**Investment in Nuclear Generation in a Restructured Electricity Market – An Analysis of Risks and Financing Options**

by

**Raphael Berger**

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Signature of Author..........................................................................................
**Technology and Policy Program, Engineering Systems Division**
**Department of Nuclear Science and Engineering**
January 18th, 2006

Certified by..........................................................................................
**John E. Parsons**
Senior lecturer in the Sloan School of Management
Executive Director of the Center for Energy and Environmental Policy Research
Thesis Supervisor

Certified by..........................................................................................
**Richard K. Lester**
Professor of Nuclear Science and Engineering
Director of the Industrial Performance Center
Nuclear Science and Engineering Reader

Accepted by..........................................................................................
**Dava J. Newman**
Professor of Aeronautics and Astronautics and Engineering Systems
Director, Technology and Policy Program

Accepted by..........................................................................................
**Jeffrey A. Coderre**
Professor of Nuclear Science and Engineering
Chairman, Department Committee on Graduate Students

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## Abstract

Since the late 1970s, the US electric power industry has been undergoing major changes. The electric utility industry had mainly consisted of highly regulated, vertically integrated, local monopolies, providing customers with all electric services at rates determined by the state regulatory agency. Deregulation and restructuring in the power industry triggered a transition towards competition in electricity generation, due to the formation of competitive markets at the wholesale level – in some states, at the retail level as well. Since utilities can no longer price at cost-of-service rates, investors in electric generation capacity, like nuclear power, will face a different set of financial risks.

Moreover, the economic context of volatile coal and gas prices, increasingly stringent NOx, SO2 and mercury regulations, and growing support for CO2 regulations will likely positively impact the value of nuclear capacity. Conversely, unresolved issues in the nuclear industry inherent to radioactive waste disposal, decommissioning and public opposition related to security concerns will likely penalize the building of new nuclear capacity. More importantly, regulatory delays in construction, mainly caused by the plant approval process by the Nuclear Regulatory Commission, undoubtedly negatively affect nuclear power because of its capital-intensiveness.

This thesis evaluates the main drivers impacting investments, and especially new investments, in nuclear power technologies to meet the increase in electricity demand in the United States. For that purpose, the ongoing change in the electric power sector and the potential evolution in all regulations concerning nuclear energy are assessed. The new risk factors facing investment in nuclear power, as well as the possible financing options, are examined. The company characteristics that most favor investment in new nuclear power plants in the United States are sketched.

The specific issue of plant construction, regulations and licensing is considered with closer attention. An analytic investment model in power generation estimates the impact of the extended construction time caused by regulatory delay in licensing on investment in nuclear power in a context of uncertainty on demand. The case study compares the dynamics of investment in nuclear power plants with gas-fired power plants – which have a much shorter construction time.

**Thesis Supervisor: John E. Parsons**
**Senior lecturer in the Sloan School of Management**
**Executive Director of the Center for Energy and Environmental Policy Research**

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## Introduction

After the rapid expansion of the nuclear fleet in the 1970s and 1980s that has substantially incorporated atomic energy into the electricity generation portfolio, no nuclear power plant has been built in the United States since 1990. Yet, although nuclear power programs in the Western world appear to have slowed down in recent years, the nuclear option is still wide open. Developing countries in Asia have significant objectives to develop their nuclear capacity, and some constructions of nuclear facilities are currently taking place in Europe.

Various elements contribute in explaining the absence of new nuclear builds in the past fifteen years in the United States. The electric power sector in the United States is undergoing a transition in which the traditional power companies, vertically-integrated monopolies, are being replaced by a collection of firms providing electricity services to consumers. After the deregulation and restructuring of the electricity sector, power generation companies are now privately owned and operated, and they face intense competitive pressure. Unlike regulated companies, they cannot pass excess costs onto consumers, and they are constrained to maintain their generation costs at low levels for fear they might have to shut down.

In this context, the nuclear industry has considerably improved its operational performance. Nuclear power plants have become safer than ever, and operators have managed to drastically lower production costs. However, the lifetime of a power generation facility is limited, and ultimately the currently operating units will be decommissioned. Absent new investments in nuclear power facilities, the nuclear capacity will eventually decrease to zero.

The purpose of this study is to understand the main factors that drive potential new investments in nuclear power. There are risks and uncertainties related to the market environment and specific to nuclear energy that shape the future of nuclear energy in the United States: those will be characterized and carefully assessed. We will also intend to analyze the recent changes in regulatory framework and legislative context to understand to what extent they might trigger a new wave of investments. We will also ask how the future investments in nuclear power plants will be shaped and what ownership and financing options will be considered.

Ultimately, in a context of uncertain demand for electricity, we will identify a cost that traditional financial analyses omit to consider: the cost associated with construction time, i.e. the cost of delay associated with uncertainty.

Part I will assess the current situation of the nuclear industry in the United States. We will analyze how deregulation impacts the nuclear industry, how nuclear power compares to other baseload electricity generation technologies, and assess the performance and future of the existing nuclear fleet.

Part II will list and analyze the risks and uncertainties related to electric power generation, especially those inherent to nuclear power. A simple financial model will evaluate the impact of some of these risks on the competitiveness of nuclear power. An analysis of the current regulatory and legislative evolution will evaluate whether the uncertainties adverse to new investments have been overcome, and appraise the possibility of new nuclear investments in the United States in the coming years.

Part III will present the recent structural evolution of the nuclear industry, exposing the trend towards consolidation. Building upon this movement, we will discuss the realistic options for new investments in nuclear power generation.

Part IV will introduce the cost of construction delay in an uncertain environment. After describing relevant dynamic equilibrium investment models, an analytic model will be developed to determine the cost of time-to-build for an electric generator facing uncertain and volatile demand.

# PART I: Current situation of the US nuclear industry

1. The US nuclear power program in the 70s and in the 80s

1.1. Brief history of the nuclear expansion in the US

The United States nuclear power program dates back to December 1951, when an experimental nuclear reactor managed to first produce electric power and light four light bulbs. After President Eisenhower's Atoms-for-Peace program, the Atomic Energy Act of 1954 announced the beginning of the development of civilian nuclear energy. In 1957, the Sodium Reactor Experiment at Santa Susana, California became the first civilian nuclear unit to generate power.

At the end of 1957, the first full-scale nuclear power plant at Shippingport, Pennsylvania, went into service, reaching 60 MW (megawatts) of electricity in twenty-one days.

In the 1960s, the US nuclear power program continues at an accelerating pace. In 1973, President Nixon creates a regulatory agency, the Nuclear Regulatory Commission (NRC), to regulate civilian use of nuclear materials.

The 1970s and 1980s were the most intensive years of the US civilian nuclear energy program. After the creation of the NRC, US utilities order a record of 41 nuclear units.

However, a major accident occurred at Unit 2 of the Three Mile Island nuclear plant near Harrisburg, Pennsylvania on March 28, 1979. Fortunately, damage only happened inside the reactor, and no one was injured. This event turned out to be a milestone for the US nuclear industry, and orders for new reactors have been significantly slowed down for a number of years. The Institute of Nuclear Power Operations (INPO) was also created in late 1979 to address issues of safety and performance.

The poor economic conditions in the US at the end of the 1970s, along with the accident at Three-Mile Island caused a number of orders to be cancelled. Although 46 units have entered service during the 1980s, the U.S. nuclear program never really regained momentum after three-Mile Island, and there have been no new orders since that time.

Of the nuclear fleet currently in operations, all power plants have come online before 1990, except the 1,150 MW Comanche Peak Unit 2 in Glen Rose, Texas which saw its construction delayed and entered service on April 6, 1993, and Tennessee Valley Authority's Watts Bar 1 nuclear power plant which was connected to the grid on February 9, 1996. By granting a license to this last unit, the NRC brought the number of operating nuclear units in the United States to 110.

1.2. Status of the current US nuclear fleet

There are now 104 fully licensed nuclear power reactors in the USA, of which only 103 are in operation[1]. Four more reactors are partly built and have valid construction licenses.

All US nuclear power plants are either Pressurized Water Reactors (PWR – 69 units, 65,100 MW) or Boiling Water Reactors (BWR – 35 units, 32,300 MW), all generically known as Light Water Reactors (LWR).

At the end of 1991, prior to the Energy Policy Act of 1992, the operable nuclear generating capacity in the United States was 97,135 MW. In March 2004, the operable capacity had evolved to 97,452 MWe. Major changes are concealed by this apparently marginal increase:

- The premature shutdown of 8 nuclear reactors occasioned a decrease of 5,709 MW;
- Power uprates are responsible for a net increase of 3,810 MW;
- The start-up of two new reactors – Comanche Peak 2 and Watts Bar 1 – brought an additional 2,315 MW online.

As of the end of 2004, the US nuclear capacity was 99,209 MW.

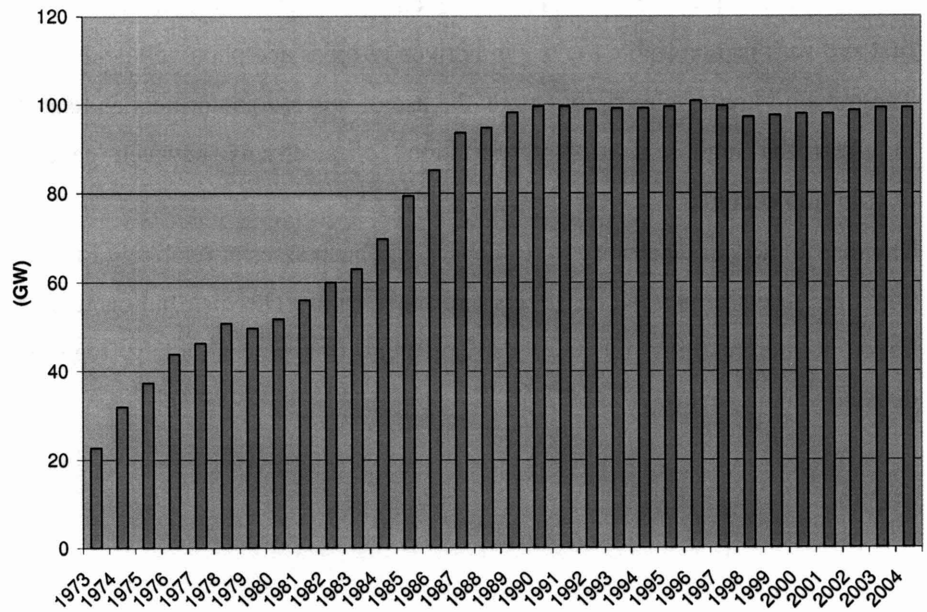


**Figure 1 – Net US Nuclear Capacity, 1973-2004**
Source: Energy Information Administration, 2005[2]

[1] Tennessee Valley Authority's Browns Ferry 1 has been shut since 1985. Refurbishment is currently being performed and operations should resume as early as 2007.
[2] EIA, 2004a

# 2. Deregulation and restructuring of the electric power sector in the United States and its consequences for nuclear power

## 2.1. Deregulation and restructuring of the U.S. electric power sector

### 2.1.1. Situation prior to deregulation

Since the 1930s, the US electric utility industry has consisted of regulated companies that were monopolies with exclusive franchises allowing them to sell electric power within their service territories at prices determined by state regulatory agencies.[3] In 1997, Joskow[4] described the sector as consisting of investor-owned or publicly-owned utilities that had de facto exclusive franchises to sell electricity to retail customers in specific geographic areas. The Investor-Owned Utilities (IOUs) accounted for as much as 75% of retail electricity sales.

Moreover, US electric utilities were typically vertically integrated companies, engaged in the business of generating electricity, long-haul transmission, and local distribution[5]:

- The generation of electricity entails the creation of electric power using falling water, internal combustion engines, steam turbines powered with steam produced with fossil fuels, nuclear fuel and various renewable fuels, wind driven turbines and photovoltaic technologies;
- The transmission of electricity entails the use of wires, transformers and substation facilities to effect the high voltage "transportation" of electricity between generating sites and distribution centers;
- The distribution of electricity to residences and businesses at relatively low voltages requires wires and transformers along streets and other paths. The distribution function is generally linked to the retailing functions (arrangements for power supply, metering, billing and demand management).

[3] NEI, 2000
[4] Joskow, 1997
[5] Joskow, 1997

### 2.1.2. Deregulation and restructuring of the power sector

#### 2.1.2.1. PURPA and the introduction of competition in wholesale electricity markets

In 1978, following the energy crisis of the 1970s, Congress passed the Public Utility Regulatory Policies Act (PURPA) which laid the principles of deregulation and competition by opening wholesale electricity markets to non-utility producers of electricity.[6]

The intent of PURPA was to encourage more efficient use of oil and natural gas through cogeneration. Many large industrial companies used their own boilers with oil or natural gas as a way to produce steam for manufacturing operations. One of PURPA's provisions allowed companies to build cogeneration plants – producing steam for both manufacturing and electricity – and required regulated electric utilities to buy that electricity. As a consequence of PURPA, the barriers of entry to small generators were lowered. PURPA helped lay the foundations for a competitive generation sector, and independent power producers (IPPs), a form of company that was not affiliated with regulated utilities, emerged.

Traditionally, electric utilities planned and built new power plants when new capacity was needed for their service area. In the 1980s, most states started to require competitive bidding for new supply. As PURPA had lowered the barriers to entry in electricity generation, competition to supply electricity became intense.[7] In the period between 1984 and 1996, U.S. electric utilities requested bids for 38,122 MW of new generating capacity, whereas bids came from IPPs for 11 times that amount (420,124 MW). As a result, independent, non-utility producers built almost half of all new generating capacity in the United States between 1985 and 1995.

In the early 1990s, independent power producers did not yet have ready access to the transmission system: they were not always able to access potential customers. In 1992, Congress removed this major obstacle and passed the Energy Policy Act. The Act mandated competition at the wholesale level and required electric utilities to allow non-utilities open access to their transmission lines.[8]

The Federal Energy Regulatory Commission (FERC) implemented the intent of the Act in 1996 with Orders 888 and 889. The objective was to "remove impediments to competition in wholesale trade and to bring more efficient, lower cost power to the Nation's electricity customers".[9] Order 888 commanded competition among wholesale electricity suppliers (10 percent of the electricity sold in the United States) and open and equal access to jurisdictional utilities' transmission lines for all electricity

[6] EIA, 2003
[7] NEI, 2000
[8] NEI, 2000
[9] EIA, 2003

producers, thus facilitating the States' restructuring of the electric power industry to allow customers direct access to retail power generation.

As a result, the electric power industry has been transitioning from highly regulated, vertically integrated, local monopolies towards competitive companies that provide the electricity while utilities continue to provide transmission or distribution services.[10]

### 2.1.2.2. Status of retail competition in power markets in the US

Retail competition, however, was not part of the Energy Policy Act of 1992, as the decision was left to states. Most observers at the time believed wholesale competition was a first step that would soon be followed by retail competition, under the impulse of industrial, commercial and residential users. The states, which regulate distribution services and retail rates for electricity within their borders, individually decide whether deregulation is in their interest.

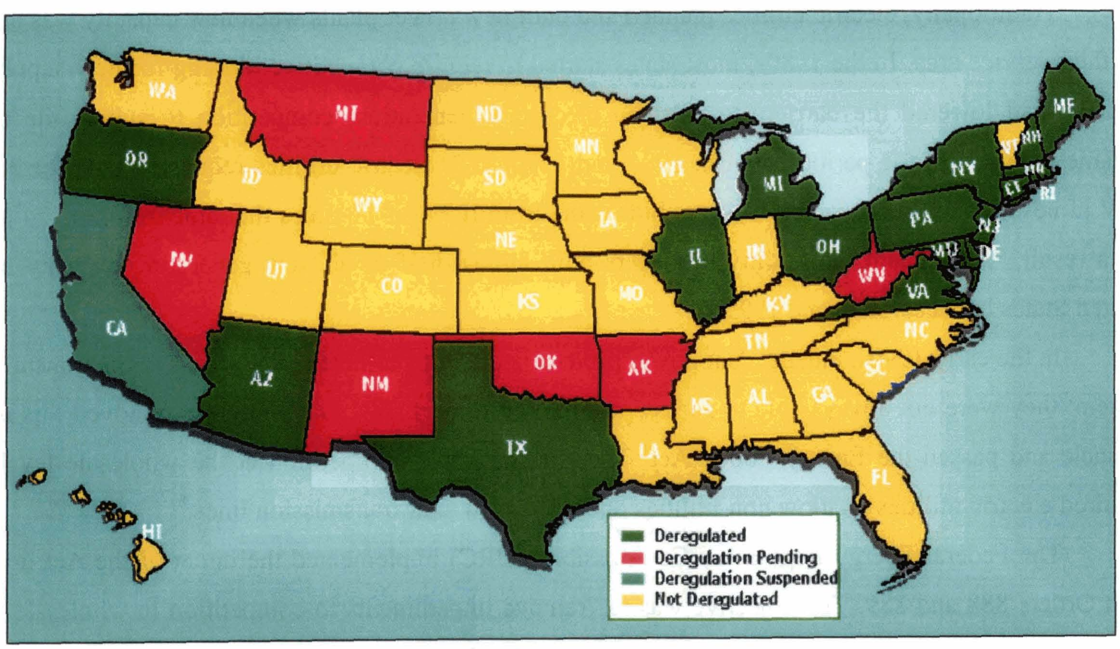


**Figure 2 – Status of Electricity Markets Open to Retail Competition**
Source: MCEnergy, Inc., 2005

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[10] EIA, 2003

Virtually all states now have regulatory proceedings under way, or are considering legislation, to restructure their electric utilities and require full competition. Some members of Congress think the federal government should intervene in the process by setting a timeline for attainment of full competition and establishing rules to manage the transition and restructuring of the electric power industry.[11] As of today, no legislation has passed. Almost half of the States have passed major legislation and/or regulations to restructure their electric power industry (see map).

California, Pennsylvania, New York, and most of New England, have historically had higher prices than the US average. As a result, they chose to open their retail electricity markets to competition, thereby allowing customers to choose their power supplier. Indeed, one of the major goals in restructuring the power sector is to lower the price for electricity. According to industry analysts, Pennsylvania is the most successful state in achieving its goals in restructuring.[12]

The principle of state restructuring legislations and regulations was to require or encourage the divestiture of generation assets. The purpose of the divestiture was to foster competition among generating companies and to prevent market power. Also, divestitures were a condition to the recovery of costs incurred by utilities for power plants and contracts under a regulated environment that may not be recoverable in a competitive market (known as stranded costs).

States in the Northeast, Texas, and the Midwest have been the most committed at conducting restructuring, and should continue towards implementing the necessary market reforms.[13] California, after the shock of the electricity crisis of 2000 and 2001 has reversed its initial deregulation plans, and is uncommitted to any clear long-term electricity strategy. A majority of the remaining states, in the Southeast, the South, and the West, have cautiously suspended or altogether rejected restructuring and competition initiatives. Having low retail prices, they are unwilling to take the risk of an electricity crisis similar to the Californian crisis.

At the end of 2000, approximately 16 percent of US electric utility capacity had been either sold to unregulated companies, or transferred to unregulated subsidiaries selling their electricity in a competition environment as opposed to cost-of-service regulatory setting.

Deregulation gives way to significant competitive pressure on the IOUs. In order to gain operating efficiencies and economies of scale, usually achieved by larger companies, the number of mergers has been increasing since 1995 – FERC has indeed approved 50 mergers. As a result, the number of electric utilities has been brought down from 98 in 1995 to 65 by the end of 2005, thereby decreasing the number of utilities by 33.7%.[14]

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[11] NEI, 2000
[12] EIA, 2003
[13] Joskow, 2003
[14] EEI, 2005

Consolidation of the US electric utility industry is expected to continue in years to come, and three mergers had been announced by the end of 2004.

### 2.1.3. Broad consequences and issues in the power sector

The main objective of the deregulation of the electricity sector is the pursuit of greater economic efficiency. The pressure from electricity market competition provides strong incentives to reduce costs and increase productivity. In such a context, low-cost power producers will thrive while high-cost plants either reduce their costs or are forced to cease operating.

Broadly, the electric power sector responds to competitive markets with innovation and improvement in performance and business practices.[15] Power companies put increasing effort into service, marketing, and focus more on profitability. Generally speaking, management, staffing policies, investment policies, customer relations, and relationships with stakeholders evolve under a competitive environment.

As a consequence of deregulation, electricity prices are made more flexible to reflect market conditions. In addition, electricity prices are generally expected to decrease following deregulation.

However, under a regulated system, despite the uncertainty about future electricity demand power producers have had protected markets for their outputs and assured rates of return in traditional markets. In a regulated environment, financial and market risks are allocated to customers: the cost incurred by a utility due to poor forecasting is passed onto customers through higher electricity prices, thereby minimizing the economic penalty to the utility for over-investment. Competitive markets radically change this situation.

Also, in a competitive market, power generators may see their customer base evolve. Contracts are based on the market price and the customer has the option to switch suppliers. This new market risk for power producers is especially large when there is a surplus of generating capacity and slow demand growth. Utilities run the risk of not selling their full output capability unless their marginal costs are low enough, or unless they have managed to negotiate long-term contracts.

As a result of competition, power generators might not be able to pay off their debts, especially if they have high marginal costs. These unrecovered capital costs, incurred within the regulated setting and threatened by a planned deregulation, may become stranded costs.

Additionally, deregulated environments give birth to a variety of electricity markets: contract markets (both long-term and short-term), future and hedging markets, and spot markets. If such markets

[15] NEA, 2000

are efficiently implemented, prices will reflect the balance between demand and supply. The balance is highly dependent upon the conditions of supply and demand, and electricity prices will reflect the balance.

Moreover, investment decisions for power plants with high capital costs or high risk/reward will evolve. Utilities are now required to bear greater performance, financial and market risks than in the past. Requirements on the initial capital outlay will become more stringent, along with requirements related to payback period and cash flows to secure debt and equity capital. Investors choose profitable options and are reluctant to invest in capital-intensive power plants, in particular those with long pay-back times, such as nuclear power plants.

## 2.2. The investment decision in a competitive marketplace

Before deciding to pursue a power generation project, investors analyze its economics to assess profitability.

Prior to deregulation in the United States, electricity rates were set by regulators using cost-of-service regulation. Power prices were determined in order to provide the utility with revenue equal to the revenue requirement, i.e. the revenue required to compensate for all expenditures associated with a power generation investment during construction, operation, and possibly decommissioning. The return was set so as to take into account the cost of financing capital.

The most popular method for determining the value of an investment is the discounted cash flow analysis (DCF). The DCF approach consists in discounting to present value all the future cash flows and in summing them up to find the net present value of the investment (NPV). The NPV rule is generally presented as the key to making investment decisions: any investment with a positive NPV is a good investment and should be pursued. If several mutually exclusive investment opportunities are competing, the option with the highest NPV should be chosen.

In order to assess the economic competitiveness of alternative generating technologies, a tool that is widely used is the real levelized cost of electricity production: "the real levelized cost of a project is equivalent to the constant dollar ("real") price of electricity that would be necessary over the life of the plant to cover all operating expenses, interest and principal repayment obligations on project debt, taxes and provide an acceptable return to equity investors over the economic life of the project. The real levelized cost of alternative generating technologies with similar operating characteristics (e.g. capacity factors) is a metric used to identify the alternative that is most economical."[16]

The levelized cost of electricity requires taking the following steps:

- Estimating capital costs, operating and maintenance costs, and fuel costs;
- Estimating technical availability in order to evaluate the average annual energy production from the power plant;
- Calculating expected annual cash flows from the power plant.
- Discounting the stream of cash flow at rates sufficient to satisfy interest and principal repayment obligations to debt investors and the minimum hurdle rate (cost of equity capital) required by equity investors, to estimate its present value;
- Revising the electricity price estimate to reach a value that brings the NPV to zero.
- The value reached above will be the levelized cost of electricity production.

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[16] MIT, 2003

## 2.3. Power plant characteristics relevant to the investment decision

There are a number of factors that affect the economics of a particular technology as well as the decision to invest in that specific technology for electricity production. The following sections summarize the features that have the most significant impact on the investment decision.

### 2.3.1. Capital costs and construction time

Electricity generation requires significant initial investment in capital equipment. For some technologies like nuclear power, the capital investment represents the largest cost component over the lifetime of the power plant and takes decades to be recovered. According to EIA estimates, 80% of the levelized cost of electricity from future nuclear plants will come from capital costs. Consequently, capital costs hold a significant part in the investment decision.

Moreover, the necessity of economies of scale require that units are rather large (sometimes above 1,000 MW), thereby requiring billion-dollar initial investments. Not only are capital costs a major cost item of nuclear power relative to other cost items, but in absolute nuclear investments require very large capital outlays.

Last, construction time is also a very important element in the investment decision. Large base-load plants can take several years to build, even absent regulatory or litigation delays. Especially when capital costs are high, long construction times can have significant impact on the value of a project, since capital has been invested but the plant is not yet in operation to provide revenue.

As we will discuss later as well, a long construction period increase the chances that the market conditions will have evolved between the time of investment and the time at which the plant eventually enters service. Consequently, there is a major competitive advantage for technologies with short construction times.

### 2.3.2. Economic lifetime

Power plants are built to operate for long periods of time. This is especially necessary for capital-intensive technologies to allow initial outlays to be recovered. Conversely, as a power plant ages, the operating costs might increase, and additional capital expenditures might be necessary to continue operations. Moreover, unless the discount rate is very low, extending the lifetime of the plant beyond a certain point will have a small impact on its present value. Those effects must be taken into account when considering the economic lifetime of a unit, i.e. the period over which to levelize electricity costs. Generally, the actual average lifetime of a power plant is largely superior to its economic lifetime, but reducing the economic lifetime allows offsetting the risk in the ultimate years. Then, if the plant is not profitable, the consequence of an early retirement is lower.

### 2.3.3. Operating costs

Technologies with high capital costs like nuclear power tend to have relatively low and stable operating costs. The operating costs are generally separated into two categories: operation and maintenance costs (O&M) and fuel costs.

For a natural gas combined cycle power plant, fuel cost may account up to half of the levelized cost of electricity production. Consequently, high volatility of natural gas prices will be detrimental to the cost of producing electricity.

### 2.3.4. Discount rate and risk premium

The finance literature has very little quantitative guidance regarding the relationship between risk and discount rates. Power plant risk, like nuclear plant risk, is to a large extent idiosyncratic, i.e. it is specific to each plant, rather than market related. Generally, the financial community agrees that idiosyncratic risk should be priced at the risk-free rate. Conversely, industry practices seem to account for risk in the choice of the discount rate, increasing the market rate by several points depending on the nature of the project considered.

## 2.4. Competing technologies for electricity generation

The present study focuses on new investments in nuclear power generation to meet electricity demand in the United States. Gas and coal are also considered as the major baseload competitors to nuclear power. Consequently they will receive the focus of the competitiveness comparison in this study. The following sections are a reminder of the assumptions used in the MIT study[17] for the levelized cost of electricity calculations. Those will later be used in a similar spreadsheet model to analyze the importance of a number of factors.

| | Parameters | Unit | Nuclear | PC | IGCC | CCGT |
|---|---|---|---|---|---|---|
| **Financial parameters** | Inflation rate | %/year | 3.0% | 3.0% | 3.0% | 3.0% |
| | US Treasury security yield | %/year | 5.0% | 5.0% | 5.0% | 5.0% |
| | Cost of debt capital | %/year | 8.0% | 8.0% | 8.0% | 8.0% |
| | Required net return on equity | %/year | 15.0% | 12.0% | 12.0% | 12.0% |
| | Debt fraction | % | 50.0% | 60.0% | 60.0% | 60.0% |
| **Project parameters** | Plant net capacity | MW | 1,000 | 1,000 | 1,000 | 1,000 |
| | Capacity factor | % | 85% | 85% | 85% | 85% |
| | Plant life | Year | 40 | 40 | 40 | 40 |
| | Heat rate | BTU/kWh | 10,400 | 9,300 | 7,800 | 7,200 |
| **Capital costs** | Overnight cost[18] | $/kW | $2,000 | $1,300 | $1,550 | $500 |
| | Construction Time | Year | 5 | 4 | 4 | 2 |
| | Decommissioning fund | $million | $350 | $0 | $0 | $0 |
| | Cost of incremental capital | $/kW/year | $20 | $15 | $15 | $6 |
| **Fuel costs** | Unit cost of fuel | $/MMBTU | $0.47 | $1.20 | $1.20 | $3.50 |
| | Fuel escalation rate | %/year | 0.5% | 0.5% | 0.5% | 1.5% |
| | Waste Fund | mills/kWh | 1.0 | 0.0 | 0.0 | 0.0 |
| **O&M costs** | Fixed O&M | $/kW/yr | $63 | $23 | $33 | $16 |
| | Variable O&M | mills/kWh | 0.47 | 3.38 | 0.80 | 0.52 |
| | O&M escalation rate | %/year | 1.0% | 1.0% | 1.0% | 1.0% |

**Figure 3 – Parameter assumptions for levelized cost of electricity calculations**
Source: MIT, 2003

### 2.4.1. Nuclear power

Specific nuclear technologies will be discussed in subsequent sections.

Similarly to other technologies, there is high uncertainty on capital costs, especially for designs that have not yet been built. The MIT study uses recent international experience to use overnight capital

[17] MIT, 2003

[18] The overnight cost is the amount that would be paid out if all capital expenses occurred simultaneously (immediately before start-up), excluding interest charges

costs in the range of $2,000 / kW, and the units could require construction times of four to five years. Joskow underlines that nuclear construction costs generally largely exceed initial estimates.[19] However, under competitive market conditions, merchant plant owners will be directly affected in the case of cost overruns, because the costs will not be passed onto consumers.

Construction time is highly uncertain due to the prospect of delays. Many nuclear constructions have been delayed beyond twelve years. Most nuclear units are above 1,000 MW.

It will be discussed later that operating costs for nuclear power plants have significantly decreased over the past 15 years. The economic lifetime of nuclear power chosen by the MIT study is 40 years, which corresponds to the duration of the initial operating license issued by NRC. However, most plants will be extended to 60 years. This has no effect on the levelized cost of electricity as the economic lifetime is not affected.

### 2.4.2. Coal

Pulverized coal combustion (PCC) is the most common coal combustion technology recently constructed in the United States. The interest in this technology has been motivated by its improved environmental performance. Integrated coal gasification combined cycle (IGCC) is also attractive from a thermal efficiency and emissions perspectives but will likely be too expensive for near-term construction in the United States.

Overnight capital cost estimates in the MIT study for pulverized coal are $1,350 /kW when including environmental compliance equipment. IGCC has capital costs of $1,500 /kW. The construction time assumed is four years, making coal technologies clearly less capital-intensive than nuclear power. Indeed, at equal overnight costs, interest expenses will be lower with a shorter construction time.

### 2.4.3. Combined cycle gas turbine

The primary gas-fired technology for new baseload electricity generation is gas turbine combined cycle (CCGT). CCGT technology has brought natural gas to the baseload market, and most of the new capacity installed since 1996 consists of CCGT power plants. Modern gas turbine plants operate at thermal efficiencies between 55% and 60%.

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[19] Joskow, 2005

Overnight capital costs are here assumed to be \$550 /kW, and the construction time is around two years. CCGT plants generally have capacities above 500 MW, and have shorter operational lives than coal or nuclear.

The major cost item for CCGT plants is fuel. Natural gas price trends will be discussed in subsequent sections, but it should be said that fuel costs can represent as much as half of the cost of electricity production.

# 3. Current competitiveness of nuclear energy

## 3.1. Comparative costs of generating electricity

### 3.1.1. Comparative levelized costs of electricity – MIT study

| Technology | Real Levelized Costs ($/MWh) |
|---|---|
| Nuclear | 67 |
| Coal | 42 |
| Gas (low) | 38 |
| Gas (moderate) | 41 |
| Gas (high) | 56 |

**Figure 4 – Comparison of levelized cost of electricity for different technologies and scenarios**
Source: MIT, 2003

The following values for levelized cost of electricity are given by the MIT study. I will make my own calculations later in this study.

"Nuclear power is not competitive in the current situation". The comparison of levelized costs of electricity suggests that nuclear power is much more costly than coal and gas, even in the high gas price cases. In the low gas price case, CCGT is cheaper than coal. In the moderate gas price case, coal and gas costs are comparable. Under the high gas price assumption, coal is significantly cheaper than gas. Of course, the dramatic increases in natural gas prices since 2003 would change these conclusions.

### 3.1.2. Nuclear versus fossil plants: economic advantages and disadvantages

Nuclear power has several advantageous economic characteristics, but also suffers from a number of disadvantageous characteristics, which seriously impact its cost-competitiveness.

Advantageous economic characteristics are as follows:

- Low and predictable fuel and operation and maintenance (O&M) production costs
  - The volatility of nuclear production costs is low because the primary energy source, uranium ore, represents a very small fraction of the total production cost.
  - The cost of the primary energy source in fossil-fired plants is a large fraction of the production cost.
- High capacity factors
  - Capacity factors for nuclear plants in the United States average around 90%.

    - For competing base-load gas-fired combined cycle plants, the projected capacity factors are in the range of 80% to 85% when averaged over the plants' lifetimes.
- Long operating lifetime
    - Operating lifetime licensing extensions have been obtained in the U.S., and the new designs project a 60-year life.
    - For competing base-load gas-fired combined cycle plants, lifetimes are not expected to exceed 25 years.

Disadvantageous economic characteristics of nuclear power are:

- Large plant size
    - The size range of most new nuclear power plants is approximately 1,000 to 1,350 MW, in order to reduce the capital costs per kW through economies of scale. They thereby encounter the risk of exceeding demand growth.
    - Base-load gas-fired combined cycle plants are in the range of 500 to 600 MW.
- Large capital outlay
    - The overnight capital cost range of new nuclear plants is estimated around $1,000 to $1,800 per kW. For a 1,350 MW plant at $1,600 per kW, an investment of $2.16 billion can be required, excluding interest costs.
    - Total overnight costs for base-load gas-fired combined cycle plant are in the $450 to $650 per kW cost 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 already optimized construction time for new nuclear plants is around 3 to 4 years.
    - For gas-fired combined cycle plant, construction time is approximately 2 years.

### 3.1.3. Split of full generation costs

In order to understand the reason for nuclear power not being cost-competitive, it is relevant to take a look at the split of full generation costs under the base-case scenario considered above. The cost split turns out to be very different from one technology to the next, as displayed in the following figure:

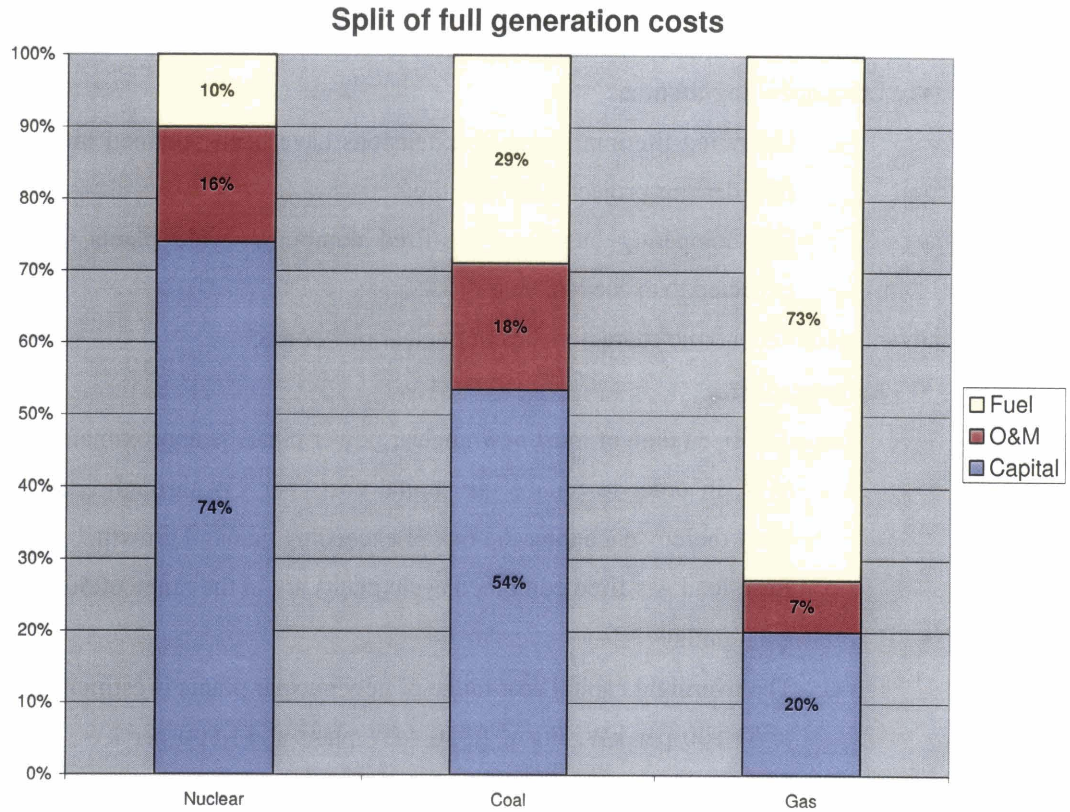


**Figure 5 – Split in full generation costs**

Capital costs of nuclear generation account for about three quarters of the total costs. Fuel costs are only 10% and operations and maintenance account for the remaining 16%. Hence, the largest portion of the costs is fixed and nuclear has very limited exposure to international commodity prices.

Fuel costs for gas represent about three quarters of the total costs. Compared with nuclear, capital costs are significantly lower. In other words, gas-fired power generation is highly dependent on the international price of natural gas.

The cost structure of coal is more balanced. About 54% are capital costs and 23% fuel costs in the total costs.

In the following sections, we will quickly examine the relevant projections that could affect the relative competitiveness of nuclear, gas and coal. Capital costs, O&M costs and fuel costs will be considered. Annual Energy Outlook projections will then be displayed to illustrate the prospects for electricity generation in the United States.

## 3.2. Capital and O&M cost trends across technologies

### 3.2.1. Coal

According to the University of Chicago, capital costs for new PCC plants range from $1,100 to $1,200 /kW depending on their location.[20] DOE estimates the future cost of IGCC units at just over $1,300 /kW and projects that its price will come down to $1,000 /kW by 2008.

The cost of operating emission control devices for both sulfur and NOx are included in the O&M costs of a coal-fired plant. The graduate decline of plant performance over its lifetime generally translates into lower availability and higher O&M costs.[21] In that respect, cap-and-trade programs with SO2 and NOx allowance trading provide incentives for power generators to find the lowest-cost mechanism to achieve emission levels.

### 3.2.2. Gas

Gas capital costs comprise less than one-third of the total cost of generation. An average estimate for a new combined cycle plant is $590 /kW.

