be kept together so as to retain their learning and teamwork from previous experience. The third source of learning by doing is between-sites replication, in which the cost reductions derive from plant standardization even though engineering staffs and construction crews may change.

Each of these sources of learning is largely independent of the other sources, but similar factors can affect each. The short time span of multiple construction jobs required for the cost-reduction benefits of on-site replication applies to a considerable extent to the factory learning by vendors. If orders arrive more or less continuously, factory staffs are maintained, but if lengthy delays occur between orders, staffs may be let go and have to be reassembled and retrained subsequently, reducing the learning benefits of more continuous production. Similarly with the between-sites replication, although more of the plant standardization benefits may survive lengthy intervals between orders. Under favorable circumstances, such as steady building activity concentrated at single sites, learning effects will be greater than under less favorable circumstances.

3.2.5. Other Sources of Overnight Capital Cost Reduction

Another principal source of cost reduction that can be affected by construction patterns is the multi-unit station effect noted in Section 3.3. Scheduling economies, as well as some fixed indirect costs such as purchasing and other administrative activities, have proved to result in reductions in overnight costs if two or more reactors can be built simultaneously at the same power station. A review of international construction experience suggests that savings from multiple-unit construction have averaged around 15 percent of the overnight cost of a single-unit construction (NEA 2000, pp. 12-13, 65-70). This effect is independent of learning effects, which themselves may be enhanced by building multiple reactors at a single station, as reported in Chapter 4.

Significant cost reduction also may derive from standardization of plant design. Much of this cost saving is thought to lie in reduction of overnight costs by eliminating duplication in FOAKE costs. Reductions in construction time from standardization also reduce interest costs (NEA 2000, pp. 12, 55-65). Again, these cost savings are distinct from the effect of standardization on learning by doing.

3.2.6. Near-Term Reactor Designs

Table 3-3 gives dollar figures underlying the percentages in Table 3-1.

Table 3-3: Capital Cost Estimates: Advanced Boiling Water Reactor (ABWR), Mature Design, in Millions of 2001 Dollars

Account	Description	ABWR
21	Structures & improvements	198
22	Reactor plant equip	290
23	Turbine plant equip	210
24	Electric plant equip	62
25	Misc. plant equip	45
26	Main cond. ht rej. system	48
	Total Direct Costs	**853**
91	Construction services	186
92	Engineering & home office services	91
93	Field supervision & field office services	79
	Total Indirect Costs	**356**
94	Owner's cost	73
96	Contingency	145
	Total	**1,426**

Source: ABWR, DOE (2001, Tables 1-4) and consultation with international technical nuclear expert.

For comparison, a published Westinghouse estimate for total costs of an AP1000 reactor, without FOAKE costs, is $1,100 to $1,200 per kW (Poulson 2002, p. 22). This figure is slightly below the $1,246 per kW for the ABWR in Table 3-3 (as implied by dividing the total cost in Table 3-3 by 10^6 to obtain dollars and 1,144, which is the capacity in megawatts of the ABWR). However, the AP1000 has not yet been built. Assigning a FOAKE cost of

30 percent to the first AP1000 would bring its cost up to an average of about $1,500 per kW. The effective cost comparison is then $1,246 per kW (or approximately $1,250 per kW) for the ABWR and $1,500 per kW for the AP1000. In contrast, the FOAKE costs for the mature design ABWR in Table 3-3 have already been paid.

Another study that disaggregates some capital costs is the assessment of the business prospects associated with an Advanced Light Water Reactor (ALWR) by Scully Capital for the DOE. The Scully representation of the ALWR is modeled roughly after the AP1000 (Scully Capital 2003, pp. 1-6, 1-90). Table 3-4 shows the composition of Scully Capital's overnight costs and compares it with the ABWR from Table 3-1.

Table 3-4: Components of Overnight and Total Capital Cost: Comparison of ALWR from Scully Report and ABWR

	Scully Capital Report, 1100 MW ALWR[a]		**ABWR[b]**
	$ per kW	**Percent of Overnight Cost**	**Percent of Overnight Cost**
Direct and indirect costs	1,190	88.1	84.7
Startup cost/owner's cost	85	1.5	5.1
Contingency cost	20	6.3	10.2
Development cost	55	4.1	-
Total overnight cost per kW	1,350		1,246
Interest cost as percent of overnight cost	17-24		21-29
FOAKE cost as percent of overnight cost	24		Paid

[a]Source: Scully Capital (2003, pp. 1-8, 1-96).
[b]Source: Table 3-1.

The costs for the Scully report in this table are for a first plant, but they exclude the FOAKE costs, which that report spreads over the first three plants, as costs above and beyond overnight costs. The Scully report uses a somewhat different accounting system than the system used in Tables 3-1 to 3-3 above. The Scully report identifies startup, buyer's contingency, and development costs as sums above and beyond the EPC costs but attributable to a specific plant. The startup costs may be more limited in scope than the full range of infrastructure costs included in the DOE owner's cost account (account 94), since they amount to only 1.5 percent of overnight costs as contrasted to the 10 percent in the ABWR reported earlier. The buyer's contingency cost reported by Scully appears to be equivalent to the contingencies account (account 96) in the DOE accounting system. The correspondence between Scully Capital's development cost and any of the standard accounts is unclear, but it amounts to nearly as large a proportion of overnight costs as owner's cost estimated for the ABWR.

Including the three accounts additional to EPC in the Scully numbers, the resulting overnight costs are slightly higher than in the estimates reported above. FOAKE costs are slightly lower than the 30 percent estimate noted above. The Scully report presumes that learning in construction would reduce the overnight costs of the second plant by 3.8 percent. Learning would reduce the fourth plant's overnight cost by 23 percent below that of the first plant (Scully Capital 2003, p. 1-8). Altogether, the Scully capital cost composition is roughly similar to the two compositions reported above.

3.2.7. Cost Implications of Opportunities for Siting New Nuclear Plants

Nth-of-a-kind cost estimates sometimes assume a full 5 percent cost reduction with each doubling of units installed. The discussion in Section 3.2.2 of the components of learning by doing suggests that realizing the full 5 percent reduction could be optimistic. Availability of demand will limit opportunities to build multiple 1,000 MW units at a single site, either simultaneously or in rapid sequence, reducing the scope for on-site replication learning. Limitations on the ability to build multiple units at a single site would also reduce the ability to obtain the additional 5 to 7 percent cost reduction attainable from simultaneous construction. The practicality of building multiple units at more remote sites, away from major demand centers, is limited by the availability of transmission capacity and could be constrained as well by availability of cooling water.

Whether siting limitations such as these constrain new nuclear power plant construction is an open question, but the issues point to the importance of developing a specific strategy for a program of nuclear expansion. Capital costs would be sensitive, within a range of nearly 10 percent, to sites selected, timing patterns, and opportunities for multiple units.

3.3. The Shares of Overnight Capital Costs and Interest Costs in LCOE

The total capital cost shares in the LCOEs of nuclear plants are only slightly higher than those of a large coal plant, as Table 3-5 shows. The overnight cost estimates for the ABWR differ somewhat from those in Tables 3-3 and 3-4 above, deriving from different sources. These sources were taken from calculations of LCOEs, which included interest costs and the major component cost shares of the LCOEs. The principal demonstration points are not affected greatly by the overnight cost variations.

The ABWR capital cost share is 64 percent and that of an AP1000 is 61 percent, while that of a large, pulverized coal plant is nearly 61 percent as well. The cost share of a gas plant is only about 32 percent, which goes some way to explaining the popularity of gas plants in recent years.

The similarity of the cost shares of the AP1000 and the coal plant is largely explained by their similar overnight costs, $1,365 per kW versus $1,350 per kW. The ABWR overnight cost is higher—$1,600—while the gas plant's cost is only about 35 percent of that. The length of the construction period also varies between the two nuclear plants and the fossil plants—7 years assumed for both nuclear plants versus 4 for the coal plant and 3 for the gas plant. Additionally, the interest rates used for the nuclear plants are higher as well, 13.5 percent versus 8 percent.

The total capital cost can be broken down into the overnight cost and interest cost shares. The coal plant's overnight cost share is actually higher than that of either nuclear plant—50 percent versus 36 to 37 percent. The interest cost shares of the nuclear plants are 55 to 60 percent larger than the interest cost share of the coal plant and nearly four times the interest cost share of the gas plant. The difference between the nuclear and gas cost shares for interest are attributable to all three components—overnight cost per kW, construction period, and interest rate.

Table 3-5: Cost Shares of LCOE: Overnight Capital, Interest, O&M, and Fuel for Alternative Nuclear and Fossil Technologies

Plant Type	ABWR	AP1000	Pulverized Coal	Gas Combined Cycle
Overnight capital cost, $ per kW	1,600[a]	1,365[b]	1,350[c]	590[c]
Weighted average cost of capital (WACC), percent	13.5	13.5	8	8
Construction period, years	7	7	4	3
Overnight capital cost share of LCOE	0.374	0.357	0.499	0.271
Interest share of LCOE	0.266	0.254	0.108	0.046
Total capital share of LCOE	0.640	0.611	0.607	0.317
O&M share of LCOE	0.282	0.304	0.136	0.053
Fuel share of LCOE	0.078	0.085	0.257	0.630

[a]Source of ABWR overnight capital cost: DOE (2001, Ch. 5).
[b]Source: Reis and Crozat (2002, p. 10).
[c]Source: EIA (2001, Table 38, p. 88).

Table 3-6 considers the influence of construction period and weighted average cost of capital on the interest and overnight cost proportions of total capital cost of a single type of plant, the ABWR. The upper panel varies the weighted average cost of capital (WACC) over a 5-year construction period, and the lower panel does the same variation for a 7-year construction period. With both variations—in interest rates, holding construction period constant, and in construction periods, for given interest rates—the interest share of capital costs increases less than proportionally. For instance, the increase in WACC from 8 to 13.5 percent is about 70 percent; the corresponding increase in the interest share of total capital costs is only about 55 percent. The 2-year increase in construction time is 40 percent of a

5-year construction period, but the increments in interest costs are from 27 to 30 percent, depending on the interest rate.

Construction interest costs are clearly an important component of total capital costs. The magnitude of the interest component over a 7-year construction period at a 13.5 percent WACC is impressive: nearly 42 percent of total capital cost. Even over a 5-year construction period, the interest costs account for nearly one-third of the total capital cost. The 13.5 percent WACC reflects a risk premium of about 4 percentage points over conventional utility financing in recent years, which has averaged around 11.5 percent on equity and 7.5 percent on debt for a WACC of 9.3 percent. These figures show nonetheless the importance of keeping construction delays under control and offering assurances that would reduce the risk premium investors require. Chapter 5 below goes into detail on choice of construction time and WACC in the energy scenarios to be analyzed.

Table 3-6: Sensitivity of Overnight and Interest Cost Contributions to Total Capital Cost: Varying Construction Time and Weighted Average Cost of Capital (WACC), for Advanced Boiling Water Reactor (ABWR)

Construction Time: 5 Years			
WACC	0.080	0.115	0.135
Interest share	0.211	0.287	0.327
Overnight capital cost share	0.789	0.713	0.673
Construction Time: 7 Years			
WACC	0.080	0.115	0.135
Interest share	0.274	0.368	0.416
Overnight capital cost share	0.726	0.632	0.584

3.4. Reactor Designs and Capital Cost Scenarios for Economic Analysis

A considerable narrowing of overnight costs estimates is accomplished by considering near-term reactor types. Choosing realistic near-term alternatives allows for uncertainty while anchoring estimates in reality. The resulting range also allows for some play in estimate in view of the various sources of latitude reviewed in this chapter.

Appendix A4 identifies current reactor designs and discusses their prospects for near-term commercialization. Four reactors appear to be particularly good candidates for deployment in the United States by the 2010 to 2015 period of concern in this study. One candidate is General Electric's ABWR, which has been built in Asia, jointly with Toshiba. Its prior construction by a U.S. vendor could simplify transferring it to the United States. Full FOAKE costs should not be incurred on a first unit in the United States since the U.S. firm's engineers would be able to transfer much of their experience with the Japanese construction. Remaining engineering costs for a first U.S. plant can be assumed to be included in engineering and home office services, account 92. Another candidate reactor is the CANDU ACR-700, which is a light water reactor that uses heavy water for moderation, manufactured by Atomic Energy Canada, Ltd (AECL). It is an advance on the CANDU 6, which has had several units built recently in China and Romania. AECL requested pre-application review for the ACR-700 by the U.S. Nuclear Regulatory Commission (NRC) in June 2002, and NRC expects to complete the process by mid-2004. The ACR-700's cost characteristics appear to overlap that of the ABWR despite the size difference (1,350 MW versus 700 MW). The low estimate of overnight costs to be used in the uncertainty analysis would represent either of these reactors. Although a CANDU reactor has not been built in the United States, the extensive recent experience of AECL with the closely related CANDU 6 could keep FOAKE costs for the ACR-700 in the United States relatively low. In the absence of further information, those costs are assumed to be coverable within engineering and home office services.

Still another candidate reactor is Westinghouse's AP1000. It is a larger version of the AP600, whose design NRC has certified. Obtaining certification for the AP1000 should be accelerated by the prior certification of its smaller version. Cost estimates for the AP1000 were considered in detail in this chapter. This reactor represents a mid-range cost.

A final candidate reactor is Framatome's Siede Wasser Reaktor (SWR) 1000, a boiling water reactor (BWR) which was considered seriously for construction in Finland. Its BWR features have been proven in the European market, and Framatome has expressed intent to submit the SWR 1000 for design certification by the end of 2005 (Cushing 2002, NRC 2002, Mallay 2002, Sebrosky 2002). Its cost per kW is expected to parallel that of Framatome's EPR (Framatome ANP 2003; UIC 2004, p. 4), which has been selected for the project in Finland, although Framatome has announced no plans for marketing that design in the United States. The SWR 1000 represents a high-end cost (UIC 2003, p. 3).

These designs span a spectrum of characteristics while having realistic prospects for near-term deployment in the United States.

The ABWR is a mature plant, the FOAKE costs on which have already been paid. Its overnight cost is estimated at $1,246 per kW. The ACR-700's construction times have been short, as little as 4.5 years from first pouring of concrete to criticality (NRC considers prior activities as part of its lead time definition), and AECL's projection of overnight costs have been as low as $985 to $1,000 per kW, although EIA (2004) suggests a cost of $1,100 to $1,200 per kW for the third construction of twin units, giving a cost similar to that of the ABWR.

The AP1000 has not yet been built. The FOAKE costs are yet to be paid. On the assumption that the entire FOAKE cost is assigned to the first plant, this plant's cost is specified at $1,500 per kW, representative of the midrange overnight cost estimate.

The EPR's overnight cost has been estimated between $1,600 per kW and a little over $1,900 per kW. Applying this cost to the SWR 1000, this range overlaps the range of overnight costs experienced recently in Asia, and thus may represent other reactor designs that could be considered. This third design's cost is taken to be $1,800 per kW.

3.5. Uncertainty in Overnight Cost Estimates

Overnight costs for each of these reactors are subject to some degree of uncertainty. Light is thrown on the uncertainty range by comparing the account compositions of the ABWR in Table 3-1 with the corresponding account composition for the ABWR reported in Rothwell (2004, p. 50, Table 1). The comparison of the two sources for same technology may give some idea of the scope for variation in total cost per kW for any particular design of reactor.

Accounts 21, 22, 23, and 91—structures and improvements, reactor plant equipment, turbine plant equipment, and construction services (indirect costs in Rothwell)—comprise 60 percent of the cost in Table 3-1 and 70 percent in Rothwell (2004). The difference between the two cost shares for a particular account, as a percent of the mean cost share for both designs, may be a reasonable scope for variation of costs in that account for either reactor. Multiplying this percent by the mean cost share of that account yields the percent variation in the total reactor cost that could be expected from variations in the costs in this account. Performing the same calculation for each of these four accounts and summing over those four accounts yields a variability of 21.5 percent of the total overnight cost.

Table 3-7 reports the range of overnight costs for each of the three reactor costs posited here, allowing for 10 percent variability in either direction from the midpoint. The cost ranges overlap only slightly between the upper range of a lower-cost design and the lower range of a higher-cost design.

Table 3-7: Uncertainties in Overnight Capital Costs, $ per kW, 2003 Prices

Characterization of Reactor	Lower Range	Midpoint	Upper Range
Average of Mature Designs	1,080	1,200	1,320
New Designs, FOAKE Costs Not Paid	1,350	1,500	1,650
Advanced New Design, FOAKE Costs Not Paid	1,620	1,800	1,980

As another source of uncertainty, of the four designs considered likely candidates for construction by 2015, only the ABWR has had its proof of concept established. The construction costs of plants whose prototypes have never been built have to be considered less certain.

A statistical estimate of a reliability range, for overnight costs, for example a 90 percent confidence range, could be estimated by performing a compound probability analysis combining probability distributions of the three sources of uncertainty, namely uncertainty as to which technology will be used, uncertainty about for any given technology, and uncertainty due to the lack of proof of concept. To do so would require probability weights on values in each of the distributions. Normal central tendencies in each of the distributions reduce the likelihood of extremely high or low values in any of the three distributions. The likelihood of extreme overnight cost values is further reduced when probabilities are multiplied together to obtain an overall compound probability distribution of overnight costs. Lacking knowledge of the actual probability distributions and recognizing the tendency for probabilities of midrange values to be higher than outlying values, it is hoped that the $1,200, $1,500, and $1,800 per kW estimate range used in this study represents a confidence interval for overnight capital costs associated with a higher degree of reliability.

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Chapter 4. LEARNING BY DOING

Summary

Reductions in capital costs between a first new nuclear plant and some n^{th} plant of the same design can be of critical importance to eventual commercial viability. In building the early units of a new reactor design, engineers and construction workers learn how to build new nuclear plants more efficiently with each plant they build. This chapter examines the evidence of cost reductions for nuclear power plants contributed by learning. The findings of this chapter are used in Chapter 9 to estimate the reduction in LCOEs due to learning effects that would take place after construction of early nuclear plants, lessening and possibly eliminating the need for government policies aimed at the nuclear power industry after building the first few plants.

A case can be made that the nuclear industry will start near the bottom of its learning curve when new nuclear construction occurs. The paucity of any new nuclear construction in the past twenty years in the United States, together with the entry of new technologies and a new regulatory system, has eliminated much of the applicable experience of the U.S. craft workforce. Participation in overseas construction may have given some U.S. engineers experience that is transferable to construction in the United States, but the international mobility of craftsmen is much less. Consequently, considerable learning is to be expected during the construction of the first few new plants.

Studies of nuclear plants built in the 1960s and 1970s report evidence of learning rates of 5 to 7 percent with doubling of plants constructed. Extending the sample of plants to those built in the 1980s weakens the ability to identify construction learning effects. Studies have found lower costs on plants built in-house by a utility itself rather than by a contractor, as much as 25 percent; but an earlier study found a 30 percent higher cost on in-house construction. It is possible that the in-house effect is the result of contractors in a market with limited competition.

A plausible range for future learning rates in the U.S. nuclear construction industry is between 3 and 10 percent. Three percent is conservative. It is consistent with a scenario involving low capacity growth, reactor orders of a variety of designs spaced widely enough apart in time that engineering and construction personnel cannot maintain continuity, some construction delays, and a construction industry that can retain internally a considerable proportion of learning benefits. A medium learning rate of 5 percent is appropriate for a scenario with more or less continuous construction, with occasional but not frequent cases of sequential units built at a single facility, a narrower range of reactor designs built by a more competitive construction industry, with delays uncommon. A 10 percent learning rate is aggressive. It would necessitate a continuous stream of orders that keep engineering teams and construction crews intact, a highly competitive construction industry, and streamlined regulation largely eliminating construction delays.

Outline

4.1. Introduction

The purpose of this chapter is to draw lessons for the future from the historical experience of learning by doing. Section 4.2 defines learning by doing. Section 4.3 reports learning rates in industries other than nuclear plant construction. Section 4.4 describes obstacles that hinder measuring learning by doing. Section 4.5 reviews the research on firm learning rates: Section 4.5.1 considers the standard approach studies that sought only to measure learning by doing; Section 4.5.2 analyzes the later studies that sought to characterize learning by doing in greater detail; and Section 4.5.3 looks at research comparing firm learning in the United States with firm learning overseas. Section 4.6 evaluates the research on industry learning by doing. Section 4.7 examines factors other than learning by doing that seven studies found to be significantly related to nuclear power plant capital costs: regulation (4.7.1), in-house management (4.7.2), multiple-unit sites (4.7.3), economies of scale and construction-time effects (4.7.4), and region (4.7.5). Finally, Section 4.8 discusses knowledge depreciation, and Section 4.9 concludes by summarizing the factors influencing alternative learning rates.

4.2. What is Learning by Doing?

As a product is produced over and over, the marginal cost of producing it often decreases. When this decrease is not a result of economies of scale or a drop in input prices, it may be a result of learning by doing. Learning by doing occurs when the human beings involved in a production process gain experience performing their tasks and, over time, find more efficient ways to do them. Costs of production decrease until potential gains in efficiency from learning are exhausted, at which point the costs level off toward an asymptote.

Learning by doing is an observed phenomenon; theories exist about where in the production process the learning occurs, but they remain theories. Epple et al. (1991, p. 59) offer a list of factors contributing to learning by doing:

> "Factors suggested as being responsible for organizational learning include: increased proficiency of individuals, including direct labor, management, and engineering staff; greater standardization of procedures; improvements in scheduling; improvements in the flow of materials; improvements in product design; improvements in tooling, layout, materials, and equipment; better coordination; division of labor and specialization; incentives; leadership; and learning by firms outside the focal firm, including suppliers and other firms in the industry."

Moreover, learning rates probably capture the learning effects from multiple, different agents within a firm: "The learning curve should be thought of as an aggregate model in the sense that it includes learning from all sources within the firm" (Yelle 1979, p. 309). Joskow and Rose (1985, p. 8) write:

> "Any simple measure of experience represents at best a characterization of a very complicated process that is not yet well understood theoretically. In most studies on learning by doing, a researcher recognizes that costs of production have decreased in a given industry. He then collects data, controls for other factors, and if he finds a correlation between costs and the production firm's experience, he concludes that learning by doing exists in that industry."

Learning by doing is most often quantified by a learning rate. A learning rate is the percentage decrease in cost each time cumulative output doubles. This definition of the learning rate can be calculated by the power law. The cost of the n^{th} unit produced is reduced, relative to the first unit produced, by a factor $(1-d)^{\ln n/\ln 2}$, where d is the percent cost reduction associated with a doubling of units produced, expressed as a fraction, and n is the unit for which this expression calculates the cost reduction. Learning by doing is expressed in learning rates because most investigations of learning curves find that learning makes its greatest impact when a production process is new: over time, learning by doing exhibits diminishing returns. The learning rate captures the diminishing returns by expressing the cost decrease as a constant percentage reduction at increasingly-spaced-out markers, that is, at doubling points of cumulative production. Alternatively, learning by doing is sometimes expressed in a progress ratio, which is simply 100 minus the learning rate. Thus, a 20 percent learning rate is equivalent to an 80 percent progress ratio.

4.3. Learning by Doing as a General Phenomenon

The first paper on learning by doing in a manufacturing process was written by T.P. Wright in 1936 on airframe production. In his pioneering article, Wright (1936) found that "the direct labor cost of manufacturing an airframe fell by 20 percent with every doubling of cumulative output" (Hatch and Mowery 1998, p. 1462). According to Yelle's (1979) comprehensive survey of learning-curve literature, nearly all of the subsequent research until the late 1960s concentrated on military applications (Yelle 1979, p.320). Yelle cites two studies by Hirsch (1952 and 1956): "Hirsch, in a comprehensive study of seven different machines built by a single manufacturer… found that the individual [learning rates] ranged from 16.5 to 20.8 percent" (Yelle 1979, p. 305). Hirsch's follow-up study found a range of 16.5 to 24.8 percent. Yelle next cites a 1958 study by R. Cole, in which Cole found "very little difference in [learning rates] between different types of manufacturing studies (18 percent to 23 percent)" (Yelle 1979, p. 305).

Learning by doing generally exhibits diminishing returns. Yelle calls this phenomena plateauing, and cites 1966 and 1971 studies by Baloff: "Baloff studied plateauing in machine-intensive manufacturing. The study consisted of twenty-eight separate cases of new product and new process startups that occurred in five separate companies in four different industries. Heavy emphasis was on the steel industry. Plateauing was observed in 20 out of 28 cases" (Yelle 1979, p. 306). Yelle detected an interesting trend in the learning-research: learning effects are greater in labor-intensive manufacturing processes than in machine-intensive processes. For example, a study by Hirsch found that "assembly [learning rates] were approximately two times as large (25.6 percent versus 14.1 percent)" (Yelle 1979, p. 306). The implication is that the more processes performed by human beings, the greater the opportunities to learn. Irwin and Klenow (1994) found in the semiconductor industry that firms learn three times more from their own cumulative production than from cumulative production of other firms and that learning spills over as much between firms in the same country as between firms in different countries.

In the research on learning by doing in the nuclear plant construction industry, nuclear learning rates are generally lower than the 20 percent average of other industries. There are many possible reasons for this phenomenon. First, and most significantly, each nuclear power plant is a unique project, making experience from previous projects less relevant. As McCabe writes, "Homogeneity maximizes the usefulness of past production experience… In contrast, power plant D&C involved designs that exhibited considerable heterogeneity, reducing the usefulness of past experience" (McCabe 1996, p. 357-358). Second, cost uncertainty (as a result of both regulation and heterogeneous plant designs) and cost-plus contracting may have reduced construction firm's incentives to reduce costs. Third, experienced construction firms may have been realizing decreasing costs but charging the higher market price (rent-capturing).

4.4. Estimation Problems

Long construction times and complex accounting practices are hindrances to estimating learning by doing. Because power plant construction projects last a number of years, complicated calculations are necessary to remove inflation and interest during construction (IDC) from the nominal cost numbers reported by utilities. Zimmerman, Komanoff, and Paik and Schriver use previous research on the typical cash flow for a nuclear power plant construction project to estimate the proportion of the reported nominal costs spent each year of construction (Zimmerman 1982, p. 301; Komanoff 1982, p. 316). Once the costs are broken down year-by-year, they use average interest rates to subtract the appropriate interest and inflation.

Cantor and Hewlett, however, are critical of the use of both the typical cash flow model and average interest rates. They claim that the cash flow model is inaccurate and introduces a bias correlated with time, leading "one to question the results of the other research, since all the variables of interest are correlated with time" (Cantor and Hewlett 1988, p. 323). Cantor and Hewlett claim to solve both problems by collecting accurate allowance for funds used during construction (AFUDC) and IDC rates from form FERC-1: "reported AFUDC rates collected from Form FERC-1 and supplemented by information from various State public utility commissions to incorporate important accounting conventions are used to derive effects AFUDC rates" (Cantor and Hewlett 1988, p. 334).

Accounting practices present another barrier to calculating costs precisely: when multiple units are built at one site, utilities often allot a disproportionate fraction of shared costs to one of the units (Komanoff 1981, p.201; McCabe 1996, p. 365). Various methods exist to control for this practice, which are discussed in Section 4.7.3. Most studies include a dummy variable in the regression (see column "multiple" in Table 4-1). Komanoff (1981) averages total costs over units at the site. Regardless of the method of dealing with it, the long construction times and thorny accounting practices involved in nuclear power plant construction projects make it difficult to calculate overnight capital costs. A comparison of data bases verified this: different studies calculate notably different overnight costs for the same plants.

Moreover, experience can be difficult to measure. Most studies use either reactors completed by a firm or reactor-years, that is, years a firm spent building a reactor. Using reactors completed by an architect-engineer "assumes learning takes place only after completion," while using reactor-years "assumes that completing a reactor in ten years is worth more than completing one in eight" (Zimmerman 1982, p. 300). Industry experience is especially difficult to quantify using regression analysis, as it is highly correlated with the time variable used in most regressions (Cantor and Hewlett 1988, p. 318).

The problem of precision is compounded when learning rates are used to model future plant construction costs; a small difference in calculated learning rate can mean significant differences in costs. McDonald and Schrattenholzer imagine a hypothetical technology and find that "decreasing the learning rate from 20 percent to 10 percent would increase technology maturing costs from $2 billion to $16 billion, and the break-even capacity from 9 to 96 GW" (McDonald and Schrattenholzer 2001, p. 256).

4.5. Firm Learning by Doing

The first attempts at quantifying learning by doing in nuclear power plant construction tried only to establish whether learning by doing existed and to measure it. Later studies had more specific goals, such as testing for the impact of industry structure or contract type on learning rates. McCabe thus calls the procedure of the early attempts the standard approach (McCabe 1996, p. 358). Section 4.5.1 deals with these early studies and Section 4.5.2 describes the later studies.

4.5.1. The Standard Approach

Table 4-1 summarizes the regression equations of five of these initial efforts at measuring learning by doing. These five studies are quite similar, and thus are easy to compare. Most of the regressions include variables for size, vintage, and firm experience, and dummy variables for whether the unit is the first at the site, whether a cooling tower was built, whether the project was managed by the utility (in-house), and what region where the plant was built. Vintage is generally used in these statistical analyses to capture the effects of increased regulation. The five studies in Table 4-1 also use data from similar time periods. The table also gives sample size, r^2 value, and estimated learning rate for each study.

Table 4-1: Summary of Regression Analyses of Learning by Doing in Nuclear Power Plant Construction

Paper/Database Size	Cost	Size	Date/Vintage	Experience	Experience2	Multiple	Cooling Tower	In-House	Regions	Other Variables	
Mooz 1979	ln (c per kW)	SIZE	CPIS	LN			TOWER		LOC1	BW	T1RSID and T2RSID
54 plants issued permits through December 1972; r^2 = 0.67; learning rate = 11.2 percent	IDC included	insignificant	Date construction permit issued	Natural log of cumulative number of LWR power plants by architect engineer			dummy; insignificant		Dummy; 1 if Northeast, 0 if other	Babcock-Wilcox manufactured the NSSS; insignificant	residuals from another regression; insignificant
Paik and Schriver 1979	ln C	ln (MW)		lnN					D1-D4	RI	RI^2
65 plants issued permits between 1967 and 1974 and which were completed or expected to be completed by 1981; r^2 = 0.78; learning rate = 21.9 percent	IDC included			cumulative number of LWR plants built by design firm			dummy was included in regression, but results were insignificant		of four regions, only two (unspecified) regional dummies were significant	"Regulation Impact Index:" Each regulation was assigned an impact rating (1-4); Sum of regulations in year of construction->	used algorithm to estimate impact of regulations during construction
Komanoff 1981	capital cost, K	MW	CUMULATIVE NUCLEAR CAPACITY	A-E		MULTIPLE	COOLING TOWER		NORTHEAST	DANGLING	
note: only statistically significant variables given in study; 46 reactors completed between December 1971 and December 1978; r^2 = 0.923; adjusted r^2 = .908; learning rate = 7 percent	$ per KW, without estimated IDC; used costs from data reported "year following commercial operation" (p.198)		captures effect of regulation	number of reactors built by architect-engineer		dummy; 1 if unit is part of a multiple-unit site, 0 if unit is stand-alone	dummy	ran separate regression to test for inhouse effects	only northeast region had significant cost difference	successor incomplete at time of study; K. unable to average costs across reactors at site	
Zimmerman 1982	log actual cost, kw	SIZE	YEAR1	(1/(1+EXPF)	(1/(1+EXPI)	FIRST	T	SELFCO	R7-R11	LETIME	LUTIME
41 plants completed between 1968 and 1980; r^2 = 0.85; learning rate in Table 3	per kilowatt in 1979$, removed estimated IDC;	in MW	in which nuclear decision was announced	experience (completed reactors) of construction firm; measures private learning	cumulative industry experience; externality associated with construction activity	dummy; 1 if first unit at site, 0 if otherwise	dummy; 1 if mechanical cooling tower	dummy; 1 if construction was done by utility	5 regions	log of the number of years orig. anticipated between announcement and operation	log of the diff. between actual and anticipated time to operation
Cantor and Hewlett 1988	ln (c per kW)	ln(SIZE)	CONSTRT	CST1		FIRST	COOL	BUILD	IPRICE	ln (construction time)	INTER
67 plants with scheduled commercial operation before 1986; adjusted r^2 =0.85; learning rate = learning coefficient insignificant	"use actual AFUDC rates and cash profiles" to remove IDC		number of days between date of construction start and 1/1/1960	(1/1+EXPF) where EXPF is number of completed reactors by "constructor"		dummy; 1 if unit is a first or single unit plant	dummy	dummy; 1 if utility was construction manager	construction labor wage rate in the plant's state	ran separate regression to capture "indirect" effects of variables through changes in construction time	interactive term between BUILD and CST1

Mooz (1979) studies 54 power plants with construction permits issued through December 1972. Using regression variables for plant size, construction permit issue date, architect-engineer experience, use of a cooling tower, region, and manufacturer, he obtains an r^2 of 0.67, the lowest of the five standard-approach studies. This is partly because only three of his variables are statistically significant: construction permit issue date, architect-engineer experience, and Northeast location. The significance of architect-engineer experience in Mooz's regression indicates that learning by doing does exist in nuclear plant construction, but there is reason be wary of the precision of the coefficient.

First, the coefficients for use of a cooling tower and for size of the plant are insignificant. Most later studies find significant cost effects related to size, as discussed in more detail in Section 4.7.4, and nearly all but Mooz find a significant cost increase related to the use of a cooling tower (Mooz himself considers this lack of significance puzzling). Second, Mooz does not control for whether or not a nuclear unit was part of a multi-unit site or whether the utility managed construction, and he only controls for one region, the Northeast. As Table 4-1 shows, later studies control for these factors and obtain more satisfactory results. Mooz's data base includes several cost estimates (as opposed to cost reports), and he does not try to remove interest during construction from reported capital costs. By using cost numbers with interest during construction included, Mooz biases his cost calculations against plants that took longer to build. All said, Mooz calculates a firm learning rate of 11.2 percent. Nonetheless, his study paved the way for later studies of nuclear plant capital costs, and it does find learning effects.

Paik and Shriver (1979) perform an analysis very similar to Mooz's, using 65 plants with permits issued between 1967 and 1974. Paik and Schriver's regression include the same variables as Mooz's, but with two major differences: Paik and Schriver use total costs, not costs per kW, as the dependent variable, and they use a regulation impact index (explained in Section 4.7.1) instead of a vintage variable (vintage is usually used a proxy for the effects of regulation) (Paik and Schriver 1979, p. 230). With an r^2 of 0.78, Paik and Schriver's regression explains a great deal more of the variance in capital costs than does Mooz's. However, it cannot be assumed that Paik and Shriver's calculation of the learning rate is precise, for the same reasons cited regarding Mooz's results. Like Mooz, Paik and Schriver do not find significant cost effects from the existence of a cooling tower, while the later studies all found significant effects.

Also like Mooz, Paik and Shriver do not include a variable to control for either first-unit status or in-house construction and do not remove interest during construction from reported capital costs. Moreover, the cost numbers for several of the last plants in Paik and Schriver's database are only estimates – construction had not yet been completed. This last factor potentially explains Paik and Shriver's relatively high learning rate estimate of 21.9 percent: realized costs in nuclear plant construction often overran estimated costs; using only cost estimates for later plants could make it appear that costs were decreasing over time. Overall, Paik and Schriver's study is similar to Mooz's and is open to the same concerns.

Komanoff (1981) studies capital costs of both nuclear and coal power plants. Employing a nuclear data base of 46 reactors completed between December 1971 and December 1978, Komanoff estimates a regression using variables for architect-engineer experience, size, cumulative nuclear industry capacity, and dummy variables for multi-unit site, dangling status, region, and use of a cooling tower (Komanoff 1981, p. 198). Utilities often allocate costs for plants at multi-unit sites unevenly. Komanoff solves this by averaging total costs over the number of units at a site; dangling status means not all the units at a multi-unit site were complete at the time of the study, making averaging impossible (Komanoff 1981, p. 201). Komanoff's study is a departure from the previous two studies in several respects. First, he controls for multi-unit sites, while Mooz and Paik and Schriver do not, and found significant cost reductions for reactors at such sites. By controlling for dangling status, Komanoff prevents disproportionate cost allocations at multi-unit sites from biasing the results against incomplete multi-unit sites.

Second, Komanoff's cost numbers better represent the overnight capital costs of building a plant: he removed estimated interest during construction from reported costs, and used costs reported in the year after the plant came online to capture substantial first-year capital costs (Komanoff 1981, p. 198). These techniques, together with Komanoff's high adjusted r^2 of 0.908 and high significance of the learning coefficient (> 99.9 percent), give his estimated firm learning rate of 7 percent appear statistically reliable. He also finds that "the 95 percent confidence interval ranges from between a 5 and 9 percent cost reduction for each doubling of experience" (Komanoff 1981, p. 200). However, Zimmerman's 1982 study and Cantor and Hewlett's 1988 studies (below) give reason to question these results.

Zimmerman studies 41 plants finished between 1968 and 1980 "for which completed cost figures are available" (Zimmerman 1982, p. 301). He uses variables for size, vintage, anticipated construction time, difference between anticipated and actual construction times, construction firm experience, industry experience, and dummy variables for use of a cooling tower, first-unit status, region, and in-house construction (Zimmerman 1981, p. 299). Zimmerman's study is most comparable with Komanoff's, mainly because both use a cash-flow model to remove estimated IDC from reported costs (Mooz and Paik and Schriver do not remove IDC, while Cantor and Hewlett use actual cash-flow data).

Although Zimmerman's study is most similar to Komanoff's, Zimmerman's regression differs from Komanoff's in several respects. First, while Komanoff uses cumulative nuclear industry capacity to capture the effects of regulation, Zimmerman uses a time variable. Second, Zimmerman includes regression variables for anticipated and actual construction time, in-house construction, and industry learning effects, while Komanoff does not. Third, Zimmerman uses an alternate form of the experience variable, 1/(1 + experience), instead of simple experience (Zimmerman 1982, p. 300). The effects of these three differences on the accuracy of results are ambiguous; most of Zimmerman's additional variables are statistically significant. Zimmerman's use of the 1/(1 + experience) form of the experience variable makes calculating a constant learning rate impossible. While the learning rate is a constant percent reduction for each doubling of experience, Zimmerman's form of the experience variable results in decreasing percent reductions at each doubling point of experience. That is, a learning curve using Zimmerman's functional form exhibits more sharply diminishing returns from learning than a standard exponential curve. Table 4-2 shows how using Zimmerman's functional form results in decreasing percent reductions at each doubling point of experience. Table 4-2 also compares Zimmerman's results using cumulative completed plants as the experience measure with his results using cumulative reactor-years: "for example, a reactor under construction for five years represents five reactor-years" (Zimmerman 1982, p. 300). Zimmerman's results resemble Komanoff's; from Zimmerman's data, a constant average learning rate (constant percent reduction) of 5 percent might be approximated. The firm learning coefficient in Zimmerman's regression is significant at over the 99.9 percent level. Learning effects are calculated by the power law expression in this study rather than by Zimmerman's variant, because the former calculation is the conventional approach.

Table 4-2: Zimmerman's Learning Effects

Experience Measure: Completed Plants	
Change in Constructor Experience	**Percent Cost Decrease**
1→2	7.4
2→4	5.9
4→8	4.0
8→16	2.7
Experience Measure: Reactor-Years	
Change in Constructor Experience	**Percent Cost Decrease**
1→2	8.0
2→4	6.5
4→8	4.5
8→16	2.7

Source: Zimmerman (1982).

Zimmerman makes an important point about calculated firm learning effects:

> "There is a potentially large bias in the estimate of internalized [firm] learning effects. A construction firm with a great deal of experience can capture rents. Such a firm can charge the price of its competitors and realize the lower cost as profit. The utility is not without bargaining power, and a likely outcome is a sharing of the rent" (Zimmerman 1982, p. 304).

That is, a construction firm may be realizing lower costs as it gains experience, but because the firm can charge the price of its less-experienced competitors, this learning effect is only partially represented in the prices paid by the utilities. This would introduce a downward bias in learning rate estimates, even if the relation of the learning to the cost paid by the utility is accurately reflected in the estimated learning coefficient. Zimmerman notes that including a regression parameter for in-house construction can help determine the extent of this bias: if utilities that manage their own construction realize lower costs than those that outsource to a construction firm, it may be evidence that construction firms are charging prices significantly above costs. He finds that on average, in-house construction resulted in 22 percent lower costs (Zimmerman 1982, p. 303). This saving may indicate that construction firms were capturing rents (in which case, calculated learning rates are biased downward, but still accurately indicate utilities' cost savings), or it may simply indicate that utilities run construction projects better. Zimmerman says of the lower costs for in-house construction: "This could reflect savings due to a better managerial arrangement, or it could indicate that in these cases the utility captured the entire rent" (Zimmerman 1982, pp. 304-305). In sum, rent-capturing may be pushing calculated learning rates downward, but that cannot be certain.

This consideration suggests a first reason to question the reliability of Komanoff's results: whereas Komanoff finds that in-house construction led to 30 percent higher capital costs, Zimmerman finds that in-house construction resulted in 22 percent lower costs. (Komanoff 1981, p.200; Zimmerman 1982, p. 303). Komanoff does not include a variable for in-house construction in his main regression. However, he estimates a separate regression to test for in-house effects: "The result was a 30 percent higher cost for self-A-E, with a 95 percent confidence interval of 13 to 50 percent and a 99.9 percent significance level" (Komanoff 1981, p. 200). Furthermore, Cantor and Hewlett's results agree with Zimmerman's (Cantor and Hewlett 1988, p. 332). This may be a result of different data bases, although Zimmerman's (1968-1980) brackets Komanoff's (1971-1978) in time.

Alternatively, it may be a result of regression techniques or cost deflation data – it is difficult to tell without access to Zimmerman's data (Komanoff provides his). The point worth noting, however, is that the two authors examining similar time periods can find widely disparate cost effects from a given factor. Moreover, Komanoff's in-house effect coefficient is significant at the 99.9 percent level – the same high significance level of the learning effects he finds. This must be taken into account when considering Komanoff's 7 percent learning rate.

Cantor and Hewlett's study includes 67 nuclear plants "with scheduled commercial operation before 1986" (Cantor and Hewlett 1988, p. 322). Their regression includes variables for size, construction labor wage rate in the plant's state (a proxy for regional cost differences), construction time, vintage, constructor experience, and dummy variables for use of a cooling tower, first-plant (at a multi-unit site) or single-plant status, and in-house construction. They also include an interactive term between constructor experience and in-house construction. This study is a departure from the previous studies mainly in its methodology for estimating overnight costs. Where Komanoff and Zimmerman uses average debt rates and cash-flow models, Cantor and Hewlett use "actual AFUDC rates and cash profiles" (Cantor and Hewlett 1988, p. 319). In a regression with an adjusted r^2 of 0.85, Cantor and Hewlett find no learning effects for construction firms; they find "some evidence" of learning effects for utilities that managed construction themselves (Cantor and

Hewlett 1988, p. 330). This may be a result of a data base that includes plants from the 1980s: Komanoff found regressions with nuclear plants built in the 1980s to be unstable (Komanoff, personal communication August 2003). It may also be a result of the rent-capturing bias—when construction firms realize lower costs as a result of experience, but charge the higher market price because they can. This rent-capturing explanation fits well with Cantor and Hewlett's findings of learning effects for in-house construction, in which there is no rent-capturing. Alternatively, Cantor and Hewlett may find no firm learning effects because of their unique capital cost methodology, an explanation they favor.

According to Cantor and Hewlett, "it is very likely that the method used in the previous research introduced measurement error into the dependent variable that is correlated with time" (Cantor and Hewlett 1988, p. 318). That is, the degree to which the average debt rates and cash-flow models were inaccurate changed over time. If this is true, then Komanoff and Zimmerman may be finding some cost effects from variables correlated with time (experience, for example) where there are, in fact, none. Indeed, Cantor and Hewlett think that this might explain why their regression finds no firm learning effects while Komanoff's and Zimmerman's do. This suggests another problem with Komanoff's results. Cantor and Hewlett estimate a regression using the differences between their derived overnight costs and Komanoff's derived overnight costs as the dependent variables: "Although the sample contained only 28 units, we found evidence that the bias is positively correlated with the experience variable. This would tend to explain the difference in results" (Cantor and Hewlett 1988, p. 330). That is, because Komanoff's derived cost numbers were off by different degrees over time, his cost-calculation methodology may create the appearance of a learning curve where none exists.

Canterbery et al. (1996) conducted a regression analysis of determinants of cost per kW for 53 nuclear plants built in the United States. They employ a particularly parsimonious specification, using only four independent variables: the plant size, the duration of the project, a regulatory variable, and a firm-level experience variable. The experience variable defined as the number of nuclear projects owner-operated by the utility prior to construction start. They estimate a 13 percent doubling rate.

In summary, Mooz's work, although pioneering, has reliability problems. Paik and Schriver also lack some of the techniques developed by the later studies. At first glance, Komanoff's results seem very reliable, especially considering that Zimmerman finds a similar learning effect for a similar period. However, Komanoff and Zimmerman find opposite effects for in-house construction, pointing to the sensitivity of statistical analyses of such complex, lengthy construction projects. Cantor and Hewlett find evidence that Komanoff's and Zimmerman's deflation methodology may have created the appearance of learning effects where there are none. Keeping in mind that rent-capturing may bias learning rate calculations downward, the standard approach to this research implies that the learning rate for nuclear power plant construction could range from 0 to 10 percent.

4.5.2. Principal-Agent Framework and Firm Learning

McCabe studies 90 nuclear units finished by the end of 1988 (McCabe 1996, p. 368). His study differs from the standard approach studies in that he used a model of learning that relies on a principal-agent framework (McCabe 1996, p. 357). The principals (the utilities) outsource construction projects to the agents (the design and construction firms), except in the case of in-house construction. McCabe recognizes a trend in the results of the standard approach studies: in-house construction projects were generally cheaper than their agent-managed counterparts, and in-house construction exhibited greater learning effects (McCabe cites Cantor and Hewlett's 1988 study). Consequently, McCabe separates projects into utility-managed and agent-managed groups to test whether utility- and agent-managers faced different incentives (McCabe 1996, p. 358). He hypothesizes that cost-plus contracts and cost uncertainty (mainly as a result of an unstable regulatory environment) reduced the incentives to learn for agent-managers. He does not deal with Zimmerman's rent-capturing hypothesis, that construction firms had profit as an incentive to reduce costs. McCabe further classifies the agent-managed projects by length of the principal-agent relationship to test whether longer relationships provide greater learning opportunities by allowing agents to better understand a utility's unique design preferences. Additionally, McCabe notes that because a utility that repeatedly manages construction in-house is essentially in a long-term relationship with itself, "In-house utilities building a series of plants should also experience relatively larger learning benefits" (McCabe 1996, p. 361).

McCabe's results generally conform to those of the standard-approach studies. In his first regression, McCabe uses the standard approach: one experience coefficient represented the experience of the unit's architect-engineer. This regression shows no significant learning effects. In his second regression, McCabe separates the experience variable into agent experience (which takes a value of 1 if the agent managed construction), principal experience (which takes a value of 1 if construction was managed in-house), and specific-relationship experience (which takes a value of 1 if an agent had previously contracted with the utility). With an adjusted r^2 of 0.87, the results indicate that in-house construction experience had a larger impact on in-house construction costs than agent experience had on agent-managed projects (McCabe 1996, p. 372). In fact, McCabe finds that for utilities, each in-house project reduced the cost of the subsequent in-house project by 11.6 percent, while for architect-engineers, that number is 2 percent (McCabe 1996, p. 371). These percentages are reductions after every project, and therefore not learning rates for doubling; roughly comparable learning rates would be about 30 percent for in-house and 6 percent for agent-managed. McCabe's approximation of learning effects assumes constant returns from learning, but nearly all the research on learning by doing finds diminishing returns. His regression results, however, advance the understanding of learning as they reveal evidence of considerably greater learning effects for utilities that manage projects in house. McCabe also finds specific-relationship experience insignificant, implying that "poor incentives rather than design variation account for the difference between agent and in-house procurement" (McCabe 1996, p. 372). That is, if design variation were responsible for the difference between in-house and agent-managed project costs, significant cost effects should be observed in long-term relationships in which an agent can better understand its principal's design preferences.

In summary, McCabe's results give evidence that the extent of learning effects depends on incentives: in-house construction exhibits greater learning by doing because utilities have greater incentive to reduce cost than construction firms do. However, McCabe's results could also support Zimmerman's rent-capturing hypothesis: perhaps construction firms exhibit less substantial learning effects because they are charging prices above their costs. It is clear that estimations of future learning rates should take market structure into account, specifically, who will be managing plant construction and the incentives agent-managers face.

4.5.3. Learning by Doing Overseas

This section reviews learning by doing in overseas nuclear power plant construction and considers the issue of transferring experience gained in recent overseas construction to future U.S. construction.

France's nuclear energy program is known for its standardization. Thomas (1988) writes that France's program was "the largest attempt at thorough-going standardization of power station design" (Thomas 1988, p. 195). The success of France's program is widely attributed to its efforts to standardize and modularize its nuclear reactors. Theoretically, learning by doing should thus exist to a higher degree in France than in the United States. By producing identical nuclear plants in series, France ensured maximum relevancy of past experience. "Standardization… makes it easier to identify empirical irregularities that point to underlying structural conditions deserving further investigation. Therefore, it promotes the learning process directly and widens the sphere of application for what has been learned" (David and Rothwell 1996, p. 191). Although there is a near consensus that France's standardization was both a catalyst in learning by doing and the reason for the French nuclear industry's success, capital cost studies on par with those focusing on the U.S. industry have not been found. This may be a result of lack of adequate data; Thomas writes that Electricité de France (EdF) releases data in a very global and aggregative form without specifying the extent of government subsidies: "This means that the absolute level of French construction costs must be treated with some care, if not suspicion, even for comparisons within France" (Thomas 1988, p. 232).

There is, however, evidence that France benefited from its standardization. Lester and McCabe (1993) used plant operation data and Thomas used construction times to evaluate the French nuclear program. Lester and McCabe found that "the equivalent availability factor"… increased more significantly in French plants than in U.S. plants, implying that the French learned how to effectively operate their plants sooner and to a greater degree than U.S. utilities learned to operate theirs (Lester and McCabe 1993, p. 435). "The equivalent availability factor is defined as the total amount of energy that a plant could have generated during the course of the year had it been called on to operated continuously at full power, divided by the maximum annual energy output at continuous full-power operation" (Lester and McCabe 1993, p. 420). Moreover, in the United States, "Inter-reactor learning (both within and among firms) is observed only when reactors of the same class are involved," implying that learning effects are more significant when plants are similar or identical. Examining construction times of French reactors, Thomas noted that although construction times did not decrease from 1971 to 1980, "Even more striking… is the fact that construction times have not risen over time" (Thomas 1988, p. 229). That is, in contrast to the U.S. and German experiences, and despite the fact that the French industry was undergoing "very rapid expansion," French construction times remained relatively constant. "There is little evidence of learning leading to reduction in construction times but this is at least in part explained by the rather short schedules that the French programme established from the beginning" (Thomas 1988, p. 232). Furthermore, a 1984 article in *Nucleonics Week* cites a study by the Electric Power Research Institute (EPRI), which found that French plants required "50 percent or less of the electric and mechanical (craft) labor consumed by the U.S. plants studied" (MacLachlan 1984, p. 2). In summary, Lester and McCabe found that the French industry realized greater learning effects in operation and maintenance, while Thomas found that France was able to avoid significant construction delays; the EPRI study found that French plants required significantly less labor to construct. All the studies explicitly attribute their findings to France's standardization and single-utility industry structure.

Japan's nuclear industry has also been characterized as successful. In a 1988 article, Navarro attributes Japan's success to standardization and a unique anti-trust policy. The Japanese Ministry of International Trade and Industry (MITI) guided Japan into a two-design reactor program. The program was designed to reap the benefits of both standardization (reduced costs, greater learning effects) and competition (pressure to keep costs down). Of standardization, Navarro writes, "Besides the benefits associated with construction time reductions, these programs are generally credited with helping Japanese utilities raise the aggregate nuclear capacity factor from a low of 37 percent in 1977 to close to 80 percent today" (Navarro 1988, p. 9). However, Navarro notes that in a statistical analysis, he was unable to find any firm-specific learning effects in Japan. Navarro attributes this lack of firm learning to the prevalence of industry learning: "This important result suggests that the various Japanese consortia have been able very quickly to assimilate and share the technological stock of knowledge necessary to build nuclear plants" (Navarro 1988, p. 7). Navarro goes on to describe Japan's unique anti-trust policy, writing that the Japanese government "encourages cooperation and concentration within industries and views resultant consortia as warriors in the international arena" (Navarro 1988, p. 9). Lastly, Navarro notes that Japan's "open and shut" licensing process allows Japanese utilities to pay lower insurance premiums on their capital (Navarro 1988, p. 10).

Although both the French and Japanese nuclear industries were relatively successful, a direct link between their success and their efforts to standardize remains unproven. Nonetheless, there is evidence implying that standardization leads to greater learning effects. A study by Kouvaritakis et al. (2002) estimates a 5.8 percent learning rate for OECD nuclear construction over the period 1975-1993 (reported in McDonald and Schrattenholzer 2001, Table 1, p. 257).

4.6. Industry Learning by Doing

Measuring industry learning by doing is more difficult than measuring firm learning by doing. Any measure of industry-wide experience is highly correlated with the time variable, making it difficult to separate the two effects statistically. Firm experience also correlates with time, although not so much so. However, what makes firm learning by doing simpler to measure than industry learning by doing is that while costs are negatively correlated with firm experience (more experience leads to lower costs), costs generally are positively correlated with industry experience (more experience seems to lead to higher costs). This effect is a result of increased regulation over time. Any measure of industry experience increases with time, and as time passes, regulations increase, making it more difficult and costly to build a plant. A statistical analysis will thus make it appear as if greater industry experience leads to higher costs. For example, while the industry might have 30 more plants under its belt in 1980 than in 1970, a plant built in 1980 will cost more. Indeed, Komanoff used cumulative industry capacity as a proxy measure of regulation effects.

4.7. Allowing for Other Factors Affecting Capital Costs

This section reviews the factors other than experience that researchers found to be significantly correlated with nuclear plant capital costs: regulation (4.7.1), in-house management (4.7.2), multiple-unit sites (4.7.3), economies of scale and construction-time effects (4.7.4), and region (4.7.5).

4.7.1. Regulation

To capture the effects of regulation, the most common technique has been to include a vintage variable. The cost in constant dollars of U.S. nuclear plants rose over the 1970s and 1980s, and the consensus among the studies is that this increase is mainly a result of increased environmental and safety regulation. Stricter standards “added significantly to the amounts of labor, materials, and equipment required to build reactors” (Komanoff 1981, p.202). The cost effects from regulation were compounded by the fact that regulations “frequently were mandated during construction, causing changes in design requirements that made it difficult for utilities to control schedules and costs” (Komanoff 1981, p. 202). The studies on plant costs go into little detail about what effects other than regulation the time-trend could be capturing; McCabe suggests changes in construction efficiency, but says little more (McCabe 1996, p. 366).

Table 4-3 shows the results of the studies. Nearly all the studies find that costs in constant dollars rose between 10 to 24 percent each year after all other factors have been controlled. First, note that regressions using permit issue date as the measure of vintage calculate generally higher percentages. Komanoff attributes the substantial difference between calculated annual increase rate using permit issue date and using plant completion date to the fact that nearly all of the reactors in his database “received their permits over a four-year span, from March 1967 to March 1971" (Komanoff 1981, p. 205). Second, note Paik and Schriver's use of a regulatory index. The index was created by assigning a numerical weight based on "impact" to each piece of U.S. Nuclear Regulatory Commission (NRC) regulation. The authors cite Bennett and Kettler (1978) who "evaluated the impact of each issuance on investment requirements with respect to both schedule and direct costs and classified their impact ranging from minor to most significant" (Paik and Schriver 1979, p. 231). Paik and Schriver used an algorithm to assign each plant a value representing the quantity and quality of regulation its designers had to face, taking into account regulation passed during the plant's construction. They found that regulation caused a 69.2 percent increase in plant cost from 1967 to 1974 (Paik and Schriver 1979, p. 235). Subsequent studies did not use Paik and Schriver's regulatory index because a vintage variable performed just as well. Komanoff used cumulative sector size to measure the effects of regulation "because it appears to capture more of the societal processes that give rise to new standards" and because it resulted in a higher r^2 value (Komanoff 1981, p. 204). However, later studies did not use cumulative sector size because, as with Paik and Schriver's regulatory index, a vintage variable performed just as well. Cantor and Hewlett write, "neither Komanoff's cumulative sector size measure nor Paik and Schriver's regulatory index performed any better than a simple time trend variable. This is because any measure of NRC regulatory activity is highly correlated with time" (Cantor and Hewlett 1988, p. 325). Cantor and Hewlett attribute their relatively low percentage to their unique deflation methods (Cantor and Hewlett 1988, pp. 327-328).

Table 4-3: Regulatory Effects

Study	Time Period	Independent Variable	Percent Change in Costs	Notes
Mooz (1979)	1965-1972	Vintage (permit issue date)	24.0, per year	
Paik and Schriver (1979)	1967-1974	Regulatory Index	15.6, per year (compound annual)	
Komanoff (1981)	1971-1978	Cumulative Sector Size	49.0, per doubling of sector size	
		Vintage (permit issue date)	23.6, per year (average)	
		Vintage (plant completion)	13.1, per year (average)	
Zimmerman (1982)	1968-1980	Vintage (nuclear decision announced)	11.0, per year	Included Industry Experience Variable - completed reactors
			18.0, per year	Included Industry Experience Variable - reactor years
Cantor and Hewlett (1988)	1966-1986	Vintage (construction start)	10.6, per year	
McCabe (1996)	1971-1988	Vintage (permit issue date)	17.3, per year	Included higher order terms (date, date^2, date^3)
Canterbery et al. (1996)	1966-1987	Cumulative number of regulations	11.1, per 10 percent increase in number of regulations	

McCabe included higher order terms; the 17.3 percent figure is a linear approximation of the curve he found. The curve, however, showed cost increases from regulation leveling off for plants with permits issued in the early 1980s. Canterbery et al. (1996) use the cumulative number of regulations in force at the time of a plant's construction as their indicator of regulatory presence, and they find a strong effect, an 11 percent increase in overnight cost for each 10 percent increase in the number of regulations.

In sum, increasing regulation resulted in about a 15 percent yearly increase in plant costs during the 1970s and 1980s. As many of the studies warn, these percentage-increase numbers should not be used to extrapolate future effects of regulation. The percentages probably capture the effects of some factors other than regulation; for example, costs per kW may have increased because the industry tried to build large plants before the technology was mature enough. Moreover, the yearly-increase figures represent regulatory effects from 1970s and 1980s regulation, when the industry was young; future regulation may be less unpredictable. A plausible, but unproven, implication from the results detailed above is that a stable regulatory environment will lead to more constant costs. As Cantor and Hewlett note: "These results are extremely important since they may be taken by the nuclear industry to imply that a stable regulatory environment… will stabilize costs" (Cantor and Hewlett 1988, p. 316).

4.7.2. In-House Management

The difference in costs between projects managed by construction firms and projects managed in-house by the utilities themselves have already been noted. Zimmerman's rent-capturing hypothesis has been noted: learning rates may be biased downward because construction firms charge prices significantly above costs. To test his hypothesis, Zimmerman looks at in-house effects and finds that in-house construction projects were, indeed, less costly than projects managed by construction firms. Zimmerman suggests that in-house savings could be a result of either rent-capturing by construction firms or efficient management by utilities. With his principal-agent approach, McCabe finds that utilities that managed construction in-house exhibited greater learning effects than construction firms. He attributes the difference to incentives: working under cost-plus contracts and in a cost-uncertain environment, construction firms had no incentive to reduce costs. Although the cause remains unclear, there is general agreement that in-house construction management results in lower-cost plants than construction-firm management.

The first two studies, Mooz (1979) and Paik and Schriver (1979), do not include a regression variable for in-house construction. Komanoff performs a separate regression to test for in-house effects, and finds that in-house managed projects were, on average, 30 percent more expensive (Komanoff 1981, p. 200). Zimmerman (1982) and Cantor and Hewlett (1988) find the opposite: in-house construction yielded 22 percent and 44.3 percent lower costs, respectively (Zimmerman 1982, p. 303; Cantor and Hewlett 1988, p. 327). As described in Section 4.5.2, McCabe finds that utilities that managed construction themselves realized over five times the learning effects of construction firms.

Cantor and Hewlett point out: "It should be recognized that the use of a binary variable to measure the cost differences between the two types of management regimes is done by necessity. In fact, there may be a range of utility involvement in the construction management, suggesting that a continuous variable, if one could be derived, would be a preferable measure" (Cantor and Hewlett 1988, p. 329).

In summary, in-house construction management yields lower costs and greater learning rates. The cause may be rent-capturing or greater incentives to reduce costs.

4.7.3. Multiple-Unit Sites

Most of the studies include a variable in their regressions to control for first-unit status. As noted, utilities often allot a disproportionate fraction of total costs at multi-unit sites to the first unit. By including a variable for first-unit status, the studies ensure that this disproportionate allocation does not bias their results. However, the coefficient associated with first-unit status tells nothing about whether reactors at multi-unit sites cost more or less than stand-alone reactors, but indicates only that the first unit costs more than subsequent units at a multi-unit site. Only Komanoff seeks to determine whether reactors at multi-unit sites cost less than stand-alones. To control for first-unit bias, Komanoff averages total costs for a multi-unit site over all the reactors at the site, so that all the reactors at a multi-unit site are assigned the same cost. He then includes a dummy variable in his regression for multi-unit status, and finds that "multiple units averaged 9.7 percent lower costs than other reactors" (Komanoff 1981, p. 201).

4.7.4. Economies of Scale and Construction-Time Effects

Because the standard approach studies use overnight costs as the dependent variable, identifying economies of scale correctly is a three-step process. The first step is to calculate what effects, if any, scaling up plant size has on overnight costs, "the quantities of land, labor and materials needed to construct a nuclear power plant" (Cantor and Hewlett 1988, p. 318). However, overnight costs, by definition, do not take into account time-related costs like interest and inflation. The second step is to determine how scaling-up plant size affects construction time, and the third step is to determine how an increase in construction time affects costs. Construction time affects real costs in two ways: an increase in construction time results in greater interest and inflation as well as greater overnight costs. Although the relationship between construction time and overnight costs is not immediately clear, Cantor and Hewlett's evidence of such a relationship is described below. Table 4-4 lists the studies' estimated scale effects. As a reference point, Komanoff wrote in 1981 that "capital cost projections of the U.S. Atomic Energy Commission (AEC), its successor agencies, and the power industry assume that nuclear costs per kW decline by 20 to 30 percent when reactor size is doubled" (Komanoff 1981, p. 200).