The cost of operation and maintenance for gas-fired power plants includes costs of emission control. However, gas-fired plants generally do not require additional pollution control equipment: this feature represents a significant O&M cost advantage. However, O&M costs share in the cost of electricity production is less than 6%. Those costs are expected to remain stable.

| | **2003** | **Long Term** |
|---|---|---|
| Capital Cost ($/kW) | 590 | 450 |
| Total O&M Cost ($ per MWh) | 2.6 | 2.6 |

**Figure 6 – Cost Estimates for New Gas Plants**
Source: University of Chicago, 2004

[20] University of Chicago, 2004
[21] University of Chicago, 2004

### 3.2.3.Nuclear

Trends in production costs will be discussed in a subsequent section of this study. As for capital costs, they are substantially lower than they were in the 1980s, but it is to be expected that the vendor's estimates are ambitious and will not be realized. Pessimistic capital assumptions should be used in estimating levelized costs of electricity until capital costs are proven.[22] This assertion should in fact be applied across all technologies for consistency purposes.

[22] Joskow, 2005

3.3. Fuel cost trends across technologies

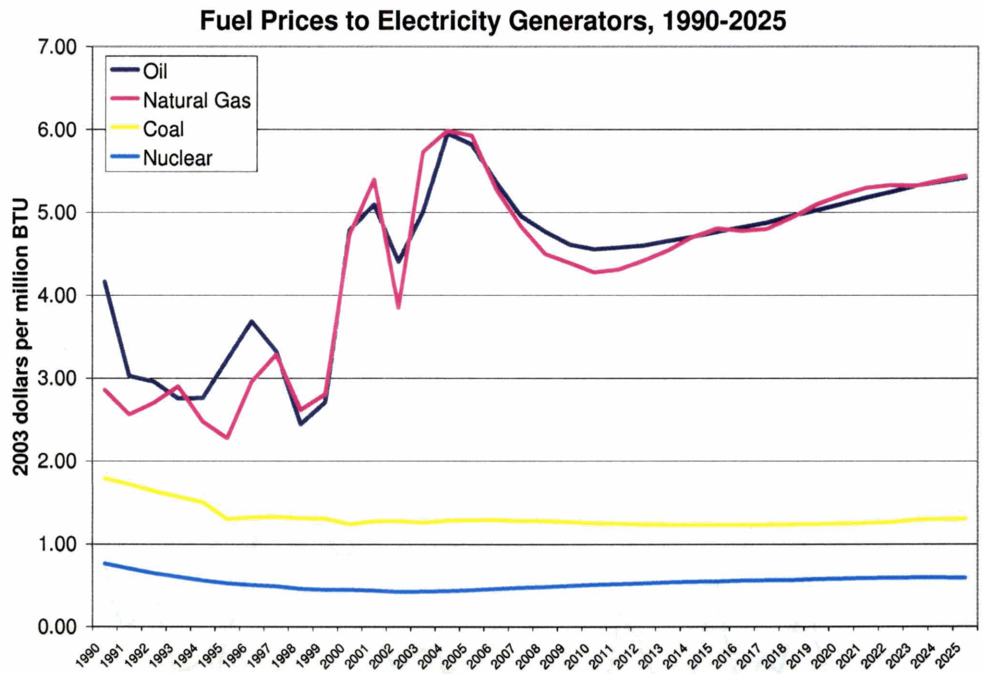


**Figure 7 – Fuel Prices to Electricity Generators, 1990-2025**
Source: Energy Information Administration, 2005

The cost of producing electricity is a function of the costs for fuel, operations and maintenance, and capital. Fuel costs make up most of the operating costs for fossil-fired units:

- For new coal-fired plants, fuel costs represent about one-half of total operating costs;
- For new natural-gas-fired plant, fuel costs would be almost 90 percent;
- For nuclear units, fuel costs typically are a much smaller portion of total production costs, and non-fuel operations and maintenance costs make up a much larger share.

The impact of higher natural gas prices in the projections is offset by increased generation from coal-fired and nuclear power plants and by higher generation efficiencies as new capacity is installed.

3.3.1.Natural Gas

The North American natural gas market is mainly driven by increasing demand from power generation, and domestic supply has been stagnant. Natural gas prices are projected to decline in the early years of the AEO2005 reference case forecast. Except for an increase in drilling levels and new production capacity coming on line, the only near-term alternative for the United States in response to current high prices is a substantial increase in imported liquefied natural gas (LNG) to fill the gap between declining North American production and rising gas demand from electricity generation.

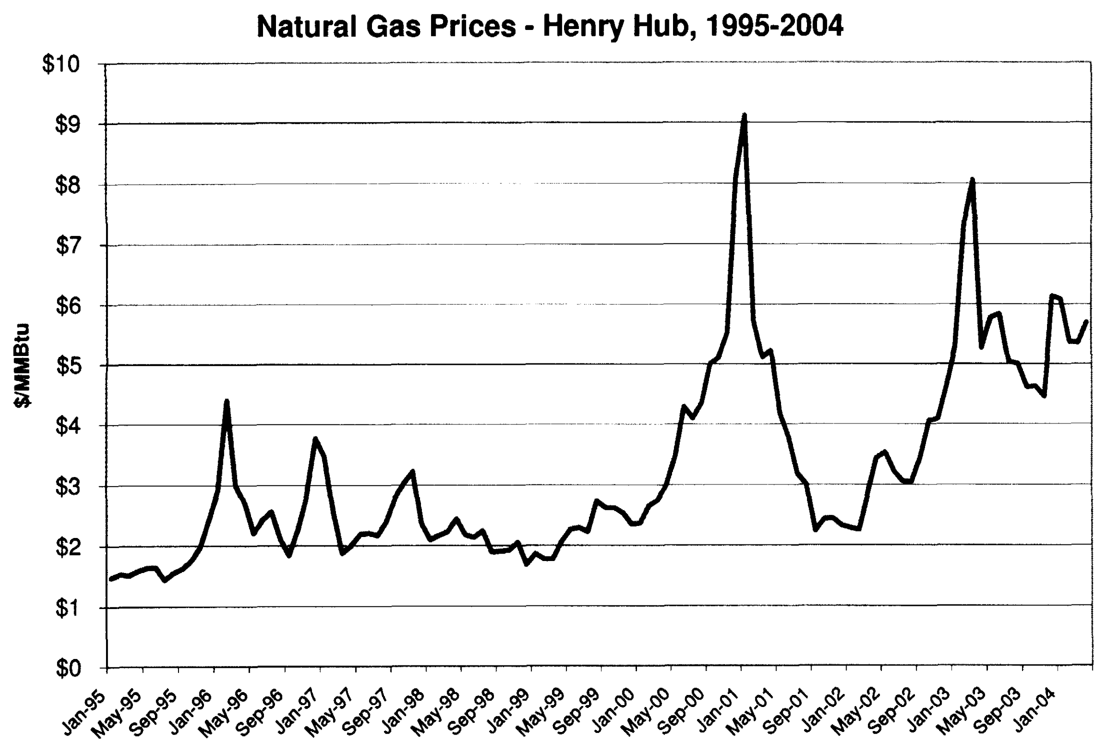


**Figure 8 – Natural Gas Prices - Henry Hub, 1995-2004**
Source: Nuclear Energy Institute, 2005

According to projections, spot gas prices at Henry Hub (pricing point for natural gas futures contracts traded on the New York Mercantile Exchange on the natural gas pipeline system in southern Louisiana) are likely to move average spot gas prices at Henry Hub around a level of $5 per million Btu.

3.3.2.Coal

Coal markets are generally affected by high natural gas prices. In 2002, when spot natural gas prices were low, gas-fired generation increased substantially. This trend was reversed sharply in 2003 as prices rose above $5 per million Btu. Consequently, coal-fired generation rose in 2003 to make up the shortfall.

The increase of coal use happened in spite of the tightening restrictions on nitrogen oxides and sulfur oxides tightened.

According to EIA projections,[23] minemouth coal prices will rise initially in response to strong growth in the demand for coal in the electric power sector. High spot prices for coal are indeed embedded in new term agreements. At expiration of a contract, like many in 2004, new contracts are signed at higher prices, and most coal is sold under term agreements. Consequently, coal costs will rise steadily and possibly sharply, even if spot coal prices begin to decline.

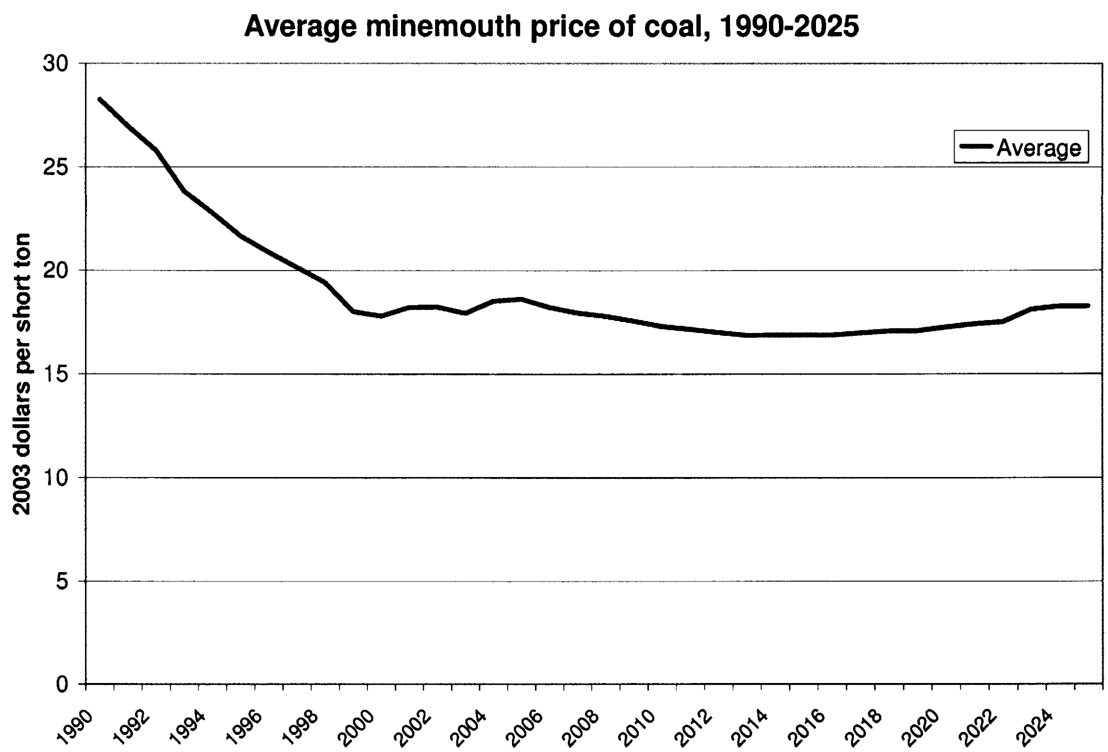


**Figure 9 – Average minemouth price of coal, 1990-2025**
Source: Energy Information Administration, Annual Energy Outlook

### 3.3.3. Uranium

Uranium spot sales represent only about 15% of global uranium demand. Suppliers sell the majority of their production through long-term contracts, direct to utilities, but with the price often related to the spot price.

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[23] EIA, 2005a

Contracts are structured at either a singled fixed price, based on reference prices and indices, or have escalation clauses related to the spot price. Delivery quantities and schedules are specified in contracts as well, and contracts usually run for three to seven years. Since long-term contracts allow buyers to eliminate their exposure to spot rallies, they have been priced at premium to spot.

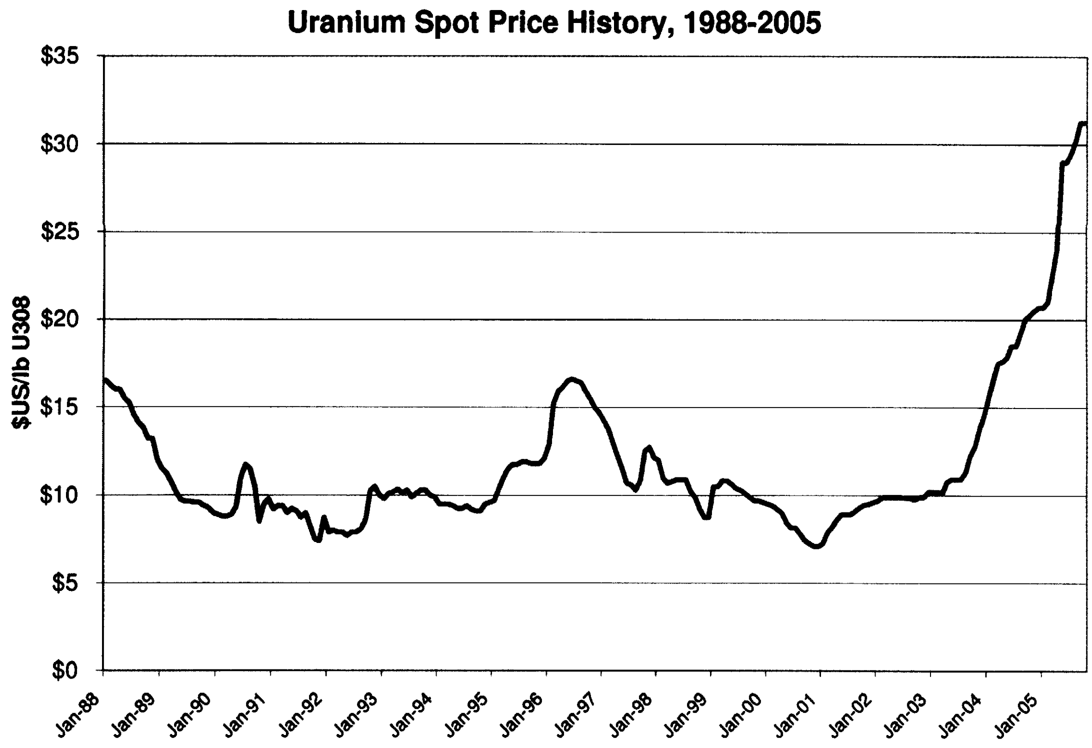


**Figure 10 – Uranium Spot Price History, 1988-2005**
Source: Ux Consulting

In the period 1970-1984, uranium production resulted in a huge commercial utility inventory to operate existing nuclear plants in the US. At that time, the spot price of uranium ranged from $30 to $45 per pound of U3O8. From 1985 to 2003, the market was essentially driven by the liquidation of the very large utility inventory. As a result, the spot price of uranium during the liquidation era was as low as $7 to $10 per pound. Starting in 2002, the price of uranium began to climb. In January 2002, it was at $10 per pound, and by the end of 2003, it was nearly $13. At the end of October 2005, it had risen to $31, the highest price since 1984. JPMorgan expects uranium spot prices to maintain momentum through 2006 up to almost $33, but to slip in 2007 towards $30.5.[24]

[24] JPMorgan, 2005

3.4. Projections for power generation fleet in the United States

Currently, the United States has an over supply of generating capacity. As of October 31, 2003, total national supply equaled 964,469 MW, distributed as follows:

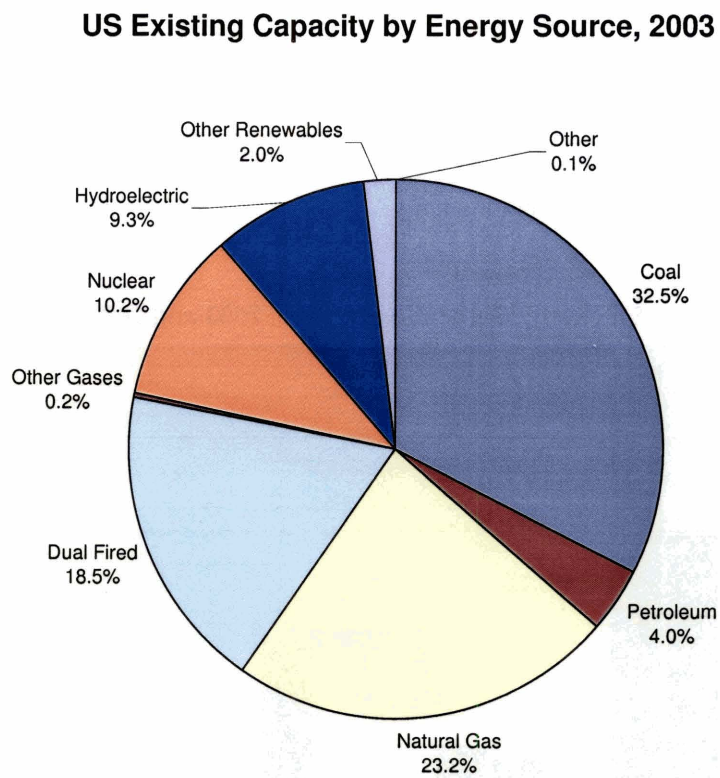


**Figure 11 – US Existing Capacity by Energy Source, 2003**
Source: Energy Information Administration

However, some of the capacity has been retired and will continue to be retired. Power plant retirements occur because of excess supply making many power plants uneconomic.

According to AEO 2005, with growing electricity demand and the retirement of 43 GW of inefficient, older generating capacity, 281 GW of new capacity will be needed by 2025.

2005 EIA projections do not forecast any new nuclear capacity coming on line by 2025 simply because there are no orders today.[25] Hydropower is also geared for baseload, but it is much more subject to weather conditions (e.g., drought). Hydropower is concentrated in certain regions and production is declining.

[25] This may change in the 2006 projections due to the Energy Policy Act of 2006

Because of deregulation and market competition in some regions, Scully Capital believes utilities will be shifting some plants to intermediate and peaking units to better match load demand and market conditions. By 2020, baseload as a percentage of total capacity should decline.[26]

The majority of new capacity additions are likely to be natural-gas-fired combined-cycle or combustion turbine, more than 80 percent needed after 2010, when the current excess of generation capacity has been reduced. Natural gas prices are likely to increase, and new coal-fired capacity is projected to become increasingly competitive. Most of the new coal capacity is expected to use advanced pulverized coal technology but advanced clean coal technology will certainly be added too, with higher capital costs but relatively low fuel costs. According to EIA, about 5 percent of the projected capacity expansion will consist of renewable generating units.

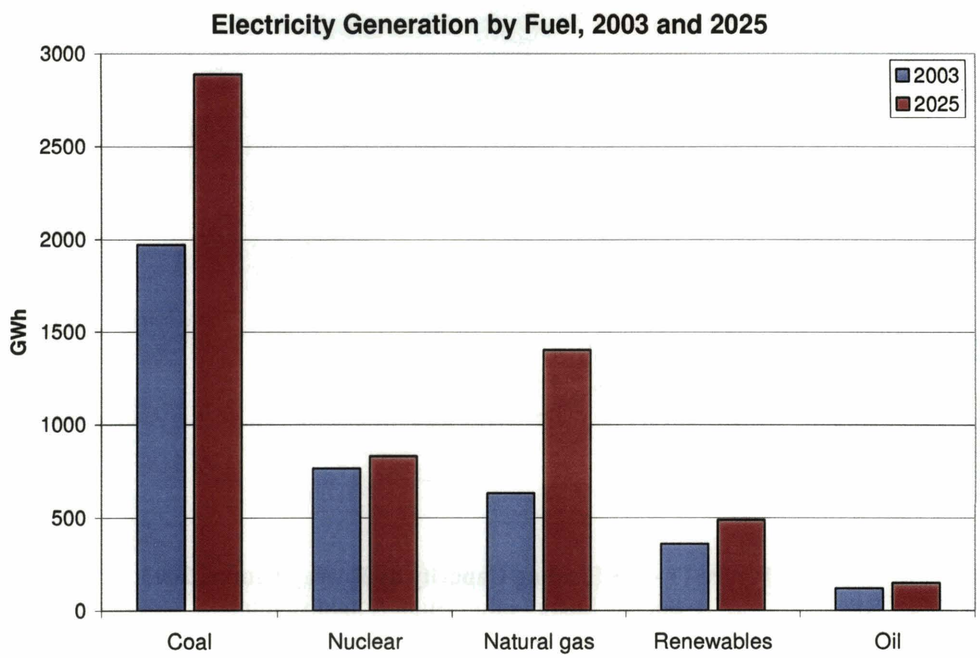


**Figure 12 – Electricity generation by fuel, 2003 and 2025**
Source: Energy Information Administration

[26] Scully Capital, 2002

# 4. Prospects for the US nuclear industry

The operating and safety performance of the existing US nuclear fleet – with 104 reactors and 99 GW of installed generating capacity – has been improving steadily since the early 1990s. During the 1980s, the nuclear fleet had serious performance problems. Moreover, public acceptance of nuclear power was undermined after the accidents at Three Mile Island and Chernobyl. Over the past decade however, the efforts made by plant operators have resulted in improvements of most performance indicators.

The nuclear consolidation trend for plant ownership and management over the past five years placed many nuclear plants in the hands of efficient operators. This has probably contributed to improving the fleet's performance. Nevertheless, nuclear ownership remains somewhat fragmented despite consolidation. The largest nuclear operator in the United States, Exelon, owns only about 15 percent of total capacity, and the top ten firms together own 61 percent. The remaining 39 percent are owned by 26 investor-owned power companies and 40 government entities and rural cooperatives.

## 4.1. Improved performance of the current nuclear fleet

In general, the impact of electricity market deregulation on the performance of nuclear power plants is expected to be positive. As reminded by the Nuclear Energy Agency,[27] it is reasonable to expect that increased competition in a deregulated market will bring about cost reductions through reductions in staffing, increased productivity, and higher availability factors, thereby improving economical performance.

### 4.1.1. Cost improvements

Marginal costs of operation, including fuel costs and O&M costs, as well as applicable repair and refurbishment expenses, are the determining costs in decisions on whether existing nuclear power plants will be continue to operate in a competitive market. Of course, these marginal costs vary with different time horizons and are applied differently for existing plants and new plants. With respect to existing power plants, marginal costs are relevant in deciding whether to continue producing power at the current level, increase power output, or permanently shut down the plants.

[27] NEA, 2000

According to NEA,[28] the merging, buying and selling of nuclear power plants in the United States today is an indication that well-run nuclear power plants are valuable assets and as such probably will reduce the risk of early retirements.

Due to its low variable production costs, nuclear power is generally used in base-load. The following graph shows the average operating costs per unit on a three-year average. The lowest level is below $10 per MWh for fuel costs and operations and maintenance costs. In addition, a large proportion of the fleet spends less than $20 per MWh.

The average production costs in 2004 were as low as $17 per MWh, whereas they were above $21 per MWh in 1990. If we add $5 to $6 per MWh for capital expenditures, insurance, and taxes, the fleet is running at costs of about $23 per MWh[29].

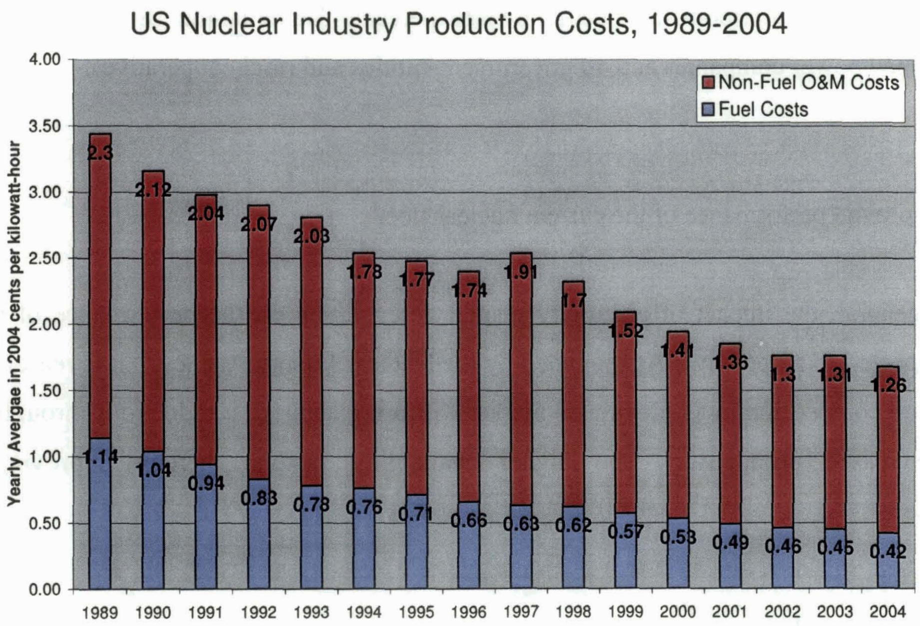


**Figure 13 – U.S. Nuclear Plant Production Costs (O&M + Fuel), 1989-2004**
Source: Nuclear Energy Institute, 2005

The profitability of nuclear power plants in the past few years is quite different from what had been expected with the introduction of competitive electricity markets. There was a widespread belief in the 1990s that nuclear plants would be uncompetitive and forced to shut down. The above graph shows the evolution of the competitiveness of nuclear production costs.

Improvements in production costs from nuclear power plants evidently come from improvement in the operational performance. As we will analyze in the next section, power output improvements of

[28] NEA, 2000
[29] NEI, 2005

nuclear power plants have been achieved mainly through improved refueling operations, longer intervals between outages and reduced outage times, and power upgrades. Furthermore, reductions in staff levels and increases in productivity and reliability have resulted in enhancing the competitive position of nuclear power plants.

4.1.2.Performance improvements

A significant achievement of the US nuclear power industry over the last twenty years has been the increase in operating efficiency with improved maintenance. In 1987, according to NEA,[30] only 42 percent of the nuclear units had capacity factors above 70 percent. The average capacity factor (output proportion of their nominal full-power capacity) has increased steadily since the 1990s and has been around 90 percent for three years in a row.

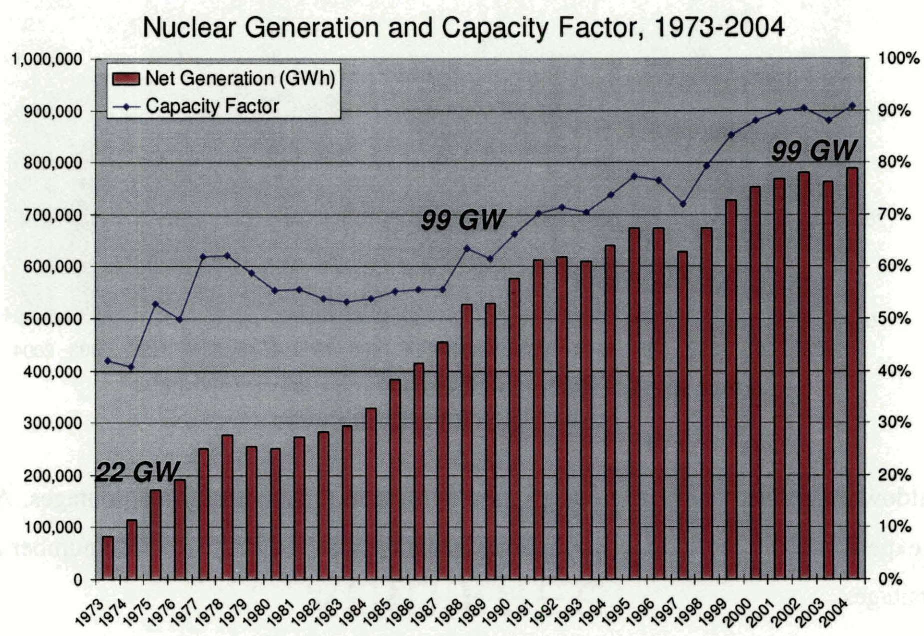


**Figure 14 – Nuclear Generation, 1973-2004 and Capacity Factor Trend, 1989-2004**
Source: Energy Information Administration, 2005

The performance of nuclear power plants in the United States has improved markedly and the following factors have resulted in costs falling substantially over the past decade.

Refueling outages are periodic shutdowns at nuclear plants necessary for the replacement of used-up fuel rods and for reshuffling of the remaining rods to ensure the proper distribution of power within the

[30] NEA, 2000

reactor core and efficient fuel burn-up. The length and the frequency of refueling outages have been considerably reduced. In the 1980s, the refueling process required a 60 to 90-day outage every 12 months. In 1990 it averaged 107 days but dropped to 40 days by 2000. Today, improved nuclear fuel designs (including elements like higher initial enrichment levels) and better outage planning have reduced these outages to an average of 34 days every 18 or 24 months. The record is 15 days. The effect of reduced refueling outage is quantifiable and has added at least 10 percentage points to average capacity factors.

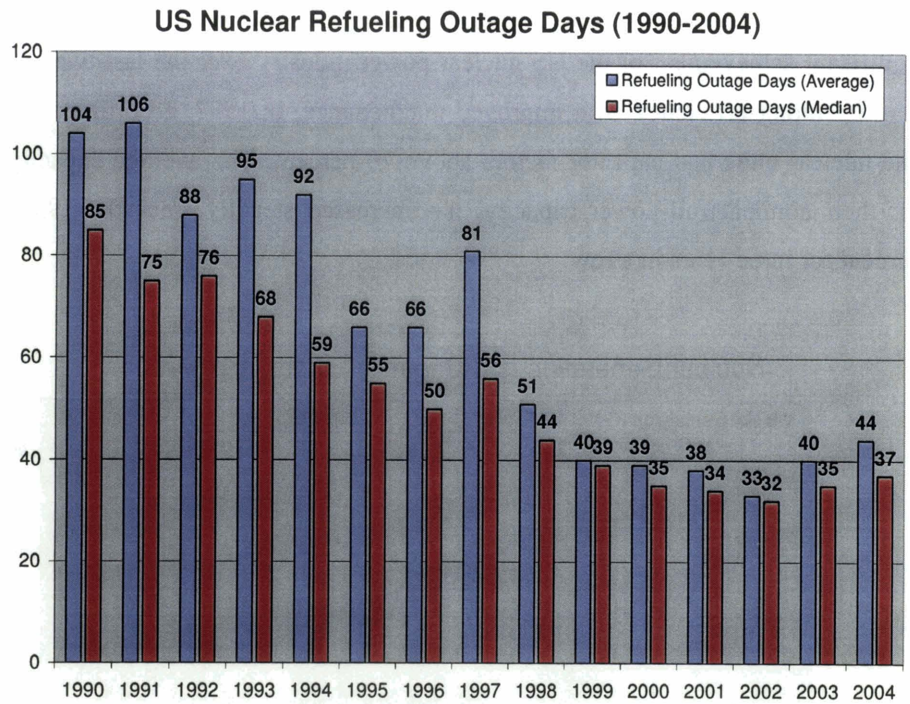


**Figure 15 – US Nuclear Refueling Outage Days, 1990-2004**
Source: Nuclear Energy Institute

Shutdowns can also occur at a nuclear power plant in the form of forced outages. Accumulation of operator experience and more effective maintenance have resulted in the reduced number and length of unplanned outages.

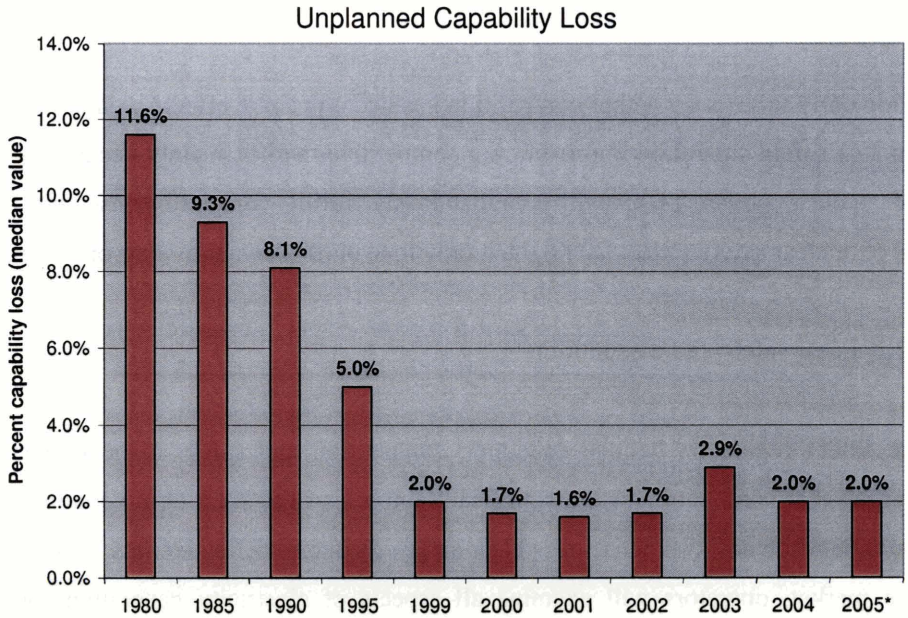


**Figure 16 – Unplanned Capability Loss**
Source: World Association of Nuclear Operators, 2005

Other factors of improved performance include the increased demand growth which allowed power plants to operate at nameplate capacity, and the efficiency improvements of staffing at nuclear power plants (from a thousand workers needed to run a plant in the 1980s to around 700 now).

All this is reflected in increased output between 1991 and 2004, from 612 billion kWh hours to 778 billion kWh, a 27 percent improvement without much change in installed capacity. The lack of capacity growth has been partly compensated since the 1990s by the first three factors listed above. After 1990, a few more reactors have come online, but the new capacity was offset by early retirements of several plants (Yankee Rowe, Trojan, San Onofre 1, Millstone 1, Haddam Neck, Maine Yankee, Big Rock Point, and Zion 1 and 2). Despite the early retirements, the total electricity generation by nuclear power plants has increased steadily from 640 million MWh in 1994 to about 788 million MWh in 2004 (an output increase equivalent to having 20 additional large units running at a 90 percent capacity factor).

### 4.2. Improved safety of the current nuclear fleet

It is too early to assess whether competition has had a positive effects on nuclear safety. One can argue that nuclear safety should be improved in a competitive market, mainly because safe and efficient operation of nuclear power plant will simultaneously fulfill competitiveness and the regulatory requirements of nuclear safety (NEA, 2000), be it only to avoid the denial of their operating licenses.

#### 4.2.1. Nuclear safety and competition

Some safety regulators believe economic competition and safety to be perfectly compatible. Others will argue that competition sets a significant emphasis over short-term economics: management decisions could be made at the expense of nuclear safety. Economic effectiveness being a major factor in a competitive market, operators will examine all aspects of electricity generation for cost-reduction purposes. In such a setting, safety upgrades and backfits are unlikely to be undertaken if they are not associated with productivity increases. The only remaining solution would then be explicit mandates by the NRC.

Furthermore, with market deregulation, nuclear safety regulatory authorities may tend to tighten their administrative control over nuclear generators, and intensify their overview in order to assure that economic deregulation does not compromise nuclear safety.[31] This tightening in regulatory control could negatively impact the competitiveness of nuclear power.

#### 4.2.2. Safety performance in the United States

The Nuclear Energy Institute (NEI) believes that high safety levels and good economic performance go hand-in-hand. US nuclear power plants have simultaneously managed to significantly reduce their production costs and achieved a high record of safety and reliability.

Safety system performance has improved from 92 percent in 1990 to an expected value of around 97 percent in 2005 according to WANO (World Association of Nuclear Operators) indicators. Unplanned automatic plant shutdowns were reduced considerably, and the number of accidents has been reduced more than threefold since 1990. In addition, collective radiation exposure of nuclear plant workers is now 40 percent of the already low levels achieved back in 1990.

[31] Bertel & Naudet, 2004

| Safety Performance Indicator | Description |
|---|---|
| **Unit Capability** | This indicator measures a plant's ability to stay on line and produce electricity. Plants with a high unit capability are successful in reducing unplanned outages and improving planned outages. |
| **Unplanned Capability Loss** | This indicator measures how much a plant is off line or unable to produce electricity due to power reductions, unplanned shutdowns or outage extensions. Plants with low unplanned capability loss have successful equipment performance and materiel condition programs. |
| **Safety System Performance** | This indicator monitors the availability of three standby safety systems – two main cooling systems and their backup power supplies – used to respond to unusual situations. The graph shows the percentage of systems achieving their availability goals each year. |
| **Unplanned Automatic Scrams** | This indicator shows the unplanned automatic scram rate. Plants with low scram rates have effective operations, engineering, maintenance, and training programs. |
| **Fuel Performance** | This indicator shows the percentage of units with no defects in the metal barrier that surrounds fuel. The industry's long-term goal is that units should strive to operate with zero defects. |
| **Chemistry Performance** | This indicator monitors the effectiveness of overall chemistry control, based on the concentration of impurities and corrosion products. This graph shows the percentage of units achieving specific 2005 goals that vary according to plant design. |
| **Industrial Safety** | This indicator tracks how many industrial accidents per 200,000 worker-hours result in lost work time, restricted work or fatalities. The nuclear industry continues to provide one of the safest industrial work environments. |
| **Collective Radiation Exposure – BWR/PWR** | This indicator measures the effectiveness of practices that reduce radiation exposure at boiling water reactors and pressurized water reactors. Low exposure indicates strong management attention to radiation protection. |

**Figure 17 –Safety Performance Indicators, definitions**

Source: World Association of Nuclear Operators, 2005

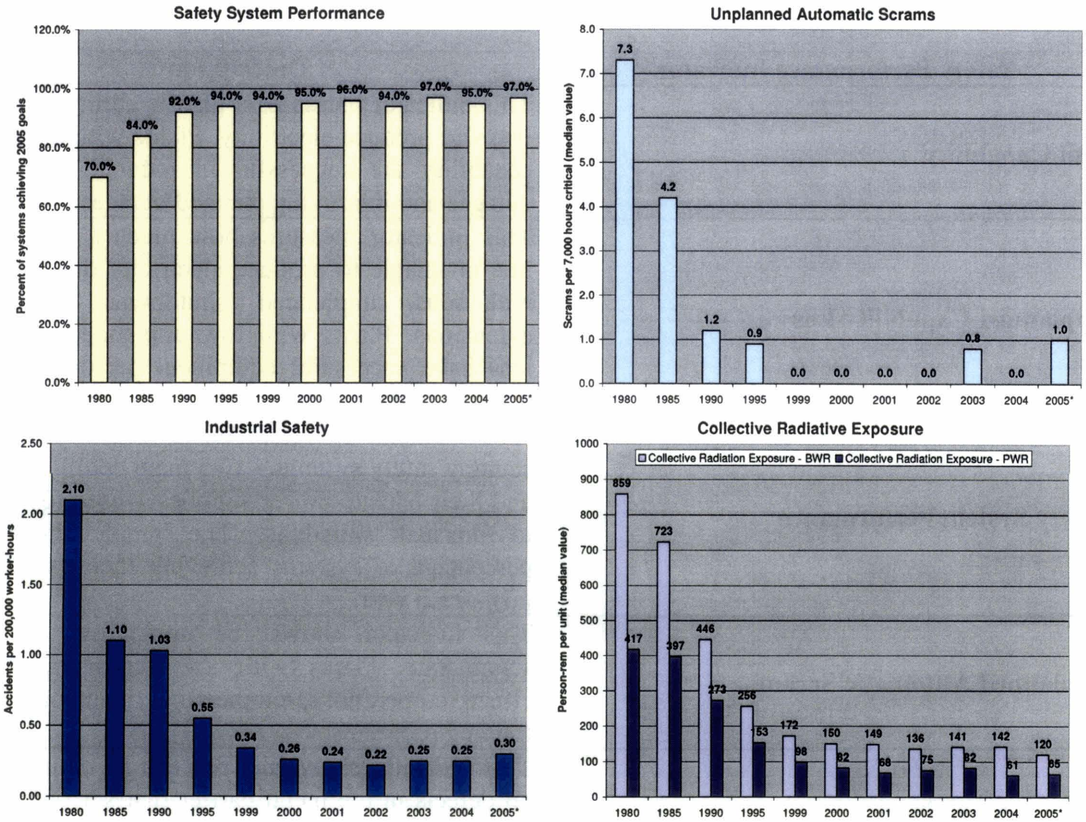


**Figure 18 –Safety Performance Indicators**
Source: World Association of Nuclear Operators, 2005

Concurrently, capacity factors have been trending upward in the same period, and according to NEI, nuclear power plants with the best performance ratings with the NRC also have the best capacity factors and the lowest O&M costs. According to NRC data, there has been a steady reduction in the number of significant events in US nuclear power plants, from an average of 2.4 events per unit in 1985 to 0.02 event per unit in 2004.

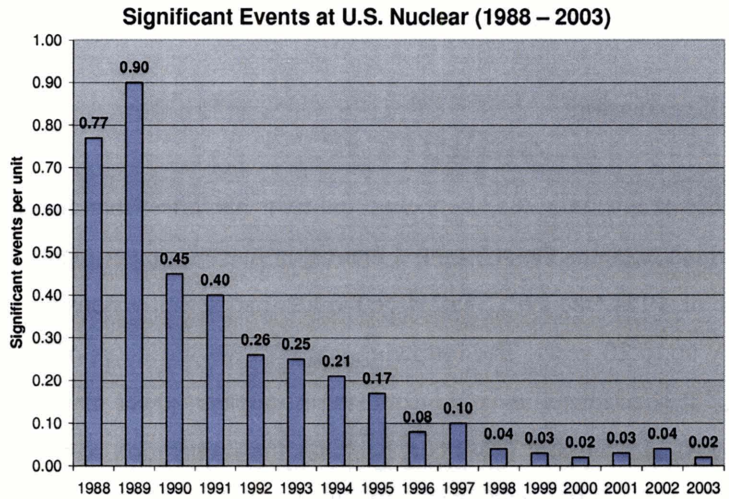


**Figure 19 – US Nuclear Significant Events (1988 – 2003)**
Source: Nuclear Energy Institute, 2004

Summing up, nuclear safety, regulatory compliance and efficient economic performance seem to be rather complementary. Safety is a key factor, since a nuclear power plants will be shut down if not operated safely. The importance of nuclear safety does not depend upon market conditions. In its final policy statement on the "Restructuring and Economic Deregulation of the Electric Utility Industry", the NRC states that economic deregulation does not preclude adequate protection of public health and safety.[32]

Thus, safety has been improving since 1990, but it is difficult to assess the main factor to which the success can be attributed. The regulatory change that appeared in the United States starting in 1995 on risk-informed regulations might also have played an important role in the safety improvements. The NRC defines risk-informed regulations as: "New techniques for measuring, analyzing, and ranking public health risks make it possible for the NRC to incorporate risk insights into its regulations. By risk-informing its regulations and regulatory processes, NRC can focus the attention of its licensees on those design and operational issues most important to safety and move away from prescriptive regulations based on conservative engineering judgments toward regulations focused on issues that significantly contribute to safety." It is also legitimate to expect cost-reductions and safety improvements from such measures, and there has not been any study to assess the contribution of safety regulatory design versus market competition. Such a study may use statistical analysis of safety performance indicators in regulated and deregulated states with or without risk-informed practices, and quantify the correlation between safety improvements and deregulation and/or risk-information.

[32] NEA, 2000

4.3. Prospects for the US nuclear electricity generation without investments in new plants

4.3.1.Plant life extension

The cost of life extension in the US is expected to be much less than that of building a new power plant of any kind, which explains the substantial interest in nuclear power plant life extension. Under the Atomic Energy Act of 1954, the NRC has issued rules that permit extension of nuclear power plant operating licenses by up to 20 years. The following graph shows the status of license renewal in the US. According to NEA,[33] it is estimated that life extension of nuclear power plants in the United States will cost approximately \$10-\$15 million: this figure includes the preparation of the renewal application, the review fees incurred by the NRC, and potentially hearings costs. License renewal will clearly allow utilities to maintain generating capacity without large investment costs for the construction of new plants as replacements.

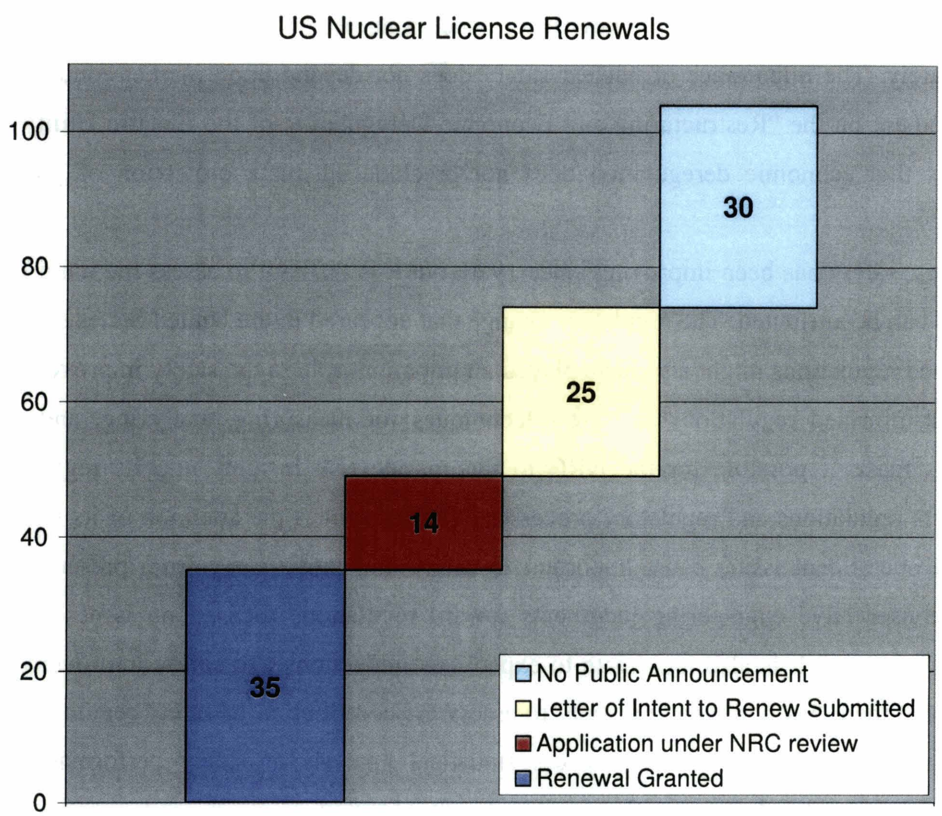


**Figure 20 – US Nuclear License Renewals, as of January 2005**
Source: Nuclear Regulatory Commission, 2005

[33] NEA, 2000

License renewal is a critical issue for the future of the existing fleet. Originally, operating licenses for current plants had been granted by the NRC for 40 years, and some will begin expiring in the next decade. For example, the oldest nuclear plant in operation in the US is Nine Mile Point 1 in New York; it came online in December of 1969, and its license, along with three others, is to expire in 2009. Approximately one quarter of the existing fleet will reach the end of their original license period before 2015.

According to various industry comments, the vast majority of existing units should get their licenses renewed. The first renewal was approved by the NRC in 2001, adding 20 years to the operating license of the 2-unit Calvert Cliffs plant in Maryland. Since then another 28 units have had their licenses renewed, making 30 renewals in all.

The license extension process typically takes around two years to complete, and 18 units are under review. Owners of at least 28 units have informed the NRC their intention to file for renewal. The remaining 30 units have not made any public announcement, but they are all still in time to prepare for the filing.

### 4.3.2. Capacity upgrades

Nuclear power plant power upgrades, or uprates, is another method for increasing capacity without building new nuclear power plants, thereby avoiding the high investment costs of such projects. Power companies in the United States have been using power uprates since the 1970s and the NRC has approved more than 100 applications totaling over 4 GW so far. Of those 4 GW of uprating, about 2 GW have been approved over the past few years, as reflected by the net increase in nuclear capacity after 2000 in the United States.

The NRC has defined three separate categories of nuclear power plant power uprates:

| **Category** | **General principle** | **Capacity changes** |
|---|---|---|
| *Measurement uncertainty recapture* | Measurement of reactor power with improved instrumentation to reduce uncertainty | ➢ 1.3 percent to 1.7 percent in most cases |
| *Stretch power uprates* | Taking advantage of extra margins of safety included in the plant's original design | ➢ Up to 7 percent can be achieved<br>➢ NRC has typically approved uprates of between 4 and 6 percent |
| *Extended power uprates* | Extensive changes to the plant's turbines, pumps, generators, and other non-nuclear equipment | ➢ 6 percent up to 20 percent<br>➢ All but one of the approved extended power uprates are BWRs |

Uprating can add as much as 20 percent to a plant's capacity. Since 2001, eight units at five sites have received uprates of between 15 and 20 percent.[34] The plants are Brunswick (two units, 15 percent), Duane Arnold (15.3 percent), Dresden (two units, 17 percent), Quad Cities (two units, 17.2 percent), and Clinton (20 percent). Five of these units are owned by nuclear leader Exelon Corp. In addition to these, six plants received uprates of between 10 and 24 percent in connection with provisional operating licenses between 1969 and 1990. Four additional cases, Vermont Yankee and the three units at Browns Ferry, have applied for uprates of between 15 and 20 percent and are under NRC review. Counting the cases under review and expected by the NRC, additions are estimated around 2 to 3 GW from uprating over the next few years.

#### 4.3.3. Refurbishments

In 1985, a period of management turmoil due to safety concerns, the Tennessee Valley Authority (TVA) shut all three Browns Ferry units.

In subsequent years, Browns Ferry units 2 and 3 resumed operations. Unit 2 was eventually restarted in 1991, and unit 3 came back online in 1995.

Browns Ferry Unit 1 is now being refurbished by TVA, for a cost of around $1.7 billion. If refurbishment occurs as planned, the 1,280 MW-unit is scheduled to be restarted in 2007.

#### 4.3.4. Capacity factor improvements

The US nuclear fleet average capacity factor reached 91 percent in 2004. However, this value is already quite close to the technical limits of reactor design. Indeed, under existing technologies, all US reactors need to shut down for refueling every 18 or 24 months. We have shown that the average duration of refueling outages had been steadily declining over the past decade to a value of 34 days. Several plants have managed to refuel in less than 20 days, but 30 days is usually a minimum, especially when other maintenance needs to be performed during the shutdown.

The maximum achievable capacity factor with one 30-day refueling outage every 18 months will be between 94 and 95 percent. Plant ageing will also mean more necessary inspection and repairs. Thus,

[34] NRC, 2005a

there is little likelihood that performance will achieve levels much above the current 91 percent on average.

### 4.3.5. Modest prospects for expansion: absent new builds, the capacity will decline

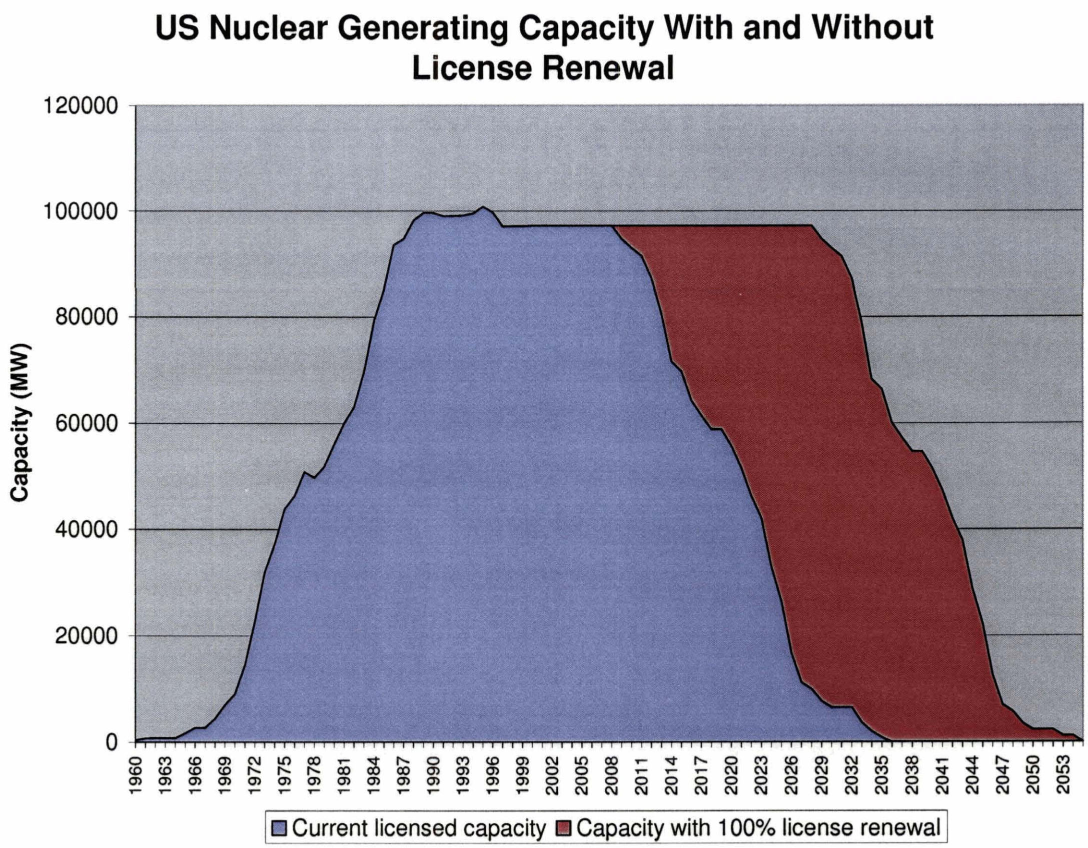


**Figure 21 – US Nuclear Generating Capacity With and Without License Renewal**
Source: Dominion Resources

The figure above shows the potential of the existing fleet in the coming years and the importance of license renewal. Uprates will augment the 99 GW existing capacity by several hundreds of megawatts per year for the next few years. In addition, the restart of Browns Ferry Unit 1, which has been down since 1985 will provide additional capacity in 2007.

However, despite this slight enlargement of the fleet,[35] the US nuclear capacity would begin a sharp decline after 2010 if licenses are not renewed. On the other hand, renewal of the entire fleet will maintain capacity until after 2025.

[35] The increase is not reflected in the above figure by Dominion Resources

If the expansion of the nuclear fleet remains so modest, it will mean a decreasing trend of the share of nuclear generation. Even with full renewal and 92 percent capacity factor, if no new plant is built, 35 years from now at the most, US nuclear capacity will be reduced by a factor of one half, and 50 years from now, the capacity will be down to zero. This gives an idea of how many new plants would have to be built if the objective was to keep the capacity constant.

According to EIA projections, the share of nuclear generation from the existing fleet will decline if no new capacity is built, from 20 percent today to 18 percent in 2015, and 15 percent in 2025. If the objective was to maintain today's 20 percent share, over 30 GW of new nuclear capacity would be needed by 2025.

# PART II: Drivers impacting potential new investments in new nuclear power plants in the United States

## 5. Characterization of risk and uncertainties related to power generation under a competitive environment

### 5.1. Risks and uncertainties faced by power generating projects

An industrial project can only be realized if it is possible to find financing to carry it out. In the case of nuclear power generation equipment, financing is an exceptionally difficult matter, especially when it comes to calling for private investment, because of the risks and uncertainties to which the project is exposed in a competitive electric market.

The first step to be taken in project finance is to identify the risks to which the project will be exposed throughout its lifetime, and to characterize them as closely as possible. Banks and private investors will only invest in a nuclear project if risks are properly mitigated.

| | **Risks and uncertainties bearing upon all power generation projects** | **Risks and uncertainties bearing upon all nuclear power generation projects** |
|---|---|---|
| *Economics/Market* | Interest rate<br>Exchange rates<br>Electricity price<br>Electricity demand<br>Coal price and supply<br>Oil price and supply<br>Gas price and supply | Uranium price and supply |
| *Technology* | Transmission availability | Construction<br>Technology and design<br>Development and siting<br>Operation and maintenance |
| *Regulation* | Environmental<br>Market-related<br>Fiscal | Commissioning and licensing<br>Safety<br>Waste storage and disposal<br>Decommissioning<br>Accidents |
| ***Other*** | Country<br>Climate<br>Force majeure<br>Legal | Political<br>Public acceptance |

**Figure 22 – Risks and uncertainties for baseload electricity generation projects**

The table above and the subsequent sections intend to classify and explain risks and uncertainties bearing upon any power generation project, and those specifically related to nuclear power projects.

## 5.2. Economics and market-related risks

### 5.2.1. Interest rate risk

Interest rate might vary over time, and variations represent a risk to the investor. Interest rate risk is defined as "The risk that a security's value changes due to a change in interest rates. For example, a bond's price drops as interest rates rise."[36]

The high capital-intensiveness of nuclear power makes it more sensitive than other technologies to the evolution of the interest rate, considering the large proportion of debt in the capital, the cost of capital is very affected by any change in the interest rate.

### 5.2.2. Exchange rates risk

Exchange rate risk is "also called currency risk, the risk of an investment's value changing because of currency exchange rates."[37]

Some of the financial commitments for a power project may be subscribed in a currency that is not $US: investments, long-term contracts for fuel supply… As a result, a depreciation of the $US compared to other currencies would create a risk on the overall profitability of the project.

### 5.2.3. Electricity price risk

Electricity prices determine the level of revenues that a utility can achieve given the total output. Consequently, in case most of the off-take is sold on the spot market, the profitability of the company will be highly sensitive to variations in the price for electricity.

It will be beneficial for a power plant to operate provided the price for electricity exceeds the marginal cost of production. As a result, a price drop would affect gas-fired plants more acutely because their operating costs are very high. Even if the price decreases, revenues are more likely to exceed operating costs for a nuclear power plant than for a CCGT: the NPP will operate while the CCGT might not. Even if the IOU owning the nuclear power plant does not generate sufficient revenue to ensure return

[36] http://biz.yahoo.com/glossary/bfglosi.html
[37] http://biz.yahoo.com/glossary/bfglosi.html

on equity of investment bearing a certain level of risk, revenues may still be sufficient to provide debt repayment, which would prevent the IOU from bankruptcy.[38]

### 5.2.4. Electricity demand risk

Evaluating the growth rate of electricity demand is a complex issue. Demand for electric power is closely intertwined with the growth rate of the economy overall: one can choose to estimate that growth around 2% a year,[39] and however reasonable that hypothesis may be, it still provides no certitude as to how high consumption from the industry will be, or how efficient energy efficiency policies will prove to be.[40] The demand risk materializes when revenues are lower because the level of long-term demand for electricity does not enable full utilization of the plant.

In a regulated context, operators in a monopolistic situation have a relatively good anticipation of demand, at least for baseload demand, that they can extrapolate from national consumption and their long term import and export contracts.

In a deregulated context, however, when a utility chooses to invest in new capacity, the underlying hope is competitiveness, that is long-term production at costs below market prices and increasing market share. Consequently, the investment decision is closely related to market price signals – even though those prices themselves depend in reverse on the investment decisions of all operators. Investments in new capacity bear higher exposure because their profitability depends on a factor that is largely variable – the market price for electricity – and operators must anticipate future prices on the basis of future demand on a macroeconomic scale and the distribution among the various actors of the market.[41]

### 5.2.5. Fuel prices and supply risk

For a given technology, the uncertainty about fuel price and the availability of supply generates a risk of losses incurred by the operator, or at least higher operating costs in case of fuel price spike or supply interruption. Consequently, the uncertainty on fuel price and supply directly impacts the competitiveness of a technology over the other.

[38] Zaleski & Méritet, 2004
[39] EIA, 2005a
[40] Pignon, 2004
[41] Pignon, 2004

In a competitive environment, should fossil-fuel prices increase, the profitability of nuclear power would increase. However, it is difficult to anticipate gas, coal or oil prices because they are highly related to technology advances and estimations of world reserves.

Price volatility for gas is higher than for coal, which is in turn greater than that for uranium. Moreover, the proportion of fuel costs within the overall cost of production plays an important part. Fuel accounts for a much larger portion of power generation costs for gas-fired plants than for coal-fired or nuclear power plant (around 72% for CCGT versus 41% for coal and 19% for nuclear, consistently with earlier calculations).

According to current forecasts, uranium supply, at least in the US, is stable, and it is unlikely that changes in uranium price would substantially affect the cost of nuclear power generation. Conversely, gas supply is at risk: transporting gas is an issue especially when done through pipelines. If the pipeline owner is unable to transport the gas because of geographic conditions, the gas-fired plant will be unable to operate.

## 5.3. Technology-related risks

### 5.3.1. Transmission availability risk

Electric power stations need the transmission network to be such that they can dispatch their production. If transmission is constrained for a power plant, the utility might lose revenues because the off-take of the plant's power production is reduced. Moreover, nuclear units are generally of a large size, which amplifies the potential problem arising from transmission capacity.

### 5.3.2. Construction risk

When undertaking a power plant project, there is always uncertainty due to the complex technologies involved that some of the costs or construction times might not have been properly estimated, or that additional costs and schedule delays might incur to the project. Construction, labor, and materials might generate uncertainty at the initial stages of the project. This is all the more true in case of a first-of-a-kind construction, lacking any previous experience.

During the construction period, the more complex the building of the power plant is, and the higher the weight of the investment, the more serious the consequences of technological issues. As a result, a large premium will be attributed to power plants that have proven to be functioning with similar designs. In other words, new designs will be penalized.[42]

### 5.3.3. Technology and design risks

Some risk bears upon the technology and design of the reactor. The source mainly lies within the possible failure or below-grade operating performance, potentially stemming from faulty design of the reactor and balance of the plant system. Should such risks materialize, the output will be reduced, and with it the revenues generated by the power plant. Consequently, investors must take this risk into account in their decision to build a power plant, and this risk includes nuclear power, considering the complexity of the technology that offers more chances of failure.

### 5.3.4. Development and siting risk

In the siting of the new power plant, investors might face unexpected costs when preparing construction, some of which coming from specific site designs. For nuclear reactors, there could be a high cost in trying to build at new sites rather than at existing sites.

By choosing to build at non-greenfield sites, already hosting a nuclear unit, some of the siting risk would be offset.

The Early Site Permit process is also supposed to prevent such shortcomings.

### 5.3.5. Operation and maintenance risk

Poor or inefficient management, operation, and maintenance of a reactor may result in increasing O&M costs. During operations, nuclear power plants implement innovating and complex technologies, at an even higher level than coal-fired or gas-fired power plants. Even with a long operating experience, as well as good ratings, risk premium and insurance have large fees. Those premiums would turn out even higher in case of a major technological change.

[42] Zaleski & Méritet, 2004

## 5.4. Regulatory risks

Regulations and their stability are very important before investment, especially in the case of a nuclear power plant. Shifts in regulations may affect critical phases of the development of a project. There are several types of uncertainties regarding regulations that could affect investment in power generation. Some of them bear upon any kind of project in electric power generation, and some are specific to nuclear power.

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### 5.4.1. Construction, commissioning and licensing regulatory risks

In large-scale power projects, there are specific regulatory measures regarding project development that have considerable impact on the investment decision. Those regulations may include siting, commissioning and licensing. Regulations influence the profitability of a project because of the time constraints and potential additional costs they may impose on the utility undertaking the new construction, should there be extended construction times or delays in the process.

In the United States, regulatory changes have caused the decline of the nuclear power program, with frequent extensions in construction time and unpredicted costs. The accident at the Three Mile Island power plant has required regulations to change.[43]

The United States has now implemented a new regulatory system that should lead to more stability and shorter construction times comparable to countries such as France and Japan. It involves Design Certification, Early Site Permits (ESP) and Combined Construction-Operating Licenses (COL), and will be later discussed in this study.

### 5.4.2. Environmental regulations risk

Although other sources of electric power do not face the same skepticism as nuclear power, public opinion and governments might impose measures regarding emissions. Those measures could be more or less binding for utilities, and concern $SO_2$, $NO_x$, particulate matters as well as greenhouse gases.

Policies could include the implementation of a carbon tax that would penalize $CO_2$ emissions (or any other type of tax on other emissions), tax credits for low-emitting power generation technologies, emissions trading… All the above measures would impose an additional cost on emission-intensive, and

[43] Zaleski & Méritet, 2004

more specifically on carbon-intensive generation technologies. Nuclear energy being a pollution-free source of electricity would consequently become more attractive in such a context, as coal and gas would be penalized by additional costs.

### 5.4.3.Safety regulations risk

Safety measures represent a large portion of the operation and maintenance costs. Any accident or precursor event could awaken concern about the safety of power plants, and result in a change in safety regulations, thereby increasing the O&M costs.

Conversely, the spreading of the use of "risk-informed regulations" would tend to reduce some of the maintenance costs based on the probabilistic risk of failure of certain components, and there is also a chance safety regulations might soften on a local basis.

Consequently, safety regulatory changes represent a risk (positive or negative) which might affect the way an investor makes a decision for a nuclear power plant.

### 5.4.4.Market regulations risk

After the process of deregulation of the energy industries, there is still some uncertainty on whether some of the rules might evolve.

There is a chance investment strategies might evaluate the risk of such changes. As an illustrative example, a threat to reduce the cap in SO2 emissions in the Acid Rain program would undoubtedly affect the behavior in investment in emission control technologies. Similar considerations can be made for investment in nuclear power or other new power plants in the US.

### 5.4.5.Fiscal risk

The uncertainty inherent to a fiscal policy is that tax rates could change at any moment, thereby affecting the expected profitability of an investment. Although it might not bear a very high probability in the United States, there are countries where investment is largely affected by fiscal risk.

### 5.4.6. Waste disposal and decommissioning risk

The uncertainty bearing upon waste storage and disposal as well as on decommissioning relates to the costs for disposing of spent fuel and, to a lesser degree, low-level waste, as well as the costs for decommissioning.

Waste management is a very important risk to be covered for the investor. Final waste management is normally the responsibility of public authorities. Even without a new project, existing radioactive waste should be dealt with. If the public authorities deal with the waste, it is natural that they should charge the utility for waste storage and disposal, and even the decommissioning of the plant at the end of its life.[44]

Regulations in the US are currently designed so that a utility undertaking a new project must provision decommissioning funds to a certain amount. There are still some technical and regulatory uncertainties on those issues and uncertainty about the fee, which puts the investor in a difficult position, considering the decommissioning funds have to be saved initially. Moreover, managing the saved funds might turn out to be an issue for the utility. The United Kingdom had to face the problem when it turned out that all of the decommissioning funds had been invested in high risk and high return stocks during the internet bubble, and that a reasonable portion of the invested capital was lost.

Investors are required to save a relatively small amount of money initially for future decommissioning. As a result, even with large premiums to cover risk, such charges have a small impact on the investment decision.

### 5.4.7. Accident risk

After the accidents occurred in 1979 at the Three Mile Island nuclear power station and in 1986 at the Chernobyl nuclear power station, concerns have arisen about the safety of nuclear energy. In any case, the risk incurred by investors relates to third party liability and the costs of remediation and recovery in case of a major accident, force majeure, or terrorist incident.

In 1957, Congress passed the Price-Anderson Act, which provides for payment of public liability claims in the event of a nuclear incident. The act provides an umbrella of insurance protection, and it ensured that enough money would be available to pay liability claims that could result from a major nuclear accident or attack.[45]

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[44] Zaleski & Méritet, 2004
[45] NEI, 2005b

## 5.5. Other sources of risk and uncertainty

### 5.5.1. Country risk

"The financial risks of a transaction that relate to the political, economic, or social instability of the country of the debtor, and is over and above the credit risk of the borrower"[46]

### 5.5.2. Climate risk

Wind farms have the highest exposure to climate risk in their operating requirements. Indeed, the strength and steadiness of the wind is most important for the efficiency of a wind farm. The intermittency of the wind impedes the full competitiveness of wind power technologies. As a result, wind farm operators must cover themselves against that risk.

Moreover, the recurrence of climate disorders and the increased frequency of natural disasters that seem to form into patterns increase the risks of system failure in general: hydraulic resources shortages, heat waves or cold waves, electric wires wrenching...). This can also explain the progressive implementation of climate derivatives markets.[47]

### 5.5.3. Force majeure risk

The financial definition of a force majeure risk is a risk "that there will be prolonged interruption of operations for a project finance enterprise due to fire, flood, storm, or some other factor beyond the control of the project's sponsors."[48] The factors could include natural disasters, strikes, civil wars...

[46] http://www.tefo.org/trade-finance-glossary/c.html
[47] Esnault, 2002
[48] http://financial-dictionary.thefreedictionary.com/Force+majeure+risk

### 5.5.4. Legal risk

Legal risk is "risk from uncertainty due to legal actions or uncertainty in the applicability or interpretation of contracts, laws or regulations."[49] Legal risk highly depends on an institution's circumstances, but it generally entails issues such as potential bankruptcy from legal proceedings, application of the terms included in a contract, choice of the legal system if there are discrepancies across entities involved in the transaction, mediation and arbitration systems, ex-post renegotiation of a contract...

### 5.5.5. Political risk

Generally speaking, political risk is the "risk that a country's government will suddenly change its policies."[50] It is measured by the consistency of government policies and the quality of economic management. Elements like foreign debt or foreign exchange reserve are taken into account. This category of risk includes changes that could occur in the political system and that would question the initial hypotheses of the investment, such as taxation rate, foreign currency control and circulation of capital, laws on the participation of foreign companies in the capital of local firms, sovereign risks of expropriation or nationalization, etc.[51]

For an investor, it is essential to evaluate the political authorities' attitude and its stability when deciding on whether to finance any technology-based project, all the more for a power project. When the sector in question is deregulated, profitability is a key factor and the impact of bad investment decisions bears upon the investors, hence the necessity of stable political orientations. In extreme cases, the project will not receive the permits and licenses necessary for operation. Otherwise, operations might be interrupted or delayed, thereby preventing the project from being unprofitable. Construction can be delayed, due to new regulatory provisions that make the licensing process stricter or that increase operating costs. Those issues are all the more intense for nuclear power investment because of both its capital intensiveness and the opposing opinions. The future of nuclear power clearly depends on the pro- or anti-nuclear attitude adopted by the government.[52]

There are countries that chose to renounce the nuclear option. Among those countries, some were not operating any nuclear power plant, and some simply opted out of nuclear with a profitable and

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[49] http://www.riskglossary.com/link/legal_risk.htm
[50] http://www.investopedia.com/terms/p/politicalrisk.asp
[51] Pignon & Tarbe, 2004
[52] Zaleski & Méritet, 2004

operating nuclear fleet. Examples can be found in Sweden, Germany and Belgium. Those decisions to stop all nuclear operations can be maintained if the political majority in power at the time of the decision remains, or be overruled if the majority changes. Those public attitude changes will highly depend on whether no-nuclear energy policies can function in a sustainable manner, especially on an economic and environmental standpoint, as well as on whether nuclear-inclusive energy policies succeed.[53]

Obviously, when the political majority is against any nuclear power program, no new nuclear power plant will be built. However, potential investors must evaluate the risk related to any change in the attitude of the political authority. In the US, had Al Gore been elected for President in 2000, any hope of a new nuclear energy program would have been in vain in the short run, whereas, although not decided yet, George W. Bush is favorable to the nuclear option and there is some hope it might lead to new investments.[54]

The necessity for the investor to appropriately evaluate the probability of a change in public attitude towards nuclear power is even higher during the period between the beginning of construction and the beginning of operation. After operation has started, there is a lower chance that the government might require closure and decommissioning of the plant. In Germany, any operating plant is authorized to continue operation until the end of the payback period.[55] In contrast, other sources of electric power, even fossil-fuel power generation, do not face the same risk of a ban.

#### 5.5.6.Public acceptance risk

For obvious reasons, the attitude political authorities adopt towards a technology is highly influenced by public opinion. Regarding public opinion matters, nuclear power has a string disadvantage compared to other power generation technologies. There are individuals and organizations utterly opposed to nuclear energy for various reasons regarding accident risks, the long term liability of radioactive waste, proliferation concerns, etc. Those fundamental disagreements are very difficult to argue and technological development can barely offset the concerns of such entities. Moreover, such opposition often holds a very wide media broadcast: consequently, they can result in public opinion swings at times when nuclear power programs are being discussed.

As was discussed above, there are countries, such as Germany, where pubic opinion was in such disfavor against nuclear energy, that the government had to pass bills to opt out of nuclear power. Such

[53] Zaleski & Méritet, 2004
[54] Zaleski & Méritet, 2004
[55] Zaleski & Méritet, 2004

political decisions can be either maintained even if public opinion evolves in favor of nuclear power. In Sweden for instance, operation of nuclear power plants proved to be a success, and public opinion changed. Like any political decision, there can be underlying agreements between political entities involving related issues and which compromise over nuclear energy matters.[56]

## 5.6. Effect of nuclear-specific risks on investments

As a consequence of a number of risks characterized above, the assumptions of the base-case scenario for calculations of levelized costs of electricity are subject to uncertainties. Therefore, it is useful to conduct sensitivity analyses in order to determine the impact of different assumptions on the cost of producing electricity.

As a first step, the most critical input assumptions were tested: some of the key assumptions are varied by 5% and the change in levelized costs of electricity is calculated. The results of this analysis are displayed below for the nuclear power, coal (pulverized coal) and gas (combined cycle).

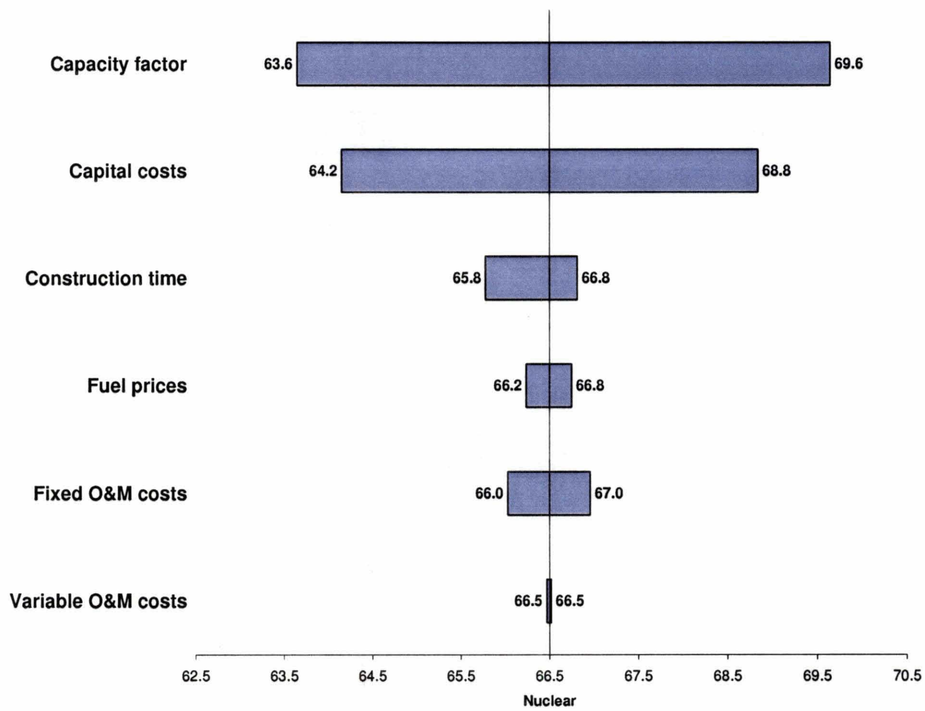


**Figure 23 – Sensitivity of LCOE to a 5% change in key assumptions – Nuclear**

[56] Zaleski & Méritet, 2004

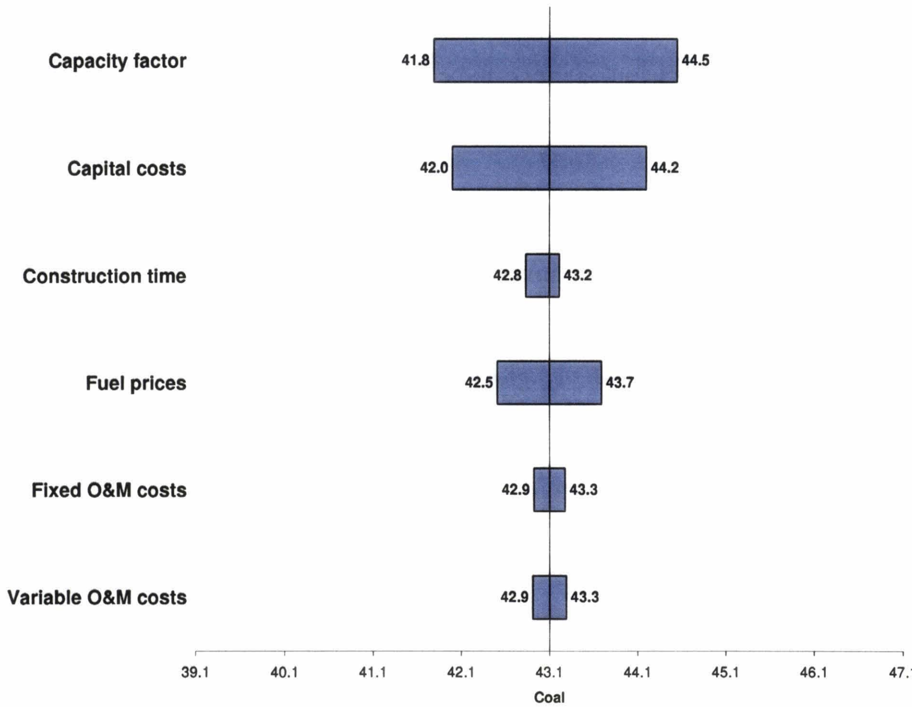


**Figure 24 – Sensitivity of LCOE to a 5% change in key assumptions – Coal**

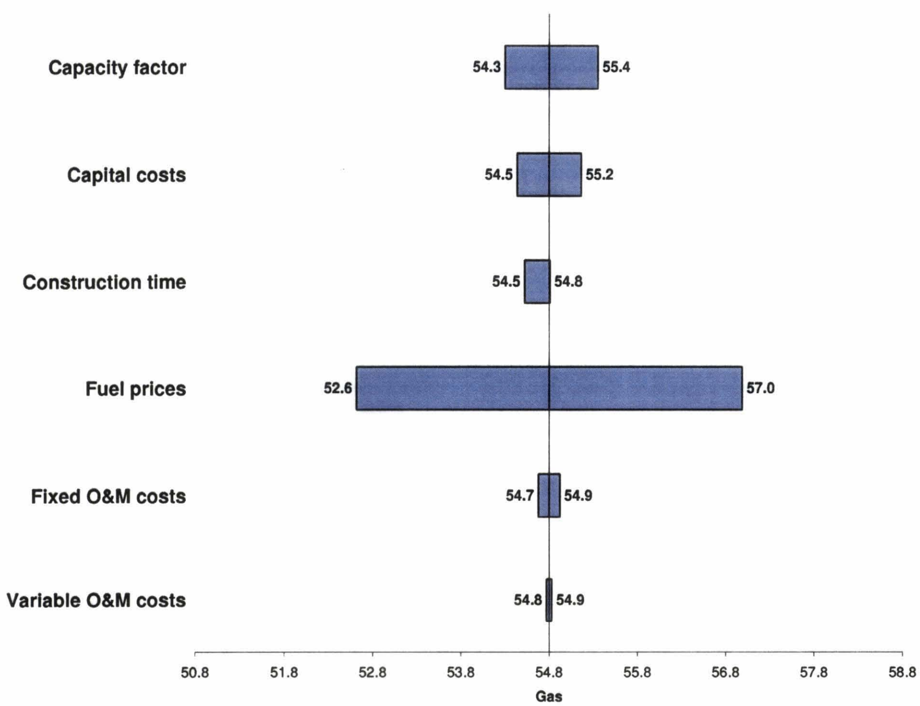


**Figure 25 – Sensitivity of LCOE to a 5% change in key assumptions – Gas**

The results of this analysis show the relative importance of a change in important elements of the LCOE calculations.