Table 4-4: Economies of Scale

Study	Scale Economies; Results of Doubling Unit Size	Scale Economies with IDC/Construction-Time Effects
Mooz (1979)	Insignificant	
Paik and Schriver (1979)	N/A; did not use cost per kW as dependent variable	
Komanoff (1981)	13 percent reduction in cost per kW	With IDC effects, 10 percent cost reduction
Zimmerman (1982)	11.1 percent reduction In cost per kW	
Cantor and Hewlett (1988)	36.2 percent reduction in cost per kW	With construction time- overnight cost relationship, 9 percent increase
McCabe (1996)	Insignificant	
Canterbery et al. (1996)	51 percent reduction in cost per kW	

In Mooz's study, the size coefficient in his regression was insignificant, implying no economies of scale. However, he did not take construction-time effects into account; doing so may have added costs and implied diseconomies of scale. Paik and Schriver (1979) used plant costs, not costs per kW costs, as the dependent variable, making testing for economies of scale impossible. Komanoff found that doubling reactor size led to a 13 percent reduction in costs per kW when overnight costs were used as the dependent variable. Komanoff recognized that construction-time effects had to be considered: "Doubling reactor size extended construction time by an average of 28 percent… the resulting increase in IDC adds approximately 3 percent to real costs, so that the net effect of doubled size is only a 10 percent cost reduction" (Komanoff 1981, p. 200). Komanoff's results imply slight economies of scale; however, Cantor and Hewlett's results (below) indicate that Komanoff should have considered the construction time-overnight cost relationship in addition to the construction time-interest relationship. Zimmerman found that doubling unit size resulted in an 11.1 percent reduction in costs per kW, but the size coefficient had "relatively large standard error" (Zimmerman 1982, p. 302). Moreover, Zimmerman did not take construction-time effects into account.

Cantor and Hewlett's study departs from previous studies by accounting for the relationship between construction time and overnight costs. This relationship is not intuitive: overnight costs, by definition, contain no time-related costs. However, Cantor and Hewlett hypothesize that construction time might increase overnight costs in three ways. Construction delays could result in morale problems, a stricter regulatory environment (since regulation increases with time), and increased hiring costs (since workers often must be laid off and then re-hired). They find overnight costs correlated with construction time beyond the 95 percent significance level. Using just overnight costs and no construction-time effects, Cantor and Hewlett find that a doubling of unit size resulted in a 36 percent decrease in costs per kW. However, when the construction time-overnight cost relationship is taken into account, the longer construction time necessary to build larger plants makes a doubling in plant size 9 percent more expensive, in costs per kW. "Thus, there appears to be some evidence supporting the claims that the industry has attempted to build units that are too large to be efficiently managed by the constructors" (Cantor and Hewlett 1988, p. 318). The construction time-overnight cost relationship excludes the construction time-interest cost relationship which affects LCOE.

Marshall and Navarro (1991) deal with the measurement rather than the concept of overnight costs. They observe that the calculation of overnight costs as the sum of expenditures over the construction period must be placed on a correct time basis to satisfy the requirements of capital theory. They point out that overnight costs as commonly calculated cannot accurately represent economies of scale because they leave out construction-time effects. The summation of construction expenditures must be dated to the completion date of the plant, which requires the proper correction for price-level change in the calculation of overnight costs. In their test for economies of scale in Japanese nuclear plants using overnight costs dated to plant completion dates, they find that when overnight costs are used as the dependent variable, economies of scale seem to exist, but when opening-date overnight costs are used, the size coefficient is insignificant, implying no economies of scale exist (Marshall and Navarro 1991, p. 153). Although Marshall and Navarro are critical of the previous studies' calculation of overnight costs, they come to the same conclusion – if economies of scale exist, they are minimal. McCabe (1996) uses Marshall and Navarro's opening-date cost and finds the size coefficient insignificant (McCabe 1996, p. 370). Canterbery et al. (1996, p. 558, n. 4) note that Marshall and Navarro's contention that the definition of overnight costs exclude inflation is incorrect.

The results on size effects are diverse. In Mooz's regression, the size coefficient is insignificant. Paik and Schriver do not use costs per kW, so their results cannot be used to test for economies of scale. Komanoff finds evidence of slight economies of scale, taking into account construction time-interest effects but not construction time-overnight cost effects. Cantor and Hewlett find evidence of slight diseconomies of scale, taking into account construction time-overnight cost effects, but not construction time interest effects. Zimmerman finds evidence of modest economies of scale, but the coefficient is only marginally significant. Using opening-date overnight costs, both Marshall and Navarro (1991) and McCabe (1996) find no evidence of economies of scale, but Canterbery et al. (1996) find a strong size effect reducing cost. It seems reasonable to conclude that few if any scale economies existed in nuclear plant construction in the 1970s and 1980s to confound the identification of learning effects.

4.7.5. Region

All of the studies included some measure to control for region. Utilities building in different regions face different input costs and different inflation rates. Komanoff, Cantor and Hewlett, and McCabe used the Handy-Whitman index to control for regional differences in cost of living. Other studies do not mention such adjustments. All of the studies include a variable in their regressions to account for different input prices. Studies often note construction labor as a major input that varies significantly in cost across regions. Construction wage rates "are generally about 5 percent higher in the Northeast than in the Midwest and 25 percent higher than in the Southeast" (Komanoff 1981, p. 199). Another potential source of regional cost differences is difficulty finding a site. For example, in the Pacific region, builders have had to consider seismic potential, while developers in the densely-populated Northeast have had to find a site sufficiently far from urban centers.

Table 4-5 shows the results of the studies. The first four (Mooz through Zimmerman), use regional dummy variables. These four studies found that plants built in the Northeast cost more than plants built elsewhere. Komanoff, for example, found that plants built in the Northeast were "28 percent more expensive, on average, than plants in other regions" (Komanoff 1981, p. 199). The last two studies, Cantor and Hewlett's and McCabe's, do not use regional dummies, but their regressions confirm that differences in construction labor costs account for a good deal of cost differences. Both Cantor and Hewlett and McCabe found that regional wage rate correlated with plant cost at 95 percent significance (Cantor and Hewlett 1988, p. 326; McCabe 1996, p. 371). Altogether, plants built in the Northeast were more expensive than plants built elsewhere, to a large extent a result of construction wage rates.

Table 4-5: Regional Cost Differences

Study	Number of Regions Controlled For	Independent Variable	Findings
Mooz (1979)	5	Dummy	Northeast 38.8 percent more expensive than other regions
Paik and Schriver (1979)	4	Dummy	South 21.3 percent cheaper, Mountain 23 percent cheaper than Northeast and Central
Komanoff (1981)	3	Dummy	Northeast 28 percent more expensive than other regions
Zimmerman (1982)	5	Dummy	Midwest 28.1 percent, South 30.2 percent, Mountain/Texas 39.3 percent, Pacific 14.8 percent less expensive than Northeast
Cantor and Hewlett (1988)	50	Construction labor wage rate in state where plant is located	Labor wage rate by state correlated with plant costs per kW at 95 percent significance
McCabe (1996)	4	Average union wage rate in BLS region	Average wage rate by region correlated with costs per kW plant at 95 percent significance

4.8. Forgetting and Knowledge Depreciation

Organizational forgetting (or alternatively, knowledge depreciation) occurs when knowledge is lost during a break in production. Argote and Epple (1990) note: "Knowledge could depreciate because individual employees forget how to perform their tasks or because individuals leave the organization and are replaced by others with less experience" (Argote and Epple 1990, p. 922). The concept of organizational forgetting is relevant to the present study because of both the long-term hiatus in nuclear construction in the United States and the potential for short-term interruptions should construction resume.

Argote and Epple summarize the literature on knowledge depreciation in manufacturing; none specific to construction was found. They cite one study in which unit costs were higher after a break such as a strike, and another study that found "recent output rates may be a more important predictor of current production than cumulative output" (Argote and Epple 1990, p. 921). Argote and Epple also cite Lockheed's experience with the L-1011 Tri-Star as an example of knowledge depreciation: after a period of low production of the Tri-Star, Lockheed's costs were higher than when production first began.

Knowledge depreciation is relevant to near-term nuclear construction in the United States in so far as recent experience from overseas plant construction is not perfectly transferable. If the overseas experience were not transferable at all, the only experience the U.S. industry possesses would be from 1970s-1980s era construction. No literature was found on international transfer of construction learning. Knowledge depreciation also should be considered when projecting future learning rates: if construction is sporadic, learning effects will suffer.

4.9. Conclusion

The evidence from international nuclear construction implies that standardization increases learning effects. The evidence from U.S. nuclear construction history, especially when compared with overseas construction, implies that unpredictable regulation reduces potential for learning. Moreover, the literature on knowledge deprecation implies that construction stoppages impair learning by doing. The extent to which the U.S. nuclear construction industry is competitive is especially important: the significant difference between in-house and agent-managed learning rates implies that incentives to reduce costs (as from competition) are a catalyst for learning by doing to exist—or at least affect where the savings go.

Based on the literature with its mixed results and the considerations of Chapter 3, a reasonable range for future learning rates in the United States nuclear industry is 3 to 10 percent. The upper part of this range is reasonable if nuclear plants are standardized, if the regulatory environment is stable, if the nuclear plant construction industry is competitive, and if engineering teams and construction crews are kept more or less continuously employed. The lower part of the range is more reasonable if the number of units that can be built at a single site is limited, and construction across sites is discontinuous.

In light of the empirical evidence, a conservative learning rate is 3 percent. It is appropriate for a scenario in which regional demand for new capacity is sufficiently saturated that only a single new 1,000 MW reactor could be built at a facility. Orders are spaced apart by a year or more, allowing engineering teams and construction crews to be reassigned. Orders are allocated among several types of reactor, spreading experience across different technologies. Some construction delays allow dispersal of personnel. The structure of the construction market lets construction firms retain a large proportion of cost savings from learning as profits rather than passing them on to the buyers.

A medium learning rate is 5 percent. It is appropriate for a scenario featuring more or less continuous construction, but not necessarily many cases of sequential units built at a single facility. A narrower array of reactor designs would be built, and competition in the construction industry would cause more of the cost reductions from learning to be passed on to buyers. Construction delays would be uncommon.

An aggressive learning rate would be 10 percent. A continuous stream of orders would keep engineering teams and construction crews together and there would be more instances of building multiple reactors at the same site. Several reactor designs might be deployed, but each in sufficient numbers to obtain maximal learning among all parties, from manufacturing through engineering and construction. Regulation would streamline construction times, and delays would be largely eliminated.

Table 4-6 summarizes the conditions associated with different learning rates.

Table 4-6: Conditions Associated With Alternative Learning Rates

Learning Rate (Percent for Doubling Plants Built)	Pace of Reactor Orders	Number of Reactors Built at a Single Site	Construction Market	Reactor Design Standardization	Regulation Impacts
3	Spread apart 1 year or more	Capacity saturated, no multiple units	Not highly competitive; can retain savings from learning	Not highly standardized	Some construction delays
5	Somewhat more continuous construction	Somewhat greater demand for new capacity; multiple units still uncommon	More competitive; most cost reductions from learning passed on to buyers	Narrower array of designs	Delays uncommon
10	Continuous construction	High capacity demand growth; multiple units common	Highly competitive; all cost reductions passed on	Several designs; sufficient orders for each to achieve standardization learning effects	Construction time reduced and delays largely eliminated

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Chapter 5. FINANCING ISSUES

Summary

As a prelude to considering energy scenarios for the future, which will be the capstone of the study in Chapters 9 and 10, this chapter develops the basic financial model used to analyze nuclear energy economic viability. Features of the U.S. tax system are introduced. Risk is considered in some depth. To provide a benchmark for the energy scenarios for the future that will contemplate alternative nuclear energy policies, the model is used to estimate the sensitivity of economic viability to uncertainties in the no-policy case.

Taxes

Recognition that nuclear energy plants will be owned and operated by utilities or other private providers requires introducing tax treatment of debt and equity, deduction of depreciation from taxable income with effects of different allowed depreciation schedules, effects of special tax provisions, and effects of inflation on taxes.

Risk

The perceived risk of investments in new nuclear facilities is widely appreciated to contribute to the risk premium on any new nuclear construction. Principal sources of risk are the possibilities that new plants will exceed original cost estimates and that construction delays will escalate costs. In this chapter guidelines from the corporate finance literature are used to specify likely relationships between project risk and risk premiums for corporate bonds and equity capital. Risk premiums have an important influence on the economic competitiveness of nuclear energy. A 3 percent risk premium is used for the first few plants.

No-Policy Scenarios

In using the financial model to study sensitivity to uncertainties, an overnight cost range for new nuclear plants of $1,200 to $1,800 per kW is used, based partly on the three technologies discussed as being realistic in Chapter 3. Given the capital cost range, the LCOE of new nuclear plants in the absence of policies is from $53 to $71 per MWh, with a 7-year construction time. The range is lower at $47 to $62 per MWh with a 5-year construction time. Costs remain outside the range of competitiveness with coal and gas, which have LCOEs of $33 to $41 per MWh and $35 to $45 per MWh, respectively.

The nuclear LCOE for the most favorable case, $47 per MWh, is close but still above the highest coal cost of $41 per MWh and gas cost of $45 per MWh. Longer debt terms and longer plant life span reduce nuclear LCOEs, but still do not bring them into the competitive range. The impact of construction delays is large, particularly if a 2-year delay occurs after all outlays have been made—capable of making the nuclear LCOE range from $61 to over $76 per MWh. These no-policy results provide benchmarks indicating the extent to which policies to be considered in Chapters 9 and 10 are needed to reduce nuclear LCOEs.

Outline

5.1. Introduction

To ascertain the conditions under which nuclear power will be competitive in the marketplace requires a financial model of private sector decisions. The required model is more elaborate than the LCOE model of Chapter 1 used to compare LCOEs in previous studies, because of tax considerations omitted there. Within the required financial model, careful attention is paid to rates of return on debt and equity that investors will demand in view of market perceptions of the riskiness of nuclear power investments. Introducing these considerations permits estimation of the cost of electricity that will have to be covered by revenues of operators of new nuclear facilities if these facilities are to be viewed by the private sector as warranted investments. These costs in the no-policy case are the starting point for considering policies that would make nuclear power competitive.

Section 5.2 develops the financial model that will be used for policy analysis in the present study. Section 5.3 reviews the finance literature for guides to risk premia and capital structure to be expected for new nuclear facilities. Section 5.4 lays out baseline assumptions in the absence of policies aimed at the nuclear power industry and applies the financial model to arrive at LCOEs in the no-policy case. Sensitivities to the baseline assumptions are explored.

5.2. The Financial LCOE Model

5.2.1. Basic Equation

The levelized cost of electricity, or LCOE, is defined as the constant real price of electricity over the life of the plant that compensates debt and equity investors at their required rates of return. Interest on debt accrues during the construction period and debt holders are repaid with equal annual payments over the debt term. Equity holders invest during the construction period and receive profits after tax and debt payment over the plant life. The LCOE is the electricity price that yields the internal rate of return required by equity holders on the returns accruing to them.

Equity is considered, with debt as an expense, rather than treating them symmetrically as in the pre-tax LCOE model, because of the different tax treatment of debt and equity returns. LCOE is the electricity price that solves the following equation:

PRESENT VALUE OF EQUITY INVESTMENT DURING THE CONSTRUCTION PERIOD

= PRESENT VALUE OF NET REVENUE EARNED BY EQUITY OVER THE LIFE OF THE PLANT

where

NET REVENUE = EARNINGS FROM LCOE REVENUE BEFORE INTEREST AND TAXES (EBIT)

– INTEREST EXPENSE – TAX EXPENSE + DEPRECIATION – REPAYMENT OF DEBT

Annual gross revenue equals the quantity of electricity generated multiplied by its price. Revenue in each year t is calculated as annual electricity production multiplied by the nominal electricity price in year t: $R_t = Q_t L_t$. Electricity production is calculated as plant capacity in megawatts (W) times the capacity factor (CF), times the number of hours in the year: $Q_t = W \cdot 8760 \cdot CF_t$. The nominal electricity price (L_t) in year t is the levelized cost of electricity (LCOE) in 2003 prices compounded at the rate of inflation from the year of the plant's opening, at time $t = 0$: $L_t = LCOE(1+\pi)^t$, where LCOE is the real price of electricity expressed in 2003 dollars, and π is the annual inflation rate.

The expenses consist of yearly fuel cycle costs described in Appendix A5, plus other yearly variable and fixed operating and maintenance costs and insurance as described in Section 1.4, plus decommissioning costs. The expenses are assumed to grow at the rate of inflation.

The spreadsheet model uses the GoalSeek function of Excel to solve the equation iteratively for LCOE.

5.2.2. Capital Investment

Overnight cost is the real dollar capital cost at the beginning of the construction period and is allocated equally to each year of the construction period. To accommodate the features of the tax system in this model, it is necessary to allow for inflation, so the real capital cost must be converted into nominal dollars over the life of the plant. Accordingly, the nominal outflow in each year of the construction period, recorded as negative revenue prior to the beginning of electricity sales, is:

$$I_t = C \cdot (1/n) \cdot (1 + \pi)^t,$$

where C is real overnight cost expressed in 2003 dollars, n is total construction time in years, I_t is the nominal investment in construction year t, where construction is from $t = -n$ to $t = -1$. Investment is assumed to occur at the beginning of a calendar year.

5.2.3. Interest

Interest costs are deductible against the corporate income tax. They are affected by risk considerations, which will be analyzed, and by loan guarantees, which is one of the financial policies that will be considered.

5.2.4. Taxes

Corporate income tax payments as well as state and local taxes are subtracted from revenues. As discussed more fully below, taxes give rise to depreciation allowances. Moreover, the policies aimed at the nuclear power industry to be considered in this study operate through affecting tax expense. These policies include investment tax credits, production tax credits, and accelerated depreciation.

5.2.5. Depreciation

Depreciation only becomes effective in an LCOE calculation when taxes are considered, because it is an allowance in the tax code that permits subtraction of an amount of capital expense from a year's taxable income. With no taxes, the only requirement is to recover the capital cost over the life of the plant. The life of the plant matters, but the time path at which the plant is assumed to depreciate is irrelevant.

A percent of the depreciable asset base can be deducted from gross income each year. Depreciation begins as the plant starts to operate. Two schedules are employed in the model, the Modified Accelerated Cost Recovery System (MACRS) and Straight Line, to examine the impact of different depreciation methods on LCOE. The Modified Accelerated Cost Recovery System (MACRS) schedule is a 1986 modification of the Accelerated Cost Recovery System (ACRS), which was established by the Economic Recovery Tax Act of 1981. Both ACRS and MACRS represent a departure from previous depreciation rules which were closely allied to financial depreciation concepts that attempt to depreciate an asset over its economic lifetime. The federal tax code assigns a 15-year depreciation period to electric utility plants under MACRS (IRS 2002, p. 93). MACRS allows declining balance or straight-line depreciation for classes of assets that include power plants. Declining balance is used here.

The depreciable asset base is measured in nominal dollars at the time of disbursement. Consequently a lengthier construction period, or a delay at the end of a construction period, would reduce the depreciable asset base relative to overnight costs because inflation has more time to raise other prices. This effect reduces the real value of the allowable deduction from revenues and hence would reduce the value of the depreciation allowance. While inflation has offsetting effects on revenues from electricity sales and prices of fuels and O&M outlays, the effect on the depreciation is not neutral.

During the construction period, part of the financing comes from debt investors and the other from equity holders. According to accounting rules, interest on debt outstanding is capitalized and added to the depreciable asset base, so the total asset base consists of nominal debt investment, equity investment, and interest expenses during the construction period. The depreciable asset base excludes equity appreciation.

5.3. Theory and Evidence of Risk Premiums and Capital Structure

This section is concerned with risk associated with new nuclear plants. The purpose is to develop guidelines for returns on equity, returns on debt and debt-equity ratios, to be used in the financial modeling of the present study. Section 5.3.1 characterizes the risks facing investments in new nuclear plants. Section 5.3.2 reviews studies of effects of uncertainty on decisions to build nuclear plants. Section 5.3.3 deals with required return on equity, 5.3.4 with required returns on debt, and 5.3.5 with debt-equity ratios. Section 5.3.6 addresses the choice of debt maturity.

5.3.1. The Nature of Financial Risks Facing New Nuclear Plants

New plants built in the United States in the next decade will have designs that have never been built in the United States, which increases the construction risks perceived especially on the first few units. Construction overseas of these designs, or closely related ones, will reduce only a part of the construction risk perceived for U.S. construction.

New nuclear power plants are large because the additional size improves the economics of a plant's thermal properties. The large size of the investment can add to the risk premium, particularly when the effect of the additional capacity coming on line in a particular market is considered. Some new coal plants are the same size or larger, which will tend to raise their risk premiums, but even the larger coal plants are expected to take only an average of 4 years to build. The length of the construction period (5 to 7 years) can further add to perceived financial risk (Lesceour and Penz 1999, p. 13).

The regulatory process was a source of construction delays and cost overruns during the 1970s and 1980s. The recent combining of construction and operating licenses into a single step gives hope that construction delays and uncertainties encountered in the last generation of nuclear plants can be avoided in new construction, but in the absence of actual experience, there is a perception that nuclear plants are riskier than others, as discussed by Scully Capital (2002a, 2002b).

5.3.2. Previous Studies of the Decision to Build Nuclear Plants

The influence of risks on an investor's willingness to undertake a nuclear power investment depends on the source of the risk as well as the level. Pindyck (1993) uses a model with two types of uncertainty to calculate critical values of expected capital cost in nuclear power plants, that is, costs above which an investor will not undertake a project, or if the project has begun, will cancel it. One type of uncertainty is technical uncertainty; the other input is cost uncertainty. Technical uncertainty involves uncertainties in completing the project. These uncertainties become resolved over the implementation period of the project—they either show themselves to be innocuous, and the project is completed, or they prove to be insuperable, and the project is abandoned. These risks are largely diversifiable. The input cost uncertainties are largely or totally outside the control of the investor. Wage rates and costs of materials are determined in larger markets, and in the case of nuclear power projects, these uncertainties include the possibility of regulatory changes. Input cost risk is partly nondiversifiable, because the input prices will be correlated with overall economic activity. The greater is the degree of input cost risk, the lower is the critical value of the expected capital cost that determines the go/no-go decision. The higher are perceived technical risks, the higher is the expected capital cost that the investor will tolerate.

A simple investment rule, using a risk-free interest rate, gives a critical value of capital cost per kW. Converting the 1982 prices from Pindyck's Table 3 (p. 70) to 2003 prices reveals a range on critical capital cost values from a high of $2,448 to a low of $1,649.

Investment is assumed to go forward as long as expected capital costs do not exceed these values.

Pindyck's study assumes a price of electricity and, using a risk-free interest rate, determines the threshold price of capital above which an investor would not buy a nuclear power plant. In contrast, the approach of the present study assumes a required price for capital, and using a weighted average cost of capital that includes an interest premium, determines the price of electricity.

Sommers (1980), using a logit regression analysis of 113 utilities, found that greater uncertainties about nuclear capital costs and construction times lowered the probability that a utility would invest in a nuclear plant rather than a coal plant. Capital cost uncertainty had a stronger dampening effect on the likelihood of a utility's investing in a nuclear plant than did the relative capital cost of nuclear and coal investments.

While the Sommers study corroborates the importance of risk factors this study has identified, it focuses on the probability that an investor would undertake construction of a nuclear plant. In contrast, the present study addresses the incentives that would be required to induce investors to undertake construction.

5.3.3. Required Rates of Return on Equity

5.3.3.1. Traditional CAPM and Its Irrelevance to the Present Study

The most widely used model of equilibrium equity asset pricing remains the capital asset pricing model (CAPM) of Sharpe (1964), Lintner (1965) and Black (1972) and Mossin (1966). The central implication of the CAPM is that expected returns for each asset (let this be r_i for asset i) should bear a linear relationship with the expected returns of the market as a whole. The CAPM equation is $r_i = r_f + \beta_i (r_m - r_f)$, where β_i is a measure of co-movement of each firm with the market. Expected stock returns are higher for firms with high correlations with the market return. Investors demand a premium for holding stocks which are highly correlated with the market, that is, for holding non-diversifiable or systematic risk. A model very similar to the CAPM is a consumption-based capital asset pricing model (CCAPM). This model suggests that expected asset returns have a linear relationship with overall marginal utility of consumption as determined by performance of the economy at large. Though there have been other theories of equilibrium asset pricing, CAPM and CCAPM are still most prevalently used. CAPM has become a central tool of financial analysis in the finance industry (see for example Graham and Harvey (2001) who find that firms rely heavily upon CAPM techniques).

CAPM and CCAPM do not include an effect of own variance of asset returns, a property often considered to be counter-intuitive. The reason for lack of effect of own variance is brought out in the Markowitz (1959) portfolio selection model (a building block of CAPM). Investors can completely rid themselves of any assets' idiosyncratic risk by diversifying, through the holding of a market basket containing essentially an infinite number of securities. Since total market risk cannot be diversified away, only the correlation of securities returns with the market remain as a determinant of a security's value.

The evidence of the empirical validity of CAPM is mixed at best. Representative studies are Black, Jensen, and Scholes (1972), Fama and MacBeth (1973) who found limited success for CAPM over some years, and Fama and French (1992) who find no evidence at all for the CAPM. Banz (1981), Chan and Chen (1991), Stattman (1980) and Rosenberg et al. (1985) find that other factors besides CAPM beta help to explain equity returns, contrary to the central tenant of CAPM. The industry has continued to use the CAPM as a central tool in financial analysis, probably due to 1) its theoretical attractiveness, 2) its easy applicability using easily accessed data 3) lack of a better alternative and 4) its widespread base of understanding among forty years of MBA graduates.

A fundamental point for the present study is that new nuclear plant risk is idiosyncratic and not market risk. The risks involve events that are specific to a nuclear plant and have no expected correlation with overall market events. Thus, according to strict CAPM theory nuclear plant risk should have no effect on investors' valuation of the firm, and thus no effect on the required rate of return on equity for a firm building a nuclear plant.

5.3.3.2. Idiosyncratic Risk

Notwithstanding CAPM theory, own variance (the variance of a stock's returns) and idiosyncratic risk (the standard deviation of the error term from a regression of firm returns on the market over time) are also sometimes tested used as determinants of expected stock returns, such as in Douglas (1969). These measures fell out of favor in the face of the rapid acceptance of the CAPM and in light of alternative explanations for why own-variance effects may falsely appear to explain asset returns, such as is described by Miller and Scholes (1972) and tested by Fama and MacBeth (1973) and Roll and Ross (1980). However, idiosyncratic measures of risk have recently become a focus of renewed attention.

More recent papers, Tolley and Nielson (1992) and Nielson (1993), have reexamined this effect and have found support for own variance, both theoretically and empirically. Using techniques similar to Fama and French (1992), Nielson (1993) finds that own variance indeed explains some of the cross-variation in expected stock returns. Nielson also supports the size and the book to market (B/M) effects discussed above, but finds evidence that these may be proxies for the own variance effect. For a further contribution and references to other recent studies where own variance affects returns, see Tolley and Nielson (2003).

5.3.3.3. Previous Studies of Nuclear Power Equity Returns

Some papers have addressed the financing of nuclear plants specifically. However, these studies are for facilities built in the 1970s and 1980s in an environment which may not be similar to plants in the future. Most importantly these studies were done when the plants were fully operational, after they had been completed. Therefore they have little if any bearing on uncertainty about prospective construction costs for a plant with new technology not yet built or for regulatory uncertainty surrounding the decision to build a plant, which are risks of concern the present study. Farber (1991) studied the effect of adopting nuclear technology on equity costs of electric utilities prior to the Three Mile Island (TMI) accident. Farber studied the effects on equity returns of thirty-six nuclear power adopters and twenty-five non-nuclear firms. He concluded that adoption of a nuclear plant increases a firm's CAPM equity beta. In addition, he concluded that the leniency of regulators may moderate the risk-increasing effect of nuclear power. Brooks and D'Souza (1982), Bowen et al. (1983), and Fraser and Kolari (1983) found that the TMI accident appeared to increase the expected beta risks of four utilities owning nuclear capacity, although Uselton et al. (1986) subsequently found the effect to be transitory.

Hearth et al. (1990) examine the effect on stock prices of cancellations of nuclear power plants. The authors found that decisions to cancel nuclear power plants under construction appeared to result in significant negative excess stock returns. This loss was found to be bigger with the ratio of the sunk costs relative to the utility's market value. Kalra et al. (1993) measure the U.S. stock market reaction to the April 1986 nuclear Chernobyl power plant accident. The authors found that after the Chernobyl event the betas for all power utilities (conventional, mixed and nuclear) rose.

Fuller et al. (1990) studied the reaction of financing environment of three special events: Three Mile Island accident, the Chernobyl catastrophe and the Washington Public Power Supply System bond default. Based upon the authors' cross-sectional analysis it was estimated that a 3 percent increase in the allowed rate of return for nuclear utilities would have been required to offset the discount associated with nuclear power.

Hill and Schneeweis (1983) use stock price data to study the effect on the stock returns of public utility firms of the TMI nuclear accident. The authors find that impact of the Three Mile Island accident on non-nuclear electrical utility firms was less than that on nuclear based utilities. Hewlett (1984) found that investors in nuclear firms required a 1 to 2 percent risk premium.

As noted, since these studies refer to utilities that already had nuclear plants, refer to a past regulatory environment, and in some cases rely on estimates of beta no longer accepted in the literature, they are at best suggestive and in any case give little if any help in choosing a required rate of return applicable to a firm that will build a new nuclear plant in the future.

5.3.4. Required Rates of Returns on Corporate Bonds

The academic literature generally assumes (see Elton et al., 2001) corporate debt carries the same rate of return as U.S. Treasury Bonds plus a premium. The premium is comprised of three parts 1) a premium for expected default risk, 2) a state tax premium (as income from corporate bonds is taxed and Treasuries are not), and 3) a premium for attracting risk-averse investors.

Theoretical reduced-form models explaining risky bond prices (and therefore expected returns) include Duffie and Singleton (1997), Jarrow et al. (1997), Lando (1997), Das and Tufano (1996) and Madan and Unal (1998). Option-based models stemming from the Black-Scholes (1973) option pricing formula are found in Merton (1997), Longstaff and Schwartz (1995), Galai and Masulis (1976), and Jones and Rosenfeld (1984).

The academic studies attempting to empirically explain corporate bond rates are sparser than for equities. Elton et al. (2001) find that most of the third part (risk aversion factor) is responsible for most of the bond premium, and that expected default premium is responsible for the least. Barrett et al. (1986) find a decrease in utility bond prices as a reaction to the 1979 Three Mile Island nuclear power plant accident.

Bond rating firms, most notably Standard and Poor's and Moody, appear essentially to evaluate default probability. Recent corporate bond yields were (from Moody, November 2003, twenty-year maturities) 5.54 percent for the AAA rated bond, 5.88 percent for the AA grade bonds, 6.03 for the A rated bonds and 6.59 percent for the Baa grade bonds. For comparison, the yields on twenty-year U.S. Treasury bonds during the same period were about 5.1 percent.

Altman and Kishore (1998) find the following percentages of par recovery rates one month after firms declare bankruptcy by grades of debt : AAA have about 68 percent rates of recovery, AA and A have about sixty percent, BBB bonds have about 49 percent, BB 39 percent, B and CCC 38 percent, and default have zero percent recovery rates.

5.3.5. Debt-to-Equity Ratios

The finance literature on the determinants of the debt-equity ratio is mixed. A starting point is the Modigliani and Miller (1958) study showing that under certain assumptions the debt-equity ratio is irrelevant. Current opinion is split between two main competing theories, neither of which is completely convincing in light of empirical tests. First, the static trade-off model proposes that firms have a target debt-equity ratio. In this model, debt has certain advantages: debt possibly lowers taxes, increases monitoring of management and motivates management. These advantages are weighed against debt's drawbacks, as noted in Jensen and Meckling (1976) and Myers (1977): possibly higher expected bankruptcy costs and higher costs due to agency problems.

The main competing theory is the Myers (1984) and Myers and Majluf (1984) pecking order theory. Here, asymmetric information and transactions costs drive firms to finance operations in the following order 1) retained earnings, 2) safe debt, 3) somewhat riskier debt and finally 4) riskier debt and equity. Once again, equity is more expensive due to asymmetric information: management knows more about firm outcomes than outside financiers who will, sometimes, be induced to buy over-priced equity. That is, equity will be over-priced due to asymmetric information, management knows that current shares are over-priced, reducing debt.

Much of the empirical work of an academic nature related to debt-equity ratios does not focus on risk. Work which does speak to risk generally finds a small role for risk in capital structure. See for example, Marsh (1982), Ghosh et al. (2000), Kale et al. (1991) and Fama and French (2003).

There is an on-going debate on whether industry-specific effects on debt-equity ratios exist. Schwartz and Aronson (1967), Scott (1972), Scott and Martin (1975), Bowen et al. (1982), Martin and Henderson (1984) and Bradley et al. (1984), Hull (1999), and Sibley (1999) find inter-industry differences in debt equity ratios. Remmers et al. (1974), Belkaoui (1975), and Sekely and Collins (1988) all fail to find evidence of differences in debt-equity across industries. Graham and Harvey (2001) surveyed 392 CFOs regarding their use of financial tools and targets. The responses indicated that if firms do have leverage targets, those targets are quite soft.

5.3.6. Debt Maturity

Multiple factors influence corporate borrowers' and lenders' choice of debt maturities. Moreover, debt maturity, debt-equity ratio and risk premium are interrelated. A number of models relate risk and capital structure to maturity choice, but no comprehensive model of all three choices has been found. The first sub-section (5.3.6.1) places maturity choice within the general context of the term structure of interest rates. The second sub-section (5.3.6.2) addresses informational asymmetry problems that may pose important risks in financing new nuclear power plants. The third sub-section (5.3.6.3) deals with the influence of other risks on maturity choice, and the fourth (5.3.6.4) discusses the influences of transaction costs and taxes. The fifth sub-section (5.3.6.5) addresses interactions between choices of debt maturity and capital structure. The sixth sub-section (5.3.6.6) reviews empirical evidence on risk and debt maturity. The final sub-section (5.3.6.7) summarizes.

5.3.6.1. Term Structure

The term structure of interest rates underlies debt maturity choices. An important consideration is the slope of the term structure, i.e., rate of rise of interest rates that must be paid as maturity length increases. Empirical evidence has shown that firms take into account the relative cost of short- and long-maturity bonds when issuing debt (Barclay and Smith 1995, Guedes and Opler 1996, Stohs and Mauer 1996, Graham and Harvey 2001). Other things being equal, firms gravitate to shorter maturity instruments when term structure slopes are steep, and toward long term instruments when slopes are shallow or negative. However, the slope of the term structure is clearly not the only determinant of maturity choice as the following sub-sections bring out.

5.3.6.2. Influences of Asymmetric Information on Debt Maturity Choice

When a lender either cannot assess the accuracy of a borrower's information regarding a project, or when a lender cannot easily monitor the actions that a borrower agrees to undertake as part of a loan contract, asymmetric information problems exist. One problem is signaling. Another is the principal-agent, or agency, problem. Both problems are amenable to sorting solutions. Lenders devise a menu of debt maturities and interest rates that would leave them equally well off and let borrowers reveal their private information by selecting a particular combination that best serves their own interests.

In the signaling problem with private information, lenders cannot easily assess the accuracy of information borrowers provide. This situation occurs for construction cost estimates for new nuclear power plants. As the Scully report (2001a) brought out, one concern of investors is that vendors' cost estimates may not be borne out. Modeling of this problem suggests that borrowers with prospects that are unobservable to lenders choose short-term debt due to bond holders' fears that the firm may have poor prospects and consequently would be willing to give low rates only for short term bonds (Flannery 1986; Kale and Noe 1990; Rousseau 1999; Diamond 1991, 1993; Diamond and Rajan 2001; Berger et al. 2003). Firms with good prospects that are observable only to management sell short-term bonds because management knows that after its prospects are recognized as good by lenders, the firm can then re-finance at lower rates. Barclay and Smith (1995) find evidence that firms use debt maturity to signal information and firms with larger information asymmetries issue shorter term debt, and Benmelech (2003) finds evidence that firms with more salable, or redeployable, assets have longer debt maturities, implying a possible signaling with maturity. Antoniou et al. (2002) find no association of debt maturity with firm quality among French and German firms, which they suspect is due to those countries' legal structures, and modest support for signaling with maturity among U.K. firms. Bali and Skinner (2003) find evidence that higher project risk leads to shorter maturity.

In a well-known financial agency problem (Jensen and Meckling 1976; Myers 1977), firms that are recognized as having opportunities to transfer wealth from bondholders to equity holders by increasing the riskiness of their operations during the term of the contract, can signal their willingness to forego such opportunities by selling debt at the shorter end of the maturity spectrum. In the case of a loan on a nuclear power plant, where agency costs could exist is in ensuring construction quality. As part of the regulatory process, the utility must specify the characteristics of the plant in considerable detail. The U.S. Nuclear Regulatory Commission (NRC) reviews the plans, and under the revised 10 CFR 52, will issue a combined construction and operating license. Permission to operate is subject to confirmation that the actual construction conforms to plans. This supervisory function of NRC serves at least partially to assure the lender that the borrowing utility is performing according to contract. From the lender's perspective, if the construction is not performed in accordance with the contract, which would be determined by NRC inspections, the borrower would incur additional construction costs, possibly jeopardizing the repayment of the loan. A utility could signal its belief that its construction quality will meet NRC's standards by taking a shorter maturity loan.

5.3.6.3. Effects of Non-Informational Risks on Debt Maturity Choice

Liquidity risks tend to push debt maturities to the long end of the spectrum. A temporary problem could force issuers to refinance at unattractive rates. If bad news about a borrower arrives near the refinancing date, investors would raise the default premium on new debt. Firms with projects that could experience temporary problems will be motivated to hold longer-term debt, so as to face the debt renewal less frequently (Johnson 1967, Flannery 1986, Diamond 1991).

Some firms will want to match maturities of their liabilities and their assets. This motivation would be stronger when transactions costs and liquidity risks are higher (Mitchell 1991, Sarkar 1999). A bond would mature at the date an asset is to be sold or begin generating positive cash flow, avoiding both the need to roll over shorter maturity bonds and the higher cost of longer term bonds. Morris (1976) finds that financing long-lived assets with short-maturity debt could decrease the uncertainty of net income if interest rates are positively correlated with net operating income.

5.3.6.4. Transactions Costs and Taxes

Small debt issues have proportionally higher transactions costs than large issues. Large firms, such as those likely to build new nuclear power plants, would tend to choose shorter term debt to take advantage of lower market rates at the shorter end of the term structure (Fisher et al. 1989). In general, long-term debt allows its holders greater flexibility in timing of capital gain and loss declarations, and this flexibility is an option having value. Firms can sell long-term bonds for relatively more than short term bonds if this tax-timing option is highly valued (Brick and Palmon 1992).

Interest rate volatility reduces the present value of debt tax shields from short-term financing, making long-term debt attractive when interest rates are volatile (Guedes and Opler 1996, Brick and Ravid 1985, 1991; Kim et al. 1995). If new nuclear plants reached financing stages during a period of volatile interest rates, borrowers could be expected to want longer debt maturities. Kane et al. (1985) model the tax advantage to debt, net of a market premium for added bankruptcy risk, adjusting maturity and the debt-equity ratio to maximize firm value including the tax shield, with the result that optimal maturity is negatively associated with the tax advantage of debt. As the value of a tax shield falls, the debt-equity ratio falls and maturity lengthens. Policies that reduced tax obligations on new nuclear plants could increase the value of longer maturities.

5.3.6.5. Interactions between Choices of Debt Maturity and Capital Structure

To the extent that risks are affected by both debt-equity ratios and debt maturity, the two choices will be made simultaneously. For example, in a world of agency problems, should the debt-equity ratio be so low that bankruptcy is almost impossible, the incentive to lower debt maturity as a signal would disappear and the firm would move to a longer maturity. In this way there is a trade-off between debt-equity ratio and debt maturity (Lee et al. 1983, Diamond 1991, Leland and Toft 1996, Elyasiani et al. 2002, Ju and Ou-Yang 2003).

5.3.6.6. Empirical Evidence on Relationships between Risk and Debt Maturity

Stohs and Mauer (1996) find that larger and less risky firms with longer-term asset maturities use longer-term debt, debt maturity varies inversely with earnings surprises and a firm's effective tax rate, and firms with high and very low bond ratings use short-term debt. Guedes and Opler (1996) find that large firms with high credit ratings tend to borrow at very short and very long terms, while low rated firms borrow at the middle of the spectrum, which they suggest is consistent with a trade-off between liquidity and agency effects.

5.3.6.7. Conclusions on Debt Maturity

Debt maturity is influenced by both project and firm characteristics. The choice of maturity involves a trade-off with interest rates and the debt-equity ratio. Informational uncertainties tend to encourage shorter-term debt. Firms financing assets that are either riskier or perceived to be riskier typically find some advantage to borrowing at shorter maturities, other influences being equal. Tax considerations and the correlation of a firm's income with economy-wide indicators such as interest rates or a stock market index also can influence maturity choice. The debt-equity ratio and maturity tend to move in opposite directions in the valuation of tax shields. A judgmental conclusion is that the various influences, on net, work against choice of highly lengthy maturities in the financing of new nuclear power plants.

5.3.7. Conclusions on Financial Effects of New Nuclear Plant Risk

Most of the finance literature on equity returns, bond returns and debt-equity ratios has dealt with a large number of considerations, with risk as such being considered if at all as only one consideration. The bottom line is that no readily identifiable - much less empirically verifiable - estimate of the effects of a new nuclear plant on a firm's finances is available from the literature. A strand running through the work reviewed is that with judicious relaxation of the stringent assumptions of traditional finance theory there could be an effect of own risk. It should be noted that, apart from academic investigation, received opinion of practitioners is that these effects exist both for equity and debt returns. The literature does, however, suggest relatively shorter debt terms for investments with the characteristics of new nuclear plants. The foregoing considerations inform the judgmental choices of financial effects of new nuclear plants to be used in the financial modeling of the present study.

5.4. No-Policy Scenario Analyses of LCOEs

Section 5.4.1 reviews the characteristics of nuclear and fossil plants that contribute to their relative economic advantages. Section 5.4.2 reports the values of cost and performance and market variables used in the LCOE calculations in the benchmark no-policy case. Sections 5.4.3 and 5.4.4 discuss the use of these variables in sensitivity and scenario analysis.

5.4.1. Nuclear versus Fossil Plants: Economic Advantages and Disadvantages

Nuclear power has several advantageous economic characteristics, but also suffers from a number of disadvantageous characteristics as perceived by investors, as summarized by LaBar (2002). Advantageous economic characteristics are as follows:

- Low and predictable fuel and operation and maintenance (O&M) production costs. Nuclear production costs exhibit low volatility over both the short and long term because the primary energy source, uranium ore, represents a very small fraction of the total production cost. On the other hand, the cost of the primary energy source in fossil-fired plants is a large fraction of the production cost.

- High capacity factors. The operating nuclear plants in the United States now consistently achieve fleet-average capacity factors in the 90 percent range. The projected lifetime averaged capacity factors for competing baseload gas-fired combined cycle plants are in the range of 80 to 85 percent.

- Long Operating Lifetime. Operating lifetime licensing extensions have been obtained for several U.S. nuclear plants and more are expected in the future. New nuclear plants are being designed for a 60-year life. On the other hand, there is little experience in the long-term operation of competing baseload gas-fired combined cycle plants. Nominal gas-fired combined cycle plant lifetimes are not expected to exceed 25 years.

Disadvantageous economic characteristics of nuclear power are:

- Large plant size. Most new nuclear power plants are designed in the size range of 1,000 to 1,350 MW to gain economy of scale benefits and reduce the capital costs per kW. A drawback of this size range is high potential for exceeding demand growth. Widely used baseload gas-fired combined cycle plants are in the range of 500 to 600 MW.

- Large capital outlay. Total overnight capital costs of new nuclear plants are estimated to be in the $1,000 to $1,800 per kW cost range. For a 1,350 MW plant at $1,600 per kW, an investment of $2.16 billion can be required, excluding interest costs. The competing baseload gas-fired combined cycle plant capital cost is in the $450 to $650 per kW range. A 600 MW combined cycle plant at $650 per kW would require an investment of less than $0.4 billion.

- Long construction time. The construction time for new nuclear plants, even if optimized to achieve short construction times, is in the range of 3 to 4 years. The construction period for competing gas-fired combined cycle plant is about 2 years.

- Investment financing. The higher capital cost results in a higher total investment at risk and the longer construction time results in higher interest costs during construction as well as longer time-at-risk. These factors contribute to required returns on equity and debt.

The investment-financing hurdle may become easier to overcome as nuclear plant ownership has become increasingly concentrated. Twelve utilities, plus Tennessee Valley Authority (TVA), now own and operate nearly two-thirds of plants. The larger owners, now with 75 percent of U.S. capacity, are able to manage a portfolio of units. They can consider financing new units based on a larger balance sheet of total asset value. In addition, stock prices of nuclear utilities have recently outperformed non-nuclear utilities (Scully Capital 2002). Thirteen utilities account for 75 of the 103 nuclear plants and all of them are operating more than 2,000 MW of electrical capacity.

5.4.2. Parameter Values Used for the No-Policy Case

Table 5-1 identifies the parameter values used for the important parameters in calculations of LCOEs under the assumption that no policies are employed.

The three capital costs correspond to four nuclear plant designs, each with its own overnight cost, selected for analysis, as already discussed in Section 3.4. To review, one design is a mature plant, the FOAKE costs on which have already been paid. The ABWR and ACR-700 are such designs. Their overnight cost is assigned a value of $1,200 per kW. Another design is a plant that has not yet been built, the FOAKE costs on which are yet to be paid, such as the AP1000. On the assumption that the entire FOAKE cost is assigned to the first plant, this plant’s cost is $1,500 per kW. The third capital cost is chosen to represent the Framatome reactor under consideration for construction in Finland. Its overnight cost is $1,800 per kW.

Table 5-1: Parameter Values for No-Policy Nuclear LCOE Calculations

Item	Parameter Value
Overnight Capital Cost	$1,200 per kW $1,500 per kW $1,800 per kW
Plant Life	40 years
Construction Time	7 years
Plant Size	1,000 MW
Capacity Factor	85 percent
Hours per Year	8,760 hours
Cost of Debt	10 percent
Cost of Equity	15 percent
Debt Term	15 years
Depreciation Term	15 years
Depreciation Schedule	MACRS[a]
Debt Finance	50 percent
Equity Finance	50 percent
Tax Rate	38 percent
Nuclear Fuel Cost	$4.35 per MWh
Nuclear Fixed O&M Cost	$60 per kW
Nuclear Variable O&M Cost	$2.10 per MWh
Nuclear Incremental Capital Expense	$210 per kW per year
Nuclear Decommissioning Cost	$350 million
Nuclear Waste Fee	$1 per MWh

[a]Modified Accelerated Cost Recovery System

5.4.2.1. Nuclear Construction Time

Nuclear construction projects are divided into several phases (DOE 2001a, pp. 13-16; DOE 2001b, pp.4-11 to 4-12). The start-up phase consists of early site permitting, design certification, plant licensing, site preparation, and procurement of long lead-time components such as pressure vessels and steam generators. Procurement continues during the construction phase. The final phase is start-up and testing. The stated DOE position of a 5-year construction schedule is based on the new streamlined regulatory policy. The base case in the present study is 7 years for anticipated construction time. This is the time period of major financial outlays prior to revenue generation from power sales. The business significance of this period is that it is a time of negative cash flow, during which interest costs accrue on expenditures. This duration is based on the assumption that the business community will form expectations taking account not only of the newer announced regulatory procedures but also of earlier experiences with construction times. The Scully interviews with financial and utility executives (Scully 2002a, p. 1-76), as well as anecdotal reports, reinforce the importance to the business community of expectations regarding construction time. Deutsche Bank's LCOE calculations for new nuclear power in the United States rely on a 7-year construction period (Smith and Hove 2003, Figure 66, p. 77).

Later policy scenarios in this study allow for revision of expectations from 7-year to 5-year construction times for later plants, based on more favorable than expected business outcomes with the first few plants. For simplicity, expenditures are assumed to occur equally in each year of construction. Experiments with more refined patterns of expenditures were found to be of little consequence.

It is important to recognize that the construction times used in the LCOE calculations are expected construction times, from which actual construction times may deviate. The profitability calculations that inform investment decisions are based on expected values of the variables in the LCOE formulation: sale prices of electricity, overnight cost, nuclear fuel costs, and O&M costs, as well as construction times. The influence of the expectation of the construction time on calculated LCOE is particularly important and has been of particular concern to the investment community. As noted above, the expectation of construction time for first plants will be heavily influenced by previous U.S. experience. However, new experience will give investors new data with which to update their expectations, and if construction times turn out to be the 5 years that DOE and vendors emphasize, investors will adjust their expectations accordingly.

5.4.2.2. Base Cost of Capital

The base cost of debt and equity to utilities was assessed from current Bloomberg's data (Bloomberg, Inc., 2004), adjusting for maturity and the currently abnormally low interest rates. The constituent firms of the Standard and Poor's 500 Utilities Index were used as the benchmark for the cost-of-debt and -equity calculations here because those data are widely used in gauging utility company performances. Individual data on weighted average costs (WAC) of debt and equity were taken for 37 of the largest utilities in the United States. Since Bloomberg reports the weighted average cost of debt post-tax, those numbers were converted to pre-tax with the formula WAC of Debt Before Tax = WAC of Debt After Tax / (1 – Effective Tax Rate). The effective tax rate for each utility is available from Bloomberg. The average WAC of debt for these utilities, adjusted to pre-tax basis, is 5.34 percent, and that for equity is 8.63 percent.

In its calculations of the costs of debt and equity for individual utilities, Bloomberg uses the 10-year U.S. Treasury bond as the risk-free rate, and adds its own debt and equity risk factors above that base rate. The 10-year generic government bond traded at 3.747 percent on the morning of March 15, 2004. The 30-year government bond traded at a spread of 1 percent above the 10-year rate, and the 15-year bond traded at 51 basis points above the 10-year bond. Thus, adjusting the Bloomberg capital cost estimates for a more appropriate maturity would add between .5 and 1 percentage point to the WACs of debt and equity reported in the previous paragraph.

The current bond yield is at a decadal low, as the Federal Reserve still holds the Federal Funds rate at 1 percent. These low rates are not expected to last long. It would be more appropriate to use an average of historical rates to smooth out the current aberration.

Using a 300-day moving average to smooth out the fluctuations in the yield on the generic 30-year government gives a return about 50 basis points above the current yield.

Thus the total adjustment to the base rates reported in Bloomberg, to account for term-structure and the currently low rates, is between 1 and 1.5 percentage points. These adjustments give a cost of equity between 9.64 and 10.13 percent and a cost of debt between 6.35 and 6.84 percent. For purposes of the present study, these capital cost estimates are rounded to 10 percent for equity and 7 percent for debt.

5.4.2.3. Risk Premium

While the finance literature has much to say about risk and bond and equity rates, it does not provide clear, quantitative guidance on the relationship between risk and interest rates, as the above review brings out. Many factors influence the relationship, and the subject is actively researched. Financial terms in recent nuclear construction overseas are not a satisfactory guide to a risk premium in the United States because of differences among countries in business practices, differences in business climate, varying degrees of involvement of governments in nuclear projects, and differences in regulatory regimes.

Themes in the above review are that nuclear plant risk is idiosyncratic (plant specific) rather than beta (market related) and that agreement is lacking on the effect of idiosyncratic risk on required returns. These considerations hinder estimation of the effect idiosyncratic risk as a variance concept. However, another and quite direct effect of nuclear plant risk is its effect on expected return. While risk leading to dispersion in possible future returns adds to variance, it also affects the expected returns if it is asymmetrical, as it is in the case of new nuclear plants. For the outcome where all goes according to plan, a normal projection of returns can be made. But the upside risk of favorable surprises is less than the downside risk from unforeseen delays and the like.

The investor maximizing expected returns will be indifferent between a security with normal market risk yielding a return of r and an investment with noticeable asymmetric downside risk yielding some higher return r_R, is needed to induce investors to hold the riskier security. The expected gross return for a security with normal market risk is 1+r, which provides for paying back the original dollar invested. Through security pricing, investors will make 1+r equal to the expected return on a security with asymmetric downside risk. The expected gross return on the security with asymmetric downside risk is the gross return on a dollar invested $1+r_R$ times the probability that the investment will be successful, plus the probability that it will be unsuccessful times the fraction of the dollar that will be recovered if unsuccessful, or $[p_S + (1 - p_S)f_L](1 + r_R)$ where p_S is the probability of a normal or successful outcome and f_L is the fraction of the dollar that will be recovered in the event of an unsuccessful outcome. Setting 1+r equal to $[p_S + (1 - p_S)f_L](1 + r_R)$ and re-arranging gives

$$1+r_R = (1+r)/ [p_S + (1-p_S)f_L].$$

Letting the risk premium be ρ, so that $r_R = r + \rho$ and solving for ρ gives

$$\rho = (1 + r)\{-1 + 1/[p_S + (1 - p_S)f_L]\}$$

which in the special case where nothing is recovered ($f_L = 0$), gives $\rho = (1+r)[(1-p_S)/p_S]$.

Table 5-2 below shows risk premiums for different combinations of probabilities of experiencing an unsuccessful outcome and extent of loss in the event of such an outcome. Each scenario uses a normal rate of return of 10 percent.

Table 5-2: Risk Premiums for Alternative Investment Losses and Loss Probabilities, $1\text{-}p_s$

Probability of Unsuccessful Outcome ($1\text{-}p_S$)	**Percent of Investment Value Recovered (f_L):**				
	50	**25**	**0**	**-25**	**-50**
1.00%	0.6%	0.8%	1.1%	1.4%	1.7%
2.00%	1.1%	1.7%	2.2%	2.8%	3.4%
2.50%	1.4%	2.1%	2.8%	3.5%	4.3%
3.00%	1.7%	2.5%	3.4%	4.3%	5.2%
3.50%	2.0%	3.0%	4.0%	5.0%	6.1%
4.00%	2.2%	3.4%	4.6%	5.8%	7.0%
5.00%	2.8%	4.3%	5.8%	7.3%	8.9%
6.00%	3.4%	5.2%	7.0%	8.9%	10.9%

Loss of 50 percent of the value of the investment, in the first column of Table 5-2, would represent a case in which the investor considers it plausible that construction delays or higher-than-expected component costs could cause the new plant's LCOE to be considerably higher than the best case. Overruns of this magnitude can occur if cost overruns involve capital costs, which are the most important component of nuclear power costs, or if delays occur that increase the carrying or interest cost before plants begin operation, which again is an important cost component. A loss in asset value would be incurred. The cost overruns could cause the borrower to default on the loan, leaving the lender to sell the plant for a price consistent with an LCOE of competing coal or baseload gas plants which could be half that of the nuclear plant. A similar scenario could account for column 2, in which 25 cents on the dollar are obtained. The 100 percent loss in column 3 (0 cents on the dollar) would be associated with the prospect of not being allowed to open the plant after it is built, despite the structure of the new regulatory system. In columns 4 and 5, the lender also considers the prospect of getting its bond rating downgraded, in addition to its losses on the project. The project losses in these cases would decrease the asset value of the firm more extensively than through loss of the direct investment. Each of the alternatives is a set of possible outcomes expected to occur with probability less than one, a set of possible losses with associated probabilities used by investors in assessing risks of equity and debt holding. These are possible losses, not actual losses.

Assuming that investors form consortia to spread their risks, the LCOE calculations in the present study use a risk premium of 3 percent. Such a risk premium is consistent with a 5.3 percent probability of the 50 percent loss (column 1 of Table 5-2), a 3.5 percent probability of the 75 percent loss (column 2), a 2.5 percent probability of the complete loss (column 3), and 2.1 and 1.8 percent probabilities of the losses to affiliated assets (columns 4 and 5). Informal conversations with a number of Wall Street analysts corroborated the reasonable magnitude of the 3 percent premium as a lower bound estimate.

5.4.2.4. Debt-to-Equity Ratio

Allowing for differences between market capitalization and book value, debt-equity ratios for the larger utilities in the United States currently average in the neighborhood of 50-50 (Bloomberg, Inc. 2004).

5.4.2.5. Utility Regulatory Status and Financial Risk

Regulation of electric utilities in the United States, which has included both rate-of-return and retail price regulation, has tended to shield utilities from market price risks, thus reducing their costs of capital (Joskow 1997; Hogan 2002). The Energy Policy Act of 1992, implemented with FERC Orders 888 and 889 in 1996, deregulated electricity wholesale markets. Presently 18 states and the District of Columbia are actively preparing to deregulate retail markets, and 10 other states have passed legislation to do so or are studying how to do so (PNNL 2004).

Evidence from both the United States and the U.K. suggests that the deregulation of the 1990s placed more of this risk on the firms, removing it from direct payment by consumers (Nwaeze 2000; Buckland and Fraser 2001). Whether the direct placement of risk on consumers or producers has a net negative or positive effect on retail prices appears to remain an open question. In the continued movement to further restructuring and retail deregulation, political and regulatory risks exist that tend to raise the hurdle rates for new generation investments in currently regulated states (Ishii and Yan 2004).

Under regulation, utilities occasionally faced the risk of having some portion of construction costs disallowed from their rate base. While rate-of-return regulation might prevent capital markets from charging risk premiums appropriate to such risks in new generation projects, both lenders and equity holders might decline to supply funds for projects with such risks without such compensation. It is not clear that the financial strength of a firm would have more influence than the characteristics of a project in the financial market's assessment of risk. While issuance of project bonds for a project perceived as risky by financial markets would incur a risk premium that senior debt for firm financing might avoid, the latter strategy could result in a general downgrading of the firm's debt, which could be more costly than the isolated project financing.

The full effects of deregulation and restructuring on capital costs for new generation capacity do not appear to be thoroughly understood.

5.4.2.6 Coal and Gas Construction Times and Overnight Costs

For its LCOE calculations, Deutsche Bank used an overnight cost of $1,119 per kW for pulverized coal baseload plants, with 4-year construction time, and $590 per kW overnight cost for gas turbine combined cycle (GTCC) baseload plants, with 3-year construction times (Smith and Hove 2003, Figure 65-66, pp. 76-77). MIT (2003, Table A-5.A.4, p. 135) used $1,300 per kW for pulverized coal plants and $500 per kW for GTCC generation, with 4- and 2-year construction periods respectively. Drennan et al. (2002) average EIA and Platt's data, deriving overnight costs of $1,182 per kW for coal generation and $588 for GTCC generation, with 3- and 2-year construction times respectively.

Investigation of recently planned pulverized coal plants and GTCC plants yielded ranges of overnight costs from $933 to $1,700 per kW for coal, with an average of $1,460, and $450 to $708 for GTCC, with an average of $567. Anticipated construction times for coal ranged from 2 to 5 years and for GTCC from 12 to 24 months (Alliant Energy 2004; Armistead and Barnes 2002; *Bristol Herald Courier* 2004; Calpine 2001; Dominion Energy 2001, 2004; Energy Info Source 2003; *Generation Markets Week* 2002; *Houston Business Journal* 2001; Lignite Energy Council 2004; Mazur 2003; *Merchant Power Monthly* 2004a, 2004b; Midwest Generation 2004; Minnesota Environmental Partnership 2004; Nebraska Public Power District 2003, 2004; NRG Energy 2004; Peabody Energy 2004; Reuters 2001, 2004; Sargent & Lundy 2004); The Shaw Group 2001; *Tyler Morning Telegram* 2004; Wisconsin Public Service Corporation 2002; Xcel Energy 2004).

5.4.3. Competitiveness of Nuclear Power in the No-Policy Case

Table 5-3 reports the first-plant LCOEs for the three reactor types, distinguished by their overnight costs, for 5- and 7-year construction periods. In each case, the plant life is 40 years, and the debt term is 15 years. The interest rate on debt is 10 percent and the return on equity is 15 percent. LCOEs in this and subsequent tables were derived using an iterative process that provides the appropriate return to equity based on free cash flow available to the utility.

The LCOEs reported in Table 5-3 are for first plants. Even though the ABWR and ACR-700 are of mature design, their construction experience has been outside the United States, so a first plant of one of these designs built in the United States should be considered a first-of-a-kind in this country, since only a portion of the overseas learning would be immediately transferable to the U.S. construction. The LCOE for the mature-design reactors ($1,200 per kW), with an optimistic 5-year construction period is $47 per MWh. The other two reactor designs have higher LCOEs, and a 7-year construction period would raise those costs. These LCOEs are calculated with a 15-year MACRS (Modified Accelerated Cost Recovery System) depreciation schedule. Using a 15-year straight-line depreciation schedule raises these LCOEs by about 4 percent.

Table 5-3: First-Plant LCOEs for Three Reactor Costs, 5- and 7-Year Construction Periods, $ per MWh, 2003 Prices

Construction Period	Mature Design, Foake Costs Paid, $1,200 per kW Overnight Cost	New Design, Foake Costs Not Yet Paid, $1,500 per kW Overnight Cost	Advanced New Design, Foake Costs Not Yet Paid, $1,800 per kW Overnight Cost
5 years	47	54	62
7 years	53	62	71

A question for the LCOEs of Table 5-3 is how close they are to the LCOEs of competing fossil generation. Tables 5-4 and 5-5 report the LCOEs for coal and gas generation, for alternative capital costs, fuel prices, and construction periods.

In Table 5-4, the coal plant's overnight cost ranges from $1,182 per kW to $1,430 per kW. The low overnight cost is an average of costs used in Drennan at al. (2002), originating from EIA and 2002 Platt's data. The mid-range of $1,300 per kW was used by Reis and Crozat (2002), and the high cost is an average of recently announced pulverized coal generation projects. See Section 6.2.4 for further discussion regarding new coal plants. Projected construction times for recently announced pulverized coal plants in the 1000 MW size range have varied from 2 to 4 years. The coal price of $1.02 per MMBtu is an average of prices used in Drennan at al. (2002), also originating from EIA and 2002 Platt's data; the price of $1.23 per MMBtu corresponds to 2003 delivered coal prices; and the price of $1.15 per MMBtu is EIA's 2004 forecast for 2015, with subsequently declining real prices. Coal plants are assumed to be financed at interest rates of 7 percent on debt and 12 percent on equity. Considering different capital costs, coal prices and construction times, the range from the scenarios is $33 to $41 per MWh.

Table 5-4: LCOEs for Pulverized Coal Plants, 85 Percent Capacity Factors, Alternative Overnight Costs, Coal Prices and Construction Periods, $ per MWh, 2003 Prices

	Overnight Cost								
	$1,182 per kW			$1,350 per kW			$1,460 per kW		
	Coal price, $ per MMBtu								
	1.02	1.23	1.15 & Varying over Forecast[a]	1.02	1.23	1.15 & Varying over Forecast[a]	1.02	1.23	1.15 & Varying over Forecast[a]
	Cost per MWh								
2-yr construction	33	35	35	36	38	37	37	39	38
3-yr construction	34	36	35	37	39	38	38	40	39
4-yr construction	35	37	36	37	39	39	39	41	40

[a]From a price of $1.15 per MMBtu in 2015, the forecast varies between $1.13 and $1.14 through 2020; rises to $1.15 through 2022; and reaches $1.16 in 2023, at which level it remains for the remainder of the plant life.

In Table 5-5, the gas plant's overnight cost ranges from $500 per kW to $700 per kW. The low and high overnight costs represent the range reported in recent GTCC plants, while the mid-range cost is an average of costs used in Drennan et al. (2002). Recent construction times have ranged from 12 to 24 months. The gas price of $3.39 per MMBtu is an average of prices used in Drennan at al. (2002), originating from EIA and 2002 Platt's data. It corresponds to an average of 2001 and 2002 gas price forecasts for the period 2010 to 2015. The price of $4.30 per MMBtu corresponds to the 2003 gas price forecast for the same period; the price of $4.25 is EIA's 2004 forecast for 2015, and that forecast has gas prices rise to $4.51 by 2020, which accounts for the slightly higher LCOEs under that price forecast than under the constant price of $4.30 per MMBtu. As with coal, the interest rates are 7 percent for debt and 12 percent for equity. The lowest LCOE is $35 per MWh, and the highest is $45 per MWh.