The costs of production for nuclear power are extremely sensitive to capacity factor and capital cost variations. Since the ratio of capital costs to short term marginal costs is higher than for other technologies, it was predictable that a variation in capacity factor would affect all positive cash flows and have a large impact on marginal benefits. Because annualized capital costs represent around 75% of LCOE, it is no surprise either that uncertainty in capital costs propagates to a large extent as well. This also explains why LCOE is not highly sensitive to fuel cost variations, as fuel costs account for a much smaller share of production costs.

Coal-fired power generation is, to a lesser extent, capital intensive, which explains similar trends in sensitivity to capacity factor and capital costs. Fuel representing a larger share in coal-fired electricity production, it was also likely to have a larger impact than in the case of nuclear power.

Last, gas has much lower capital costs, which explains why a small variation in capital costs or capacity factor has little impact on LCOE. Fuel costs are the largest cost item in gas-fired power generation: as a result, LCOE are very sensitive to fuel prices. This also explains why gas prices are a very important element of the investment decision in nuclear power: high increases in natural gas prices could greatly contribute in making nuclear power cost-competitive with gas-fired electricity production.

## 5.7. Comparison with other studies

Several studies have been published to assess the economics of nuclear power, and there are conflicting views on whether nuclear energy is competitive over time with other baseload options.

A study by the Ministry of Economy, Finance, and Industry in France supporting the Flamanville projects has recently concluded that nuclear energy was the lowest-cost option.

In the United States, the MIT study and the University of Chicago Study concluded nuclear power was more expensive than other sources. The Canadian Energy Research Institute and the Royal Academy of Engineering in the United Kingdom have also assessed the economics of nuclear power.

The disagreement between the studies is essentially due to differing assumptions regarding nuclear plants capital costs and capacity factors, and most importantly discount rate and cost of capital. Regional variations in the fuel price and labor costs also play an important role.

Moreover, Page: 71
an important explicit assumption of the MIT study is that the cost calculations were carried out for conditions appropriate to merchant plant investments. Those conditions have significant consequences on

the general economic and financial environment. Conversely, the studies by the French Ministry of Economy, Finance, and Industry and by the Royal Academy of Engineering assume investments are made by the public sector (in France, Electricité de France). Other studies do not explicitly state equivalent assumptions.

All studies agree on the fact that if fossil fuel prices continue to rise, the competitiveness of nuclear power will be improved.

Also, European assessments of nuclear power economics now also must include the price of CO2 allowances under the EU Emissions Trading Scheme, which began in January 2005. Long-term prices are uncertain for many reasons, but emissions are currently trading at around 17 euros/ton of CO2. The competitiveness of nuclear energy is improved relative to fossil fuels. It is supposed to have been a factor in the Finnish decision to build a fifth nuclear reactor.

| | | **MIT[57]** | **UofC[58]** | **CERI[59]** | **RAE[60]** | **DGEMP[61]** |
|---|---|---|---|---|---|---|
| **Year published** | | 2003 | 2004 | 2004 | 2004 | 2003 |
| **Capital cost** | $/kW | 2,000 | 1,500 | 2,080 | 2,000 | 1,835 |
| **Rate of Return** | % | 15 | 12.5 | 8 | 7.5 | 8 |
| **Capacity factor** | % | 85 | 85 | 90 | >90 | >90 |
| **Operating life** | Years | 40 | 15 | 30 | 25 & 40 | 35–50 |
| **Depreciation period** | Years | 15 | 15 | — | 25 & 40 | 35–50 |
| **Construction period** | Years | 5 | 5–7 | 6 | 5 | 5 |
| **Variable operating costs** | $/MWh | 15 | 5.35 | 3.1 | 6.9 | — |
| **Fixed operating costs** | $/kW | 0 | 60 | 60 | 71 | — |
| **Generating cost** | $/MWh | 67–70 | 54–62 | 43–59 | 39–42 | 26 |

**Figure 26 – Summary of Recently Published Studies of Nuclear Power Costs**
Source: MIT, University of Chicago, CERI, Royal Academy of Engineering, DGEMP[62]

[57] MIT, 2003
[58] University of Chicago, 2004
[59] Canada Energy Research Institute, 2004
[60] Royal Academy of Engineering, 2004
[61] DGEMP, 2003
[62] Direction Générale des Energie et Matières Premières, office of the French Ministry of Economy, Finance, and Industry in charge of energy and raw materials

6. Nuclear power worldwide – the nuclear option is still open

6.1. Worldwide historic trends and prospects for new nuclear construction

6.1.1. Growing momentum in nuclear reactor construction

As of 2005, 31 countries were operating 439 nuclear plants for electricity generation, for a total net installed capacity of 366 GWe, and nuclear energy represented around 16% of the world's electricity generation.

In absolute value, nuclear energy seems to be growing worldwide. Whereas a nuclear comeback is still debated in the United States, the following graph shows that, in spite of a slow-down at the end of the 1980s, nuclear power was never abandoned.

The International Atomic Energy Agency (IAEA) has significantly increased its projected worldwide nuclear generating capacity,[63] bringing it to at least 60 new plants in the next 15 years, making 430 GW in place in 2020. It would bring capacity 17% higher than existing capacity in 2005.

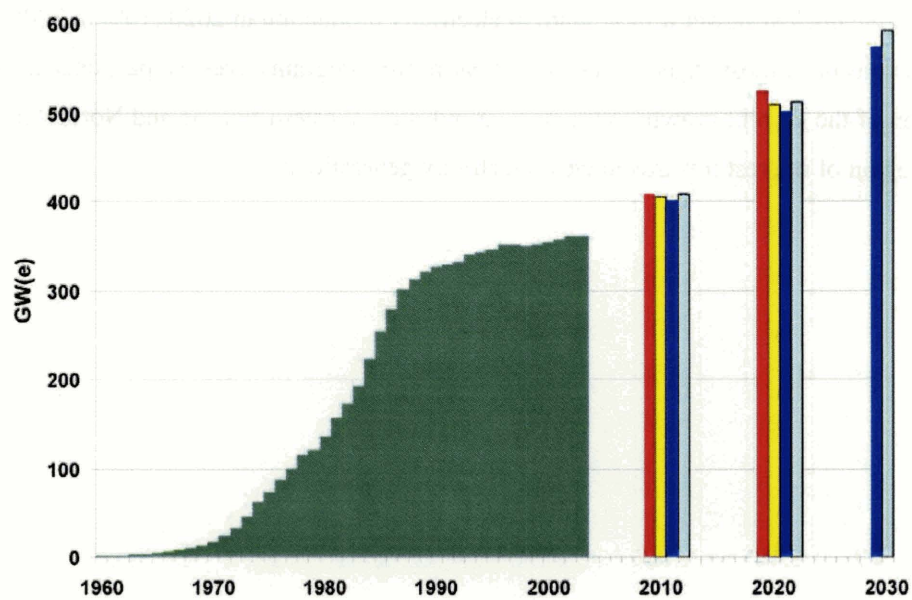


**Figure 27 – Historical growth in global nuclear capacity and the IAEA's high projections**
Source: McDonald, 2005

[63] WNA, 2005a

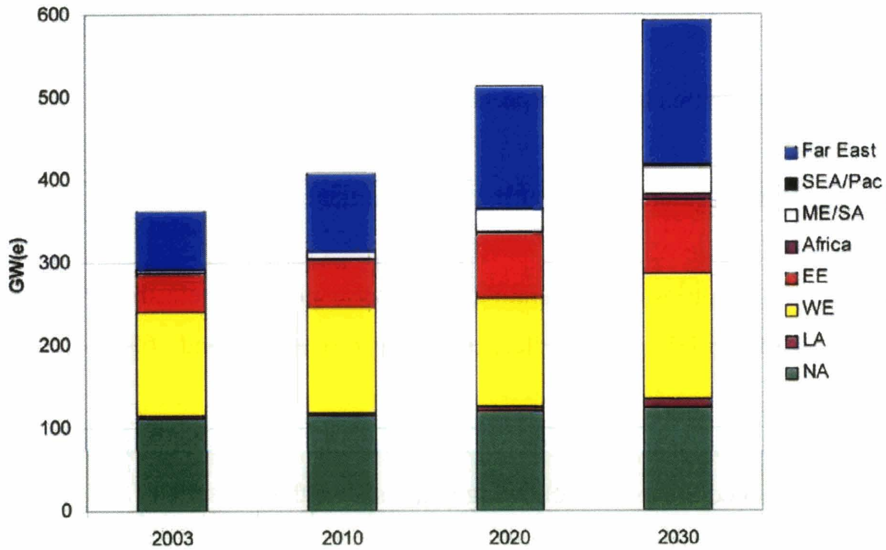


**Figure 28 – Regional distribution of global nuclear capacity in the IAEA's high projection**
Source: McDonald, 2004

The projection revisions are based on specific plans and actions taken in countries like China, India, Russia, Finland and France, along with the new perspectives attributable to the Kyoto Protocol. This would give nuclear power a 17% share in electricity production in 2020 (16% in 2005).

Asia has been most eager to pursue nuclear power programs over the past decade, and represent a large portion of the current growth in the nuclear industry. Western Europe and North America also seem to show a regain of interest towards nuclear electricity generation.

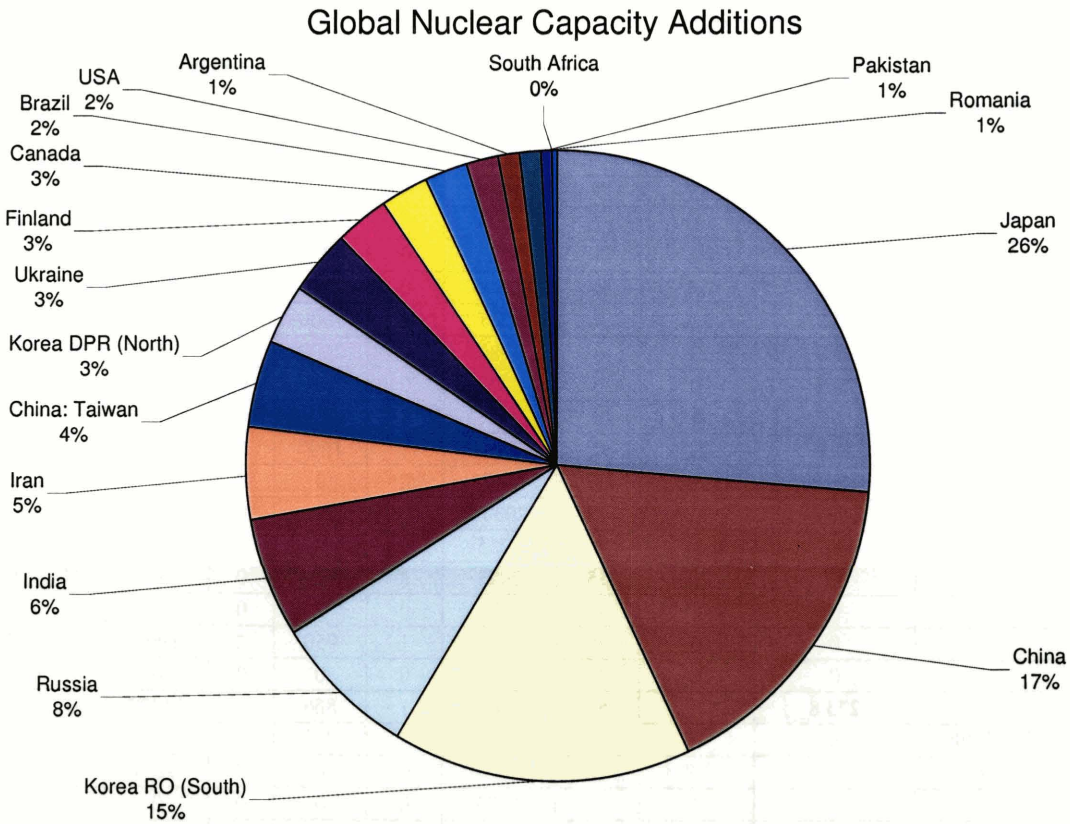


**Figure 29 – Planned Global Nuclear Net Capacity Additions (60 GWe in total)**
Source: World Nuclear Association, 2005

In the 1950s, the initial developments of the civilian use of nuclear energy were led by the United States and a subset of Western European countries. Since the 1990s, however, while the nuclear pioneers progressively stopped adding nuclear capacity, other countries, suffering energy crises since the 1970s, took on the nuclear option, most notably among Asian nations.

For means of comparison, North America and Western Europe accounted for 87% of the nuclear power capacity built in the 1960s, 77% in the 1970s, and 71% in the 1980s and down to 44% in the 1990s. Since 2000, not a single nuclear power plant has gone online in either region.

Thirty-one countries now have commercial nuclear power reactors in operation, and thirty-eight countries are operating, building or proposing nuclear capacity. As of September 2005, almost 60 GW of new nuclear capacity in 17 countries is currently on order or under construction, and an additional 64 GW have been proposed.

| | Nuclear Electricity Generation 2004 | | Operable | | Under Construction | | On order or Planned | | Proposed | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Country** | **billion kWh** | **% total** | **No** | **MWe** | **No** | **MWe** | **No** | **MWe** | **No** | **MWe** |
| Argentina | 7.3 | 8.2 | 2 | 935 | 1 | 692 | 0 | 0 | 0 | 0 |
| Armenia | 2.2 | 39 | 1 | 376 | 0 | 0 | 0 | 0 | 0 | 0 |
| Belgium | 44.9 | 55 | 7 | 5728 | 0 | 0 | 0 | 0 | 0 | 0 |
| Brazil | 11.5 | 3 | 2 | 1901 | 0 | 0 | 1 | 1245 | 0 | 0 |
| Bulgaria | 15.6 | 42 | 4 | 2722 | 0 | 0 | 0 | 0 | 1 | 1000 |
| Canada | 85.3 | 15 | 18 | 12595 | 0 | 0 | 2 | 1540 | 0 | 0 |
| China | 47.8 | 2.2 | 9 | 6587 | 2 | 1900 | 8 | 8000 | 19 | 15000 |
| China: Taiwan | 37.9 | 21 | 6 | 4884 | 2 | 2600 | 0 | 0 | 0 | 0 |
| Czech Republic | 26.3 | 31 | 6 | 3472 | 0 | 0 | 0 | 0 | 2 | 1900 |
| Egypt | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 600 |
| Finland | 21.8 | 27 | 4 | 2656 | 1 | 1600 | 0 | 0 | 0 | 0 |
| France | 426.8 | 78 | 59 | 63473 | 0 | 0 | 0 | 0 | 1 | 1600 |
| Germany | 158.4 | 32 | 17 | 20303 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hungary | 11.2 | 34 | 4 | 1755 | 0 | 0 | 0 | 0 | 0 | 0 |
| India | 15 | 2.8 | 15 | 2993 | 8 | 3638 | 0 | 0 | 24 | 13160 |
| Indonesia | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 2000 |
| Iran | 0 | 0 | 0 | 0 | 1 | 950 | 2 | 1900 | 3 | 2850 |
| Israel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1200 |
| Japan | 273.8 | 29 | 55 | 47700 | 1 | 866 | 12 | 14782 | 0 | 0 |
| Korea DPR (North) | 0 | 0 | 0 | 0 | 1 | 950 | 1 | 950 | 0 | 0 |
| Korea RO (South) | 124 | 38 | 20 | 16840 | 0 | 0 | 8 | 9200 | 0 | 0 |
| Lithuania | 13.9 | 72 | 1 | 1185 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mexico | 10.6 | 5.2 | 2 | 1310 | 0 | 0 | 0 | 0 | 0 | 0 |
| Netherlands | 3.6 | 3.8 | 1 | 452 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pakistan | 1.9 | 2.4 | 2 | 425 | 0 | 0 | 1 | 300 | 0 | 0 |
| Romania | 5.1 | 10 | 1 | 655 | 1 | 655 | 0 | 0 | 3 | 1995 |
| Russia | 133 | 16 | 31 | 21743 | 4 | 3600 | 1 | 925 | 8 | 9375 |
| Slovakia | 15.6 | 55 | 6 | 2472 | 0 | 0 | 0 | 0 | 2 | 840 |
| Slovenia | 5.2 | 38 | 1 | 676 | 0 | 0 | 0 | 0 | 0 | 0 |
| South Africa | 14.3 | 6.6 | 2 | 1842 | 0 | 0 | 1 | 165 | 24 | 4000 |
| Spain | 60.9 | 23 | 9 | 7584 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sweden | 75 | 52 | 10 | 8904 | 0 | 0 | 0 | 0 | 0 | 0 |
| Switzerland | 25.4 | 40 | 5 | 3220 | 0 | 0 | 0 | 0 | 0 | 0 |
| Turkey | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 4500 |
| Ukraine | 81.1 | 51 | 15 | 13168 | 0 | 0 | 2 | 1900 | 0 | 0 |
| United Kingdom | 73.7 | 19 | 23 | 11852 | 0 | 0 | 0 | 0 | 0 | 0 |
| USA | 788.6 | 20 | 103 | 97838 | 1 | 1065 | 0 | 0 | 2 | 2850 |
| Vietnam | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 2000 |
| **WORLD** | **2618.6** | **16** | **441** | **368,246** | **23** | **18,516** | **39** | **40,907** | **98** | **64,670** |

**Figure 30 – Nuclear Power Plants Operating and Under Construction**
Source: World Nuclear Association, 2005

6.1.2.Substantial constructions in Asia

| | Operating (GW) | Nuclear Generation Share (%) | Under Construction (GW) | Additions Target (GW) |
|---|---|---|---|---|
| **China** | 6.6 | 2 | 2.0 | 30 by 2020 |
| **India** | 2.6 | 3 | 4.1 | 18 by 2020 |
| **Japan** | 45.5 | 25 | 3.2 | 15 by 2015 |
| **Russia** | 21.7 | 17 | 1.9 | 15–25 by 2020 |
| **South Korea** | 16.8 | 40 | 0.0 | 10 by 2015 |

**Figure 31 – Countries with Substantial Targets**
Source: World Nuclear Association, 2005

China has 9 nuclear reactors and 6.6 GW in operation. 2 GW are currently under construction, and the nuclear power program aims at bringing an additional 30 GW of new nuclear capacity online before 2020, using both foreign and indigenous designs. Government approval has been granted for about one third of the 30 GW, and China is now reviewing bids for four pressurized water reactors. Contracts should be awarded in fall 2005.

Japan – despite recent problems at operating reactors – plans to expand its nuclear program. With an installed capacity of 45.5 GW, Japan currently has three reactors for a total of 2.4 GW under construction. Moreover, 15 GW are on order or scheduled to go online before 2015, some of which are currently undergoing government approval. Recent nuclear accidents and safety scandals have deteriorated public acceptance of nuclear power in Japan. Early in 2001, slow demand growth led the major utility TEPCO (Tokyo Electric Power Company) to postpone plans for twelve major fossil fuel plants but maintained its schedule for four new nuclear plants.[64]

India has nine reactors under construction and expected to be completed by 2010. From the 2.6 GW currently in operation, and 4.1 GW under construction, the plan is to expand the current fleet to 20 GW by 2020. A few early plants used American and Canadian designs. New plants, on the contrary, will be either of Indian-design (heavy water reactors) or Russian-built (PWRs).[65]

Russia has engaged in an expansion plan to build 15 to 25 GW of new nuclear capacity by 2020. After retrofitting or shutting down the Chernobyl-type plants, Russia has 21.7 GW in operation. The five reactors under construction add up to 4.5 GW, due for completion in 2010. New construction includes a 750 MW fast breeder reactor. This will increase Russia's nuclear power capacity to 50 GW. Construction of a sixth plant has been halted because of lack of funds. Russia also plans five reactors to replace existing units at Leningrad, Novovoronezh, and Kursk.

[64] WNA, 2005a
[65] Page: 77
This will possibly change as a result of the proposed new bilateral agreement for cooperation between the US and India.

South Korea has steadily built up its nuclear power capability and fleet over the past three decades. It has 15.9 GW in operation and plans to bring an additional 10 GW online by 2015 with nine new reactors. South Korea used US, Canadian and French designs before 1990and has developed its own designs thanks to technology transfer.

In Iran, nuclear power plant construction was suspended in 1979, but an agreement with Russia was signed in 1995 to complete a 1000 MWe PWR at Bushehr. Construction is well advanced and a further unit is planned. Iran's uranium enrichment program has become the central point of contention with Europe and the United States, over whether it is pursuing nuclear weapons.

In addition, nations as diverse as Pakistan, South Africa, Argentina, Indonesia, Vietnam, Egypt and Turkey have shown interest in nuclear power.[66] Pakistan intends to build a new 300 MWe reactor at Chasma, and the government has signed a contract with China for construction and financing. Argentina is developing plans to complete the stalled Atucha-2 reactor. Indonesia has completed the feasibility study for its first 1800 MWe nuclear power station. Vietnam is also considering its first nuclear power venture, and Egypt and Turkey have for decades included a nuclear power plant in their electricity plans.

[66] WNA, 2005a

6.2. Comparison with investment in other technologies

To understand the extent to which nuclear power is gaining momentum internationally, it is relevant to consider other sources of electric power and the pace at which their construction is expected to occur in the coming years. The International Energy Outlook[67] carries out such projections, and the following discussion is based on the results from their 2005 report.

In 2002, worldwide electricity generation capacity was 3,315 GW. In order to meet the projected electricity demand between 2002 and 2025 (end of the forecast period), the installed capacity will have to grow to 5,495 GW in 2025, with a compound annual growth rate of 2.2%.

Since the beginning of the 1980s, high world oil prices lead to increased use of natural gas and nuclear power, and to reinforce coal-fired electricity generation. The IEO2005 reference case expects increased use of natural gas for electricity generation to continue. Coal is expected to retain the largest market share for electricity generation, though it will decrease in favor of gas-fired power generation. Hydropower and other renewable energy sources are projected to grow by 54% between 2002 and 2025, maintaining their share of total electricity generation near the current level of 18%.

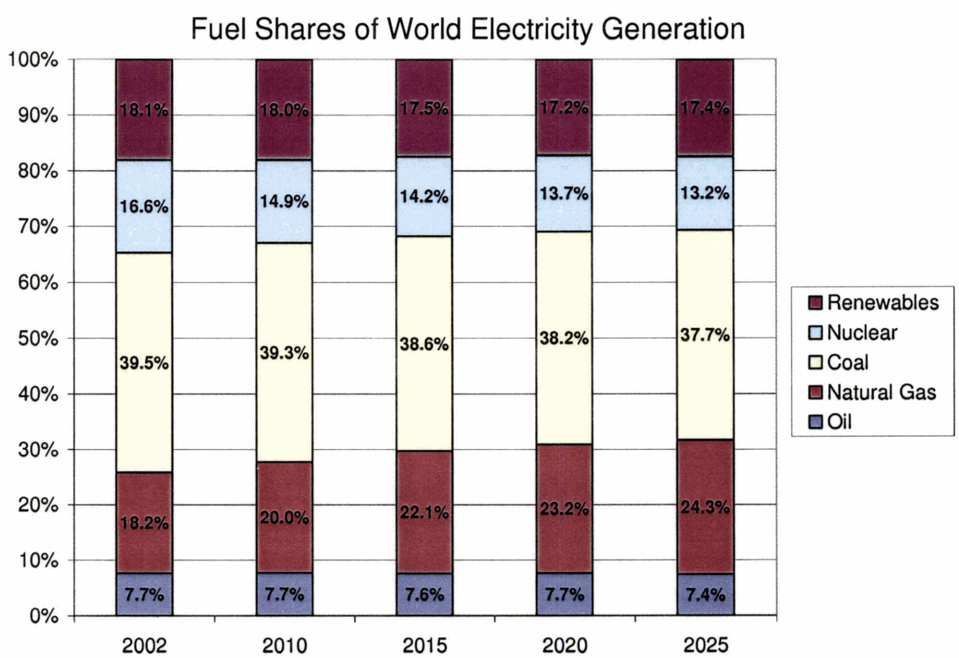


**Figure 32 – Fuel Shares of World Electricity Generation**
Source: International Energy Outlook, 2005

[67] EIA, 2005b

Despite the argument made in the preceding section, nuclear power should see its role reduced, from 16.6% in 2002 to 13.2% in 2025. Some new reactors are expected to be added over the forecast period, mostly in the emerging and transitional economies, but it is not projected to maintain the share of nuclear electricity generation at current levels. One can argue that the forecast is from 2002, and that some countries which were not expected to take on a new nuclear power program did, or that other countries with active civilian nuclear energy have declared their intention to build more nuclear capacity.

## 7. Qualification of recent developments impacting potential new investments in nuclear power

### 7.1. Growing public acceptance of potential new nuclear power constructions

We have already discussed the importance of public opinion when considering new power plant projects. In the United States, the general public has long been skeptical about nuclear power. According to the MIT study,[68] a majority of Americans approve the continued use of nuclear power, but oppose the building of new nuclear power plants. Although public opinion has softened since the accident at the Three Mile Island accident in 1979, there is still a strong public concern. More specifically, there is still a large majority of people opposing the construction of a new nuclear power plant within 25 miles from their dwelling. The most important factors weighing upon public attitude are in decreasing order of importance:

- Perceived environmental harm caused by nuclear power;
- Safety performances and waste disposal issues;
- Perceived costs associated with nuclear power;
- Concerns about global warming.

The evidence from the MIT survey also suggests that a public information campaign to change perceptions might not be enough to change public opinion.

However, a more recent survey carried out for the Nuclear Energy Institute by Bisconti Research [69]Inc. in 2005 shows that public acceptance has grown over the years, and that 70%of the US population are now in favor of nuclear power, and only 24 percent oppose it. Moreover, 69% of the population finds it acceptable to build new nuclear power plants if it is required by increased electricity needs. 58% said that new nuclear plants should definitely be built, and 74% wanted the option to build new plants to be kept open. More than three times as many strongly supported nuclear energy than strongly opposed it. Two thirds of self-described environmentalists favor it. This trend is quite homogeneous region by region. The general public is favorable to public policies regarding nuclear power such as investment incentives (64%) and public-private partnerships (80%).

The strong momentum for support of nuclear energy comes from near unanimous belief in the future importance of nuclear energy; awareness of nuclear energy's clean-air benefits, efficiency and reliability; and growing confidence in nuclear power plant safety.

[68] MIT, 2003
[69] Bisconti, 2005

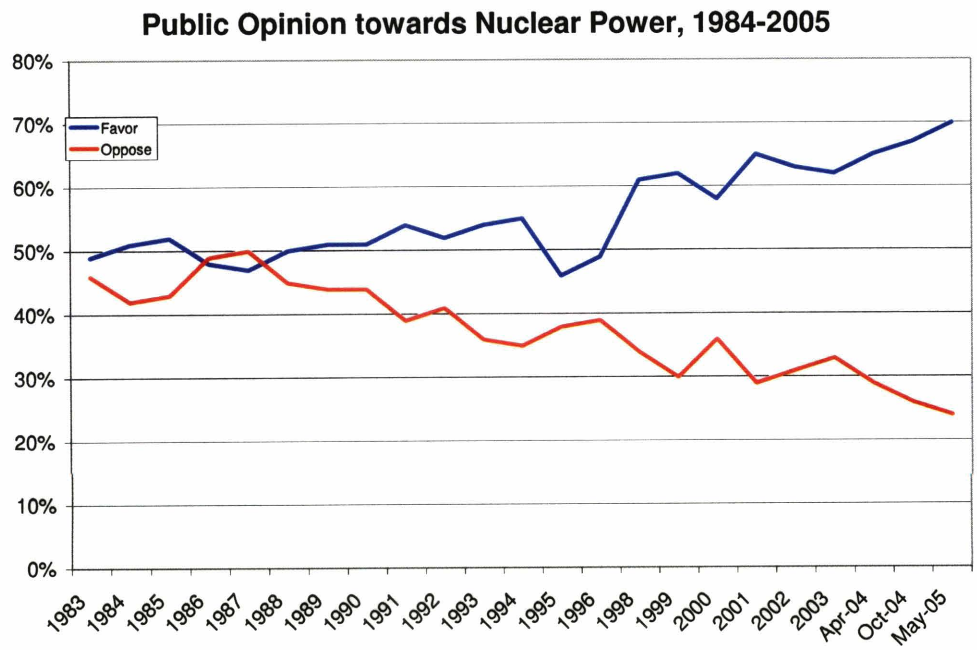


**Figure 33 – Public Opinion towards Nuclear Power, 1984-2005**
Source: Bisconti Research, July 2005

## 7.2. Yucca Mountain and the issue of nuclear waste disposal in the US

### 7.2.1. US need for radioactive waste disposal

Radioactive waste disposal is an unavoidable issue for nuclear power. Establishing long-term disposal solutions for spent nuclear fuel and low-level radioactive waste is indispensable. Indeed, spent nuclear fuel rods are intensely radioactive after they have been removed from the reactor core. The rods are then stored for cooling in large pools, which remove heat and block radiation. After several years, rods can be removed from the pool to be placed for long-term storage in large concrete casks. The latter solution has been widely used as the pools have been filling up over the years.

In the United States, the efforts to solve the radioactive waste issue have been stalled and nearly 50,000 metric tons of uranium from spent nuclear fuel is currently stored. Of the 103 nuclear reactors operating in the United States, approximately 50 reactors will exhaust on-site pool storage capacity for used nuclear fuel by the end of 2005 and will have to consider other storage measures that will be costly to consumers.

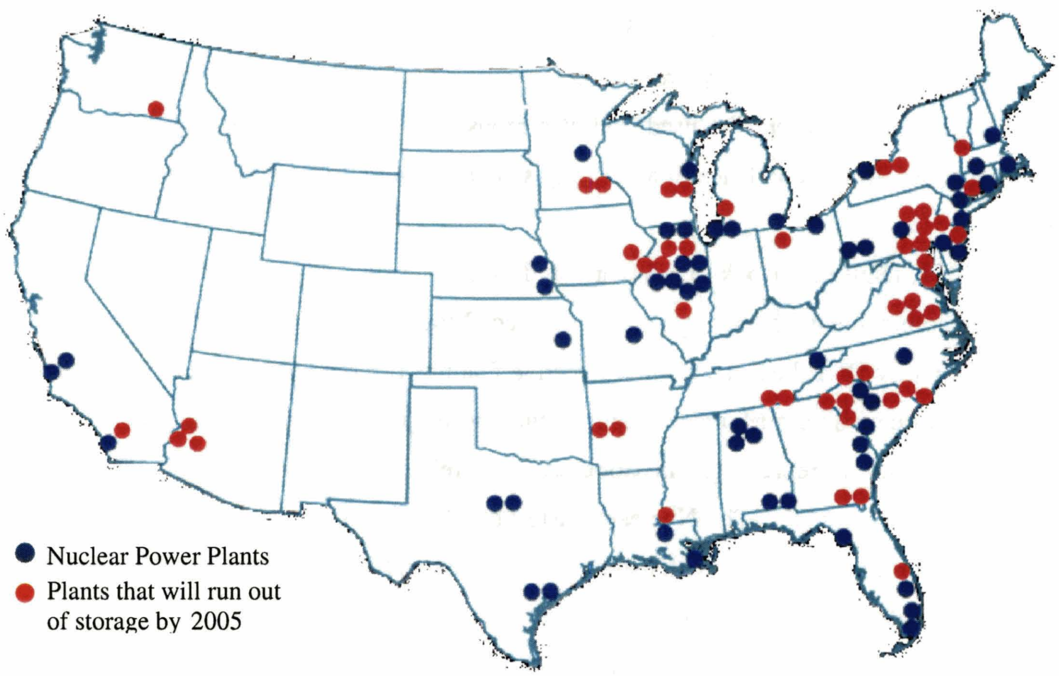


**Figure 34 – 52 Plants Will Run Out of Used Fuel Storage by 2005**
Source: Nuclear Energy Institute

Like many other nations, the United States has determined that spent nuclear fuel should be disposed of in a permanent geologic repository. Yucca Mountain, adjacent to the nuclear weapons test range near Las Vegas, Nevada, was formally chosen as the site when Congress ratified a decision by President George W. Bush in 2002.

### 7.2.2. The Yucca Mountain project

After the Nuclear Waste Policy Act of 1982, Congress assigned the Department of Energy (DOE) to the responsibility for managing used fuel from the nation's nuclear power plants and high-level radioactive waste from U.S. defense programs by building a disposal facility. Additionally, the Nuclear Regulatory Commission (NRC) was charged with establishing regulations and licensing construction, operation and closure of the repository. The Environmental Protection Agency (EPA) was assigned to set public health and safety standards for the operation of a repository. The 1982 legislation called for two repositories.

The federal government's waste program was to be financed by a tax levied on electricity generated by nuclear power. Since 1983, nearly $24 billion has been committed to the Nuclear Waste Fund by consumers of electricity from nuclear power plants. DOE signed contracts with electricity companies agreeing to accept the used fuel at a repository, beginning in 1998. Consequently, in 1985, EPA promulgates 40 CFR 191 health and safety standards and NRC issues 10 CFR 60 generic licensing standards.

In 1983, DOE undertook preliminary studies of nine sites in six states. The conclusions of DOE were three recommendations, among which the Yucca Mountain site. In 1986, however, Yucca Mountain was ranked first by DOE because of the protective features offered by the aridity and remoteness of the site. The literature on Yucca Mountain suggests that the site was picked on the basis of "politics". Indeed, the State of Nevada is represented in Congress by a relatively small congressional delegation, and is outnumbered by other states. The Nuclear Waste Policy Act of 1982 is amended in 1987, selecting the Yucca Mountain Site for more extensive site characterization, emphasizing the need for a second repository on or after January 1, 2007, but no later than January 1, 2010.

In the following years, the Civilian Radioactive Waste Management Program faced changing legislative mandates, regulatory modifications, fluctuating funding levels, and the evolving and often conflicting needs and expectations of diverse interest groups. The different were realizing the complexity and the costs of the challenge. It seemed that many of the initial expectations would not be met.

In 1992, the Energy Policy Act required EPA to set standards for Yucca Mountain based on National Academy of Sciences recommendations, and directed NRC to make technical requirements consistent with EPA rule. In 2001, EPA issued 40 CFR 197 to limit radiation doses received by the public from the planned high-level waste disposal facility at Yucca Mountain. The standards set a 15 millirems per year dose limit for the first 10,000 years after the facility was closed.

In 1996, a coalition of state utility regulators, attorneys general and utilities with nuclear plants from more than 20 states filed suit to force DOE to take the used fuel. The U.S. Court of Appeals reaffirmed DOE's legal obligation to begin accepting used fuel in 1998. Following that ruling, federal courts have continued to hold DOE accountable to its fuel acceptance deadline based on various legal principles. Since 1998, the U.S. Court of Federal Claims ruled on several occasions that DOE breached its contract to begin used fuel acceptance. Unforeseen expenses at short-term storage sites and damages represent a potential taxpayer liability of more than $56 billion. In August 2004, Exelon Corp. settled a few cases with DOE related to this liability, and Exelon is to receive an initial payment of $80 million and continue to collect additional damages each year until DOE removes the used fuel from the company's plant sites.[70]

In 2002, Congress approved the Yucca Mountain site, and the president signed into law a resolution designating Yucca Mountain as the site of a federal repository for used nuclear fuel and high-level radioactive waste from defense programs. This decision was later supported by State governors, legislators, utility commissioners, and consumer and citizen organizations. Indeed, the Yucca Mountain project is believed by many as an important milestone in meeting the nation's environmental, energy and national security goals.

After Congress and Presidential approval, DOE needs to place its effort in obtaining licenses from NRC to build and operate a repository. Completion of the application is close and a license application to the NRC should be submitted soon. The framework by which the NRC will assess the Yucca Mountain application is based on the same risk-informed, performance-based principles that the industry has applied in building its improvements in safety performance.

DOE is years behind in meeting its commitment to electricity ratepayers. Since presidential and congressional approvals of Yucca Mountain in 2002, Nevada has been trying to challenge the decision. In July 2004, the U.S. Court of Appeals in Washington, D.C., issued decisions on a group of such consolidated cases. In its rulings, the appeals court rejected all of Nevada's claims, except its challenge regarding the 10,000-year compliance period for meeting EPA regulatory requirements to protect the public from radiation exposure. The court ruled that a scientific report requested by Congress in 1992 favored a period longer than the 10,000-year compliance. The federal government was given two options:

[70] NEI, 2005c

reinstating the 10,000-year compliance period by legislation or revising the EPA regulations to address longer time frames. To ensure safety beyond 10,000 years to 1 million years, EPA has proposed a separate, higher dose limit based on natural background radiation levels that people currently live with in the U.S. (350 millirems).

At the end of 2004, DOE announced the submission of a license application to the NRC was delayed, and that the 2010 deadline for accepting used fuel from reactor owners and operators would not be met. Energy Secretary Samuel Bodman committed to submit the license application in 2005.

### 7.2.3. Yucca Mountain is not a show-stopper

According to NEI[71], delay is not critical for the operation of existing reactors or the construction of new ones. Completing the Yucca Mountain project is very important, especially in the perspective of regaining public acceptance. But the existing fleet can operate and new plants can be built even if Yucca Mountain is delayed until 2020 or later. Onsite storage remains a viable option, and will be necessary even if spent fuel is stored at Yucca Mountain very soon.

Moreover, Yucca Mountain's capacity is limited by statute to a total of 70,000 tons of heavy metal. As of 2005, there are about 50,000 metric tons of commercial used nuclear fuel and about 12,000 metric tons of defense high-level radioactive waste awaiting disposal at Yucca Mountain. An additional 2,000 metric tons is generated each year. DOE expects to begin receiving up to 3,000 metric tons a year of used fuel beginning in 2016; the 70,000 metric ton political limit will not be reached until at least 2040.

In total, approximately 120,000 tons of spent nuclear fuel and high-level defense waste are lined up for geologic disposal. The number varies for it depends on reactor operating license renewals, potential early closures, and foreign research reactor fuel of US origin. Some believe that plutonium from dismantled nuclear weapons may be mixed with radioactive waste and placed in the repository.