Table 5-5: LCOEs for Gas Turbine Combined Cycle Plants, 85 Percent Capacity Factors, Alternative Overnight Costs, Gas Prices and Construction Periods, $ per MWh, 2003 Prices

	Overnight Cost								
	$500 per kW			**$588 per kW**			**$700 per kW**		
	Gas price, $ per MMBtu								
	3.39	**4.30**	**4.25 & Varying over Forecast[a]**	**3.39**	**4.30**	**4.25 & Varying over Forecast[a]**	**3.39**	**4.30**	**4.25 & Varying over Forecast[a]**
	Cost per MWh								
1-yr construction	35	41	42	36	42	43	37	44	44
2-yr construction	35	41	42	36	43	43	38	44	45

[a]From a price forecast of $4.25 per MMBtu in 2015, a peak of $4.51 is reached in 2021, from which the forecast falls to $4.48 by 2025, at which level it remains for the remainder of the plant life.

Comparison of the $47 per MWh LCOE of the $1,200 per kW built in 5 years, in Table 5-3, with either of the fossil LCOEs in Tables 5-4 and 5-5, shows no surprise. No observers have expected the first new nuclear plants to be competitive with mature fossil power generation without some sort of temporary assistance during the new technology's shake-down period of the first several plants. However, the comparison of the LCOEs in these three tables shows the magnitude of the competitive gap that any policies would have to bridge.

5.4.4. Sensitivity Analysis for First Nuclear Plants

Before proceeding to the analysis of such policies in Chapter 9, sensitivities of the no-policy case to several parameters are considered. Table 5-6 reports the effects of a longer plant life than the 40 years used in the LCOEs reported in Table 5-3, as well as alternative capacity factors and construction periods. As Table 5-6 shows for the $1,200 per kW ABWR or ACR-700 reactor, a 60-year plant life has a minimal impact on the LCOE, because of the discounting of the additional 20 years of life span beginning 40 years from the present, regardless of capacity factor or length of construction period.

Table 5-6: Effects of Capacity Factor, Construction Period, and Plant Life on First-Plant Nuclear LCOE for Three Reactor Costs, $ per MWh, 2003 Prices

Capacity Factor, Percent	Overnight Cost					
	$1,200 per kW		$1,500 per kW		$1,800 per kW	
	5-year construction period					
	Plant Life		Plant Life		Plant Life	
	40 years	60 years	40 years	60 years	40 years	60 years
85	47	47	54	53	62	61
90	44	43	51	50	58	58
95	42	41	49	48	56	55
	7-year construction period					
	Plant Life		Plant Life		Plant Life	
	40 years	60 years	40 years	60 years	40 years	60 years
85	53	53	62	61	71	70
90	50	49	58	58	67	66
95	47	47	56	55	64	63

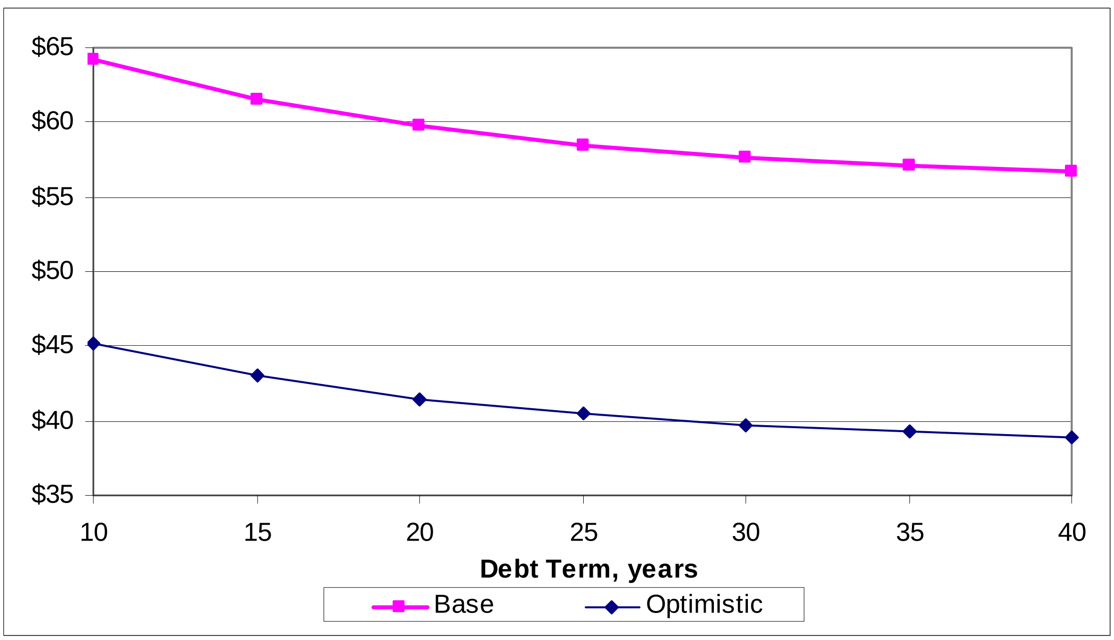
With an 85 percent capacity factor, the additional 20 years of plant life reduces the LCOE of the $1,200 per kW plant by $0.72 per MWh if it can be built in 5 years, or by $0.79 per MWh if construction takes 7 years. The $1,500 and $1,800 per kW plants experience similar impacts.

Capacity factor adds directly to the ability to produce revenue. The base capacity factor of 85 percent may appear low relative to recently achieved availability levels in U.S. nuclear plants, in the range of 90 to 92 percent. Some questions have been raised whether those high levels are sustainable, and it is worth considering that capacity factor in a newly opened plant may be something below its long-term operating level, which would have a large effect on discounted revenues and correspondingly raise LCOE. Table 5-6 also reports the sensitivity of the LCOEs of Table 5-3 to variations in capacity factor, from 85 percent through 95 percent, for 5- and 7-year construction periods. The $1,200 per kW plant could achieve an LCOE as low as $42 per MWh with a 95 percent capacity factor, if the plant could be built in 5 years.

Lengthening the debt term reduces the LCOE. The upper line in Figure 5-1 shows the LCOE of a first $1,500 per kW plant, built in 7 years, with debt terms ranging from 10 years to 40 years. Varying the debt term by 30 years from a short term of 10 years to a long term of 40 can reduce the LCOE by a little more than 10 percent. While addressing such financing structure can help keep the LCOE down, by itself it is not a panacea.

The lower line of Figure 5-1 supposes that each cost and performance parameter is at its most optimistic value and examines the effect of changing the debt term. This calculation is for a plant built in 5 years, at $1,200 per kW overnight cost, with 60 percent debt and 40 percent equity, and expecting a 60-year operating life. Debt and equity interest rates remain at 10 and 15 percent. The LCOE with a 25-year debt term is $40 per MWh, and extending the debt term to 40 years by only another $1.50 per MWh, to $39 per MWh. This is close to the range of gas-fired power, but the combination of cost and performance assumptions is probably too optimistic for a first plant. Nonetheless, the ability of shifting the basic cost and performance parameters within a range of values that may be realistic for a later plant offers promise for the commercial viability of some nth plant in the future.

Figure 5-1: The Effect of Debt Term: First-Plant LCOEs for a $1,500 per kW, AP1000, and $1,200 per kW Plant with Reduced Construction Time and Higher Debt Ratio, $ per MWh, 2003 Prices



The impact of construction delays is addressed in Table 5-7. The $1,500 per kW reactor design is chosen for illustration. Two cases are considered in a 7-year construction period. The first row of the table reports the LCOE with no construction delays. The second row reports the impact of a 2-year hiatus in construction coming in the middle of the construction period, and the bottom row places the delay after 7 years, when all construction outlays have been expended but power sales from the plant have not been allowed to begin.

A 2-year delay in the middle of the construction would increase the interest component of total capital costs enough to raise the LCOE 12 percent above what it would be in the absence of delays—from $62 to $69 per MWh. A comparable period of delay after all expenditures have been put out at interest would raise the LCOE by 24 percent. The seriousness of construction delays for economic viability cannot be underestimated.

Table 5-7: The Impact of Construction Delays on the First-Plant LCOE of a $1,500 per kW Plant, $ per MWh, 2003 Prices

No delay	62
Delay in middle of construction period	69
Delay after end of construction period	76

An inflation rate of 3 percent is used in all LCOE calculations. Experimentation indicates some sensitivity of the real LCOE to the inflation rate. To keep the real interest rate constant, when varying the inflation rate, a corresponding adjustment is made in the interest rates. For example, to experiment with a 2 percent inflation rate from a base rate of 3 percent, 1 percentage point is subtracted from the debt and equity interest rates. Reducing the inflation rate from 3 percent to 2 percent in this manner reduces LCOE by a little less than 4.5 percent.

5.5. Conclusion

The analysis here indicates that reasonable variations in the cost and performance parameters of new reactor designs do not appear able to bring these new plants fully into the competitive range of generation costs, although the variations do help materially. Reducing the construction period of a plant with $1,500 per kW overnight cost from 7 years to 5, extending plant life, and rearranging the debt term of the financing all reduce the nuclear LCOE, the lowest-cost nuclear cases remain just above the highest-cost coal and gas cases. Increasing capacity factor, for any given capital cost and construction time, from 85 to 95 percent would decrease LCOE by a little less than 10 percent. The results here are for first new plants coming on line in 2015. The effects of learning by doing and favorable construction and operating outcomes on LCOEs of subsequent plants will be considered in Chapter 9.

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Part Two: Outlook for Nuclear Energy's Competitors

Part Two considers the prospects for gas and coal as the major baseload competitors to nuclear generation. Consideration is given to technologies that could reduce costs of gas- and coal-fired electricity, fuel price changes that could affect relative competitiveness, and the potential effect of greenhouse gas controls on costs of fossil-fuel generation.

Chapter 6. GAS AND COAL TECHNOLOGIES

Summary

This chapter examines the near-term prospects for improvements in gas- and coal-fired electricity generation that would affect their costs relative to nuclear power. Some modest efficiency improvements are foreseen in the near term for gas technologies, but the prospects for coal technologies appear to be farther in the future.

The most common combustion technology used in recently constructed coal plants in the United States is pulverized coal combustion (PCC). The thermal efficiency of most fluidized beds used for power generation is similar to that of conventional PCC plants. Interest in the use of this technology has been stimulated by its better environmental performance even when utilizing lower grade fuels. However, its cost competitiveness remains in question. Integrated coal gasification combined cycle (IGCC), while attractive from a thermal efficiency and emissions perspectives, is likely to be too expensive to enter the U.S. market in the near term.

More advanced coal-fired technologies are still in early R&D stages. Since little can be said about their near-term commercialization potentials, they are not included as realistic possibilities for reducing coal-fired generation costs within the time scope of the present study.

The primary gas-fired technology for new baseload electricity generation is gas turbine combined cycle. Modern gas turbine plants with a triple-pressure heat recovery steam generation (HRSG) system with steam reheat can reach thermal efficiencies above 55 percent. A gas turbine, with steam cooling of the turbine blades and nozzles, combined with an advanced HRSG is expected to operate at an efficiency level of 60 percent in the near future. The goal of most world manufacturers is to reach overall thermal efficiencies of the combined plant of 60 percent in the short term, primarily by increasing firing temperatures. Other cycle improvements could lead to thermal efficiencies nearing 65 percent.

Since fuel costs are generally two-thirds of the levelized cost of gas-generated power, a 5 percentage-point increase in efficiency could result in an approximate by 8 percent cost decrease, which although small, could affect competitive margins across generation types.

Outline

6.1. Introduction

Fossil fuel technology continues to be the primary source for electric power generation. Moreover, it appears that its market dominance will continue for the foreseeable future. Concerns over its environmental impacts have spurred efforts to find alternatives as well as improve the current technology. The purpose of this chapter is to describe the current and near future fossil-fired power generation technologies, noting prognoses for improvements in efficiency and emissions control. Finally, an assessment of the costs for a new coal-fired or gas-fired plant incorporating all necessary emissions control is provided.

6.2. Coal-Fired Power Plant Technology

Since the early 1900s, coal power has provided the bulk of electricity generated in the United States because of its low price (Gillenwater 1996, p. 19). Since 1965, the thermal efficiency of steam turbines increased steadily and then plateaued (Gillenwater 1996, p. 21). There has been a general trend toward larger plants to take advantage of scale economies, but there is a threshold beyond which reliability becomes difficult to ensure in these large units (Gillenwater 1996, p. 21).

6.2.1. Current and Future Technology

6.2.1.1. Pulverized Coal Combustion (PCC)

Pulverized coal combustion (PCC) is the most widely used method for burning coal for power generation. Older PCC plants offer efficiencies around 30 percent while newer sub-critical steam units with high quality coal can reach 35 to 36 percent efficiencies. Newer units employing supercritical steam may reach efficiencies of 45 percent. However, supercritical boilers are more highly integrated than the simpler sub-critical PCC designs and require advanced steel materials. As materials advance, government R&D programs hope to reach efficiencies as high as 50 percent. Further technological improvements depend on the development of new materials capable of withstanding higher temperatures and pressures (Smith and Hove 2003, p. 39).

6.2.1.2. Fluidized Bed Combustion (FBC)

Fluidized bed boilers were developed in the 1990s and can utilize waste coal that could not be burned for power in other boilers (Smith and Hove 2003, p. 41). The advantage of fluidized bed combustion (FBC) is that it encourages complete combustion at a lower temperature than that of PCC. While the units are cleaner than a corresponding PCC plant, its efficiencies only range from 30 to 35 percent. The most current technology utilizes the pressurized circulating fluidized bed boiler (PCFB) in which the entire combustion chamber is placed under pressure and may deliver higher efficiencies.

6.2.1.3. Integrated Gasification Combined Cycle (IGCC)

IGCC technology demonstrates 10 to 20 percent more efficiency than conventional pulverized coal plants, achieves up to 98 percent SO_2 removal, and reduces NO_X emissions to approximately 0.1 lb per Btu (DOE 1999, p.17). IGCC plants can obtain efficiency levels of 40 to 45 percent with current technologies (Smith and Hove 2003, p. 42). Research and development projects target 60 percent efficiencies. The immediate technological challenge remains the consumptive nature of the gas clean-up process, which currently requires that the syngas be cooled before cleaning and ultimate feeding into the turbine (Smith and Hove 2003, p. 42).

There is only one gasification plant operating as baseload today in the United States—Tampa Electric Co.'s Polk Plant, a 250-MW IGCC plant that has been in operation since 1996 (Alvey 2003, p. 22). However, the experience with current coal-fired demonstration plants (250 to 300 MW) indicates that additional development is required to reduce capital costs and improve both plant availability and reliability to achieve competitive power production costs and commercial acceptance.

6.2.1.4. Current Research

Research on coal-fired technologies focused on increasing performance and decreasing emissions are in early stages. DOE is leading the research effort with its Future Gen, Vision 21, and Advanced Turbine Systems programs (DOE 1999b, p. 12).

6.2.2. Emissions Control Technology

As the use of coal power continues, many of the existing units will be outfitted with enhanced emission controls in the next decade to meet more stringent environmental regulations for sulfur dioxide (SO_2), oxides of nitrogen (NO_X), mercury (Hg), particulate matter (PM), and potential greenhouse gases such as carbon dioxide (CO_2). These controls include flue gas desulfurization, low-NO_X burners (LNBs), selective catalytic reduction systems (SCR), and particulate matter controls. Moreover, as a result of the New Source Review provision, all new plants are required to install the best available control technology, which affects coal's competitiveness with other electric power generation sources. Finally, should carbon sequestration become a requirement in the future, coal power would be put at a significant disadvantage considering its high carbon content. Carbon sequestration costs are discussed further in Section 8.3.

6.2.3. Future Power Plant Construction Considerations

The current stock of coal plants is aging and, as a consequence of New Source Review, is being utilized more intensively. Few coal-fired retirements, re-powering projects, or capacity additions are planned, as utilities and non-utilities show reluctance to assume high investment risks (Gillenwater 1996, p. 3). Utility and non-utility companies probably will not make long-term capital investments as long as the increased demand for electricity at coal-fired power plants can be met through extending the life, increasing the utilization of existing capital, or both (Gillenwater 1996, p. 3). Additionally, investors generally see limited opportunities for new baseload capacity in the United States over the next 10 years (EIA 2003, p. 3). Moreover, given the uncertainty over environmental regulation and the need to minimize long-term capital risk, private companies are unwilling to invest in long-term R&D to improve technology without government support (DOE 1999b, p. 2).

6.2.4. Cost Estimates

6.2.4.1. Mining and Transportation Costs

Continued technological developments for extracting and hauling large volumes of coal in both surface and underground mining suggest that further reduction in mining costs is likely. However, EIA expects improvements in labor productivity to remain the key element to lower coal-mining costs (EIA 2003, p. 87).

In 1997, transportation costs averaged 41 percent of the delivered price of contract coal shipments to electric utilities. With an increase in the Western market share, an increase in the average shipping distance may lead to increased transportation costs. Rail costs and transportation bottlenecks lead to regional differences because coal is now being shipped over longer distances (Smith and Hove 2003, p.13). However, EIA projects that rail rates for Western coal will decline gradually over the next two years with improvements to railroad infrastructure (Smith and Hove 2003, p. 34).

6.2.4.2. Fuel Supply and Price

Coal is stored in substantial quantities at power plants, and most utility companies have long-term supply contracts to stabilize coal prices. Consequently most utilities have continued to pay low and stable prices for their coal, thereby limiting exposure to the higher prices experienced in 2002. Western coal costs are lower than Eastern costs because of the thickness of the coal seams and high productivity associated with large-scale surface mining, but Western coal tends to have a lower energy content per unit weight than Eastern coal (Smith and Hove 2003, p. 34). Coal supply and price projections are reported in Section 7.2.

6.2.4.3. Capital Costs

Capital costs for new PCC plants range from $1,100 to $1,200 per kW depending on their location, and supercritical PCC plants tend to cost closer to $1,200 per kW. PCFB capital costs are around $1,200 per kW, with somewhat lower gas cleanup costs as part of this figure (Smith and Hove 2003, p. 38). DOE estimates the future cost of IGCC units at just over $1,300 per kW and projects that its price will come down to $1,000 per kW by 2008 (Smith and Hove 2003, p. 42).

6.2.4.4. Operation and Maintenance Costs

O&M costs include the cost of operating emission control devices for both sulfur and NO_X (Smith and Hove 2003, p. 24). Plant performance declines gradually over a plant's lifetime, translating into lower availability and higher O&M costs. Cap-and-trade programs provide incentive for companies to find the lowest-cost mechanism to achieve emission levels. Allowance prices provide an indication of the marginal cost to the generator for controlling emissions. Allowance price estimates are discussed in Chapter 8.5.

6.2.4.5. Total Costs

Capital, O&M costs, and efficiency vary considerably among new plants, depending on design considerations, fuel types, and location, as shown in Table 6-1. PCC plants utilizing supercritical steam offer higher efficiencies at higher capital costs. Different fuel supplies and emission controls cause O&M costs to vary. In general, the CFB units offer lower O&M costs because they do not require coal pulverization and involve simpler emission controls. O&M costs also vary depending on plant utilization (Smith and Hove 2003, p. 38).

Table 6-1: Cost Expectations for New Coal Plants in 2003

	PCC High-Env	PCC Low-Env[a]	CFB	IGCC
Capital Cost ($ per kW)	1,189	1,119	1,200	1,338
Fuel Cost ($ per MWh)	11.26	11.26	12.04	9.44
Total O&M ($ per MWh)	7.73	6.52	5.87	5.19
Construction time (years)	4	4	4	4
Thermal Efficiency (percent)	36	36	34	43

Source: Smith and Hove (2003, p.1).
[a]PCC-low env represents a hypothetical new plant built in a region with less stringent environmental compliance requirements.

6.3. Gas-Fired Power Plant Technology

During the 1990s, construction of natural gas-fired power plants have increased greatly as a result of deregulated natural gas markets, low fuel costs, and increased environmental regulations. Moreover, short construction lead times and low capital costs have given natural gas an advantage over its competitors.

6.3.1. Combined-Cycle Technology

The primary gas-fired technology for new baseload electricity generation is gas turbine combined cycle (GTCC). The combined cycle system is a combination of two technologies: the gas turbine and the steam turbine. In a gas turbine, natural gas is burned in combination with a steady stream of high velocity compressed air. The hot combustion gas is then passed through an array of rotating and stationary airfoils that turn a generator to produce electricity. For the second or bottoming cycle, a heat recovery steam generation system (HRSG) and steam turbine are added to take advantage of the thermal energy produced from the first combustion cycle.

Modern gas turbine plants with a triple-pressure HRSG with steam reheat can reach efficiencies above 55 percent. ABB-Alstom claims 58 percent efficiency of a combined cycle plant built around its GT24/26 reheat gas turbines; the same efficiency is cited by Siemens, for the Westinghouse steam-cooled W501G/701G gas turbine or V94.3a gas turbine, combined with a triple pressure HRSG. A gas turbine, with steam cooling of the turbine blades and nozzles, combined with an advanced HRSG is expected to operate at an efficiency level of 60 percent in the near future. The goal of most world manufacturers is to reach overall thermal efficiencies of the combined plant of 60 percent in the short term, generally by increasing firing temperatures (Franco 2002, p. 1504).

DOE has recently cited the General Electric (GE) "H" class GTCC system for its performance promise. The new system is claimed to reach an overall thermal efficiency of 60 percent through its increased gas turbine firing temperature of 1430 degrees C with a pressure ratio of 23:1 (Corman 1996, p. 1).

In spite of manufacturer claims of 60 percent efficiency, most industry experts suggest efficiencies in the range of 55 to 58 percent would be a preferable range to account for plant-to-plant variation such as ambient air differences and other environmental factors (Claeson Colpier 2002, p. 313).

6.3.2. The Future of Gas Turbine Combined Cycle Technology

Research into increasing the efficiency of combined-cycle technology is proceeding with several developments that allow higher firing temperatures, better turbine performance, and more efficient recovery of heat. The engineering literature has paid considerable attention to the optimization of HRSG. Two basic exhaust heat recovery processes can be used to increase efficiency: (1) recuperation, in which the recovered heat is used in the same gas turbine cycle; and (2) bottoming cycle, in which the exhaust is used as a heat source for a second and essentially independent power producing cycle (Heppenstall 1998, p. 838). In addition, basic optimization of HRSG parameters such as mass flow rates and heat exchanger efficiencies can produce substantial increases in overall efficiency. The efficiency increase can vary from 2 percent for HRSG optimization alone, to 6 to 7 percent using post combustion reheating, inter-cooling, and gas-to-gas recuperation (Franco 2002, p. 1515).

While significant increases in efficiencies are technically feasible, increased component and plant complexity could result in increased cost. The thermodynamic performance of a plant is usually reflected in the fuel cost. The fuel cost savings as a result of increases in thermal efficiency are shown in Table 6-2, which suggests that, on average, a

5 percentage-point increase in thermal efficiency will result in an 8 percent reduction in fuel cost. For example, at a 40 percent thermal efficiency, which is equivalent to a heat rate of 8,530 per kWh, and a $3.15 per MMBtu cost of gas, the fuel component of the levelized cost of electricity (LCOE) of a combined cycle plant would be $27 per MWh.

Table 6-2: Thermal Efficiency Effect on Fuel Cost of GTCC, $ per MWh, 2003 Prices

Thermal Efficiency, Percent	Heat Rate, Btu per kWh	Fuel Cost Contribution to LCOE, in $ per MWh		
		At Fuel Price[a], in $ per MMBtu, of:		
		3.15	3.75	4.70
40	8530	27	32	40
45	7582	24	28	36
50	6824	22	26	32
55	6204	20	23	29
60	5687	18	21	27
65	5249	17	20	25

[a]Data generated using fuel price estimates from Smith and Hove (2003) and an average 2009 gas contract price from NYMEX (2003).

6.3.3. Breakdown of Costs by Capital, Fuel, and O&M

The cost of generating electricity with gas turbine combined cycles depends not only on the capital cost of the plant, but also the cost of fuel, thermal efficiency, load, and operation and maintenance costs. In addition, differences in national and regional market characteristics and local site conditions can mask the influence of various factors. However, for the purposes of this chapter average values will be used.

Fuel cost is the primary consideration in assessing the LCOE for gas-fired generation. By most estimates it comprises nearly two-thirds of the total cost of generation. As discussed in Section 9.4, the natural gas price has been relatively volatile in recent years due to declines in productivity and proven reserves, among other, more transient factors. Accordingly, higher fuel prices could cause a reassessment of the economic viability of gas-fired generation. Natural gas price models and their forecasts are discussed in Section 7.3. Deutsche Bank suggests average gas prices above $4 per MMBtu in the short run as a critical point at which fuel switching may occur (Smith and Hove 2003a, p. 22). Capital costs comprise less than one-third of the total cost of generation. An average estimate for a new combined cycle plant is $590 per kW (Smith and Hove 2003a, p. 77). The final consideration is the cost of operation and maintenance (O&M), which includes costs of emission control. Generally gas-fired plants do not require additional pollution control equipment, which provides a significant O&M cost advantage, but O&M comprises less than 6 percent of the LCOE of gas-fired plants (Smith and Hove 2003a, p. 19). Table 6-3 shows Deutsche Bank's present and future cost projections for gas plants.

Claeson Colpier et al.'s (2002) analysis suggests that the great reduction in gas-fired electricity costs through the 1990s was the result of a worldwide increase in installed capacity and attendant experience with combined cycle technology in electricity generation. If GTCCs become the generation technology of choice, the trend would likely continue, moderated by declining marginal returns to learning, discussed in Chapter 4. According to Claeson Colpier et al., holding the fuel price constant, the stable progress ratio for the cost of generating electricity is approximately 94 percent. That is, at the next point where installed capacity doubles, the capital cost should fall by 6 percent, or a 6 percent learning effect in the terminology of Chapter 4. The likelihood, however, of a further doubling of capacity in the short term is small, and therefore its effect on the overall cost of electricity minor compared to gains in thermal efficiency and fuel cost.

Table 6-3: Cost Estimates for New Gas Plants

	2003	**Long Term[a]**
Plant Size (MW)	300	300
Capital Cost ($ per kW)	590	450
Lead Time (Years)	3	3
Fuel Price ($ per MMBtu)[b]	3.75	3.15
Fuel Cost ($ per MWh)	23.6	19.9
Total O&M Cost ($ per MWh)	2.6	2.6
Annual Capital Cost ($ per MWh)	10.2	7.8
Levelized Cost ($ per MWh)[c]	36.4	30.3

Source: Smith and Hove (2003).

[a]Long term is the length of time required for fuel prices to reach an equilibrium, approximately 2006 (p. 77).

[b]Fuel price based on 2003 EIA estimate, plant efficiency set at 54 percent; price does not include post-combustion emissions control.

[c]Levelized cost is the sum of fuel, O&M, and annuitized capital costs.

6.3.4. Natural Gas Emissions, Control Technology, and Costs

When compared with emissions from coal-fired plants, combined cycle plants produce significantly less of the six criteria pollutants established by the 1990 Clean Air Act. Natural gas produces no sulfur dioxide or ash, and smaller quantities of volatile organics, CO_2, and NO_X gases. However, for the purposes of this report, only nitrogen oxides (NO_X) will be considered. NO_X gas emissions are formed during the combustion of natural gas and other fossil fuels by high temperature oxidation of atmospheric nitrogen. CO_2 is a natural byproduct of fossil fuel combustion and is currently not a federally regulated gas.

In general, NO_X emissions from gas-fired electricity generation are lower than most current limits. As discussed in Section 8.5.2., there is regional variation among NO_X standards, and some states such as California and Texas require additional emissions control technology. Similarly to coal-based technology, gas-fired generation can employ low-NO_X burners (LNBs) and selective catalytic reduction systems (SCR) to achieve standards as low as 2.5 parts per million (PPM). In addition, should carbon sequestration be required, its effect on gas-fired electricity costs probably would be much lower than the effect on coal-fired costs as a result of the lower carbon emissions from natural gas. Carbon emissions are discussed in more detail in Chapter 8.

6.3.5. Summary of Future Gas Generation Cost Estimates

The future competitiveness of natural gas-fired generation lies in its fuel cost, which is nearly two-thirds of the overall cost of gas LCOE. Two main factors affect the fuel cost: thermal efficiency and the fuel price. A 5 percentage-point increase in thermal efficiency can reduce the fuel cost by 8 percent. However, the most important cost consideration for gas generation remains the fuel price. Since 1998, supply problems have resulted in volatile fuel prices. Table 6-4 shows the sensitivity of gas-fired LCOE to fuel price.

Table 6-4: Effect of Fuel Price on Gas LCOE, $ per MWh

Thermal Efficiency, Percent	Gas Price					
	$3.00	**$3.40**	**$3.80**	**$4.20**	**$4.60**	**$5.00**
50	33	35	38	41	43	46
55	31	33	36	38	41	43
60	29	32	34	36	39	41

Source: Smith and Hove (2003).

Assuming the gas supply infrastructure is stabilized in the near term and new supply options such as LNG are realized, the current cost advantage of natural gas generation should continue. A forecast of the future cost of generation can be calculated using an estimate of the fuel price and future thermal efficiency. Assuming that a 5 percentage-point increase in thermal efficiency can be achieved by 2020, the cost of gas-based generation could be expected to be approximately $30 per MWh. Should environmental regulations tighten for NO_X and greenhouse gases such as CO_2, LCOE would likely increase as indicated in Table 6-5.

Table 6-5: Effect of Environmental Controls on 2020 Gas-Fired LCOE[a]

	2020	2020 w/ 2.5 ppm NOx Limit	2020 w/ 2.5 ppm NOx + CO_2 Capture
Plant Size (MW)	300	300	300
Capital Cost ($ per MW)	450,000	450,000	450,000
Lead Time (Years)	3	3	3
Fuel Price ($ per MMBtu)	3.78	3.78	3.78
Fuel Cost ($ per MWh)	20.3	20.3	20.3
Total O&M Cost ($ per MWh)[b]	2.6	4.0[c]	6.3[b,d]
Capital Cost ($ per MWh)[e]	7.8	7.8	7.8
Levelized Cost ($ per MWh)	30.7	32.1	44.4

[a] 2020 Thermal efficiency set at 63 percent, estimated fuel cost taken from Table 6-4, capital cost and O&M cost values taken from Smith and Hove (2003).
[b] Incremental emissions control costs include cost of capital and O&M but are reflected in total O&M cost.
[c] Additional SCR unit for NO_x control adds $1.4 per MWh (Onsite Syscom Energy Corp., 1999, p. 4).
[d] Additional monoethanolamine (MEA) unit for CO_2 capture adds $2.3 per MWh (David 2000a, p. 3).
[e] Annual capital cost = depreciation cost/depreciation term. Depreciation cost is determined using a weighted average cost of capital (WACC) of 11.3 percent. Depreciation term is 25 years. (Smith and Hove 2003a, p. 75.)

6.4. Summary of Future Coal and Gas Technologies

The near-future coal- and gas-fired power generation technologies look much the same as the current technologies. There is some prospect of modest efficiency improvements in gas technology, but significant advances in coal technology appear further in the future. Integrated gasification combined cycle plants would have an advantage over current pulverized coal plants if reduction of carbon emissions became a priority. Capital costs in all of these technologies are well understood, but the fuel price prognoses for coal and gas technologies differ, the former universally considered to be stable, the latter much more volatile and subject to uncertainties.

Table 6-6 summarizes the cost characteristics of the current and near-future technologies.

Table 6-6: Cost Characteristics of Fossil-Fired Electricity Generation

	Pulverized Coal Combustion	Coal, Circulating Fluidized Bed	Coal, Integrated Gasification Combined Cycle	Gas Turbine Combined Cycle
Capital Cost ($ per kW)	1,189	1,200	1,338	590
Fuel Cost ($ per MWh)	11.26	12.04	9.44	23.60
Total Operations and Maintenance Cost (O&M) ($ per MWh)	7.73	5.87	5.19	2.60
Construction time (years)	4	4	4	3
Current Thermal Efficiency (percent)	30 to 35	30 to 35	40 to 45	55 to 60
R&D Thermal Efficiency Targets (percent)	45	45	60	65

Sources: Table 6-1, Table 6-3.

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Chapter 7. FUEL PRICES

Summary

This chapter examines forecasts for the three fuels of concern: coal, natural gas, and uranium. Coal prices in the United States are not expected to increase. Forecasts for natural gas prices are mixed, although EIA forecasts a 20 to 30 percent increase over 2002 levels by 2020. The supply elasticity of uranium is estimated by several sources to be between 2.3 and 3.3, which should keep uranium prices down in the near term.

Some uncertainty surrounds projections of fuel price changes, which can alter relative competitiveness between gas and coal, and can also affect competitiveness of both with nuclear. This chapter sums up the significant similarities and differences in the underlying methodologies of the various models for coal, natural gas, and uranium supply.

Coal supplies worldwide are expected to be sufficiently elastic that even a doubling of demand is not expected to increase price appreciably. Much of the work on coal prices is short-term in nature and hence is of limited usefulness for the projections needed for the present study. Long-term changes in past decades that have affected coal prices have included dramatic increases in coal mining efficiency, the past trajectory of which may be of some help in predicting the future. Among the model forecasts, there is general agreement that coal production will increase over the next 20 to 30 years (35 to 50 percent). The international forecasts foresee a rise in the international coal price (25 to 30 percent), while the forecasts for the U.S. coal price to utilities uniformly predict a decline (10 percent).

EIA's 2003 gas price predictions are for a 10 percent dip from the 2003 level, followed by a 38 percent increase by 2025. Its 2003 supply prediction is for a relatively smooth 34 percent increase over the 2003 level by 2025, reduced in the 2004 prediction to 15 percent. EIA's 2004 forecast projects less of a price dip in 2005, followed by a larger rise relative to 2000 levels by 2025.

The International Energy Agency (IEA) and EIA have uranium market models, but they are limited. The International Atomic Energy Agency (IAEA) offers an outlook on potential uranium market trends, but it does not incorporate a model of investment in exploration. Since the fuel cost share of nuclear power generation is less than 10 percent, variation in uranium prices will have only a limited effect on the overall cost of nuclear generation of electricity.

Outline

7.1. Introduction

This chapter reviews and evaluates fuel price forecasts to be used in the analysis of nuclear power's competitiveness with coal and gas. The chapter examines major modeling systems of coal, natural gas, and uranium supply currently in use by government and international agencies, focusing on their supply functions for these fuels and the sophistication of the price forecasts.

A focus on current levels of known reserves of a resource, in terms of a certain number of years' consumption remaining, can prompt alarm at the prospect of running out of a critical mineral such as natural gas from North America. Short-term price fluctuations extrapolated to the future can yield intermediate-term forecasts that could cause major changes in the electricity sector were they to materialize.

Sections 7.2, 7.3, and 7.4 review models of coal, natural gas, and uranium supply. Models of oil supply are excluded from this analysis since the use of oil for electricity generation is not widespread in the United States. Section 7.5 examines modeling systems that deal with the fuels in a generic manner. Section 7.6 summarizes the price and supply projections.

7.2. Coal

Three economic models of coal are reviewed in this section, the EIA's National Energy Modeling System (NEMS), the European Union's Prospective Outlook on Long-Term Energy Systems (POLES), and the International Energy Agency's World Energy Model (WEM).

7.2.1. The Forecasting Models: NEMS, POLES, and WEM

NEMS and POLES include different specifications to forecast coal production and prices. The Coal Production Submodule (CPS) of NEMS is responsible for the construction of annual supply curves for each combination of region, mine type, and coal type found in the United States. Using two-stage least squares regression methodology, a supply function is created that relates price to mine capacity utilization (EIA 2003c, p.8). It is then calibrated to the most recent data (EIA 2003c, p.17).

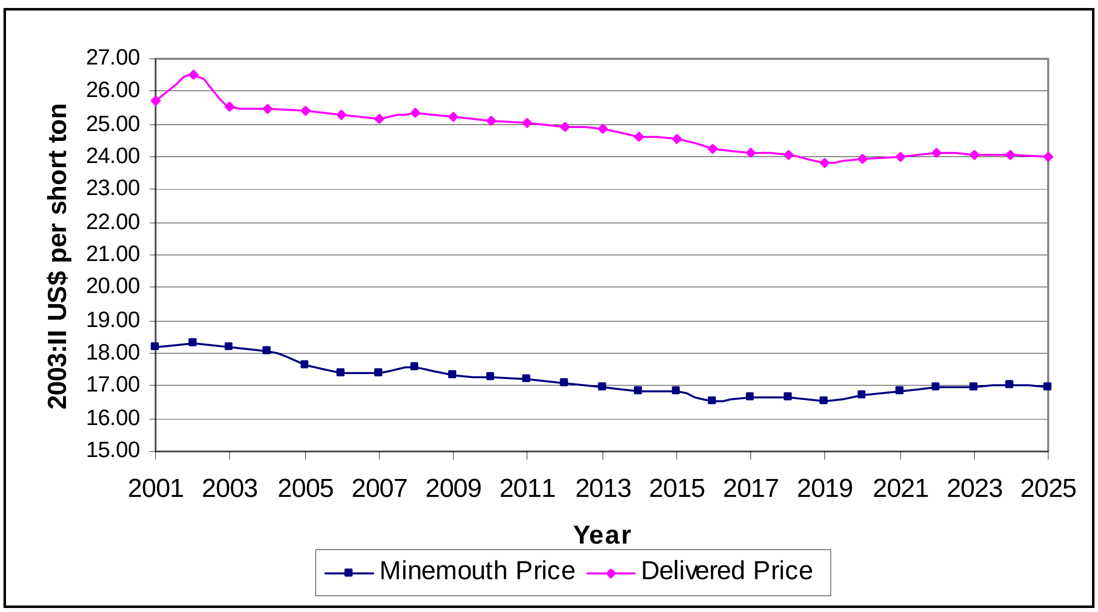
The POLES model evaluates future coal supply from a global perspective. It estimates production for each of thirty-two national and regional markets. National and regional supplies are modeled as a function of the previous year's coal production, a short-term price effect, a long-term price effect with a distributed lag and asymmetric response factor, coal consumption in the current and previous year, and an autonomous technological trend, differentiating between exporting and non-exporting areas in its supply specifications (Criqui et al. 2003, 2.3). For countries that are large producers or exporters of coal, also called swing producers, which includes the United States, POLES models a national coal price that is influenced by two costs: the mining and operating cost, and the capital, transport and loading cost (Criqui et al. 2003, 4.3.1). National prices are then used to calculate international coal prices on four aggregated markets: the American market, the Euro-African market, the Eastern European market, and the Asian market (Criqui et al. 2003, 4.3.2).

WEM does not model coal supply explicitly, and exogenously determines the prices of all fossil fuels (IEA 2002, p. 500). It appears to assume a flat supply curve for coal since it assumes that sufficient coal reserves exist to meet world demand and that coal reserves are evenly distributed throughout the world, unlike oil and gas (IEA 2002, p. 512).

7.2.2. Coal Price Projections

EIA's *Annual Energy Outlook* 2004 (AEO 2004) NEMS forecasts a decline in the minemouth price of coal due to mining productivity improvements. Figure 7-1 shows NEMS' forecasts of minemouth (f.o.b) and delivered (c.i.f.) prices of coal from 2001 to 2025. The difference between the c.i.f. and f.o.b prices increases about 15 percent between 2001 and 2012, suggesting that NEMS is projecting rising transportation cost to that date; this may reflect a shift to Western coal, which must be transported longer distances on average. Thereafter the difference falls back to its 2001 magnitude.

Figure 7-1: NEMS Projections for U.S. Coal Prices



Source: EIA (2004).

POLES projects a modest increase in the world coal price despite a sustained growth in consumption for the four major world regions (European Commission 2003, p. 23). The forecast recognizes the downward pressure on prices that will be exerted by gains in productivity and predicts a price of $11.43 per ton in 2030. This represents an increase of 15 to 35 percent from current price levels, depending on the market considered (European Commission 2003, p. 23).

WEM calculates a constant steam coal price of $40.92 per ton for the period of 2002 to 2010, which is the average price for the years 1997 to 2001. Between 2010 and 2030, the price is assumed to increase linearly, reaching $46.16 per ton in 2030 (IEA 2002, p. 52). WEM projects increases in demand, and in transportation costs (international, via sea) due to higher oil prices, to exert upward pressure on the world coal price (IEA 2002, p. 52). At the same time, the drop in costs of mining coal resulting from production relocation and productivity gains are projected to push the price down (IEA 2002, p. 52). The transportation cost in the 2003 NEMS applies to domestic transportation in the United States from mines to electric utilities. This difference could explain the divergent trends of coal transportation costs between NEMS and WEM.

Tables 7-1 summarizes these models' projections of coal price as well a private forecast. Year 2000 values of all projections have been normalized to a base value of 100, and subsequent year prices are relative to 2000 prices.

Table 7-1: Coal Price Projections[a]

Year	**2000**	**2005**	**2010**	**2015**	**2020**	**2025**	**2030**
NEMS, AEO 2004	100[b]	100	99	96	94	94	N/A
POLES	100[c]	N/A	N/A	N/A	N/A	N/A	133
WEM	100[d]	N/A	111	N/A	117	N/A	125
Hill & Associates, U.S. Price to Utilities	100[b]	N/A	N/A	84	89	N/A	N/A

[a] Year 2000=100.
[b] $25.47 per short ton.
[c] $8.57 per barrel oil equivalent (BOE), average of markets.
[d] $36.72 per ton.

The U.S. projections are in agreement with one another. NEMS and Hill & Associates both predict declining coal price trends from 2000 through 2015; after that date NEMS' projection continues to decline while Hill's rises somewhat. This reflects EIA's expectation of continued improvements in labor productivity and the expansion of production to the more productive Western U.S. coal mines (EIA 2003a, p. 104). Both POLES and WEM project rising trends while the U.S. forecasts project declining trends.

7.3. Natural Gas

Natural gas forecasts are made with NEMS, POLES, and WEM.

7.3.1. National Energy Modeling System (NEMS)

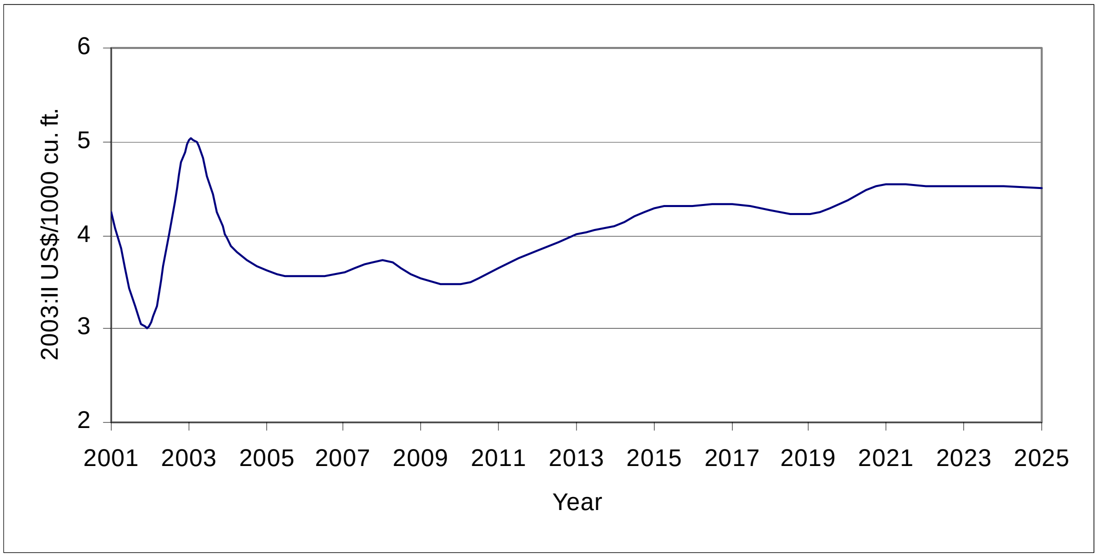
NEMS's treatment of natural gas supply is sophisticated in its reserve-production-price interactions and comprehensive in its resource coverage (EIA 2003e). Based on MacAvoy and Pindyck (1974, Chapter 3), NEMS's natural gas model incorporates investment in exploration as a function of expected profitability, which depends in turn on existing reserves and the current ratio of production to reserves. The success of exploration in finding new reserves is estimated econometrically from historical data, and newly discovered fields infer additional reserves that require additional drilling before they can be declared proven. The supply and wellhead price projections are derived by solving two equations, one relating production from existing wells to recent price changes, the other relating wellhead price in the current year to the previous year's expected price, expected and actual production, and the oil price. A supply curve for gas is generated from the solution to this equation.

NEMS projects gas production from unconventional deposits, including coalbed methane, tight gas sands, and gas shales, estimating economic feasibility of recovery on the basis of their locations, resource quantity and quality, and technology. Arctic gas is modeled on the basis of discrete projects, each requiring pipeline construction, using discounted cash flow to assess the profitability of the pipeline.

Liquified Natural Gas (LNG) imports are treated with a foreign natural gas supply submodule. LNG competes with CIF (the cost including insurance and freight) domestic gas price in the vicinity of a terminal rather than with the free-on-board (FOB) wellhead price.

NEMS forecasts the average Lower 48 natural gas wellhead price to increase steadily from around 2005 through 2025, following a dip after the early 2000s spike. Figure 7-2 shows the reference case trend. Depletion of North American gas resources is cited as the primary factor driving the increase in the wellhead price (EIA 2003a, p. 75). The production forecast of AEO 2003 is for a 34 percent increase over the 2000 level by 2025, but the AEO 2004 forecast lowers that to a 15 percent increase.

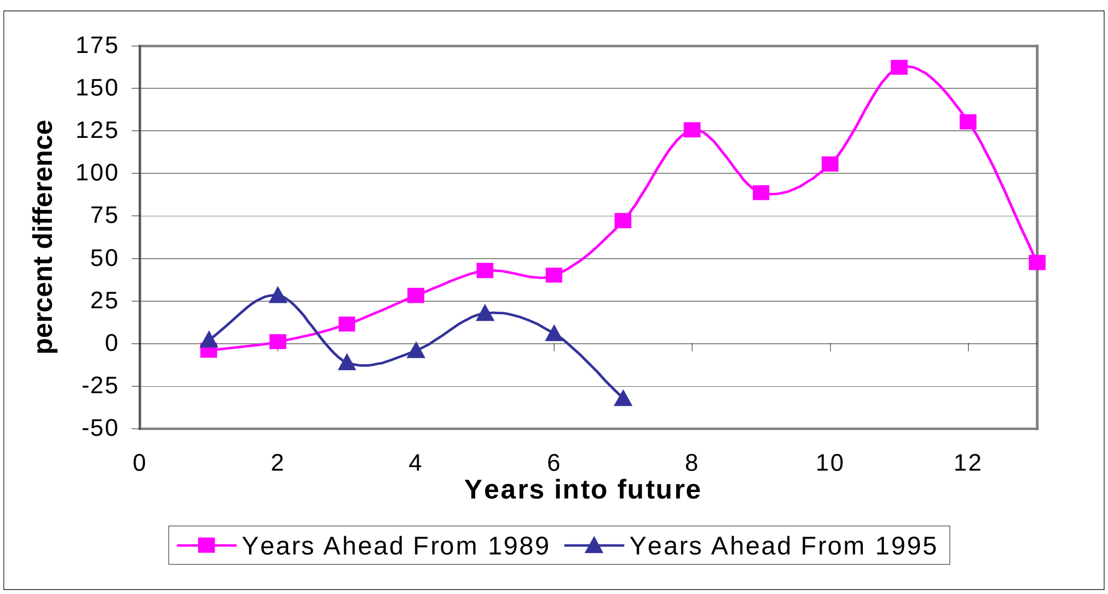
Figure 7-2: U.S. Lower 48 Average Natural Gas Wellhead Price



Source: EIA (2004).

Figure 7-3 shows NEMS' forecast errors of gas prices from two years' forecasts. Only 7 years are available to compare forecasting performance, but the 1995 forecast may be superior to the 1989 forecast since it cycles around zero instead of trending off, although they are predicting for different calendar years. It seems that NEMS' gas price forecasts, even if they are off by 25 percent, are improving with experience.

Figure 7-3: Natural Gas Wellhead Price: Difference between Actual and Forecast



Source: Holte (2001, Table 8).

As with coal, it is evident that EIA has not been entirely successful in its forecasts of natural gas prices. There is also evidence of learning in the forecasting methodology, as the 1995 forecasts perform better than the 1989 forecasts. Natural gas was the last fuel to be affected by regulatory reforms following the period of more extensive controls on energy markets in the 1970s and early 1980s, and the trends of natural gas prices and production in competitive markets have not been stable. In earlier projections, the natural gas outlook was strongly influenced by the world oil price forecast, which was subject to its own error. Beyond market factors, transient external factors such as severe weather are not anticipated by the forecasting models (Holte 2001).

7.3.2. Prospective Outlook on Long-Term Energy Systems (POLES)

Like the POLES model for coal supply, the POLES gas supply model simulates production in national modules, then adjusts the production of the swing producers according to international market interactions. Prices are determined for three markets—American, European, and Asian. The national modules incorporate a discovery-process model for gas supply, but specific drilling effort for gas is not modeled. Gas discoveries are limited by ultimate recoverable resources of gas, but are modeled as a function of the drilling effort for oil rather than by direct modeling of gas exploration. POLES makes this simplification partly because of lack of data but primarily because “oil companies look for oil and many time[s] find gas” (Criqui et al. 2003, 2.2).

The European Commission’s “World Energy, Technology, and Climate Policy Outlook” (WETO) uses POLES to predict gas prices on three continental markets, America, Europe/Africa, and Asia. In the European/African market, the price is forecasted to rise steadily to $32 per barrel (bbl.) in 2030. In the American market, prices first decline from the high level of 2000 down to $16 per bbl. by 2010, and then rise steadily to $29 per bbl. in 2030. In the Asian market, prices rise from $23 per bbl. in 2001 to $38 per bbl. in 2030. The differences between the three regional prices are attributable in part to the mix of pipeline gas and LNG but more generally reflect the low degree of integration of gas markets across world regions, as found in Chapter 9. The price differentials are expected to “diminish significantly” over the forecasting horizon as the gas supply mixes become more similar (European Commission 2003, p. 21).

The rapid growth in natural gas reserves observed in the past is expected to continue for the next decade, followed by a moderate decrease (European Commission 2003, p. 42). WETO predicts that interregional gas trade would represent roughly 36 percent of worldwide gas consumption in 2030, compared to 14 percent currently. This increase in the gas trade “will imply new investments in long distance pipelines from producing to consuming regions and significantly increased LNG trade and investments in LNG infrastructure” (European Commission 2003, p. 90).

7.3.3. World Energy Model (WEM)

The gas supply module in WEM estimates production field by field to determine short-term production profiles, while in the long term production is limited by ultimately recoverable resources and a depletion rate estimated through historical data. Ultimately recoverable resources depend on a recovery factor, which reflects technological improvements in drilling, exploration, and production. The trend in the recovery rate is a function of the gas price, which is set exogenously, and a technological improvement factor (IEA 2002, pp. 510-511).

WEM considers three regional gas markets, North America, Europe, and Asia. In North America, natural gas prices are projected to average around $2.62 per MMBtu in 2002 and to remain at that level until 2005. Prices will then start to rise as rising demand causes the region to become increasingly reliant on more costly sources, such as LNG, unconventional gas, and Alaskan gas (IEA 2002, p. 50). Prices reach $3.15 per MMBtu by 2010 and continue to rise in line with oil prices (IEA 2002, p. 50). IEA's 2002 *World Energy Outlook* predicts rising import dependence for the OECD North America region. In 2000, this region's net gas imports amounted to only 1 percent of the total primary gas supply, but by 2030, imports are expected to rise to 26 percent of the total primary gas supply (IEA 2002, p. 117).

7.3.4. Current Issues in Natural Gas Supply

The recent increases in natural gas prices have led to divergent opinions on the future of natural gas in the United States. In one view these price increases represent fundamental shifts in supply and demand that have long-term implications for the natural gas market and will only worsen in the future because of dwindling gas reserves (Simmons 2003). Currie (2003) emphasizes longer-term deterioration of gas pipeline and storage infrastructure, post-deregulation, as a major problem facing the gas industry, but in the long-run time period of the current study, capital markets will supply that infrastructure.

A recent study by the National Petroleum Council (NPC) also blames the higher gas prices in recent years on a fundamental shift in the supply-demand balance (NPC 2003, p. 23). However, the NPC believes the tight market situation "can be moderated" (NPC 2003, p. 23) by allowing exploration and production in currently restricted areas offshore and in the Rocky Mountains, using new technologies that can protect sensitive environmental resources (NPC 2003, pp. 76-77).

7.3.5. Summary of Gas Price Projections

Table 7-2 reports NEMS, POLES, and WEM projections of natural gas prices through 2020, and two private forecasts reported by the AEO 2003, those of Global Insights, Inc. (GII) and Energy Ventures Analysis, Inc. (EVA). The NEMS forecasts from the AEO 2003 and AEO 2004 are reported in the first two rows of the table, showing a sharp increase in EIA's gas price forecast between these two years. Prices are expressed relative to a base of

2000 prices set to 100. NEMS and POLES agree on the dip between 2000 and 2005 and subsequent rise through 2020. WEM and the two private forecasts do not report near-term forecasts but agree on a rising trend by 2010, from a level below 2000 prices.

Table 7-2: Natural Gas Price Projections[a]

Year	2000	2005	2010	2015	2020
NEMS Lower 48 U.S .Wellhead Price, AEO 2003	100[b]	75	86	93	96
NEMS Lower 48 U.S. Wellhead Price, AEO 2004	100[b]	92	88	109	111
POLES, American Market Price	100[c]	69	73	81	94
WEM North American Market Price	100[d]	N/A	69	N/A	87
GII Lower 48 U.S. Wellhead Price	100[b]	N/A	N/A	82	84
EVA Lower 48 U.S. Wellhead Price	100[b]	N/A	N/A	99	81

[a]Year 2000=100.
[b]$3.93 per 1000 cu. ft.
[c]$21.95 per BOE (bbl oil equivalent).
[d]$4.09 per MMBtu.

7.4. Uranium

7.4.1. International Atomic Energy Agency's *Analysis of Uranium Supply to 2050*

Due to the long time spans involved in the life cycles of uranium mines and nuclear power plants, projections for uranium require a longer forecasting horizon compared to other fuels (IAEA 2001, foreword). In its projections of global uranium production, the International Atomic Energy Agency (IAEA) considers three uranium demand cases (low, middle, and high) covering a range of assumptions regarding global economic growth and nuclear energy policy. In the low demand case, economic growth is of medium pace, with energy demand growth consequently low. In this case, energy policies are ecologically driven, and nuclear power is phased out by 2100. The medium demand case is also characterized by medium economic growth, low energy demand growth, and ecologically driven energy policies, but the entire world, including developing countries, sees a sustained development of nuclear power. The high demand case foresees high economic growth and a "rich and clean" energy future without recourse to strict environmental policies. Nuclear power develops significantly in the high demand case (IAEA 2001, p. 1).

The main focus of the IAEA analysis is to assess the adequacy of conventional uranium resources to satisfy market-based production requirements. Conventional resources are defined as those that have an established history of production where uranium is either a primary product, co-product, or important by-product (e.g., gold). Such resources are grouped into categories. The categories range from highest to lowest on a scale of confidence in the future availability of each type of resource. Production centers and their associated resources are also ranked by projected production costs. The order in which production centers fill market-based production requirements is based on availability confidence level and cost. It is assumed that the lowest-cost producer in the highest-confidence category will satisfy the first increment of demand, followed by progressively higher-cost, lower-confidence producers until annual demand is filled (IAEA 2001, pp. 2-3).

The IAEA study does not include an explicit projection of uranium prices, but it does project the years when production centers of various cost ranges and confidence levels will be cost-justified to begin operations. These projections, contained in Table 7-3, should be interpreted as "an indirect indication of market price trends" (IAEA 2001, p. 4). For example, in the first row, in the medium demand case, using only reasonably assured resources (RAR), production costs will fall in the range of $55 to $82 per kilogram (kg) of uranium by 2019, and will not jump to the higher range of $82 to $136 per kg until 2024. Accepting the stock of resources described by RAR plus estimated additional resources of confidence level I (EAR-I), those two years would be pushed back to 2021 and 2027, and adding estimated resources of confidence level II (EAR-II), these two years would be 2021 and 2029.

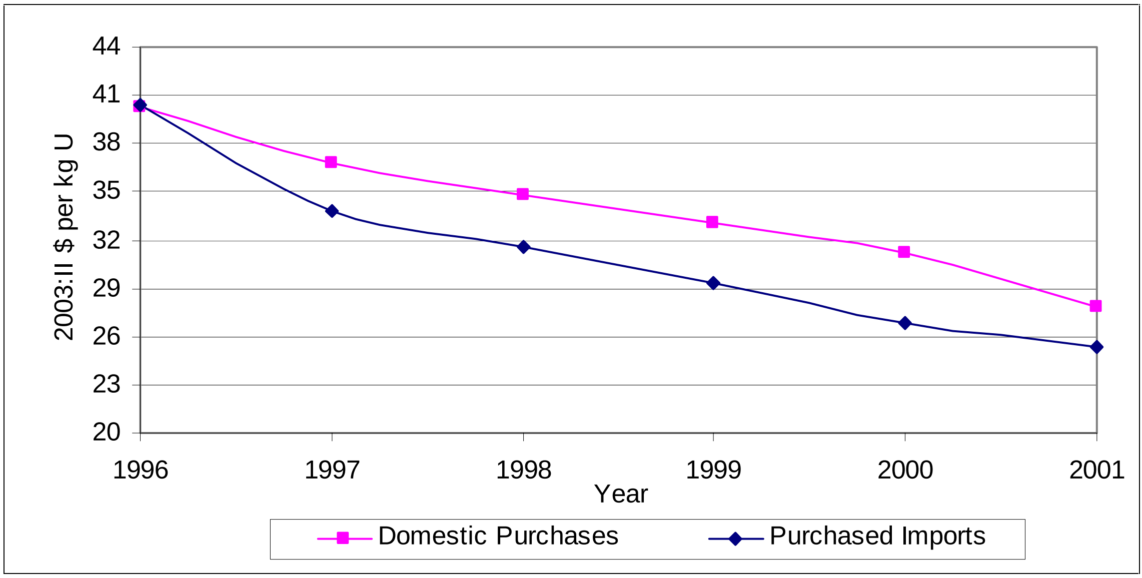
Table 7-3: Year When Production Centers Become Cost Justified

Confidence Level Regarding Resource Availability: Adding Resources of Decreasing Certainty	**Price of Uranium**		
	$55 to $82 per kg U	**>$82 to $136 per kg U**	**>$136 per kg U**
	Medium Demand Case Price of Uranium		
RAR[a]	2019	2024	2028
RAR + EAR-I[b]	2021	2027	2034
RAR + EAR-I + EAR-II[c]	2021	2029	2041
	High Demand Case Price of Uranium		
RAR	2013	2019	2023
RAR + EAR-I	2015	2022	2026
RAR + EAR-I + EAR-II RAR + EAR-I + EAR-II	2015	2023	2031

Source: IAEA (2001, p. 4).
[a] Reasonably assured resources
[b] Estimated additional resources of confidence level I
[c] Estimated resources of confidence level II

Figure 7-4 shows recent uranium prices in the United States. These prices correspond to production in the cost categories below $36 per kg U and $36 to $55 per kg U (IAEA 2001, p. 33).

Figure 7-4: U.S. Average Price of Uranium



Source: EIA (2003f).

7.4.2. International Energy Agency's "Global Uranium Supply Outlook"

In its 2001 "World Energy Outlook" (IEA 2001), the International Energy Agency (IEA) examined the current and possible state of worldwide uranium production and brought together outside studies on the subject, including the IAEA study described above.

Uranium prices fell throughout most of the 1990s, largely due to the sale of secondary supplies. The availability of these supplies has prevented the global imbalance between production and consumption of primary uranium from affecting prices. The IEA predicts that uranium prices will not rise significantly in the medium term. The fact that market prices have been kept at artificially low levels has given producers little incentive to undertake major exploration (IEA 2001, p. 368).

In the longer term however, prices may rise as secondary supplies released at the end of the Cold War are depleted and commercial inventories drop by 2020. Consequently, market prices will likely rise to reflect higher production costs. The long lead time between uranium discovery and production, typically 10 to 15 years, means that producers must be assured that prices will remain high enough to support investment in exploration (IEA 2001, p. 369).

7.4.3. Estimates of Uranium Supply Elasticity

Low prices and the availability of large, known uranium reserves have stifled incentives to invest in exploration for new uranium resources for some years. However, if price rose enough to stimulate substantial investments in exploration, new uranium resources far larger than today's resource estimates are likely to be found, according to Bunn et al. (2003, p. 106). Three studies have attempted to estimate the price elasticity of supply for uranium. Bunn et al. developed an empirical relationship relating uranium supply to price, based on a supply curve, $R = 2.1(p/40)^E$. They used quantity and price estimates from three other studies to estimate the magnitude of the elasticity, E. Table 7-4 summarizes their elasticity estimates. The table also includes the resources projected at particular prices under the different elasticity estimates.

Table 7-4: Estimates of Uranium Resources

Source	E	R(MtU) p ≤ \$84 per kgU	R(MtU) p ≤ \$136 per kgU
Uranium Information Centre	3.32	21	105
Deffeyes and MacGregor	2.48	12	40
DOE Office of Nuclear Energy	2.35	11	34

Source: Bunn et al. (2003, p. 113).

Although these estimates are based on limited data, Bunn et al. suggest that the total amount of uranium recoverable at or below $136 per kgU is considerably larger than the amount reported in 2001 by IAEA, anywhere from two to six times larger. They note that the relationships resulting in smaller resource estimates are based solely on geological relationships, without considering the likelihood that technology for recovering uranium at lower cost will improve in the future. They claim that technological improvement is "virtually certain," providing the example that uranium is now recoverable at less than $55 per kgU from ores in copper mines with concentrations as low as 4.5 parts per million (Bunn et al. 2003, p. 113).

7.4.4. Uranium Market Model of the U.S. DOE

The Uranium Market Model (UMM), last revised in 1996, is a microeconomic simulation model that matches uranium supplied by the mining and milling industry with the demand for uranium by electric utilities operating nuclear power plants (Das and Lee 1996). The model considers every production center and utility worldwide, as well as holders of stockpiled uranium and other suppliers. The model makes annual projections for 10 global regions, one of which is the United States.

The UMM represents uranium supply with an annual short-run supply curve that relates increments of potential production to the market price. Supplies come from production and releases from official stockpiles and private inventories. Production costs are exogenous but take into account the size of reserves, annual production capacity, ore grade, and type of production process.

The demand for uranium by electric utilities with nuclear power plants is derived exogenously. Individual reactor requirements are summed into utility-specific or regional totals. Reactor requirements are inelastic with respect to uranium prices, but utilities' inventory demand responds to uranium spot prices.

7.4.5. Effects of Uranium Price on Cost of Nuclear Power Generation

The fuel cost share nuclear power's busbar cost is small, around 10 percent (Papay 1997, Paulson 2002). Moreover, the uranium cost share of the total fuel cost is about 10 percent (NEA 1994). Thus, it is unlikely that changes in uranium price of foreseeable magnitude would materially affect the cost of nuclear power generation.