Nevertheless, the capacity of a repository at the Yucca Mountain site has been determined politically, not scientifically. Congress chose to limit the capacity of the Yucca Mountain repository to 70,000 metric tons of heavy metal or equivalent in the 1982 Nuclear Waste Policy Act. One of the reasons for this capacity limitation is the intention to keep a balance between the Eastern and the Western part of the country: by limiting capacity at Yucca Mountain, Congress expected that another site would be chosen near the East Coast to welcome high-level radioactive waste as well.

Scientific analysis demonstrates that the Yucca Mountain site is physically capable of holding much more used fuel than the politically-determined capacity. The Environmental Impact Statement

[71] NEI, 2005c

conducted by the Department of Energy showed that the site could safely dispose of 120,000 metric tons. Some scientists even believe that repository capacity could be extended to 200,000 metric tons.

The decision will remain in the hands of Congress as to whether it wants to authorize a second repository or increase the capacity at Yucca Mountain. According to the Nuclear Waste Policy Act of 1982, DOE will report to Congress between 2007 and 2010 on the need for a second national repository.

In any case, spent fuel from new reactors would not be sent to the repository for many years. Indeed, Yucca Mountain will accept the oldest, coolest fuel first to avoid the risks of remaining decay heat that would degrade canisters. Fuel from a new reactor would be last in line for disposal. Thus the timing of Yucca Mountain completion has little practical impact on new nuclear reactors.

### 7.3. The new NRC regulatory process

#### 7.3.1. Before vs. After

The vast majority of the US commercial nuclear plants were licensed during the 1960s and 1970s. Commercial nuclear energy was new, and the regulatory process evolved along with the new industry. Under 10 CFR Part 50,[72] nuclear plants were issued a construction permit based on a preliminary design. An operating license was granted only after construction was complete and hundreds of millions of dollars (in some cases billions) had been spent.

A major flaw in the licensing and construction process was that construction permits were issued on the basis of designs that were neither standardized nor complete, and safety issues were not fully resolved until the plant was essentially complete. In many cases, only 10% of the design was complete at the construction permit stage. The old process often involved significant rework and redesign.

Furthermore, after the Three Mile Island accident of 1979, NRC required design changes to plants under construction before they could be licensed to operate. Options for addressing these issues during construction were limited and costly, resulting in delays and cost overruns. Indeed, once the plant was built, it had to receive a license to operate. During that period, the facility stood idle, while the licensing proceeding progressed. In some cases, projects took 10-plus years to complete, and overruns reached several billion dollars. Hence, the process was clearly inefficient.

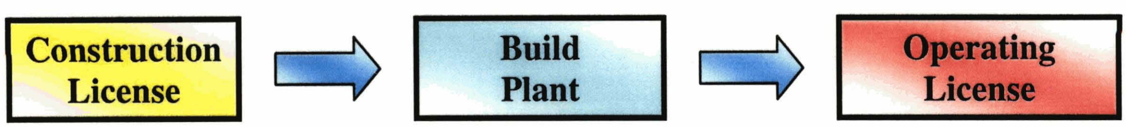


**Figure 35 – Old Process: The two-step licensing process (10 CFR 50)**
Source: Nuclear Regulatory Commission
Note: In this sequential process, regulatory reviews were overlapping: Process was inefficient, unpredictable and invited abuse. The last phase, post-building was an opportunity for intervention, hearings and delay.

In 1989, the Nuclear Regulatory Commission (NRC) established a new licensing process – 10 CFR Part 52[73] – in order to address flaws in the licensing process. In the 1992 Energy Policy Act, Congress affirmed and strengthened the new licensing process.

[72] NRC, 2005b
[73] NRC, 2005b

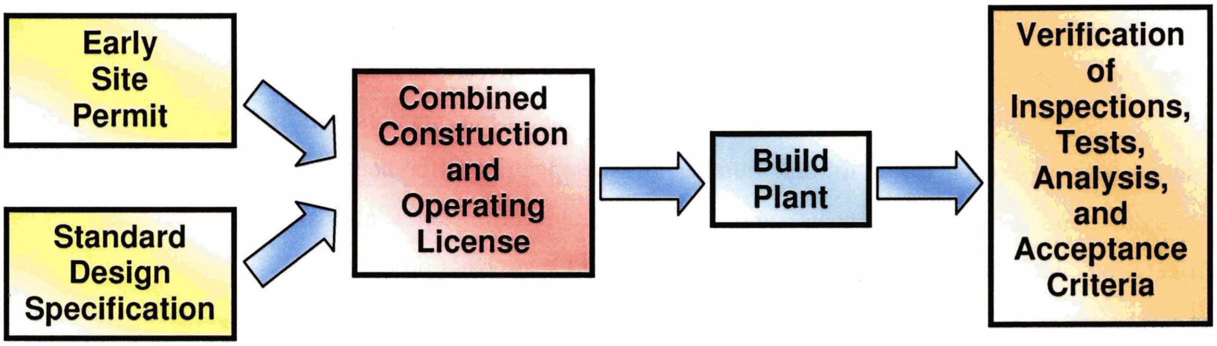


**Figure 36 – New Process: Combined licensing process (10 CFR 52)**
Source: Nuclear Regulatory Commission

Note: In this process, all regulatory reviews are completed before major capital investment at risk. Potential for delay significantly reduced. There is an opportunity for public comment at the COL phase, and an opportunity for hearing at the ITAAC phase, but the threshold is very high

The new process is intended to move the bulk of licensing and safety issues to the beginning of the process, ahead of construction, through three components:

- Design Certification;
- Early site permits (ESP);
- Combined construction permits and operating licenses (COL).

To ensure that a company builds a new plant according to its license, the NRC introduced ITAAC, a process that determines which kinds of inspections, tests, analyses and acceptance criteria it will use to ensure the plant is built according to the design approved in the licensing proceedings.

#### 7.3.1.1. Design Certification

The approval of standard design process allows for plant designers to secure advance NRC approval of standard plant designs. Later, these plant designs can be ordered, licensed for a particular site and built.

Following an exhaustive NRC safety review, agency approval of standard designs is formalized via a specific design certification rulemaking. This process allows the public to review and comment on the designs up front—before any construction begins. NRC design certification fully resolves safety issues associated with the design. The NRC approves the design for 15 years.

To date, the NRC has certified three plant designs. Work is proceeding toward certification of a fourth design, and the industry expects at least three new designs to begin the certification process in the next three years. The advanced designs considered for new investments will be later discussed.

Standardization offers significant benefits. It means that reactors will be built in families of the same design, except for a limited number of site-specific differences. Standardization will reduce construction and operating costs, and lead to greater efficiencies and simplicity in nuclear plant operations, including safety, maintenance, training, and spare parts procurement.

There is international experience of standardization choices. The French nuclear program is based on standardized nuclear plant designs. Over nearly two decades, France built 34 standardized 900-MWe (megawatts of electric power) reactors and 20 1,300-MWe reactors, which now supply about 75 percent of the country's electricity.

#### 7.3.1.2. Early Site Permit

The early site permit (ESP) process enables companies to obtain approval from the NRC for a nuclear power plant site before deciding to build a plant. The process resolves any site suitability issues before companies commit funds to a project.

Companies can "bank" sites approved by the NRC for up to 20 years and build when the time is right. Having a pre-approved site can dramatically shorten the time to bring a new plant to market.

ESP applications consist of three components:

- A site safety analysis;
- An environmental report;
- Emergency planning information.

Federal, state and local government officials and the public have opportunities to participate in each of these at various stages during the NRC review process.

An ESP review process encompasses a range of reactor designs. Companies are enabled to select the best design when they proceed with a decision to build.

The concept of "plant parameters envelope" concept allows the NRC to assess the suitability of a site based on a generalized plant description that takes into account the characteristics of several designs – for example, the height of the tallest building and the greatest cooling water requirement for any design under consideration.

#### 7.3.1.3. Combined Construction and Operating License

10 CFR 52 provides for issuance of a combined construction permit and operating license, also known as a combined construction and operating license (COL). A COL may reference a certified design, an ESP or both.

All issues resolved in connection with earlier proceedings associated with a standard design or site will be considered resolved for purposes of the COL proceeding. This makes the process more efficient by allowing the NRC review and a public hearing for a COL to focus on remaining issues related to plant ownership, design issues not resolved earlier, and organization and operational programs.

Moreover, granting a COL signifies resolution of all safety issues associated with the plant. Neither ESP nor COL commits anyone to build anything, but they will expedite future plans for new build.

Whether the constructed plant conforms to the requirements of the license and is ready to operate can obviously not be addressed up front. For this, 10 CFR 52 provides the ITAAC process, which specifies the inspections, tests, analyses and acceptance criteria that will be used to assess the completed plant.

ITAAC are quantitative indicators agreed upon during the design certification process and in the combined license. They then will be used during construction to determine that the constructed plant conforms to its licensing requirements. They allow the NRC to verify that a plant is built to specifications and they allow the project developer to prove that the plant is built to specifications. They are formally incorporated into COL. If the standards are met, there are no grounds for hearings, and there will be no delay after COL is issued.

### 7.3.2. Impact of the new process

#### 7.3.2.1. Benefits from the new process

All regulatory approvals are moved to the front of the process. Issues related to safety are resolved as soon as possible, and the license is issued at the start, not at the end. Consequently, the design will likely be about 90% complete before construction starts.

Although the new process has more steps, more information is available to the public earlier and issues are resolved early in the development. This allows for higher levels of certainty for investments.

Even if delays occur for various reasons, this will happen at the front-end of the procedure, before construction begins, i.e. before significant capital investment is at risk.

There are opportunities for delays in the ITAAC phase, when inspections, tests and confirmatory analyses are performed to ensure that the facility has been built in accordance with the design, but the industry believes there is a low probability that this will happen.

The benefits from the new process are summarized in the following table designed by the Nuclear Energy Institute.

| Then | Now |
|---|---|
| Changing regulatory standards and requirements | More stable process: NRC approves site and design, single license to build and operate, before construction begins and significant capital is placed "at risk" |
| No design standardization | Standard NRC-certified designs |
| Inefficient construction practices | Lessons learned from nuclear construction projects overseas incorporated, and modular construction practices |
| Design as you build | Plant fully designed before construction begins |
| Multiple opportunities to intervene, cause delay | Opportunities to intervene limited to well-defined points in process, and must be based on objective evidence that ITAAC have not been, will not be, met |
| Technology still evolving | Technology mature, stable designs |

**Figure 37 – Nuclear Plant Licensing: "Then and Now"**
Source: Nuclear Energy Institute, 2005[74]

[74] NEI, 2005d

7.3.2.2. Time-to-market with the new process

According to the Nuclear Energy Institute,[75] the first ESPs and COLs will take longer than follow-on applications. The time-to-market under the new licensing process should be as follows:

<table>
<tr><th></th><th>First applications (months)</th><th>Nth applications (months)</th></tr>
<tr><td>ESP</td><td colspan="2">33-36</td></tr>
<tr><td>Design Certification</td><td colspan="2">36-60</td></tr>
<tr><td>COL</td><td>27-60</td><td>22–36</td></tr>
<tr><td>Construction</td><td colspan="2">45</td></tr>
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7.3.2.3. Quantitative impact of the new process

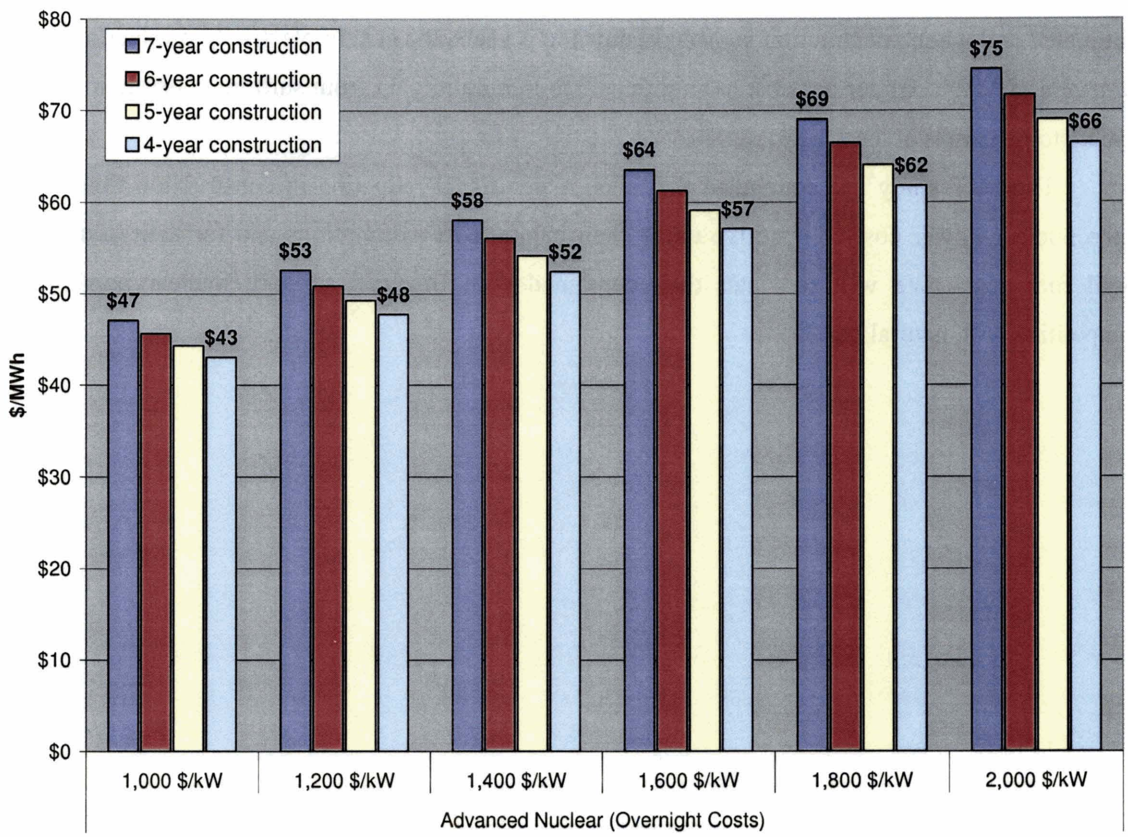


**Figure 38 – Cost reductions from the new licensing process**

[75] NEI, 2005d

The graph displayed above shows calculation of levelized costs of electricity in various cases. The set of assumption used to make the calculations is still the one used in the MIT study on the "Future of Nuclear Power".[76]

The assumption that is varying is the capital cost of building a nuclear power plant, here ranging from $1,000 /kW to $2,000 /kW. The upper value of $2,000 /kW is the base case assumption from the MIT study. The $1,000 /kW correspond to the expectations of vendors for the capital costs of advanced nuclear designs, and after a number of plants have been built, i.e. FOAKE costs have been paid.

The second parameter that is changing is the construction time, from 4 to 7 years. The purpose of changing the value of the construction time is to assess the impact of construction delays on the cost of electricity generated, or conversely the impact of the new licensing process, reducing the probability of delays, on that same cost. Construction time is the period between the initial investment and the beginning of operations.

It is clear from the LCOE calculations, no matter what capital cost assumption, when delays are eliminated and when construction is brought down to 4 years, the cost of electricity production is reduced by several $/MWh. Under our cost assumptions, the minimum gain from shifting construction time from 7 years to 4 years is at least 10%.

The MIT study has concluded that even a significant reduction in construction time would not make nuclear power cost-competitive under their capital cost assumptions and for their assumptions of fossil fuel costs. We will see later that, combined with financial support, nuclear power becomes competitive with natural gas.

[76] MIT, 2003

7.4. Nuclear power technology options

Generation III reactors generally represent an evolution of current nuclear technology. Their designs generally have a 60-year operating life. The main evolutions of advanced reactors from existing technology are:

- Improved safety (e.g. redundant safety systems);
- Improved operational efficiency (e.g. longer periods between refueling and/or greater thermal efficiency);
- Reduced construction time and costs (e.g. better design and/or new materials);
- Reduced operating costs (e.g. system simplification and automation).

| **Design** | **Type** | **Design Certification Status** |
|---|---|---|
| ABWR | BWR | Approved |
| System 80+ | PWR | Approved |
| AP-600 | PWR | Approved |
| AP-1000 | PWR | Expected in 2005 |
| ESBWR | BWR | Application in 2005 |
| ACR-700 | CANDU | Application in 2005 |
| PBMR | HTGR | Application early 2007 |
| EPR | PWR | Application early 2008 |

**Figure 39 – Certification Process for New Reactor Technology Options in the United States**
Source: Energy Information Administration, 2005[77]

[77] EIA, 2005c

### 7.4.1. Certified designs

Since the beginning of the new regulatory processes, the NRC has approved three design certifications (ABWR, System 80+ and AP-600), and a fourth is expected to be completed in 2005 (AP-1000). Another application for design certification is expected to be filed in 2005 (ESBWR).

The NRC gave final design certification for both the ABWR and the System 80+ in May 1997, noting that they exceeded the safety goals by several orders of magnitude. The ABWR has also been certified as meeting European requirements for advanced reactors.

#### 7.4.1.1. Advanced Boiling Water Reactor

The Advanced Boiling Water Reactor (ABWR) has several examples in commercial operation in Japan, and two more under construction in Taiwan. It can be built to have a high or medium net electrical output of around 1,350 MW and 600 MW, respectively. The ABWR operated on the same principles as the BWR, but is designed to be safer, simpler to operate, easier to maintain and less expensive to build (e.g. the inclusion of internal reactor pumps instead of external recirculation pumps eliminates piping and connections for increased safety and decreased costs), smaller and with shorter construction time and lower expenses. Furthermore, the ABWR has a longer operating cycle and shorter required refueling time increase their availability factor.

#### 7.4.1.2. System 80+

The System 80+ is an advanced pressurized water reactor designed by Westinghouse, ready for commercialization. Eight System 80 reactors in South Korea incorporate many design features of the System 80+, which is the basis of the Korean Next Generation Reactor program with the APR1400 design. Westinghouse BNFL no longer actively promotes the design for domestic sale.

#### 7.4.1.3. Westinghouse AP-600

The Westinghouse AP-600 gained final design certification from the NRC in Dec 1999. The 600 MW advanced reactor is more innovative and smaller. It has passive safety features and its projected core damage frequency is nearly 1000 times less than today's NRC requirements.

The initial advanced light water reactor designs have been praised for their improvements in reactor safety and simplicity, but construction costs remain a barrier to commercial success in the U.S.

Moreover, separate from the NRC process – and beyond NRC requirements – the US nuclear industry has selected one standardized design in each category – the large ABWR and the medium-sized AP-600 – for detailed first-of-a-kind engineering work.[78] The $200 million program was half-funded by the Department of Energy and meant to provide firm information on construction costs and schedules to prospective buyers. The evaluation was conducted by the Tennessee Valley Authority (TVA) for construction at Bellefonte.

### 7.4.2. Designs in certification

Any new reactor built in a near future is likely to use designs either recently certified or soon to be. Interest in new reactor construction in the United States has focused on the two following designs, the AP-1000 and the ESBWR.

#### 7.4.2.1. Westinghouse AP-1000

Westinghouse Electric Co., now a subsidiary of British Nuclear Fuels, Ltd. (BNFL) received its final safety evaluation and final design approval for the AP-1000 PWR from the NRC in September 2004; the final design certification rulemaking is expected to be complete in December 2005. It is the result of a 1300 man-year and $440 million design and testing program.

The AP-1000 incorporates passive safety features in place of the redundant active safety systems found in existing plants. A smaller version of this design, the AP-600, was approved in December 1999 but has received little interest because of its economics. The 1,100 MW AP-1000 design requires the same development and licensing costs and staffing levels as the AP-600, and about the same size site and structures.

Capital costs are projected at 1,000 $/kW[79] and modular design will reduce construction time to 36 months. The 1100 MW AP-1000 generating costs are expected to be below $3.5 cents/kWh.

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[78] WNA, 2005b

[79] Nth-of-a-kind cost estimates without site or owner costs

#### 7.4.2.2. General Electric ESBWR

This Economic Simplified, Boiling Water Reactor design is an evolution of GE's NRC-approved ABWR design. Both reactors produce 1,350 to 1,500 MW of power, but the ESBWR uses passive safety systems.

Three ABWR units are operating in Japan, and three more are under construction there and in Taiwan. These designs' large capacity and 24-month fuel cycle are particularly attractive from an economic standpoint, but the ESBWR's passive safety design gives it the edge over the ABWR.

GE has filed for design certification in summer 2005, with a 7500-page application representing a decade of work. The design certification process for ESBWR will take at least three years.

The AP-1000 and ESBWR designs are particularly attractive because they are designed for passive safety, meaning that no external power or operator action is needed to assure safety. Instead natural forces like convection, gravity, and evaporation can cool the reactor core in an emergency. Large tanks of emergency cooling water sit directly above the reactor vessel as well.

Passive safety simplifies the plant by requiring less equipment, less construction material, and smaller buildings, allowing for faster, cheaper construction and decommissioning. Westinghouse claims that, compared with an active safety design, the AP-1000 contains 50 percent fewer safety valves, 35 percent fewer pumps, 80 percent less safety-grade piping, 85 percent less cable, and 45 percent less seismic building volume.

### 7.4.3.Designs in pre-certification

Designs that vendors anticipate submitting for certification during the next two years include the ACR700, the EPR and IRIS. The process of certification takes several years and depends heavily on how unique the proposed design is and whether the design is supported by potential vendors and buyers. NRC hearings have emphasized that new and innovative designs might take more time for certification because of limited NRC staff familiarity with the designs.

Pre-certification is a technical concept within the NRC regulatory environment, the process can mean many things to potential reactor vendors. A number of reactor types are at NRC pre-certification stage.

- The Siedewasser Reaktor is a Framatome ANP design for an advanced BWR, originally designed by Siemens. It presently has no U.S. utility sponsor and is no longer being actively promoted by Framatome which now emphasizes its EPR design.
- The ACR700 is an evolution from AECL's internationally successful CANDU line of Pressurized Heavy Water Reactors. As is the case for most non-LWR reactors, most U.S. utilities, nuclear engineers, and regulators have only limited working familiarity with the design. Interest was initially shown by Dominion Resources, but the utility has recently switched to the ESBWR design in anticipation of the slow regulatory approval process for the innovative Canadian-design.
- The Gas-turbine Modular Helium Reactor is an HTGR design developed primarily by the U.S. firm, General Atomic. Entergy has participated in GT-MHR development and promotion.
- Westinghouse's IRIS (International Reactor Innovative and Secure) is a significant simplification and innovation in PWR technology. Pre-certification is proceeding, and the IRIS reactor may show potential during the next decade. However, IRIS presently has no utility sponsor in the US.

The following reactors are at pre-certification and have chances of being supported by a utility in the coming years.

#### 7.4.3.1. Eskom PBMR

The Pebble-bed Modular Reactor, which uses helium as a coolant, is part of the HTGR family of reactors and thus a product of a lengthy history of research, notably in Germany and the United States.

More recently the design has been promoted and revised by the South African utility Eskom and its affiliates. Westinghouse BNFL is a minority investor. Prototype variations of the PBMR are now operating in China and Japan.

Certification procedures in the U.S. have slowed, but never have been abandoned.

At around 165 MWe the PBMR is one of the smallest reactors now proposed for the commercial market. This is considered a marketing advantage because new small reactors require lower capital investments than larger new units. Several pebble-bed reactors might be built at a single site as local power demand requires.

Small size has been viewed as a regulatory disadvantage because most licensing regulations (at least formerly) required separate licenses for each unit at a site.

The NRC also does not claim the same familiarity with the design that it has with Light Water Reactors. Fuels used in the PBMR would include more highly enriched uranium than is now used in LWR designs.

Exelon pulled out of the effort in 2003, leaving the PBMR without a US sponsor.

#### 7.4.3.2. Framatome-ANP EPR

Framatome ANP announced in early 2005 that it would market its European Pressurized Water Reactor design in the United States and has recently begun pre-certification.

The EPR is an evolutionary PWR design with a high net electrical output (1,600 MW). Its components have been simplified and considerable emphasis is placed on reactor safety.

The design is now being built in Finland with a target completion during 2009 at an estimated cost of €3.0 billion.

The French government also plans to build an additional EPR at Flamanville 3 in France starting in 2007. Present French policy suggests that additional EPRs might replace additional commercial reactors now operating in France starting in the late 2010s.

The EPR was bid in early 2005 in competition to the AP1000 for four reactors at two sites in China.

The proposed size for the EPR has varied considerably over time but might be around 1600 MWe. Earlier designs were as large as 1750 MWe. In either case the EPR would be the largest design now under consideration in the United States. Some redesign might occur for the U.S. market.

Framatome designs its reactors according to European codes and standards and will have to demonstrate their compatibility with US code requirements. Framatome had earlier indicated that U.S. certification for the EPR would occur after European development proceeded.

This decision has since been made and Duke Power is evaluating the EPR, along with the AP1000 and ESBWR, for a COL application process that began during 2005. A formal COL application by Duke would occur several years later though design selection might occur earlier.

### 7.4.4. Other designs

#### 7.4.4.1. Designs in anticipated pre-certification

Two designs, the ACR1000 (Atomic Energy of Canada Limited) and the 4S (Toshiba) have not been formally submitted for pre-certification in the United States. The designs are now receiving attention and there is a chance they might be submitted for certification:

- ACR1000: same series than the ACR700, with lower costs, three-year construction time. Dominion Resources indicated in late 2004 that it might place effort in the ACR1000 after certification of the ACR700
- 4S: very small molten sodium-cooled reactor (10 MWe), designed for remote locations and to operate for decades without refueling (comparable to a nuclear battery). Toward the end of 2004, the town of Galena, Alaska granted initial approval for Toshiba to build a 4S reactor in that remote location, but NRC indicated it was not familiar with the 4S design and that design certification might be costly and prolonged.

#### 7.4.4.2. Generation IV reactors

The U.S. Department of Energy participates in the Generation IV International Forum (GIF), an association of thirteen nations that seek to develop a new generation of commercial nuclear reactor designs before 2030.[80]

The U.S., Canada, France, Japan and the United Kingdom signed an agreement on February 28, 2005 for additional collaborative research and development of Gen IV systems.

Criteria for inclusion of a reactor design for consideration by the initial GIF group include:

- Sustainable energy (extended fuel availability, positive environmental impact);
- Competitive energy (low costs, short construction times);
- Safe and reliable systems (inherent safety features, public confidence in nuclear energy safety);
- Proliferation resistance (does not add unduly to unsecured nuclear material) and physical protection (secure from terrorist attacks).

Potential generation IV systems include:

[80] Morgan Stanley, 2005

- Gas Cooled Fast Reactors (GFR);
- Fluid Lead Cooled Fast Reactor (e.g. Lead or Sodium);
- Fast neutron spectrum Supercritical Water Cooled Reactor (SCWR); and
- Very High Temperature Reactor (VHTR).

Currently, these systems are still in the design stages as significant technology gaps exist (for example, materials that can withstand very high temperatures and fuel technology).

In the near future, potential nuclear plant owners will shy away from unfamiliar designs and vendors, as well as from the additional cost, schedule, and technology risks they present. Nonetheless, it is in the interests of nuclear plant owners to maintain a competitive reactor supplier industry.

## 7.5. Consortia to test the new regulatory process

Although the combined licensing process is much more attractive to potential nuclear plant builders than the two-step process, testing the process has just begun, and it will take at least several more years before the first COL is issued.

The COL program has two objectives: to encourage utilities to take the initiative in license application, and to encourage reactor vendors to undertake detailed engineering and arrive at reliable cost estimates.

### 7.5.1. Early Site Permit

Three companies filed for an ESP during September and October 2003, with decisions expected in late 2006:

- Dominion for North Anna (Virginia);
- Exelon for Clinton (Illinois);
- Entergy for Grand Gulf (Mississippi).

Southern Company is reviewing sites and plans to file an ESP application to the NRC in 2006. The application should take around three years to review.

None of these companies currently has concrete plans to build a nuclear power plant.

### 7.5.2. Combined Construction and Operating License

Although the combined licensing process is much more attractive to potential nuclear plant builders than the two-step process, testing the process has just begun, and it will take at least several more years before the first COL could be issued.

In 2003, the Department of Energy (DOE) called for COL proposals under its Nuclear Power 2010 program on the basis that it would fund up to half the cost of any accepted. The COL program has two objectives: to encourage utilities to take the initiative in license application, and to encourage reactor vendors to undertake detailed engineering and arrive at reliable cost estimates.

According to the World Nuclear Association, for the first COL application, DOE matching funds of up to about $50 million are available. For the second, up to some $200 million per vendor, are available to be recouped from royalty.

Three consortia have received DOE funding in November 2004 for the demonstration of the new nuclear licensing process.

| *Consortium* | DOMINION | NUSTART ENERGY | TVA |
|---|---|---|---|
| *Members* | • Dominion<br>• Bechtel Power Corp.<br>• GE Energy | • Constellation Generation Group<br>• Duke Energy<br>• EDF International North America<br>• Entergy Nuclear<br>• Exelon Generation<br>• Southern Co.<br>• Florida Power & Light Co.<br>• GE Energy<br>• Progress Energy<br>• Tennessee Valley Authority<br>• Westinghouse Electric | • TVA<br>• GE Energy<br>• Toshiba<br>• USEC Inc.<br>• Global Fuel-Americas<br>• Bechtel Power Corp |
| *Designs* | • GE ESBWR | • GE ESBWR<br>• Westinghouse AP1000 | • GE ABWR |

**Figure 40 – Consortia characteristics**
Source: Nuclear Energy Institute

7.5.2.1. NuStart Energy consortium

NuStart Energy Development LLC comprises nine major utilities: Exelon, Entergy, Southern, Constellation, Duke, Tennessee Valley Authority (TVA), FPL Energy, Progress Energy. It was brought together by Entergy and represents more than half of the US nuclear plants.

It involves Westinghouse, General Electric and EDF International and will pursue the Westinghouse AP1000 and GE's ESBWR technology options before submitting applications.

Initially, the consortium was considering the six following sites, four of which already house operating nuclear power plants:

- Scottsboro, Alabama: The Bellefonte Nuclear Plant, an unfinished site owned by the U.S. government's Tennessee Valley Authority.
- Port Gibson, Mississippi: The Grand Gulf Nuclear Station, owned by Entergy.
- St. Francisville, Louisiana: The River Bend Station, owned by Entergy.
- Aiken, South Carolina: The Savannah River Site, a U.S. Department of Energy nuclear weapons lab.

- Lusby, Maryland: The Calvert Cliffs Nuclear Plant, owned by Constellation Energy.
- Oswego, New York: The Nine Mile Point plant, owned by Constellation Energy.

NuStart eventually identified Entergy's Grand Gulf site for an ESBWR reactor and TVA's Bellefonte site for an AP1000 reactor. The consortium plans to submit both license applications in 2008.

NuStart's role will end at issuance of the licenses. Once NRC issues the licenses, the utilities selected for the COL test, either alone or in partnerships, will make the decision as to move ahead with construction. They would then take over the licenses from NuStart in order to build and operate the plants. Construction could start as early as 2010, with at least one plant operating by 2014, according to NuStart.

The NuStart consortium is headed by an Exelon senior executive. In May 2005 it signed an agreement with DOE to split the estimated $520 million cost of completing detailed engineering work on one of the two designs.

Before the announcement of the site selections, several local areas had passed resolutions supporting selection of their communities for a new build plant. On 11 July, two Alabama jurisdictions also weighed in. The Scottsboro city council and the Jackson county commission each passed a resolution supporting TVA in construction of a new reactor at the Bellefonte site, whether through the TVA-led consortium or through NuStart.

#### 7.5.2.2. Dominion-led Consortium

The second consortium is led by Dominion and originally included Atomic Energy of Canada Ltd (AECL), Hitachi and Bechtel.

The initial option pursued was AECL's ACR-700, developed from the successful Candu heavy-water reactor design, but with light water cooling. Hitachi and Bechtel have been key contributors in successfully completing the recent Candu plants in China.

However, in January 2005, AECL and Hitachi were replaced by General Electric and the ESBWR was favored over the ACR-700. The reason for this change was the NRC indication that certification of the ACR design would be very slow because of its lack of familiarity with the design. Conversely, a US technology, developed from already approved designs, is expected to be much quicker.

The consortium is currently looking at Dominion's existing nuclear site at North Anna, Virginia. In April 2005, the Dominion-led consortium signed an agreement with DOE to split the estimated $440 million cost of its COL work on the ESBWR, and development costs will be shared with NuStart. In addition to these costs, the main design certification and engineering costs will be borne by the vendor partners.

#### 7.5.2.3. Tennessee Valley Authority consortium

Under the same DOE program, the TVA consortium, consisting of the Tennessee Valley Authority, GE Energy, Global Nuclear Fuels, Toshiba, Bechtel, and USEC received DOE funding in May 2004 to study cost and schedule of building two GE-designed advanced boiling water reactors (ABWR) at Bellefonte, Alabama, the site of a partially completed TVA nuclear plant. The $4 million feasibility study was half funded by DOE.

The TVA site has two large PWR units whose construction was abandoned in 1988 after $2.5 billion had been spent and unit 1 largely (88%) completed.

The 1350 MWe ABWR was the first Generation III reactor design to enter service. A number of units are operating and under construction in Japan.

TVA has apparently decided not to proceed as they would be the only ABWR units in USA. However the figures are noteworthy: twin 1371 MWe ABWRs would be $1611 per kilowatt, or if they were uprated to 1465 MWe each, $1535 /kW, [81] and built in 40 months.

#### 7.5.2.4. Duke Energy

In March 2005, Duke Power informed the NRC that the EPR was one of three reactor designs it was considering for a COL application for a new reactor in its service territory.

Duke conducted a study of the scope, schedule and costs for preparing a COL and, before the EPAct of 2005 was preparing to award its first pre-application contracts. However, Duke has made no final decision to proceed with construction of a new plant.

[81] Owner's costs are not included in the TVA study

### 7.6. The Energy Policy Act of 2005

#### 7.6.1. Overview of the Energy Policy Act of 2005

In late July 2005, the US House and Senate passed the Act by wide margins. It is the first comprehensive federal energy legislation in 13 years. President George W. Bush signed the Act into law on August 8, 2005.

The Energy Policy Act of 2005 differs fundamentally from the Energy Policy Act of 1992, which introduced wholesale power market competition. Whereas the 1992 Act promoted a competitive market framework, the 2005 Act induces markets to adopt certain technologies and to invest in certain areas.

According to various consulting reports,[82] the Act will:

- Allow consolidation of ownership in the power cestor: By repealing the Public Utility Holding Company Act of 1935, a major barrier to mergers and acquisitions has been removed;
- Provide incentives for a diverse energy portfolio and foster innovation: The Act provides incentives for advanced nuclear power, IGCC and wind power plants for purposes of fuel diversity;
- Stimulate investment and upgrading of infrastructures, through financial incentives for transmission investments, and for advanced coal and nuclear plants construction;
- Favor the declining trend of electricity intensity, by promoting end-use efficiency;
- Support the hybrid structure of the electricity generation sector, by allowing both competitive generators and utilities to take advantage of the financial incentives contained in the Act.

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[82] ICF, 2005; UtiliPoint, 2005

7.6.2.Nuclear power provisions including in the act

The Act has a number of provisions that should contribute to facilitating the construction of new nuclear power plants in the US. The focus of the Act is on advanced reactor designs, and the main provisions are the following.

7.6.2.1. Production tax credits

Electricity produced from qualifying advanced nuclear power facilities can claim production tax credit as high as 1.8 cents/kWh for the first eight years of operation. This applies for up to 6,000MW of nuclear capacity, provided it is online before 2020: if the new capacity exceeds 6,000 MW, the amount will be distributed on a pro rata basis (with an annual cap of $125 million per GW).

7.6.2.2. Loan guarantees on new projects

As a greenhouse gas emission-free technology, advanced nuclear power will be covered by an 80% loan guarantee from the Secretary of Energy. Loan guarantees are particularly attractive for merchant generating companies. They provide the possibility to develop highly leveraged projects at cheaper costs; some regulated companies may also take advantage of the loan guarantees, because they reduce the cost of borrowing.

Loan guarantees and production tax credits work differently, but both have the same effect: a reduction of the cost of electricity from the first plants. Since their effect will be combined, there will be a larger reduction of the cost of electricity for the first new plants.

7.6.2.3. Insurance against delays

Under the licensing process for new nuclear plants, project developers receive all regulatory approvals before construction begins, before significant capital investment is placed at risk. Although the licensing process is designed to preclude delay, there still is a residual risk of delays during construction. Such delays will have a lower probability but we have seen that, if they occur, they can have high financial consequences.

The Secretary of Energy may use federal funds to pay for all or part of the costs incurred as a result of delays (including principal, interests and costs related to replacement power) caused by litigation or a "breakdown in the regulatory process" at NRC approval, if those delays exceed 180 days. The support is available for six reactors of three different types: the first two plants can receive up to $500 million each, and four more can receive as much as $250 million each.

#### 7.6.2.4. Extension of the Price Anderson Act

The main purpose of the Price-Anderson Act is to ensure the availability of a large pool of funds to provide prompt compensation for members of the public who would incur damages from a nuclear or radiological incident, including the costs of incident response or precautionary evacuation and the costs of investigating and defending claims and settling suits for such damages, regardless of who might be liable. Approximately $200 million have been paid in claims by the insurance pools since the Price-Anderson Act went into effect.

The liability protection for NRC licensees and DOE contractors, which aims at protecting operators of the financial risk of plant accidents, is extended for 20 years until 2025 (fifth extension since 1957): as a result, owners of power plants coming online before 2025 are eligible for the same liability protection that is available for the existing fleet.

#### 7.6.2.5. Modification of the rules for decommissioning trust funds

The new legislation also includes updated tax treatment of nuclear decommissioning trust funds.

Before the Energy Policy Act of 2005, there were two types of funds: non-qualified and qualified. The main difference between the two types of fund was related to the tax-deductibility of contributions: contributions to non-qualified funds were not deductible, while contributions to qualified funds were a deductible business expense, and earnings on qualified funds were taxed at a lower rate. Until the new energy legislation, only regulated companies subject to cost-of-service regulation could establish qualified funds.

The change from the EPAct of 2005 is the repeal of that requirement. All power companies can now establish qualified funds and deduct contributions to those funds, whether they are regulated or not. This has some effect for unregulated companies constructing merchant nuclear power plants.

Moreover, non-qualified funds will be liquidated to constitute qualified funds. Companies will be allowed to deduct those amounts from taxable income over the remaining lifetime of the plant.

In a nutshell, the change in tax rules eliminates the difference between unregulated and regulated companies' contribution to decommissioning funds.

#### 7.6.2.6. Significant commitment to nuclear power

The new energy legislation also creates a substantial R&D portfolio of almost $3 billion. The funding will go to new developments of advanced designs and testing of the new licensing process, as well as research and development for hydrogen production and next-generation plant designs.