7.5. Other Models

The models reported in the fuel-specific sections above developed distinct models for coal and natural gas. Two energy models, Argonne National Laboratory's and the International Institute for Applied Systems Analysis' (IIASA) models, offer fuel forecasts with specifications that are not specifically tailored to individual fuels.

7.5.1. Energy and Power Evaluation Program

The Energy and Power Evaluation Program (ENPEP) was developed at Argonne National Laboratory and is distributed by Adica Consulting, LLC. ENPEP simulates energy markets and determines supply/demand balances over a long-term period of up to 75 years. The BALANCE module of ENPEP models a national energy network consisting of energy activities from production to final utilization, each called a node. The nodes are connected by links, which convey price and quantity information between nodes (Adica 2002, pp. 1-3).

The Depletable Resource Node models the production of a depletable resource, such as coal, natural gas, or crude oil, which can be domestically produced or imported. The equation associated with this node relates the cost of producing or importing increments of a given resource to the cumulative amount of the resource produced or imported. This equation represents ENPEP's long-run supply curve for the resource (Adica 2002, p. 5).

7.5.2. Model for Energy Supply Strategy Alternatives and their General Environmental Impact (MESSAGE)

7.5.2.1. The Model

The Model for Energy Supply Strategy Alternatives and their General Environmental Impact (MESSAGE) was developed by IIASA. MESSAGE models fuel supply through detailed domestic resource extraction constraints and elasticity definitions, in addition to constraints on imports and exports.

MESSAGE calculates a supply elasticity as the change in price relative to a reference price level that results from a change in supply over a reference supply level (Messner and Strubegger 2001, p. 47). The model contains an equation that balances production and import of primary energy with central conversion, transport, and export requirements (Messner and Strubegger 2001, p. 28). This equation takes into account the level of technology involved in the extraction a given resource (Messner and Strubegger 2001, p. 29).

MESSAGE was used for the projections in *Global Energy Perspectives*, published jointly by IIASA and the World Energy Council (WEC) in 1998. Although this publication does not include projections of fuel prices, it does include projections of fuel production by region. The projections for North American (U.S. and Canadian) gas production under six different scenarios are shown in Table 7-5. The timing and extent of new discoveries of reserves and resources are incorporated as assumptions in the scenarios (IIASA and WEC 1998, p. xiii). The numbers indicate that the scenarios represent distinctly different futures, even within a period of only three decades.

All the scenarios in MESSAGE project increasing North American natural gas production from 2000 through 2020, although scenarios B, C1 and C2 see production falling off from 2010 to 2020.

Table 7-5: MESSAGE Forecasts of North American Gas Production

North America Natural Gas Production (Mtoe)			
Scenario	**2000**	**2010**	**2020**
A1: high growth, ample oil and gas	587	727	806
A2: high growth, return to coal	580	716	734
A3: high growth, fossil phaseout	620	794	997
B: middle course	583	712	690
C1: ecologically driven, new renewables with nuclear phaseout	506	569	545
C2: renewables and new nuclear	507	593	562

7.6. Conclusion

The models examined in this report differ in the scopes of their projections. The coal and gas models account for feedbacks between proven reserve base, price, and exploration, but the uranium models remain more rudimentary in their characterizations of supply.

The projections of NEMS focus on future energy trends in the United States, while POLES, WEM, and MESSAGE have a more international orientation. This section summarizes some of the important similarities and differences in the underlying methodologies of the various models for coal, natural gas, and uranium supply and recapitulates their projected trends.

7.6.1. Coal

NEMS' coal supply modeling is the most sophisticated among the three models examined. The U.S. forecasts, from NEMS and Hill & Associates, agree on a declining coal c.i.f. (cost including insurance and freight) price forecast from 2000 through 2020 of about 10 percent, but POLES and WEM both predict rising international coal prices, as much as 25 to 30 percent. All the models agree that coal production will increase 35 to 50 percent over the next 20 to 30 years.

7.6.2. Natural Gas

As with coal supply models, NEMS provides the most comprehensive model of gas supply. Gas prices are projected to fall after the initial spikes, a pattern replicated across the models. Production is projected to increase over the forecast horizon by 15 to 40 percent, across models and scenarios.

7.6.3. Uranium

While IAEA offers an outlook on potential uranium market trends, it does not incorporate a model of investment in exploration. It warns that exploration needs to occur to ensure a low-cost supply of uranium but does not model factors influencing it. Unlike the natural gas models, none of the uranium modeling take into account the determinants and uncertainties of exploration, possibly because there has been relatively little recent exploration for uranium. Unique factors are at play in uranium exploration, chiefly the long lead time between discovery and production. The major issue in the future of uranium is the cost at which future exploration might allow supplies to be produced.

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Chapter 8. ENVIRONMENTAL POLICIES

Summary

The future costs per MWh of the major competitors to nuclear energy, not just the present costs, need to be considered. In addition to process technology advances and possible fuel price changes that could reduce coal- and gas-fired costs, environmental considerations could serve to raise the cost of these competitor sources in view of their significance as a source of air pollution. This chapter assesses the potential magnitudes of these cost increases on coal- and gas-generated electricity.

In view of global climate concerns, an important emission that remains largely uncontrolled but could be subject to controls in the future is carbon. Carbon emissions can be reduced only by thermal efficiency improvements, which have rather tight limits. Capture and sequestration therefore are the longer-term environmental control possibilities for carbon.

Despite a recent application of capture and sequestration in a gas-fired plant in Norway and an innovative example of sale and re-use between a gas-fired utility in North Dakota and an oil company in Canada, the technology and likely costs of carbon sequestration are in pre-commercial stages.

While the technologies of carbon capture, transport, injection, and sequestration cannot be said to be commercialized yet, some cost estimates are available. On a per-megawatt hour basis, assuming 100 km transportation by pipeline, a summary is:

> $36 to $65 per MWh for pulverized coal combustion (PCC), including an energy penalty of 16 to 34 percent
>
> $17 to $29 per MWh for gas turbine combined cycle (GTCC), including an energy penalty of 10 to 16 percent
>
> $20 to $44 per MWh for integrated gasification combined cycle (IGCC), including an energy penalty of 6 to 21 percent.

An alternative measurement of the future costs of carbon control is through the use of permit markets similar to those used by the Acid Rain Program and Federal NO_X Budget. Prices generated through permit market trading are interpreted as the approximate future cost of reducing present emissions. Thus the prices can be used to estimate the mean cost of meeting current emissions standards on a per MWh basis. Partly because of the present lack of a carbon emission standard, the results of models estimating the future price of potential greenhouse gas permits that have been reviewed have varied greatly. A carbon price range ($50 to $250 per metric ton) has been used to construct upper and lower bounds to the electricity cost impact. For coal, the cost impact is likely to be between $15 and $75 per

MWh, and for gas, it is between $10 and $50 per MWh. Significant uncertainty exists in these estimates due to uncertainty in the amount of carbon that is likely to be controlled.

Outline

8.1. Introduction

This chapter examines the future environmental costs of fossil fuel energy, particularly coal-fired and natural gas-fired electricity. The costs and benefits of current and potential future technologies for the mitigation of carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM) are discussed.

Section 8.2 examines the present and projected future emissions from electricity generation in the United States, focusing on criteria pollutants associated with fossil power generation. Section 8.3 discusses the current state of carbon sequestration technology and investigates the impacts that legislation regarding carbon emissions may have on the future of fossil fuel-fired power plants. Section 8.4 discusses the potential effects of a carbon tax and emissions permit trading. Section 8.5 discusses the effect of current NO_X and SO_2 emissions trading programs.

8.2. Present Situation and Future Projections

The role of fossil fuels in future electricity generation is projected to increase significantly over the next two decades. EIA (2002) projects the share of electricity generated from fossil-fuel fired plants to be 80 percent by 2020, up from 69 percent in 1999.

Natural gas-fired and coal-fired power plants are significant contributors to emissions of many criteria pollutants and carbon dioxide. In 2000, coal-fired electricity generation emitted 2,154 million tons (short tons used throughout this chapter unless otherwise noted) of carbon dioxide (CO_2), or 14.1 percent of total emissions (EPA 2002a). Coal-fired power plants emitted 10.7 million tons of sulfur dioxide (SO_2) and 4.7 million tons of nitrogen oxides (NO_X), or 62 percent and 17.5 percent of total emissions, respectively (EPA 2002a). Emissions from natural gas-fired plants were much lower, both because of lower output from these plants and because emission rates for natural gas-fired plants are lower than for coal-fired plants. Electricity produced from natural gas in 2000 emitted 359 million tons of CO_2, roughly 2 percent of total CO_2 emissions (EPA 2002a). Natural gas-fired electricity generators emitted 0.08 million tons of SO_2, and 0.5 million tons of NO_X, or roughly 0.5 percent and 1.9 percent of total emissions, respectively (EPA 2002a).

EIA projections put CO_2 emissions from natural gas and coal-fired power plants at 3,182 million tons in 2020, with 2,625 million tons of CO_2 coming from coal burning plants and 505 million tons coming from natural gas-fired electricity generators. These amounts represent 13 percent and nearly 3 percent of projected CO_2 emissions in 2020 from all sources (EIA 2003c). Future emissions of SO_2 from coal-fired power plants are capped by the Clean Air Act Amendments of 1990 (CAAA 1990) at 8.95 million tons. NO_X emissions are projected to be roughly 4.5 million tons in 2020 (EPA 2003c).

8.3. Carbon Sequestration Technology and Costs

One of the most widely discussed means of reducing CO_2 emissions is carbon capture and sequestration. The basic method is to capture CO_2 and inject it into secure geologic formations or into the deep ocean for long-term storage. This method holds much promise, and in a 1997 report, the President's Committee of Advisors on Science and Technology (PCAST) recommended that funding within DOE's fossil-energy R&D program be reformulated, emphasizing new technologies such as carbon capture and sequestration (PCAST 1997, p. 5).

Two current projects are being studied to better understand the feasibility of this type of solution in the reduction of global CO_2 emissions. These are the Weyburn project in Saskatchewan, Canada and the Sleipner project in the North Sea off the coast of Norway. The motivations behind these two projects differ.

The Weyburn oil field, located in southeastern Saskatchewan, was discovered in 1954, containing approximately 1.4 billion barrels of oil. As production rates declined in the field, CO_2 flooding (injection of CO_2 into the field to increase production) was used to recover an additional 130 million barrels of oil and permanently sequester approximately 15.4 million net tons of CO_2 for a total of 19.8 million tons of CO_2. CO_2 is captured at the Great Plains Synfuels Plant in North Dakota (coal-fired power plant) and transported in a supercritical state (2,100 pounds per square inch (psi)) via 323-km pipeline to the Weyburn site. Approximately 2,756 tons of CO_2 per day have been injected into the reservoir since September 22, 2000 (Brown et al. 2001).

The CO_2 sequestered at the North Sea Sleipner gas fields is not the result of burning fossil fuels, but is an impurity that is removed to prepare the gas for market. Formerly, the CO_2 was vented to the atmosphere. When Norway instituted a tax on offshore carbon emissions of U.S. $50 per tonne, it became economically viable to capture and sequester the separated CO_2 (the tax was later lowered to $38 per tonne). By avoiding this tax on one million tonnes of CO_2 annually (3 percent of Norway's total CO_2 emissions), Statoil was able to recover its investment of $80 million in two years (Adam 2001).

Since, 1996 Statoil has been injecting the separated CO_2 into a sandstone layer, known as the Utsira formation, 800 to 1,000 meters below the seabed (IEA 2003). After separation, the CO_2 must be compressed to a supercritical state and injected into the rocky reservoir.

A seismic survey done by the British Geological Survey (BGS) in 1999 showed that the CO_2 injected into the reservoir is likely to remain in place. The potential for storage is large. One percent of this reservoir would hold three years' emissions from all the power plants in Europe (Adam 2001). A BGS report indicated that the North Sea has the potential to hold all of the CO_2 from European power stations for 800 years (800 billion tonnes) (IEA 2003). One concern is that the CO_2 may begin to compress, rather than dissipate throughout the formation, making future injection more difficult (Adam 2001).

8.3.1. Separation and Capture

According to Herzog, all current commercial CO_2 capture is based on chemical absorption of CO_2 from flue gas using a monoethanolamine (MEA) solvent (Herzog 1999, p. 4). The MEA/CO_2 solution is sent to a stripper where it is heated, and nearly pure CO_2 is released and the MEA is recycled (Herzog 1999, p. 5). Herzog notes that the majority of costs associated with carbon sequestration are incurred in separation and capture.

8.3.2. Cost Estimates

David (2000) compares several different studies to estimate costs associated with CO_2 separation and capture for three types of new (not retrofit) power plants: Integrated Gas Combined Cycle (IGCC), Pulverized Coal Combustion (PCC), and Gas Turbine Combined Cycle (GTCC). He adjusts all the studies to a common economic basis to compare costs across studies. The averages David computed across studies for each plant type are reported in Table 8-1. The energy penalty is the additional input energy required to separate and capture the CO_2. Additional energy means additional CO_2, so the relevant figure is not CO_2 captured, but CO_2 avoided.

Table 8-1: Average Costs Across Studies: IGCC, PCC, and GTCC (David 2000)[a]

Plant Type	Incremental Cost of Capture per MWh	Average Cost per Ton of CO_2 Avoided	Energy Penalty, Percent
IGCC	\$17.2	\$27	6.4 to 21.4
PCC	\$34.8	\$52	15.9 to 34.1
GTCC	\$15.9	\$51	9.8 to 16.1

[a]Although not specified in David's reports, this study's calculations confirm that these figures are metric tons, or tonnes. Yearly operating hours = 6,570 hrs per year; capital charge rate = 15 percent per year; coal price at lower heating value (LHV) = \$1.24 per MMBtu; natural gas price (LHV) = \$2.93 per MMBtu (David 2000).

8.3.3. Transport and Injection

Storage of CO_2 is feasible in many different locations, including ocean storage—both at intermediate depths (> 1,500 m) and deep lake injection (> 3,000 m)—depleted gas and oil reservoirs, deep saline aquifers, and unminable coal seams (Ormerod 2002, Davison 2001). Transportation methods are dependent on both the location of the CO_2 source and the location of the sequestration site. Transportation methods include pipeline, truck, and ocean tanker. Costs associated with transportation would also be highly dependent on the distance and method used, but average costs have been estimated.

Herzog (2004, p. 10) notes that the costs of transportation via pipeline can vary greatly, depending on factors such as terrain and population density. He estimates the costs of pipeline transportation of CO_2 for a 1,500 MW coal-fired power plant (equivalent to a flow rate of 10 million metric tonnes per year) to be $0.50 per metric tonne per 100 km. Lower flow rates could be as high as $2.00 to $3.50 per metric tonne CO_2 per 100 km (Herzog 2004, Figure 5). These figures are more in line with those cited by the IEA Greenhouse Gas R&D Programme of approximately $1 to $3 per tonne CO_2 for 100 km (Davison 2001). Herzog's estimate of truck transportation of CO_2 is $6.00 per metric tonne per 100 km. Table 8-2 estimates the costs of transporting CO_2 from different plant types using the (low) estimates from Herzog (2004) for pipeline transport ($0.50 per metric tonne per 100 km) and (high) truck transport ($6.00 per metric tonne per 100 km). The estimates presented are based on the following assumptions:

- Energy penalties for plant types are equal to the averages from studies presented in David (2000), or 14.53 percent, 25.18 percent, and 13.05 percent for IGCC, PCC, and GTCC plants, respectively, though no energy penalty is included for the additional energy required to transport the CO_2 by truck;

- Distance from plant to injection site of 500 km (David 2000 notes that all power plants in the United States are located within 500 km of possible sequestration sites); and

- Capture rates of 88.2 percent, 86.9 percent, and 88.0 percent for IGCC, PCC, and GTCC plants, respectively (David 2000).

Table 8-2: Ground Transportation Cost Estimates, by Plant Type, $ per MWh

Plant Type	**Pipeline @ $0.50 Per Metric tonne-100 km**	**Truck Transport @ $6.00 per Metric tonne-100 km**
IGCC	1.9	22.8
PCC	2.1	25.7
GTCC	0.9	11.0

The IEA Greenhouse Gas R&D Programme estimated the costs associated with ocean transport of CO_2. Ormerod (2002) notes: "Comparable 0.5 m diameter pipelines … cost about $1.6 million per km. Such pipelines have the capacity for 18,000 [tones of CO_2 per day]…. The cost of transporting CO_2 for 500 km, by such a pipeline, would be around $12/t CO_2…." (Ormerod 2002, p. 13). Ormerod also notes the significant advantages a larger diameter pipe would have, with a 1-m diameter pipe transporting four times as much per day, but costing less than four times the price of the 0.5-m pipe. The IEA Program estimates transportation by tanker would be around $2 per tonne of CO_2, though added to this would be the costs associated with a CO_2 holding tank at the port, the platform, and the vertical pipe, as well as operating expenses (Ormerod 2002, p.14).

Two basic options exist for CO_2 sequestration, storage in the oceans and underground storage. Three main geological structures are available for permanent or semi-permanent CO_2 sequestration: depleted oil or gas reservoirs, deep saline aquifers, and unminable coal beds. Each option offers different benefits. The IEA Greenhouse Gas R&D Program estimates that depleted oil and gas reservoirs could store 920 Gt (Gigatonnes) of CO_2, deep saline aquifers 400 to 10,000 Gt, and unminable coal beds an additional 15 Gt.

Herzog (1999) estimates injection and storage costs for CO_2 to be between \$3 and \$5.5 per tonne of CO_2. Table 8-3 shows the additional costs injection and storage would impose on power generation, by plant type. As with transportation costs, the cost per MWh is highest for PCC plants and lowest for GTCC plants. These differences are due to the variations by plant type in CO_2 produced per kWh of electricity generated. The IEA Greenhouse Gas R&D Program estimates that the cost of storage in depleted oil and gas reservoirs and deep saline formations to be \$1 to \$3 per tonne CO_2 (Davison et al. 2001).

Table 8-3: Injection and Storage Cost Estimates, by Plant Type, \$ per MWh

Plant Type	Injection & Storage @ \$1.00 per tonne-CO_2	Injection & Storage @ \$5.50 per tonne-CO_2
IGCC	0.8	4.2
PCC	0.9	4.7
GTCC	0.4	2.0

8.3.4. Summary of Carbon Mitigation Costs

For any power plant there are costs associated with producing the power. If CO_2 emissions become costly, either through a tax on emissions or through costs associated with sequestration, these costs become part of the private cost of producing power. Alternatively, any revenue from the sale of captured CO_2 would be subtracted from the costs. These costs have the form:

$$F_X + C_{Capture} + C_{Transport} + C_{Injection} - P_{Sale} + T_{CO2} = F_{X+CO2},$$

Where:

F_X is cost of power production at facility type X = {IGCC, PC, NGCC}) without sequestration and capture
$C_{Capture}$ is the cost of separation and capture/compression for CO_2
$C_{Transport}$ is the cost of moving the captured CO_2 to the sequestration site
$C_{Injection}$ is the cost of inserting the captured CO_2 into the sequestration site
P_{Sale} is the benefit received by the power company from the sale of its product
T_{CO2} is any tax imposed on CO_2 emissions.

There is an additional energy penalty involved for both transportation and injection that is not included in the energy penalty for separation and capture.

Using this formulation, Table 8-4 summarizes the cost components of the full cycle of carbon sequestration, including capture, transport, and injection and storage. The transport costs assume a 100-km pipeline as an average across plants. The capture costs are the largest component, injection, and storage the smallest, and transport the most variable. Coal plants would face the greatest expense, although IGCC technology is better adapted to capture carbon than is pulverized coal, and gas the least.

Table 8-4: Summary of Components of Carbon Sequestration Cost, $ per MWh

Plant Type	Capture	Transport	Injection and Storage	Total
IGCC	17	2 to 23	1 to 4	20 to 44
PCC	34	2 to 26	1 to 5	34 to 65
GTCC	16	1 to 11	.5 to 2	17 to 29

8.4. Carbon Tax and Emissions Permit Trading

A cap-and-trade program similar to the current SO_2 abatement program may be implemented in the future. Like carbon taxes, carbon permit markets are intended to equalize marginal costs of abatement, only a permit price is set by a market rather than by a regulator. Thus, these prices are likely to be closer to the true cost of abatement than a carbon tax.

Predicting the actual price of carbon emissions the market will bear is complicated by numerous uncertainties relating to supply and demand, the introduction of the Kyoto Protocol, and other factors. Ultimately, the carbon price will rise or fall as a function of the amount to be abated and the number of buyers and sellers participating in the market. As abatement targets become more stringent, the cost of carbon abatement will increase and with it the viability of low-carbon-generation options (WWF 2003, p. 8).

The availability of more economic substitutes could contribute to lower allowance prices. While carbon sequestration technology continues to improve, fuel switching between high-carbon-content coals to natural gas is currently the most accessible method for lowering carbon emissions. Natural gas plants emit less CO_2 and other pollutants than coal plants. Depending on the future price of natural gas, large-scale substitution away from coal could occur in response to a carbon control program.

8.4.1. Review of Carbon Price Estimates

Despite an already large and growing demand for information upon which to formulate reasonable price expectations, little reliable information is available (Springer 2003, p. 1). Numerous models simulate a global market for carbon dioxide (CO_2) or greenhouse gas (GHG) emission permits. For example, Burtraw et al. (2002) have shown that permit prices necessary to achieve a given target are likely to vary by allocation method. Based on a 6 percent emissions reduction phased into the electricity sector in 2008, the auction method results in an allowance price of $25 per ton of CO_2 in 2012. Under grandfathering, the price is $38, and under allocation by generator performance it is $40.

Several other studies have attempted to predict the price of carbon, but they offer limited insight, since their scenarios and price estimates differ considerably. A review of the SO_2 market by Smith et al. (1998) suggests that a full implementation would result in prices between $389 and $1,005 per ton SO_2, whereas actual prices since 1994 have not surpassed $212. The performance of emissions market models in predicting SO_2 allowance prices in the case of the U.S. Acid Rain Program may forecast the ability of comparable models' accuracy to predict prices in the more complicated GHG market (Springer 2003, p. 4).

More recently, EIA (2003b) completed an analysis of the proposed McCain-Lieberman Climate Stewardship Act, which contains a cap-and-trade program similar to the Acid Rain Program. NEMS assessed the cost of greenhouse gas mitigation measures per ton of carbon at $79 in 2010, $129 in 2016, and $210 in 2025.

8.4.2. Estimated Effect of Carbon Control

To estimate the range of effects of a carbon tax on the price of electricity, taxes of $50, $100, $150, and $250 per ton were used. Using a sample of 214 coal plants and 222 gas-fired plants selected from EPA's Emissions and Generation Resource Integrated Database (EGRID), the average incremental cost of electricity of the per ton carbon price was calculated using the following formulation:

$$[\text{Total Annual } CO_2 \text{ Emissions (tons)} \bullet 0.273 \bullet \text{Carbon Price (\$ per ton)}] / [\text{Total Annual Net Generation (MWh)}].$$

Table 8-5 summarizes the calculations from this equation.

Table 8-5: Costs of Carbon Control, $ per MWh

Carbon Price $ per ton	Incremental Coal-Fired Cost	Incremental Gas-Fired Cost
50	14.9	9.73
100	29.8	19.47
150	44.7	29.20
250	74.5	48.67

8.5. The Effect of Tradable Emission Permit Programs on Electricity Prices

The purpose of examining current tradable emission permit programs is two-fold. First, analysis of the permit allowance prices provides an indication of the future costs to electricity generators of reducing present emissions. Second, examining the performance over time of current permit programs may provide insight into the potential cost of a carbon program.

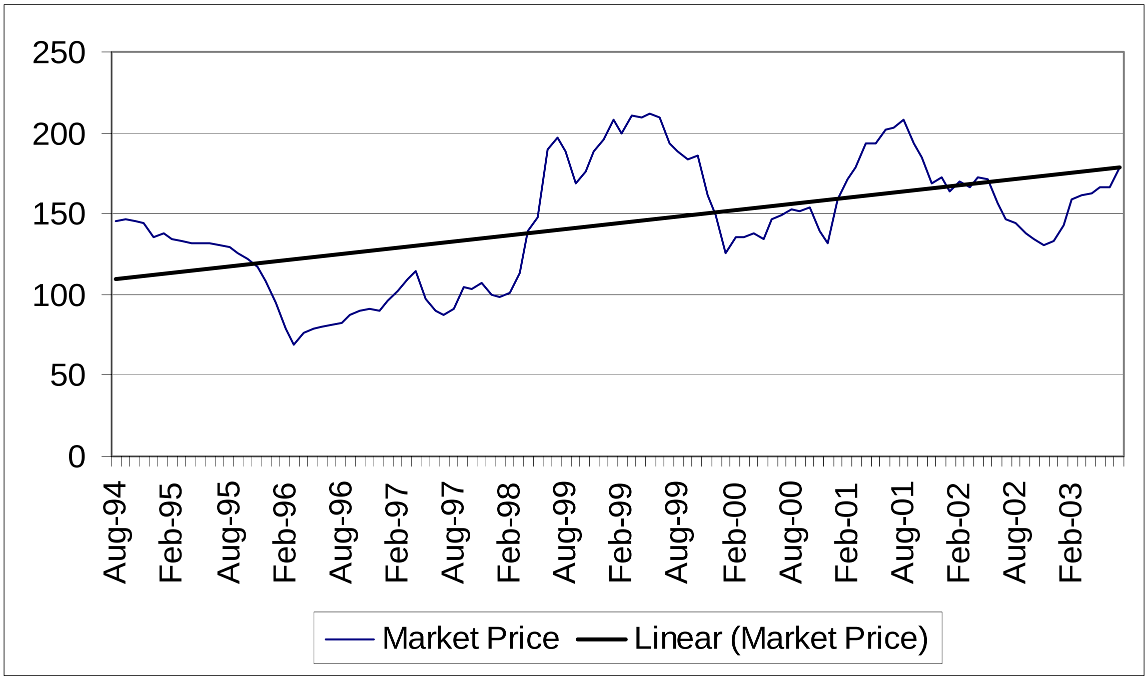
8.5.1. The SO_2 Case

The U.S. SO_2 cap-and-trade program was established as a result of the 1990 Clean Air Act Amendments under the authority granted by Title IV, which included several measures to reduce precursor emissions of acid deposition. The SO_2 component consisted of a two-phase cap-and-trade program for reducing SO_2 emissions from fossil-fuel-burning power plants located in the lower 48 states of the United States. Beginning in 2000, the Phase II cap equivalent to an average emission rate of 1.2 lbs. of SO_2 per MMBtu was instituted for all electric generating units greater than 25 MW (Burtraw et al. 2003a, pp. 2-6)

Since allowances are readily substitutable for abatement, this single price provides a common reference point and a coordinating mechanism for all owners of affected sources in deciding whether to abate more or less at any one time and thereby to equalize the marginal cost of abatement. The cap-and-trade system generally has been regarded as efficient as evidenced by its high volume of trading since its inception in 1994.

Allowance prices have varied greatly, from a low of \$64 in 1996 to a high of \$212 in 1999. The average price since Phase II of the Acid Rain Program is \$164, with a low of \$125 and a high of \$208. In spite of the wide variation, there appears to be a general upward trend in allowance prices, as shown in Figure 8-1.

Figure 8-1: Trends in SO_2 Allowance Prices



Source: EPA (2002b).

Year 2000 emissions data from 214 coal-fired plants (600 MW or larger) were used to approximate the effect of SO_2 abatement measures on the cost of generating electricity (EPA 2002a). Plants that had input emission rates above the Phase II emissions rate limit of 1.2 lbs. per MMBtu were assigned a corresponding number of allowances. The incremental cost per kWh generated was then determined by dividing the total cost of allowances by the net annual generation for each plant. The average cost for the 83 plants that were over the limit was calculated at $0.50 per MWh, but the range of costs was $0.07 to $1.23 per MWh.

8.5.2. The NO_X Budget Program

The Northeast's NO_X Budget program is similar to the Acid Rain Program in that they are both cap-and-trade programs. The NO_X budget however, only operates during the summer months when emissions are highest. Beginning in 1999, the program was implemented in three phases that will result in a 65 to 75 percent reduction in NO_X emissions by 2003 and a final standard equivalent to 0.15 lbs. per MMBtu (Farrell 2000).

While initial market activity resulted in high price volatility, more recent prices have been more stable. NO_X allowances for 1999 generally ranged from $1,500 to $3,000 per ton, and in one period reached $7,000. Since 2000 however, prices have stabilized around $750 per ton (OTC 2002). Using this as a point of reference, the approximate impact on the cost of generating electricity can be determined. In 2003, the broader NO_X State Implementation

Plan (SIP) regional program is expected to begin adding states to the original Ozone Transport region to a total of 20 states. One hundred eighty-six gas (300 MW or larger) and coal (600 MW or larger) plants from the NO_X SIP call region were selected to determine the average incremental cost of electricity (EPA 2002a). The calculation of incremental cost is the same as the SO_2 calculation above, but the data are adjusted for the ozone season, which refers to the summer months when emissions limits apply. The average cost for the 126 coal plants above the limit was $1.3 per MWh and the average cost of the 15 gas plants above the limit was $0.4 per MWh.

8.5.3. Conclusion

Analysis of the SO_2 allowance market suggests that coal-fired electricity generators can expect an average cost of $0.50 per MWh to meet current emissions standards. However, older less efficient plants can expect costs closer to $1.20 per MWh and newer more efficient plants closer to $0.10 per MWh. The NO_X allowance market indicates that coal plants can expect an average cost of $1.3 per MWh to meet Phase III emission limits, whereas gas plants were rarely over the limit, and those that were had an average cost of $0.40 per MWh. Allowance prices could change, however, should the NO_X budget program become annual or federalized to include all 48 states.

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Part Three: Nuclear Energy In The Years Ahead

Part One considered the cost of new nuclear electric power and Part Two considered the cost of electricity from coal and gas that nuclear power will have to meet if it is to be competitive. Parts One and Two are used here in Part Three to estimate what policies or combination of policies are needed to make nuclear power competitive in 2015. Looking farther to the future, prospects for 2025 and beyond are considered.

Chapter 9. NUCLEAR ENERGY SCENARIOS: 2015

Summary

No-Policy Benchmark

As indicated in Chapter 3, capital cost ranges are patterned on reactors taken to be realistic possibilities for deployment by 2015: (1) the General Electric ABWR such as is already built in Japan, and the ACR-700, the CANDU 6 version which has been built in China and Romania, on which first-of-a-kind engineering (FOAKE) costs have been paid, with overnight cost for either reactor of $1,200 per kW, (2) a Westinghouse AP1000, whose sister reactor the AP600 has been certified by NRC but on which FOAKE costs have yet to be paid, with overnight cost of $1,500 per kW and (3) the Framatome SWR 1000, similar to a larger version in advanced planning stages in Finland, with overnight cost of $1,800 per kW.

As noted in Chapter 5, the financial model developed there gives no-policy LCOEs on first new nuclear plants of $53, $62, and $71 per MWh respectively. This range assumes business expectations of construction times as long as 7 years and a 3 percent additional risk premium. None of these new nuclear LCOEs are as low as the $33 to $45 per MWh range of LCOEs for coal-fired and gas-fired generation.

Individual Financial Policies

Starting from the no-policy benchmark, the financial model has been used to estimate the effects of various financial policies. According to the financial model, a loan guarantee of 50 percent of construction costs would reduce nuclear LCOE for the lowest cost reactor to $49 per MWh under likely business expectations. Accelerated depreciation, whose most liberal terms would extend to immediate expensing, could reduce the LCOE for the lowest cost reactor in this case to $47 per MWh. An investment tax credit as high as 20 percent, refundable so as to be useable as an offset to nonnuclear activities of a utility, would reduce this number to $44 per MWh. None of the foregoing policies alone would achieve competitiveness even for the lowest cost reactor under likely business expectations of a 7-year construction period and added debt and equity risk premiums of 3 percent for nuclear power. A production tax credit of $18 per MWh for the first 8 years would reduce the LCOE of the lowest cost reactor under likely business expectations to $38 per MWh, which is within the range of competing coal and gas LCOEs. This tax credit is what has been considered in legislation proposed in 2004. It would however achieve competitiveness only for the most optimistic cost outcome. Moreover, it is a back-end policy that permits increased revenue only in later years when power is being produced, not in the more crucial near-term front-end construction period. A conclusion is that no single financial policy alone can definitely be counted on to bring about nuclear competitiveness by 2015.

Combinations of Financial Policies

While no single financial policy may be sufficient to enable nuclear power to enter the marketplace competitively, the financial model indicates that a combination of policies at reasonable levels could do so. For example, a combination of a 20 percent investment tax credit, which has the advantage of reducing needs for front-end dollars, and an $18 per MWh production tax credit for 8 years, would be sufficient to lower costs to the competitive range for all but the highest cost reactor, and even that would be fairly close.

The present study assumes that, in distinction to current business expectations, actual experience may turn out to be more favorable to nuclear power. If a group of investors believes that a 5-year construction period is realistic and with no extra risks, LCOEs for first nuclear plants would be in the competitive range. This study has been limited to traditional financial instruments and has not considered any other possible means of finding and convincing a group of investors to participate in new construction.

N^{th} Plants and Nuclear Competitiveness

The above estimates are for policies needed to bring about construction of first new nuclear facilities beginning in 2015. A question of importance is the extent to which policies would need to be extended beyond the first plants. Learning by doing will reduce costs beyond the first plants. It will make a contribution but by itself is not sufficient to safely ensure self-sufficient competitiveness. Under aggressive learning assumptions, the LCOE for the fifth plant, when learning is largely completed, is $44 per MWh for the lowest cost nuclear reactor, assuming a construction period of 7 years, which is at the very upper end of the range of gas-fired LCOEs. Reducing construction time to 5 years reduces this LCOE to $40 per MWh. Both cases assume maintaining the 3 percent risk premium.

This result is changed further if the experience with the first few plants is that they can be built in a reasonable time, and that they can be operated successfully. In this event, the risk premium on their financing can be expected to fall. Given a 5-year construction period, with a debt rate of 7 percent and equity rate of 12 percent, which are rates comparable to those for coal and gas, instead of the higher risk adjusted debt and equity rates of 10 percent and 15 percent assumed for the first new nuclear plants in view of past experience with their riskiness, LCOEs for nuclear reactors are obtained more definitely within the required range of competitiveness for the fourth or fifth plants. The LCOEs for the two lower cost nuclear reactors are $35 per MWh for the fourth plant and $34 per MWh for the fifth plant, meeting the requirements for market self-sufficiency for a 5 percent and 10 percent learning rate. This study indicates that even under pessimistic learning assumptions nuclear power could definitely become self-sufficient in the market after cessation of initial policy assistance if overnight costs were $1,200 or $1,500 per kW.

An optimistic learning rate, together with shorter construction time and elimination of the risk premium, gives a fifth-plant LCOE of $39 per MWh if initial overnight costs are $1,800 per kW. The LCOE is $40 per MWh under the most pessimistic learning rate for the fourth and fifth plants. These costs are within the upper end of the range of coal- and gas-fired LCOEs.

Robustness of Conclusions

The results are sensitive to assumptions about overnight costs and plant construction times, but both of these are included in the analysis. The results are not very sensitive to plant life. Competitor prices deserve mention. Rising gas prices would disadvantage electricity generated by gas, but coal prices appear unlikely to rise. The major effect could be substitution of coal for gas, with nuclear still competing against coal generation at essentially the same cost per MWh as in the analysis here. Stringent measures to control greenhouse gases would disadvantage both gas and coal, making nuclear energy easily competitive in the marketplace. While this contingency provides a policy reason for having nuclear capability in place, it conservatively is not included in the 2015 outlook assumed here for nuclear energy.

Outline

9.1. Introduction

Three nuclear plant costs were considered in the no-policy scenario, introduced in Chapter 5. To recapitulate, they are patterned after three candidate reactors: (1) a mature plant such as the ABWR and ACR-700, the FOAKE costs on which have already been paid, with an overnight cost of $1,200 per kW; (2) a design not yet built, such as the AP1000, the FOAKE costs on which are yet to be paid, with an overnight cost of $1,500 per kW; and (3) the Framatome SWR 1000, similar to a larger version in advanced planning stages in Finland, whose overnight cost is estimated at $1,800 per kW. The cost range also allows for uncertainty in cost estimates for reasons other than reactor type.

This study investigates what would be necessary to allow nuclear power to come into the marketplace in the event that first plants were found to be not competitive with fossil power generation. Accordingly, this chapter focuses on potential federal policies for early plants.

Section 9.2 recapitulates the no-policy starting point, giving first-plant LCOEs for the three nuclear reactor designs and for the current fossil generation alternatives, applying the financial model developed in Chapter 5. The remainder of the chapter applies the model to policy alternatives. Section 9.3 examines the effects of several policies that might be implemented to offer support to new nuclear plants. To examine the viability of nuclear power after learning by doing has reduced costs during construction of the first few plants, Section 9.4 calculates the busbar costs that new nuclear plants could deliver without any policy support. Section 9.5 calculates LCOEs of fossil generation under alternative fuel-price and environmental-policy scenarios. Section 9.6 summarizes the findings of the chapter.

9.2. First-Plant Nuclear and Fossil LCOEs

Table 9-1 summarizes from Chapter 5 the LCOEs of a first nuclear plant, for each of the three reactor costs being considered, assuming a 7-year construction period. According to the financial models, a $1,200 per kW reactor could deliver power at $53 per MWh. The $1,500 per kW reactor could deliver power at $62 per MWh. The $1,800 per kW reactor could deliver power at $71 per MWh.

Table 9-1: LCOEs for a First Nuclear Plant, with No Policy Assistance, 7-Year Construction Time, 10 Percent Interest Rate on Debt, 15 Percent Rate on Equity, 2003 Prices

Overnight Cost, $ per kW	1,200	1,500	1,800
LCOE, $ per MWh	53	62	71

Table 9-2 reports the LCOEs for coal and gas generation. The range for coal-fired power is \$33 to \$41 per MWh, while the range for gas-fired power is \$35 to \$45 per MWh.

Table 9-2: LCOEs for Coal and Gas Generation, 7 Percent Interest Rate on Debt, 12 Percent Rate on Equity, 2003 Prices

	Pulverized Coal Combustion	Gas Turbine Combined Cycle
Overnight cost, \$ per kW	1,182 to 1,430	500 to 700
LCOE, \$ per MWh	33 to 41	35 to 45

Comparison of the LCOEs in Tables 9-1 and 9-2 sets out the policy challenges. The LCOEs of first new nuclear plants must be reduced considerably. The longer term challenge is to be able to reach these levels without continuing support at some n^{th}-plant construction.

9.3. Impact of Alternative Policies Supporting New Nuclear Construction

9.3.1. Individual Financial Policies

Four types of financial policy are considered here: loan guarantees, accelerated depreciation, investment tax credits, and production tax credits. Another possible policy is to extend the licensing period from 40 to 60 years. This policy was found to reduce LCOE by only about 1 percent and is not considered further.

9.3.1.1. Loan Guarantee

A loan guarantee could be applied to some portion of the capital costs which are financed by borrowing. A federal guarantee of, say, 25 percent of the borrowed funds would allow the borrowing rate on 25 percent of the borrowed funds to fall as low as the risk-free rate. The weighted debt rate is $r_d = sr + (1-s)r_m$; where r_d is the weighted average interest rate on debt financing; s is the fraction of the loan that the government guaranteed; r is the risk-free interest rate, say 5 percent as geared to the 10-year Treasury note; and r_m is the market interest rate on a loan of the risk class for this asset. The total effect of the loan guarantee on the weighted average cost of capital depends in turn on the debt-to-equity ratio: $WACC = \delta r_d + (1-\delta)r_e$, where δ is the fraction of the capital that is borrowed and r_e is the required rate of return on equity, which also will include the risk premium that the market determines for this class of assets. With 50 percent of the funds borrowed, a 10 percent borrowing rate, and a 15 percent equity rate, and no loan guarantee, the WACC would be 0.125. With a 25 percent loan guarantee, the WACC falls to 0.10.

Table 9-3 shows the effect of loan guarantees on nuclear plant LCOEs for the three reactor costs being considered for loan guarantees of 25 percent and 50 percent. Even a 50 percent guarantee lowers the LCOE of the $1,200 per kW reactor by at most $4 per MWh. LCOEs are still almost as far above the cost per MWh for coal-fired and gas-fired generation as with the no-policy alternatives.

Table 9-3: Nuclear LCOEs with Loan Guarantees, $ per MWh, 2003 Prices

Loan Guarantee	Mature Design $1,200 per kW		New Design $1,500 per kW		Advanced New Design $1,800 per kW	
	Construction time		Construction time		Construction time	
	5 years	7 years	5 years	7 years	5 years	7 years
0 (no policy)	47	53	54	62	62	71
25 percent of loan	45	50	53	58	60	67
50 percent of loan	45	49	52	57	59	65

9.3.1.2. Accelerated Depreciation

Current tax laws specify a 15-year depreciation period for electric utilities under U.S. corporate tax code's Modified Accelerated Cost Recovery System (MACRS), which is the no-policy case. Two more greatly accelerated depreciation schedules are examined here, 7 years and the limiting case of expensing, or writing off the entire investment cost in the first year of production. While expensing is not a U.S. practice, it is common in European countries. Table 9-4 reports LCOEs under each of these allowance schedules, for plants with 5-year and 7-year construction periods.

Table 9-4: Nuclear LCOEs with Accelerated Depreciation Allowances, $ per MWh, 2003 Prices

Depreciation Policy	Mature Design $1,200 per kW		New Design $1,500 per kW		Advanced New Design $1,800 per kW	
	Construction time		Construction time		Construction time	
	5 years	7 years	5 years	7 years	5 years	7 years
15 years (no policy)	47	53	54	62	62	71
7 years	44	50	51	58	58	67
Expensing (1 year)	41	47	47	54	54	62

Accelerated depreciation, even expensing, is not a particularly effective support policy. For example, expensing, which is the extreme of accelerated depreciation, brings down the cost for the $1,200 per kW reactor by only $6 per MWh.

9.3.1.3. Investment Tax Credit

An investment tax credit allowing a business to claim a percentage of its investment as a direct offset against its tax obligation in the year of the investment is more potent in affecting LCOE than is accelerated depreciation, which is reasonable since depreciation is only a deduction from income rather than a direct offset against taxes and, moreover, spreads the allowances out over as much as 15 years.

The investment tax credit modeled here is refundable, allowing the owner to apply the credit to the income earned from other assets if the credit is larger than the tax on the asset from the asset. The entity envisioned as investing in the new nuclear plant is a utility with several plants rather than the owner of only a single plant. If a new nuclear plant operated at a loss in its very first years and thus had no tax obligation, the owner could apply the investment tax credit from it against taxes on income generated by other plants.

Table 9-5 shows the LCOEs for each of the three reactor costs, assuming 7-year and 5-year construction times, a 10 percent investment tax credit, and a 20 percent investment tax credit. The reductions in LCOEs for each plant, moving from no policy, to 10 percent, to 20 percent, while as large as $9 to $13 per MWh, leave each reactor design outside the competitive range with fossil generation. Even the 20 percent tax credit does not bring the $1,200 per kW plant into competitive status with the fossil fuel generation plants. The 20 percent credit for the $1,500 per kW reactor closes the competitive gap by about 50 percent. For the $1,800 per kW reactor, the 20 percent credit just drops the LCOE to $58 per MWh, even further out of the competitive $34 to $36 per MWh range. A further possible benefit of an investment tax credit is that the investor receives this benefit early in the life of the project—during construction when there is a drain on cash flow—rather than later, such as a production tax credit would offer when revenues from sales of power are already generating positive cash flow.

Table 9-5: Nuclear LCOEs with Investment Tax Credits, $ per MWh, 2003 Prices

Tax Credits	Mature Design $1,200 per kW		New Design $1,500 per kW		Advanced New Design $1,800 per kW	
	Construction time		Construction time		Construction time	
	5 years	7 years	5 years	7 years	5 years	7 years
0 percent (no policy)	47	53	54	62	62	71
10 percent	43	47	50	55	57	63
20 percent	40	44	46	51	52	58

9.3.1.4. Production Tax Credit

Like the investment tax credit, the production tax credit is a direct offset against tax obligation. A firm is offered a tax credit on each kWh of power it produces, for a specified number of its first years of operation. A production tax credit of $18 per MWh, non payable, with duration of 7 years is considered. This credit is the magnitude of the current production tax credit for renewable energy, and its duration is that specified for advanced nuclear generation in Section 1310 of the Conference Energy Bill of 2004. The production tax credit is reported in Table 9-6.

Table 9-6: Nuclear LCOEs with Production Tax Credits, $18 per MWh, 8-Year Duration, $ per MWh, 2003 Prices

Tax Credit Policy	Mature Design $1,200 per kW		New Design $1,500 per kW		Advanced New Design $1,800 per kW	
	Construction time		Construction time		Construction time	
	5 years	7 years	5 years	7 years	5 years	7 years
0 (no policy)	47	53	54	62	62	71
$18 per MWh, 8-year duration	32	38	40	47	47	56

With a 7-year construction period for a first plant, assumed to be expected by the business community in view of risk concerns, the $18 per MWh credit brings the LCOE of the $1,200 per kW reactor from its no-policy level to a level within the upper end of the range of coal-fired LCOEs of $33 to $41 per MWh and into the middle of the range of gas-fired LCOEs, $35 to $45 per MWh. This credit leaves the LCOE of the $1,500 per kW reactor just beyond the competitive range of gas-fired generation. The LCOE of the $1,800 per kW reactor remains well above the competitive range.

An optional feature of a production tax credit is that it may be specified as a long-term, low-interest or interest-free loan. Called a repayable tax credit, the repayment term could be as long as 20 or 25 years. Discounting the distant-future repayment to the present, the repayable version of this tax credit is nearly indistinguishable from a production tax credit with the loan forgiven. The repayable version of this credit was investigated, and its results were very close to those of the non-repayable credit in Table 9-6.

In practice, some restrictions might be imposed on the amount of power on which a utility may receive such a credit. In the 2004 Conference Energy Bill, the credit is not to exceed $125 million per 1,000 MW of new capacity. The present analysis imposes this cap on payments, which limits the credit effectively to $16.79 per MWh.

9.3.1.5. Summary of Individual Policies

In summary, with the expectation of a 7-year construction period, no individual financial policy can be counted on unambiguously to bring the LCOE of first new nuclear plants within the range of LCOE competitive with fossil generation. A 50 percent loan guarantee can bring the $1,200 per kW LCOE down to $49 per MWh, and an accelerated depreciation policy allowing full expensing reduces its LCOE to $47 per MWh. The investment tax credit is somewhat more potent, but the best LCOE even for the lowest reactor costs of $1,200 per kW is $44 per MWh with a 20 percent investment credit. However, an $18 per MWh production tax credit lasting 8 years, with a cap of $125 million per 1,000 MW, can bring the $1,200 per kW LCOE to $38 per MWh, which is in the upper half of the range of LCOEs that may be delivered by coal-fired generation. However, the production tax credit helps cash flow only after the plant has been built and does not reduce the heavy drain on near-term dollar requirements during the construction period.

The figures in the preceding paragraph are for a construction time of 7 years, assumed to be used in utility investment decisions for first nuclear plants in view of risk concerns, even though a favorable 5-year construction period may actually be experienced after the fact. This section has also presented figures for a 5-year construction period. LCOEs under single financial policies for plants built in 5 years are 9 to 15 percent below those under the same policies for plants built in 7 years. The 2-year difference in construction time would make the difference between reaching or not reaching the competitive cost range with fossil generation for the production tax credit with the $1,200 per kW plant.

Ambiguities in achieving nuclear competitiveness through uses of any single policy are reduced if a combination of policies is considered.

9.3.2. A Combination of Policies

In Table 9-7, the effects of the two most effective policies when acting together are considered for both 5- and 7-year construction periods: the $18 per MWh production tax credit, with a duration of 8 years, and the 20 percent investment tax credit. The table reports the initial, no-policy LCOE in the upper row, and the impacts of the combination of policies in the lower row. The LCOEs are reported for the three reactor costs and for 5- and 7-year construction periods.

Table 9-7: Effects of Combined $18 per MWh 8-Year Production Tax Credits and 20 Percent Investment Tax Credits on Nuclear Plants' LCOEs, $ per MWh, 2003 Prices

Mature Design $1,200 per kW		New Design $1,500 per kW		Advanced New Design $1,800 per kW	
Construction Time		Construction Time		Construction Time	
5 years	7 years	5 years	7 years	5 years	7 years
No policies:					
47	53	54	62	62	71
With combination of policies:					
26	31	31	38	37	46

With an expected 7-year construction period, the combination of the $18 per MWh 8-year production tax credit and the 20 percent investment tax credit would bring the LCOE of the $1,200 per kW reactor below the range of fossil LCOEs and that of the $1,500 per kW reactor into the upper half of the range of coal-fired LCOEs. The LCOE of the $1,800 per kW reactor would remain above the range of fossil LCOEs.

If it were possible to lower construction times expected by the business community for first nuclear plants to 5 years, nuclear LCOEs would be in the competitive range even for the highest cost reactor, and would be well below it for the others

9.4. The Competitive Status of Nth Plant New Nuclear Facilities without Financial Policy Support

Section 9.4.1 addresses the LCOEs of sequential plants under various scenarios involving learning rates, construction time, and financing. Section 9.4.2 summarizes the findings of Section 9.4.1.

9.4.1. Nth-Plant Nuclear LCOEs: Learning, Streamlined Regulation, and Risk Reduction

A critical question for new nuclear power is whether, after the initial plants have been supported, nuclear power can be produced at prices competitive with coal and gas generation. During the construction of early plants, learning can be expected to take place in manufacturing and construction, lowering overnight cost. As an additional consideration, if the construction and cost uncertainties that lead to high risk premiums on early financing rates are resolved, debt and equity rates can be expected to fall to levels closer to those on coal and gas generation.

This section examines the effects of three rates of cost reduction from learning: 3, 5, and 10 percent for each doubling of the number of completed plants. As noted in Chapter 3, 3 percent is the safest rate of cost reduction to assume. Five percent would be optimistic. Ten percent would be aggressive, but may not be out of the realm of possibility. Before proceeding to the full array of cost-reducing effects that could be expected from the successful construction of the first eight new plants, Table 9-8 provides a starting point by showing the effects only of the payment of FOAKE costs and learning. To show the separate contributions of FOAKE payment and learning, the LCOE of the second plant is calculated under two assumptions: in the first of the rows reporting LCOEs for the second plant, only FOAKE costs are paid after the first plant, and no learning occurs; in the second of the rows reporting LCOEs for the second plant, the learning effect is added to the FOAKE payment effect. In all subsequent plants, the FOAKE cost has been paid with the construction of the first plant, and the benefits of cumulative learning effects are experienced.

Comparing the two lines for the second plants, the payment of FOAKE costs alone reduces the LCOEs of the $1,500 and $1,800 per kW plants by $9 per MWh. There is no effect on the $1,200 per kW plant because its FOAKE costs were assumed to have been paid in previous construction. The addition of learning effects contributes another reduction of $2 per MWh for the $1,200 and $1,500 per kW plants and an additional $ 2 to $5 per MWh for the $1,800 per kW plant, depending on the learning rate. Continuing through the first eight plants, payment of FOAKE costs and learning effects, taken together but with no other benefits of building new plants, could bring the $1,200 and $1,500 per kW plants into the upper end of the competitive range with coal- and gas-fired plants with a learning rate of 10 percent, but not with lesser learning rates. The LCOE of the $1,800 per kW plant remains outside the competitive range at the eighth plant, even under a 10 percent learning rate.

Table 9-8: LCOE for Successive Nuclear Plants, First to Eighth Plants, Learning Effects and Payment of FOAKE Costs Only, $ per MWh, 2003 Prices

Plant	*Scenario*				Initial Overnight Cost								
					$1,200 per kW			$1,500 per kW			$1,800 per kW		
					Learning Rate								
	FOAKE Costs	***Construction Time***	***Risk Premium***	***Debt Share of Financing***	3%	5%	10 %	3%	5%	10%	3%	5%	10%
					LCOE ($ per MWh)								
1	*Already paid on $1,200 plant*	*7 years*	*3%*	*50%*	53	53	53	62	62	62	71	71	71
2	*All paid, no learning*	*7 years*	*3%*	*50%*	53	53	53	53	53	53	62	62	62
2	*All paid, with learning*	*7 years*	*3%*	*50%*	51	51	49	51	51	49	60	59	57
3	*All paid, with learning*	*7 years*	*3%*	*50%*	51	50	47	51	50	47	59	58	55
4	*All paid, with learning*	*7 years*	*3%*	*50%*	50	49	45	50	49	45	59	57	53
5	*All paid, with learning*	*7 years*	*3%*	*50%*	50	48	44	50	48	44	58	56	52
6	*All paid, with learning*	*7 years*	*3%*	*50%*	50	48	44	50	48	44	58	56	51
7	*All paid, with learning*	*7 years*	*3%*	*50%*	49	48	43	49	48	43	58	55	50
8	*All paid, with learning*	*7 years*	*3%*	*50%*	49	47	42	49	47	42	58	55	49

Table 9-9 shows the LCOEs of each plant, from the first through the eighth, as cost and construction time uncertainties are resolved, in addition to the payment of FOAKE costs and the effects of learning. Table 9-10, in addition to the effects shown in Table 9-9, allows the debt share of financing to respond to the resolution of uncertainties. The LCOEs of the first four plants are the same in Tables 9-9 and 9-10, but those of plants five through eight in Table 9-9 include the influence of increasing debt shares.

Each row in those tables refers to a plant, in order of its construction, identified in the left-most column. The four columns under "Scenario" describe important conditions of construction and financing that can be anticipated to change as construction progresses: FOAKE costs are paid, construction time is reduced, and the risk premium on nuclear construction is eliminated.

The time patterns of changes in Tables 9-9 and 9-10 are judgmental since no data exist to offer unambiguous guidance, and other sequences of events may be reasonable.

However, in the present analysis, the first two plants of each type are built under expectations of 7-year construction periods. With the third plant, the financial community accepts the expectation that these plants can be built in 5 years. After the first plant is built with a 5-year expected construction time, the risk premium on new nuclear construction disappears with the financing of the fourth plant. Since the risk premium reflected the uncertainties surrounding the operation of the new regulatory system and the capability to bring plants on-line within projected cost and on time, once those two capabilities have been demonstrated, the premium disappears immediately rather than going away gradually. From the fifth plant through the eighth, no further changes occur in financing circumstances, leaving learning the only source of falling construction costs and LCOEs. In Table 9-10, developments continue in financing beyond the fourth plants.

Consider the first plant in Table 9-9. FOAKE costs have already been paid on the $1,200 per kW plant, since it has been built overseas. The anticipated construction time used for financial planning is 7 years, an expectation of the business community developed on the basis of current information and experience with nuclear plants built earlier. The risk premium over that of fossil plants is 3 percentage points for debt and equity, and 50 percent of the construction costs are financed with debt. No learning has taken place on the first plant, so the LCOEs of the three plant types are $53, $62, and $71 per MWh as in the earlier first plant analysis.

The second row reports on the second plant. FOAKE costs are all paid on the first plant, so the $1,500 and $1,800 plants' overnight costs are reduced by $300 per kW. The construction time is anticipated to remain at 7 years, and the risk premium and debt share of financing remain as they were on the first plants. However, what has been learned on the first plant reduces the overnight cost of the second plant. The LCOEs under different learning rates differ for each plant, with higher learning rates yielding lower LCOEs. For third plants, the reduction in expected construction times contributes to lowering LCOEs by $7 to $9 per MWh, which however is still not sufficient to achieve competitiveness.

In Table 9-9, almost all of the cost reduction that is achieved by the eighth plant has been obtained with the fourth or fifth plant. The substantial drop in LCOE on the fourth plant is due to disappearance of the extra risk premium on nuclear plants. With the moderate and optimistic cost reductions of 3 and 5 percent, the fourth and fifth $1,200 and $1,500 per kW plants reach competitiveness with the mid-range coal and gas generation, and the $1,800 per kW plant would reach competitiveness with the high-cost end of the fossil LCOEs of Tables 5-4 and 5-5. Under the aggressive cost reduction of 10 percent, the fourth and fifth $1,800 per kW plants would be competitive with the mid-range fossil costs.

Table 9-9: LCOE for Successive Nuclear Plants, First to Eighth Plants, $ per MWh, 2003 Prices

Plant	*Scenario*				Initial Overnight Cost								
	FOAKE Costs	***Construction Time***	***Risk Premium***	***Debt Share of Financing***	$1,200 per kW			$1,500 per kW			$1,800 per kW		
					Learning Rate								
					3%	5%	10%	3%	5%	10%	3%	5%	10%
					LCOE ($ per MWh)								
1	*Already paid on $1,200 plant*	*7 years*	*3%*	*50%*	53	53	53	62	62	62	71	71	71
2	*All paid*	*7 years*	*3%*	*50%*	51	51	49	51	51	49	60	59	57
3	*All paid*	*5 years*	*3%*	*50%*	45	44	42	45	44	42	52	51	48
4	*All paid*	*5 years*	*Gone*	*50%*	36	35	33	36	35	33	41	40	37
5	*All paid*	*5 years*	*Gone*	*50%*	35	34	32	35	34	32	40	39	36
6	*All paid*	*5 years*	*Gone*	*50%*	35	34	32	35	34	32	40	39	36
7	*All paid*	*5 years*	*Gone*	*50%*	35	34	31	35	34	31	40	39	35
8	*All paid*	*5 years*	*Gone*	*50%*	35	34	31	35	34	31	40	38	35

In Table 9-10, the debt share of financing responds to the reduced uncertainties dispelled by the successful construction of the first four plants. Financing of the fifth and sixth plants can be accomplished with a greater proportion of debt, 60 rather than the 50 percent of the first four plants. The debt share rises to 70 percent for plants seven and eight, reducing LCOEs for those plants by a further 5 to 10 percent.

Table 9-10: LCOE for Successive Nuclear Plants, First to Eighth Plants, with Debt Share Responding to Reduced Risk, $ per MWh, 2003 Prices [a]

Plant	*Scenario*				Initial Overnight Cost								
	FOAKE Costs, status	***Construction Time***	***Risk Premium***	***Debt Share of Financing***	$1,200 per kW			$1,500 per kW			$1,800 per kW		
					Learning Rate								
					3%	5%	10%	3%	5%	10%	3%	5%	10%
					LCOE ($ per MWh)								
1	*Already paid on $1,200 plant.*	*7 years*	*3%*	*50%*	53	53	53	62	62	62	71	71	71
2	*All paid*	*7 years*	*3%*	*50%*	51	51	49	51	51	49	60	59	57
3	*All paid*	*5 years*	*3%*	*50%*	45	44	42	45	44	42	52	51	48
4	*All paid*	*5 years*	*Gone*	*50%*	36	35	33	36	35	33	41	40	37
5	*All paid*	*5 years*	*Gone*	*60%*	**34**	**33**	**31**	**34**	**33**	**31**	**38**	**37**	**35**
6	*All paid*	*5 years*	*Gone*	*60%*	**34**	**33**	**30**	**34**	**33**	**30**	**38**	**37**	**34**
7	*All paid*	*5 years*	*Gone*	*70%*	**32**	**31**	**29**	**32**	**31**	**29**	**36**	**35**	**32**
8	*All paid*	*5 years*	*Gone*	*70%*	**32**	**31**	**29**	**32**	**31**	**29**	**36**	**35**	**32**

Table 9-11 reports the LCOE of fifth plants, separating the cost reductions relative to first plant among the three sources. Although the combined effects are able to reduce the LCOE of the fifth plants to levels well within the competitive range with fossil generation, all three effects—learning, reduced construction time, and the elimination of the risk premium are necessary to accomplish that cost reduction.

Table 9-11: Contributors to LCOE Cost Reduction for Fifth Plant: Learning, Reduced Construction Time, and Elimination of Risk Premium, $ per MWh, 2003 Prices

Sources of Cost Reduction	Initial Overnight Cost					
	$1,200 and $1,500 per kW			$1,800 per kW		
	Cost Reduction with Doubling of Plants Built			Cost Reduction with Doubling of Plants Built		
	3%	5%	10%	3%	5%	10%
Learning only	50	48	44	58	56	52
Learning and reduced construction time	44	43	40	51	50	46
Learning, reduced construction time, and reduced risk premium	35	34	32	40	39	36

9.4.2. Findings: Nth-Plant Competitiveness of Nuclear Power

Under optimistic but not aggressive assumptions, a fifth new nuclear plant could thus deliver power at a price competitive with fossil generation. Either the $1,200 or the $1,500 per kW reactor, with a 3 percent learning rate, a 5-year construction period, and finance rates comparable to those of fossil plants, could deliver power at $34 to $35 per MWh. New nuclear plants would be competitive with no further government assistance. The fossil fuel LCOEs assume no change in environmental policies toward coal and gas generation, as well as continued low prices for gas. Tightened emission restrictions would raise these fossil LCOEs above the levels in Table 9-2, as will be discussed below.

9.5. Alternative Scenarios for Fossil Generation

Technological improvements in coal and gas generation are not expected to be of sufficient magnitude by 2015 to drastically lower their LCOEs and are not considered here. However, the possibility that recent gas price increases continue during the next decade is explored, since fuel costs comprise a major share of gas LCOE. The other major scenario that is explored for fossil generation contemplates the possibility that carbon emissions will be restricted as an environmental policy.

9.5.1. Higher Natural Gas Prices

EIA's projection for natural gas prices sees a one-third increase in real price by 2020. The gas price used in the low end of the LCOE calculations of Table 9-2 is \$3.39 per MMBtu. A gas price of \$4.25 to \$4.30 per MMBtu would yield an LCOE of \$42 to \$43 per MWh. New gas plants might not be built at expected prices of this level, in view of the lower cost of coal generation under these circumstances.

9.5.2. Environmental Policies for Fossil Generation

Some tightening of NO_x and SO_2 emissions for coal-fired and gas-fired power plants could occur in the future, but the cost impacts of plausible further restrictions are not great. The larger unknown in future environmental policy concerns the possibility of carbon emission restrictions. Considering the complexity of grandfathering allowances in current environmental regulations, a myriad of scenarios could be constructed for a policy of carbon emission limitations.

This analysis considers a system of limitations with emission permit trading but simplifies the institutional detail. Because of the potentially high cost of transporting captured CO_2, it is assumed that plants located immediately adjacent to suitable sequestration sites will be the only plants to restrict their CO_2 emissions, and they will sell their emission permits to plants that would have to transport their captured CO_2. After trades, the marginal emission reduction costs will be those of carbon capture and of injection and storage. In this way, transportation costs could be avoided.

The costs used to represent carbon capture, injection, transportation, and storage costs are taken from Table 8-4, as averages of the individual ranges for pulverized coal-combustion and gas turbine combined cycle plants. These costs are on a per-megawatt-hour basis, so they are added to the LCOEs calculated on the basis of other cost and performance parameters. Table 9-12 compares the coal-fired and gas-fired LCOEs with current environmental regulations with LCOEs under greenhouse policy of the character described here. The coal-fired plant LCOE would be increased two and one-half times, while the gas-fired plant LCOE would rise by one-half.