In addition to research, development, demonstration and commercialization funding, the Energy Policy Act of 2005 creates a position of Assistant Secretary for Nuclear Energy.

### 7.6.3.Impacts for the US nuclear industry

#### 7.6.3.1. Anticipated implications for the US nuclear industry

The R&D provisions applying to nuclear power in the Energy Policy Act of 2005 clearly show the commitment of the US government to the construction of next-generation nuclear power facilities.

The combination of the production tax credits, the standby support for delays due to litigation and regulatory approval process, the loan guarantee and the extension of the Price Anderson Act liability protection is likely to play an important role in improving the competitiveness of new nuclear power plants, in mitigating the financial risks inherent to construction, thereby facilitating the financing of new projects. UtiliPoint believes there should be several new facilities constructed in the next ten years.

According to UtiliPoint,[83] the Energy Bill also favors first movers in the advanced reactor market. The AP1000 Westinghouse design has been approved and certified, which makes it well-positioned, and the ESBWR from GE will enter the certification process very soon. This can explain why both consortia involving Westinghouse and GE are preparing applications in the near future.

The Act does not have any provision related to long-term storage of radioactive waste or to the Yucca Mountain project. However, the federal government is still committed to provide a waste storage facility to take on the waste from existing nuclear plants.

#### 7.6.3.2. Quantitative impacts on nuclear power competitiveness

The following graph shows a comparison of the levelized costs of electricity for nuclear power, natural gas and coal. The assumptions are still those used in the MIT study.

For coal-fired power plants, two technologies are considered, Pulverized Coal and Integrated Gasification Combined Cycle.

For natural-gas-fired power plants, the technology considered is still combined cycle. Several scenarios are considered, depending on the assumption on the price of natural gas. As was stated earlier in this study, long-term natural gas prices should be 5 $/MMBtu. The range considered in the levelized cost calculations is from 4 to 6 $/MMBtu.

[83] UtiliPoint, 2005 (UtiliPoint International, Inc. provides independent research-based information, analysis, and consulting to energy companies, utilities, investors, regulators, and industry service providers)

For nuclear power plants, two dimensions vary in the calculations. The first one is the assumption on capital costs, similarly to the calculations previously displayed, ranging from 1,000 $/kW to 2,000 $/kW. The other dimension is the set of policies considered. Four cases are analyzed:

- Base-case with no policy;
- Production tax credit;
- Loan guarantee;
- Production tax credit and loan guarantee.

Moreover, three options are considered for the cash-flow calculations:

- Stand-alone project without carry-forward of the unused tax credit: no "banking" of the credit is possible;
- Stand-alone project with carry-forward of the unused tax credit: "banking" of the credit is possible;
- Project within a large company: The maximum tax credit is used every year, on the nuclear project or other projects within the company.

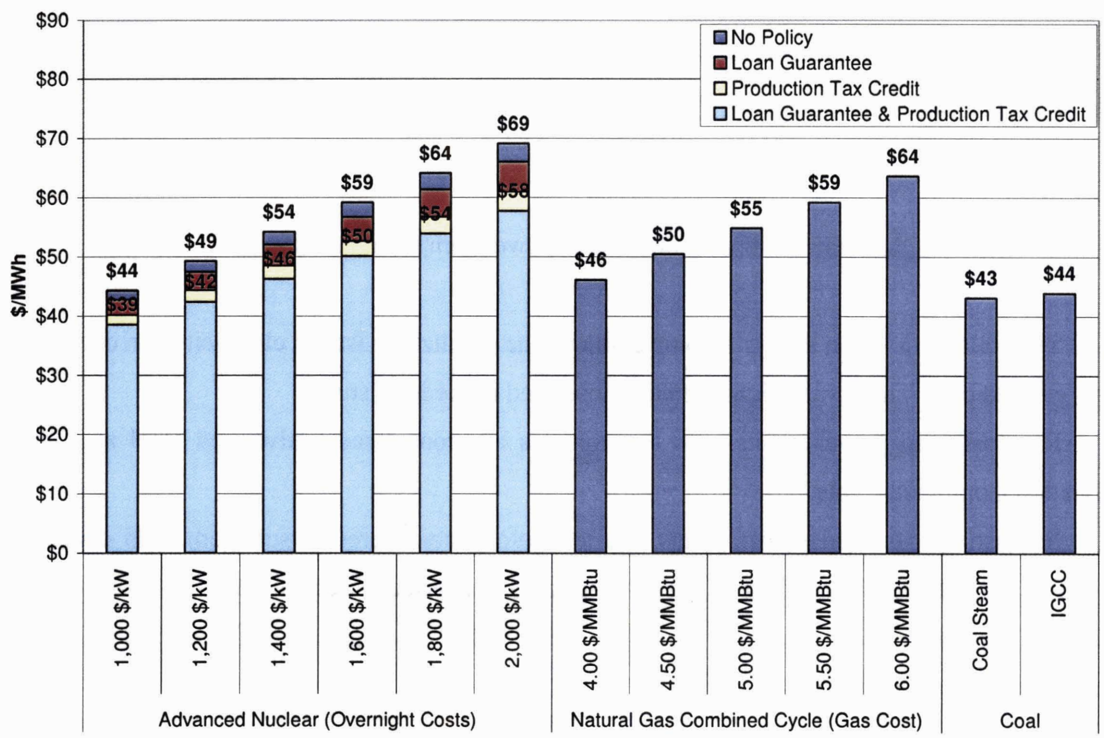


**Figure 41 – Nuclear power competitiveness – Stand-alone project without tax credit carry-forward**

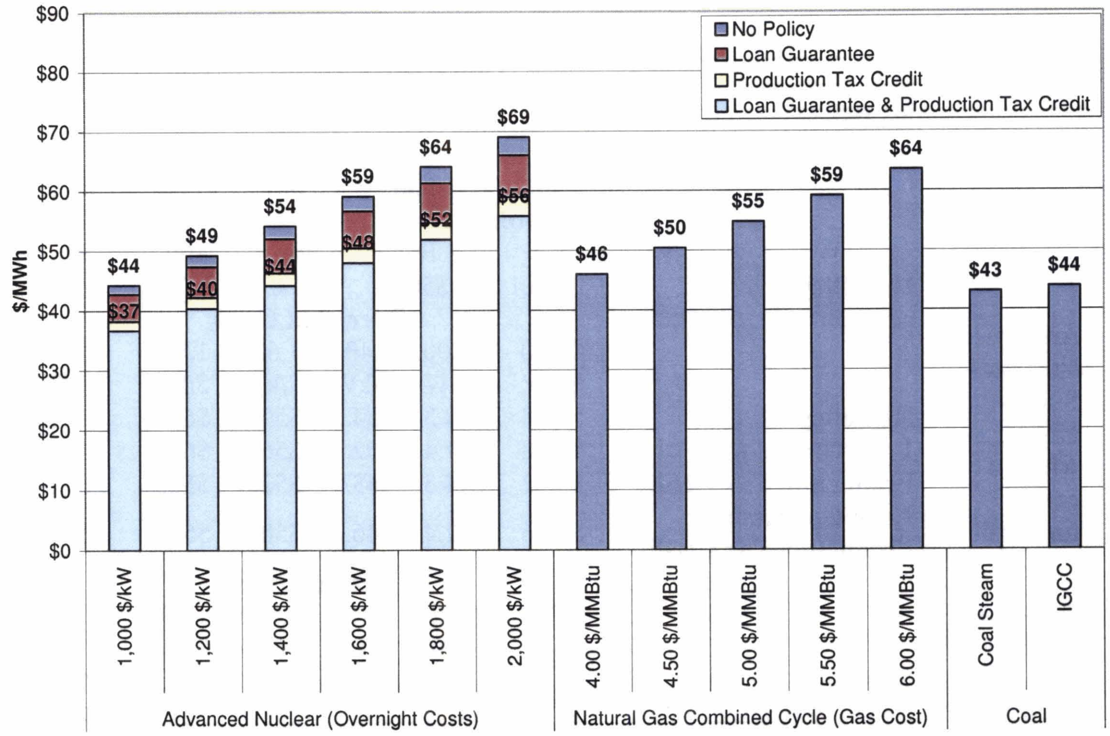


**Figure 42 – Nuclear power competitiveness – Stand-alone project with tax credit carry-forward**

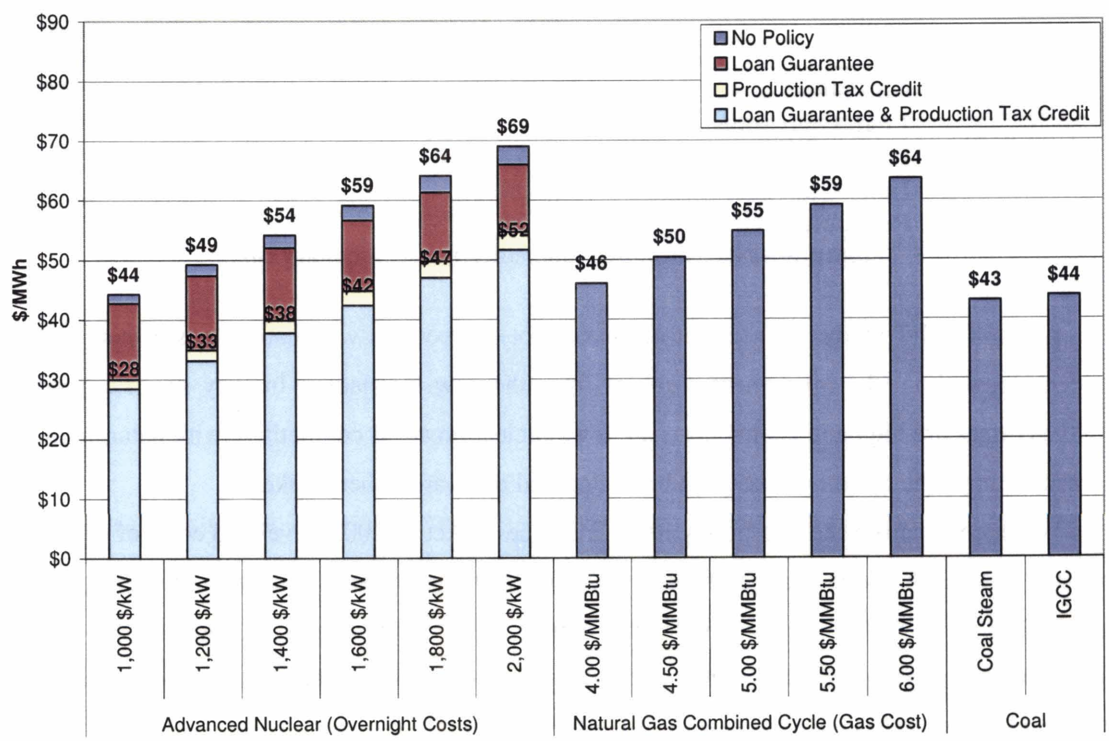


**Figure 43 – Nuclear power competitiveness – Project within a company**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | **Coal technology** | | | | | |
| **Coal** | | Coal Steam | | | IGCC | | |
| | **No Policy** | $43.1 | | | $43.9 | | |
| | | **Gas Price** | | | | | |
| **Natural Gas Combined Cycle** | | 4.00 $/MMBtu | 4.50 $/MM Btu | 5.00 $/MM Btu | 5.50 $/MM Btu | 6.00 $/MM Btu | |
| | **No Policy** | $46.1 | $50.5 | $54.8 | $59.2 | $63.6 | |
| | | **Overnight Costs** | | | | | |
| **Advanced Nuclear – Stand-alone without carry-forward** | | 1,000 $/kW | 1,200 $/kW | 1,400 $/kW | 1,600 $/kW | 1,800 $/kW | 2,000 $/kW |
| | **No Policy** | $44.3 | $49.3 | $54.2 | $59.1 | $64.1 | $69.0 |
| | **Loan Guarantee** | $42.8 | $47.4 | $52.1 | $56.7 | $61.4 | $66.0 |
| | **Production Tax Credit** | $40.2 | $44.3 | $48.5 | $52.6 | $56.8 | $60.9 |
| | **Loan Guarantee & Production Tax Credit** | $38.6 | $42.4 | $46.2 | $50.0 | $53.9 | $57.7 |
| | | **Overnight Costs** | | | | | |
| **Advanced Nuclear – Stand-alone with carry-forward** | | 1,000 $/kW | 1,200 $/kW | 1,400 $/kW | 1,600 $/kW | 1,800 $/kW | 2,000 $/kW |
| | **No Policy** | $44.3 | $49.3 | $54.2 | $59.1 | $64.1 | $69.0 |
| | **Loan Guarantee** | $42.8 | $47.4 | $52.1 | $56.7 | $61.4 | $66.0 |
| | **Production Tax Credit** | $38.2 | $42.3 | $46.3 | $50.5 | $54.7 | $59.0 |
| | **Loan Guarantee & Production Tax Credit** | $36.7 | $40.4 | $44.2 | $48.0 | $51.9 | $55.8 |
| | | **Overnight Costs** | | | | | |
| **Advanced Nuclear – Company** | | 1,000 $/kW | 1,200 $/kW | 1,400 $/kW | 1,600 $/kW | 1,800 $/kW | 2,000 $/kW |
| | **No Policy** | $44.3 | $49.3 | $54.2 | $59.1 | $64.1 | $69.0 |
| | **Loan Guarantee** | $42.8 | $47.4 | $52.1 | $56.7 | $61.4 | $66.0 |
| | **Production Tax Credit** | $30.0 | $34.9 | $39.9 | $44.8 | $49.8 | $54.7 |
| | **Loan Guarantee & Production Tax Credit** | $28.5 | $33.1 | $37.8 | $42.4 | $47.0 | $51.7 |

**Figure 44 – Nuclear power competitiveness – Summary chart**

As in the MIT study, we see that nuclear is not competitive with natural gas or coal in the base case scenario, without the investment stimulus from the new legislation. In very specific cases where natural gas prices are high and capital costs are low, nuclear power is competitive with natural gas, but for first constructions, the optimistic assumptions on capital costs are rather unlikely.

When considering the two policy items from the EPAct of 2005, levelized costs of electricity are significantly reduced. From a range of 44 to 69 $/MWh in the no policy scenario, the EPAct reaches a range of 38 to 58 $/MWh in the stand-alone without carry-forward case to a range of 28 to 52$/MWh. Nuclear power then becomes cost competitive, except for very low natural gas prices or very high capital costs.

As a conclusion, the economics of nuclear power are considerably improved by the Energy Policy Act provisions. If the economics were the only element holding new nuclear power construction back, then it is likely new nuclear power plants will be built in the coming years.

### 7.6.4.Nuclear industry response to new nuclear investments

The Energy Bill should provide regulatory certainty, possible risk insurance for the first few plants, and other incentives. For NEI representatives, the industry was on the brink of acting as soon as the bill was final.

Indeed, after the Energy Policy Act of 2005, the number of COL applications expected has increased, and a growing number of companies are considering application in a near future. The following sections briefly go over each of the projects.

#### 7.6.4.1. UniStar Nuclear

In September 2005 Areva and Constellation Energy formed a joint venture – UniStar Nuclear – Joint initiative by Constellation and Areva to develop projects on own account, or in partnership with other companies.

The joint venture is aimed at providing a business framework to build at least four of Areva's advanced 1600 MWe Generation-3+ EPR nuclear units in the USA. The US EPR (US Evolutionary Power Reactor) from Framatome-ANP is the US version of the European Pressurized Reactor being built in Finland, planned for France and that has been bid for China. Areva Inc. is currently making modifications to the EPR design for conditions in the USA – the main difference being the need to output at 60Hz instead of 50Hz. Bechtel Power Corporation will support the joint venture with engineering and construction expertise.

Constellation is part of the NuStart consortium, and to accommodate the new EPRs it withdrew two sites from consideration for NuStart COL. The UniStar COL timetable would be much the same as NuStart's, with application in 2008, construction start in 2010 and operation 2015.

On October 27, 2005, Constellation Energy announced yesterday its intention to file for an Early Site Permit (ESP) in 2007 and a combined construction and operating license (COL) in 2008.

Sites currently under evaluation include Constellation's Calvert Cliffs Nuclear Power Plant and the Nine Mile Point Nuclear Station. Constellation expects to complete its evaluation and select a site by early next year. The development and deployment will be pursued by UniStar Nuclear.

The announcement from Constellation follows similar announcements this month from Duke Power and Progress Energy.

#### 7.6.4.2. Duke Power

Duke Power, a business unit of Duke Energy, plans to submit the application to the U.S. Nuclear Regulatory Commission (NRC) within the next 24-30 months.

Duke plans to use Westinghouse Electric Co.'s Advanced Passive 1000 (AP1000) reactors, which are each able to generate 1,100 MW of electricity.

The utility said it will await the outcome of the NRC's review, expected around 2010, before deciding whether to build the reactors, which would then come on line by 2015. Duke is still evaluating potential sites for the new reactors, but they will be located within the utility's North and South Carolina service territory.

Duke officials also told reporters they also would be considering potential partners for a new reactor project, though they did not elaborate.

#### 7.6.4.3. Progress Energy

On November 1st 2005, Progress Energy announced that it plans to seek licenses to build up to four nuclear reactors at two locations, with one site in Florida and another in the Carolinas.

The company plans to submit applications for both sites to the U.S. Nuclear Regulatory Commission (NRC) by 2008. Construction would begin two years later, with operations beginning as early as 2015.

On August 29, 2005, Progress Energy had previously notified NRC that its plans could result in its submittal of a COL application for a new nuclear power plant in Florida. At that time, Progress Energy had also notified NRC that it expected to select a potential site and reactor vendor by the end of 2005.

The plants would be built primarily to meet demand for baseload generation needs in both of its service areas. Progress has not added new baseload generating plants since the mid-1980s, but its total number of customers has risen by a million, say company officials.

#### 7.6.4.4. Southern Nuclear

Southern Nuclear Operating Company announced in August 2005 that it had selected its Vogtle Nuclear Station in Georgia for consideration as a site for new nuclear units. In 2006, Southern Nuclear plans to file an ESP application or preliminary data for the COL application.

#### 7.6.4.5. South Carolina Electric and Gas Co

SCANA, the parent company of South Carolina Electric and Gas Co., and Santee Cooper announced in August that they are considering extending an existing nuclear generation joint ownership agreement so that they can study construction of a new nuclear generation facility. The two companies currently co-own the V.C. Summer Nuclear Station near Jenkinsville, South Carolina.

Any plant would be intended to meet forecast needs in 2015. This evaluation process will involve consideration of various types of baseload generation, including natural gas-fired plants, coal-fired plants and nuclear plants.

#### 7.6.4.6. Entergy

Entergy's River Bend site in Louisiana was on NuStart's list of six semifinalist sites. NuStart praised the strong showing of state and local community support for the River Bend proposal.

In its September 22 announcement, NuStart stated River Bend and the other five sites are "excellent locations for an advanced nuclear unit from a financial and technical standpoint."

In late 2007 or early 2008, Entergy will decide whether to submit its COL applications for Grand Gulf and River Bend to the NRC.

# 8. Unresolved uncertainties

## 8.1. Environmental constraints on $CO_2$ emissions

This study has not gone into details about the potential regulatory changes regarding greenhouse gas emissions in the United States.

There is no doubt that imposing a carbon tax, or implementing a CO2 cap-and-trade system would be very beneficial to nuclear power, especially if the carbon tax was to be set at a high price, or if the carbon cap was chosen stringently.

Yet, the MIT study shows that, absent the new energy legislation, the amount of the tax required to make nuclear power competitive under pessimistic capital cost assumptions would be above 100 $/ton of CO2 emitted.[84] Although it is a relevant academic exercise to consider the impact of a large span of policies, it seems rather unrealistic that, should a tax be implemented its level would be as high as 100 to 200 $/ton of CO2. The prices of CO2 allowances in the EUTS (European Union Trading System) suggest that the cost of compliance to CO2 regulations is one order of magnitude below (although the cap is not excessively stringent in the European Union).

The pricing model used in the Texas Institute for the Advancement of Chemical Technology (TIACT) report[85] on the economics of the potential nuclear power plant contains a feature for the possible imposition of emissions regulation, and the resulting increase in electricity prices. Yet they argue that a nuclear power plant project should not rely on increased pricing from environmental legislation, as it is only one possible future, rather distant in their opinion. Besides, with the level of uncertainty and political controversy related to global climate change, relying on US potential emissions legislation would be an unreasonable basis for an investment.

Although nuclear is advocated as a pollution-free technology, the argument appears to be more powerful to win public opinion than to shape financial investment analysis. In various interviews, reports and studies where industry executives are asked about major drivers of investment in nuclear power, they did not appear to be factoring in the probability of CO2 regulations in the United States.

In a nutshell, while CO2 emissions regulations may become an element in assessing profitability, in the current situation, the possibility of a change in the legislative environment with stringent emissions constraints is not a key driver to rely on when considering potential investments in new nuclear power plants in the United States.

[84] MIT, 2003
[85] TIACT, 2005

8.2. Uncertain capital costs

According to Joskow,[86] vendors are generally optimistic about capital costs, and there is an incentive to underestimate cost contingencies to advertise the cost-competitiveness of a design. Yet this poses the problem of how to evaluate a nuclear power plant project with a high level of uncertainty on capital costs (which account for a large share of the cost of electricity generation).

According to Geoffrey Rothwell,[87] cost contingencies closely approximate one standard deviation of the lognormal probability distribution of actual costs. From that theory, the TIACT report draws conclusions about the contingencies placed on projects by capital cost estimators.

The upper bound of the cost estimates is evidently what is of the highest interest if one chooses to mistrust vendor's cost estimates. Eventually too, the supplier will bid sufficiently high to avoid accounting losses. With Rothwell's contingency cost theory, The TIACT report develops an upper bound of the actual costs for a number of technologies. The results of this cost uncertainty analysis are shown in the following figure. The capital cost estimates represent a confidence interval of 95%. (I.e. there is a 2.5% probability of receiving quotes that are higher than the upper bound).

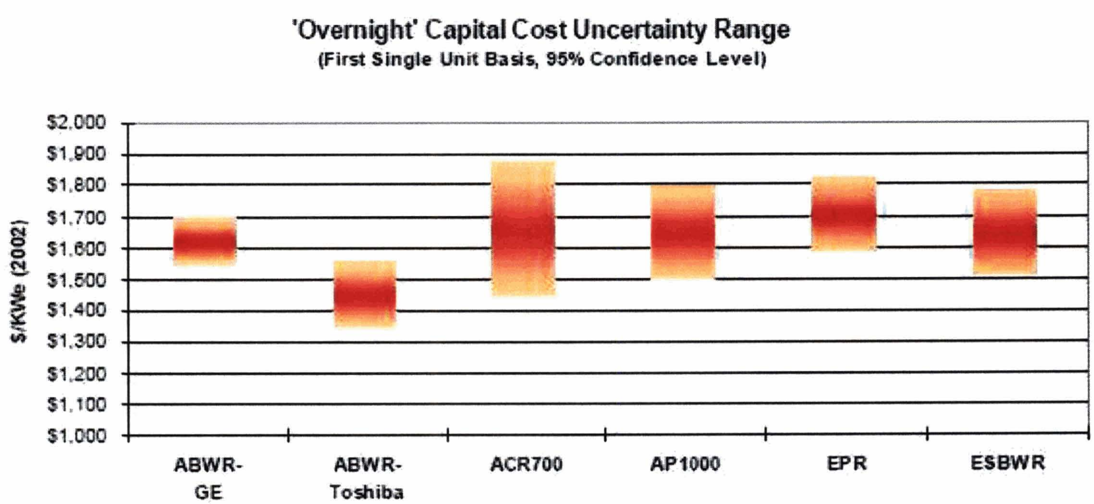


**Figure 45 – Capital cost uncertainty**
Source: TIACT, 2005

The figure above displays capital cost range for the designs most likely to be used for the potential new builds. The upper bound is generally substantially different from the capital costs quoted by

[86] Joskow, 2005
[87] Rothwell, 2004

vendors or from the average value. Also, more mature designs achieve a much lower upper bound than the ones in less developed stages.

As newest designs are built, the level of uncertainty will evidently decrease, and first-of-a-kind engineering costs will be paid, so that the range will be both narrower and lower. The question is now whether under today's degree of certainty and level of capital costs, projects will have a positive NPV.

### 8.3. Appropriateness of decommissioning funds

#### 8.3.1. Decommissioning after permanent shutdown

After a nuclear power plant is permanently shut down, it must be decommissioned. This entails two steps:[88]

- The company operating the plant decontaminates or removes contaminated equipment and materials; places spent fuel in dry storage until final disposal.
- The company deals with the small amount of radioactivity remaining in the plant, which must be reduced to harmless levels through a cleanup phase-decontamination.

#### 8.3.2. Decommissioning funds in competitive markets

Competition in electricity markets should impose the same financial risks on both nuclear and other power generators: the essential difference is the degree of these risks, which may be affected by the size of investment. Nuclear power, however, has some specific liabilities and associated risks due to political and regulatory uncertainties regarding plant decommissioning costs. The specificity of the risks associated with decommissioning is the uncertainty about the magnitude of these costs, for which there is limited commercial experience.

Concerns associated with decommissioning and waste disposal include:

- The adequacy of funding provisions to meet current estimated target costs;
- The accuracy of the target costs themselves;
- The adequacy of regulatory requirements for ensuring sufficient funding.

Decommissioning of nuclear power plants is expected to be a costly process. Since decommissioning begins after the plant stops generating revenue, utility management is required to set aside funds for this work while the plant is operating.

According to NEA,[89] some OECD countries require an initial endowment and annual contributions from nuclear generators – a fixed amount per kWh of generation – while others require nuclear generators to include funding for decommissioning costs in their financial plans.

Power generators are supposed to anticipate the costs of decommissioning and accumulate the funds over the life of the plant. The uncertainty about the accuracy of the cost estimates brings uncertainty

[88] NEI, 2002
[89] NEA, 2000

over the adequacy of funds accumulated. This concern is greater in competitive markets: contributions to decommissioning funds are predicted on assumed electricity sales volumes, and fund contribution per kWh of sales; since sales volumes are not certain, this method could lead to a shortfall in fund contributions.

Early closures of nuclear power plants are also an issue since the decommissioning funds are accumulated throughout the lifetime of the plant. An early closure will result in insufficient funds to cover decommissioning costs. Assessing and allocating financial responsibility for the potential shortfalls is problematic. With market competition, there will be strong pressure from investors and shareholders to identify, quantify and secure all liabilities as soon as possible. The lack of experience in decommissioning may hamper new investments if liabilities are not more accurately identified.

In the United States, NRC has established regulations and associated guidance on nuclear power plant decommissioning. Each plant must file a post-shutdown activities report with the NRC prior to the expiration of its operating license or within two years after the plant has permanently shut down.

In 1998, the NRC approved a new decommissioning funding rule for nuclear power plants "to reflect conditions expected from rate deregulation of the electric power industry". Nuclear power plants are required to put aside funds for their decommissioning during operations. Federal and state regulators help companies ensure that enough money is set aside, so the funds are not under the direct control of the companies: power generators cannot be used for purposes other than decommissioning.

The funding of decommissioning costs is factored into current rate structures over the life of the nuclear plants. As of 2001, $23.7 billion of the total estimated cost of decommissioning the nation's nuclear power plants had been collected. Assuming an average decommissioning cost of about $320 million per unit, this leaves an unfunded liability of approximately $11.6 billion, which companies must be allowed to recover over their plants' remaining operating lives.[90]

### 8.3.3. US Experience to date

Since 1960, more than 70 test, demonstration and power reactors have been retired throughout the United States. These include more than 40 research reactors ranging in size from less than a watt to two megawatts, four demonstration nuclear power reactors (the largest, 256 MW), as well as a number of large commercial nuclear power plants.

[90] NEI, 2002

The U.S. nuclear industry has gained much experience in decommissioning from Shippingport, Pathfinder, and the prematurely shutdown Shoreham plant[91]. The industry also has gained experience from the more recent decommissioning of the Yankee Rowe and Fort St. Vrain plants.

However, those reactors were relatively small (except for Shoreham, 800 MWe), and there is still some uncertainty on decommissioning costs for commercial-size nuclear power reactors. This issue is not cited as a major hurdle for new investments by industry executives.

[91] Shoreham completed its 5% power testing but was never put into commercial operation

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# PART III: Financing options for new nuclear investments

# 9. Evolution of the nuclear industry structure

## 9.1. Expected industry trends from the introduction of market competition

As earlier stated, electricity market competition is generally expected to concentrate efforts by plant owners to reduce expenditure on generation and to maximize returns. In addition to the improvements in plant performance and operation mentioned above, competition has brought improvements to the management and business arrangements of nuclear utilities. In the United States, a diverse group of nuclear utilities is seeking ways to improve the organization of nuclear generation businesses as competition develops.

Varley and Paffenbarger were right as early as 1998 when forecasting the likelihood of reorganization and consolidation.[92] According to them, consolidation of nuclear power activities was likely. Single-unit nuclear power installations generally have higher fixed operating costs per unit of electrical output because of the specialized infrastructure, staff, and regulatory activities required for nuclear installations, regardless of size. A likely strategy for owners of single-unit nuclear power plants was to consolidate the business operations of their units with other plants through mergers. Some utilities were also to sell their nuclear plants or shares in nuclear units.

Two strategies were to compete among nuclear power owners:[93]

- Some companies with good records of nuclear plant operation can seek opportunities to expand their activities through operating agreements or acquisitions of nuclear generation and related companies. For these companies, the basic strategy is to develop and take advantage of their strengths in nuclear power.
- A contrasting strategy is to diversify activities into other types of generation or entirely new business areas. Utilities who consider that their activities are too highly concentrated in nuclear power generation, or those with poor records of nuclear plant management, may favor this strategy.

[92] Varley & Paffenbarger, 1998
[93] Varley & Paffenbarger, 1998

## 9.2. Consolidation in the nuclear industry

### 9.2.1. Ownership Consolidation

At the end of 1991, the number of individual utilities (including minority owners) that had some ownership interest in operable nuclear power plants was 101. At the end of 1999, the number of such utilities had dropped to 87, and the largest 12 of them owned 54% of the capacity, slightly up on 1991. By mid-2002, the largest 12 owned as much as 68% of total nuclear capacity, due to many acquisitions and mergers in 2000 and 2001.

| Buyer | Reactors | Net MWe sold | Plant price ($ million) | Sale Completed (expected) | Price ($/kW) | Remaining life (yr) | Value[94] ($/kW.yr) |
|---|---|---|---|---|---|---|---|
| Entergy | Pilgrim | 670 | 14 | July-99 | 21 | 13.1 | 1.6 |
| AmerGen | Three Mile Island | 786 | 23 | December-99 | 29 | 15.3 | 1.9 |
| AmerGen | Clinton | 924 | 20 | December-99 | 22 | 27.5 | 0.8 |
| AmerGen | Oyster Creek | 619 | 10 | August-00 | 16 | 8.9 | 1.8 |
| PECO (Exelon) et al. | Peach Bottom, Hope Creek, Salem | 714 | 20 | January & October 2001 | 28 | 18.7 | 1.5 |
| Entergy | Fitzpatrick & Indian Point 3 | 1743 | 636 | November-00 | 280 | 15.2 | 18.4 |
| Entergy | Indian Point 2 | 939 | 502 | September-01 | 49 | 12.9 | 3.8 |
| Dominion Resources | Millstone | 1947 | 1193 | March-01 | 613 | 20.4 | 30 |
| Constellation | Nine Mile Point | 1536 | 675 | November-01 | 439 | 19.1 | 23 |
| Entergy | Vermont Yankee | 510 | 145 | July-02 | 288 | 10.3 | 28 |
| FPL Energy | Seabrook | 1024 | 749 | November-02 | 731 | 28.1 | 26 |
| Exelon | Clinton, TMI, Oyster Creek | 1210 | 276 | October-03 | 228 | 12.7 | 18 |
| Constellation | R E Ginna | 495 | 408 | June-04 | 810 | 26.1 | 31 |
| Genco & CPSE | South Texas | 630 | 279 | May-05 | 443 | 24.6 | 18 |
| Dominion | Kewaunee | 540 | 192 | July-05 | 355 | 9.1 | 39 |
| FPL Energy | Duane | 419 | 300 | (early 2006) | 716 | 9.0 | 80 |

[94] Value is defined as price per kilowatt divided by the number of remaining years on the license

Arnold

**Figure 46 – US Nuclear Plant Sales**
Source: World Nuclear Association, 2005

New investment has occurred only in States which have opened their retail electricity markets to competition. There has been no sale of plants in states with traditional US cost-plus pricing. The World Nuclear Association gives the following information on nuclear power plant sales since 1998.[95]

- In mid-1999, the 670 MWe Pilgrim plant was sold to Entergy, by Boston Edison, for $14 million plus $67 million for fuel.
- In late 1999, AmerGen, the joint venture of British Energy and PECO Energy (now Exelon), completed its purchase of the 930 MWe Clinton nuclear plant and the 790 MWe Three Mile Island plant in 1999. However, its plan to acquire control of the two-unit Nine Mile Point nuclear power station (614 & 1140 MWe) was derailed by a minor shareholder exercising its veto. Later, Constellation bid successfully for the units.
- In March 2000, Entergy Corporation reached agreement to buy the New York Power Authority's Indian Point-3 (965 MWe) and Fitzpatrick (778 MWe) nuclear power plants for US$ 967 million, topping a bid by Dominion Resources. The sale closed in November 2000.
- In November 2000 Entergy became the successful bidder for ConEd's 939 MWe Indian Point-2 unit (including the shut down unit 1 and 76 MWe of gas turbine capacity). The price was $502 million plus $100 million for fuel. ConEd will purchase the output at an average of 3.9 cents/kWh. The price per kilowatt is very much higher than earlier nuclear plant transactions.
- In June 2000 AmerGen received approval to purchase the elderly 650 MWe Oyster Creek plant for US$ 10 million, and the 522 MWe Vermont Yankee plant for $61 million. However, the latter deal was vetoed by state regulators and the plant was auctioned.
- In August 2000 Dominion Resources agreed to pay US$ 1.3 billion in cash for the Millstone nuclear plant, about $600/kW capacity. The Northeast Utilities plant comprises the 1150 MWe unit 3 and the 858 MWe unit 2, respectively 14 and 25 years old. Unit 1, which is being decommissioned, is also included. The price includes $105 million for fuel, but only 93.5% of unit 3, since minority shareholders wished to remain.
- In November 2000, Public Service Co. of New Mexico agreed to purchase two Kansas utilities owning 94% of the 1170 MWe Wolf Creek nuclear plant.
- In December 2000 Constellation Energy, owner of Calvert Cliffs nuclear power plant, agreed to buy Nine Mile Point for US$ 815 million, including fuel. The deal takes in unit 1 (609 MWe, started in 1969) and 82% of unit 2 (1148 MWe, started 1988) for $737 million, plus $78 million for fuel. This is about 3.5 times the price which had been agreed with AmerGen for the plant in 1999. Constellation has agreed to sell 90% of its output to the vendors for 10 years at about 3.5 cents/kWh. Some $450 million in decommissioning funds will be transferred to Constellation.
- In 2001 PECO (now Exelon) and PSEG concluded the purchase of minor shares in five large reactors from Connectiv.
- In August 2001 Entergy Corporation became the successful bidder for the 29-year old Vermont Yankee power station. Entergy paid $180 million for the 522 MWe plant, $35 million of this for fuel. It will take over both the decommissioning liability and the existing fund for this. Power will be sold to local utilities (former owners) for 3.9 to 4.5 cents/kWh to 2012. Entergy paid almost three times the price which had been agreed in 2000 with AmerGen.

[95] WNA, 2005b

- In April 2002 FPL Energy became the successful bidder for 88.2% of the 12 year old Seabrook plant. The utility will pay six utility vendors US$ 836.6 million for the 1161 MWe PWR reactor, being $749.1 million for the plant (including decommissioning trust fund), $61.9 million for fuel and the balance for components of an uncompleted second unit.
- In September 2003 British Energy (BE) agreed to sell its most profitable asset - the half share of US utility AmerGen, to FPL Energy for US$ 276.5 million. The proposed deal was the result of its plan to realize the value of its AmerGen equity independently of Exelon - its joint venture partner. Exelon then exercised its right of first refusal and bought the share, subject to regulatory and other approvals. The sale was required by the UK government's restructuring provisions for BE.
- In November 2003 Dominion agreed to pay $220 million cash for Kewaunee, a 540 MWe Wisconsin reactor, the figure including $36.5 million for fuel. The sale was finalized in July 2005. Some $392 million in decommissioning funds will be transferred.
- Also in November 2003, Constellation Energy agreed to buy the R E Ginna nuclear power plant for $401 million plus $21.6 million for fuel. The 495 MWe PWR started up in 1969 and is among the best-performing in USA. The sale was contingent upon the license extension taking its life to 2029. A planned uprate enabled by 1996 steam generator replacement will increase capacity to 580 MWe. A sales contract commits 90% of ten years output to RG&E at 4.4 cents/kWh average.
- In March 2004 Cameco Corp. agreed to buy 25.2% of the South Texas Project - two 1250 MWe PWRs which started up 1988-89 - for $279 million plus fuel, but two of the owners then exercised right of first refusal, leaving Cameco with a $7 million consolation fee.
- In July 2005 FPL Energy agreed to pay $380 million for 70% of newly-uprated Duane Arnold BWR from an Alliant Energy subsidiary, which will continue to buy the power. The plant is run by Nuclear Management Co.

**Figure 47 – US Nuclear Plant Sales, detailed summary**
Source: World Nuclear Association, 2005

Acquisitions have mostly taken place in regions where electricity rates are higher, due to the potential for higher profit margins if the plants' production costs can be reduced.

Of the 5,900 MWe involved to mid 2000, half was associated with plants having 1998 production costs above 2.0 cents per kWh. The reason is that sellers tended to consider the higher-cost plants as potential liabilities and were willing to get rid of them for a fraction of their book value. Conversely, the larger utility buyers considered the plants to be potential assets, depending only on their ability to lower the production costs.

### 9.2.2. Consolidation and market liberalization

The map below was extracted from a paper by Bruce Lacy.[96] It displays the status of plant sales and of state liberalization on the same figure. There are various symbols for sales of plants:

[96] Lacy, 2004

- Plants that have been part of corporate mergers or ownership consolidation of plants that have had multiple owners
- Plants that are part of an expanded fleet ownership based on purchase of other plants
- Plants for which their ownership is essentially unchanged.

The string correlation between liberalization and nuclear plant sales, mergers and consolidations is quite obvious on the map.