Table 9-12: Fossil Fuel Generation LCOEs with and without Greenhouse Policies, \$ per MWh, 2003 Prices

	Under Current Environmental Policies	Under Greenhouse Policy
Coal-fired	33 to 41	83 to 91
Gas-fired	35 to 45	58 to 68

Even if clean coal research were to reduce the carbon sequestration costs associated with coal plants by 50 percent, an LCOE of $65 per MWh could still emerge. Improved capture and sequestration technology for gas plants could leave the gas LCOE in the range of the mid-$50s per MWh. Reasonable scenarios for new nuclear power would yield LCOEs competitive with such coal and gas costs.

While stringent greenhouse policies would very likely make nuclear power competitive on its own, the policy analysis in this chapter concerned with 2015 does not rely on them. Implications of greenhouse policies for the 2025 and beyond are considered in the next chapter.

9.6. Conclusions

Among the financial instruments considered in this study, production tax credits are most effective in reducing LCOEs, followed by investment tax credits. Loan guarantees and accelerated depreciation are less effective. Starting from the no-policy benchmarks LCOEs of $53, $62, and $71 per MWh for $1,200, $1,500 and $1,800 per kW reactors, only one individual financial policy in isolation (the $18 per MWh production tax credit over 8 years, applied to a $1,200 per kW reactor) would bring these reactor designs' costs for a first nuclear plant within the competitive range with fossil fuel power generation of $35 to $45 per MWh. However, the production tax credit is a back-end policy that achieves competitiveness through increasing net revenues from sales after the plant is constructed. It does not provide front-end dollars in the here and now of the construction period to which greater weight would be given.

Still considering first new nuclear plants, applying two policies together as a package, yields a policy combination that could bring two of the reactor designs well into a competitive LCOE range with fossil-fired generation. A combination of an investment tax credit of 20 percent and an $18 per MWh production tax credit applied for 8 years is sufficient to bring the $1,200 and $1,500 per kW reactors within the competitive cost range. That policy package would let the more costly $1,800 per kW reactor reach competitive cost levels if investors were convinced that a first plant could be built in 5 years.

This analysis for first nuclear plants has concentrated on results to be expected assuming an expectation of a 7-year construction period and added debt and equity risk premiums of 3 percent, reflecting business attitudes found in the Scully Capital report as well as anecdotal evidence. Financial policies have been analyzed under these assumptions. We have emphasized that actual experience may turn out to be more favorable. If it were possible to find investors willing to accept the likelihood of a more favorable outcome, the need for financial assistance would be reduced, even conceivably eliminated. One-time guarantees of construction costs, or DOE construction and sale of plants, are examples of policies going beyond the type of traditional financial measures considered here that could be considered to overcome business concerns about nuclear plant risk. It is beyond the scope of the present study to consider the pros, cons, and realism of these types of measures for first new nuclear plants.

Consider finally the competitiveness of later nuclear plants. Learning effects can be expected to reduce overnight capital costs. Successful construction and operation experience, aided by streamlined regulation, should reduce expected construction time and also permit a reduction of risk premiums. With learning rates of 3 to 5 percent, construction periods of 5 years, and financing rates comparable to those of fossil plants, the $1,200 and $1,500 per kW reactors would be competitive with fossil power by the fifth plant. If successful contractor and operator experience with early plants permitted the reduction of risk premiums on debt and equity finance for fifth plants, both of these reactors would operate well within the competitive range, and the $1,800 per kW reactor would reach the upper end of the competitive range. The results suggest that nuclear power could become competitive on its own after a fairly brief period of policy assistance.

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Chapter 10. NUCLEAR ENERGY SCENARIOS: BEYOND 2015

Summary

The long gestation periods involved in nuclear research, the long lags entailed in gearing up the nuclear industry for production, to say nothing of the long-term nature of security and environmental problems bearing on nuclear energy, make it prudent to attempt to look several decades ahead in making decisions about nuclear energy policy.

Uncertainties of virtually every kind increase as a longer time horizon is considered. While achieving precision becomes increasingly difficult as one attempts to look out farther to the future, the direction of some events has been persistent over the past few decades and shows every sign of continuing. These include perhaps most clearly the continued growth in demand for electricity and continued growth in severity of environmental problems. Beyond these, all the policy concerns addressed in Part Two above seem likely to continue. The likelihood that they will become more serious seems great.

Exhaustive consideration is not feasible here. The present study closes by considering three matters of particular importance for 2025 and beyond, having implications for nuclear energy strategies now.

First is *nuclear energy technology*. Much is already known about the momentum of nuclear cost reductions using existing technology. Much is also known about nuclear energy R&D on new technologies that will come to fruition after 2025. The R&D is ongoing and must be planned years ahead.

The importance of cost reductions from first-of-a-kind-engineering (FOAKE) costs and learning by doing beyond FOAKE has been verified above in Part Three. There is every reason to believe that this type of experience will continue. If presently available Generation III technologies are deployed for several years beginning in 2015, as contemplated in this study, cost reductions from their replication could extend to 2025 and beyond.

New designs from R&D work on Generations III+ and IV reactors, with many specifics now already in motion, may be commercialized soon after 2025. R&D in general has the potential to reduce costs. Cost reduction will be a prerequisite to commercialization.

The Pebble Bed Modular Reactor (PBMR), a relatively near-term technology, could make a particular contribution to reducing costs in view of its modularity. With independent units of 110 MW, an 1,100 MW power plant could be constructed in a sequence permitting units begun earlier to be brought on line earlier. Interest during construction, which has normally accounted for one quarter of nuclear LCOE, could be greatly reduced, perhaps even to minor proportions. Furthermore, once proof-of-principle was established, the smaller amounts of capital at risk in a single project—viewing the individual units as separate projects—would reduce the risk premium that larger projects now have to pay. The

advantages of modular construction might be enough by themselves to make nuclear power self-sufficient in the marketplace.

A more general lesson is that attention to potentials for cost reductions as a major consideration in planning nuclear R&D directions will increase the likelihood of commercial viability. The findings emphasized in this study, that reducing construction time and risk premiums greatly reduce nuclear energy costs, underscore this lesson.

A second major consideration is *global warming*. The longer the time horizon in the future that is considered, the more likely it is that the priority given to global warming will increase, leading to urgent need to replace coal- and gas-fired electricity generation. In view of the time it takes to gear up the nuclear industry, this eventuality is one of the reasons for national concern with maintaining a nuclear energy capability.

As one considers years increasingly farther beyond 2025, the probability grows ever greater that global warming will be perceived, not just as a potential threat, but rather as a reality calling for stringent action. If this view is accepted, the prospect of environmental policies greatly restricting carbon emissions in the period after 2025 must be admitted as an increasingly real possibility. Even if carbon capture and sequestration technologies are improved, and their costs reduced, a requirement that fossil power plants capture carbon could increase their LCOEs by 50 to 100 percent over current levels. Nuclear power would then acquire an unquestioned advantage over its gas and coal competitors.

A third major consideration is *hydrogen.* As brought out in Appendix A8, the widespread introduction of hydrogen-powered vehicles to replace gasoline-powered vehicles would greatly increase the demand for energy to produce hydrogen. Some impacts could occur by 2015, but these were conservatively not considered in projecting demand for nuclear energy by 2015 in the present study. Assuming success in meeting the expressed national commitment to developing a commercially viable hydrogen vehicle, use of hydrogen vehicles will be widespread by 2025 and beyond.

The possibility exists that heat from nuclear reactors will be the energy source of choice for producing hydrogen. Alternative possibilities include continued use of steam methane reforming and electrolysis using electricity from fossil generation. However, the carbon emissions from these sources would be acting simply to replace the reduction in carbon emissions from displacement of gasoline-powered vehicles. If there were serious restrictions on the use of coal and gas because of their carbon emissions, nuclear energy would have a clear competitive edge. A full analysis of the implications of increased demand for hydrogen is beyond the scope of this study. Still, the point again is that a contingency that could become real by 2025 could favor the demand for nuclear power.

While many uncertainties cloud the future beyond 2025 in addition to those considered, the uncertainties bearing on nuclear energy that emerge from the present study suggest the likelihood of an increased demand for nuclear energy beyond 2025.

Outline

10.1. Introduction

While the future beyond 2025 clearly holds many uncertainties, this chapter identifies three particular areas which could affect nuclear power. Continued experience in construction and operation of the Generation III reactors built by 2015 can be expected to continue lowering their costs. Generation IV reactor designs are expected to still be in demonstration stages in 2015, and some may still be in research stages. Some Generation III+ or early Generation IV designs may reach commercialization by 2025 or soon after. Section 10.2 addresses developments in these areas.

As a non-polluting electricity source, nuclear power can be expected to benefit from tightening of environmental policies on fossil generation. Section 10.3 considers the future of environmental policies.

A third major area of uncertainty affecting nuclear power in the more distant future is the possible emergence of a hydrogen economy. Large-scale substitution of hydrogen for oil in the transportation sector could increase the demand either for heat or for electricity substantially. Producing hydrogen by steam methane reforming would release carbon emissions that would have been emitted otherwise from the direct burning of oil, making nuclear power a more attractive source of hydrogen production. Section 10.4 addresses hydrogen issues.

10.2. Reactor Costs

The cost of nuclear reactors almost certainly will continue to be a major concern in the commercial nuclear power industry. Two major sources of cost reductions in the post-2025 period will be continued learning on the reactor designs built between 2015 and 2025, and the introduction of some cost-effective designs not yet commercialized.

10.2.1. N^{th}-of-a-Kind Costs

Cost reductions from learning, in both component manufacturing and construction, can be expected to continue, although the exponential learning rate—the rule of thumb of a constant percentage cost reduction with every doubling of new plants—will attenuate the learning effect of each new plant. A constant 3 percent learning rate with plant doubling would bring the overnight cost of a $1,200 per kW first-cost reactor down to $1,000 per kW by the sixty-fourth plant, and a 5 percent learning rate would reduce the same overnight cost to $880 per kW. Over the next quarter century 64 new plants could easily be built.

10.2.2. New Reactor Designs

Generation IV reactors include a variety of advanced designs, but the cost at which they can deliver electricity will continue to be an overriding concern in their commercialization. The Pebble Bed Modular Reactor (PBMR) is one of the nearer-term designs, and its modularity could confer cost advantages. With independent units of 110 MW, an 1,100 MW power plant could be constructed in a sequence that permitted units begun earlier to be brought on line earlier, reducing construction interest. Beyond that advantage, once its proof-of-principle was established, the smaller amounts of capital at risk in a single project—viewing the individual units as separate projects—could reduce the risk premium that larger projects might have to pay.

10.3. Environmental Policies

The longer the time horizon in the future that is considered, the more likely it is that global warming will become a pre-eminent concern, leading to urgent need to replace coal- and gas-fired electricity generation. In view of the time it takes to gear up the nuclear industry, this eventuality is one of the reasons for national concern with maintaining a nuclear energy capability.

The LCOEs calculated in Chapter 9 for coal and gas generation under potential greenhouse policies may be high compared to the technology that actually emerges in the next several decades, but indicate that even with major cost reductions in meeting environmental goals from fossil electricity generation, nuclear power would be the more competitive electricity source.

10.4. New Demands for Electricity: The Hydrogen Economy

If hydrogen were to make a major inroad on oil in transportation fuels, how to produce the hydrogen could prove to be a major issue. As reported in Appendix A8, production of hydrogen using steam methane reforming is capable of reducing carbon emissions on balance, although production by electrolysis at coal plants would increase those emissions. Producing hydrogen with nuclear power by thermo-chemical processes would emit no carbon, offering a 100 percent reduction in carbon emissions with no take-back effect through the hydrogen production.

Of the currently available methods of producing hydrogen, electrolysis, which would require considerable electricity, has not been tried at large scales of production. Steam methane reforming, the current production method of choice, needs process heat that could be supplied by either gas or nuclear reactors, but its economic viability is subject to the price of its feedstock, and its production emits carbon unless steps are taken to capture it. Thermal water-splitting is an alternative, non-carbon-emitting chemical process, and it can be powered by nuclear energy.

Nuclear reactors produce large amounts of heat that can be used for a variety of applications. The addition of a gas or steam turbine would allow production of electricity. Adding a thermo-chemical water splitting unit would permit hydrogen production. Looking to the post-2025 future, variations on modular helium reactors such as the GT-MHR described in Appendix A4, may be candidates for supplying the process heat for hydrogen production. The Very High Temperature Reactor (VHTR), the next generation modular helium reactor (MHR), consists of 600 MW (thermal) modules specially designed to supply the required heat for thermo-chemical water splitting processes while avoiding tritium contamination of hydrogen (Schultz 2003, p.4; Southworth 2002). The Advanced High Temperature Reactor (AHTR) is an alternative to the MHR concept, as it is very large (2,400 MW) and uses a molten salt coolant as opposed to helium (Forsberg 2003, p. 1077). Both, however, require additional research in high temperature materials and integration with hydrogen production techniques before commercialization is possible.

10.5. Conclusion

While many uncertainties cloud the future beyond 2025 in addition to those considered, the uncertainties bearing on nuclear power that emerge from the present study suggest the likelihood of an increased demand for nuclear power beyond 2025.

References

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Appendix: Major Issues Affecting the Nuclear Power Industry in the U.S. Economy

Appendix A1. PURPOSE AND ORGANIZATION OF STUDY

The focus of the study is on technologies for supplying baseload electricity—nuclear, coal-fired, and gas-fired technologies. Renewables technologies are not considered since they are not baseload. While hydroelectric facilities supply baseload generation in some parts of the United States, the major opportunities for hydro projects have been taken already, and significant new construction of hydroelectric facilities is not expected. Table A1-1 presents the shares of generation furnished by different technologies in the United States.

Table A1-1: Shares of Total U.S. Electricity Generation, by Type of Generation

Energy Source	Net Generation, Percent
Coal	50.1
Nuclear	20.2
Natural Gas	17.9
Hydroelectric	6.6
Petroleum	2.5
Non-hydro Renewables	2.3
Other Sources	0.4
Total	**100**

Source: EIA (2003), Electric Power Monthly.

This study aims to synthesize what is known about the factors affecting the viability of nuclear power and to make the best possible estimates of a range of future possibilities. The organization of the study is as follows.

Appendix A2 assesses the state of knowledge about future demands for electric generating capacity, as revealed by market and plant models. The date at which new capacity will need to be built in the United States is estimated in Appendix A3.

Appendices 4 through 10 consider other major factors that affect the nuclear power industry. The subjects include new nuclear power technology, waste disposal, nuclear regulation, nonproliferation goals, hydrogen, and energy security.

Part One of the body of the report is concerned with the market competitiveness of nuclear power. Subjects include levelized costs, comparisons with international nuclear costs, capital costs, the effect of learning by doing, and financing issues.

Part Two of the body of the report deals with fossil-fired generation, which is the major competitor to nuclear power. Subjects include gas- and coal-fired technology, fuel prices, and major environmental policies.

Part Three of the body of the report develops policy scenarios for the future. The first set of scenarios is for nuclear plants built starting in 2015, which is the projected next realistic time to complete a new plant. The second set of scenarios is for plants built beyond 2025.

Appendix A2. ELECTRICITY FUTURES: A REVIEW OF PREVIOUS STUDIES

Summary

Two principal types of models have been used to investigate electricity futures: plant models and market models. *Plant models* calculate the cost of electricity generation from a specific type of power plant. Costs are calculated on a levelized basis (LCOE), combining operating and capital costs to arrive at a cost per kWh, which if charged will recoup the cost of supplying electricity. Costs are calculated at the busbar level in order to focus on electricity generation costs abstracting from locally varying distribution costs.

Market models forecast the demand for electricity and the mix of electricity generating capacity that will come online to meet future levels of expected demand. Aggregate demand and supply functions are estimated and brought together simulating market behavior, often at the regional level.

By presenting cost per kWh figures, plant studies provide a useable common denominator. If nuclear energy can enter the marketplace at a cost per kWh equal to or less than other baseload electric power sources, it can hope to find a niche as a major power source. Cost per kWh is not a perfect measure inasmuch as it will be an average of actual magnitudes that depend on local conditions.

Focusing on cost per kWh simplifies analysis by eliminating the need for elaborate projections of the precise share of nuclear in the nation's energy mix. The essential question becomes: Will nuclear power enter the marketplace as a viable baseload option? It may do so with greater or less robustness, which may vary from place to place, and if the niche is to be expanded, will enter at a rate influenced by how fast other baseload sources are retired. It is not necessary to consider these details, at least in the first instance. There is little point in proceeding to these details unless the prerequisite cost per kWh is achieved that is necessary for a viable niche.

Within each category of model, different underlying numerical assumptions contribute to the principal differences in projections. The most significant of these are differences in overnight costs and interest rates for nuclear capacity, overnight costs for coal generation, and fuel costs for gas generation. Among the plant models, the most important structural difference is the inclusion or exclusion of taxes. The market models are sufficiently complex that reasons for differences in their projections frequently are difficult to pinpoint. The results depend on black box calculations that the reader cannot replicate, with a resulting lack of intuition as to what is driving the results.

Plant models appear better suited to the present investigation concerned with the viability of nuclear power. Their structures are straight forward enough to permit calculations to be transparent. Plant models however are far from being totally transparent. Frequently, plant calculations are made whose documentation is insufficient to permit

evaluation. Later in this study, attempts are made to narrow the range of uncertainty suggested by the sometimes wide differences in LCOE estimates from the previous studies.

Outline

A2.1. Introduction

The purpose of this appendix is to assess the models that have been used to project nuclear generated electricity costs, nuclear shares of electric generation capacity, and aggregate electricity demand and supply. This review concentrates on recent and significant models. The models can be divided into two types, plant models and market models. The plant models calculate the busbar or levelized cost of electricity (LCOE) from a single plant of a particular type. The market models project the price of electricity supplied, the types of generating plants used, and the quantity of electricity supplied. In addition, the market models contain, implicitly or explicitly, supply-demand interactions and decisions of businesses.

Section A2.2 reviews plant electricity models. Section A2.3 reviews market models. Section A2.4 reports on a hybrid model. Section A2.5 draws conclusions for the analysis to be undertaken in this study.

A2.2. Plant Models

Plant models focus on the economics of electricity generation from a single type of power plant. Called levelized-cost-of-electricity, or LCOE models, they are used to explore various influences on generation cost. Beyond that, they are sometimes used to provide cost information for market models. Section A2.2.1 describes a generic plant, or LCOE, model. Section A2.2.2 reviews several specific plant models.

A2.2.1. LCOE Estimation Using Plant Models

Plant economic models of electricity generating plants are primarily concerned with predicting the cost of electricity generation. The cost of power generation is dependent on the cost of building, operating, and maintaining the power plant, and is commonly referred to as the levelized cost of electricity, or LCOE. The LCOE is a measure of the generation cost of electricity, in constant dollars, for a plant using a particular generating technology over lifespan.

The major components of the LCOE equation are:

LCOE = Capital Cost + Operating and Maintenance Cost + Fuel Cost.

This equation includes both up-front capital costs and yearly costs that recur annually over the life of the plant. The LCOE calculation amortizes the capital cost components to place them on a yearly basis comparable to the annual costs. Given the rate of return required by investors, the LCOE is the price that must be received for power if costs are to be covered.

A2.2.1.1. Capital Cost

Capital costs are treated in detail in Chapter 3, so only a brief guide to the contents of the capital cost component of the LCOE equation is offered here. The base for the capital cost portion is the overnight cost for a generating plant. Overnight cost is construction costs without interest charges. It is generally quoted in terms of dollars per kilowatt of capacity. As plants are not in fact built overnight, the total capital cost per kilowatt can vary depending on the construction time and financing terms.

Overnight costs are not firm quotations from generating plant suppliers, but rather are estimates of the cost to build a new plant of a given type. In the case of fossil fuel plants, where plant construction occurs at a relatively steady pace, the overnight cost estimates are based on historical costs, and variation in cost is expected to be minimal. However, because no new nuclear plants have been built in the United States recently, the margin of error in estimating overnight construction costs for nuclear plants is larger.

Estimates of overnight costs sometimes assume an n^{th}-of-a-kind plant, a plant whose design has been built frequently enough in the past that there is little potential for further reductions in cost due to improvements in construction experience. Most fossil plants fall into this category. By contrast, when a completely new type of power plant is built, it incurs first-of-a-kind-engineering or FOAKE costs, which represent the pre-construction engineering work required for implementing a prototype technology. Inclusion or exclusion of FOAKE costs for newer, advanced nuclear reactor designs and the lack of recent historical experience has contributed to considerable variability in overnight construction cost estimates for new nuclear power plants. There may, in addition, be learning effects for the first few plants beyond the first one.

A power plant's capacity factor, the percentage of total rated power that is used, reflects the effect of scheduled and unscheduled downtime on the total amount of power that the plant is able to generate in a given year. Variations in the expected capacity factor can make a significant difference to the busbar cost of electricity, as an increase in the expected capacity factor has the same effect as lowering capital costs per kilowatt. Historically, U.S. nuclear power plants suffered from initially low capacity factors, but these have improved in recent years to levels approaching 90 percent.

The expected lifespan of the plant also affects the cost of electricity, as capital costs are typically recovered over the lifespan of the plant. While power plants are designed for specific operating lifetimes, many fossil plants are operating beyond their original design lives, and a number of nuclear plants are currently requesting license extensions and undergoing refurbishing to extend their lifespan. A longer plant life lets the capital in a plant generate more electricity and consequently lowers capital cost per kilowatt, but because of discounting, beyond a certain point (40 years or so), increasing the expected lifespan of the plant has only a small effect on the present-value cost represented by the LCOE. Most of the capital costs are recovered in the first 20 years of operation.

A2.2.1.2. Yearly Operating Costs

Yearly operating expenses have to be paid as long as the plant is still operational. Many of these do not vary with the amount of power being generated. For example, employee wages, general maintenance, and overheads are in this category. They are usually historically well established and exhibit low variance. They tend to make up the smallest portion of busbar electricity costs across generation plant types. For these reasons, they are not typically disaggregated in great detail.

Fuel costs are the major component of variable costs, since for most power plant types the only element of cost that varies directly with the amount of power generated is fuel. Some power generation technologies such as renewables like solar and wind have zero variable cost, but the baseload plant types—fossil and nuclear—have significant variable costs. Fuel price is an input into a plant model, along with the plant's heat rate, a measure of BTUs needed to generate a kilowatt-hour of electricity. Lower heat rates correspond to more efficient plant designs and hence lower variable costs of operation.

Many plant models use the heat rate in their calculations to allow for improvements to technology that reduce the heat rate. In addition, different fuel types have different BTUs, which is significant for plants that can accept more than one type of fuel. For example, differing grades of coal are in use by coal-fired power plants, and each grade has a different average BTU content, so the LCOE of a plant may differ according to its location because of fuel costs, among other local factors.

A common assumption in LCOE models for nuclear plants is that total cost for nuclear fuel per kilowatt-hour or per year is given. This approach works satisfactorily for nuclear power, as the heat rates across previously built nuclear plants are fairly similar, and fuel costs are only a small fraction of the cost of nuclear power generation. Since nuclear plants are run as baseload at a relatively constant capacity, and the price of nuclear fuel has been quite stable, the cost of nuclear fuel from year to year is predicted to be quite stable.

A2.2.1.3. Externalities

Power plants often produce unwanted byproducts, such as waste heat, greenhouse gases, and toxic elements. Other less visible externalities also exist, such as spent fuel and possible weapons proliferation effects in the case of nuclear power plants. In recent years, tightening environmental regulations have meant that power producers have to include the cost of controls to reduce these externalities – particularly SO_2 and NO_X – into their cost calculations. In the future, CO_2 emissions may be regulated, and some models allow for the costs of limiting those emissions.

A2.2.2. "Business Case for New Nuclear Power Plants" by Scully Capital

Scully Capital was contracted by the U.S. Department of Energy (DOE) to examine the feasibility of new nuclear power plants from an industry and financial perspective. The

Scully Capital report first qualitatively examines the risk factors that are critical to the nuclear plant decision, such as nuclear waste disposal, the public perception of nuclear risk, and government support. Scully Capital includes a model for calculating the economics of nuclear power from a project financing perspective. The model is used to analyze the economics of investing in nuclear power, under alternative assumptions about capital costs and financing structure.

The Scully Capital model's focus is on investors' perceptions of profitability. The model solves for the internal rate of return (IRR) on equity in the investment, assuming a wholesale price of baseload electricity, which is the implied LCOE received (Scully Capital 2002, p.101). The results can be re-arranged to express LCOE as a function of investor required rate of return, which is done in Chapter 1.

The Scully Model uses EPC or Engineer-Procure-Construct costs as the base for the capital cost of nuclear power. These costs are based on the AP1000 reactor by Westinghouse and appear to come directly from Westinghouse estimates (Scully Capital 2002, p.90). As a component of overnight costs, EPC costs do not contain any financing charges, but owner's costs, contingency costs and other development costs are added to the EPC cost, adding about 10 percent to arrive at full overnight costs before financing. A range of EPC costs from $1.6 billion to $1.0 billion for a 1,100 MW reactor is used, the range reflecting improvements in technology and construction experience that could eventually reduce the cost of construction. Translated into per kW terms, the resulting cost range is $909 to $1,454 per kW.

A2.2.3. GenSim

The GenSim model from Sandia National Laboratories (Drennan et al. 2002) is a generic LCOE model. The LCOE calculation is (Drennan et al. 2002, p. 10)

$$LCOE = \frac{I(CRF)}{Q} + \frac{O\,\&\,M}{Q} + \frac{E}{Q},$$

where *I* is capital investment, including finance costs; *CRF* is the capital recovery factor, specified as $CRF = \frac{r(1+r)^n}{(1+r)^n - 1}$, in which *r* is the real discount rate and n is the plant life; *Q* is annual plant output in kilowatt hours; *O&M* is fixed and variable operation and maintenance costs; and *E* is externality costs. The report identifies *F* as fuel costs, but the term does not appear in the published version of the report on the model. Presumably a term +F/Q is omitted from the reported equation rather than from the actual model. The model is written in the software package Powersim Constructor (Drennan et al. 2002, p. 7).

The technologies for which the model has calculated LCOEs include nuclear, coal, gas combined cycle, solar photovoltaic, solar thermal, and wind. The published report uses a nuclear capital cost (presumably an overnight cost) of $1,853 per kW.

A2.2.4. The MIT Nuclear Power Study

MIT's *Future of Nuclear Power* (published in July 2003) is concerned with nuclear power as an option for the United States by 2050. A part of the study uses a plant model to calculate busbar electricity cost that includes federal taxes, inflation, and real cost escalations, among other complications. Overnight cost is based on EIA's *Annual Energy Outlook 2003*, and in the reference case is $2,000 per kW (MIT 2003, p. 43). Nuclear power reaches competitiveness with fossil generation by 2050 based on assuming carbon taxes of $50 to $200 per ton of carbon raising fossil costs, 25 percent reduction in nuclear overnight costs, reduction of construction period from 5 years to 4 years, increases in capacity factor from 75 to 85 percent, and lower financing costs due to reduced risk.

The MIT financial model is formally similar to the financial model developed in Chapter 5 of the present study, but the focus of the present study is on the near term rather than the long term (2015 rather than 2050). The present study considers detailed differences in financial policies for plants coming on line in 2015 and shortly thereafter. The longer term focus of the MIT study precludes this type of analysis.

A2.3. Market Models

Market models are intended to replicate in some detail the electricity market of the United States, including interactions between electricity suppliers, region-specific information about electrical generation, demand, and transmission, and other market forces affecting electricity supply and demand.

A2.3.1. Basics of Market Models

A market model typically simulates the interaction between electricity supply and demand over a multi-year forecast horizon, with a view to providing projections of how electricity generation capacity evolves over time. Most market models simulate the response of the supply-side to changes in electricity demand, as well as to changes in the prices of fuel and other costs of production. Despite the intricacy of the market interactions specified in market models, the heart of a market model is still an LCOE model that calculates the price any particular power plant needs to receive for its electricity. This information is used in electricity dispatching assignments affecting price and capacity forecasts.

One market modeling approach is to take a detailed, regional approach. A complex electricity market model will therefore contain detailed, region-specific data on electrical loads and generation types and will determine construction of new plants based on projected peak and base-load demands. An alternative approach abstracts from the difference between peak and baseloading, and treats electricity capacity and demand as uniform across the year. In this approach the capacity that has to be satisfied is the peak-load capacity plus a reliability premium to ensure a margin for unexpected outages, assuming that market forces ensure specific plants are built where they are most cost efficient.

A2.3.1.1. Modeling Issues

Over the long term, electricity consumption increases with population growth and the level of economic activity or development in a region. Most electricity demand models contain economic and population growth models that produce an estimate of electricity demand growth as an output. The historical record of electricity use, and assumptions about the growth rates of the economy, population, and energy intensity, are major inputs to electricity demand models.

Supply-side models need to represent how electricity capacity evolves over time, in response to changing capital and fuel costs, and demand. Supply models depict the power generating industry's decisions in response to changing electrical demand and input costs. Crew and Kleindorfer (1986, Chapter 3) shows the structure of the short- and long-term decisions that the forecasting models implement in considerable detail.

Capacity models begin with the existing U.S. stock of electrical generation capacity as the reference point. Additional capacity is added by the model to provide for projected increases in electrical demand and to replace existing power plants which have to be retired due to age, environmental, or other cost reasons.

Market models use a plant LCOE model to choose a least-cost generation alternative, but market models do not build only the plants with the lowest projected LCOE. LCOEs are only generic estimates for a particular region, and, if two technologies are close in terms of projected costs, the market as a whole may in fact build plants of both types because of location-specific cost differences that are too fine-grained to reflect in the LCOE calculations based on average characteristics for a region. Various market-sharing algorithms are used to allocate new capacity among technologies with similar costs.

A2.3.1.2. Market Models and Electricity Market Deregulation

Electricity market deregulation has been the most significant change affecting energy markets in recent years (Joskow 2000, 2001a, 2001b, 2003; Joskow and Kahn 2002). Almost all the market models reviewed here assume either that the market is still regulated, or that the market is deregulated and perfectly competitive. Market models typically split demand and supply between regulated and deregulated regions to compensate for the fact that different regions of the United States are undergoing varying degrees of electricity market deregulation.

Differences in model specifications of regulated and deregulated electricity markets center on price formation. Regulated markets have regulated prices that will follow costs with some time lags. In unregulated markets, price is determined by supply and demand with market price being set at any given time by the marginal producer's cost. The specification of deregulated market interactions is more complicated than that of regulated markets, but the fundamentals are common across the two regimes because both are fundamentally based on costs of electricity generation.

A2.3.2. The National Energy Modeling System (NEMS)

The National Energy Modeling System (NEMS) is the most comprehensive energy model reviewed here. It was developed by the Energy Information Administration (EIA), and is used to generate EIA's energy forecasts, including the *Annual Energy Outlook* forecasts. NEMS is considered by many to represent the U.S. government's official energy forecast, although different government agencies possess and use other energy market models. This section describes the interactions of two submodules of the Electricity Market Module (EMM) of NEMS, which is responsible for producing forecasts on the electricity market out to the medium term.

A2.3.2.1. Electricity Market Module (EMM)

The electricity market module simulates the electricity market in each year of a forecast, producing an optimal solution in which electricity suppliers meet electrical demand in the most economical manner (EIA 2003c, p.6). To create this forecast, the EMM employs four sub-modules, the Electricity Capacity and Planning (ECP) and the Electricity Financing and Pricing (EFP) submodules being most important to this study.

The ECP submodule models the U.S. electricity market largely by North American Electric Reliability Council (NERC) regions. Beginning with existing generating capacity in each region, the ECP takes regional load information from the Loan and Demand-Side Management submodule. EIA provides the ECP with data on overnight construction costs, O&M costs and heat ratings for plant types. Fuel prices are supplied to the ECP from a separate module. Allowing for interregional transmission, the ECP uses load and cost data to determine optimal capacity for each region (EIA 2003b, pp. 40-70).

With data on all existing plants, the ECP is simulated over a 20-year period. Starting with the existing stock of generating capacity, ECP builds new capacity in response to projected load increases. Older plants are retired only when their continued operation costs rise above their replacement costs. Consequently NEMS projects that many plants will remain operating beyond their design lifetimes.

Although a chief consideration of ECP is cost minimization, always choosing the lowest-LCOE plant is not considered realistic because the cost inputs are regional rather than site-specific estimates. ECP includes a market-sharing algorithm to let technologies that are marginally more expensive than the lowest-cost option be selected for construction in proportion to their cost competitiveness (EIA 2003a, p. 67).

The EFP submodule calculates the cost of capital, including the debt-to-equity ratio, and passes this information to the ECP. The debt interest rate is the prevailing rate on new long-term AA rated corporate bonds, and the equity rate is determined with the Capital Asset

Pricing Model (CAPM), which adds a risk premium reflecting a project's specific volatility compared to that of the market to the risk-free rate of return (EIA 2003a, pp. 167-168). The EFP submodule appears to assume uniform risk for all electricity generation projects.

A2.3.2.2. Complexity, Accuracy, and Transparency in the NEMS Model Structure

NEMS is the most complex and detailed electricity model currently in widespread use. It incorporates many realistic factors, such as regional demand differences, transmission constraints, and individual plant characteristics. Its detail contributes to its ability to closely replicate market outcomes in individual regions. At the same time, the complexity added by the additional detail reduces the model's transparency, reducing the ability to pinpoint reasons for some of its results. A more aggregated model may not lose a significant degree of accuracy compared to NEMS at the national level. Some reduced accuracy could be compensated by greater transparency compared to NEMS.

A2.3.2.3. Studies using NEMS – *Annual Energy Outlook* Series

The *Annual Energy Outlook* (AEO) annual series provides comprehensive twenty-year projections of U.S. energy markets. AEO defines a base case that "focuses on . . . long-term fundamentals, including the availability of energy resources, developments in U.S. electricity markets, technology improvement, and the impact of economic growth on projected energy demand and prices through 2025" (EIA 2003a).

AEO projects the prospects of nuclear power conservatively, primarily because a significantly higher capital cost is projected for nuclear power compared to coal and gas. Even though natural gas prices are expected to rise over the medium term, from the $3 range to $3.50 per thousand cubic feet in 2025, natural gas is still expected to be the most cost competitive standard generating technology through 2025. The rise in natural gas prices causes some shift in construction of new power plants to coal-fired plants, but not to nuclear plants, identified as the reference case in AEO 2004. Unless the underlying assumptions are modified so as to change the relative cost characteristics of the three main generating technologies, or impose some systemic constraints on the cost-minimizing power plant selection procedure, AEO will likely continue to make projections of significantly increased natural gas-fired generating capacity, some new coal-fired capacity in the medium term, and no new nuclear capacity.

A2.3.2.4. Studies Using NEMS— EPRI

The Electric Power Research Institute (EPRI) produced a study in 2003 using NEMS to support its "Vision 2020" goal of 50,000 MW of new nuclear generating capacity by 2020 (EPRI 2003a, p. vi). Because NEMS did not project any new nuclear generating capacity by 2025, EPRI created several scenarios that allowed the growth of significant nuclear generating capacity.

EPRI's most significant revision is that new 1,000 MW advanced nuclear plants could be built starting in 2005, at a capital cost of $1,250 per kW (EPRI 2003a, p. xiii), well below the EIA estimates of about $2,000 per kW for advanced nuclear plants (EIA 2003b, Table 40). EPRI considers this revision in nuclear plant costs to be the foundation of its base case scenario, which otherwise leaves the other input assumptions used by EIA in NEMS unchanged. Under the EPRI base case, new nuclear power starts being deployed in 2009, reaching 23 GW by 2020 and 135 GW by 2035 (EPRI 2003a, sect. 3-4).

EPRI's other scenarios reduce capital costs by a further 10 percent and raise natural gas prices, both resulting in higher initial deployments of nuclear power. The introduction of a carbon tax starting at $5 per ton in 2011 and rising to $50 per ton in 2020 raises the cost of power generation from coal significantly, and to a lesser extent, that of gas. Since nuclear power is a non-polluting technology, nuclear power would become a relatively cheap baseload generating option, displacing significant coal generation and holding down the growth of gas generation (EPRI 2003a, sect 3-12). Nuclear power would account for the majority of power generation by 2050 under this scenario.

A2.3.3. The All Modular Industry Growth Assessment (AMIGA) Modeling System

The *All-Modular Industry Growth Assessment Modeling System* (AMIGA), developed at Argonne National Laboratory (Hanson 1999), is a computable general equilibrium model of the U. S. economy with considerable sectoral detail. It is benchmarked to the 1992 Bureau of Economic Analysis (BEA) interindustry data, which it aggregates to 300 sectors.

AMIGA's electricity module starts with the current stock of generating capacity, and dispatches generating units against an aggregate electricity demand curve in the order of variable costs of different generating technologies. When the module determines that growth in electrical demand would lead to a shortfall in supply, it builds new capacity based on plant life-cycle cost of alternative technologies.

A recent Pew Center report on energy futures (Mintzer et al. 2003) uses the AMIGA model. The Pew study's major concern is with the impact of various scenarios and possible U.S. energy futures on the environment.

In the first of three scenarios, "Awash in Oil and Gas," abundant fossil fuels lead to continued increase in energy consumption. Due to low natural gas prices, gas turbine combined cycles replace most retiring coal and nuclear capacity. No new nuclear power plants are built, since fossil fuel prices remain low (Mintzer et al. 2003, p. 7).

In the "Technology Triumphs" scenario, government initiatives lead to advances in technologies such as distributed generation, fuel cells, and renewables. The share of electricity from nuclear power remains constant as retiring reactors are replaced with next-generation reactors (Mintzer et al., p. 13). The energy market is dominated by hydrogen, renewables, and other efficient and low-emission technologies.

In the "Turbulent World" scenario, confidence in nuclear power erodes, leading the government to let the Price-Anderson Act lapse in 2010. Without the insurance provisions of Price-Anderson, new reactor construction is not undertaken after 2010, although a few are built prior to that date (Mintzer et al. 2003, p. 21).

Within each scenario, the Pew study simulates policies designed to constrain carbon emissions, increase energy efficiency, and spur R&D on distributed generation, renewables, and hydrogen technologies. These policies increase the shares of these new technologies, and all three scenarios see major increases in renewable electricity supply and distributed generation, while natural gas consumption is moderated (Mintzer et al. 2003, Tables 12, 14-15, pp. 52-54).

The Pew study uses an overnight cost for nuclear plants of $2,645 and $2,835 per kW (Mintzer et al. 2003, Table 6, p. 34). These costs help to explain the reduced role of nuclear power in favor of power from advanced renewables technologies.

A2.3.4. Integrated Planning Model, U.S. Environmental Protection Agency

The Integrated Planning Model, or IPM, is a proprietary model developed by ICF Resources, Inc. and used by the U.S. Environmental Protection Agency (EPA). IPM is designed to characterize deregulated wholesale electric markets (EPA 2002, p. 2-7). EPA links the IPM with its own National Electric Energy Database System (NEEDS) to assess the effects of environmental regulations on the U.S. electricity industry.

IPM structure is similar to NEMS but emphasizes environmental constraints and emission trading systems. NEEDS aggregates the plant data from EIA's yearly survey of power plants into model plants that represent a number of actual plants on the basis of characteristics such as region, technology type, capacity, and heat rate. The 103 nuclear plants are aggregated into 47 model plants (EPA 2002, pp. 2-4, 2-5).

Electricity demand and generation are modeled internally for each NERC region, with regions linked by inter-regional transmission. New power plants are selected for construction to meet new demand and replace retiring plants on a cost-minimizing basis. (EPA 2002, sect. 2-2). IPM examines the impact of current emissions regulations on the electric power industry using a 20-year forecast horizon.

All additional capacity growth from the present to 2020 is projected to come from natural gas-fired combustion turbine and combined cycle units. No nuclear or coal units are selected for construction (EPA 2002, p. 9-5). In fact, some nuclear units are retired because the model finds that life-extension retrofits are uneconomic. EPA takes data for advanced nuclear plants' cost and performance characteristics from EIA's AEO 2001, assuming a cost of $2,465 per kW for a 600 MW advanced nuclear plant that is built between 2005 and 2009, dropping to $2,276 per kW for plants built from 2015 onwards. The high capital cost estimates for nuclear technology are the primary reason why nuclear energy is not selected by IPM.

A2.4. A Hybrid Model: SAIC's Power Choice Model

The Science Applications International Corporation (SAIC) study (Reis and Crozat 2002) developed a systems dynamics model called Power Choice to study the effect of variations in government policies, including waste disposal policies, on the generation technologies chosen by power companies. While the model's central component is a variant of an LCOE calculation, and the study projects market penetration of different generation technologies, it does not use market supply and demand concepts to derive those projections.

The principal driver of Power Choice is a pre-tax plant model that calculates a discounted profit per megawatt-hour. Competition does not drive profit to zero as most LCOE models assume. The busbar cost of a particular generation type is subtracted from an assumed retail price of $70 per MWh (Reis and Crozat 2002, p. 54), to obtain profit per MWh in any period. Profit for nuclear construction is discounted with a risk premium, which government policy can affect, above the base discount rate. These calculations are made for coal and natural gas plants and five types of nuclear reactors: the Advanced Boiling Water Reactor (ABWR), the Advanced Pressurized Water Reactor (APWR), the AP1000, the Gas Turbine-Modular Helium Reactor (GT-MHR), and the Pebble-Bed Modular Reactor (PBMR). A market sharing formulation is developed that allocates new construction in some proportion to the ratio of each generation type's discounted profitability.

Overnight costs of the AP1000 and GT-MHR are specified at $1,365 per kW and $1,126 per kW respectively. The federal government, as part of a nuclear power strategy, is assumed to pay for half of the construction cost of an unspecified number of new plants. FOAKE costs are assumed to be spread over the first eight plants (Reis and Crozat 2002, p. 10).

Without re-licensing or other government actions, the current stock of nuclear reactors is projected to shut down at the end of their remaining lifespans, which Power Choice estimates at 20 years. The share of nuclear power declines to zero in 20 years. Government re-licensing extension delays the withdrawal of current nuclear reactors by 20 years. The additional nuclear waste generated is projected to be well within the limits of Yucca Mountain and on-site storage. However, with re-licensing alone, Power Choice projects the eventual decline of nuclear power to zero in 40 years.

If government support provides half the pre-construction costs of the AP1000 and the GT-MHR, the AP1000 design is projected to provide 25 GW of power by year 20. Adding the GT-MHR to the scenario increases nuclear power output to more than 60 GW in about 30 years due to its lower overnight cost and lower nuclear waste production. The main constraint in this segment of the scenario is nuclear fuel waste, which prevents additional

AP1000 or GT-MHR reactors from being built once Yucca Mountain limits are reached (Reis and Crozat 2002, p. 11).

A final action considered by SAIC is an introduction of an advanced fuel cycle that recycles spent fuel via advanced fast reactors (AFRs), which are estimated to cost $2,000 per kW. This plan removes the nuclear waste limitation since the AFRs recycle the majority of waste produced by the AP1000 and GT-MHR reactors. Once AFRs are built, starting around year 25, growth of AP1000 and GT-MHR reactors rises to more than 375 GW of capacity in year 80. AFR growth reaches more than 150 GW in year 80 (Reis and Crozat 2002, p. 14). Nuclear waste, meanwhile, declines from a high of nearly 1.5 Yucca Mountain Equivalents (YME) in year 25 to less than 0.25 YME in year 80.

A2.5. Conclusions

Table A2-1 summarizes the characteristics of the different plant and market models that have been reviewed in this appendix. The table brings out the varieties of plant type, forecast horizons, treatment of environmental costs, and nuclear power data sources that have been used. Cost assumptions from the four plant models identified in bold font—the Scully model, the GenSim model, NEMS, and SAIC's Power Choice model—are used in Chapter 1 a pre-tax LCOE model developed in this study to examine sources of differences in LCOE estimates.

Plant and market models are constructed for different purposes, although market models generally contain plant cost calculations as well as market interactions. The complexity of market models, even though soundly constructed, makes it difficult to understand the reasons for forecast results or to calculate how different assumptions would change them.

The plant models that calculate LCOE are simpler in structure, and the basic structure is well accepted. Nevertheless, reported versions differ considerably in assumptions that affect costs and in degree of documentation and financial detail, rendering comparison of results difficult. Results for nuclear LCOEs are heavily influenced by two assumptions, overnight capital costs and interest rates, and the choices of these values typically are not discussed in great detail.

Table A2-1: Plant and Market Model Summary

Model Identification	Plant Type	Forecast Horizon	Treatment of Environmental Costs	Source of Nuclear Power Data
Plant Models				
Scully Capital-DOE (Nuclear Energy)	Nuclear (AP1000)	up to 2010	No	Vendor, 2002
Electricity Generation Cost Simulation Model (GenSim)/Sandia	Wide spectrum of energy sources	Current year	Has capability	Energy Information Administration (EIA) and Platt's (McGraw-Hill) Database, 2003
MIT Study	Nuclear, coal, gas	up to 2050	Carbon tax	EIA, 2003
Market Models				
National Energy Modeling System (NEMS)-EIA	Wide spectrum of energy sources	20 years from present	No	EIA, 2003
NEMS-Electric Power Research Institute (EPRI)	Nuclear, coal, gas	up to 2050	Carbon tax	Vendors, 2002
All Modular Industry Growth Assessment Modeling System (AMIGA)/ Pew Charitable Trust	Wide spectrum of energy sources	up to 2035	Yes	Argonne National Laboratory, Vendors, 2001
Integrated Planning Model (IPM)/Environmental Protection Agency (EPA)	Nuclear, coal, gas	20 years from present	Yes	EIA
Hybrid Models				
Science Applications International Corporation (SAIC) Power Choice Model	Nuclear, coal, gas	80 years from present	Carbon tax	DOE and Vendors, 2001

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http://www.eia.doe.gov/oiaf/aeo/assumption/electricity.html,
http://www.eia.doe.gov/oiaf/aeo/assumption/tbl39.html,
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Appendix A3. NEED FOR NEW GENERATING CAPACITY IN THE UNITED STATES

Summary

This appendix assesses future electricity demand and compares it with existing capacity to estimate a range on the time in the future when added capacity building will need to start. Projections by the Energy Information Administration (EIA) and the North American Electric Reliability Council (NERC) are compared with projections based on historical relationships between demand growth and GDP growth. The historical relationships yield growth rates roughly 1 percentage point higher than EIA's forecasts and .5 percentage-points above NERC's.

From a national perspective, even with an annual growth rate in electricity demand of 2.7 percent, new capacity will not be needed before 2011. The aggregate view obscures some NERC regions in which capacity additions will be needed before that date. Even under low demand growth, new capacity is needed in 5 of the 11 NERC regions by 2010. It is safe to say that demands for new electricity generating capacity will be sufficient to justify significant amounts of new capacity by 2015, which is the year of new plant construction used in the analysis of viability of nuclear power in the present study.

Outline

A3.1. Introduction

This appendix compares future electricity demand with existing capacity to estimate when new electricity generation capacity will be needed. Sections A3.2, A3.3, and A3.4 examine the three main sectors of electricity demand, residential, commercial, and industrial. Section A3.5 reviews the literature on the effects of price on electricity demand. Section A3.6 assesses several other potential influences on future demand. Section A3.7 provides a national projection of demand growth and reports forecasts of additions to generation capacity. Section A3.8 gives a regional breakdown of forecasted demand and capacity growth in the United States. Section A3.9 summarizes and draws conclusions on both national and regional demand.

A3.2. Major Types of Electricity Demand

The three major sectors of electricity consumers—residential, commercial, and industrial—each claims about one-third of national consumption, and they all respond to price changes, at least in the long run. However, their long-term growth rates have differed, the predictability of their demands differ, and they are subject to some different influences.

A3.2.1. Residential Demand

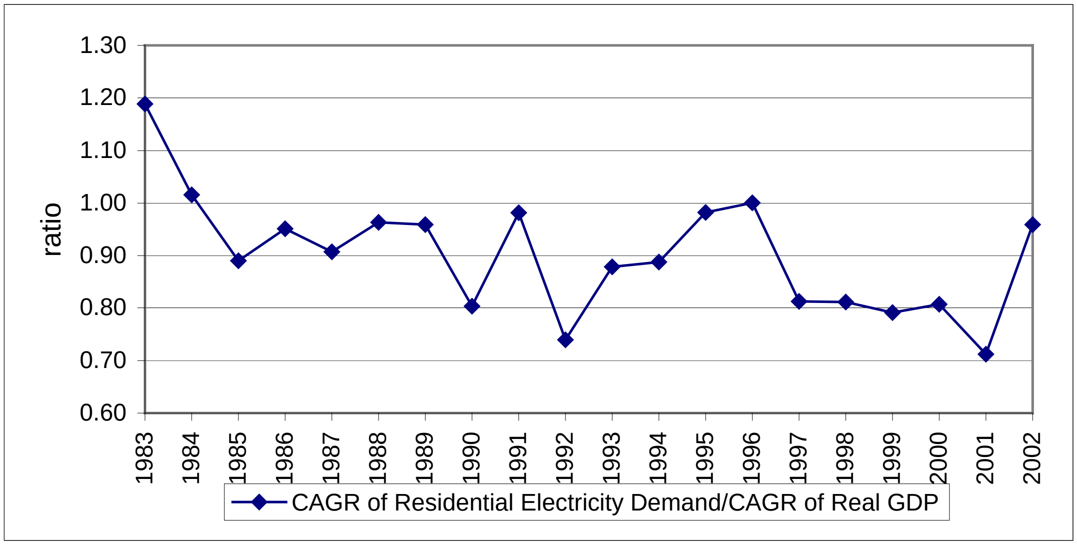
Over the 20 years 1982 to 2002, residential electricity demand has increased an average of 2.8 percent annually, while GDP has advanced 3.3 percent per year. This relationship appears to have remained fairly steady over the entire period. Figure A3-1 shows that while residential electricity demand growth is uneven, its moving average is about 40-50 basis points below GDP growth in recent years. The average ratio of residential electricity demand growth to GDP growth is about 0.9, with most of the deviation due to weather fluctuations. Therefore, based on purely historical trends, residential electricity demand could be expected to grow around 2.6 to 2.8 percent per year, given GDP growth of 3.1 percent per year.

The major influences on residential energy consumption during the next two decades are likely to be changes in the energy efficiency of existing appliances, the emergence of new appliances, and the continued movement of the population to the South and West.

For several decades, energy conservation policies have aimed at reducing the energy-efficiency gap, a phenomenon in which consumers invest less in energy-efficient appliances than would be expected, given interest rates, appliance costs, and electricity prices, with limited success. There is little agreement to date on the cause of this phenomenon, but these appliances currently account for roughly half of residential energy consumption (EIA 2003a, Table A.4), so a substantial reduction in the load they draw could be important. EIA's high-technology forecast assumes greater market penetration of higher-efficiency appliances, which reduce the growth rate of residential electricity consumption by nearly 30 basis points.

Whether policies or prices will induce greater acceptance of energy-efficient appliances in the coming decades remains uncertain.

Figure A3-1: 10-Year Moving Average of Residential Demand Growth/ GDP Growth Ratio



Sources: EIA (2003b), BEA (2003).

A large number of new, high-technology consumer appliances, computing equipment among them, comprise nearly 30 percent of residential electricity consumption, a magnitude of importance to the future of residential demand growth, but alternative methods of forecasting their growth yield conflicting results (Koopmans and te Velde 2001). Using a top-down approach based on historical trends, EIA (2003a, Table A.4) projects a 3.5 percent annual growth in these appliances' electricity consumption, but Koomey et al. (1995), using EPRI's bottom-up model, Residential End-Use Energy Planning System (REEPS) project less than half growth to 2010 and even less after that. Overall, the implication of these new appliances for residential demand growth is unclear.

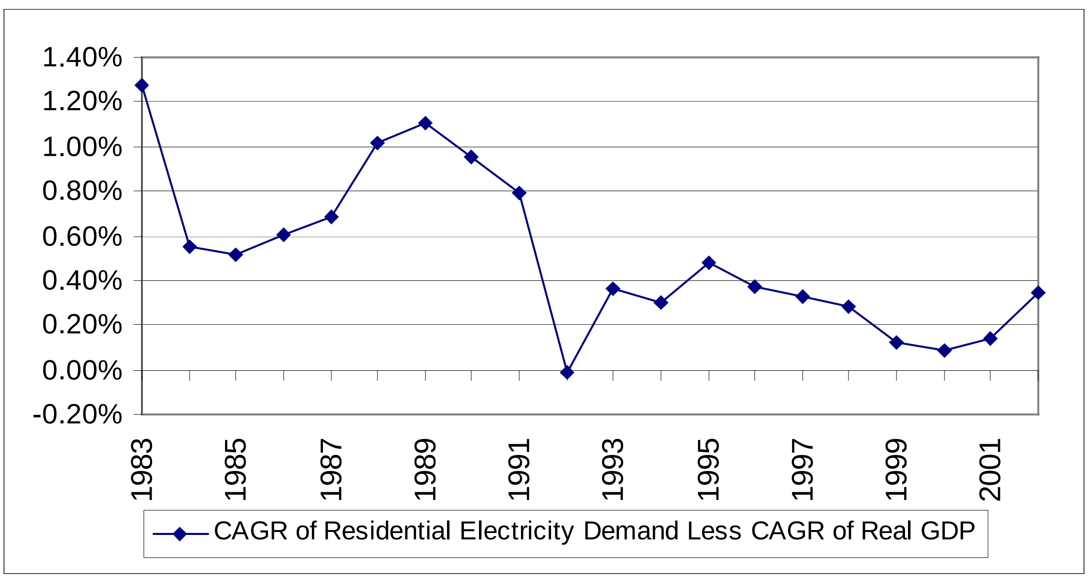
Residences in the South and West have a greater tendency to use electricity for space heating and cooling than those in the Northeast and Midwest, where air conditioning is less common and gas is more widely used for heating (EIA 1997). Between 1978 and 1997, the number of households in the South and West increased 46 and 56 percent, compared to 13 and 17 percent in the Northeast and Midwest (BLS 2003). Continuation of this population redistribution trend could add substantially to electricity demand.

EIA's *Annual Energy Outlook 2003* (AEO 2003) projects average residential electricity demand growth of 1.7 percent per year through 2020, while it reports the Global Insight projection at 2.1 percent per year over that period. Both projections are well below the historical growth rate of 2.8 percent. Over-prediction of appliance efficiency improvements may be responsible for a large proportion of the AEO's consistent under-forecasts of residential electricity consumption growth. Of the three major influences on residential electricity demand growth for the next two decades, two have considerable uncertainty, so looking to the historical growth rate for guidance may be useful. Over the last three decades, annual residential electricity demand growth has been around 90 percent that of GDP growth. Using EIA's assumption of a 3.1 percent GDP growth rate for 2001 to 2010 (referencing Global Insight) would yield a 2.8 percent annual growth in residential electricity demand. Dampening that growth by 20 to 30 basis points EIA predicts for improved electricity efficiency would cut that growth rate to 2.5 percent. Allowing for population growth and its continued regional redistribution could add another 10 basis points, bringing an overall residential electricity consumption growth rate to 2.6 percent. A GDP growth rate of 3.2 percent from 2010 to 2020 would raise the residential demand growth rate to 2.7 percent during that decade.

A3.2.2. Commercial Demand

Historically, commercial electricity demand growth has somewhat outpaced GDP growth. As Figure A3-2 shows, commercial demand growth has averaged about 1.2 times the rate of GDP growth, the corresponding gap between commercial demand growth and GDP growth being about 50 basis points.

Figure A3-2: 10-Year Moving Average of Commercial Demand Growth/ GDP Growth Gap



Sources: EIA (2003b), BEA (2003).

Assuming GDP growth of 3.1 percent, historical trends would point to a future annual growth rate of 3.7 percent in the commercial sector, 1.2 times the rate of annual GDP growth, and 60 basis points above the rate of annual GDP growth.

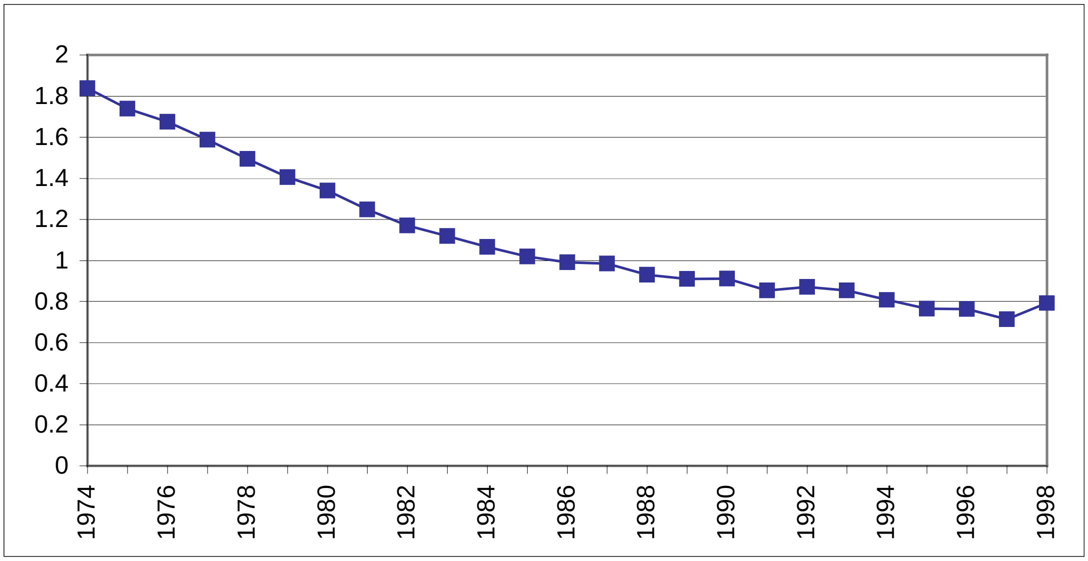
Heating is proportionally less important in commercial demand than in residential demand, while lighting is a far larger factor, claiming about 25 percent of load in 1998. Computing equipment contributes a relatively minor load (EIA 2002b).

The main drivers of commercial growth will continue to be new and improved electronic appliances and new buildings, offset by efficiency improvements. The Internet has not had a significant effect on electricity demand, telecommuting has not emerged as a common practice, and e-commerce still accounts for only a small fraction of retail sales. Despite the optimism of Romm et al. (1999) about these sources of influence on commercial electricity demand, it seems premature to depress forecasts of commercial demand growth on that basis. This leaves only historical trends to form a basis for this forecast. Again, from Section 3.1, this would be 3.8 percent annually over 2002 to 2010 (given 3.2 percent annual real GDP growth) and 3.7 percent annually over 2002 to 2020 (given 3.1 percent annual real GDP growth).

A3.2.3. Industrial Demand

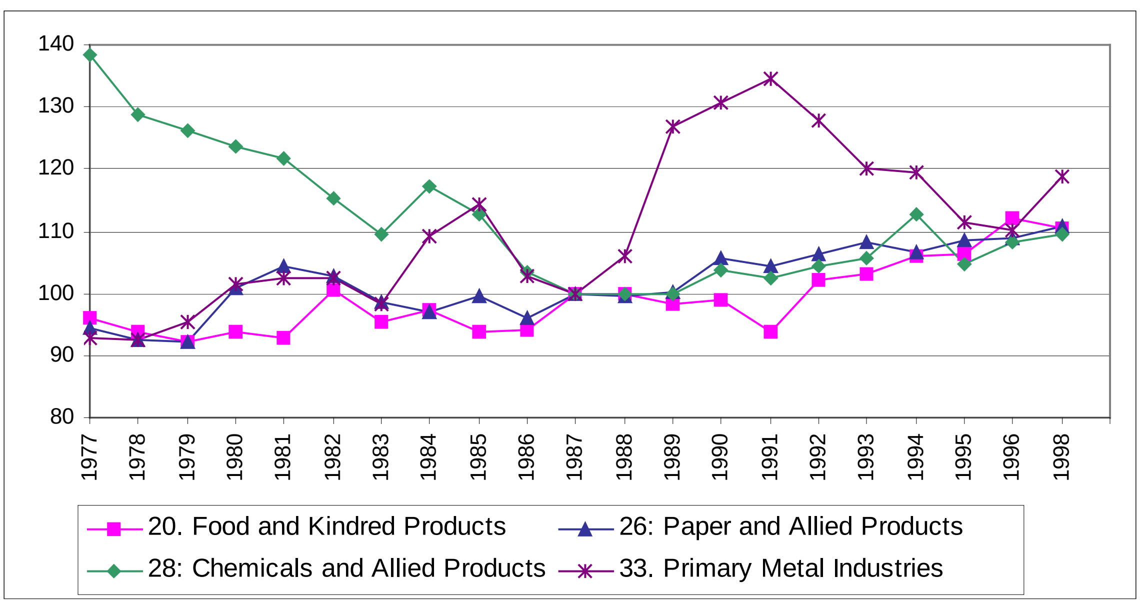
Industrial electricity has been the most volatile and most difficult to predict. Manufacturing accounted for 85 percent of industrial electricity demand in 1998 (EIA 1998), and Figure A3-3 shows that as a whole, manufacturing has become less electricity intensive per dollar of output since the mid-1970s. However, the four most electricity-intensive industries—food, paper, chemicals, and primary metals—have displayed no clear trends in efficiency, in Figure A3-4.

Figure A3-3: Ratio of Manufacturing Electricity Consumption to Manufacturing Output over Time, in Logs



Sources: EIA (1998), U.S. Census Bureau (ASM, CM).

Figure A3-4: Ratio of Industry Electricity Usage to Industry Quantity Index (1987=100)



Sources: EIA (1998), U.S. Census Bureau (ASM, CM), BEA (2003).

Industrial demand for electricity will be affected not only by future rates of economic growth and energy efficiency advances of individual industries, but also by changes in the sectoral composition of production as well, and these are difficult to predict. Again looking to historical trends, the percent of U.S. GDP deriving from manufacturing has been steady between 1987 and the recession year of 2001, fluctuating between only 16 and 17 percent (BEA 2003). Future trends of manufacturing electricity use may be influenced more by sectoral shifts than by reductions in the U.S. manufacturing base. For example, the output of electronics and other electronic equipment grew by nearly 14 percent a year from 1987 to 2001, while that of total manufacturing averaged only about 2.5 percent a year. The high-technology industries are not especially electricity-intensive, but with continued pressure from overseas on traditional U.S. manufacturers, they may grow proportionally more in the coming decades. Altogether, it may be difficult to improve on a projection of the 1992-2000 trend of 1.2 percent annual growth of manufacturing electricity consumption growth to the period 2002 to 2020.

A3.3. Electricity Prices

Electricity prices may rise or fall in the future, but the response of consumption to price changes is governed by the elasticity of demand for electricity. This section reviews econometric studies of own-price elasticities for the residential. The literature's general conclusion on electricity is that it is a fairly price-inelastic good for the residential sector in the short run but considerably more elastic in the long run. Cross-price elasticities are minimal because of the high equipment costs involved with switching fuels as well as the unavailability of natural gas and other alternative fuels in many areas.

The short-run elasticity measures the adjustment in the level of use of existing appliances that results immediately from a price change. The long-run elasticity also incorporates the change in electricity demand that results from changes in the appliance stock in longer-term adjustment to new prices. For thinking about electricity demand over a decade or more, the long-run elasticity is the more relevant measure.