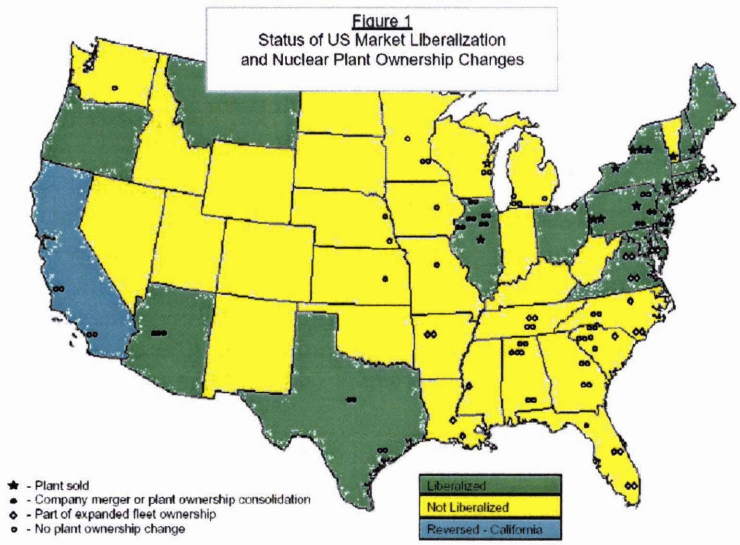


**Figure 48 – Status of US Market Liberalization and Nuclear Plant Ownership Changes**
Source: Bruce Lacy, 2004

The graph below shows another type of relationship between timing of retail competition and plant sales in those states. Vermont aside, all the transactions have occurred only after state liberalization, as was already suggested by the map above. There seems to be a strong correlation between advent of liberalization and nuclear plant sales in individual states.

This would suggest or confirm that deregulation and restructuring in the electric power sector has triggered nuclear power plant sales, driven by competitive pressures.

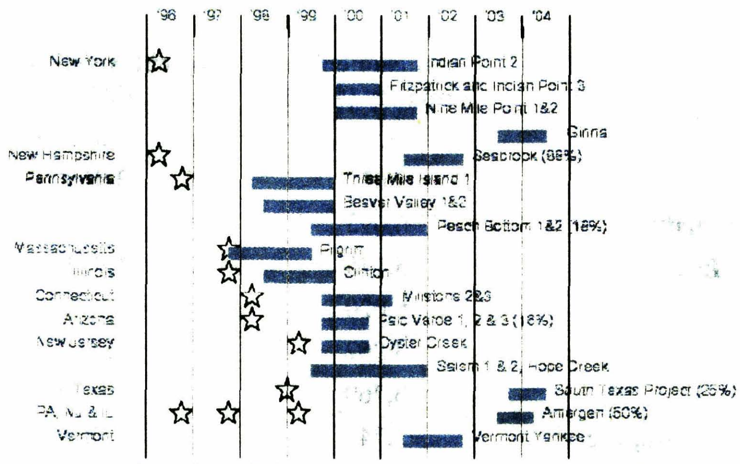


**Figure 49 – Timeline of State Liberalization and Nuclear Plant Sales**
Source: Bruce Lacy, 2004

### 9.2.3. Corporate Mergers

Corporate mergers have accompanied most of the nuclear generation capacity involved in consolidation announcements.

Exelon was formed by a $32 billion merger of Unicom and PECO Energy, the two largest owners of US nuclear generating capacity, involving 14 reactors, plus 3 AmerGen units.

The merger of Carolina Power & Light and Florida Progress Corporation involved 5 reactors at 4 sites. The last regulatory hurdle was cleared in November 2000.

GPU merged with FirstEnergy for $8.5 billion, and the deal involved 4 units and was approved in November 2001.

We have discussed that consolidation of nuclear plant ownership and management over the past five years put many plants in the hands of efficient operators, which has contributed to the fleet's improved performance.

Even with consolidation, the table below shows that nuclear ownership remains fragmented in the United States. The largest nuclear owner, Exelon, has about 16% of total capacity. The top ten firms make 61% of all nuclear power capacity in the country. The remaining 39% are owned by 26 investor-owned power companies and 40 government entities and rural cooperatives.

| Company | Total Nameplate Capacity (MW) | Recent Acquisitions (MW) | Percent of US Total |
|---|---|---|---|
| **Exelon Corp.** | 15,557 | 2,515 | 16 |
| **Entergy Corp.** | 9,010 | 3,966 | 9 |
| **Tennessee Valley Authority** | 6,695 | | 7 |
| **Dominion Resources, Inc.** | 5,175 | 1,923 | 5 |
| **Duke Energy Corp.** | 5,020 | | 5 |
| **FPL Group, Inc.** | 3,962 | 1,022 | 4 |
| **FirstEnergy Corp.** | 3,760 | | 4 |
| **Constellation Energy Group, Inc.** | 3,748 | 2,050 | 4 |
| **Southern Co.** | 3,598 | | 4 |
| **Progress Energy, Inc.** | 3,597 | | 4 |
| **All Others** | 39,090 | | 39 |

**Figure 50 – Top US nuclear owners, May 2005**
Source: Nuclear Energy Institute, 2005[97]

### 9.2.4.Prospect for consolidation

#### 9.2.4.1. Merger of Exelon and PSEG

In late December of 2004, Exelon announced its desire to acquire PSEG. This would be the industry's first truly strategic merger in several years. The first motivation for the alliance, according to the Edison Electric Institute,[98] is the ability to create efficiencies at all levels of the combined company, including generation, transmission, distribution and power marketing

Exelon is the industry's largest operator, with 17 units and 18 GW of capacity. PSEG's three nuclear plants would receive Exelon's economies of scale and operating expertise. PSEG credit quality, having suffered from nuclear plant outages, should be improved.

According to Edison Electricity Institute, if the deal is approved, the combined company will have approximately $27 billion in annual revenues, $3.2 billion in net income, 52,000 MW of generation capacity, nearly $80 billion in assets, and will serve approximately 7 million electric and 2 million gas customers in Illinois, New Jersey and Pennsylvania.

On June 30, 2005, the Federal Energy Regulatory Commission (FERC) approved the deal. In July 2005, shareholders of both companies approved the transaction. The merger also received approval from

[97] NEI, 2005e
[98] EEI, 2005

regulatory agencies in New York and Connecticut. The proposed merger still requires approval from New Jersey, Pennsylvania and Illinois state regulators, the Nuclear Regulatory Commission, and an anti-trust review by the Department of Justice or the Federal Trade Commission.

#### 9.2.4.2. Outlook for Consolidation

According to the WNA,[99] concentration of ownership seems set to continue where deregulation of power markets occurs, because the management of aging plants and license renewals will further induce single-unit owners to sell their plants.

With the high prices achieved in the most recent transactions, other utilities are expected to decide to follow the auction route as well. The auctions and increased competition among more buyers are likely to push acquisition prices, which have moved even higher since the Clinton, Pilgrim and Three Mile Island purchases. The prices per kilowatt for decades-old US nuclear plants have increased more than ten-fold since mid-1998.

In 2000 and 2001 one third of US nuclear capacity was consolidated through mergers, purchases, and alliances. From 1990 to 2004 the number of operating companies/organizations halved, and eventually there could be only 10 to 12 US nuclear utility operators.

According to Scully Capital,[100] the concentration and consolidation process has brought improvement in operations and financial health of the utilities. Moreover, larger owners tend to manage a portfolio of units that is not exclusively nuclear. As a result, they consider financing new units based on the total asset value of their larger balance sheets, not necessarily with a project-based approach.

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[99] WNA, 2005c

[100] Scully Capital, 2002

## 9.3. New form of consolidation: contract operators

The Nuclear Management Company is a joint venture formed in 1999 by four Midwest utilities for the purpose of operating the nuclear plants that they owned and operated - seven nuclear plants at five sites and in three different US states. The venture was approved by the Nuclear Regulatory Commission as a nuclear operating company.

The contract operator took over operation, fuel procurement, and maintenance of eight nuclear units at six sites for a total of 4500 MWe. The nuclear units continue to be owned by the utilities, each with 20% of NMC. The utilities remain responsible for spent fuel and decommissioning.

The main drivers of contract operators such as NMC, as with mergers, are cost reductions and streamlined operations. According to Bruce Lacy (2002), with NMC, the nuclear plant owners are positioned to act more quickly and more confidently when liberalization opportunities present themselves. For new investors, the contract operated plant should represent a better-understood, more stable and more reliable operation, with greater financial certainty.

In September 2003, Entergy Nuclear signed an agreement to take over management of Nebraska's Cooper nuclear power plant, an 800 MWe boiling water reactor with a poor operating record. Entergy will be paid a fee and will be eligible for up to 50 percent more in incentive payments for improved safety and regulatory performance. It will be reimbursed for all employee-related expenses. Nebraska Public Power District will retain ownership, will be the sole operator and licensee and will take all power produced. Entergy, the second largest US nuclear operator, sees such arrangements as a potential growth area.

## 10. Financing new nuclear power plants in the United States

### 10.1. Why financing nuclear power plants is an issue

The financing issue of nuclear power isn't exclusively related to the competitiveness of the technology with other sources of electric power. Even if the expected NPV of the project is positive, and even it is greater than that of all other power generation projects, the sheer size of the investment in a nuclear power plant, on the order of $2 billion per unit, represents a significant challenge to overcome.

The Enron collapse also affected the approach to power plant projects. Investors have become more conservative, and would require a higher percentage of equity investment. Absent loan guarantees provisions included in the Energy Policy Act of 2005, if 50% of equity capital is required, owners will need to provide about $1 billion: as a consequence, the company's stock valuation will be affected. Besides, the capital is at risk: losing $1 billion would jeopardize the financial health of most companies.

However, new nuclear plants are not uniquely large capital projects. Multi-billion dollar projects are not uncommon elsewhere in the energy industry. Richard Myers[101] gives the example of the Hibernia oil platform offshore Newfoundland, which was a $6 billion project. He mentions that the costs of LNG projects can be significantly higher than new nuclear plants. In order to manage the risk associated with these projects, the petroleum industry typically uses shared ownership of production facilities.

Therefore, in theory, an investment in nuclear power should not be different from any other large-scale investment, provided risk is properly characterized and mitigated. Issues would arise if some risk items had high perceived expectations of occurrence and no mitigation strategy associated.

The TIACT report[102] carries out an extensive analysis of the ways to overcome the financing obstacle through ownership arrangements to spread the equity investment and risk among a selection of parties. The report puts forward two key elements that are likely to play a major role in potential nuclear investments: the involvement of large industrial electricity users and the deregulation of wholesale and retail electricity markets.

For large industry users, taking an equity position in a new nuclear plant is a way to secure a long term supply of electricity characterized by cheaper and relatively certain costs. Moreover, in a deregulated electricity market, the private financing of the plant, as opposed to a situation in a regulated state, would make shareholders' capital at risk for the costs. Even if there are long term power purchase agreements to offset some risk, private financing of a $2 billion project represents a large investment and risk for a single owner to undertake.

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[101] Myers, 2005
[102] TIACT, 2005

## 10.2. Financing a new nuclear power plant

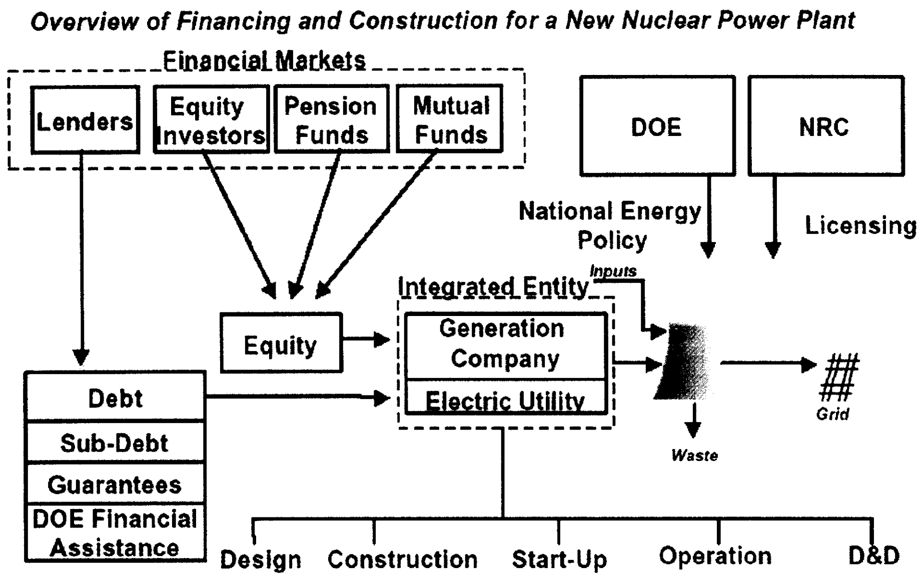


**Figure 51 – Overview of Financing and construction for a new Nuclear Power Plant**
Source: Scully Capital, 2002

### 10.2.1. Corporate financing structure

The power generating company is the borrower with the backing of the parent company of the integrated entity (Combination of a power generation company and an electric distribution company).

Power generation assets are treated as being on-balance sheet for accounting purposes.

Capital structure is generally comprised of 50% debt capital and 50% equity capital (in book value).

### 10.2.2. Project financing structure

A special purpose vehicle (SPV) is the borrower, rather than the corporate parent. The transaction is supported by contractual arrangements between the SPV and various other parties, which typically include the engineering and construction (E&C) contractor, the equipment vendor, and the power purchaser: no recourse to the parent companies. Lenders are secured by the assets and cash flows generated by the facility being constructed.

The power generation asset is often treated for accounting purposes as off the balance sheet of the power generation company, and on the balance sheet of the SPV.

This approach, classical to fossil-fired power generation, has become much less attractive. Decreases in corporate borrowing spreads (i.e., the margin that lenders require over and above the bank's cost of funds) and increases in project finance borrowing spreads (due to declines in credit quality among deregulated generation companies) has widened the spread differential between these financing options. Consequently, "off-balance sheet" financing has become much more expensive relative to corporate financing. Additionally, rating agencies have begun to view project financings as "on-credit" (i.e., on the balance sheet of the corporate parent) despite the off-balance sheet financing structure.

As a result, corporate financings, carrying the credit of the corporate entity, are in many cases a favored financing alternative.

### 10.2.3. Recent Financing Experience

High capital costs for new nuclear power plants are expected to continue to be in favor of external borrowing, whatever financial structure, since it is unlikely any utility would have sufficient liquidity from internally generated cash flow to support cash needs of such projects. Moreover, even if the utility did have adequate liquidity, it would still resort to debt financing to reduce the average cost of capital.

In the past 12 months, corporate acquisition financings for existing power generation assets with nuclear-related risks have been successful (e.g. Exelon Generating with a portfolio including nuclear plants generated a strong cash flow)

Recent financing experience for existing nuclear generating facilities on a non-recourse basis demonstrated that lenders are not yet ready to accept exposure to risks that have a nuclear element as their central focus. Entergy's acquisition of three existing nuclear power plants resulted in a structure in which the parent company was asked to provide a guarantee against the operating performance of the plants. Lenders appear unwilling to accept this risk even with the track performance record. They are only willing to accept dispatch and energy demand risk on a non-recourse basis.

## 10.3. Nuclear power and Wall Street

For Caren Byrd,[103] Executive Director at Morgan Stanley, nuclear power has been out of the headlines for some time, and investors today really spend little time thinking about nuclear issues or operations. Nuclear power has demonstrated its ability for good nuclear operations, the economics of nuclear are improving, and nuclear regulatory issues have remained rare.

The average years of utility investment experience is only about 8 years (since the restructuring of the electricity sector). As a result, investors and analysts of nuclear companies were not involved when nuclear power was coming of age. In a survey conducted among top analysts of the nuclear industry, all respondents considered nuclear generation to be positive from an investment point of view. For some of the analysts, nuclear concentration increases the perceived risk a company faces

### 10.3.1. Nuclear Compared With Other Fuels

Environmental compliance issues for coal have clearly made nuclear generation more attractive. Nuclear is sometimes viewed as a natural hedge against environmental burdens on coal. In fact, when the value of coal generation goes down, the value of nuclear generation goes up, showing the importance of a balanced generation portfolio. This relative attractiveness is expected to widen in the future, as environmental requirements increase, affecting the cost and risks of coal generation.

Nuclear generation is also attractive with regard to comparisons to gas generation. Its value as an investment has been enhanced by the dramatic increases in gas prices. Some analysts see nuclear generation as a proxy for gas reserves, and thus a valuable resource. Provided nuclear runs well, especially in markets where gas is on the margin, it can prove a profitable investment. Although nuclear generation would be notably less attractive if gas prices were to decline to historically more normal levels, such a drop is not expected for another 3 to 5 years. Moreover, even if gas prices fall, the volatility in gas prices increases the value of nuclear for the stability and predictability of its cost structure.

[103] Byrd, 2004

### 10.3.2. Nuclear Operations

Investors are interested in the recent track record of strong operations. Investors value that the nuclear industry is achieving near-term efficiency without sacrificing long-term operations or safety.

Capacity factor is the most measurable and easily available statistic for operations. The fact that capacity factors have exceeded 90% in the past four years is widely acknowledged. Overall, Byrd says investors are confident about the long-term perspective of strong operations. Most analysts assume in their investment analysis that the industry will be able to maintain the current high capacity factors, and even improve it by some. However, some expect deterioration in capacity factors as existing units age. This concern is especially intense for deregulated market operation, since a 1% reduction in capacity factor translates directly into millions of dollars of foregone earnings. Consequently, there is a significant pressure on financial results and investors' appraisals of nuclear stocks.

Sustaining high levels of efficient operations is the risk most often cited by investors. Only 50 percent of Byrd's respondents have high confidence for indefinitely sustained efficient operations without some operating issue in the future.

Moreover, investors realize the serious financial repercussions of an extended nuclear problem, as was witnessed for FirstEnergy's Davis-Besse outage. Davis-Besse was a specific event and not an industry issue and FirstEnergy was able to sustain the financial impact of that 25 month outage. However, for companies where nuclear is fully deregulated, such an occurrence could be a death blow.

Also, safety is not a major concern for the financial community. The record of safe operations is appreciated by investors, and even the recent public opinion polls are telling about the general public's confidence. Investors also put a low probability of terrorism being a real risk for the industry.

### 10.3.3. Nuclear Ownership Changes

Overall, investors have embraced the consolidation of nuclear generation by the industry. Over time, investors have reacted increasingly positively to nuclear transactions, and each nuclear power plant sale has been seen as a value-enhancing event for shareholders on both sides of the transaction:

- Buyers have been considered disciplined in their purchases, and have realized operational improvements of purchased units. Investors say nuclear purchases have made buyers more attractive as an investment.

- Sellers have generally received attractive terms and in most cases good purchased power contracts. They have used the funds received to strengthen their financial positions and they have been able to better focus on other parts of their business.

As long as consolidated companies keep up with efficient operations and appropriate risk management, any additional consolidation in the industry will be seen as positive.

Single site nuclear companies still remain financially attractive. Operating costs are generally competitive with those of multi-station companies. Single station nuclear generation seems to generally work best when companies are still regulated, because revenues are not interrupted when units are shut down. Investors benefit from the nuclear generation with little risk from lack of scale and scope.

On the other hand, investors especially value scale and scope when nuclear generation is located in deregulated markets. Investors tend to worry about the risk of earnings volatility from nuclear generation. In a deregulated market, when a company's only nuclear unit is down, replacement power must be found. The marginal cost of replacement power can be high, and these costs can't be passed on to customers. Shareholders have to bear this risk and a higher return may be required.

### 10.3.4. New Nuclear Plants

The investment community has seen the series of announcements relating to exploring the feasibility of new nuclear units. The industry had three separate proposals, and one of the groups submitting the proposals has been joined by eight US companies.

The financial community is aware that the purpose of each consortium is to test the feasibility of new nuclear units and specifically to see if the NRC licensing provisions will work to support the construction of economically competitive new nuclear generation. However, analysts have very short time horizons as opposed to those projects dealing with licenses by 2010 and new units by 2014.

Analysts are split on whether a commitment to actually build new nuclear will be made by the industry within the next 5 years. Investors, as citizens, understand that the country has few alternatives for clean, reliable and available energy sources, and see the potential role of nuclear energy in the energy future. Yet they are concerned about the economic viability of nuclear. The challenges are the following:

- Public perception about the safety of nuclear;
- Siting and NIMBY issues;
- Qualified work forces (both for construction and operation);
- Storage of spent nuclear fuel;
- Financial issues, the key issues.

### 10.3.5. Financing issues

COL process: The licensing process – Construction and Operation License (COL) process – still bears some uncertainties as to whether it will be effective and how expensive it will turn out to be. Investors do not wish to put a significant amount of their equity into this pre-construction process. To investors, logic recommends that vendors provide the majority of the private funds needed for this licensing process, because they have the most to gain financially from it. Construction Process: Investors are very leery to say that they will be there to put their money at risk during the construction phases of the early mover plants. There is too much uncertainty about whether the COL will work as designed, and investors do not want to bear the risk that a plant will be completed and not allowed to operate. Also, the market risk of the economics of this generation will be on investors' minds.

Governmental Assurances: According to Byrd, governmental grants, loan guarantees, production tax credits and investment tax credits have advantages and issues, but they will be crucial.

## 10.4. Project financing of the EPR reactor in Finland

The EPR reactor currently being built in Finland is an example of nuclear power investment in a Western country with a competitive electricity market, and as such it is relevant to take a close look at its structure and business model.

### 10.4.1. Nuclear power in Finland

In 2001, nuclear power held 31% of electricity generation in Finland. The remaining electricity generated came from hydropower (17.8%) and fossil fuels (51.6%). Consequently, nuclear power represents almost a third of the electricity produced domestically.

The Finnish nuclear fleet capacity factor has averaged above 91% over the past ten years – one of the highest in the world. The four operating reactors are owned by Fortum and TVO, and are located on two sites - Loviisa and Olkiluoto.

TVO's capital is shared between the Finnish government (43%) and private ownership. Among the private shareholders are electricity-intensive industries that require a specific power supply.

### 10.4.2. The foundations of the EPR project

In 2003, after ten years of halt in the European nuclear program in Europe, Finland ordered a new nuclear reactor. The electric utility TVO signed the contract with Areva and Siemens for a European Pressurized Reactor (EPR). Construction is to begin in 2005 and operation should start some time around 2010.

The reactor is a 1,600 MW reactor and the contract has been signed at 3 billion euros. It is supposed to have a 60 year lifetime, and will bring the nuclear electricity generation from 27% up to 35%.

Finland has chosen to build a fifth nuclear power plant as a political choice to meet environmental targets. The project, similarly to the potential new builds in the United States, occurs within a transitioning European context to competitive electricity markets.

Finland has chosen to sign the Kyoto protocol, and has committed to maintain its greenhouse gas emissions at 1990 levels through 2012. For that purpose, the climate strategy is to promote energy efficiency, renewable energy sources and to reduce coal use by an increased use of natural gas and nuclear power.

The industrial sector represents more than half of total electricity consumption in Finland, and the largest consumers are the paper, metallurgy and chemical industries. In the face of uncertainty of imported fuel and electricity prices, Finnish industrials have supported domestic production with stable prices. Moreover, nuclear power provides a source of baseload power that is well adapted to the future needs of the country and the load profile of power-intensive industries.

### 10.4.3. Financial interest for the paper industry

StoraEnso, UPM-Kymmene and Metsaliitto are the three main paper makers in Finland, providing around a third of paper production in Europe. The forestry and paper industries represent 7% of the GDP in Finland, and 25% of exports.

Because of large baseload electricity needs, the industry has shown strong support for the construction of a fifth nuclear reactor in Finland. Since electricity needs are so large, the volatility in electricity prices significantly threatens the stability of the industry. Delocalization to regions where electricity prices are lower is not an option for the paper industry because of the necessary proximity to forested areas.

### 10.4.4. Financing options for the Finnish nuclear reactor

TVO signed a contract of 3 billion euros with Areva and Siemens for the EPR nuclear reactor (1,875 €/kW, i.e. approximately 2,300 $/kW). In participating in the nuclear reactor project, the Finnish paper-makers guarantee there will be electricity supply in the long run and limit the impact of price risk. This commitment is materialized by the signature of a long-term fixed price contract. The contract has been signed within a project financing structure where TVO is the project developer and the papermakers are the equity investors.

The financing has developed easily due to the fact that the links between actors are strong: TVO is joint-venture with six shareholders, including PVO (55%), the number two electric utility in Finland. TVO has a 100% power purchase agreement with its shareholders at cost-of-service, any unwanted portion being sold by them into the Nordic market. Consequently, TVO makes no profit on electricity sales.

The EPR reactor will receive 25% equity capital from the paper industry. The Finnish paper makers have been among the largest contributors to the EPR reactor. However, 75% of the project is financed with five and seven year term bank loans, similar to any debt structure. The loans will later be refinanced with longer-term bonds.

The paper makers will take on their share of risk by buying the electricity at cost: if prices increase, they will be better off because they won't need to purchase their electric power from the market. However, they will incur an opportunity cost if electricity prices drop. In a nutshell, the long-term contract has a dual function: it is a hedge against price risk and an investment to secure the electricity supply at a stable price.

| | |
|---|---|
| UPM-Kymmene (forestry products via PVO energy company) | 25.63% |
| Stora Enso Oyj (forestry products via PVO energy company) | 9.39% |
| Others (forestry products via PVO energy company) | 25.18% |
| Fortum Power & Heat (government controlled power company) | 25.00% |
| Oy Mankala Ab (City of Helsinki) | 8.10% |
| Etala-Pohjanmaan Voima Oy (distr cos in NW coast of Finland) | 6.50% |
| Graninge Suomi Oy (energy co. in forestry/energy group) | 0.10% |

**Figure 52 – Ownership of the EPR reactor in Finland**

## 10.5. Analysis of recent nuclear plant sales conditions

### 10.5.1. Price conditions

We have already mentioned a number of companies have purchased nuclear power plants, with the intention of continuing to operate the plant since 1999, to a large extent as a result of the introduction of competitive markets. (cf. Figure 46)

Figure 46 shows not only the time at which each acquisition has taken place, but also the price at which the plant has been sold, and the value per kilowatt and per number of remaining years until operating license expiration.

At a glance, there is no pattern on the age of the plants sold: old plants as well as newer plants have taken part in the transactions, ranging from 12 year-old units to 31 year-old units. What this tells us is that a plant is attractive as long as it has proven good operating performance. Moreover, it seems that buyers are confident about the future performance of ageing plants.

Secondly, prices for nuclear plant sales have been escalating. This is an indication that a nuclear unit is a valued corporate asset. The initial buyers were first movers of such difficult transactions, which could explain the price increase. A nuclear asset might have been initially perceived as a liability that the seller was getting rid of, putting the selling company in a poor bargaining position. As a result, early sales were made at a high discount.

In fact, one can argue that, considering the plants that were sold were in operations and with good performance records, the discounts have been extremely high.

10.5.2. Power purchase agreement conditions

| Buyer | Reactors | Sale Completed (expected) | Value ($/kW.yr) | Remaining life (yr) | Power Purchase Agreement |
|---|---|---|---|---|---|
| Entergy | Pilgrim | July-99 | 1.6 | 13.1 | 5-year contract at 3.5 to 4 cents/kWh |
| AmerGen | Three Mile Island | December-99 | 1.9 | 15.3 | 3-year fixed price contract |
| AmerGen | Clinton | December-99 | 0.8 | 27.5 | 5-year contract (75% of output) |
| AmerGen | Oyster Creek | August-00 | 1.8 | 8.9 | 3-year contract at 3.4 cents/kWh |
| PECO (Exelon) et al. | Peach Bottom, Hope Creek, Salem | January & October 2001 | 1.5 | 18.7 | N/A |
| Entergy | Fitzpatrick & Indian Point 3 | November-00 | 18.4 | 15.2 | 3.2 cents/kWh from 46% to 31% output through 2004 and 500,000 kWh at 2.9 cents/kWh |
| Entergy | Indian Point 2 | September-01 | 3.8 | 12.9 | 3.6 cents/kWh for 100% output through 2004 100% output at 3.9 cents/kWh through 2004 |
| Dominion Resources | Millstone | March-01 | 30 | 20.4 | None |
| Constellation | Nine Mile Point | November-01 | 23 | 19.1 | 90% output for 10 years at 3.4 cents/kWh |
| Entergy | Vermont Yankee | July-02 | 28 | 10.3 | 10-year contract (100% output) at 3.9 to 4.5 cents/kWh |
| FPL Energy | Seabrook | November-02 | 26 | 28.1 | |
| Exelon | Clinton, TMI, Oyster Creek | October-03 | 18 | 12.7 | |
| Constellation | R E Ginna | June-04 | 31 | 26.1 | 90% of plant output for 10 years |
| Genco & CPSE | South Texas | May-05 | 18 | 24.6 | |
| Dominion | Kewaunee | July-05 | 39 | 9.1 | |
| FPL Energy | Duane Arnold | (early 2006) | 80 | 9.0 | |

**Figure 53 – US nuclear plant sales – Price conditions**
Source: Nuclear Energy Institute, 2005[104]

[104] NEI, 2005e

Some of the nuclear power plant sales have also had power purchase agreements (PPAs) contingent to the specific unit sold. A power purchase agreement is an off-take contract to buy part or all of the power generated by a power plant.

No clear pattern can be drawn from the conditions of the PPAs. Some transactions have occurred without any power purchase agreement, while others provide off-take agreements for 10 years and the entire output of the unit. There are also a variety of arrangements between those two extremes.

Moreover, one can notice that the duration of the PPAs is far exceeded by the remaining lifetime of the plant in all cases where off-take contract go together with the transaction. Although dispatching is an important concern for a utility, it seems that buyers were sufficiently confident in the markets in the service area of the sold plants that they didn't need the degree of certainty of off-take provided by PPAs.

Of course, this last remark does not hold for new power plants. Indeed, nuclear power plants being of rather large capacity, their introduction in a market would immediately occasion a drop in prices due to the excess supply. A power purchase agreement would then help mitigate the risk of not being able to sell power above marginal costs of production.

## 10.6. Business model and potential financing options for new investments

### 10.6.1. Ownership structure options

The TIACT report puts forward three ownership options for a nuclear power plant project in the Gulf Coast region, where the potential owners are:[105]

- Option 1: End users
- Option 2: End users, municipal utilities, power companies
- Option 3: End users, municipal utilities, power companies, nuclear industry investors

The criteria employed to assess the implications of the ownership structure options are the following:

- Organizational issues
- NRC's financial requirements for licensees
- Size of the investment for each potential owner
- Financial issues
- Required rate of return on investment

#### 10.6.1.1. Option 1

The business venture representing the new plant is 100% owned by end users, primarily from those industries that are energy intensive and sensitive to energy costs, similar to the Finnish case.

An experienced nuclear operator such as the Nuclear Management Corporation or Entergy Nuclear could operate the plant under contract.

The venture must provide NRC with assurances that it has the resources to ensure safe operation of the plant and to decommission it at the end of its life.

- Non-electric utility applicants are required to submit estimates for total construction costs and the first five years of annual operating costs and identify the source of funds to cover those costs.
- Front payment into a decommissioning trust fund, of around $150 million.

Large industrial end-users have electricity needs between 125 and 250 MW, i.e. 10-20% of a nuclear power plant output. 5 to 10 (or more) end users would be needed for the investment, with an

[105] TIACT, 2005

investment of $100 million to $200 million paid out over 4 years. Such an investment seems reasonable for large industrial companies.

The TIACT report argues that debt will have to remain below 50% and that the cost of this debt is uncertain. The Energy Policy Act of 2005 guarantees debt up to 80%, so leverage will likely be higher than planned by TIACT, with much less uncertainty on the rate of return on debt.

According to the report, end users will not be as risk-averse as Investor Owned Utilities: as a result, returns on investment will be lower by several points than an IOU, thereby improving the economics of the project.

#### 10.6.1.2. Option 2

An objection to option 1 is the capacity of the potential new reactor designs, too large for exclusively industrial users to use. Adding municipal utilities and power companies brings the project closer to the Finnish option. The example taken to illustrate such an arrangement is South Texas Project – though without industrial users – with ownership split among two municipal utilities and two investor owned utilities:

- Austin Energy, The City of Austin 16%
- AEP Texas Central Company 25%
- City Public Service of San Antonio 28%
- Texas Genco LP 30.8%

The suggested ownership share for this option is:

| Owner | Share | MW |
|---|---|---|
| Industrial end users | 15% | 210 |
| Municipal utilities | 50% | 700 |
| Generation Companies | 10% | 350 |
| Private Investor Groups | 25% | 250 |

The potential organization would be similar to option 1, except for the operational experience of some of the owners, which would be put to use instead of contracting an outside operating company.

Requirements for decommissioning will prove more complicated, because multiple owners will never be jointly and severally liable for decommissioning costs. Arrangements would have to be found for each owner to meet the NRC requirement in the way most appropriate for its situation.

The size of the investment will be smaller than in option 1 due to the larger number of parties.

A consortium is likely to benefit from favorable financing terms. The presence of a municipal utility will be a proof of predictability of customer base and stability.

The group will be diverse in its required return on invested capital. TIACT gives an estimate of 10% for the aggregate value.

##### 10.6.1.3. Option 3

This option adds nuclear industry investors such as reactor suppliers, uranium and enrichment services suppliers, and even foreign investors. TIACT believes that it would at least reduce large negative cash flows during the last two years of the construction period.

In terms of organization, NRC financial requirements, size of investment, risks and costs will be spread and risk shared across a larger span of parties.

The presence of a reactor supplier in the consortium is a positive element, for it adds assurances to the firmness of the price contract.

The desired return on investment is very diverse in this group as well. Nuclear ownership not being the core business of the industry investors, the required return will be even higher than the 10% of option 2. However, the degree of ownership of these nuclear industry investors won't go above 10%: even though their required return will be higher than for other participants, the 10% contribution of nuclear industry investors will result in an increase in the aggregated required return on investment by no more than 0.5%.

As a conclusion, TIACT recommends that the third option be chosen, considering the success of the Finnish utility TVO for its new nuclear plant.

#### 10.6.2. Risk-management strategy

##### 10.6.2.1. Quantifying risk for improved risk-management strategy

Risk-management will be a key factor in allowing for new investments in nuclear power plants in the coming years. When considering a potential investment, an investor will essentially look at the risk/reward balance.

With the new energy legislation, we have seen that nuclear power was made cost competitive and the recent performance achievements in the industry suggest that nuclear power, in normal conditions, will be a profitable investment.

The question is now on how specific projects will deal with the issue of properly accounting for the risk items to make it clear to the investor that he will be rewarded for the amount of risk he is willing to undertake.

Two studies have quantified the major risks associated with nuclear power investments. The first one, Scully Capital, conducted a survey among industry participants to find out, on a scale from 1 to 5, how each risk item was evaluated and how those risks were ranked. The more recent one, the TIACT report, conducts NPV calculations similar to those presented in this study to assess the contribution of each item to the total risk of the investment. The results of the assessment are shown below.

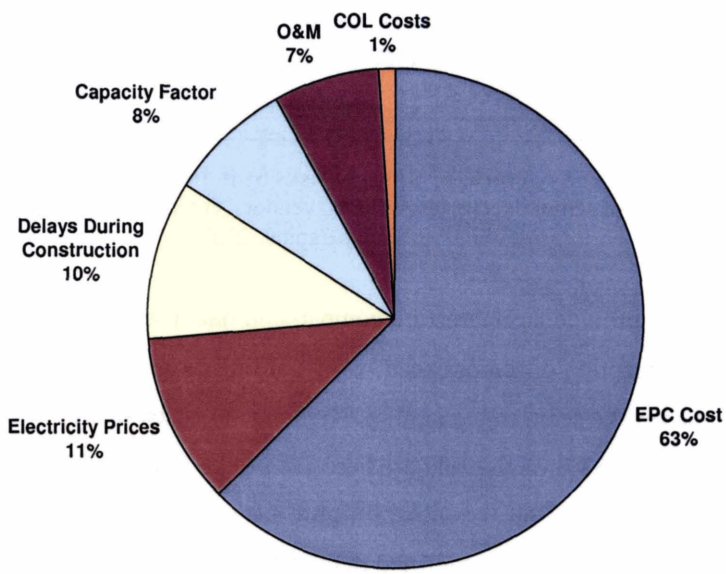


**Figure 54 – Sources of Variation in Plant NPV**
(EPC = Engineering, Procurement and Construction)
Source: TIACT, 2005

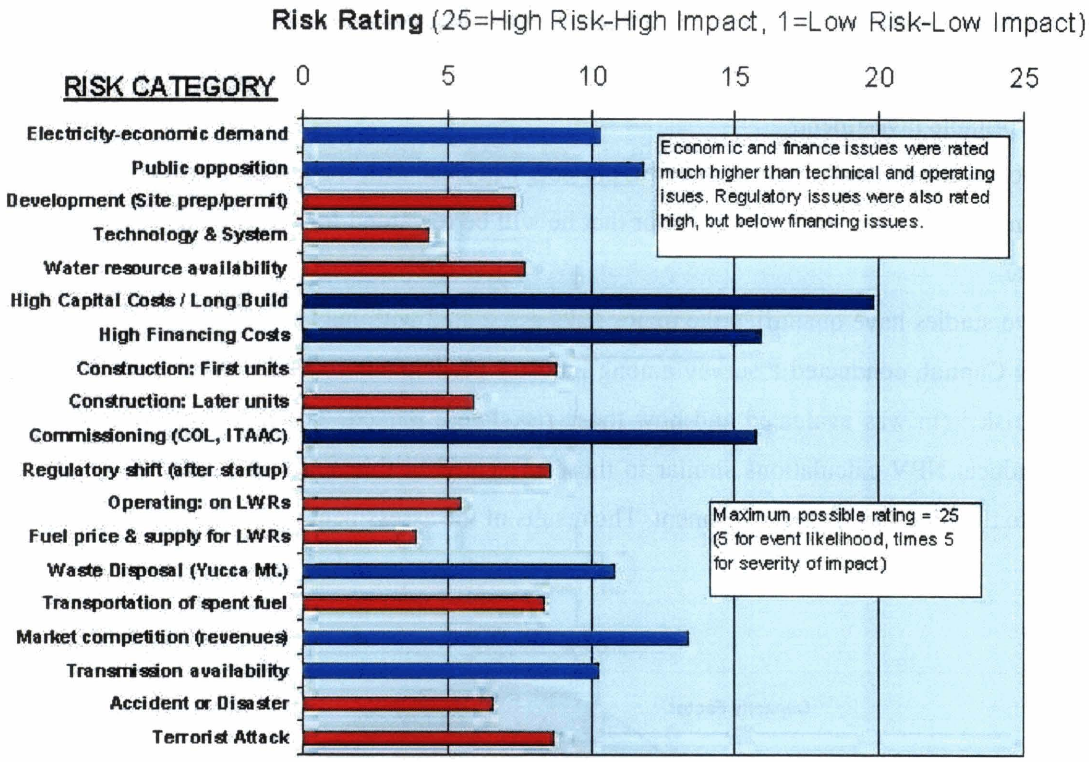


**Figure 55 – Average ratings of risks by industry executives**
(10 interviews of senior executives: utilities, vendors, engineering and construction)
Source: Scully Capital, 2002

The figures above provide an interesting comparison: one quantifies the impact of risks on NPV, and the other gives the perception of senior executives regarding those same risks.