The elasticity of residential electricity demand is a well studied parameter empirically, and estimates have varied considerably, as Table A3-1 shows. Following Bohi's (1981) suggestion that aggregate data yielded biased estimates of electricity demand elasticities, Table A3-1 reports a number of studies estimating elasticities panel or cross-section data. Giving greater weight to more recent studies suggests a long-run elasticity between -0.50 and -1.0. NEMS uses a long-run residential own price elasticity of -0.31 in the long run, and -0.25 for commercial demand (Wade 1999).

Table A3-1: Estimates of the Long-Run Own-Price Elasticity of Residential Demand for Electricity

Authors	Year	Elasticity
Chern and Bouis(1988)	1955-1964	-1.36
Halvorsen (1978)	1961-1969	-1.15
Chern and Bouis(1988)	1969-1978	-0.50
Silk and Joutz (1997)	1949-1995	-0.48
Dunstan and Schmidt (1988)	1971-1974	-1.06
Dunstan and Schmidt (1988)	1979-1982	-1.11
Rungsuriyawiboon (2000)	1960-1996	-0.98

Reiss and White (2001) find the own-price elasticity of demand for electricity ranges from -0.49 for the lowest income households to -0.28 for the highest income households. Assuming real incomes rise over the next two decades, own-price elasticity falls. Haas and Schipper (1998) find that price elasticities for energy are smaller in absolute value for falling prices than they are for rising prices, which might tend to offset the effect of rising income.

Several changes within the electricity industry could affect end-user electricity price. Greater utilization of distributed generation could reduce costs and reduce demand for new baseload generation. Fuel prices could have a significant effect on electricity price, particularly with gas-fired generation where it represents nearly two-thirds of the cost of generation. Expanded competition, the development of national markets, and the use of real-time pricing could affect the overall prices of electricity as well as the types of generation sources.

Distributed generation is the generation of electricity onsite by consumers often taking the form of Combined Heat-and-Power (CHP), in which waste heat from electricity generation is captured and used for heating or cooling. CHP facilities generate an estimated 150 million MWh annually for industrial customers but have penetrated commercial and residential markets to a lesser extent, generating only 7 to 8 million MWh annually for commercial use, and even less for residential use (EIA 2001). The aggregate impact of CHP on growth of demand from utilities in the next two decades is unlikely to dampen demand facing utilities as a whole.

The spike in natural gas prices in the early 2000s affected electricity prices, and continuing high prices could increase electricity prices. Furthermore, continuing high natural gas prices would depress residential and commercial direct demand for gas, encouraging some natural gas customers to switch to electric heat pumps in certain parts of the country. Industrial consumption might be relatively unaffected, as it relies mostly on low-cost baseload power tied in through long-term contracts.

Currently 22 states have implemented some form of deregulation for electricity. Assuming the trend toward deregulation picks back up, prices might be projected to fall. The Policy Office Electricity Modeling System (POEMS) model produced by DOE in 1998, projects the difference in electricity prices between regulated and deregulated markets by 2010 at $63 per MWh versus $55 per MWh, as existing plants move to improve efficiency and prices are bid down to marginal cost. At a long-run elasticity of demand for electricity of -1.0, that could lead to an increase in demand of nearly 15 percent, or by half that if the elasticity is -0.5.

Real-Time Pricing (RTP) is a mechanism to align customer and producer costs. The cost of producing electricity varies with the demand for electricity throughout the day, rising particularly in morning and late afternoon/early evening peaks. Charging consumers prices that reflect utilities' generation costs during the course of the day would give them incentive to shift some of their use of energy-intensive appliances to off-peak hours. While total megawatt hours might not be reduced significantly, widespread use of RTP could slow the growth of demand for new capacity.

Quantifying these effects is beyond the scope of this study, but the combination of offsetting influences they pose suggests that projection of historical trends in aggregate electricity use could wash out many minor errors and not be wide of the mark.

A3.4. Future Demands for Additional Capacity at the National Level

This section forecasts a range of future time at which new capacity will be required in order to meet national electricity demand. The first part of this section examines some current projections; the second and third parts outline parameters used for forecasting; and the last part presents projections for demand growth and time when new capacity will be needed. Utilizing figures for current generating capacity, projections for plant retirements, and a range of possible demand growth rates, it is estimated that new capacity will not be needed until 2015 at the aggregate level.

A3.4.1. NEMS Projections of Generation Capacity Growth

As a prelude to the projections presented in this section, it is important to review an already standard set of forecasts. EIA's *Annual Energy Outlook 2003* includes the results of two different scenario of electricity demand growth using the NEMS model. The first is presented as a reference scenario based on an annual growth of 1.8 percent, while the other assumes a high growth rate of 2.5 percent based on which electricity demand grows 2.5 percent annually rather than the 1.8 percent produced in the reference scenario. These scenarios yield results of a 2.2 percent annual increase in generation capacity under the high demand case and a 1.5 percent annual increase under the low demand case.

On closer examination, the results of the NEMS model seem to be at odds with the current choices for new generation, being almost entirely made up of natural gas-fired plants.

However, although natural gas has been the fuel of choice for new generation in the past, some new coal capacity announcements have been made recently. Several factors are likely at work in the renewed interest in coal, including rising natural gas prices, looser federal regulations regarding environmental retrofits to coal plants, and the proposed new energy bill, which offers incentives for coal as well as nuclear power.

A3.4.2. Current Generating Capacity and Demand

Currently, the United States has an over supply of generating capacity. As of October 31, 2003, total national supply equaled 964,469 MW (Smith 2003). Using projections for net internal demand for electricity during the summer of 2003 of 695,672 MW according to a July 2003 A.G. Edwards report (Fischer et al. 2003), and 716,728 MW according to the June 2003 Merrill Lynch report, yields a calculated reserve margin between 28 percent and 29 percent in 2003. Given the current amount of capacity, this will probably rise greater than 30 percent in 2004. This is already far in excess of suggested reserve margins necessary for investment and operation: Fischer et al. (2003) report 18 percent as ideal for investment, and Merrill Lynch (2003a) supports 15 percent to be an equilibrium level. In addition to these large reserves, there is between 25,000 MW (Merrill Lynch 2003a estimate) and 36,000 MW (Fischer et al. 2003 estimate) of new capacity that is under construction now and will come online between 2004 and 2005. This brings the total generating capacity of the United States to approximately 950,000 MW by summer of 2005.

A3.4.3. Plant Retirements

Plant retirements may speed the need for new capacity, but the extent of possible future retirements is difficult to discern. EIA, in the AEO 2003, estimates that 66,800 MW of capacity will be retired by 2010, with only 13,000 MW being retired by 2005, and virtually all of the retired capacity coming from older oil and gas fired plants. Furthermore, environmental regulations may be enacted between now and 2020 which force older, more polluting coal plants to shut down.

A3.4.4. Projections

Based on projections of electricity demand growth by sector presented earlier, this appendix estimates a total annual demand growth rate of 2.6 percent, nearly 70 basis points higher than that projected by the EIA, and 80 basis points higher than that projected by Global Insight (Table A3-2).

Table A3-2: Comparison of Forecasts of Electricity Demand Growth through 2020, Percent per Year

	Historical (1980-2001)	EIA (AEO 2003)	Global Insight	This Appendix
Residential	2.5	1.7	2.1	2.6
Commercial	3.7	2.2	2.0	3.7
Industrial	1.0	1.7	2.0	1.2
Total	2.3	1.9	1.8	2.6
GDP Growth	3.1	3.1	3.1	3.1

Source: EIA (2003a).

Table A3-3 presents projections for new aggregated generating capacity that will be needed for selected future years, given the different growth rate estimates from Table 3-2. These results are based on assumptions of a 15 percent reserve margin, a 2003 peak demand of 705,000 MW (the average of the two earlier estimates), current capacity total of 965,000 MW in 2003, and capacity close to 1,000,000 MW by 2005 (due to the addition of capacity under construction now).

Table A3-3: Estimations of Future Generating Capacity Needs

	Projected Electricity Demand Growth, Percent per Year			
Year	**1.80**	**1.90**	**2.30**	**2.60**
2003	829,412	829,412	829,412	829,412
2005	859,539	861,229	868,003	871,401
2010	939,733	946,214	972,522	985,910
2015	1,064,729	1,079,466	1,140,326	1,115,467
2020	1,272,673	1,303,019	1,431,480	1,262,048

Source: EIA (2003a).

For every growth scenario, new capacity will not be needed until 2015 if existing capacity stays close to its assumed 2005 value.

A3.5. Regional Projections of Demands for New Capacity

Section A3.7 estimates that the United States will not need new generation capacity until 2015 due to its current excess capacity. However, current excess capacity is not evenly distributed across the country, with several regions having a tight supply even if the whole nation is over-supplied. Since, power currently cannot be easily shared across regions due to significant transmission constraints, projections of future capacity needs should be differentiated by region. This section analyzes the country by region, in order to get a better sense of when capacity will be needed, how much, and where.

This section presents an analysis that applies projections of plant retirements and different demand growth rates to figures for the amount of current stock in order to gauge future capacity needs by region. The date at which new capacity would be needed by each region is estimated given two different future demand scenarios, based on high and low demand growth rates estimates.

Capacity figures come partially from the equity research reports prepared by A.G. Edwards (Fischer et al. 2003), Morgan Stanley (2002, 2003a, 2003b), and Merrill Lynch (2003a, 2003b). Their projected reserve margins are based on the available resources as calculated by the North American Electric Reliability Council (NERC) and found in Fischer et al. (2003), which concerns itself primarily with plant reliability. Therefore there is a significant amount of capacity that does not get included, because it is not committed. Merrill Lynch makes an estimate of the actual capacity in several regions, where the actual capacity is significantly higher than the reported capacity. Every effort has been made to use the highest estimate of capacity, in order to most accurately reflect the amount of capacity actually in existence going forward, as that determines what more will be built.

The timing and location of plant retirements are primarily based on the NEMS model. NEMS tries to capture some of the various factors that contribute to decision for plant retirement, including environmental regulations, projected future electricity prices, and projected future operating costs, and outputs an estimated timetable of type, timing, size, and location of retirements. Along with NEMS, A.G. Edwards' table of gas/oil fired plants with heat rates of 12,000 BTUs and above (44,000 MW) is also used (Fischer et al. 2003).   At this level of heat generation, it is impossible to operate a plant while still making a profit (Morgan Stanley 2003a, 2003b).

Region-specific demand growth rates are based on projections from NERC, EIA, and those presented earlier in this appendix. The third set of growth rates is calculated by applying the growth rates of demand estimated earlier in this paper to the shares of electricity demanded by the residential, commercial, and industrial sectors in each region. From this range of estimates, two specific growth rates are chosen to model a high and a low demand growth scenario.

The model assumes a minimum capacity reserve margin of 15 percent. This is based on historical observations: before the boom in new capacity starting in 2000-2001, reserve margins were in the 14 to 15 percent range in the United States during 1998-2000.

The effect of population shifts from region to region is not accounted for, though it can implicitly be assumed that regions to the south and west will experience higher growth than those to the north and east.

Table A3-4 reports projections of demand for new capacity for NERC regions under assumptions of high and low demand growth. The table identifies the year in which the amount of current capacity will fall short of total retirements in each region. For example, in the first row, the ECAR region will need new capacity in 2010 under a high demand growth scenario but not until 2012 under a low demand growth scenario. Even under low demand growth, new capacity is needed in five of the eleven NERC regions by 2010. It is very safe to say that demands for new electricity generating capacity will be sufficient to justify significant amounts of new capacity by the year 2015, which is the year of new plant construction used in the analysis of viability of nuclear power in the present study.

Table A3-4: Years When New Capacity will be Needed, by NERC Region, with High and Low Growth Rates of Electricity Demand

REGION[a]	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
ECAR						H		L					
ERCOT								H		L			
FRCC				H		L							
MAAC				H		L							
MAIN				H		L							
MAPP		H	L										
NEPOOL							H			L			
NYCA			H		L								
SERC											H		L
SPP									H			L	
WECC					H		L						
H= High Annual Demand Growth Projection L= Low Annual Demand Growth Projection													

Source: NERC (2003).

[a]NERC Region Definitions: ECAR, East Central Area Reliability: MI, IN, OH, KY, WV, small areas in PA and VA; ERCOT, Electric Reliability Council of Texas: most of Texas; FRCC, Florida Reliability Coordinating Council: most of Florida; MAAC, Mid-Atlantic Area Council: NJ, MD, DE, and most of PA; MAIN, Mid-America Interconnected Network: IL, most of WI, parts of MS, IA, MN; MAPP, Mid-Continent Area Power Pool: ND, SD, NE, IA, parts of WI and MT; NEPOOL, New England Power Pool: CT, ME, MA, NH, RI, VA; NYCA, New York Control Area: NY; SERC, Southeastern Electric Reliability Council: VA, GA, LA, AR, MS, TN; SPP, Southwest Power Pool: KS, OK, small areas of AR, LA, NM; WECC, Western Electricity Coordinating Council: entire western US.

A3.6. Conclusion

The United States, in the aggregate, has a large stock of excess power capacity, but it is, distributed unevenly among regions. This appendix presents some projections of future electricity capacity needs given a variety of demand and supply scenarios at the aggregate national level and by region. For the nation as a whole, new capacity is not needed until 2015 for low and high demand growth rate scenarios. However, most excess capacity is located in the South, West, and Northeast, while other regions have much lower excess capacities available presently. Five out of the eleven NERC regions would require new capacity by 2010 even under projections of low demand growth. These areas include the following states: Florida, New Jersey, Maryland, Delaware, Pennsylvania, Illinois, New York, and parts of Wisconsin and Montana. The last region to need new capacity will be SERC, the Southeastern Electric Reliability Council, which includes Virginia, Georgia, Louisiana, Arkansas, Mississippi, and Tennessee. SERC will not need to increase its current capacity until 2015 under a high demand growth scenario and 2017 under a low demand growth scenario.

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Appendix A4. TECHNOLOGIES FOR NEW NUCLEAR FACILITIES

Summary

The nuclear reactors currently in use in the United States, denoted as Generation II, were deployed in the 1970s and 1980s. These include boiling water reactors and pressurized water reactors. Advanced reactor designs, Generation III, have been developed in order to be more cost competitive with natural gas. Generation III includes the advanced boiling water reactor (ABWR) and the AP600 (pressurized water) passive-design reactor. The nuclear industry has continued to develop yet more innovative designs designated Generation III+. Generation III+ includes a gas cooled reactor, the Pebble Bed Module (PBMR), as well as a capacity upgrade from AP600 to AP1000. Generation III+ may have even lower generating costs, however, the U.S. Nuclear Regulatory Commission (NRC) has not certified these designs, and their cost estimates have greater uncertainty. The nuclear industry also has plans for Generation IV technologies, but these reactor designs may not be available for another two decades, and their cost estimates are even more uncertain.

The U.S. Department of Energy (DOE) has organized the Near Term Deployment Group (NTDG) to examine prospects for the deployment of new nuclear power plants in the United States over the next 10 years. Nuclear suppliers submitted eight plant designs for assessment. General Electric submitted designs for the ABWR as well as the European Simplified Boiling Water Reactor (ESBWR), and Westinghouse submitted designs for the AP600, AP1000, and the International Reactor Innovative and Secure Design (IRIS). The IRIS is a modular light water reactor. Framatome ANP submitted a design for the SWR 1000, a boiling water reactor (BWR) incorporating passive safety features. Eskom submitted a design for its PBMR design, and General Atomics provided NTDG its design for a Gas Turbine Modular Helium Reactor (GT-MHR). The PBMR and GT-MHR are based on gas reactors built in Germany.

The ABWR is the only reactor type that has been built. Although never built, the AP600 has obtained design certification and boasts extensive verification of its cost estimates. Like the ABWR it faces concerns with economic competitiveness. As a scaled-up version of the AP600, the AP1000 should be more economically competitive, but is still seeking design certification. Despite offering larger potential economic savings, the PBMR and GT-MHR are only in very preliminary stages, and major uncertainties are to be resolved. The IRIS project has perhaps the largest upside of the reactor types, but is not considered to be a realistic option for near-term deployment. Framatome has opened discussion with NRC to obtain certification for the SWR 1000 in the United States. GE wants to commercialize the ABWR domestically prior to introducing the ESBWR to the U.S. market.

The best near-term candidates are the ABWR, the AP1000, the SWR 1000, and the CANDU ACR-700. The first three are ALWR designs, based on the PWR and BWR designs in operation in the United States. These PWR and BWR designs account for the great majority of reactors in operation throughout the world. The ALWR designs have acquired design certification. Unlike the gas cooled reactors, the ALWR designs have no design or

engineering gaps to overcome. The ALWR has solid cost estimates based on actual building experience. Expected learning curve cost reductions will improve the cost competitiveness of subsequent plants. The CANDU ACR-700 reactor is a light water-cooled, heavy water-moderated design, a closely related version of which, the CANDU 6, has had units built recently in China and a site's second unit begun in Romania. The ACR-700 uses 75 percent less heavy water than the CANDU-6.

It is anticipated that the AP600's design certification will simplify the certification for the AP1000, but the AP600 still will not actually be built due to its smaller size. GE does not have immediate plans to commercialize the ESBWR. The PBMR, GT-MHR, and IRIS plans have too much uncertainty to be reliable candidates for nuclear plant construction in the United States in the near term. In the longer term the advanced gas cooled reactors and generation IV designs may become viable alternatives. The EPR is a large pressurized water reactor which the French Ministry of Industry is considering building as a demonstration plant by 2010. The System 80+ received NRC design certification in 1997, and plants have been built in Korea using this design, but Westinghouse has not expressed an intention to market that design in the United States.

Outline

A4.1. Introduction

This appendix reviews near-term nuclear power plant technologies to set the stage for selecting reactor designs for economic analysis in Chapter 3. Section A4.2 offers an overview of the generation of nuclear power plants, the array of nuclear technologies in operation and currently under construction. Section A4.3 describes the criteria developed by U.S Department of Energy's (DOE) Deployment Group (NTDG) for assessing the proximity of new reactor designs to commercialization. Section A4.4 briefly describes the major candidate reactors identified by the NTDG and Section A4.5 reports their scoring on NTDG's assessment criteria. Section A4.6 concludes.

A4.2. Overview of Nuclear Power Plant Designs

To offer a context for the descriptions of the near-term reactor designs, the first section below describes the major functionalities of a nuclear power plant and the trade-offs involved in the technological choices within each major component. Generations of nuclear reactors, due to technical progress, are mentioned frequently in discussion of nuclear power. The second section describes the major generations. Then, types of nuclear plants in operation are described. Two succeeding sections give figures on the nuclear plants in operation worldwide and new reactor orders as well as domestic ownership of nuclear plants. This appendix culminates with a section on the advantages and disadvantages of the nuclear power plant types, and the challenge for nuclear plant developers.

A4.2.1. Functions and Design Choices in Nuclear Reactors

The basic processes behind most nuclear power plants are similar to those in a coal plant: heat is generated, which produces steam, which in turn propels a steam turbine to produce electricity. Gas plants use gas turbines rather than steam turbines, and some reactor designs substitute a gas turbine for the steam production step. The most important difference between the coal and gas plants on the one hand and the nuclear plant on the other lies in how heat is produced. Rather than burning coal, a nuclear plant splits uranium atoms. To induce fission, a Uranium-235 atom must absorb a free neutron, destabilizing the atom. As the atom begins to decay, it releases a large amount of heat energy and gamma radiation. Each absorption and fission event induces a second, setting in motion a chain reaction. To increase the probability of neutron absorption, it is often necessary to moderate the velocity of the free neutron. This has implications for reactor designs.

The three main forms of uranium are distinguished by their atomic weights. While the most abundant form is Uranium-238, it cannot be induced to split like Uranium-235. For the purposes of electric power generation, uranium is commonly, but not always, enriched so that it contains up to 3 percent Uranium-235, and is then formed into shapes appropriate for particular reactor designs.

In addition to material and construction differences among reactor vessels and containment structures, reactor designs differ in (1) the type of fuel they use, (2) how they moderate neutron flow, and (3) how they manage the heat generated from the reaction. Fuel types include natural unenriched uranium, enriched uranium, mixed thorium-uranium, and mixed-oxide fuels (MOX). Enrichment or fuel processing increases the overall cost of fuel, which leaves natural uranium the cheapest fuel. While neutron moderation is generally required to increase the likelihood of neutron absorption by a U-235 atom, fuels that are enriched or have higher concentrations increase the probability of absorption, and consequently require less moderation than other fuel types. Because of the processing costs involved in making them, moderators such as heavy water and graphite are considerably more expensive than light water.

Several options exist for transforming the heat generated from nuclear reactions into electricity. In pressurized water reactors (PWRs), water is heated under pressure and sent to a heat exchanger to produce steam for the turbine. Alternatively, boiling water reactors (BWRs) utilize existing coolant water to generate steam, thereby reducing the chance for heat loss during its transfer. Reactors such as the CANDU use heavy water to transfer heat because it does not reduce the efficiency of the chain reaction by absorbing neutrons. While previous CANDUs (CANDU-3, 6, and 9) used heavy water to transfer heat, the ACR-700 uses light water to transfer heat and heavy water for moderation. Gas-cooled reactors utilize stable gases such as helium or carbon dioxide to act as a coolant because they have better heat transfer properties than water. Finally, gas-cooled reactors such as the GT-MHR and PBMR employ a Brayton power cycle, which is the thermal expansion of gas to power a gas turbine, when they are used to generate electricity.

As with the relationship between fuel and moderator, there are trade-offs among heat management techniques that result in differing costs and electricity production efficiencies. For example, a PWR requires that its coolant water be pressurized to 150 times atmospheric pressure to prevent it from boiling as it transfers heat to the power cycle, adding an extra cost. Conversely, a BWR is a low-pressure design that directly produces steam for power generation, using its coolant water. However, its steam is contaminated with radionuclides from contact with the reactor core, and these must be removed or shielded from the power cycle, reducing the cost savings from its low-pressure design. In another heat management technique, gas turbines are more efficient producers of electricity than steam turbines, however their costs are higher and they require the use of helium, which is more expensive than water. In sum, the array of current and future reactor designs (some of which are described in Section A4.4) are essentially alternative combinations of fuel types, moderators, and the coolants and heat utilization techniques of heat management systems that attempt to maximize the efficiency of electricity production while minimizing its cost.

The review of individual reactors in Section A4.4 emphasizes how each design represents a combination of these functions, as design choices trade off various physical and economic efficiencies.

A4.2.2. Nuclear Plant Generations

DOE and the nuclear power industry categorize nuclear reactor designs according to generations. Each generation incorporates evolutionary improvements with revolutionary concepts to take the next step in reactor technology. The first-generation reactors were the prototype commercial reactors of the 1950s and 1960s.

Generation II reactors were deployed in the 1970s and 1980s and are in commercial use today. In the United States, they include such light-water reactors as the boiling water reactor (BWR) and the pressurized water reactor (PWR), and, in Canada, the CANDU heavy-water reactor.

Referred to as advanced-design nuclear power plants, **Generation III** reactors include the advanced boiling water reactor (ABWR), the ACR-700, the System 80+ advanced pressurized water reactor (APWR), and the AP600 passive-design reactor. These designs were developed in the United States and certified by the U.S. Nuclear Regulatory Commission in the 1990s. ABWRs and APWRs have been built and are in operation in other countries around the world.

Generation III+ are reactors that can be deployed by 2010. They have been under development during the 1990s and are in various stages of design and implementation now. They include the pebble-bed modular reactor (PBMR) and the AP1000. Both have passive safety features, and the PBMR is gas-cooled, two technological features that foreshadow Generation IV reactors. The U.S. Nuclear Regulatory Commission (NRC) has not yet certified these designs.

Generation IV reactors can be deployed by 2030, and are expected to be highly economical, incorporate enhanced safety, produce minimal waste, and be impervious to proliferation. The International Reactor Innovative and Secure (IRIS) project reactor is the Generation IV reactor furthest along in development. It is a light-water reactor (LWR) incorporating advanced engineering to increase safety and reduce operational costs. Another Generation IV reactor is the gas turbine modular helium reactor (GT-MHR), which has passive safety features and is gas-cooled.

DOE considers Generation III and III+ as candidates for near-term deployment. The ABWR is attractive because it has already been built overseas, and the AP600 has already received design certification.

The Generation III+ models hold more promise economically, and the AP1000 is expected to receive design certification by 2005. The PBMR may be more economical than the AP1000, but it needs substantially more development. The Generation IV reactors IRIS and GT-MHR have the greatest potential for cost savings, but neither design will be available for near-term deployment to replace plants that are currently operational (NEI 2003).

A4.2.3. Nuclear Plant Types in Operation

The pressurized water reactors (PWRs) and boiling water reactors (BWRs) are two of the most common designs worldwide (see Table A4-1). Moreover, the PWR and BWR are the most common in the Americas and the only designs in operation in the United States. The United States has had over 70 PWRs and 40 BWRs in operation for several decades.

Table A4-1: Number and Power (in MW) of Reactors, by Type and Continent

Code	Type	Europe	Africa	Americas	Asia	Total
AGR	Advanced Gas Cooled Reactor	14 (8,360)				14 (8,360)
BWR	Boiling Water Reactor	20 (17,261)		36 (31,639)	34 (28,156)	90 (77,056)
FBR	Fast Breeder Reactor	2 (793)			2 (261)	4 (1,054)
GCR	Gas Cooled Reactor	19 (3,125)				19 (3,125)
HWLWR	Heavy-Water-Moderated, Light-Water-Cooled				1 (148)	1 (148)
LWGR	Light Water Cooled Graphite Reactor	18 (12,594)				18 (12,594)
PHWR	Pressurized Heavy Water Reactor	1 (650)		22 (14,436)	16 (4,815)	39 (20,001)
PWR	Pressurized Water Reactor	109 (106,560)	2 (1,842)	71 (65,917)	40 (32,093)	222 (206,412)
WWER	Water Cooled Water Moderated Power Reactor	32 (18,553)			1 (376)	33 (18,929)
Total		215 (167,896)	2 (1,842)	129 (119,992)	94 (65,849)	440 (347,679)

Source: 2003 Power Reactor Information System (PRIS) database, IAEA (2003).

The Gas Cooled Reactor (GCR) is far less common, and no GCR is presently in operation outside of Europe. Only two gas-cooled nuclear reactors have been operated in the United States, Peach Bottom-1 outside Philadelphia and the Ft. St. Vrain Plant in Platteville, Colorado, both of which were shut down after short periods of operation.

A4.2.4. Worldwide Nuclear Plant Operation

According to IAEA, there were 438 operating nuclear power plants worldwide at the end of 2001, with 353 GW of generating capacity. As of January 2002, the United States had 104 reactors in operation, followed by France with 59, Japan with 54, the UK with 33, the

Russian Federation with 30, and Germany with 19. Korea has increased deployment and had 16 in operation. These countries were followed by Canada, India, Ukraine, Sweden, and Spain which had 14, 14, 13, 11, and 9 respectively. Eighteen other countries had six or fewer reactors in operation (IAEA 2000). As of January 1, 2003, there were 441 nuclear power plants in operation with a total net installed capacity of 359 GW.

Six new nuclear plants were brought on line in Asian countries in 2002. They were:

- Qinshan 2-1, a 610 MW PWR in China
- Qinshan 3-1, a 655 MW PHWR in China
- Lingao 1, a 938 MW PWR in China
- Lingao 2, a 938 MW PWR in China
- Temelin 2, a 912 MW WWER in Czech Republic
- Yonggwang 6, a 950 MW PWR in Republic of Korea.

In the U.K., Bradwell units A and B, 123-MW GCRs were shut down in March 2002. In Bulgaria, Kozloduy 1 and 2 408-MW WWERs were shutdown in December 2002 (IAEA PRIS Database).

A4.2.5. Nuclear Plants Under Construction

The United States remains the leader in nuclear power generation, but that could change. Asian countries such as China, Japan, Korea, and India have been most active in building new nuclear plants. Construction started on five additional nuclear power plants in 2000— one in China, two in India, and two in Japan. In 2001 construction began on an additional reactor in Japan.

Altogether 32 nuclear plants were under construction worldwide at the end of 2001. China had eight under construction, Korea and Ukraine four, and Japan three. India, Iran, the Russian Federation, and Slovakia all had two under construction. Argentina, the Czech Republic, and Romania had one under construction. As of January 1, 2003, 32 nuclear power plants were under construction, with six new plants connected to the grid and construction beginning on seven new plants. Recently began construction is identified below:

- Kaiga 3, a 202 MW PHWR in India
- Kaiga 4, a 202 MW PHWR in India
- Rajasthan 5, a 202 MW PHWR in India
- Rajasthan 6, a 202 MW PHWR in India
- Kudankulam 1, a 905 MW WWER in India

- Kudankulam 2, a 905 MW WWER in India
- LWR – Project Unit 1, a 1040 MW PWR in Dem. P. R. Korea.

A4.3. Near -Term Deployment Design Criteria

DOE has been working with the nuclear industry to establish a technical and regulatory foundation for the next generation of nuclear plants. DOE has organized a Near Term Deployment Group (NTDG) to examine prospects for the deployment of new nuclear power plants in the United States over the next 10 years. The NTDG established the following six evaluation criteria as a basis for near-term deployment (DOE 2001).

A4.3.1. Regulatory Acceptance

Candidate technologies must show how they will be able to receive either a construction permit for a demonstration plant or a design certification by the U.S. Nuclear Regulatory Commission (NRC) within the time frame required to permit plant operation by 2010 or earlier.

A4.3.2. Industrial Infrastructure

Candidate technologies must be able to demonstrate that a credible set of component suppliers and engineering resources exist today, or that a credible plan exists to assemble them, which would have the ability and the desire to supply the technology to a commercial market in the time frame leading to plant operation by 2010 or earlier.

A4.3.3. Commercialization Plan

A credible plan must be prepared which clearly shows how the technology would be commercialized by 2010 or earlier, including market projections, supplier arrangements, fuel supply arrangements and industrial manufacturing capacity.

A4.3.4. Cost Sharing Plan

Technology plans must include a clear delineation of the cost categories to be funded by government and the categories to be funded by private industry. The private/government funding split for each of these categories must be shown, along with rationale for the proposed split.

A4.3.5. Economic Competitiveness

The economic competitiveness of candidate technologies must be clearly demonstrable. The expected all-in cost of power produced is to be determined and compared to existing competing technologies along with all relevant assumptions (includes plant capital cost, first plant deployment cost, and other plant costs). Advanced passive designs are intended to reduce the costs of maintenance and operations testing while providing safety improvements.

A4.3.6. Fuel Cycle Industrial Structure

Candidate technologies must show how they will operate within credible fuel cycle industrial structures. They must utilize a once-through fuel cycle with low-enriched uranium (LEU) fuel and demonstrate the existence of, or a credible plan for, an industrial infrastructure to supply the fuel being proposed.

A4.4. Near -Term Candidates

The reactor designs considered in this appendix are those identified by the NTDG in response to the Request for Information (RFI) issued by DOE in April 2001. The intent of the NTDG evaluation was to determine those reactor technologies sufficiently mature in design and licensing to support deployment in this decade, and to assess their respective advantages, disadvantages and readiness for near-term deployment. Eleven plant designs reviewed by NTDG (DOE 2001) are summarized in Table A4-2.

A4.4.1. ABWR

General Electric (GE) developed the 1,350 MW Advanced Boiling Water Reactor (ABWR) in cooperation with the Tokyo Electric Power Company, Hitachi and Toshiba. The reactor is water-cooled and moderated and utilizes enriched uranium fuel. The ABWR incorporates design features proven in many years of worldwide BWR operating experience, along with advanced features such as vessel-mounted reactor recirculation pumps, fine-motion control rod drives and a state-of-the-art digital, multiplexed, fiber-optic control and instrumentation system.

The ABWR design was reviewed and certified by NRC in 1996, under the provisions of 10 CFR Part 52. It is the only one of the reactor designs evaluated for near-term deployment for which all engineering is complete and there is actual construction and operating experience. Two ABWRs, Kashiwazaki-Kariwa Units 6 and 7, went into commercial operation in Japan in 1996 and 1997, and are currently in their fifth cycle of operation. More recently, two ABWR units received regulatory approval and are now under construction in Taiwan. Because the ABWR has active safety features, operation and maintenance costs would be incurred to maintain the reliability of its safety systems.

Table A4-2: Summary of New Reactor Designs

Design	Supplier	Size and Type	U.S. Deployment Prospects and Overseas Deployment	NRC Certification Status
ABWR	General Electric	1,350 MW BWR	Operating in Japan, under construction in Taiwan.	Certified in 1996.
AP1000	Westinghouse	1,090 MW PWR	Additional design work to be done before plant ready for construction.	Design certification expected September 2005.
SWR 1000	Framatome Advanced Nuclear Power (ANP)	1,013 MW BWR	Under consideration for construction in Finland, designed to meet European requirements.	Submission of materials for pre-application review to begin in mid-2004. Pre-application review completion expected 2005.
CANDU ACR-700	Atomic Energy Company, Limited (AECL)Technologies Inc., U.S. subsidiary of Canadian AECL	753 MW HWR	Deployed outside Canada in Argentina, Romania, South Korea, China and India.	Pre-application review scheduled to be completed by NRC, June 2004.
AP600	Westinghouse	610 MW PWR	Additional design work to be done before plant ready for construction.	Design is certified, but actual construction will be superseded by AP1000.
Simplified Boiling Water Reactor (ESBWR)	General Electric	1,380 MW BWR	Commercialization plan not likely to support deployment by 2010.	Pre-application review completion expected in early 2004. Application for design certification to be submitted mid-2005.
Pebble Bed Modular Reactor (PBMR)	British Nuclear Fuels (BNFL)	110 MW Modular pebble bed	No plan beyond completion of South African project.	Pre-application review closed September, 2002 with departure of Exelon.
Gas Turbine Modular Helium Reactor (GT-MHR)	General Atomics	288 MW Prismatic graphite	Licensed for construction in Russia.	Design certification application would begin by end of 2005.
International Reactor Innovative and Secure (IRIS)	Westinghouse	100 to 300 MW PWR	Plans to deploy between 2012 and 2015.	Design certification review to begin 2006.
European Pressurized Water Reactor (EPR)	Framatome-ANP	1,545 to 1,750 MW PWR	No decision on U.S. market.	Ordered for deployment in Finland.
System 80+	Westinghouse	1,300 MW PWR	Plants built in Korea. Design not planned to be marketed in United States.	Certified May 1997.
Advanced Fast Reactor Power Reactor Innovative Small Module (AFR PRISM)	General Electric, Argonne National Laboratory	300 to 600 MW, sodium-cooled	Began certification in the 1990s.	No action taken.

A4.4.2. AP1000

The AP1000 is a 1,090 MW PWR of the same basic design as the AP600, but up-rated in power to achieve economies of scale. The reactor is water-cooled and moderated and utilizes enriched uranium fuel. The AP1000 passive safety systems are essentially the same as those for the AP600, except for some changes in component capacities. The power up-rate has been achieved by increasing the length and number of fuel assemblies, the size of the reactor vessel and primary components, and by increasing the height of the containment structure, and the size and capacity of the secondary plant energy conversion components.

The AP1000 generating cost is estimated to be 30 percent less than that of AP600 because the additional power rating is achieved with a only a small increase in capital cost. AP1000 application for design certification was submitted to NRC in March 2002. NRC issued its draft safety report to Westinghouse in June 2003. A final safety evaluation is scheduled for issuance in September 2004, and the design certification rulemaking in December 2005 (NRC 2003). As with the AP600, additional detailed design work must also be done before the plant will be ready for construction.

A4.4.3. SWR 1000

SWR 1000 is a 1,013 MW BWR developed by Framatome Advanced Nuclear Power (F-ANP) in conjunction with German electric utility companies and European partners. The SWR 1000 design combines proven, conventional BWR features with passive safety features to provide enhanced safety benefits. The plant is designed to meet European requirements, including relevant requirements in German nuclear codes and standards and other recommendations proposed by German and French reactor safety commissions for the European Pressurized Water Reactor (EPR).

A four-year design phase for the SWR 1000 was completed in 1999, and included the development of a site-independent safety analysis report, a probabilistic safety analysis report, and projected construction costs. In March 2003, Framatome submitted the SWR 1000 design, along with the EPR, a pressurized water reactor to the Finnish power agency, Teollisuuden Voima Oy (TVO), for the fifth Finnish nuclear power plant. Presently no other designs appear to be under consideration for this project. F-ANP advises that in parallel with efforts to market the SWR 1000 in Europe, they may consider entering the U.S. market. F-ANP met twice in 2002 with NRC to discuss submittal of the SWR 1000 for design certification and have conveyed the intention to submit pre-certification material by mid-2004 (Cushing 2002, NRC 2002, Mallay 2002, Sebrosky 2002).

A4.4.4. CANDU, ACR-700

Canada’s current fleet of CANDU 3, 6, and 9 nuclear units are distinctive in their use of natural uranium fuel with online fueling. The CANDU 3, 6, and 9 nuclear units also have heavy water coolant and moderation. The ACR-700 is likewise unique in that it uses 2.1 percent enriched fuel and continues with online fueling, resulting in less expensive fuel costs than that for LWRs. The ACR-700 uses light water for cooling and heavy water for moderation. The ACR-700 uses 75 percent less heavy water than the earlier CANDU 3, 6, and 9 nuclear units. The ACR-700 reactor assembly is 30 percent smaller than that of the CANDU 3, 6, and 9 nuclear units. Combined with significant previous construction experience, simplification of the design and extensive use of modular construction are thought to greatly improve the ACR-700's economic competitiveness in electric power generation.

CANDU reactors have been deployed outside Canada in Argentina, India, Romania, and South Korea, which opted in 2001 to continue its nuclear power expansion with 1,000 MW units from Combustion Engineering rather than with CANDUs (Nuclear Engineering International 2001). A 728 MW CANDU 6 unit was brought to full power at China's Qinshan site in November 2002, and a second unit was brought on line in July 2003, with a construction period of 51 months from the first pouring of concrete to criticality (AECL 2002, AECL 2003b, Hedges 2002, p. 8). AECL began construction on a second 710 MW CANDU 6 unit at Cernavoda, Romania in April 2003, projecting a 48-month construction period and an overnight cost of U.S. $700 million (AECL 2003a). Atomic Energy of Canada, Limited (AECL), the CANDU's vendor, requested pre-application review by NRC of its 700-MW ACR-700 design in June 2002, and NRC expects to complete its pre-application review in mid-2004 (Van Adel 2002; AECL Technologies 2002, p. 14; NRC 2004, p. 2).

A4.4.5. AP600

The AP600 is a 610 MW PWR. The core, reactor vessel, internals, and fuel are essentially the same design as for presently operating Westinghouse PWRs. Fuel power density has been decreased to provide more thermal margin. Canned rotor primary pumps, proven in the U.S. Navy's reactor program and in fossil boiler circulation systems, have been adopted to improve reliability and maintenance requirements.

The innovative aspect of the AP600 design is its reliance on passive features for emergency cooling of the reactor and containment, provided by natural forces such as gravity, natural circulation, convection, evaporation, and condensation, rather than on AC power supplies and motor-driven components. Extensive testing of the AP600 passive cooling systems has been completed and supported by independent confirmatory testing by NRC to verify the design and analyses of the passive emergency cooling features. NRC has certified the AP600 design. Additional detailed design work would be needed before the plant would be ready for construction. However, the thermal economics of the AP1000 are superior to those of the AP600, and it is considered unlikely that the AP600 will actually be deployed, although its design certification may speed certification of the AP1000.

A4.4.6. ESBWR

The European Simplified Boiling Water Reactor (ESBWR) is a 1,380 MW, natural circulation, passively safe boiling water reactor developed by GE, in concert with international utilities, designers and research organizations. The design is based on the 670 MW passively safe SBWR, initially developed in the early 1990s with DOE support, and it utilizes many design features of the ABWR.

The substantially higher plant power, combined with extensive simplification of the reactor systems and containment structure, allow significant cost reduction in comparison with both SBWR and ABWR. Although the ESBWR offers attractive advantages, GE is not yet moving ahead with detailed engineering and design certification of the plant. GE's current plan is to proceed with ESBWR in a step-wise fashion, first with design certification, as funding becomes available, and then with detailed engineering, but only with the commitment and financial support of a plant customer.

A4.4.7. PBMR

The Pebble Bed Modular Reactor (PBMR) is a 110 MW graphite-moderated, helium-cooled reactor. Heat generated by nuclear fission in the reactor is transferred to the helium and converted into electrical energy in a gas turbine generator via a Brayton power cycle. The PBMR core is based on the German high temperature gas cooled technology and uses spherical fuel elements. The fundamental objective of the gas-cooled reactor design concept is to achieve an exceptional level of nuclear safety, via fuel design that effectively precludes the possibility of a core melt accident.

The PBMR helium gas passes through the reactor over the fuel pebbles, is heated, and then flows directly through the turbine. This power conversion unit eliminates the requirement for a heat exchanger between a primary and secondary cycle, which improves the efficiency of the plant. The turbines that are used in light water reactors operate with low-temperature and low-pressure steam.

PBMRs also refuel while in operation. New or reusable fuel pebbles are continually being added to the reactor core from the top and removed from the bottom to measure how much fissile material is left. Each fuel cycle lasts about three months, with each fuel pebble passing through the reactor about 10 times. A fuel sphere will last about three years and a graphite sphere about 13 years.

The first PBMR is planned for construction in South Africa, under a joint venture led by Eskom. The plant design is currently in the detailed engineering stage and has recently received a record of decision (ROD) by the South African government to begin construction of a demonstration module (Bennett 2003). Exelon, the largest nuclear utility in the United States, was an original member of the project and had planned to buy up to 40 modules, but has since pulled out of the project as a result of change of business focus away from nuclear power (Chalmers 2002). The pre-application design certification process for PMBR is now no longer active.

A4.4.8. GT-MHR

The Gas Turbine Modular Helium Reactor (GT-MHR) is a graphite-moderated helium cooled reactor. Each unit generates 288 MW, with up to four units comprising a complete plant. Heat generated by nuclear fission in the reactor is transferred to the coolant gas (helium) and converted into electrical energy in a gas turbine generator. The fuel consists of spherical fuel particles, each encapsulated in multiple coating layers, formed into cylindrical fuel compacts and loaded into fuel channels in graphite blocks.

The GT-MHR design offers very high thermal efficiency (approximately 48 percent) and outstanding nuclear safety. The GT-MHR is being developed under an international program in Russia for the disposition of surplus weapons plutonium. Government and private sector organizations from the United States, Russia, France, and Japan are sponsoring the development work.

General Atomics (GA) has the lead responsibility for providing U.S. technical support. The Russian GT-MHR demonstration plant is planned to be operational in 2009. A parallel GT-MHR commercial plan has been assembled and could lead to adaptation of the design to utilize uranium fuel. The detailed design produced in Russia would be converted to U.S. standards and revised as necessary for the U.S. application. At this point, GA is actively seeking a U.S. owner/operator. Although the United States has limited experience with GCR technology, much was learned from the 330 MW Fort St. Vrain Plant that has proven useful in the continued development of the GT-MHR. Built by General Atomics (GA) as a DOE demonstration plant in 1973, Fort St. Vrain was transferred in 1979 to Public Service Company of Colorado and operated for several years before being shut down in 1989, after experiencing technical problems, particularly intrusion of moisture from water-cooled bearings. The GA-built helium-cooled reactor operated at 1,400 degrees Fahrenheit and produced 330 MW of electricity. Despite operation and maintenance difficulties, the high temperature plant demonstrated enhanced safety characteristics, including significantly reduced radiation exposure to its workforce, and the use of hexagonal prismatic fuel blocks, which have continued to be used in the GT-MHR (Margolis 2003). Moreover, the plant was lauded as the first successfully decommissioned nuclear plant in 1996 (Nuclear Energy Insight 1997, p. 4). The plant has since been repowered as a combined-cycle gas turbine plant producing near 720 MW of electricity.

A4.4.9. IRIS

IRIS is an innovative small (100 to 300 MW) pressurized water reactor under development by Westinghouse. The key feature of the IRIS design is the integrated primary system, that is, all primary system components, including the steam generators, coolant pumps and pressurizer, are housed along with the nuclear fuel in a single, large pressure vessel. As such, IRIS offers potential safety advantages, primarily related to the elimination of any potential for large-break loss of coolant accident. Its small size and modular design may simplify on-site construction and make it deployable in areas not suitable for large nuclear plants.

IRIS is currently in the conceptual engineering stage and is being developed by an international consortium, with some support from DOE via the Nuclear Energy Research Initiative (NERI) Program. However, the integral primary system configuration introduces significant design and licensing challenges that will be difficult to overcome, particularly in the relatively short time frame established for near-term deployment. In key design details, IRIS is fundamentally different from any reactor licensed and operating in the United States. For that reason, extensive analysis and testing will be needed as a prerequisite to NRC licensing and commercial deployment in the United States. The IRIS sponsors' response to the NTDG RFI identifies this needed development and testing.

A4.4.10. Other Candidates (not evaluated by NTDG)

The NTDG evaluated those candidate reactor designs submitted per the requirements of the DOE Request for Information, as described above. For completeness, it is noted that other designs may also be deployable by 2010. However, these were not evaluated, and the NTDG offers no judgment as to their feasibility as near-term deployment candidates.

A4.4.10.1. EPR

The European Pressurized water Reactor (EPR) is a very large (1,545 MW or 1,750 MW) design developed in the 1990s as a joint venture by French and German companies, Framatome and Siemens. The basic design was completed in 1997, working in collaboration with other European nations, and conforms to French and German laws and regulations.

As the EPR design was being developed, there was substantial cooperation between the European utilities developing EPR user requirements and the U.S. utilities leading the U.S. ALWR Program and its Utility Requirements Document. The EPR was not submitted to the NTDG in time to support an assessment. Further, as with the SWR 1000, the designer, Framatome ANP, has not made a decision regarding entry into the U.S. nuclear market. The French Ministry of Industry is considering building a demonstration plant by 2010 (AFP 2003).

A4.4.10.2. System 80+

The System 80+ is a 1,350 MW PWR design developed by ABB-CE (now merged with Westinghouse). It conforms to the ALWR Utility Requirements Document and was certified by NRC in May 1997. Plants based on the System 80+ design have been built in Korea. However, as of this time Westinghouse has chosen not to market the System 80+ design in the United States.

A4.4.10.3. AFR and the PRISM

The Advanced Fast Reactor (AFR) and the Power Reactor Innovative Small Module (PRISM) are two Generation IV designs that utilize a fast neutron spectrum and sodium cooling for the purpose of creating a more closed fuel cycle. The use of the fast neutron spectrum allows the reactor to consume plutonium and other transuranic elements, thereby eliminating the need for additional disposal methods. The AFR is being developed to incorporate pyroprocessing that separates the fission products and re-fabricates fuel with the remaining uranium and transuranic products. The reactors range in size from 300 to 465 MW per module. Argonne National Laboratory and General Electric are working on this design (Roglans-Ribas et al. 2003; Boardman et al. 2000; Boardman, Dubberley, and Hui 2000).

A4.5. Evaluation of Near -Term Candidates

The following sections summarize the NTDG evaluation of the eight-candidate reactor designs (DOE 2001). These include assessment of each candidate's compliance with the six criteria established by the NTDG, identified design-specific gaps, projected cost performance, schedule considerations, and overall potential for deployment by 2010. In each of these evaluation categories, the NTDG conclusions for all eight candidates are summarized in tabular form. The NTDG did not evaluate the ACR-700, so the summary for that reactor is derived from the present study.

Tabular summaries are intended to provide a concise comparison of the relative merits and demerits of the reactor designs evaluated. The NTDG evaluation of the degree to which each of the candidate reactor designs meets the intent of the six criteria for near-term deployment is summarized below. The NTDG judgments in each case were based on the information submitted by the respondent, on additional information provided (including presentations at NTDG meetings) and on the experience and judgment of the NTDG team members.

A4.5.1. ABWR

- **Regulatory Acceptance:** Meets criterion. Design is NRC certified.
- **Industrial Infrastructure:** Meets criterion. International infrastructure exists and has been demonstrated on Asian ABWR projects.
- **Commercialization Plan:** Can meet criterion. ABWR has been successfully commercialized in Japan and Taiwan.
- **Cost Sharing Plan**: Meets criterion. No design-specific government funding requested.
- **Economic Competitiveness:** Can meet criterion. ABWR costs have high certainty (based on actual experience), but U.S. economic competitiveness is uncertain because of relatively high capital cost; ABWR may be competitive in some market scenarios.

- **Fuel Cycle Industrial Structure:** Meets criterion. ABWR utilizes conventional fuel of proven design.
- **Design Specific Gaps:** Economic competitiveness under some scenarios.

A4.5.2. AP1000

- **Regulatory Acceptance:** Pre-application steps are in process.
- **Industrial Infrastructure:** Meets criterion. Strong infrastructure is in place.
- **Commercialization Plan:** Can meet criterion, but require substantial financial investment to complete the detailed design.
- **Cost Sharing Plan:** Meets criterion. The Westinghouse plan proposes cost sharing and supporting rationale for design certification and detailed design.
- **Economic Competitiveness:** Meets criterion. AP1000 would be competitive in today's market.
- **Fuel Cycle Industrial Structure:** Meets criterion. AP1000 will utilize conventional nuclear fuel.
- **Design Specific Gaps:** Design Certification; financial support for completion of detailed design.

A4.5.3. SWR 1000

- **Regulatory Acceptance:** Can meet criterion. SWR 1000 design developed to meet European requirements; translation/revision to U.S. requirements will be difficult but could be achieved in time for 2010 deployment if initiated very soon.
- **Industrial Infrastructure:** Meets criterion. Strong infrastructure is in place.
- **Commercialization Plan:** Indeterminate. Plan not provided; SWR 1000 commercialization in the United States is contingent upon F-ANP decision.
- **Cost Sharing Plan:** Indeterminate. Cost sharing requested for design certification only (source and amount of funding to complete first-time engineering not identified.)
- **Economic Competitiveness:** Can meet criterion. Projected costs are attractive, but they are highly uncertain, particularly under U.S. conditions.
- **Fuel Cycle Industrial Structure:** SWR 1000 will utilize new fuel assembly design, but requires development and qualification.
- **Design Specific Gaps:** Commitment by Framatome ANP; licensing to U.S. regulatory and industry standards.

A4.5.4. CANDU, ACR-700

- **Regulatory Acceptance:** Pre-application review was requested June 19, 2002, and is expected to be completed in 2004.
- **Industrial Infrastructure:** Several similar plants (CANDU 6 units) have been completed recently or are under construction in China, Korea, and Romania.

- **Commercialization Plan:** Can meet criterion. The ACR-700 is an evolution of the proven CANDU-6 units, of which the last six have been built on or ahead of schedule and on budget.
- **Cost Sharing Plan:** Meets criterion. The AECL plan does not request any specific funding for design certification, only for NRC fees.
- **Economic Competitiveness:** AECL reports short lead times and low capital costs for twin 700 MW units.
- **Fuel Cycle Industrial Structure:** Utilizes slightly enriched uranium (SEU) and a once through fuel cycle.
- **Design Specific Gaps:** Achieving Design Certification; meeting all U.S. requirements.

A4.5.5. AP600

- **Regulatory Acceptance:** Meets criterion. Design is NRC certified.
- **Industrial Infrastructure:** Meets criterion. Strong infrastructure is in place.
- **Commercialization Plan:** Can meet criterion, but require substantial financial investment to complete the detailed design.
- **Cost Sharing Plan:** Meets criterion. The Westinghouse plan proposes cost sharing and supporting rationale for design certification and detailed design.
- **Economic Competitiveness:** Can meet criterion. Because of smaller capacity, has higher capital and operating costs than AP1000. Based on Westinghouse projected costs, AP-600 may be competitive in some U.S. market scenarios.
- **Fuel Cycle Industrial Structure:** Meets criterion. AP600 will utilize conventional nuclear fuel.
- **Design Specific Gaps:** Financial support for completion of detailed design; economic competitiveness under some scenarios.

A4.5.6. ESBWR

- **Regulatory Acceptance:** Can meet criterion. ESBWR design incorporates ABWR and SBWR design features, both previously reviewed by NRC.
- **Industrial Infrastructure:** Meets criterion. Same international infrastructure as demonstrated on Asian ABWR projects would support ESBWR.
- **Commercialization Plan:** Does not meet criterion. ESBWR commercialization plan is predicated on prior successful commercialization of ABWR. Therefore it is not likely to support deployment by 2010.
- **Cost Sharing Plan:** Meets criterion. Cost sharing requested for design certification and detailed design.
- **Economic Competitiveness:** Can meet criterion. GE did not provide cost projections; however, based on GE design economic targets and GE preliminary estimates of material quantities, ESBWR would likely be economically competitive.

- **Fuel Cycle Industrial Structure:** Meets criterion. ESBWR utilizes conventional fuel of proven design (same fuel as ABWR).
- **Design Specific Gaps:** Design certification and completion of detailed design.

A4.5.7. PBMR

- **Regulatory Acceptance:** Can meet criterion, provided that several challenging technical issues (including fuel issues) can be resolved and demonstrated to NRC satisfaction in the time frame needed for 2010 deployment. U.S licensing submittal information must be adapted from the German / South African design and test work. Pre-application steps with NRC are in progress.
- **Industrial Infrastructure:** Can meet criterion. International team is being assembled. Design contracts are in place for major equipment.
- **Commercialization Plan:** PBMR had a potential U.S. customer (Exelon) with a substantial initial commitment; however, Exelon has since changed its focus away from further nuclear development and pulled out of the project. As such, no commercialization plan beyond completion of the South African project exists.
- **Cost Sharing Plan:** Meets criterion. Proposed government cost sharing is primarily for licensing activities, including NRC confirmatory fuel characterization and test programs.
- **Economic Competitiveness:** Can meet criterion. However, projected PBMR economics are preliminary and have high uncertainty. Satisfactory economics rely on deployment of multiple modules and successful development of the design.
- **Fuel Cycle Industrial Structure:** Can meet criterion. PBMR safety and reliability hinge on successful fuel development and high quality fuel manufacture. Current plan includes ambitious program to develop, test, license and produce PBMR fuel, and presumes that initial U.S. fuel loads will be procured from a foreign supplier.
- **Design Specific Gaps:** Commercialization plan is uncertain given the recent withdrawal by Exelon; fuel development, characterization, manufacture, testing and regulatory acceptance; performance of in-reactor high temperature materials; power conversion system uncertainties with respect to components, materials and reliability.

A4.5.8. GT-MHR

- **Regulatory Acceptance:** Can meet criterion, provided that several challenging technical issues (including fuel issues) can be resolved and demonstrated to NRC satisfaction in the time frame needed for 2010 deployment. U.S licensing submittal information must be adapted from the Russian design and test work.
- **Industrial Infrastructure:** Can meet criterion, provided that the Russian industrial infrastructure can be qualified as a commercial supplier in the United States. This may be difficult to achieve in the time frame required for deployment by 2010.
- **Commercialization Plan:** Can meet criterion. However, this presumes continued U.S. government support to the Russian project, timely identification of U.S. customer and industry partners, and technical success with Russian project.

- **Cost Sharing Plan:** Meets criterion. Cost share proposal is predicated on continued U.S. Government support to Russian project and presumes substantial private sector participation for commercialization.
- **Economic Competitiveness:** Can meet criterion. However, projected GT MHR economics are preliminary and have high uncertainty. Satisfactory economics rely on deployment of multiple modules and successful development of the design.
- **Fuel Cycle Industrial Structure:** Can meet criterion. GT MHR safety and reliability hinge on successful fuel development and high quality fuel manufacture. Current plan includes ambitious program to develop, test, license and produce GT MHR fuel.
- **Design Specific Gaps:** Conversion of Russian prototype information and analyses, into documentation suitable for U.S. application; successful continuation of Russian project; fuel development, characterization, manufacture, testing and regulatory acceptance; performance of in-reactor high temperature materials; power conversion system uncertainties with respect to components, materials and reliability.

A4.5.9. IRIS

- **Regulatory Acceptance:** Does not meet criterion. Design certification in time for 2010 deployment is unlikely, because of extensive analysis and testing required.
- **Industrial Infrastructure:** Can meet criterion. International IRIS design team, which includes manufacturing capability, has been assembled.
- **Commercialization Plan:** Does not meet criterion. Commercialization plan (in time to support 2010 deployment) is unrealistic.
- **Cost Sharing Plan:** Meets criterion. Identified cost sharing would support IRIS engineering, testing and licensing.
- **Economic Competitiveness:** Indeterminate. Westinghouse projections on IRIS costs are highly conjectural; if true, IRIS would be economically competitive, but there is not yet a sufficient basis for confidence.
- **Fuel Cycle Industrial Structure:** Meets criterion, for initial fuel loads. However, more highly enriched fuel loads, intended for later years, would require new manufacturing capability.
- **Design Specific Gaps:** Steam generator design, control, and accessibility for inspection as well as maintenance; integrated system safety performance, including transient response as well as primary system/containment interaction; internal control rod drive mechanism (CRDM) development (and/or adequacy of conventional CRDMs with long drive trains).

A4.5.10. Conclusion

The ABWR, the AP600, the AP1000, ACR-700 and the SWR 1000 are the only reactor types where the vendors appear willing and potentially able to meet the NTDG criteria. The ABWR has design certification and is the only reactor type that has been built, but it still faces difficulty with economic competitiveness. The AP600 also has obtained design certification, but it has been superseded by the AP1000 and probably will not be built. As a scaled-up version of the AP600, the AP1000 should be more economically competitive, but it also needs to finance a detailed design and it is has not yet obtained design certification. The SWR 1000 appears to be the leading candidate for a project in Finland, and Framatome has met with NRC about obtaining design certification for the U.S. market.

GE wants to commercialize the ABWR domestically prior to introducing the ESBWR to the U.S. market. The remaining designs will not be able to satisfy the NTDG criteria since they are only in very preliminary stages and major uncertainties need to be resolved. The PBMR must still test fuel integrity and high temperature materials.

Eskom's plan to commercialize the PBMR has come under doubt since Exelon decided to withdraw from the project. The GT-MHR also needs to test fuel integrity and high temperature materials. Its prototype information has not been suitably documented by General Atomics to submit an application for design certification. Finally, the IRIS project still requires extensive testing of its steam generator design and control. The project must also demonstrate that its steam generators will be accessible for inspection as well as maintenance.

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Appendix A5. NUCLEAR FUEL CYCLE AND WASTE DISPOSAL

Summary

The front-end costs of nuclear fuel consist of the cost of raw ore, its conversion, its enrichment, and its fabrication. Total front-end costs amount to $3.50 to $5.50 per MWh.

In the United States, direct disposal from a once-through fuel cycle has been used, without reprocessing of spent fuel. The costs of disposal in this case consist of short-term on-site storage costs prior to permanent storage, plus a charge levied to pay for permanent storage at a central facility such as Yucca Mountain. The back-end costs are $1.09 per MWh. The total fuel cycle cost is, therefore, between $4.65 to $6.62 per MWh, or less than 10 percent of the LCOE new nuclear generation.

Reprocessing traditionally has been conducted using the PUREX process for recovering uranium and plutonium. DOE's R&D program is developing techniques designed to be still more proliferation-resistant.

Reprocessing and eventual recycle of the fissile material for reuse as a fuel in future nuclear reactors would not materially affect the economic competitiveness of nuclear energy.

Outline

A5.1. Introduction

The purpose of this appendix is to provide estimates of the contribution of fuel costs to total nuclear power costs. Section A5.2 gives background on the structure of nuclear fuel costs, of which storage, disposal, and possibly reprocessing are components. Section A5.3 describes some of these costs. DOE R&D currently underway or planned to improve the efficiency of nuclear fuel and the safety involved in its disposition is described in Section A5.4.

Section A5.5 develops estimates of the costs of waste disposal, without reprocessing and with reprocessing. Section A5.6 compares total fuel cycle costs under these alternatives. Section A5.7 concludes.

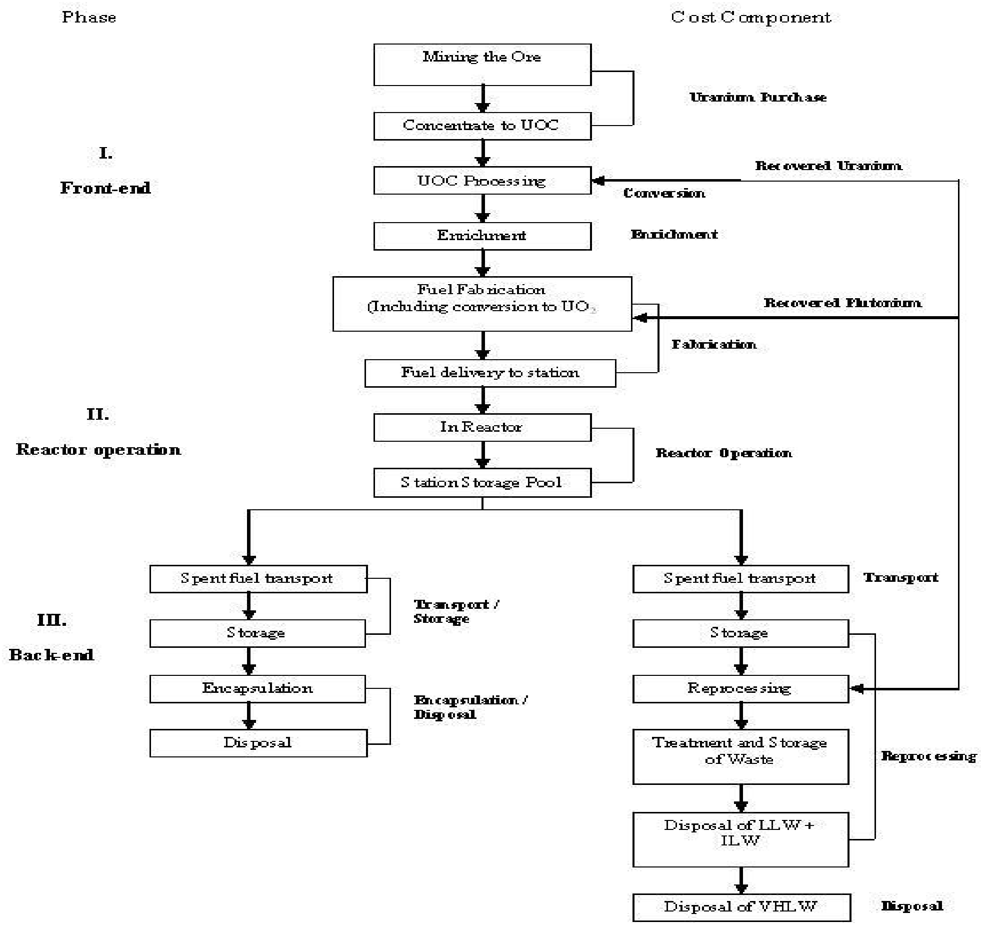
A5.2. Composition of Fuel Costs

Nuclear fuel costs consist of front-end and back-end costs. Figure A5-1 shows the stages in the nuclear fuel cycle, from the front-end mining and processing stages, through the fuel's use in a reactor, to its back-end phases of either disposal or reprocessing, followed by recycle of the fissile material.

The front-end costs consist of the cost of raw uranium, its conversion to uranium hexafluoride, the enrichment to 5 percent U^{235}, and fabrication into fuel rods, pellets or other form. Table A5-1 shows the composition of these cost components. The low and high ranges of the costs shown in the table are from alternative sources (NEA 1994, Ch. 4; NAC 2000, session 2, slide 15). These costs are incurred over a period of up to five years prior to the use of the fuel in the reactor, and the outlays incur interest costs during this period. Consequently, there is an overnight component to the cost, in the second column of the table, and a time-related component in the third column. The right-most column reports the shares of these components in the front-end fuel cost. The dominant cost component is enrichment, followed by ore purchase and fabrication.

The remaining costs can take one of two forms, direct disposal or reprocessing followed by recycle of the fissile material for reuse in a future nuclear reactor. The costs of direct disposal, as presently borne by utilities, consist of the cost of on-site storage plus the federal charge of 1 mill per kWh.

Figure A5-1.: The Nuclear Fuel Cycle



Source: NEA (1994, p. 10).

Table A5-1: Components of Front-End Nuclear Fuel Costs, $ per kg U, 2003 Prices

Process Step	Direct Outlays	Interest Cost	Total Cost	Percent of Total Cost
Ore Purchase	222 to 353	94 to 150	316 to 503	22 to 23
Conversion	40 to 94	15 to 35	55 to 129	4 to 6
Enrichment (per kg SWU)	606 to 951	197 to 306	804 to 1259	54 to 60
Fabrication	193 to 250	54 to 69	246 to 319	14 to 17
Total			**1,420 to 2,209**	**100**
$ per MWh			**3.56 to 5.53**	

Sources: NEA (1994), NAC (2000).

A5.3. Reprocessing Technologies, Leading to Recycling and Actinide Burning

The United States has thus far decided to forego the reprocessing route to employ a once-through system (in which the nuclear fuel is used and then disposed). Chapter 7 contains a summary of disposal policies in different countries. The 1977 decision not to reprocess was based in large part on concerns over nuclear proliferation because of the separation of pure plutonium by PUREX reprocessing. This section describes the processing technology system that raised U.S. concerns over proliferation potential and recent technological advances that are reducing the scope for diversion of civilian nuclear material to weapons.

Over the last 40 to 50 years, reprocessing has been used in some countries to recover unused uranium and plutonium from spent fuel. Reprocessing involves dissolving the waste fuel to allow plutonium and uranium to be separated from the other wastes. Spent fuel typically contains a little over 1 percent by weight of plutonium, about 95 percent uranium and about 4 percent waste products. The separated uranium can be enriched again for use as fuel, while the plutonium is made into mixed oxide (MOX) fuels (Bunn et al. 2003, pp. 2-3).

Reprocessing traditionally has been conducted through the PUREX process. PUREX is an aqueous process that involves shearing and dissolving spent fuel in nitric acid for subsequent solvent extraction of plutonium and uranium from residual minor actinides and fission products. The spent fuel is unloaded from containers into an interim storage facility and then remotely transferred to the preparation cell for cutting off, shearing and dissolution in a shearing machine. After that, the extracted solution is transferred for clarification (to remove the suspended particles) and purification from fission products. Uranium and plutonium are chemically separated and eventually consumed in future reactors. The remaining liquid is high-level waste, which is stored in cooled tanks prior to vitrification and, later disposed in a deep geological repository.

Since reprocessing followed by multiple recycles and actinide burning reduces the volume and long term toxicity of nuclear wastes, it could be used in conjunction with other storage options to mitigate or defer capacity constraints. These possibilities will be considered in the analysis of the economic costs of disposal.

Reprocessing and recycle of the uranium and plutonium, and actinide burning in future fast reactors provides another way to reduce the volume and toxicity of radioactive waste for disposal.

In 1999, a new process, UREX, was proposed by DOE; the UREX process was developed as a more proliferation-resistant variation of PUREX; it is devised so that only uranium is separated as a pure product from the transuranics, (comprised of plutonium plus minor actinides) plus fission products. By preventing the separation of plutonium from the other radioactive species, it degrades the usability of plutonium for weapons applications. Then, the commixed transuranic product can be further processed to reduce the overall amount of high-level waste (UIC 2004).

Pyroprocessing is a non-aqueous reprocessing technology, developed in the 1980's and 1990's for recycle of fast-breeder reactor fuel. Pyroprocessing separates actinides (i.e., uranium plus transuranics) from fission products present in spent fuel. The mixture of actinides produced results in an unusable form for weapons applications and can be recycled in fast reactors for further energy extraction. One of pyroprocessing's main advantages is compactness such that it can be conducted on-site, which eliminates the various costs and other risks of transportation. PYRO-A is a variant of pyroprocessing designed to follow after the UREX process, in which the mixture of transuranics (i.e., plutonium plus minor actinides) from UREX are further separated from the fission products. The fission products are then converted into a ceramic composite for simpler disposal (UIC 2004).

A5.4. DOE Advanced Fuel Cycle R&D

Near-term goals for DOE's advanced fuel cycle research are to further develop proliferation-resistant processes that reduce total spent fuel volume, separate long-lived highly toxic elements, and reclaim spent fuel's valuable energy (DOE 2003a). These include development of spent fuel treatment processes such as uranium extraction (UREX and UREX +) technology and pyroprocessing, as well as development of fuels that allow the transmutation of plutonium into elements that cannot be used for nuclear weapons.

Longer-term goals are to explore methods that would reduce the long-term radiotoxicity and heat load of high-level waste sent to repositories. Research into the development of next-generation nuclear fuel cycles seeks to simultaneously increase the energy production derived from nuclear fuels and to ease the radioactive waste disposal processes. Possibilities include the fast neutron spectrum reactors or accelerators to facilitate transmutation of the actinides.

A5.5. Costs of Direct Disposal and Projections of Costs for Reprocessing

The back-end fuel cycle cost consists of temporary storage at the site of the nuclear power generation, followed by permanent disposition at a central facility such as Yucca Mountain. The first sub-section below estimates these costs, on a per kWh basis, if the spent fuel is not reprocessed. The second sub-section estimates the costs if spent fuel is reprocessed. The final sub-section compares the full back-end costs with and without reprocessing.

A5.5.1. Direct Disposal

Nuclear plants were designed to temporarily store spent nuclear fuel (SNF) before it is transferred to a final repository. On-site storage uses water pools (also known as wet storage), which keeps the fuel cool as it undergoes radioactive decay. Recently, dry cask storage has been used to store SNF that has been water-cooled for one year in sealed steel casks to increase the available on-site storage capacity. Wet and dry on-site storage, however, are considered temporary solutions, as they are intended to allow fresh SNF to cool before its final disposal (Bunn et al. 2001, p. 10).

Since the early 1980s, Yucca Mountain, Nevada, has been the site proposed by DOE for the construction of a centralized high-level radioactive waste storage facility. The plans call for a permanent underground storage complex intended to house all of the high-level radioactive waste that currently exists in the United States and that will be produced in this country through the year 2041. The Yucca Mountain project is projected to proceed in stages: development (1983 to 2003), licensing (2003 to 2006), construction (2006 to 2010), emplacement (2010 to 2041), monitoring (2041 to 2110), and closure (2110 to 2119) (DOE 2002).

The Yucca Mountain project has been funded in two main ways. Congress has made appropriations to cover the disposal of defense-related nuclear wastes, while a tax of one 1 mill (one-tenth of a cent) per kWh since 1983 has been levied on power produced at nuclear power plants in order to fund the disposal of commercially produced wastes. As of this date, the fund totals almost $18 billion. The money from this fund, along with the proceeds from its investment income over the coming decades, has been projected to be sufficient to pay for the Yucca Mountain project.

While Yucca Mountain's currently legislated capacity is 70,000 metric tons, DOE's Environmental Impact Statement suggests that the site could safely accommodate more than 120,000 metric tons (DOE 2002). Other sources suggest 150,000 to 200,000 metric tons may be possible (Peterson 2003, p. 28; NEI 2003).

With regard to estimation of disposal costs, for the temporary on-site storage phase total capital cost to establish new dry storage facilities at a reactor site is estimated to range from $8 to $12 million regardless of the amount of waste to be generated (Bunn et al. 2001, p. 13). Costs to purchase and load dry casks range from $60 to $80 per kilogram of heavy waste (kgHM). Operating costs are modest since there is little to be done after loading, except security and safety monitoring, maintaining its NRC license. For a reactor that generates 1,000 metric tons of heavy metal waste over a 40-year lifetime, the total cost for 5 years of dry cask storage would be approximately $120 million. Assuming the plant generates 0.006 lbs. of spent nuclear waste per MWh (DOE 2003b), the cost to a 1,000 MW reactor would be 0.09 mills per kWh, or $0.09 per MWh.

For permanent disposal, the estimated total cost for disposal at Yucca Mountain is approximately $56 billion. This includes an estimated $49.3 billion in future costs and $6.7 billion in past costs (DOE 2001a, p. 1-1). This cost estimate covers every stage of the Yucca project, from development to permanent closure. DOE's (2001b) recent investigation of the current fee system determined that the charge of 1 mill per kWh is sufficient to cover the costs of storing all high-level wastes generated through 2041. Calculations below corroborate this assessment.

The commercial cost per kWh excludes disposal costs for defense-related wastes, which are anticipated to comprise 10 percent of the total volume but will account for 29 percent of the total cost (DOE 2001b, p. 4). For purposes of this analysis, the 29 percent portion of defense-related appropriations is excluded from the commercial cost calculation. The remaining 71 percent of the total cost amounts to \$39.8 billion. Assuming an expanded capacity of 120,000 metric tons, and debiting 10 percent for defense-related wastes, leaves 108,000 metric tons of current and future commercial nuclear waste to pay for the \$39.8 billion in total costs of Yucca Mountain. These figures are converted to a kWh cost basis as follows: \$39.8 billion ÷ [(108,000 metric tons waste x 2,200 lbs per metric ton) ÷ (0.006 lbs per MWh ÷ 1,000 kWh per MWh)] = 0.001. Thus, the cost of disposal at Yucca Mountain storage is projected to be about 1 mill per kWh, or about \$1 per MWh.

A5.5.2. Reprocessing, Recycling, and Actinide Burning

As the United States has not reprocessed nuclear fuel for many years, any estimate of the effect of reprocessing on back-end costs in this country remains especially tentative (Bunn et al. 2003). However, British Nuclear Fuels, Ltd. (BNFL) in the U.K. and COGEMA in France offer reprocessing services internationally, and their prices can be used as rough guideposts to potential U.S. reprocessing costs.

The U.S. scenario involves reprocessing and permanent storage at Yucca Mountain. The cost of reprocessing per kg of usable fuel includes \$63 per kg for transportation of waste fuels, and \$904 per kg for the reprocessing cost for a total of \$967 per kg (NEA 1994, p.12, converting to 2003 prices). Capital costs are included in the \$904 per kg reprocessing cost. A kg of UO_2 reactor fuel yields approximately 399,000 kWh (NAC, 2000). Expressing the reprocessing cost on a per kWh basis, \$967 per kg of fuel/399,000 kWh per kg fuel = 2.4 mills per kWh, or \$2.40 per MWh, for the reprocessing costs.

For comparison, independent estimates of the relative costs of reprocessing versus no-reprocessing are available. Based on uranium prices of about \$50 per kg U_3O_8 and using statistical analysis to take standard deviations around mean values, NEA (1994, p. 14) estimates a spread of 0.95 to 1.11 mills per kWh (converted to 2003 prices) for the difference between treating and not treating spent fuel. Lobdell (2002, p.18) estimates 1.82 mills per kWh difference between reprocessing and not reprocessing for the United States. Bunn et al. (2003, executive summary), who annuitize the costs of new processing facilities into their cost estimate of reprocessing, report an increase in cost of 1.3 mills per kWh from reprocessing, using a uranium price of \$40 per kg and a reprocessing price of \$1,000 per kgHM. An average of these cost estimates and that estimated here is about 1.65 mills per kWh, or \$1.65 per MWh. The fabrication costs, associated with recycling plutonium and uranium, as well as the added reactor cost of consuming this material would need to be included in the overall calculation.

Under the disposal alternative considered in this sub-section, the total amount of heavy metal waste would be reduced to approximately 887 kg per year or 35.5 metric tons over a 1,000 MW reactor's lifetime (MIT 2003, p. 30). Using the costs above, the total life cycle cost of 5 years' dry storage would be about $43 million dollars or $1,210 per kgHM. Assuming a plant using reprocessing generates 0.00011 kg of heavy metal waste per MWh, the cost of on-site storage for 5 years would be 0.05 mills per kWh. This estimate could be affected if the actinides are not consumed prior to disposal, since the costs for disposal are highly dependent upon the relative toxicity of the fuel.

Peterson (2003, p. 28) estimates the technical capacity of Yucca Mountain for fission products from a closed fuel cycle to be 200,000 MT, which is larger than the 120,000 MT assumed for the direct disposal because the fission products separated in the reprocessing can be packed more closely together. Reserving 10 percent of the total capacity for defense-related wastes, the total capacity available for commercial wastes is 180,000 MT. Assuming that the total cost of Yucca Mountain continues to be $39.8 billion and 0.00011 kg of fission products per MWh is produced (MIT 2003, p. 30), the incremental cost of storage at Yucca Mountain would be 0.24 mills per kWh, or $0.24 per MWh. This estimate, additionally, could be affected if the actinides are not consumed prior to disposal.

A5.5.3. Summary

Table A5-2 summarizes the cost components of direct disposal, or the back-end costs of the fuel cycle currently used in the United States. The cost estimates calculated here are tentative and rely on approximations which could be refined. Nevertheless, they point to magnitudes which, even if raised by a factor of two or three, would still be small.

Table A5-2: Disposal Costs, $ per MWh, 2003 Prices

Fuel Cycle Component	Cost
Temporary on-site storage	0.09
Permanent storage at Yucca Mountain	1.00
TOTAL	1.09

A5.6. Total Fuel Cycle Costs

Table A5-3 adds the front-end and back-end costs of nuclear fuel for direct disposal. This includes temporary storage on-site of $0.09 per MWh and the $1 per MWh fee for disposal at Yucca Mountain, yielding a total fuel cycle cost of $5.44 per MWh.

Table A5-3: Fuel Cycle Cost Components under Direct Disposal, $ per MWh, 2003 Prices

Fuel Cycle Component	Cost
Front-end cost	4.35
Temporary on-site storage	0.09
Disposal at Yucca Mountain	1.00
TOTAL	5.44

Three sensitivities of the estimates in Table A5-3 may be noted. First, the range of front-end costs associated with disposing of the fuel directly, from Table A5-1, is $3.56 to $5.53 per MWh, which yields a range in total fuel cycle costs of $4.65 to $6.62 per MWh around the $5.44 mid-range estimate in Table A5-3 for the benchmark situation of no reprocessing. Second, a doubling of the price of uranium ore would increase the total fuel cycle cost in Table A5-2 by $0.61 per MWh. Third, if long-term storage on site were required due to delay in opening Yucca Mountain, the cost of on-site storage would rise modestly, by $0.43 per MWh. None of these sensitivities materially affects nuclear power's LCOE.

A5.7. Conclusion

Fuel cycle costs are not a major factor in the economic competitiveness of nuclear power. The larger waste disposal questions, involving advanced fuel cycles, concern broad policy issues related to proliferation issues considered in Appendix A7.

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Appendix A6. NUCLEAR REGULATION

Summary

The U.S. Nuclear Regulatory Commission (NRC) was created to conduct all licensing and regulatory functions for the nuclear power industry. It is involved in the regulation of activities from mining uranium to plant decommissioning. Historically, the construction and operation permitting process has been at the center of many delays and cost increases for new nuclear power plants.

An amendment to the Code of Federal Regulations (10 CFR Part 52) provides for combined construction and operation permitting and is aimed at streamlining the permitting process. The combined Part 52 license is designed to allow investors the opportunity to resolve many uncertainty issues before committing large amounts of money to an investment in a nuclear facility.

Reducing construction delays and lowering the risk premium to investors necessary to compensate for the possibility of delays or cancellations due to regulatory activities could lower the cost of power from a nuclear plant significantly. Table A6-2, derived from the financial model of Chapter 5, compares levelized cost of power (LCOE) for nuclear plants under different regulatory regimes. The first regime, reflecting the older procedure, assumes 7-year construction time, 12 percent interest rate on debt, 15 percent required return on equity, and a reduction in construction costs of 3 percent for doubling the number of plants. The second regime, reflecting the new regulatory procedures, assumes a 5-year construction time, 7 percent interest rate on debt, 12 percent required return on equity, and 5 percent reduction in construction costs for double the number of plants. The electricity cost reduction for lower cost plants is 31 percent and 53 percent for higher cost plants.

Outline

A6.1. Introduction

This appendix examines the impacts of regulation on the future construction and operation costs of nuclear power facilities. Section A6.2 reviews the current regulatory framework. Section A6.3 presents estimates of costs of delay and uncertainty that may be reduced by streamlined regulation. Section A6.4 concludes that benefits of reducing construction delays and investor uncertainties are substantial.

A6.2. Current Regulatory Framework

Regulation of nuclear energy in the United States originates with the Atomic Energy Act (AEA) of 1954 (42 USC 2011 et seq.) and is enumerated in the relevant sections of the Code of Federal Regulations (CFR). The federal government has assumed most regulatory responsibilities in this area; in fact, courts have struck down many state efforts to regulate nuclear energy more independently (Hillegas 1983). While states can still regulate those areas the federal government has chosen not to address, federal preemption has ensured the regulatory supremacy of the federal government in nuclear energy. The U.S. Nuclear Regulatory Commission (NRC) was created to conduct all licensing and regulatory functions (Schoenbaum 1988).

A6.2.1. Mining Regulations

Although the AEA does not set forth detailed provisions regarding the mining of uranium or thorium, NRC is responsible for issuing licenses for the extraction of these materials. In recent years, several U.S. facilities have been licensed to recover uranium (OECD 1999). DOE can also issue permits for uranium exploration on federal lands.

A6.2.2. Regulations for Importing and Exporting Nuclear Fuels and Equipment

In 1995, NRC issued rules making regulations on the import or export of nuclear fuels and equipment conform to the International Atomic Energy Agency's (IAEA) principles of transboundary movement. The new standards, much like the old regulations, focus on issues of nuclear proliferation and require licenses to export or import nuclear wastes and mixed wastes. Separate categories and requirements exist for materials that become incidentally radioactive. NRC consults with other federal agencies regarding exports of radioactive materials and must receive explicit approval prior to transit from all affected countries.

A6.2.3. Nuclear Facilities: Construction and Operation Licenses

All nuclear power plants in the United States are licensed by NRC pursuant to the provisions of the AEA. NRC's Office of Nuclear Material Safety and Safeguards licenses fuel cycle facilities, and the Office of Nuclear Reactor Regulation issues reactor licenses (42 USC 5801-5844).

For many years, NRC's licensing process occurred in two steps, with the issuance of a construction permit and then (two or three years before scheduled completion) an operating permit (10 CFR Part 50). These steps were consolidated and made part of the AEA in 1992, so that the entire licensing process could occur in one step (10 CFR Part 52). The one-step licensing procedure was designed to allow an early resolution (or an earlier failure to reach resolution) of safety and operation issues. In particular, Part 52 requires early resolution of site suitability issues, emergency preparedness, and consideration of environmentally superior sites. For a summary of licensing procedures see Table A6-1 below.

The construction permit section must address (1) environmental and plant safety and (2) anti-trust issues. If NRC finds the application to be complete, a notice is published in the Federal Register and the application is distributed to all interested state and federal agencies. At this point, NRC's review of the application includes a focus on several key areas: safety, environmental protection, and anti-trust.

A safety review for the proposed design is conducted pursuant to the Standard Review Plan, a guide containing detailed design information about every reactor system and component. The Advisory Committee on Reactor Safeguards, an independently and statutorily created body, also reviews the application for design and safety, and then issues an opinion to NRC regarding the sufficiency of the application.

An Environmental Impact Statement (EIS) is also prepared by NRC (pursuant to the National Environmental Policy Act, NEPA), evaluating any environmental impacts of the project. The draft EIS is published in the Federal Register for comment. NRC then publishes its final EIS, which addresses all comments received.

NRC also begins the anti-trust review and forwards this initial report to the Department of Justice (DOJ) for comment. When the Attorney General's analysis and advice is received, NRC publishes its final determination on the anti-trust issues.

The operation permit is intended to ensure that the plant has been constructed in accordance with the approved construction design, and that the plant can operate safely. Under the old licensing system, this process began a few years prior to the completion of construction, whereas Part 52 requires the applicant to submit the procedures it will undertake and acceptance criteria it will use to ensure that after construction the plant has been built according to plan and can operate safely. Although these procedures and conditions are specified in advance, NRC must find that all of these criteria have been met.

After public hearings, NRC publishes a decision about the license application, which may be appealed directly to the Commission. After this first appeal, interested parties can appeal to the local U.S. Court of Appeals for further review.

Table A6-1: Comparison of One-Step and Two-Step Licensing

Old Two-Step License Procedure	Construction Permit · Preliminary Safety Analyses · Environmental Review · Financial and Anti-Trust Statement · Public comment on each section Operating License · Submission of Final Design · Final Environmental and Safety Analysis · Further public comment on each section
New One-Step License Procedure	Pre-Application Activities · Early Site Permit (includes environmental review) · Standard Reactor Design Certification · Public comment Combined License · License Authorizes Construction and Operation · Includes same information as two-step procedure · Can reference early application activities · Public comment within 180 days of reactor start-up

A6.2.4. Inspections and Reporting Requirements

The operating license contains detailed provisions regarding periodic inspections (NEA 1999). NRC conducts regular safety inspections in conjunction with full-time reactor site inspectors. The results of these inspections are published. Moreover, nuclear power plants are periodically reviewed for other operational characteristics (called the Systematic Assessment of License Performance, or SALP). Throughout its operational life, the reactor facility is also required to report specific types of information to NRC on a regular basis.

A6.2.5. Regulating the Protection of Workers from Radiation

Regulations applicable to worker safety at nuclear facilities attempt to (1) inform workers about the health problems from radiological exposure, (2) educate workers about methods to reduce exposure, and (3) encourage workers to report problems to NRC (NEA 1999). Some of the specific regulations include setting an annual limit for radiation doses, monitoring personnel for exposure, providing radiation protection equipment and the training to use it, informing workers about exposure hazards, and providing training regarding applicable warning labels, instructions, and signs. In addition, nuclear plants are still subject to all the requirements of the Occupational Safety and Health Act (OSHA).

A6.2.6. Emergency Response

The Three Mile Island accident in 1979 resulted in no off-site radiological exposures, but it led to a more formalized system of emergency preparedness. NRC created standards for state and local emergency planning and required that these plans be made in conjunction with the Federal Emergency Management Agency (FEMA) (Goxem 1988). This contingency planning includes emergency notification systems like sirens and broadcast warnings, as well as periodic emergency drills.

A6.2.7. Regulation of Radioactive Wastes

NRC, DOE and EPA work together to regulate the management and disposal of radioactive wastes in the United States. The regulatory framework, economic costs, and other issues related to this subject are discussed at length in Chapter 5.

A6.2.8. Operating License Renewal

Pursuant to the AEA, an operating license can be renewed (10 CFR Part 54). Currently, NRC regulations allow as many as 20 additional years of operation through renewal.

A6.2.9. Decommissioning

NRC's responsibilities for health and safety carry over into the decommissioning of nuclear power plants. Decommissioning is defined as taking a nuclear reactor safely off-line and then reducing radioactivity to a level that permits unrestricted use of the site property.

A6.3. Major Regulatory Costs

Many of the regulatory requirements outlined above are similar to the types of regulatory costs that many U.S. businesses face. Licensing and reporting requirements are common in many industrial sectors. These costs, although significant, are not unexpected and are ordinary business expenses. Over the past decades, NRC, coordinating with the nuclear power vendors and utilities, has worked to create a less burdensome regulatory structure while still protecting the public welfare (NRC 1978). Several major reports have highlighted some areas for reform and improvement: (1) renegotiation of safety, security, and emergency programs that currently exceed NRC requirements; and (2) greater regulatory flexibility about operation or construction matters that are economically advantageous and cause no reduction in safety (NEA 1998, NEA 1998, NRC 1978).

One baseline estimate for the cost of the regulatory process (essentially the fee structure for licensing and reporting without additional problems or delays) is approximately 1 mill per kWh (The Nuclear Tourist 2003), or only $1 per MWh. The major regulatory costs have been due to unanticipated delays and uncertainty that can contribute to the riskiness of investing in nuclear facilities

A6.3.1. Costs of Delay

Capital costs contribute 60 to 64 percent of the LCOE of nuclear power (see Table 3-5). Interest costs over a 7-year construction period can be nearly 30 percent higher than they would be for the same overnight cost over a 5-year construction period (Table 3-6). The resulting LCOE can be about $5 to $6 per MWh, or roughly 13 to 15 percent, higher as a consequence. Expressed as a saving that could be obtained by reducing a construction period from 7 years to 5, this amounts to a 12 to 13 percent saving.

Similarly, a two-year halt in the middle of construction could increase the LCOE of a nuclear power plant by over $7 per MWh, and a two-year delay between the completion of construction and bringing a nuclear plant on-line can add nearly $15 per MWh to its LCOE (Table 5-7). This is a possible additional cost that could be avoided, beyond the basic no-policy LCOE.

A6.3.2. Costs of Uncertainty

The risk that a plant, once begun, will not be completed or if completed will not be allowed to operate, makes investors skittish. Either they will require a higher risk premium, which will lead to a higher cost per megawatt hour of the power that eventually does get produced from the plant, or they will decline to invest at all. Calculations in Chapter 9 indicate that reducing the required risk premium on investment in a nuclear plant to levels comparable to those for coal- and gas-fired plants would reduce the LCOE of the nuclear plant by $9 to $14 per MWh. This amounts to a reduction of roughly 26 to 32 percent for eighth plants, depending on the initial capital cost and the ability of learning by doing to reduce overnight costs (Tables 9-8 to 9-10). This combines the effect of the shortened construction period, noted in the previous sub-section, at a given interest rate, and lower interest rates over the shorter construction period, resulting in a total reduction in LCOE of $14 to $21 per MWh.

A6.3.3. Potential Benefits of Improved Regulation

This section pulls together the construction-time and risk-reduction benefits that improved regulation could confer and takes into further consideration the expectation that a smoother regulatory procedure could enhance learning by doing. Table A6-2 compares the LCOE of an eighth plant under the previous regulatory regime with that of an eighth plant under an improved regime. This comparison assumes that the former circumstances allow a 3 percent learning rate—that is a 3 percent reduction in overnight costs with each plant doubling—and that the improved circumstances permit a 5 percent learning rate. The first row of the table reports the LCOEs of the eighth plant of each design built in 7 years, at interest rates of 12 percent on debt and 15 percent on equity, and with a 3 percent learning rate on overnight cost reductions. The $1,200 or $1,500 design would have an LCOE of

$49 per MWh. The difference between these two beginning overnight costs is that FOAKE costs have not been paid on the $1,500 plant; once those costs are paid, the learning effects operate on the same overnight costs across the two designs. The LCOE of the $1,800 design would be $58 per MWh. These LCOEs are the result of status-quo regulation.

The second row reports the LCOEs for those plants, built in 5 years, at interest rates of 7 and 13 percent on debt and equity, and with a 5 percent cost reduction for learning. The LCOE for the $1,200 or $1,500 design is $34 per MWh, and that for the $1,800 design is $43. These LCOEs are the result of the improvements in the regulatory procedures.

The third row reports the percent reduction in LCOE that would derive from the improvements in regulation between rows one and two. The improved regulation would yield a 31 percent reduction in eighth plant LCOE for the $1,200 and $1,500 designs and a 53 percent reduction for the $1,800 design. The difference in percent LCOE reduction is due to the different capital costs: the larger capital-cost plant benefits proportionally more because the levelized capital component of its LCOE is larger.

Table A6-2: LCOEs for Eighth Nuclear Plants, with No Policy Assistance Other than Improved Regulation, $ per MWh, 2003 Prices

Beginning Overnight Cost, $ Per kW	
1,200 or 1,500	1,800
7-year construction time Interest rates: 12 percent on debt, 15 percent on equity Learning effect: 3 percent reduction in cost for doubling plants built	
49	58
5-year construction time Interest rates: 7 percent on debt, 12 percent on equity Learning effect: 5 percent reduction in cost for doubling plants built	
34	38
Percent reduction in LCOE due to improved regulation	
31	53

A6.4. Conclusion

In sum, the benefits of reducing construction delays and investor uncertainties are substantial. Shortening the construction period and reducing the risk premium can have a combined effect of reducing a nuclear plant's LCOE by 30 percent.

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Appendix A7. NONPROLIFERATION GOALS

Summary

Countries that have chosen reprocessing include Belgium, China, France, Germany, India, Japan, Russia, Switzerland, and the U.K. These countries engage in reprocessing to separate plutonium and uranium from fission products for further use as fuel for reactors. Countries that have chosen direct disposal without reprocessing include the United States, Canada, Finland, South Korea, Spain, and Sweden. A chief concern with reprocessing is that the plutonium could be diverted to develop nuclear weapons. Several industrial countries have, in the past, provided reprocessing as well as enrichment technology and services to others, purportedly increasing the opportunities for theft or transfer of technology, equipment, or products.

International regulation of nuclear energy takes the form of a combination of treaties, international organizations and multilateral and bilateral agreements. The key components are the Treaty on the Non-Proliferation of Nuclear Weapons, the International Atomic Energy Agency, whose safeguards system verifies compliance, informal international groups and the Convention on Physical Security for Nuclear Materials, which sets international security standards for storing, using and transporting nuclear material. Implementation of the President's February 11, 2004, speech would provide added safeguards preventing reprocessing and enrichment technology spreading to rogue countries or terrorists.

Resolution of these issues involves broader policy considerations beyond the scope of the present study. The future economic viability of nuclear power, however, does not depend on their resolution. As Appendix A6 shows, the difference in the cost of nuclear waste handling, as between once-through disposal and reprocessing, is too small to materially affect the economic viability of nuclear power.

Outline

A7.1. Introduction

This appendix reviews practices in different countries (Section A7.2), and summarizes international arrangements aimed at preventing proliferation (Section A7.3). Section A7.4 provides information on the current Administration policy regarding the spreading of enrichment and reprocessing technology outside a set of countries considered to be reliable fuel suppliers who in compliance with international nonproliferation requirements. The concluding section assesses the implications of proliferation considerations for the present study.

A7.2 International Comparison of Nuclear Fuel Disposal Policies

Technological considerations in direct disposal and reprocessing were discussed in Appendix A5. Attention was given to the traditional PUREX method of reprocessing and the newer UREX method, along with further DOE developmental efforts. Countries have reacted differently to the technological alternatives. Table A7-1 provides a comparison of fuel cycle and nuclear waste disposal policies.

Reprocessing separates plutonium and uranium from fission products and recovers them for use as new fuel for reactors while reducing the volume of high-level waste and the radioactivity life of low-level waste. The recovered plutonium is stored in facilities controlled by the International Atomic Energy Agency (IAEA) or is combined with uranium and manufactured into mixed oxide (MOX) fuel used to feed certain type of nuclear reactors. The remaining radioactive liquid fission products are mixed with other materials, vitrified, and placed in metal canisters for storage. Among the countries conducting reprocessing that were mentioned above, France, the U.K., and Russia have large-scale reprocessing facilities and provide reprocessing services commercially to a number of other countries. Belgium and Italy have reprocessing facilities for research, and Japan is building a commercial reprocessing facility. Also, enrichment technology is located in several Western countries, Russia, and the Far East.

In the United States, reexamination of the U.S. choice of once-through policy is occurring, in order to consider proliferation resistance characteristics of the newer UREX and PYRO methods of reprocessing and further DOE development of disposal technologies discussed in Appendix A5. These techniques may be able to meet nonproliferation goals since they do not require plutonium to be separated from higher actinides or transported since they are recycled together in the reactor. As a consequence, proliferation risks are lowered, mainly through a substantial reduction in the risk of theft or misuse of plutonium.

Table A7-1: International Comparison of Nuclear Waste Disposal Policies

Country	Fuel Cycle Policy	Facilities and Progress toward Final Repositories
Belgium	Reprocessing	Central waste storage and underground laboratory established. Construction of repository to begin about 2035.
Canada	Direct Disposal	Underground repository laboratory established. Repository planned for use in 2025.
China	Reprocessing	Central spent fuel storage in Lan Zhou
Finland	Direct Disposal	Spent fuel storage in operation. Site selection studies underway for deep repository for commissioning in 2020.
France	Reprocessing	Two facilities for storage of short-lived wastes. Site selection studies underway for deep repository for commissioning in 2020.
Germany	Reprocessing (under review)	Low-level waste (LLW) sites in use since 1975. High-level waste (HLW) repository to be operational after 2010.
India	Reprocessing	Research on deep geological disposal for HLW.
Japan	Reprocessing	LLW repository in operation. HLW storage facility at Rokkasho-mura; investigations begun for deep geological repository.
Russia	Reprocessing	Sites for final disposal under investigation.
South Korea	Direct Disposal	Central interim HLW storage planned for 2016. Central LLW and intermediate level waste (ILW) repository planned for post-2008. Investigating deep HLW repository sites.
Spain	Direct Disposal	LLW and ILW waste repository in operation. Final repository site selection program for commissioning in 2020.
Sweden	Direct Disposal	Central spent fuel storage facility in operation since 1985. Final repository for LLW and ILW in operation. Underground research laboratory for HLW repository. Site selection for repository underway, to begin disposal in 2008.
Switzerland	Reprocessing	Central interim storage for all wastes under construction. Underground research laboratory for high-level waste repository, with deep repository to be completed by 2020.
United Kingdom	Reprocessing	LLW repository in operation since 1959. HLW is vitrified and stored. Underground HLW repository planned.
United States	Direct Disposal	Three LLW sites in operation. Decision in 2002 to proceed with geological repository at Yucca Mountain.

Source: UIC (2004, pp. 9-10).

A7.3. The Nonproliferation Regulatory Framework

The nuclear nonproliferation regime consists of a combination of treaties, international organizations, and multilateral and bilateral agreements complemented by several unilateral actions intended to deter further spread of nuclear weapons. Key components of the regime are the Treaty on the Non-Proliferation of Nuclear Weapons (NPT), the International Atomic Energy Agency (IAEA), whose safeguards system verifies NPT compliance, informal international groups, and the Convention on Physical Security for Nuclear Materials, which sets international security standards for storing, using and transporting nuclear material. This section describes the extent of the NPT, the role of IAEA as well as its mission and safeguards system, and the responsibility of other organizations and arrangements.

A7.3.1. The Treaty on the Non-Proliferation of Nuclear Weapons

The Nuclear Nonproliferation Treaty (NPT) was concluded in 1968, came into force in 1970, and was indefinitely extended in 1995. Its main goals are to prevent the spread of nuclear weapons, to make sure that peaceful nuclear technology is not diverted, to facilitate access to peaceful nuclear technology, and to promote disarmament. It provides the legal and institutional basis for nonproliferation internationally and depends for its success on countries not violating their commitments. In particular, it establishes the framework for an inspection system based on an agreement between each participating state and IAEA. Currently, 187 nations are party to the NPT.

A7.3.2. Role of the International Atomic Energy Agency (IAEA)

IAEA was created in 1957 to help nations develop nuclear energy for peaceful purposes. It has the role of establishing and administering nuclear safeguards arrangements, which are designed to deter diversion of nuclear material.

One of IAEA's missions is to verify through its inspection system that states comply with their commitments under the NPT and other nonproliferation agreements, to use nuclear material and facilities only for peaceful purposes.

Article II of the basic Statute of IAEA specifies the role of IAEA in terms of preventing nuclear proliferation: "the Agency shall seek to accelerate and enlarge the contribution of atomic energy to peace, health and prosperity throughout the world. It shall ensure, so far as it is able, that assistance provided by it or at its request or under its supervision or control is not used in such way as to further any military purpose" (IAEA 1997).

Part B of Article III indicates that "in carrying out its functions, the Agency shall conduct its activities in accordance with the purposes and principles of the United Nations to promote peace and international co-operation, and in conformity with policies of the United

Nations furthering the establishment of safeguarded worldwide disarmament and in conformity with any international agreements entered into pursuant to such policies…" (IAEA 1997). It also mentions that the Agency shall "establish control over the use of special fissionable materials received by the Agency, in order to ensure that these materials are used only for peaceful purposes…" (IAEA 1997). Additionally, Article XI, Part F(4) indicates that assistance to members provided by the Agency for any project shall not be used in such a way as to further any military purpose and that the project shall be subject to the safeguards.

In its medium-term strategy statement IAEA recognizes the trend in the world towards a greater emphasis on the need for more effective verification of nonproliferation undertakings through strengthened safeguards covering both declared and undeclared nuclear material and activities. In addition, according to the Agency, "there is a prospect of a global ban on the production of fissile material for explosive purposes, which could entail major expansion of the Agency's verification activities" (IAEA 2001). Accordingly, one of the three medium-term substantive objectives of IAEA is to ensure the peaceful use of nuclear material. This implies providing greater assurance that countries are fulfilling their nonproliferation commitments, assisting the international community in nuclear arms control and reduction efforts and improving the security of nuclear material.

A7.3.3. Other Regulatory Arrangements

While the IAEA was beginning to develop its regulatory system, several established regional organizations took the same path. Six western European nations established EURATOM as the nuclear branch of the European Economic Community, and afterwards, the Organization for European Economic Co-operation established the European Nuclear Energy Agency (ENEA). Both bodies set up their own administrative regulations, including safeguards systems. Later, formal relationships related to the safeguards were established between these agencies and the IAEA. For example, a formal agreement between individual countries, EURATOM, and IAEA leads the implementation of safeguards in many countries in Europe.

Two fundamental objectives of the EURATOM Treaty are to ensure the establishment of the basic installations necessary for the development of nuclear energy in the Community, and to ensure that all users in the Community receive a regular and equitable supply of nuclear fuels. Additionally, other treaties of global scope with an objective of disarmament rather than nonproliferation are supporting the regime. As an illustration, the Partial Test Ban Treaty (PTBT), which prohibits open nuclear weapon tests, was implemented in 1963. Also, NPT participants reaffirmed their commitment to prohibit the production of any further fissile material for weapons in 1995, leading to the Comprehensive Test Ban Treaty (CTBT).

A7.4. Current Administration Policy Regarding Nonproliferation Applicable to the Nuclear Fuel Cycle

In a recent speech at the National Defense University, President Bush said, “The 40 nations of the Nuclear Suppliers Group should refuse to sell enrichment and reprocessing equipment and technologies to any state that does not already possess full-scale, functioning enrichment and reprocessing plants. This step will prevent new states from developing the means to produce fissile material for nuclear bombs. Proliferators must not be allowed to cynically manipulate the NPT to acquire the material and infrastructure necessary for manufacturing illegal weapons” (Bush 2004).

A7.5 Conclusion

There is a lack of agreement about whether or not the availability of current reprocessing and enrichment technology under current regulatory mechanisms are increasing nonproliferation risk. Pursuing proliferation-resistant fuel cycle technology will clearly allay these concerns. Also, implementation of the President’s policy of capping the spread of enrichment and reprocessing technology would provide added safeguards to prevent reprocessing or enrichment technology spreading to rogue countries or terrorists.

Resolution of these issues involves broader policy considerations beyond the scope of the present study. The future economic viability of nuclear power, however, does not depend on their resolution. As Appendix A6 shows, however, the difference in the cost of nuclear waste handling, as between once-through disposal and reprocessing, is too small to materially affect the economic viability of nuclear power.

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Appendix A8. HYDROGEN

Summary

Success in the current efforts to make the hydrogen car an economic reality would reduce U.S. dependence on foreign oil and could have potentially large environmental benefits. Intensive R&D efforts are underway to reduce fuel cell costs. Mass production costs need to be reduced on the order of one-half to two-thirds to achieve widespread adoption.

Combining hydrogen with oxygen creates essentially no pollution since the by-product of this type of energy conversion is water. The environmental benefits of hydrogen would however be tempered if fossil fuels with their attendant carbon emissions are used to produce the hydrogen, simply replacing carbon emissions from oil with emissions from fossil power generation or steam methane reforming. Nuclear energy may provide a pollution-free input for production of hydrogen. Hydrogen could be produced using electricity from nuclear power in an electrolysis process, or it could be produced using thermo-chemical processes with nuclear reactors as the energy source. A hydrogen economy accompanied by more stringent efforts to control carbon emissions could greatly expand the demand for nuclear power.

Outline

A8.1. Introduction

If the hydrogen fuel cell vehicle makes a significant market penetration, the demand for hydrogen will increase dramatically, and new sources for its production must be found. One promising possibility would use high-temperature nuclear reactors to provide the heat source for steam methane reforming or thermal cracking. This appendix considers the prospects for a hydrogen economy to provide additional benefits from nuclear power generation. First, the hydrogen fuel cell vehicle (FCV) is considered: the near-term prospects for its market penetration and the demand for hydrogen that would derive from its widespread adoption. Following the consideration of the FCV, the prospects for generation of hydrogen from nuclear power are examined.

A8.2. Hydrogen-Fueled Vehicles

The motivation to reduce air pollution and greenhouse gases caused by vehicle emissions, coupled with the need to reduce dependency on foreign oil, has speeded the race to produce commercially viable vehicles that use gasoline-alternative fuel such as battery hybrid vehicles and fuel cell vehicles. The hydrogen FCV has been given much attention in recent years as an alternative to current gasoline-powered internal combustion engine (ICE) vehicles. The hydrogen FCV fits the category of zero-emission vehicle (ZEV) as its byproduct is water.

A8.2.1. Challenges to the Creation of a Hydrogen Vehicle Fleet

The successful introduction of hydrogen cars requires a hydrogen fuel cell capable of powering an automobile in a manner comparable to the internal combustion engine. On the infrastructure side is the need for a distribution system to deliver the hydrogen fuel to the driving consumer. The rest of this section will be primarily concerned with these two major issues.

A8.2.2. Hydrogen Fuel Cells

A hydrogen fuel cell converts hydrogen and oxygen (or air) into water, producing electricity and heat in the process. As hydrogen flows into the fuel cell on the anode side, a platinum catalyst facilitates the separation of the hydrogen gas into electrons and protons (hydrogen ions). The hydrogen ions pass through a membrane (the center of the fuel cell) which acts as the electrolyte and, with the help of the platinum catalyst, combine with oxygen and electrons on the cathode side, producing water. The hydrogen electrons at the beginning of the anode side which cannot pass through the membrane will flow from the anode to the cathode side through an internal circuit containing a motor or other electric load, which consumes the power generated by the cell.

A8.2.2.1. Comparative Efficiency among the FCV, ICE and EV

A conventional internal combustion vehicle has an energy efficiency of 10 to 15 percent. The hydrogen FCV is around 30 percent efficient. The hydrogen FCV is similar to the battery-operated electric vehicle (EV) in that they both convert chemical energy into electricity and require minimal maintenance. The reactants in a battery are stored internally while the hydrogen fuel is stored externally in an FCV fuel tank. In this way, the hydrogen fuel cell is very much like a battery that can be recharged when drawing power from it, except that instead of recharging using electricity, a fuel cell uses hydrogen and oxygen. A battery EV has only about 26 percent well-to-wheel efficiency, as energy is required for electricity generation and a little energy is consumed in heat while operating the battery (Nice 2003). The hydrogen FCV has the highest efficiency among the three.

A8.2.2.2. The Components of the PEM Fuel Cell

The Polymer Electrolyte Membrane (PEM) fuel cell is one of the five types of fuel cell. It is the fuel cell that is under consideration by automobile manufacturers. The electrolyte in the PEM is a plastic or polymer membrane.

The electrodes separated by the membrane allow the electrochemical reaction to take place. The catalyst is a substance that participates in these reactions by increasing their rate of reaction but is not consumed in the reactions. A catalyst made of platinum works best for both electrodes because it is sufficiently reactive in bonding the hydrogen and oxygen intermediates required to facilitate the electrode processes, and also is capable of effectively releasing the intermediate to form the final product. The platinum catalyst is unique and is a very important part of the PEM fuel cell, but it is very expensive.

A8.2.2.3. Current Models of the FCV

The requirements for producing a FCV include the efficiency of the vehicle, ease of refueling, gas mileage, speed and performance, and design. Several automakers have successfully designed and manufactured a hydrogen FCV which uses hydrogen as its fuel or hybrid FCV which runs on both hydrogen and battery. Honda, General Motors, and Toyota are three of the leaders in the design of FCVs.

The Honda FCX has 80 horsepower and uses 201 ft-lb of torque. It has a maximum speed of 93 mph, a 170-mile range, and accelerates from 0 to 60 mph in 10 seconds. It has 45 percent efficiency and a fuel efficiency of 50 mpg. It weighs 3,713 lbs and is 166” in length, 64.8” in height and 69.3” in width. The FCX electric motor produces an equivalent amount of torque to a Honda V6 engine, and its overall performance is comparable to a Honda Civic. Its 170-mile range is double the range of traditional battery-powered electric vehicles but only half of the range of gasoline cars. The Honda-designed Ultra uses capacitors to store energy generated by the fuel cell, and its regenerative braking provides quick bursts of power during acceleration, providing instantaneous response and higher fuel efficiency (Honda 2002).

The GM Hy-Wire has 80 horsepower with 159 lb-ft of torque, a maximum speed of 96 mph, and a 180-mile range. The absence of booster batteries onboard conserves weight and space and demonstrates that the fuel cell can produce sufficient electricity on demand. GM hopes that between 2010 and 2020 it will become the first company to sell one million fuel-cell vehicles (GM 2002).

The Toyota fuel cell hybrid vehicle (FCHV) has 109 horsepower with 194 lb-ft of torque, a maximum speed of 96 mph, and an 80-mile range. It has undergone 18 months of testing in California and Japan, but there are still many product, operational, and logistical issues to address. Toyota does not expect that commercialized fuel cell-powered vehicles will achieve any great market significance until at least 2010 (Toyota 2002).

A8.2.2.4. Projected Costs of the PEM fuel cell and Hydrogen FCV

Fuel cell cost estimates vary and are difficult to interpret. Several estimates are reported in this section. Ogden (2002, p. 70) indicates that the cost of fuel cell stacks must be reduced to the neighborhood of $50 to $100 per kW as compared to the current $1,500 per kW for the hydrogen FCV to be economically viable.

A report conducted by TIAX in May 2003 for a Hydrogen and Fuel Cells Merit Review Meeting estimates that the cost of a 50 kW fuel cell system based on 2001 near-term technology and a production rate at a high volume of 500,000 units per year was $324 per kW, where 67 percent of that cost was for the fuel cell, 24 percent for the fuel processor, 6 percent for the assembly and indirect, and 3 percent for balance-of-plant.

A hydrogen fuel cell with fuel processor converts other hydrogen carriers such as methanol or various hydrocarbons into hydrogen. According to A.D. Little (2001), a 50 kW fuel cell fuel processor system is estimated to cost $14,700, of which 60 percent goes to producing the fuel cell, 29 percent to the fuel processor, 8 percent to assembly and indirect costs and 3 percent to the balance of plant. This makes the cost of the fuel cell $8,820 or $176 per kW as compared to $8,850 or $177 per kW in a non-fuel processor system fuel cell that does not convert hydrogen carriers into hydrogen.

In a report on the comparative assessment of fuel cell cars produced by MIT's Laboratory for Energy and the Environment (LFEE), the cost for hydrogen and gasoline-fuel cell hybrids is projected to be $22,140 to $23,400, or 23 to 30 percent higher than the 2020 baseline vehicle costs of $18,000 (Weiss et al. 2003). Analysis by A.D. Little (2001) concurs that even with optimistic assumptions about performance and cost, factory costs would likely be 40 to 60 percent higher than for ICE vehicles. Moreover, ownership cost would be $1,200 to $1,800 higher than for conventional ICE vehicles (Weiss et al. 2003, p. 7). The existing FCV models are currently too expensive to put on the market; for instance, the Honda FCX costs $2 million, or $100,000 if mass produced. The General Motors Hy-Wire costs

$5 to $10 million, or $65,000 if mass produced (Marcus 2003), while the Toyota FCHV is selling for $1 million in Japan, or leasing for around $10,700 per month (FuelCells.org, 2003).

Table A8-1 reports current costs for three prominent hydrogen vehicles, and in two of the cases, the estimated cost if mass produced. Intensive R & D efforts are underway and will need to reduce mass production costs on the order of one-half to two-thirds to achieve widespread adoption.

Table A8-1: Current Costs of Honda, Toyota, and General Motors Fuel Cell Vehicles, 2003 Prices

Model	Single Production Cost	Mass Production Cost
Honda FCV	$2,000,000	$100,000
Toyota FCHV	$1,000,000	Not reported
General Motors Hy-Wire	$5,000,000	$65,000

Sources: BBC (2003), BW (2002), Edmunds (2003).

A learning-curve model developed to analyze the mass production cost structure of PEM fuel cells indicates that significant reductions in membrane, electrode, and bipolar plate costs could be achieved if mass production were to begin soon (Tsuchiya and Kobayashi 2003, p. 2). This could result in total fuel cell costs falling by half ($886 per kW) in the next 3 years to a level competitive with an internal combustion engine ($38 per kW) by 2020 (Tsuchiya and Kobayashi 2003, p. 5).

A8.2.2.5. Efforts to Commercialize the Hydrogen FCV

Efforts are ongoing to accelerate the commercialization of hydrogen FCVs. However, economies of scale, costs of parts, and production logistics remain uncertain.

A8.2.2.5.1. Funding and Research

President Bush announced in his 2003 State of Union Address that $1.2 billion would be allocated to research for the United States to develop clean, hydrogen-powered automobiles (U.S. Department of State 2003). $136 million ($96 million from the government and $40 million from applicant cost sharing) has been allocated to 24 firms and educational institutions for research in advanced fuel cell technology for vehicles, buildings, and other appliances, and in hydrogen technology (DOE 2003). The fuel cell research will focus on overcoming technological barriers to commercialization, including durability, high costs, heat utilization, and catalyst development.

The high cost of platinum used in the catalyst for hydrogen fuel cells is a clear hindrance to producing commercially viable vehicles. One way to lower platinum catalyst levels is to construct the catalyst layer with the highest possible surface area. The Los Alamos National Laboratory (LANL) has developed a fabrication process for fuel cell membrane electrode assemblies with reduced platinum loading that decreases the cost of the catalyst by 90 percent (LANL 2000).

Danish Power Systems has developed a PEM fuel cell stack system that meets automaker requirements for an operating temperature that runs at up to 200 degrees C and is easier to cool than the low-operating ones that run below 100 degrees C. The membrane of each PEM fuel cell is made of PBI, a thermally high resistant material that possesses unique properties that increase efficiency and costs less than the traditional Nafion (Bjerrum 2003).

Hydrogen technology research is also heavily funded to overcome the technical barriers of storage capacity and cost, along with improving life cycle cost and energy efficiency and improving methods of hydrogen production (Rose 2003a). For example, DOE has funded projects to develop methods to safely store hydrogen to enable at least a 300-mile vehicle range, which it considers a critical requirement for successful vehicle commercialization.

A8.2.2.5.2. Federal FCV Pilot Study

The federal government is currently involved in a ten-year program to help facilitate the commercialization of fuel cell technology (Rose 2003b). It has been proposed that the Secretary of Energy lead a cooperative effort among federal agency fleet operators and private-sector FCV companies in a cost-shared program to purchase, operate and evaluate FCVs in integrated service for federal fleets to demonstrate their commercial viability in a range of climates, duty cycles, and operating environments.

This $495 million program includes two phases to reach the goals of this pilot-fleet demonstration. Phase I runs from 2004-2007, and includes the purchase of 500 passenger vehicles, 500 Department of Defense (DOD) vehicles, 100 transit buses, 100 school buses and 20 fueling stations, demonstrating a range of fuels and fueling strategies. Phase II runs from 2008 to 2011, when the federal government would meet 50 percent of its civilian vehicle fleet needs with fuel cell vehicles, or purchase 5,000 passenger vehicles annually. During this phase, the DOD and the Cabinet secretaries would set their own targets on the number of military vehicles or mobile equipment and specialty vehicles needed.

A8.2.2.5.3. Proposed Tax Incentives

The Breakthrough Technologies Institute, Inc. recently published a report that included a FCV ten-year market entry support plan (Rose 2003b). The report recommended a short-term consumer-based tax incentive that would reduce the incremental cost for early adopters and help the FCV industry build production capacities to reach economies of scale. It suggested that Congress continue the existing $4,000 tax credit system for qualifying fuel FCVs.

In addition, the report proposed that Congress enact a tax credit for the installation of fuel-cell re-fuelling infrastructure that is accessible to the public. These re-fuelling programs would also include a direct tax credit of 50 percent of the cost of the station up to $150,000. The report also proposed that fuel for FCVs be offered a $.30 per gasoline-of-gallon-equivalent tax credit in 2003, $.40 per gallon in 2004 and $.50 per gallon from 2005 to 2012.

A8.2.3. Hydrogen Fuel Distribution Infrastructure

A major challenge to the viability of the hydrogen economy is the necessity of a hydrogen fuel distribution infrastructure. Three restrictions describe its current state: consumers will not purchase FCVs without adequate fueling stations, manufacturers will not produce vehicles without real demand, and fuel providers will not build fueling stations without vehicles to fuel. To overcome what has been characterized as a chicken-or-egg problem, Ogden (1999, p. 268) suggests that distributors initially piggyback on existing energy infrastructure, e.g. building production facilities at fueling stations, thereby avoiding the need to build an extensive pipeline system. Alternatively, Melaina (2003, p. 753) suggests a phased approach beginning with building small capacity fueling stations that only store hydrogen, until greater demand is built, a strategy endorsed by NRC (2004, pp 2-9 to 2-10). Either way, the development of a distribution infrastructure that will support cost-effective refueling will be an investment challenge, probably more for fuel suppliers than for vehicle suppliers. The fact that the two are distinct businesses may complicate the challenge.

A8.2.4. Viewpoints on the Prospects of the Hydrogen FCV

Current views on the development of hydrogen FCVs vary greatly. On one hand, environmentalists seem to welcome the possibility of a clean fuel, automakers appear to view this as a niche market with gains to be made, and the government seeks to reduce foreign oil dependence. The Allied Business Intelligence group (ABI) forecasts that the global fuel cell vehicle market will number 800,000 by 2012 (Wengraff 2003). Other groups, however, believe research in hydrogen power is a political effort to allow fossil fuel dependent companies to sustain their markets. It is claimed that funding some research now provides the appearance of a change in the energy industry while extending the time that the country will be fossil-fuel dependent. In between are those who suggest that comparing hydrogen energy, given its current economic and scientific uncertainties, with other alternatives does not give a clear answer about the promise of hydrogen.

Support from the government has come in the form of DOE’s FY2004 budget proposal for a $123 million increase in federal research support. David Cole, director of the Center for Automotive Research suggests that, “…there is a very high rate of improvement in technology and with strong leadership, maybe, just maybe they can do it” (Flint 2003). A poll sponsored by Millennium Cell, Inc. and US Borax, Inc. in April 2003 that surveyed 1,006 Americans age 18 or older found 85 percent of Americans willing to try hydrogen-fueled vehicles, while only 12 percent expressed an unwillingness to try the vehicles (EERE 2003).

At the other end of the spectrum, the National Hydrogen Energy Roadmap and other sources suggest that the Bush administration has been working to ensure that hydrogen production will remain fossil fuel-dependent and dirty, as 90 percent of all hydrogen would be refined from oil, coal and natural gas while the remaining 10 percent will be cracked from water using nuclear energy. The process of producing the fuel cells from hydrocarbons will continue America's dependence on fossil fuels and still emit carbon dioxide, the primary cause of global warming (CNN 2003; Lynn 2003; ITS 2002; Kolber 2003; Hunt 2002).

In between are those who think that given the major scientific and economic improvements necessary to be successful, funds could be better used to focus on more viable options (Popely 2001; Tromp et al. 2003). David Cole warns that fuel cells may not ultimately be the solution to reducing fossil-fuel dependence, since hybrid electric vehicles, diesels, or a new technology could prove more cost-effective (Flint 2003). The Natural Resources Defense Council contends that funding of the hydrogen car cuts the budget for other federal research into clean energy by $47 million (Rosenbaum 2003).

A8.3. Considerations for Large-Scale Hydrogen Production

Should natural gas prices rise, electrolysis of water may become the primary hydrogen production method to meet the needs of a growing FCV market. Kruger's (2000) analysis of electric power requirements suggests that by 2010, 165 GW of additional capacity would be needed to meet increased hydrogen demand from the use of 20,000 fuel cell vehicles, beyond the requirements to meet other sources of demand growth. This would amount to a 20 percent increase over current capacity.

While renewable energy sources can be used to produce hydrogen, those fail to meet the scale demanded by industry: using wind power would require as many as 640,000 windmills occupying 71,000 square miles (about the size of Indiana and Ohio); power generation using biomass would require four times as much plant material as U.S. farmers currently grow; the solar option would require $4.8 trillion worth of solar panels and equipment occupying 3,000 square miles (NEI 2003). Reducing these estimates by one-half would not materially relax the limitations to renewables supplying hydrogen at an industrial scale.

Sufficient domestic coal exists to fire electrical plants to provide both the electricity and the hydrogen needed for several hundred years. Building new power plants required to meet this demand would be a large—but not infeasible—task, but coal-fired power plants generate carbon dioxide and other emissions. Without expensive emission control methods, coal plants would simply discharge these substances into the atmosphere at a different location from automobiles, increasing carbon emissions on balance. Such a strategy would do little to combat pollution and global warming or harness the environmental benefits of hydrogen. Production of hydrogen using steam methane reforming is capable of reducing carbon emissions on balance, but only modestly. Substituting hydrogen for gasoline in vehicular transportation would reduce carbon emissions from the gasoline but would involve carbon emissions from the production of the hydrogen. When the reductions in vehicle emissions from substituting hydrogen for gasoline are balanced against the increases in emissions from the gas-steam methane reforming (SMR) units producing the hydrogen, the substitution would reduce about 18 percent of the carbon emitted per gallon of gasoline, based on calculations with information from Honda (2003), EPA (2003), and ORNL (2003).

Nuclear power plants, on the other hand, can generate the heat necessary to produce hydrogen through a variety of alternative processes. Nuclear power produces no greenhouse gases. Nuclear energy is the only energy source that produces no air emissions but still has enough production potential to generate the required quantities of hydrogen.

A8.4. Hydrogen Production Techniques

Several methods exist for producing hydrogen, all of which involve extracting pure hydrogen gas from hydrogen-containing compounds. This section considers how these techniques can be used in conjunction with the outputs of nuclear energy—electricity and heat—to economically create hydrogen.

Presently hydrogen is manufactured almost exclusively by steam methane reforming, which uses methane as a feedstock. Steam methane reforming uses heat, but it releases carbon dioxide as a by-product. Carbon-free methods can extract hydrogen from water using energy by electrolysis and thermo-chemical cycles (Forsberg 2003, p. 1075). Electrolysis techniques are commercially available but are used only at small scales currently, and they use electricity rather than heat. The thermo-chemical cycles could be powered by advanced nuclear reactors.

A8.4.1. Steam Methane Reforming

Steam methane reforming is a two-step process that results in the production of carbon dioxide and hydrogen. In the conventional process, natural gas is simultaneously used as a source of hydrogen and is burned to produce heat to drive the reaction at a temperature of 800 to 900ºC. It remains the most economical method of producing hydrogen. Typical thermal efficiencies for steam reforming processes are about 70 percent. However, as has been noted, this process merely relocates where carbon dioxide is emitted rather than contributing to greenhouse gas reductions. Molburg and Doctor (2003) report on a simulation of hydrogen production via a steam methane reforming process, without and with carbon sequestration. At a methane price of $2.85 per MMBtu, the process could produce hydrogen at a cost of $0.83 per kg while releasing 1,366 tons of CO_2 per day. Capturing CO_2 would increase the cost by 35 percent, to $1.12 per kg.

It is possible that the amount of natural gas required for the process can be greatly reduced by utilizing the heat from nuclear reactors. The necessity to transport heat has resulted in a number of problems such as diffusion of product and the creation of impurities. The Japan Atomic Energy Research Institute (JAERI) is leading the current research on steam reforming in combination with a nuclear reactor. The institute has developed a heat exchanger type of nuclear reactor for the reforming process that has minimized many of the operational issues. Since this uses standard hydrogen production technology it represents the only near-term nuclear-hydrogen technology (Forsberg 2003, p. 1075).

A8.4.2. Electrolysis

Electrolysis, while a mature technology, has been used historically to produce pure hydrogen only in small quantities. Electrolysis is essentially the splitting of water molecules by electricity. Electrodes, a cathode and an anode, placed in an alkaline solution drive the movement of electrons. Hydrogen forms at the cathode and oxygen at the anode.

While current electrolyzers have efficiencies approaching 85 percent or better, electrolysis is not competitive for large-scale production of hydrogen, given its capital cost and electricity consumption. Current capital costs are estimated to be near $600 per kW (Forsberg 2003, p. 1075). Average electricity consumption is 4.5 kWh per cubic metres of hydrogen, (Kruger 2000, p. 128).

A possibility for improving the economic conditions for electrolysis would be for electricity generators and hydrogen production facilities to agree to use off-peak electricity for the electrolysis production (Crosbie and Chapin 2003, p. 3). Several studies have shown that when electricity is cheap enough, for example at off-peak rates of $2 to $3 per megawatt-hour, hydrogen might be produced at a price competitive with the price of gasoline or diesel fuel. NRC (2004, p. 5-16) concludes that electricity prices will be critical to the use of electrolysis for hydrogen production.

A8.4.3. Thermo-Chemical Cycles

Thermo-chemical cycle water-splitting processes offer the potential for making hydrogen at temperatures in the range of 700 to 900ºC. This process is considered to be the leading long-term option for hydrogen production (Crosbie and Chapin 2003, p. 9). The basic cycle involves the thermal decomposition of water into hydrogen and oxygen using an ionic solution to mediate the reaction.

The most promising of these cycles are the calcium-bromine process and the sulfur-iodine process. Currently, neither of these thermo-chemical processes has progressed to the point of commercial viability, perhaps partly because there has not been the economic incentive to do so. Recently, however, interest in environmental benefits and energy independence has increased attention to these methods. Recent estimates indicate that thermo-chemical production costs could be 60 percent of current electrolysis costs using nuclear reactors dedicated to hydrogen production (Forsberg 2003, p. 1075).

Thermo-chemical processes would be conducted from nuclear reactors dedicated to hydrogen production. The greater proportion of the heat generated by the reactor would be used for the hydrogen production, but the waste heat could be used to power a steam turbine which would generate electricity that could be sold outside the hydrogen production facility.

In this production process, the ability to sell electricity from a hydrogen facility would reduce the cost of hydrogen production.

A8.5. Conclusion

Extensive market penetration of the fuel cell vehicle would greatly increase the demand for hydrogen. Current costs of those vehicles, however, are not competitive with ICE vehicles, particularly because of the materials used in the fuel cell membrane. Companies and government agencies are funding research and investment to reduce these costs. Near-term prospects for market penetration remain difficult to assess.

Should the demand for hydrogen burgeon with new demands from the transportation sector, there are a number of process options for producing large amounts of hydrogen for a future hydrogen economy. The maturity of these various techniques differs, with some of the most efficient and useful processes still working their way through development. Nuclear power, because of its zero air emissions, offers potential synergies and cost efficiencies for the production of hydrogen.

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Appendix A9. ENERGY SECURITY

Summary

Nuclear power could provide energy security benefits as a potential source of hydrogen to replace oil in the transportation sector and more generally as a substitute for gas-generated electricity.

Energy security has been discussed primarily in connection with oil and the political instability of the Middle East. A direct link to electricity is limited by the small amount of electricity produced using oil. One way by which nuclear electricity generation could be related to oil security is via cogeneration of hydrogen for widespread use in transportation. If cogeneration with nuclear power is the least expensive source of hydrogen, it would contribute to speeding the adoption of hydrogen vehicles, reducing dependence on oil.

Currently the United States imports about 4 percent of its natural gas in the form of LNG, but this percentage could grow if substantial new capacity is devoted to gas-fired production and if North American gas production expands only very sluggishly. As international trade in LNG becomes more extensive and the United States participates in it more deeply, this energy security linkage could become more important.

The effect of foreign dependence on gas is influenced by differences between world oil and gas markets. The world natural gas market is less unified than the world oil market. Price increases in one part of the world are not as quickly and completely transferred to other countries as with oil, as shown by analysis of natural gas prices for over thirty countries. Results show high correlations of gas price movements within Europe, but low correlations between European countries and non-European countries. Canadian, Mexican and U.S. gas prices are highly correlated with one another, but none of these North American countries' prices is highly correlated with either European or Asian prices. Gas prices in Taiwan and Japan, both of which import considerable amounts of LNG from Indonesia and Malaysia, are highly correlated, as would be expected in that regional market. However, their gas prices were essentially uncorrelated with gas prices in North America or Europe.

This balkanization of natural gas prices around the world suggests that while countries may be subject to economic repercussions from gas supply shocks in their own regions, they tend to be insulated from supply shocks in other regions.

Gas does not pose as great an energy security threat as oil, but, still, nuclear power generation capacity could become a significant defense against regional gas supply interruptions. Interruptions could extend increasingly to offshore sources, given the likelihood of only limited additional imports from Canada and Mexico.

Projections of gas prices are reported in Chapter 7. Recent projections from a number of models have forecast gas prices in 2020 to be slightly below their levels in 2000, in constant dollars. However, in the recent period of gas price volatility and uncertainty about

supplies, EIA revised its 2020 forecast, published in the *Annual Energy Outlook 2004* (AEO 2004), upward by 15 percent, to be 11 percent higher than in 2000 and 20 percent above prices in 2005. The current EIA forecast predicts the average wellhead price for the lower 48 states to vary from $3.62 per MMBtu in 2005 to $4.51 per MMBtu by 2025 (in 2003 dollars).

Given a national interest in encouraging greater reliance on nuclear power (see NEPDG 2001, pp. 5-15—5-17; Abraham 2004; DOE and Nuclear Power Industry 2004, Foreword; Bush 2004), the question arises: What are the criteria for deciding what proportion of new baseload capacity should be devoted to nuclear power? The answer to this question depends partly on the variety of 21st century uncertainties that the nation needs to be prepared for. Uncertainties affecting demands for nuclear power include foreign policy, the environment, natural gas and other significant events. As only one example, a probability exists that environmental events will substantially increase the cost of producing electricity with gas and coal relative to the cost of nuclear generation, increasing the demand for nuclear generation. Maintaining some nuclear capacity now could avoid the costly and lengthy adjustment costs of gearing up a nuclear industry that might otherwise be in a run-down condition. To do so could be a prudent procedure as part of making optimal decisions in the face of an uncertain future. A decision model is developed that compares the costs of being prepared for such events with the expected benefits if the risk materializes. Using this model, the study develops a numerical example of the amount of new capacity to devote to fossil and nuclear electrical generation. In this example, 25 percent of new capacity would be nuclear. Further research along these lines could greatly aid future decisions.

Outline

A9.1. Introduction: What Energy Security Is

Energy security is to be distinguished from national security in the military sense although sufficiently dire scenarios could envision supply reductions severe enough to compromise military capabilities. Of more immediate concern is the possibility that sharp, short-lived events affecting energy could damage the economy. This has been the experience of the United States and the rest of the world since the 1970s, and even earlier, in the face of unexpected oil supply interruptions and consequent price shocks.

This appendix addresses the potential for nuclear power to lessen energy security vulnerabilities. The next section examines the energy security issues involved in the oil market. Section A9.3 considers the routes by which nuclear power could contribute to enhanced energy security. Natural gas used for electricity generation provides a possible link between nuclear power and energy security. Section A9.4 examines the natural gas market for characteristics that could make gas an energy security risk.

A9.2. Oil and Energy Security

Section A9.2.1 describes the recent oil price shocks, Section A9.2.2 characterizes the significance of the unity of the world oil market, and Section A9.2.3 notes the importance of the geographic concentration of world oil reserves.

A9.2.1. The Track Record with Oil

The recent history of the world oil market is one of recurrent shocks. Fringe suppliers have responded to the price increases but with lags of up to several years. Real oil prices have come back down in each case, to pre-OPEC levels, dramatically in the 1985 price collapse. After a few years, it seems as though the world's expectations have adjusted to think that oil can no longer be an economic threat, and the cycle repeats itself. Economic damages result from the price shocks.

The oil price shocks of 1973 to 1974, 1979 to 1980, and 1990 to 1991 were contributors to the ensuing recessions. In each case, a shock to supply resulted in a sharp price rise—an unprecedented price rise in the first of these three episodes. The 1973 to 1974 episode was the result of deliberate output restriction by the Organization of Petroleum Exporting Countries (OPEC). Much of the world had considerable difficulty in distinguishing what turned out to be a temporary rise in the oil price from a transition to permanently higher prices of all energy, and it took several years for the world economy to recognize the transience of the price regime. Research on a myriad of energy-using and –producing technologies began in the mid-1970s, and the price levels, and their expected lengthy duration prompted equally enthusiastic oil exploration. Both endeavors were largely successful, and prices had begun to come down just as the second great price shock occurred.

The 1979 to 1980 events began with supply interruptions from Iran during the Khomeini revolution and were supplemented with further interruptions when Iraq took the opportunity to attack Iran in 1980. Both events fortuitously interrupted oil production and shipments from both Iran and Iraq, and the slack was not picked up by the OPEC swing producer, Saudi Arabia. Both the Iranian Revolution and the beginning of the Iran-Iraq War took the world by surprise, and the political and military consequences were uncertain for well over a year. By 1982, the United States was well into recession. The political uncertainties of the Persian Gulf disturbances were resolved over the next few years, and the energy R&D and oil exploration sparked by the OPEC embargo's price shock reached fruition. By 1985, the world supplies of oil had greatly increased, and at the same time oil intensities of all types of industrial production had begun to fall significantly. The result was the 1985 oil price collapse.

Iraq's invasion of Kuwait in August 1990 cut off Kuwaiti oil supplies, and for over two months the integrity of Saudi supplies was in question. After some negotiation, Saudi Arabia compensated for much of the lost production, but Iraq's military action had caught the world by surprise and the military uncertainty lasted until the allied invasion began in mid-January 1991. Prices rose by 50 percent overnight and remained near that level until the beginning of the allied attack. The economic uncertainties of the situation were resolved rapidly, but the United States, which had been on the brink of recession prior to August 1990, fell into a full-scale recession with the push from the oil price shock.

OPEC has demonstrated some cartel power in recent years, but it has been tempered by the reserve army of fringe producers that has emerged as a consequence of the earlier oil price shocks. While Saudi Arabia remains the swing producer—the cartel leader—its price power appears to be weaker, although a few random events around the world could put it back in the driver's seat for a time.

Oil has clearly been an economic problem. Hamilton (1983) presented evidence that the post-1973 relationship between oil prices and U.S. recessions went back to the late 1940s. Despite occasional suggestions that these oil price shocks were only fortuitously associated with the ensuing recessions, the preponderance of the evidence indicates that the oil supply shocks have indeed had major recessionary impacts (Jones et al. 2004).

A9.2.2. A Unified World Oil Market

While the dynamics of oil prices, with its storability, are interesting, it is sufficient for present purposes to emphasize the relative unity of the world oil market. Oil can be shifted around the world at relatively low cost by tankers and low-pressure pipelines in response to relatively small differentials in price. Price differentials will always exist according to the physical qualities of oil and the expense of refining them at particular facilities, but changes in the price of one grade of oil in one location in the world are invariably followed closely by nearly parallel changes in the prices of all other grades of oil all over the world.

The unity of the world oil market leaves all countries facing similar price movements when a sizeable supply shock emerges in any part of the world. This is an important characteristic of the economics of oil. A corollary to this consequence of a unified world oil market is that if a single country were to substitute entirely away from oil, its economy could still be vulnerable to a world downturn caused by an oil price shock to countries still using oil. This latter consequence is a more remote event than the inexorability of oil price changes occurring relatively uniformly worldwide, but it remains a consideration in the effectiveness of longer-term energy strategies.

A9.2.3. Concentration of Oil Reserves

As is well known, world oil reserves are extremely heavily concentrated in a relatively small region of the world—the Persian Gulf. Despite discoveries in the North Sea and across Central Asia, an estimated 60 to 75 percent of known reserves remain in a few countries surrounding the Persian Gulf, although current production is somewhat less concentrated. This concentration of reserves, and their ownership by those countries' governments, gives considerable market power to those countries.

In addition to the physical concentration of oil reserves in a small number of countries, the political instability of the region adds an additional element of unpredictability to supplies and prices. The Iranian Revolution did not intentionally take Iran's oil production off line, but that occurred as a concomitant to the temporary disorder. The prospect of political turmoil elsewhere in the region cannot be fully discounted. Temporary disruptions to its oil fields would represent a major reduction in world supplies that could not be made up quickly by increased production in other regions.

Both characteristics—geographical concentration and concentration in an unstable region—contribute to the volatility of the world oil market.

A9.2.4. Oil Price Shocks and Gas-Fired Electricity Generation

To date, energy security issues for the United States have involved oil. Very little oil is used in the generation of electricity in the United States. Among industrial countries, only Italy continues to have a substantial fraction of its generation capacity in oil-fired units. Oil is used primarily in the transportation sector, which also uses very little electricity. In view of the tenuous linkage between electricity and oil, does nuclear power have a role in energy security? One possible link is the use of natural gas in electricity.

A link between oil and electricity through the use of natural gas in electricity generation would be a near-term link, one that could operate presently. Oil and natural gas are substitutes in some industrial uses, so an oil price shock could raise natural gas prices facing electric utilities as well as industrial gas consumers. That would raise electricity prices. The substitutability between coal and oil is currently lower than that between oil and gas because of less extensively overlapping uses.

The extent of actual substitutions between oil and gas in industrial uses, which would be the driver of cost increases for gas-fired electricity generation, would probably depend on the character of the oil price increase. A short, sharp price shock such as the industrial world has experienced several times since the early 1970s, could fail to motivate industrial oil consumers to switch to gas if the oil price is expected to fall rapidly and the switch-over costs were high relative to the cost of curtailing production for an expected short period. Nonetheless, a two- or three-year-long period of elevated oil prices would see natural gas prices rise in response, to keep their prices per MMBtu roughly equal. A longer-term, probably slower, oil price increase such as would be associated with dwindling worldwide reserves rather than a cartel action, would certainly be matched with parallel gas price increases.

A9.3. The Present and Future of Natural Gas

The potential link between natural gas and nuclear power requires an examination of the place of natural gas in the U.S. energy system, both currently and prospectively. The two most critical questions are (1) is the United States rapidly depleting North American gas reserves, permanently driving up the price of natural gas? and (2) could the United States be subject to a natural gas price shock, comparable to an oil price shock, from an overseas supply disruption, whether or not it becomes dependent on imports? This section considers the present situation to set the stage to address these two questions.

A9.3.1. The Recent Price Increases and Forecasts for the Future

In recent years, the spot price for natural gas has displayed volatility and become increasingly unpredictable. As more gas powered electric plants have come online, the historical difference between winter and summer gas demand has diminished. EIA has had to readjust its price forecasts repeatedly due to the changes in the natural gas market. According to a Deutsche Bank report, EIA's long-term gas price forecasts have been off by an average of $1.20 per MMBtu over the last 15 years, while the 3-year forecast has been off by $0.70 per MMBtu (Smith and Hove 2003, p. 10). Table A9-1 shows the current EIA forecast predicting the average wellhead price for the lower 48 states to vary from $3.62 per MMBtu in 2005 to $4.51 per MMBtu by 2025 (in 2003 dollars).

Table A9-1: Natural Gas Prices, Recent and Forecasts, $ per MMBtu, in 2003 Prices

EIA Price Forecast	2000	2001	2005	2010	2015	2020	2025
Average Wellhead Price	3.92	4.24	3.62	3.48	4.29	4.38	4.51
Average Import Price	4.14	4.59	3.76	3.87	4.69	4.69	4.77
Average Price	4.03	4.30	3.65	3.57	4.39	4.45	4.57

Source: EIA (2004).

A9.3.2. U.S. Natural Gas Consumption and Longer-Term Gas Supplies in the Continental United States and Canada

The United States relies primarily on domestic natural supplies. Domestic sources accounted for 84 percent of the 22.5 trillion cubic feet of total consumption in 2002. About 94 percent of U.S. natural gas imports are from Canada (EIA 2003a). Most of the imports, approximately 94 percent of them in 2002, come from Canada through the pipelines that integrate the North American system. Net imports from Canada equaled 3.46 tcf, and this level is expected to increase at an annual rate of 2.3 percent to a level of 5.51 tcf per year in 2020 (EIA 2003). Other than Mexico, which has traditionally accounted for only a small fraction of imports, the alternative source of natural gas is the more expensive liquefied natural gas (LNG), available from overseas producers. LNG options are discussed further below.

The natural gas reserve situation for the United States is considered bleak by some observers, with approximately 8.5 years of proven reserves (Simmons 2003). Some of the locations with known reserves are off-limits to drilling currently. Nonetheless, others observe that the United States has had about 8 years of proven natural gas reserves for half a century (Fisher 1994). The United States resembles Canada in that both countries are among the top producers of natural gas, but do not figure among the list of countries with largest reserves.

There is no consensus on the volume of natural gas that is available for production. The total endowment of technically recoverable gas resources is the sum of proven reserves, undiscovered conventional field resources, and potential reserves from continuous accumulations. Continuous accumulations are the deposits such as tight sands gas, coal-bed methane, and shale. The most recent full survey by the U.S. Geological Survey (USGS) in 1994 indicated that the total U.S. gas endowment was 2,230 tcf. However, over the past three decades each estimate by USGS has been somewhat different, which may indicate influence of better technology in all areas of exploration. To better account for changing technology as well as trends in exploration, USGS has recommended using reserve growth as a more accurate measure of gas availability (Schmoker and Dyman 2001a, p. 1).

An estimated 40 percent of undiscovered natural gas exists on federal land. In several areas, the government has restricted access to federal lands. Outside of the western Gulf of Mexico, production companies are prohibited access to virtually all federal lands offshore the lower 48 states. About 9 percent of resource-bearing land in the Rockies is also off limits, and access to another 32 percent is significantly restricted. The National Petroleum Council (NPC) in 1999 estimated that 213 tcf of natural gas exists in areas under federal access restrictions (NPC 1999, p.42). Recently NPC updated its estimate to 204 tcf of restricted natural gas (NPC 2003, p.35), suggesting some stability in that estimate.

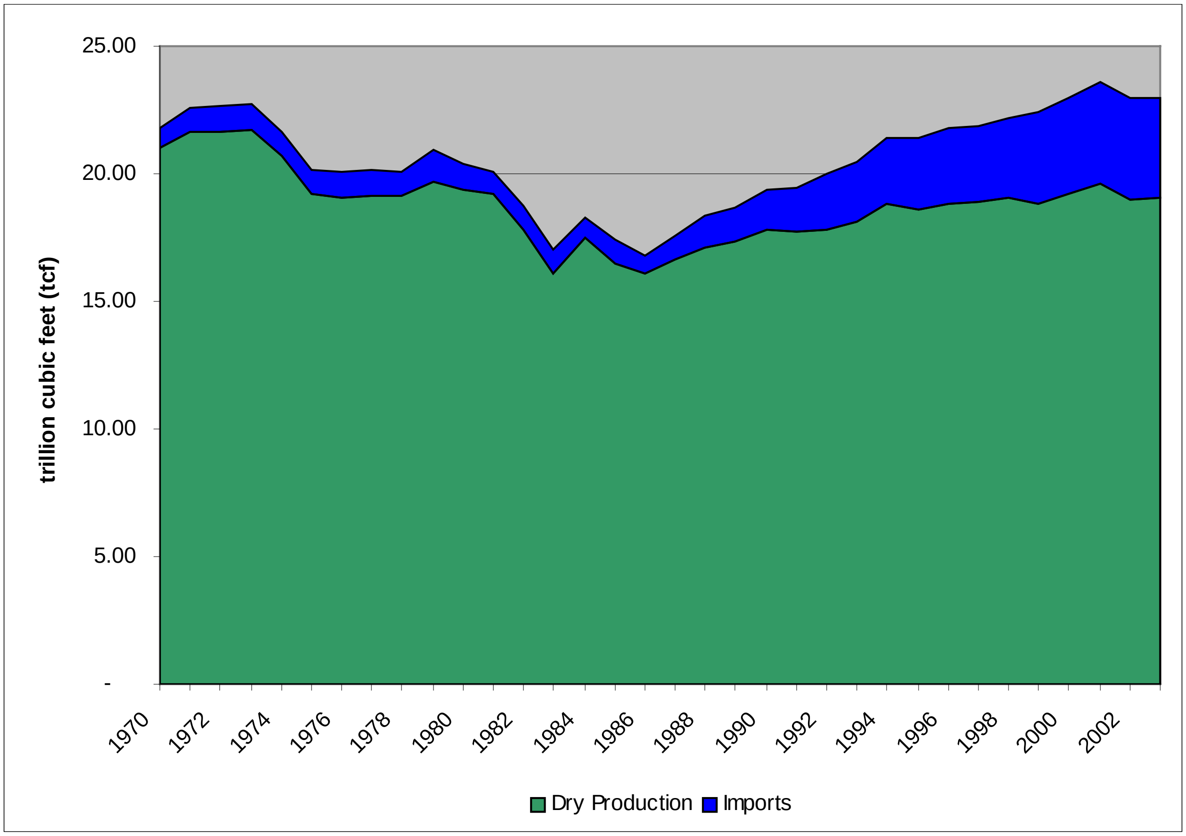
Canadian reserves amount to approximately 60 tcf, according to the Canadian National Energy Board (ERB 2001). Since Canada draws down its reserves at a rate of 21 bcf per day, it would exhaust its currently known reserves in approximately 8 years, although this calculation does not allow for new discoveries or an acceleration of the exploration rate. Some observers believe that Canada would be hard pressed to find new reserves if consumption of gas increased dramatically. Canadian companies would need to find an alternative to the Western Canada Sedimentary Basin, which currently accounts for 95 percent of the Canadian reserves and is considered one of the most productive in North America.

Opinions exist in the gas industry that recent technological advances in exploration and drilling will revitalize the discovery of new reserves, particularly in previously little explored areas. Fisher (1994) discussed how technological improvements have continually overridden estimates of reserves, and technology has continued to advance in the decade since his article was written. An assessment that the continental United States and Canada will be largely depleted of their natural gas resources in the next decade may be an overstatement.

A9.3.3. Gas Imports—LNG

Worldwide reserves of natural gas continue to be immense and relatively untapped. For gas fields that are remote from their ultimate consumers, long haul pipeline transportation is prohibitively expensive. Alternatively, the market flexibility offered by LNG represents a new opportunity to increase supply. Growth in LNG trade has been substantial since the early 1990s in response to increased world gas demand and reduction in production costs. Imports of LNG by the United States make up a small percentage of the total supply of natural gas. Figure A9-1 shows the history of U.S. natural gas consumption and imports.

Figure A9-1: U.S. Natural Gas Production and Imports, 1970-2003



Sources: EIA (2002, 2004b, 2004c).

The LNG market is considerably larger in Asia than in North America. Natural gas consumed in Japan, Korea, and Taiwan is virtually all imported LNG. Until the recent upswing of LNG activity in the Atlantic Basin, six Japanese utilities alone accounted for almost 40 percent of the world's LNG trade (Jensen 2003, p. 12). While the United States has imported only small volumes of LNG, it gets a majority of what it does import from Trinidad and Tobago, Qatar, and Algeria, but also receives shipments from Nigeria, Oman, Australia, Indonesia, and the United Arab Emirates. According to EIA (2003a), the United States imported 0.16 tcf of natural gas in the form of LNG in 2000. EIA forecasts LNG imports to increase at an average annual rate of 8.6 percent, to levels of 0.83 tcf of natural gas by 2020, provided that the necessary infrastructure is in place.

Prices for LNG tend to be higher than for non-liquified gas, the difference arising from the more expensive maritime transportation and the liquefaction and regasification processes needed to ship the gas. If the recent price trend of natural gas continues and prices remain consistently above $3 per mcf in 2003 prices, LNG may become an increasingly profitable alternative. However, the recent gas price spikes have been attributed partly to stressed transmission and storage infrastructure, and partly to extreme weather. In the long run, the infrastructure issues will be worked out, even if the details cannot be foreseen precisely at present. Additionally, a rule of thumb in the gas business is that over the longer term, the natural gas price will be equivalent in MMBtu terms to the price of oil, so forecasts for continuing gas price increases that take no account of real oil prices may be inadequate.

Until the past few years, almost all LNG trade took place under committed long-term contracts, but recently short-term contracts—but not quite a spot market—have become more common—rising from 1.5 percent of all LNG transaction in 1997 to 7.8 percent in 2001 (Jensen, 2003, p. 8). With the large capital investments required in LNG liquefaction, transportation, and regasification, investors have been reluctant to build LNG facilities without long-term contracts, typically as long as 20 years. It is not clear that this linkage between long-term contracts and capital investment in LNG will change significantly in the future.

The United States presently has four LNG terminals, only two of which are currently open. Numerous sites have been suggested for additional terminals, but most have encountered environmental problems in siting. Significant expansion of LNG imports would require new terminals.

A9.3.4. Vulnerability of Gas to Price Shocks

Weather anomalies are a primary source of natural gas demand shock. The price spikes they cause should not precipitate any pause in economic activity that would lead to recession. Unusually bad weather, despite the temporary hardships it causes, is never expected to last very long and produces no long term economic uncertainties. A longer-term, gradual warming trend such as would be associated with global climate change, might increase or decrease the demand for electricity between cooling and heating seasons, but even a net increase would produce a gradual gas price increase that markets should be able to absorb without temporary dislocations.

Infrastructure problems and wellhead supply interruptions are possible sources of supply interruptions. The former could cause localized supply disruptions, but probably not generalized price increases. With regard to wellhead supply interruptions, some of the major gas-producing regions of the world have problems with potential political instability: Indonesia, Central Asia, Nigeria, Algeria, and Saudi Arabia with its significant natural gas reserves in addition to its oil reserves. Political turbulence in any of these regions could interrupt its gas exports, such as occurred with Iranian oil in 1979. However, gas reserves are distributed more evenly around the world than are oil reserves, which lowers and possibly eliminates, any particular producer's market power. This low degree of market power also would imply a smaller proportional disruption of world supply if any one producer experienced a production shut-down from political disruption.

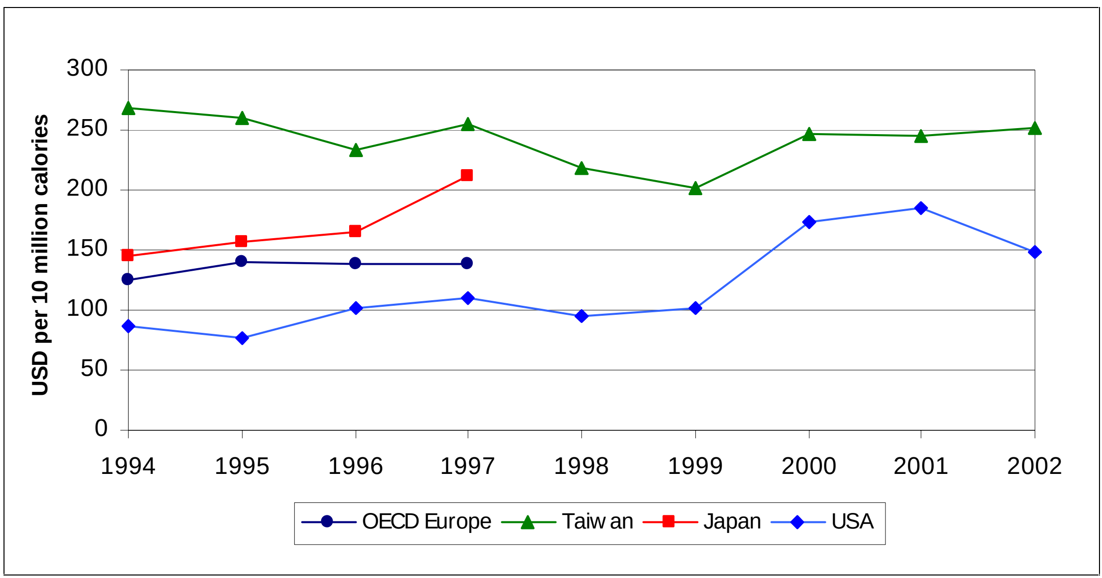
The question remains, however, whether a disruption in any particular world region would cause parallel price movements in gas prices throughout the world. The next section addresses that issue.

A9.3.5. The World Gas Market

Prices of natural gas in 34 countries from 1994 through 2002 (EIA 2003b, 2003c, 2003d) were studied to determine how closely they move in tandem. If a unified world natural gas market exists, the correlations among gas prices should be positive and close to one in magnitude. Rather than a single market, three large groupings appear to emerge—North America, Europe, and East Asia—although more complete country coverage could identify further separate markets.

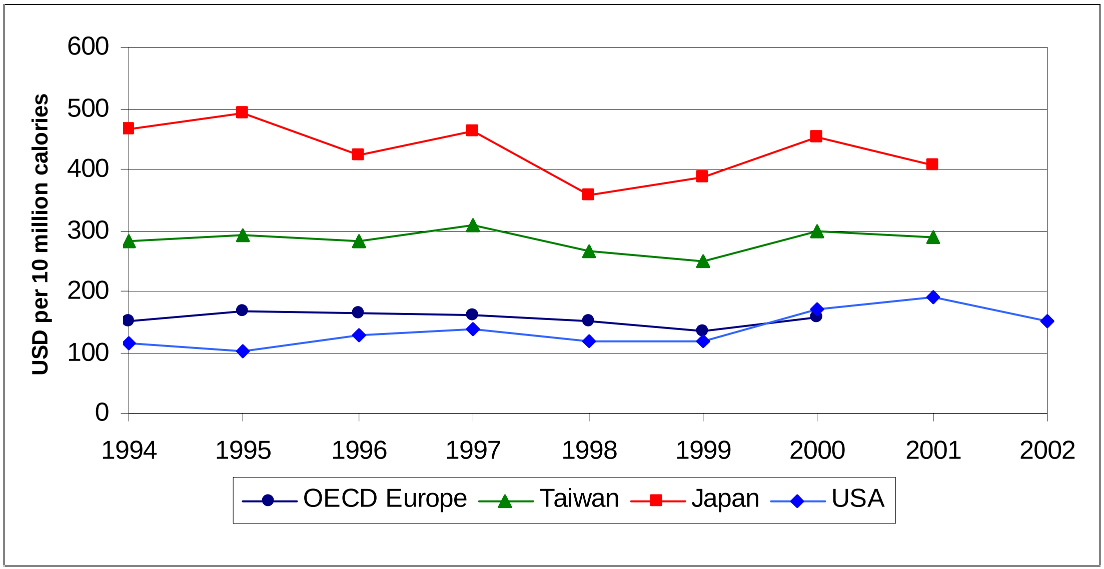
Figures A9-2, A9-3, and A9-4 show natural gas prices in 2003 prices for the United States, OECD Europe, Japan, and Taiwan, from 1994 through 2002, for the electric utility, industrial, and household sectors. The visual impression is of varying degrees of co-movement among the prices in these four regions.

Figure A9-2: Electric Utility Sector Gas Prices in the United States, OECD Europe, Japan, and Taiwan, 1994-2002, in 2003 Dollars



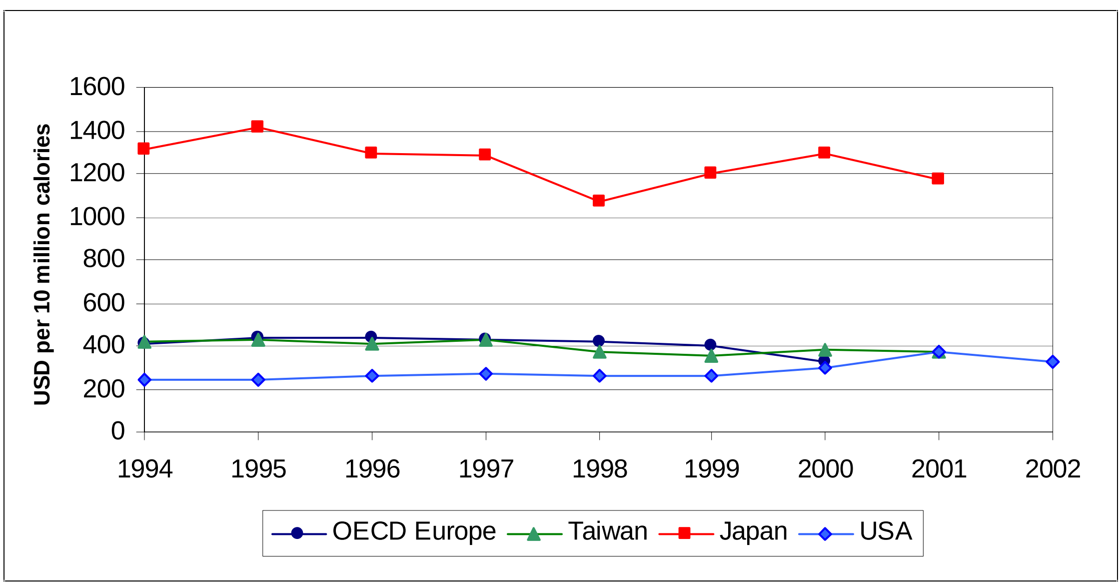
Source: EIA (2003b).

Figure A9-3: Industrial Sector Gas Prices in the United States, OECD Europe, Japan, and Taiwan, 1994-2002, in 2003 Dollars



Source: EIA (2003c).

Figure A9-4: Household Sector Gas Prices in the United States, OECD Europe, Japan, and Taiwan, 1994-2002, in 2003 Dollars



Source: EIA (2003d).

Table A9-2 reports some of the correlation coefficients estimated between U.S. gas prices and those of the countries for which sufficient years' prices were available. Canadian and Mexican gas prices are highly correlated with U.S. prices. Some of the European countries, and even South Africa, show some high positive correlations with U.S. prices in some sectors, but the overall OECD-U.S. correlations are all negative.

Table A9-2: Correlation Coefficients between Natural Gas Prices (Yearly Averages, 1994 to 2001, in 2003 \$ per 10^7 Kilocalories) between the United States and Various Countries

	Electric Utility Sector		Industrial Sector		Household Sector	
	Correlation Coefficient	Probability Correlation Coefficient is 0	Correlation Coefficient	Probability Correlation Coefficient is 0	Correlation Coefficient	Probability Correlation Coefficient is 0
OECD Europe	-0.32	0.68	-0.11	0.81	-0.61	0.14
Mexico	1.00	0.00	0.99	0.00	na	na
Greece	na	na	0.87	0.06	-0.63	0.37
Canada	na	na	0.81	0.02	0.87	0.01
South Africa	na	na	0.68	0.06	na	na
Poland	na	na	0.62	0.10	0.64	0.08
Italy	na	na	0.59	0.29	0.84	0.03
Venezuela	0.75	0.25	0.06	0.91	0.14	0.76
Japan	0.71	0.29	-0.30	0.47	-0.44	0.28
Czech Republic	-0.55	0.13	-0.38	0.32	0.65	0.06
Finland	-0.58	0.10	-0.44	0.24	0.64	0.06
Belgium	0.89	0.11	-0.86	0.14	-0.21	0.65

In other country-level correlations estimated over this same time period, most of the countries of Western and Eastern Europe are in a reasonably well integrated natural gas market, at least in the electric utility and industrial sectors. The household sector gas prices are highly correlated among Western European countries and among most Eastern European countries, but not between Western and Eastern. Japanese and Taiwanese industrial gas prices have a correlation coefficient of 0.88, but their electric utility sector gas prices have a negative correlation, -0.44. Utility and industrial sector gas prices in the United States, Canada, and Mexico have high positive correlation coefficients, but information on Mexican household gas prices is not available. Venezuelan and U.S. utility gas prices are highly correlated (0.75), if with weak statistical significance but their industrial and household gas prices are essentially uncorrelated. Since Venezuela is tied to the United States through its oil imports, it might be expected that the two countries would share a single natural gas market as well. Information is not available to assess the extent to which South American gas markets are integrated with North American gas markets. Columbia was disturbed politically in 2003 by the possibility of exporting its abundant natural gas reserves to North America, while Peru has been making explicit investment plans to export its gas (Webber 2003). Thus, it appears that closer integration of North and South American gas markets is a possibility in the relatively near term.

The correlation coefficients between the United States and OECD Europe are negative and small for both utility and industrial gas prices. Japanese and OECD Europe industrial and utility gas prices have small, negative correlation coefficients. From Table 9-2, the Japanese utility sector gas price has a statistically insignificant correlation with U.S. utility gas prices but the two countries' industrial sector gas prices are negatively correlated.

These data suggest the existence of at least three major world markets in natural gas that are not particularly well integrated. The East Asian market is largely an LNG market, but the North American and European markets are primarily pipeline markets, with LNG supplies at the fringes. It is not clear why the Japanese and U.S. utility and industrial sector gas prices have their pattern of correlations. The greater part of the U.S. small LNG imports are from the Atlantic Basin LNG market rather than the Pacific Basin market.

A9.3.6. Implications for Natural Gas as an Energy Security Issue

Wide distribution of natural gas reserves prevents the world natural gas markets from being cartelized. As a result of substantially greater transportation costs than oil, there does not appear to be a unified world market for natural gas, which has both benefits and drawbacks from the energy security perspective. The benefit is that supply disturbances originating overseas are difficult to transmit directly to U.S. gas prices. The drawback is that when a sharp supply-demand shift occurs in the United States, sending gas prices skyward, it would be difficult to alleviate the problem quickly with imports. This is the classic energy security problem. It would exist if domestic (or North American) gas supply shocks emerged, but probably would be little affected by overseas shocks.

The prognosis for dwindling natural gas reserves in the continental United States and Canada is subject to a wide range of opinion. New exploration and drilling technology may find and extract vast new quantities of natural gas in North America at prices eventually around $3 per mcf in 2003 prices. The energy-content price parity with oil should keep gas prices down, regardless of the progress of recoverable reserves. However, should reserves not expand, or expand only modestly, the supply of gas to gas-fired utilities would not grow rapidly enough to match electricity demand growth. Currently operating gas plants would have quasi-rents in view of their existing capacity that could make them affordable using gas priced significantly above the oil energy equivalent, at least for a while. The extent to which LNG imports could supplement dwindling domestic gas supplies is subject to further estimation. Capital cost and financing issues, contract-term issues, and environmental issues in siting terminals are all involved. If a low-reserve scenario emerged, and it could not be eliminated by LNG imports, capacity expansions would be in coal and nuclear technologies rather than in gas. Thus the longer-term prospect for a gas-nuclear power connection lies in the possibility that North America actually is running out of economically exploitable natural gas reserves.

A9.4. Energy Security Implications for Nuclear Power

Industry, concerned as all people are mainly with everyday business, does not necessarily take full account of the transcendent national reasons motivating energy security, particularly since businesses must heavily discount distant risks in order to compete in capital markets. Given a broad national interest in energy security and the nuclear role (see NEPDG 2001, pp. 5-15—5-17; Abraham 2004; DOE and Nuclear Power Industry 2004, Foreword; Bush 2004), the policy question arises: What are the criteria for deciding what proportion of new baseload capacity should be devoted to nuclear power?

At the heart of energy security issues are uncertainties about the future. Current sources of electricity supply could be subject to major supply or demand shocks. Section A.9.4.1 discusses three among several major possible sources of uncertainty that could affect nuclear power—national security, the environment, and the hydrogen economy. Section A9.4.2 develops a model containing a probability distribution of future prices recognizing that the costs of expanding nuclear power are greater, the more rapidly expansions of capacity are attempted. Time is required to efficiently bear plant construction costs, and more importantly, to acquire the highly specialized education, skills, training and experience used in nuclear design, construction and operation—much of which depends on a cadre of cooperating firms and educational institutions. The existence of these costs in the presence of uncertainty about future price leads to an optimal amount of capacity to maintain in order to be prudently prepared for the future. An appendix considers more elaborate models.

A9.4.1. Sources of Uncertainty

Some sources of uncertainty relate to national security. For example, nuclear power plants will be built in many nations around the world during the 21st century, and some, possibly many, of them will reprocess their spent nuclear fuel. The security of nuclear material from reprocessing in the United States, should it decide to reprocess, is not a major concern, but the security of such materials in some countries could be more of a problem. The United States has a national security interest in seeing that nuclear materials are strictly safeguarded at all locations in the world and do not fall into the hands of governments or private groups that would convert them into weapons. While the United States has limited influence on the choice of fuel cycle in nuclear power plants in other countries, it can have more influence on international protocols for safeguarding such materials—but only if the United States is viewed as possessing credible technical authority in civil nuclear power. If the domestic nuclear power industry withers, the likelihood will diminish that the rest of the world would continue to view U.S. opinions on nuclear fuel protocols as seriously.

Another source of uncertainty concerns the environment: it is possible that the external cost of fossil electricity generation will become unacceptably high, reversing the present relative costs of nuclear and fossil generation. Retaining nuclear power on that option would reduce high adjustment costs of gearing up a moribund nuclear capacity in the future.

A third source of uncertainty concerns the possible emergence of a hydrogen economy, with a greatly increased demand for production of hydrogen from non-fossil heat sources such as those supplied by nuclear power. A longer-term link between oil security and electricity revolves around the possibility of the widespread adoption of hydrogen vehicles, replacing oil-fueled vehicles. If hydrogen vehicles were adopted on a massive scale, the demand for electricity to generate hydrogen would expand several-fold, and nuclear power would offer a non-emissive option for expanding generation capacity.

A9.4.2. Toward Modeling Uncertainty

If the future were known with certainty, there would be no reason to try to be prepared for events that might happen when more than one outcome is possible. The future cost of fossil power generation may or may not be greater than the cost of nuclear power generation. For example, stricter greenhouse gas controls could raise the future cost of fossil generation substantially above the cost of nuclear generation. While it is not known for sure whether and when the controls might be introduced, the risk motivates building nuclear capacity in order to be prepared for the possibility that the price of fossil generation will rise.

How to react to risk requires comparing the costs of being prepared with the expected benefits. If nuclear power capacity could be expanded instantaneously, there would be no reason to add to nuclear capacity—unless and until fossil capacity actually becomes more expensive. However, if time is required to expand nuclear capacity once a decision is made to do so, it will pay to have nuclear capacity on hand in advance. How much to have on hand depends on the probability of the environmental occurrence and the costs of building up nuclear capacity. In the model below, fossil power plants are subject to the possibility of higher cost in the future, but they can be built without driving up their construction cost. Nuclear plants are not subject to similar future price uncertainties, but a rapid build-up of nuclear capacity would drive up their construction costs. A rule for optimizing additions to nuclear capacity is to equate expected cost, as the probability-weighted average of costs of fossil generation with and without the environmental occurrence, to the short-run marginal cost of adding nuclear capacity.

Let c_F be the cost of fossil generation if the present situation of very few controls on greenhouse emissions is continued. Let p be the probability of an undesirable environmental or other event increasing the cost of fossil generation to c_F^*, so that 1-p is the probability of a continuation of c_F. Then the expected cost of electricity generation from the capacity that will be added in the economy in any year is

$$EC = (1-p)[c_F(\underline{k}-k_N)+f(k_N)]+p[c_F^*(\underline{k}-k_N)+f(k_N)],$$

where $\underline{k}$ is the addition to total electric generation capacity and k_N is the addition to nuclear capacity, so that $\underline{k}$ - k_N is the addition to fossil capacity. $f(k_N)$ is the cost of bringing new nuclear power online and is a function of the amount of new nuclear capacity that is added.

To minimize expected costs, set the derivative of the expected cost expression with respect to nuclear capacity equal to zero:

$$\frac{dEC}{dk_N} = (1-p)[-c_F + f'(k_N)] + p[-c_F^* + f'(k_N)] = 0$$

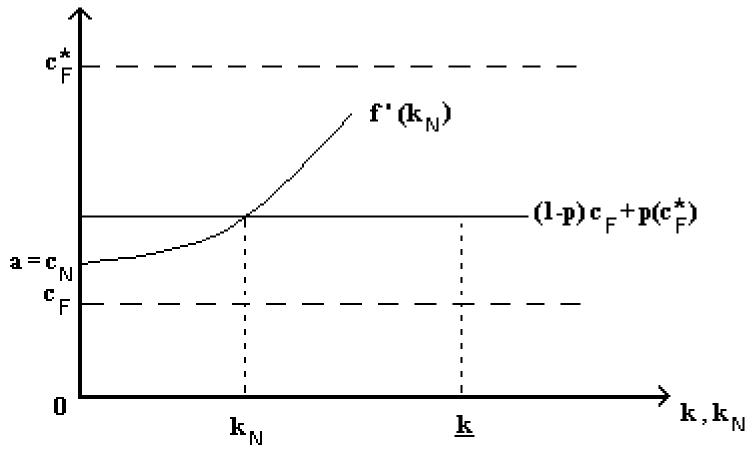
which on re-arrangement gives

$$f'(k_N) = (1-p)c_F + pc_F^*,$$

stating the rule that the marginal cost of nuclear capacity additions should equal the expected marginal cost of fossil capacity additions, taking account of the probabilities of high and low costs of fossil generation. Since f' is a function of k_N, optimal additions to nuclear capacity are determined by the equalization of the marginal nuclear expansion cost to the probability weighted average fossil cost.

Figure A9-5 depicts this equilibrium. Current fossil electricity cost, c_F, is the lower dashed horizontal line; c_F^*, the highest dashed horizontal line, is the higher cost of fossil cost if stricter greenhouse measures are introduced. The middle solid line represents the probability-weighted average of current and potential fossil costs. $f'(k_N)$ is the rising marginal cost curve showing how the cost of a unit addition to capacity rises with the amount of capacity expansion, due to shortages of people and materials that have to be overcome. The intercept a (= c_N) is the long run cost of a unit addition to capacity if the short run shortages were not encountered. The point where $f'(k_N)$ intersects the weighted fossil cost identifies the optimal addition to nuclear capacity, k_N^*. Total addition to generating capacity, $\underline{k}$, is to the right, the difference between the two values representing additions to fossil capacity.

Figure A9-5: Determination of Additions to Nuclear Capacity



New nuclear capacity k_N will expand until the marginal cost of nuclear power has risen from its long run value of c_N to the expected price of fossil, giving a proportionate rise of $[(1-p)c_F + p\,c_F^* - c_N]/c_N$. Let η be the elasticity of the excess of marginal cost over its long run value with respect to the fraction of the nation's new electricity capacity devoted to nuclear capacity in a year. Then the fraction devoted to new nuclear capacity will equal the proportionate excess of marginal cost over its long run value divided by η, or $(1/\eta)\,[(1-p)c_F + p\,c_F^* - c_N]/c_N$. Using suggestive probability values and anticipated generation costs, with $p = 0.2$, $c_F = 35$, $c_F^* = 70$, and $c_N = 40$, and $\eta = 0.20$, the proportion of new nuclear capacity is 0.25 indicating that one-fourth of new capacity is nuclear. This model deals with the costs of adding new capacity. The proportions of existing fossil and nuclear capacity, which are sunk costs, have no influence on this marginal decision. Consider, for example, the model applied to France, which possesses a much higher proportion of its stock of power generating assets in nuclear than does the United States. The relative cost of adding fossil and nuclear capacity in France would guide French new-capacity decisions, independently of the distribution of its current stock, although the French relative cost might differ from the U.S. relative cost and therefore produce a different mix of new capacity than the U.S. relative costs yield.

To throw light on the role of each of these parameters, Table A9-3 reports a sensitivity analysis of the share of new nuclear construction calculated by the model. The top panel varies the probability of the undesirable environmental event, p. At 5 and 10 percent probabilities of such an event, new nuclear capacity is not built. Above a probability of 20 percent, the nuclear share of new construction rises rapidly, accounting for 100 percent of new capacity with a probability of 50 percent. The second panel varies the elasticity of marginal cost, η, which is the elasticity of the excess of marginal cost over its long run value with respect to the fraction of the nation's new electricity capacity devoted to nuclear capacity. When that elasticity takes a very low value, nuclear construction costs rise very little when rapid construction occurs, and it is reasonable that under such circumstances the nuclear share of new construction is very high. If the elasticity has a value of 1, the nuclear share of new construction falls to 5 percent. In the third panel the nuclear cost is varied from a low value of parity with current fossil costs, $35 per MWh, to a high of $80 per MWh. When nuclear power costs are the same as current fossil costs, 100 percent of new construction is nuclear. However, the nuclear share drops off rapidly as the nuclear cost rises above $40 per MWh. Between $40 and $50 per MWh, the nuclear share of new construction falls to zero. The bottom panel varies the future fossil cost. A high future fossil cost is important to the nuclear share of new construction. Between fossil costs $60 and $70 per MWh, the nuclear share begins to rise to 25 percent at the base-case value of $70 per MWh and to 50 percent at $80 per MWh.

Given the importance of the topic, it would be highly desirable to undertake future research on refining estimation of the p's, c's, and the $f'(k_N)$ function. The latter would entail investigating the lags encountered in adjusting human capital and applied R&D when nuclear capacity expands and analyzing rising costs encountered in the expansion.

Table A9-3: Sensitivity of Model Calculation of Nuclear Share of New Construction

Vary p (probability of environmental costs)					
Parameters	Parameter values				
			Base case		
p probability of environmental costs	**0.05**	**0.1**	**0.2**	**0.3**	**0.5**
η elasticity of marginal cost	0.2	0.2	0.2	0.2	0.2
c_1 current fossil cost ($ per MWh)	35	35	35	35	35
c_2 current nuclear cost ($ per MWh)	40	40	40	40	40
c_3 future fossil cost ($ per MWh)	70	70	70	70	70
Nuclear share of new construction	**0**	**0**	**0.25**	**0.69**	**1.00**

Vary η (elasticity of marginal cost)					
Parameters	Parameter values				
			Base case		
p probability of environmental costs	0.2	0.2	0.2	0.2	0.2
η elasticity of marginal cost	**0.05**	**0.1**	**0.2**	**0.5**	**1**
C_1 current fossil cost ($ per MWh)	35	35	35	35	35
C_2 current nuclear cost ($ per MWh)	40	40	40	40	40
C_3 future fossil cost ($ per MWh)	70	70	70	70	70
Nuclear share of new construction	**1**	**0.5**	**0.25**	**0.1**	**0.05**

Vary c_N (nuclear cost)					
Parameters	Parameter values				
		Base case			
p probability of environmental costs	0.2	0.2	0.2	0.2	0.2
H elasticity of marginal cost	0.2	0.2	0.2	0.2	0.2
C_1 current fossil cost ($ per MWh)	35	35	35	35	35
C_2 current nuclear cost ($ per MWh)	**35**	**40**	**50**	**60**	**70**
C_3 future fossil cost ($ per MWh)	70	70	70	70	70
Nuclear share of new construction	**1**	**0.25**	**0**	**0**	**0**

Vary c_F^* **(future fossil cost)**					
Parameters	Parameter values				
			Base case		
p probability of environmental costs	0.2	0.2	0.2	0.2	0.2
H elasticity of marginal cost	0.2	0.2	0.2	0.2	0.2
C_1 current fossil cost ($ per MWh)	35	35	35	35	35
C_2 current nuclear cost ($ per MWh)	40	40	40	40	40
C_3 future fossil cost ($ per MWh)	**50**	**60**	**70**	**75**	**80**
Nuclear share of new construction	**0**	**0**	**0.25**	**0.38**	**0.5**

A9.4.3. Appendix

Much additional work on energy portfolio considerations, beyond the scope of the present study, could be undertaken. The following preliminary discussion indicates possible directions.

Consider a representative consumer, where each period is endowed with 1 unit of a non-storable resource (time for instance) that can be used solely to generate electricity. The consumer can choose between two generation technologies–nuclear and fossil fuel. The return from the nuclear technology is risk-free, while the return from the fossil fuel technology is not. In particular, suppose that each period there are two possible states of the world–peace (p) with probability π_t and war (w) with probability $1-\pi_t$. Then the return on each technology (the amount of electricity generated using one unit of the resource with the given technology) is given by

$tech \backslash state$	p	w
N	R^n	R^n
FF	$R^{ff}(p)$	$R^{ff}(w)$

with $R^{ff}(p) > R^n > R^{ff}(w)$. For simplicity, assume that each of the two technologies is linear in the amount of the resource used. The generated electricity, e, can then be used to produce consumption, c, using the technology

$$c = f(e) = Ae^{\alpha}, \quad 0 < \alpha < 1. \tag{1}$$

The consumer's preferences are represented by the utility function

$$U(c) = \frac{1}{1-\sigma} c^{1-\sigma}, \quad \sigma \geq 0 \tag{2}$$

with σ as the (constant) coefficient of relative risk aversion. We will analyze two different cases, depending on different assumptions about the availability of the electricity generating technologies and the timing of the decision which technology to use.

Consider the following three assumptions:

Assumption 1: Both generation technologies are freely available and there is no capacity constraint–that is, all of the resource can be used with a given technology.

Assumption 2: The consumer decides what fraction of the resource will be used with each generation technology *before* the state of the world is known.

Assumption 3: There are no environmental externalities.

In this case, the consumer solves

$$\max_{\{q_t\}} \sum_{t=0}^{\infty} \beta^t E_t U'(f[q_t R^n + (1-q_t) R^{ff}(z)]), \tag{3}$$

where $z = \{p, w\}$, E_t is the conditional expectation operator, and q_t is the fraction of the resource that will be used with the nuclear technology in period t. Since there is no intertemporal decision in this case, the above problem is equivalent to

$$\max_{\{0 \le q_t \le 1\}} E_t U(f[q_t R^n + (1-q_t) R^{ff}(z)]) \tag{4}$$

The first order condition for program (4) is

$$\pi_t U'[f(e(p))] f'[e(p)][R^n - R^{ff}(p)] +$$

$$(1-\pi_t) U'[f(e(w))] f'[e(w)][R^n - R^{ff}(w)] + \mu_t - \lambda_t = 0 \tag{5}$$

where $e(z)$ is the amount of electricity generated in state z, π_t is the conditional probability of peace, and μ_t and λ_t are Lagrange multipliers on the constraints $q_t \ge 0$ and $1 - q_t \ge 0$ respectively. It thus follows that

$$\frac{U'[f(e(w)] f'[e(w)]}{U'[f(e(p)) f'[e(p)]} \gtreqless \left(\frac{\pi_i}{1-\pi_i}\right) \frac{[R^{ff}(p) - R^n]}{[R^n - R^{ff}(w)]} \tag{6}$$

as $q_t = 1$ and $q_t = 0$ respectively, while (4) holds with equality for any interior value of q_t. Evaluating expression (6) at equality and using the particular functional forms for $U(.)$ and $f(.)$ we obtain

$$[\frac{e(p)}{e(w)}]^{1-\alpha(1-\sigma)} = (\frac{\pi_t}{1-\pi_t}) \frac{[R^{ff}(p) - R^n]}{[R^n - R^{ff}(w)]}. \tag{7}$$

Let

$$B \equiv \{(\frac{\pi_t}{1-\pi_t})\frac{[R^{ff}(p)-R^n]}{[R^n - R^{ff}(w)]}\}^{1/[1-\alpha(1-\sigma)]}.$$

Then (7) becomes

$$\frac{qR^n + (1-q)R^{ff}(p)}{qR^n + (1-q)R^{ff}(w)} = B;$$

this in turn gives

$$q = \frac{BR^{ff}(w) - R^{ff}(p)}{BR^{ff}(w) - R^{ff}(p) + (1-B)R^n}. \tag{8}$$

Since $BR^{ff}(w) - R^{ff}(p) + (1-B)R^n < 0$, the inequalities in (6) are reversed, giving $q_t^* q$ as $q \geq 1$ and $q \leq 0$ respectively. The optimal fraction of the resource devoted to the nuclear technology is therefore given by

$$q^* = Min\{Max\{0, q\}, 1\}. \tag{9}$$

For interior solutions we can calculate various elasticities of q^*. In particular,

$$\varepsilon_\pi = \frac{d \ln q}{d\pi}\pi \tag{10}$$

with

$$\frac{d \ln q}{d\pi} = \frac{(dB/d\pi)R^{ff}(w)}{BR^{ff}(w) - R^{ff}(p)} + \frac{(dB/d\pi)[R^n - R^{ff}(w)]}{BR^{ff}(w) - R^{ff}(p) + (1-B)R^n}$$

and

$$\frac{dB}{d\pi} = \frac{B}{[1-\alpha(1-\sigma)]\pi(1-\pi)}.$$

Similarly,

$$\varepsilon_\sigma = \frac{d\ln q}{d\sigma}\sigma \quad (11)$$

where $d\ln q/d\sigma$ has exactly the same form as $d\ln q/d\pi$ with $dB/d\sigma$ in place of $dB/d\pi$, while

$$\frac{dB}{d\sigma} = \frac{B\alpha}{[1-\alpha(1-\sigma)]^2}\ln\{(\frac{\pi_t}{1-\pi_t})\frac{[R^{ff}(p)-R^n]}{[R^n-R^{ff}(w)]}\}.$$

The principal factor involved in this characterization of the electricity portfolio problem is adjustment costs: without higher costs from having to build new nuclear capacity rapidly should a particular state of the world occur, it would be sensible to wait for that state of the world to emerge before building. However, with higher costs of rapid investment, it pays to have some of the nuclear asset in reserve. This is a form of insurance policy, in which possessing some amount of the more expensive asset lets producers avoid some costs with some probability.

Still another approach is that of real options, or irreversible investment theory (Pindyck 1991, Dixit and Pindyck 1994). The value of current investments in energy R&D has been studied with real options models (Schimmelpfennig 1995, Davis and Owens 2003). Guillerminet (2001) has used an options model to study investment in nuclear power as a hedge against the possibility that the cost of fossil generation will rise.

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ACRONYMS

Acronym	Definition
ABB-CE	Asea Brown Boveri - Combustion Engineering
ABI	Allied Business Intelligence
ABWR	Advanced Boiling Water Reactor
ACR	Advanced CANDU Reactor
ACRS	Accelerated Cost Recovery System
AEA	Atomic Energy Act
AEC	Atomic Energy Commission
AECL	Atomic Energy Canada, Limited
AEO	Annual Energy Outlook
AFR	Advanced Fast Reactor
AFP	Agence France Presse
AFUDC	Allowance for funds used during construction
AGR	Advanced Gas Cooled Reactor
AHTR	Advanced High Temperature Reactor
ALWR	Advanced Light Water Reactor
AMIGA	All Modular Industry Growth Assessment Modeling System
ANL	Argonne National Laboratory
ANP	Advanced Nuclear Power
APWR	Advanced Pressurized Water Reactor
ASM	Annual Survey of Manufactures
BALANCE	Energy network module from ENPEP
BBC	British Broadcasting Corporation
BBL.	Barrels
BEA	Bureau of Economic Analysis
BGS	British Geological Survey
BLS	Bureau of Labor Statistics
B/M	Book to market
BNFL	British Nuclear Fuels, Ltd.
BOE	Barrel of oil equivalent
Btu	British thermal unit
BW	Business Week
BWR	Boiling Water Reactor
CAAA	Clean Air Act Amendments
CANDU	Canada Deuterium Uranium
CAPM	Capital asset pricing model
CCAPM	Consumption-based capital asset pricing model
CCGT	Combined cycle gas turbine
CF	Capacity factor
CFB	Circulating fluidized bed
CFR	Code of Federal Regulations

Acronym	Definition
CHP	Combined Heat-and-Power
CIF	Cost, insurance, and freight charges for shipping products
CM	Census of Manufactures
CO_2	Carbon dioxide
COGEMA	COGEMA Nuclear Fuels
COL	Construction and Operating License
CNN	Cable News Network
CPI-U	Urban Consumer Price Index
CPS	Coal Production Submodule
CPS	Current Population Survey
CRDM	Control rod drive mechanism
CTBT	Comprehensive Test Ban Treaty
D&D	Decommissioning and decontamination
DIGEC	Direction du gaz, de l' électricité et du charbon
DoD	Department of Defense
DOE	U.S. Department of Energy
DOJ	Department of Justice
EAR	Estimated additional resources
ECAR	East Central Area Reliability
ECP	Electricity Capacity and Planning
EdF	Èlectricité de France
EERE	Energy Efficiency and Renewable Energy
EFP	Electricity Financing and Pricing
EGRID	Emissions & Generation Resource Integrated Database, U.S.EPA
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EMM	Electricity Market Module
ENEA	European Nuclear Energy Agency
ENPEP	Energy and Power Evaluation Program
EPA	U.S. Environmental Protection Agency
EPC	Engineer-procure-construct
EPR	European Pressurized Reactor
EPRI	Electric Power Research Institute
ERB	Energy Research Board
ERCOT	Electric Reliability Council of Texas
ESBWR	European Simplified Boiling Water Reactor
ESP	Early Site Permit
EURATOM	European Atomic Energy Community
EV	Electric vehicle
EVA	Energy Ventures Analysis, Inc.
F-ANP	Framatome Advanced Nuclear Power
FBC	Fluidized bed combustion
FBR	Fast Breeder Reactor

Acronym	Definition
FCHV	Fuel cell hybrid vehicle
FCV	Fuel cell vehicle
FCX	Honda FCX fuel cell vehicle
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FOAKE	First-of-a-kind-engineering
FOB	Free on board, shipper pays shipping costs
FRCC	Florida Reliability Coordinating Council
GA	General Atomics
GCR	Gas Cooled Reactor
GDP	Gross Domestic Product
GE	General Electric
GenSim	Electricity Generation Cost Simulation Model
GHG	Greenhouse gas
GII	Global Insights, Inc.
GM	General Motors
Gt	Gigatonnes
GTCC	Gas Turbine Combined Cycle
GT-MHR	Gas-Turbine Modular Helium Reactor
GW	Gigawatt
Hg	Mercury
HLW	High-level waste
HTGR	High-Temperature Gas-Cooled Reactor
HRSG	Heat recovery steam generation
HWLWR	Heavy-Water-Moderated, Light-Water-Cooled
IAEA	International Atomic Energy Agency
ICE	Internal combustion engine
IDC	Interest during construction
IIASA	International Institute for Applied Systems Analysis
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
ILW	Intermediate level waste
IPM	Integrated Planning Model
IPP	Independent Power Plant
IRIS	International Reactor Innovative and Secure
IRR	Internal rate of return
ITS	Institute of Transportation Studies
JAERI	Japan Atomic Energy Research Institute
kg	Kilogram
kgHM	Kilograms of heavy metal
KgU	Kilogram of uranium
kW	Kilowatt
kWh	Kilowatt hour

Acronym	Definition
LANL	Los Alamos National Laboratory
LCOE	Levelized cost of electricity
LFEE	MIT Laboratory for Energy and the Environment
ln	Natural logarithm
LHV	Lower heating value
LLW	Low level waste
LNB	Low-NOX burner
LNG	Liquefied natural gas
LWGR	Light Water Cooled Graphite Reactor
LWR	Light-water reactor
MAAC	Mid-Atlantic Area Council
MACRS	Modified Accelerated Cost Recovery System
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
MEA	Monoethanolamine
MESSAGE	Model for Energy Supply Strategy Alternatives and their General Environmental Impact
MHR	Modular helium reactor
MIT	Massachusetts Institute of Technology
MITI	Ministry of International Trade and Industry
MMBtu	Thousand Thousand British Thermal Units
MOX	Mixed-oxide
MSLL	Materials System Laboratory
MT	Metric ton
Mtoe	Millions of tons of oil equivalent
Mtu	Metric ton of uranium
MW	Megawatt
MWh	Megawatt hour
NAC	Nuclear Assurance Corporation
NEA	Nuclear Energy Agency
NEEDS	National Electric Energy Database System
NEI	Nuclear Energy Institute
NEMS	National Energy Modeling System
NEPA	National Environmental Policy Act
NEPDG	National Energy Policy Development Group
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NERI	Nuclear Energy Research Initiative
NPC	National Petroleum Council
NPT	Nuclear Non-Proliferation Treaty
NO_X	Nitrogen oxide
NPC	National Petroleum Council
NRC	National Research Council

Acronym	Definition
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NTDG	Near Term Deployment Group
NYMEX	New York Mercantile Exchange
O&M	Operation and maintenance
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of the Petroleum Exporting Countries
ORNL	Oak Ridge National Laboratory
OSHA	Occupational Safety and Health Act
OTC	Ozone Transport Commission
PBMR	Pebble Bed Modular Reactor
PCAST	President's Committee of Advisors on Science and Technology
PCC	Pulverized coal combustion
PCFB	Pressurized circulating fluidized bed boiler
PEM	Polymer Electrolyte Membrane
PHWR	Pressurized Heavy Water Reactor
PM	Particulate matter
PNNL	Pacific Northwest National Laboratory
POEMS	Policy Office Electricity Modeling System
POLES	Prospective Outlook on Long-Term Energy Systems
PPM	Parts per million
PRIS	Power Reactor Information System Database
PRISM	Power Reactor Innovative Small Module
PSI	Pounds per square inch
PTBT	Partial Test Ban Treaty
PUREX	Plutonium uranium extraction – Plutonium uranium oxidation reduction
PWR	Pressurized water reactor
PYRO-A	Pyrometallurgical
R&D	Research and development
RAR	Reasonably assured resources
REEPS	Residential End-Use Energy Planning System
RFI	Request for Information
RHR1	First generation high temperature reactor
RHR2	Second generation high temperature reactor
ROD	Record of decision
RTP	Real-Time Pricing
SACS	Saline Aquifer CO_2 Storage
SAIC	Science Applications International Corporation
SALP	Systematic Assessment of License Performance
SBWR	Simplified Boiling Water Reactor
SCR	Selective catalytic reduction systems
SERC	Southeastern Electric Reliability Council

Acronym	Definition
SIP	State Implementation Plan
SMR	Steam methane reforming
SNF	Spent nuclear fuel
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
SUV	Sport utility vehicle
SWU	Separative work units
SWR	Siede Wasser Reaktor (Boiling Water Reactor)
tC	Tonnes Carbon
tcf	Thousands of cubic feet
TIAX	TIAX, LLC
TMI	Three Mile Island
TVA	Tennessee Valley Authority
TVO	Teollisuuden Voima Oy
UIC	Uranium Information Centre
UMM	Uranium Market Model
UREX	Uranium extraction
USGS	U.S. Geological Survey
VHTR	Very High Temperature Reactor
W	Watt
WAC	Weighted average costs
WACC	Weighted average cost of capital
WCSB	Western Canada Sedimentary Basin
WEC	World Energy Council
WECC	Western Electricity Coordinating Council
WEM	World Energy Model
WEO	World Energy Outlook
WETO	World Energy, Technology, and Climate Policy Outlook”
Wh	Watt hours
WNA	World Nuclear Association
WWER	Water Cooled Water Moderated Power Reactor
WWF	World Wildlife Federation
ZEV	Zero-emission vehicle