At a glance, the results seem rather similar. High capital costs, delays in construction and market competition account for over 84% of risk and are perceived to be have the highest impact on investment. Financing costs are not displayed on the TIACT figure because they haven't chosen it as a variable; neither is public perception, for it is not quantified in the NPV calculations.

The new licensing process should reduce most of construction delays due to regulatory or litigation matters. Financing costs have been lowered by the Energy Policy Act of 2005. A good risk-management plan will allocate a large amount of energy at resolving at least the following major risk items:

- High capital costs / long construction (EPC costs)
- Delays in construction
- Market competition (Electricity prices)

### 10.6.2.2. The "tollgate approach to investment"

In order to facilitate the financing of a nuclear project in the Gulf Coast region, the TIACT report[106] developed a tollgate approach that deconstructs the risks so that they can be addressed separately and step-by-step, and that reward can appropriately match risk at every investment stage. The tollgate plan is displayed in the following figure.

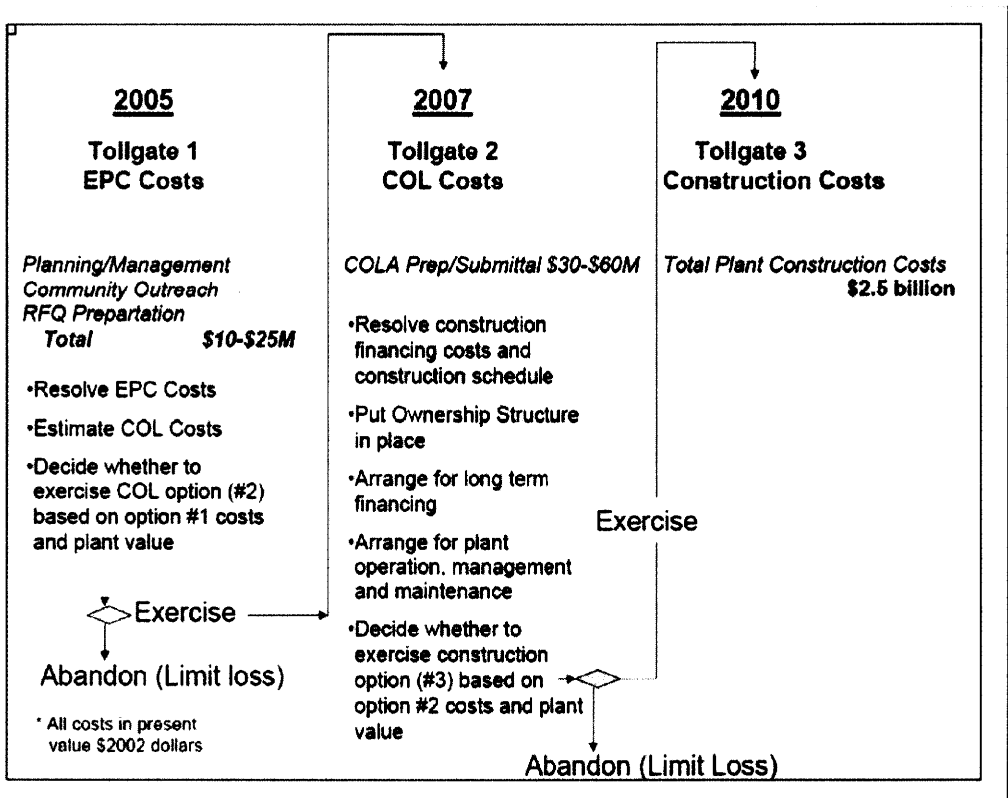


**Figure 56 – Texas Gulf Coast Nuclear Plant Tollgate Plan**
Source: TIACT, 2005

Risk is highest at the first tollgate, where the investment is small: such a contribution will be found provided it is rewarded with a significant upside. Risks are reduced to a more acceptable level at the last tollgate. It will then be easier to find the larger group of investors required to finance the project, with much more reasonable terms as risks have been significantly reduced.

This approach has the crucial benefit of resolving uncertainties when capital outlays are the lowest, similar to the new NRC licensing process. The remaining investment may be foregone if uncertainties are resolved unsatisfactorily.

[106] TIACT, 2005

The major risk items that can be controlled are then resolved at the following tollgates:

| Risk | Management Strategy |
|---|---|
| Total Overnight Capital Cost | Tollgate #1 |
| Delays During Construction | Tollgate #3 |
| Electricity Prices Plan | Tollgate #3 |

10.6.2.3. Engineering, Procurement and Construction costs

We have seen earlier that capital costs represent a significant portion of the cost of nuclear power generation. Accordingly, the profitability of a project will be highly sensitive to capital costs.

The EPC costs (Engineering, Procurement and Construction costs) are defined as the costs to engineer the plant, procure the components, equipment, material, and labor, and to construct the facilities. Solving the uncertainty about EPC costs would offset an important portion of the risk, and this is the main motivation for the nuclear provisions of the Energy Policy Act of 2005, and the funding from DOE to the various consortia created in the past few years. Reducing risk will require the acquisition of more accurate capital cost information to which suppliers could commit.

According to TIACT,[107] until a firm price contract for a plant built in the U.S. is signed with a supplier, the level of contingency will not go below 5%. Even additional engineering information will not bring in more certainty: even with a design 90% close to completion, there will still be substantial risk that costs will turn out to be higher than publicly quoted estimates.

One of the reasons given is that cost items do not take into account commercial terms and conditions at the pre-proposal stage. Moreover, vendors would rather provide the lowest possible cost estimates than be perceived as non-competitive. Finally, the TIACT report mentions the designs of the turbine islands are out of date and that cost information is not detailed.

In order to offset the risk of the supplier bids, The TIACT report suggests going out for bids at the very beginning of the process, even before the COL application has been submitted, in order to secure the commercial terms and conditions. The bids would be on a fixed-price fixed-schedule basis, thereby shifting the risk to the EPC supplier. This would allow submitting price targets to investors with a much more reasonable degree of confidence.

Finding the $12 million financing for this initial pre-COL step would be a difficult task, but once the hurdle is overcome, it would very much facilitate the following stages of the project.

[107] TIACT, 2005

#### 10.6.2.4. Early community outreach

The new NRC licensing process has reduced the opportunity of delays due to public opposition to the stage at completion of construction and before the ITAAC tests are run. Even though the public appears to favor new nuclear power plants, there is still a chance that anti-nuclear lobbies might take the opportunity of a time where all capital has been invested and the plant is standing idle.

Reaching out to the public at early stages is a way to address construction delay risk that TIACT suggests in its report. Confronting the public before any key decision is made, like site selection, is a better method to reduce delays than insisting that the NRC resist pressure during construction.

The early public outreach program could begin as soon as the project starts, i.e. when the ownership consortium is decided. The consortium would provide information and address all sources of concern so as to build support across the community. Opposition could also be neutralized early on from anti-nuclear groups.

#### 10.6.2.5. Power purchase agreements

Due to the large scale of nuclear units, installing a nuclear power plant in a certain region will substantially affect supply for electricity, thereby affecting prices downwards. Power purchase agreements are a method for coping with the market imperfection that nuclear capacity cannot be added in marginal amounts.

The experience from the nuclear power plant sales in the United States shows that power purchase agreements have not constituted an indispensable tool to help transactions. There are chances that if they can be avoided, i.e. in case where there will be a sufficient amount of certainty on baseload demand, they will be avoided. Otherwise, the conditions will be on the shortest possible terms and on price formulas as flexible as can be.

However, in situations where uncertainty in demand is most intense, consumers will play a key role in financing, particularly large industrial users and electric distribution utilities. New nuclear plant financing may require long-term off-take arrangements to produce more reliable information about future demand. PPAs evoke a commitment from the customers, and will support the creditworthiness and the terms of financing of new nuclear plant construction in the United States.

### 10.6.3. Anticipated characteristics of new investments

By way of the Energy Policy Act of 2005, the government will help offsetting the first-time design and engineering costs and mitigating the risks associated with new nuclear plants. In spite of the new regulatory process, until the first few new plants are built, investors will inevitably perceive nuclear construction as riskier than other forms of generating capacity, thereby increasing required returns on debt and equity capital.

However, there is a financing challenge to the first few plants of any series of new capital-intensive baseload power plants. As capital costs decline, and they are likely to do, and as the licensing process proves efficient and predictable, future builds will be financed without the support provided for the first few projects by the recently voted energy legislation.

NEI expects to see a spectrum of project and financing arrangements.[108] Construction will be financed like any other large-scale construction project. There will be regulated and merchant projects, with varying degrees of leverage, many sources of equity capital. The projects will be built by single companies, by consortia for risk-sharing purposes, by companies on behalf of others. Arrangements may involve project financing structures, and either be full-recourse or non-recourse to the project developers' balance sheets. Other structures like the Finnish TVO model may also be used.

[108] NEI, 2005d

# PART IV: Analytic investment model in power generation

11. Evaluation of the impact of regulatory delays on the future potential builds in nuclear capacity in the case of cost competitiveness

In studies about the relative competitiveness of power generating technologies, the most popular metric against which projects are compared is the levelized cost of electricity: the minimum price of electricity for the project to break even at the end of its economic life. A project will be considered cheaper and better if its LCOE is lower.

This method has a number of weaknesses, most of them related to the necessity of simplifying assumptions in a financial model. A number of characteristics are assumed to remain constant throughout the lifetime of the power plant, while most of the actual values are highly variable, and average values are chosen. The rationale is that the variability of certain components of electricity generation technology valuation will have low impact on the lifetime value of the project, impact which is taken care of through the use of a risk-adjusted discount rate.

Moreover, the variability of load is generally not properly taken into account. Depending on the marginal cost of production of a technology, the merit-order will impose that the production of some units will not be dispatched, or that some units will be temporarily shutdown at certain times where demand for electricity is lower than supply. In fact, the purpose of reserve margins is that there always exists excess production capacity for peak loads. The peaking units will otherwise remain shut-down. Thus, the LCOE method is only valid for baseload units that would dispatch all of their output, or for peaking units if the uncertainty on load is accurately accounted for. Uncertainty undermines the accuracy of the LCOE analysis, and even if effort is placed in estimating the average annual load, there will inevitably be residual omitted uncertainty.

Along the same line, the LCOE method is a static analysis of the investment decision. It does not explicitly consider the unit of capacity as part of a dynamic environment with parameters external to the project itself but relevant to the investment decision in a given technology. The evolution of demand for electricity, the capacity currently being built, the rate at which capacity has been built in the past few years are not a base to decision-making. By renouncing the market context and its dynamics, the LCOE method misses information that could have great effect on the decision between several projects.

Also, when the time dimension is added, temporality features are added in. A very important one is the construction time of the project. On first impression, it seems that construction time is accounted for by the LCOE model: the longer the construction time, the longer the period between the sinking of the initial outlay and the start-up time. We have commented in this study on the fact that construction time is a key factor for capital-intensive projects like nuclear power plants. Yet, if demand and prices evolve through time, the length of the construction period carries another aspect related to uncertainty. Not only does the investor face uncertainty about demand and prices for electricity from the moment the plant is built, but there also is an additional period during which the situation may evolve – favorably or unfavorably – before the first positive cash flow of the project, namely the construction period.

This study is ultimately aimed at analyzing the impact of this additional uncertainty on investment in power generation. Construction time is a feature that places generation technologies like nuclear power and gas-fired power in very different positions, for it takes much less time to build a combine cycle gas turbine power plant than a nuclear power plant. The two technologies will compete in some areas for baseload power generation. The following analytical model will intend to analyze how the economics of each technology in addition to their differing construction time will place them relatively to each other in a given region. The overall impact on prices for electricity will also be carefully examined.

The first section will lay the basis of the investment model developed for this study, and the quantitative assumptions used for simulations. Simulations will then be run in the second section so as to gain practical insight on the investment dynamics in electricity generation.

## 11.1. Investment model

In this section, the ultimate investment model will be reached in three steps by progressively taking new elements into account.

The first step will be the presentation of a model of dynamic investment where there is only one generation technology and where construction is assumed to be instantaneous. The addition from the LCOE model is the effort to take uncertainty of demand and the resulting price process into account. The model was developed by Leahy[109] in 1993.

The second step will be to incorporate time-to-build into the investment decision. There will still be only one generation technology, and the model will straightforwardly implement the work of Grenadier.[110]

The third and final step in the development of the model will be to introduce two competing technologies with different characteristics. Although this study does not derive a closed form solution in competitive equilibrium, assumptions are made to approximate the solution and gain the insight from the modeled situation.

### 11.1.1. The Leahy model

#### 11.1.1.1. General principle – deterministic case

The Leahy model is a model of investment in a competitive equilibrium, where the price of the traded good clears the market (i.e. equates aggregate supply and demand for the good). In our situation, an instantaneous equilibrium will determine the price of electricity according to the installed electric capacity and the demand for electricity function.

The industry considered will consist of a continuum of homogeneous firms. Thus, each unit of installed capacity will have identical characteristics in all respects. Moreover, the continuum assumption means that units of capacity will be considered infinitely divisible.

All firms are assumed to be risk-neutral. This can mean that risk has already been accounted for in other parameters of the technology, but that the discount rate at which cash flows will be discounted is the risk-free discount rate.

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109 Leahy, 1993
110 Grenadier, 2000

Another strong assumption Leahy makes in this model is the perfect competitiveness of the industry. The number of potential entrants is infinite, so it is assumed that they are all price takers: infinitesimal investments have no effect on the market.

All incumbents and potential entrants produce with the same technology at constant returns-to-scale with a constant production cost of $c$.

The firms' assets will be referred to as its installed capacity (in our case electric capacity). The firm's output is considered non-storable and is produced in proportion to the installed capacity. To keep the following assertions as general as possible, we will not refer to the output as electricity.

We also assume that capital is infinitely divisible. One unit of capital produces one unit of output. At any point in time, a firm may invest in a unit of capacity at a cost of $k$. The investment is irreversible and all firms discount their cash flows at a discount rate of $r$, taken to be the risk-free interest rate.

The time horizon considered in this investment problem is infinite. The assumption is therefore that a unit of installed capacity will be capable of producing one unit of output indefinitely.

Since the firms are price takers, too small relative to a market to affect its price, it is convenient to think of each infinitesimal unit of capacity as a separate firm. The advantage of this assumption is to keep expected profits of the firm finite in the case of constant returns-to-scale.

The firms' output may be sold in a competitive market at time $t$ at the market clearing price $p_t$. Under the assumptions above, the total market capacity can be seen as equal to the market supply $q_t$ at time $t$.

Also, in order to carry uncertainty in our investment problem, we introduce a potential exogenous demand shock that may either rise or fall over time, and is noted $x_t$ at time $t$. For now, the demand shock will be treated as deterministic.

The relationship of the market price of the good $p_t$, the market supply $q_t$, and the demand shock $x_t$ is summarized in the following time-invariant inverse demand curve $p_t = D(q_t, x_t)$, $D_1 < 0$, $D_2 > 0$.

For any value of installed capacity $\hat{q}$, the profits accruing for each unit of capacity are finite, i.e. $E_t \int_0^\infty e^{-rt} \left( D(\hat{q}, x_t) - c \right) dt < \infty$.

#### 11.1.1.2. The assumption of myopic behavior

We now introduce the key concept of Leahy's model: the myopic firm. A myopic firm is a firm which completely ignores the effect of the investment of other firms on the price process. The myopic firm will make the assumption that the industry-wide capacity will remained fixed forever and that the price process will be driven solely by exogenous shocks. In other words, the price process that the myopic firm uses to evaluate an investment opportunity assumes no other firm will invest.

Hence, the myopic firm has static expectations about industry output, as capacity is expected to remain constant forever. On the other hand, it has rational expectations regarding other factors influencing the market clearing price.

The implications of the myopic assumption are that the firm will treat $q_t$ as fixed forever at its value $\overline{q}$. The entry time $T$ at which the firms decides on an additional unit of capacity is chosen so as to maximize the net present value of profits, according to the following maximization program: $\max_T \left\{ \int_T^\infty e^{-rt}\left(D(\overline{q}, x_t) - c\right)dt - e^{-rT}k \right\} = \max_T \left\{ \int_T^\infty e^{-rt} D(\overline{q}, x_t)dt - e^{-rT}\left(\frac{c}{r} + k\right) \right\}$.

In this case, the first order condition for the choice of $T$ is $p_T = c + rk$. In other words, the myopic firm will always choose to invest at a point when price equals the annuity value of capital, also known as the long-term marginal cost of production.

The second order condition states that the price process is such that before the investment is triggered, the price is below $c + rk$. For that reason, $c + rk$ is known as the trigger price for investment.

In principle, there can be many choices of $T$ that would satisfy the first and second order condition. As a result, the myopic firm will choose the one that maximizes profits.

#### 11.1.1.3. The optimality of myopic behavior

In the following sections of his paper, Leahy proves that myopic behavior will yield a competitive equilibrium.

First, it is assumed that competitive firms will follow myopic investment policies. We need to prove that this behavior will induce a situation where the NPV of an investment at any time of entry will be equal to the discounted present cost of entry $\frac{c}{r} + k$.

As we said earlier, with myopic behavior, at the time of investment the price is equal to $c + rk$. Let us now determine the NPV between investment times. We assume that investment is triggered at time $t_1$ and $t_2$ but that no investment is triggered in the interval $]t_1, t_2[$. Since no investment takes place in that period, capacity will be constant at the level of $t_1$ during that interval.

The NPV on this interval is necessarily smaller than $\left(\frac{c}{r} + k\right)\left(1 - e^{-r(t_2 - t_1)}\right)$, which is exactly the gain from delaying the cost of entry from $t_1$ to $t_2$, or else a myopic firm would not wait until $t_2$ to invest.

Conversely, revenues can be no less than $\left(\frac{c}{r} + k\right)\left(1 - e^{-r(t_2 - t_1)}\right)$, or some firms that invested at time $t_1$ would find it optimal to postpone investment until $t_2$.

As a result of the considerations above, the NVP over the interval $]t_1, t_2[$ is exactly $\left(\frac{c}{r} + k\right)\left(1 - e^{-r(t_2 - t_1)}\right)$. Under a myopic behavior, a firm invests when price is at $c + rk$. Therefore, if in the interval $]t_1, t_2[$ the firm invests continuously, the NPV will be $\left(\frac{c}{r} + k\right)\left(1 - e^{-r(t_2 - t_1)}\right)$ too. By integrating over all intervals, we get an NPV of $\frac{c}{r} + k$.

Consequently, since $\frac{c}{r} + k$ is the optimal NPV in a competitive equilibrium, myopic behavior is optimal in competitive equilibrium.

#### 11.1.1.4. Myopic behavior with uncertainty in demand shocks

So far, the demand shock had been treated as deterministic. The demand shock will now be treated as a diffusion process.

Uncertainty will necessarily affect the behavior of both competitive and myopic firms in this case. In competitive equilibrium, since price generally declines following capacity addition, the cost of uncertainty in this investment situation will be that the trigger price will be higher than the annuity value of capacity. There is also a value for myopic firms in remaining uncommitted in an uncertain environment, which also cause the price trigger to increase above annuity value of capital.

The rest of the model remains unchanged, and now the demand shocks follow a price diffusion process of the following form $dx = \mu(x)dt + \sigma(x)dw$, where $dw$ is a Wiener process. One could choose, as is often done in the investment literature, a geometric Brownian motion with $\mu(x) = \mu x$ and $\sigma(x) = \sigma x$.

Leahy proves that the increase in the trigger price is the same in both myopic and competitive firms. The proof is the main body of Leahy's paper and I will refer the reader to it for further details on the proof.

He also proves that the solution to the social planner's problem is equivalent to the behavior of myopic firms. Indeed, the optimum in the social planner's maximization program maximizes the contribution of each unit of capacity to the social welfare, which is what is being done by the myopic firm when choosing the optimal entry time. The social planner will therefore follow myopic policies as well.

#### 11.1.1.5. Price process

We have assumed earlier that firms were price takers. Yet, firms will decide on investment at the same instant, and as they install capacity together, the price will be affected. Consequently, in figuring the competitive equilibrium investment rule, the price process has to be derived endogenously.

Let us write $P^*(q)$ the price trigger strategy. In competitive equilibrium, Leahy shows that this level of price acts as a reflecting barrier, a price ceiling that reflects the price from above, and prevents further price growth. In the stochastic equilibrium, the price is allowed to decrease below the trigger level. It can then climb back to it and entrants prevent it from ever growing above again. Consequently, the uncertain price will evolve below the trigger level, and as soon as the level is hit, the price will remain constant at that level during a window of time and go back to a lower level. The same phenomenon will reproduce when the trigger is reached again.

It is now possible to derive the price trigger explicitly in particular cases that are easy to solve, from that solution we will derive the competitive equilibrium. Other papers inspired by the Leahy model have conducted similar work, like Murto who compared two types of technologies under a competitive equilibrium context, one with infinitely divisible capacity and one with large-scale non-divisible capacity.[111]

[111] Murto, 2003

#### 11.1.1.6. Example – Dixit and Pindyck, 1994

In order to get an explicit solution to the competitive equilibrium, we will use assumptions common to many investment models.

First, we will choose an explicit inverse demand function that has the form $D(q,x) = xq^{-\frac{1}{\eta}}$, where $\eta$ is the price elasticity of demand.

Secondly, we will also assume that the demand shock follows a geometric Brownian motion $dx = \mu x dt + \sigma x dw$, where we have written $dw$ the underlying Wiener process.

Dixit and Pindyck[112] find a derivation of the price trigger using the method of contingent claims analysis or dynamic programming, and give the investment trigger for a myopic firm, which is independent of the industry installed capacity. $P^* = \frac{\beta}{\beta - 1}(r - \mu)\left(\frac{c}{r} + k\right)$, where $\beta = \frac{1}{2} - \frac{\mu}{\sigma^2} + \sqrt{\left(\frac{\mu}{\sigma^2} - \frac{1}{2}\right)^2 + \frac{2r}{\sigma^2}}$ is the positive root of the equation $\frac{1}{2}\sigma^2 s(s-1) + \mu s - r = 0$.

An important assumption in the derivation of the price trigger is that $r - \mu > 0$, i.e. the demand shock grows at a greater rate than the risk-free interest rate. Indeed, if it were not the case, the firm would never invest and would always be better off waiting and simply keeping open the option to invest in a new unit of capacity. For our investment problem, $r$ is the expected rate of return of owning the completed project. It is the risk-free equilibrium rate. If we have $r - \mu > 0$, the expected rate of capital gain on the project is less than $r$. The quantity $r - \mu$ is seen as an opportunity cost of delaying investment and instead keeping the option to invest. If we had $r - \mu < 0$, there would an opportunity benefit in keeping the option alive, and firms would never invest. The opportunity benefit would come from the fact that it would always be profitable to wait to invest because the asset was going to be growing in value. This would result in an asset of infinitely large value. This assumption is not realistic, hence the assumption of $r - \mu > 0$.

Since $\frac{1}{2}\sigma^2 \beta(\beta - 1) + \mu\beta - r = 0$, we have that $\frac{1}{2}\sigma^2 \beta(\beta - 1) + r(\beta - 1) + \mu\beta - r\beta = 0$ and $\frac{\beta}{(\beta - 1)}(r - \mu) = r + \frac{1}{2}\sigma^2\beta$. Consequently, we can say

[112] Dixit & Pindyck, 1994

that $P^* = \left(1+\frac{1}{2}\frac{\sigma^2}{r}\beta\right)(c+rk) > c+rk$ . This result confirms that there is a positive cost associated with the uncertainty in the demand shock process.

The uncertainty premium can be quantified as the ratio of trigger prices with and without uncertainty. We get a premium of $1+\frac{1}{2}\frac{\sigma^2}{r}\beta = 1+\frac{\sigma^2}{4r}+\frac{-\mu+\sqrt{\left(\mu-\frac{\sigma^2}{2}\right)^2+2r\sigma^2}}{2r}$. When volatility goes to zero, i.e. when uncertainty is infinitely reduced, the ratio evidently goes to 1 and the premium goes to 0.

This could be understood in the following way: the true cost of the technology depends upon the volatility of the demand in the market where the technology is to be employed. In the face of uncertainty, the traditional LCOE is not correct, because it does not accurately measure the true cost given the demand uncertainty. The LCOE method in our case would give a trigger price for investment of $P^* = c + rk$ at the level necessary to break even taking the discounting into account. However the method does not at all account for the price uncertainty generated by demand uncertainty. The LCOE method omits the uncertainty from the market environment in which the technology is built.

Uncertainty induces a premium of $\frac{1}{2}\frac{\sigma^2}{r}\beta(c+rk)$ which is the direct effect of demand volatility. The cost of uncertainty will be defined as the price ratio $1+\frac{1}{2}\frac{\sigma^2}{r}\beta$. The price trigger will be an uncertainty-adjusted LCOE: Price Trigger = LCOE * Cost of Uncertainty.

It is an assumption of the model that once installed, a unit of capacity will produce one unit of output. Therefore, production costs will always be incurred by the firm in every period. The equilibrium will not here depend on the relative importance of investment cost to production cost. From now on, lifetime costs will be noted $K = k + c/r$.

### 11.1.2. The Grenadier model

In this section, we will be adding another element to our investment problem. So far, capacity was built instantaneously. There was no lag between the moment at which the decision to add capacity was made and the moment when the capacity effectively became operational to produce the good. The new feature of the investment model is that in the subsequent paragraph, all characteristics will remain, except that there will be a time-to-build for capacity. There will be a constant delay between the instant of the decision and the instant of installation.

#### 11.1.2.1. General principle of the model

All the assumptions of the Leahy model remain. We are also placing ourselves in the particular case of a geometric Brownian motion from now on, and the market inverse demand function is still of constant elasticity in the following form $p_t = x_t q_t^{-1/\eta}$.

Firms can add units of capacity at a lifetime cost of $K$ per unit comprising a sunk cost of $k$ and a production cost of $c$.

We now introduce a lag between the time at which a new unit is purchased and the time at which this unit can be used in production. This lag can be seen as a time-to-build the new unit of capacity or include any form of regulatory delay. We note the investment lag $\delta \geq 0$. A unit of capacity purchased at time $t$ will be ready for operation at time $t+\delta$. However, the cost of installing a unit of capacity will be incurred immediately.

In that sense, let us consider two technologies which have identical LCOEs. Another way to see this is the two technologies have identical long-term marginal costs at start-up ($c+kr$ is the same for both technologies). The only difference between the two technologies is that they have different construction times: one has time-to-build $\delta$ and one doesn't. Then, the $t=0$ present value of the LCOE of the technology with time to build will be $(c+kr)e^{-r\delta}$ and the $t=0$ present value of the LCOE of the technology without time-to-build will simply be $c+kr$. As a result, the technology with time-to-build will be "cheaper" at the investment decision than the technology without time-to-build. Of course, the consumer surplus will be smaller since demand is served starting at a later date.

We define $q_{comm}$ the amount of committed capacity, that is the existing capacity plus the capacity currently being built. We also define $q_{constr}$ the amount of capacity currently under construction – i.e. capacity that initiated construction in the interval $(t-\delta, t]$. We have the following: $q_{comm}(t) = q(t) + q_{constr}(t)$ and $q(t+\delta) = q_{comm}(t)$.

The aim of the model is to construct a competitive equilibrium in which firms have rational expectations. Such an equilibrium will determine prices and entry strategies simultaneously, and strategies, prices and expectations must be mutually consistent. Also, a competitive equilibrium will have the characteristic that the present discounted value of profits will equal the construction costs at the time of investment.

The equilibrium evolves as if to maximize the expected present value of social welfare in the form of consumer surplus. The rate of consumer surplus is the area below the demand curve $S(x_t, q_t) = \int_0^{q_t} x_t q^{-1/\eta} dq = \frac{\eta}{\eta - 1} q^{\frac{\eta-1}{\eta}}$.

The maximization problem facing the social planner is reduced to the following optimal control problem: $J(\Omega_0) = \max_{[q_s, s>0]} E\left[\int_0^{\infty} e^{-rt} S(x(t), q_{comm}(t-\delta)dt) - \sum_t K e^{-rt} \Delta q_{comm}(t) \middle| \Omega(0) = \Omega_0\right]$

We noted $\Delta q_{comm}(t)$ the increment in capacity at instant $t$, $\Omega(t)$ the current state of the industry, and $\Omega_0$ the initial state of the industry. The current state of the industry is fully known by the knowledge of demand, existing capacity, capacity in construction and the times at which capacity construction started for the capacity still being built and can be written $\Omega(t) = \{x(t), q(t), q_{constr}(t), \Lambda(t)\}$, where $\Lambda(t) \equiv \{\tau \in (t-\delta, t], q_{comm}(\tau) > q_{comm}(\tau^-)\}$.

In appearance, it seems that the introduction of a time to build makes the investment decision far more complicated, because the solution to the investment problem requires more information, information about all initiation times of all the units that are currently under construction.

To handle the complexity arising from the new information, we will use and outline the procedure outlined in Grenadier.

For more details on the derivation of the competitive equilibrium solution, see Grenadier.[113]

### 11.1.2.2. Grenadier's solution

To solve the central planner's problem, Grenadier simplifies the state space. Knowledge only about $x(t)$ and $q_{comm}(t)$ is sufficient for determining equilibrium new entry.

First, the maximization problem can be rewritten as follows:

$$J(\Omega_0) = E\left[\int_0^{\delta} e^{-rt} S(x(t), q_{comm}(t-\delta)dt) \middle| \Omega_0 = (x_0, q_0, q_{constr,0}, \Lambda_0)\right]$$

$$+ \max_{[q_{comm,s}, s>0]} E\left[\int_{\delta}^{\infty} e^{-rt} S(x(t), q_{comm}(t-\delta)dt) - \sum_t K e^{-rt} \Delta q_{comm}(t) \middle| \Omega_0 = (x_0, q_0, q_{constr,0}, \Lambda_0)\right]$$

[113] Grenadier, 2000

We can see that the second term does not depend on the path of entry over the period $(-\delta,0]$, but only on the value of the committed capacity $q_{comm,0}$. Therefore the result of maximization with $\Omega_0 = (x_0, q_0, q_{constr,0}, \Lambda_0)$ is the same as the result with $\Omega_0 = (x_0, q_{comm,0}, 0, \{\ \})$. The maximization can be rewritten as follows:

$$J(x_0, q_0, q_{constr,0}, \Lambda_0) = E\left[\int_0^{\delta} e^{-rt} S(x(t), q_{comm}(t-\delta)dt) \middle| \Omega_0 = (x_0, q_0, q_{constr,0}, \Lambda_0)\right]$$

$$+ \max_{[q_s, s>0]} E\left[\int_{\delta}^{\infty} e^{-rt} S(x(t), q_{comm}(t-\delta)dt) - \sum_t Ke^{-rt} \Delta q_{comm}(t) \middle| \Omega_0 = (x_0, q_{comm,0}, 0, \{\ \})\right]$$

It can be rewritten again as follows:

$$J(x_0, q_0, q_{constr,0}, \Lambda_0) = J(x_0, q_{comm,0}, 0, \{\ \})$$

$$+ E\left[\int_0^{\delta} e^{-rt} S(x(t), q_{comm}(t-\delta)dt) \middle| \Omega_0 = (x_0, q_0, q_{constr,0}, \Lambda_0)\right]$$

$$- E\left[\int_0^{\delta} e^{-rt} S(x(t), q_{comm}(t-\delta)dt) \middle| \Omega_0 = (x_0, q_{comm,0}, 0, \{\ \})\right]$$

We can write $V(x, q_{comm}) = J(x, q_{comm}, 0, \{\ \})$ and solve the problem for the artificial economy in which all capacity is completed. The problem is now finite-state and much simpler to solve.

Since there are constant returns to scale, the problem is an optimal instantaneous control problem. According to Grenadier, in this case it is optimal for the industry to grow continuously rather than in discrete jumps. We will consider $q_{comm}(t)$ continuous, and $\Delta q_{comm}(t)$ will be in fact noted $dq_{comm}(t)$.

Grenadier uses traditional option pricing, like Dixit and Pindyck cited earlier, to solve the problem. The ultimate result for $V(x, q_{comm})$ is given by the following formula:

$$V(q_{comm}, x) = \frac{-\eta \cdot K}{(\beta-1)(\eta-\beta)} \left(\frac{\beta(r-\mu)e^{(r-\mu)\delta}}{\beta-1} K\right)^{-\beta} q_{comm}^{\frac{\eta-\beta}{\eta}} x^{\beta} + \left(\frac{x}{r-\mu}\right) \frac{\eta}{\eta-1} q_{comm}^{\frac{\eta-1}{\eta}}.$$

The competitive equilibrium strategy is characterized by the trigger function $x^*(q_{comm})$. The $q_{comm}$ th unit of supply will be initiated the first moment that the demand shock rises to the trigger level $x^*(q_{comm})$. The trigger function is also derived in the paper and can be expressed as $x^*(q_{comm}) = \dfrac{\beta}{\beta-1}(r-\mu)Ke^{(r-\mu)\delta} q_{comm}^{\frac{1}{\eta}}$.

Although the strategy resembles the real options trigger strategy, there are two elements which make it fundamentally different: the dependence on the level of committed capacity $q_{comm}$ and not on installed capacity of price, and the consideration given to the time-to-build parameter.

### 11.1.2.3. Grenadier's strategy

Let's try to characterize the main difference between the Grenadier situation and the Leahy situation. With instantaneous construction, the optimal strategy is to invest the first moment that the price process rises to the price trigger $P^*$. We will see that, with time-to-build, the entry strategy will be to invest when the discounted expected value of the price in $\delta$ years equals the trigger $P^*$.

Indeed, $p(t+\delta) = x(t+\delta)q(t+\delta)^{-\frac{1}{\eta}} = x(t+\delta)q_{comm}(t)^{-\frac{1}{\eta}}$, and when we discount the expected value, we can write that $e^{-r\delta}E_t(p(t+\delta)) = e^{-r\delta}E_t(x(t+\delta))q_{comm}(t)^{-\frac{1}{\eta}} = x(t)e^{-(r-\mu)\delta}q_{comm}(t)^{-\frac{1}{\eta}}$. Then $x(t) = x^*(t) = \frac{\beta}{\beta-1}(r-\mu)Ke^{(r-\mu)\delta}q_{comm}{}^{\frac{1}{\eta}}$ is equivalent to $e^{-r\delta}E_t(p(t+\delta)) = \frac{\beta}{\beta-1}(r-\mu)K = P^*$.

In Leahy, any positive demand innovations cause a corresponding volume of capacity additions such that price does not rise above P*.

In Grenadier, any positive demand innovations cause a corresponding volume of commitments to capacity additions such that expected price at $t+\delta$ does not rise above P*. As a result, in Grenadier the price can rise above P*, and will generally be brought down after $t+\delta$.

Therefore, the impact of time-to-build is a change of the strategy by replacing the current price by the discounted expected price in $\delta$ years. If one was to compare the same technology with equal costs at start-up (identical $c+rk$ ), it would be necessary to discount the capital costs $\delta$ years back in the time-to-build context. Consequently, as you vary time-to-build keeping other things constant, the present value of LCOE is brought down from $c+kr$ to $(c+kr)e^{-r\delta}$, or aggregate costs from $K$ to $Ke^{-r\delta}$. As a result, the price trigger is formally lowered from $P^*$ to $P^*e^{-r\delta}$. What is really occurring is that the price trigger remains, but the construction time imposes that the decision be made sooner because of the time value of money: this explains the $e^{-r\delta}$ factor. The difference between the Grenadier solution and the Leahy solution is that in the case of Grenadier, the producers need to consider an investment $\delta$ periods in advance. The impact on the demand trigger will likewise become $x^* = \frac{\beta}{\beta-1}(r-\mu)Ke^{-\mu\delta}q_{comm}{}^{\frac{1}{\eta}}$.

Let's calculate the ratio of demand triggers in the Grenadier and in the Leahy case, without and with time-to-build for technologies of identical long-term marginal costs at start-up $\frac{x^*(\delta)}{x^*(0)} = e^{-\mu\delta}$. This value is a measure of the true cost of time-to-build. We will choose to define $e^{-\mu\delta}$ as the cost of time-to-build. The cost of time-to-build seems to be independent of the risk-free interest rate, and more importantly independent of the volatility of demand.

The price process will equally change in the presence of time-to-build and compared to the Leahy situation. Instead of committing capacity in order to maintain the current price below the trigger, capacity will be committed so as to maintain the discounted expected price below that same trigger. In fact the process for $q_{comm}$ will evolve as follows: at the first instant that $x(t)$ reaches the trigger value $x^*(q_{comm} + dq_{comm})$, $q_{comm}$ will rise to the level $q_{comm} + dq_{comm}$.

At the limit where $\delta$ would converge towards zero, we find ourselves in the Leahy situation with instantaneous construction. Indeed, investment is triggered when the demand shock reached the demand trigger, and $\frac{x^*(\delta)}{x^*(0)} = e^{-\mu\delta}$ converges to 1 when $\delta$ goes to zero. Also, $q_{comm}$ converges towards the installed capacity as time-to-build tends to zero.

### 11.1.2.4. Grenadier's asset values

The final component of the description of the competitive equilibrium in Grenadier is the valuation of existing assets. Let $W(\Omega_0)$ denote the value of a completed asset. The value of a completed asset is the discounted expected value of future equilibrium output prices $W(\Omega_0) = E\left[\int_0^\infty e^{-rt} P(t)dt \middle| \Omega(0) = \Omega_0\right]$.

The result of the integral above is given in Grenadier by the following expression

$$W(\Omega_0) = xe^{-(r-\mu)\delta} \int_{-\delta}^{0} e^{-(r-\mu)s} q_{comm}(s)^{-\frac{1}{\eta}} ds + xe^{-(r-\mu)\delta} \frac{q_{comm}{}^{-\frac{1}{\eta}}}{r-\mu} - x^{\beta} \frac{e^{-(r-\mu)\delta}}{\beta(r-\mu)} \left[\frac{\beta(r-\mu)}{\beta-1} e^{(r-\mu)\delta} K\right]^{1-\beta} q_{comm}{}^{-\frac{\beta}{\eta}}$$

.

The intuition for the formula above is the following: the first term is the present value of the future stream of cash flows from time $0$ to $\delta$. The second term is the present value of the future stream of cash flows from time $\delta$ to $\infty$, assuming that supply remains constant over that period. The third term subtracts out the loss of value from future increase in market supply from time $\delta$ to $\infty$.

Given the value of a completed asset, the value of an asset beginning construction is derived as follows. The asset does not receive any cash flow in the period of construction between $0$ and $\delta$. A construction cost is subtracted from the option value. If we note $G(x,q)$ the value of the asset just beginning construction we get that $G(x,q) = xe^{-(r-\mu)\delta}\frac{q^{-\frac{1}{\eta}}}{r-\mu} - \frac{e^{-(r-\mu)\delta}}{\beta(r-\mu)}\left[\frac{\beta(r-\mu)}{\beta-1}e^{(r-\mu)\delta}K\right]^{1-\beta} x^{\beta} q^{-\frac{\beta}{\eta}} - K$.

Entry occurs at the trigger value $x^*(q)$, where the equilibrium value of the unit of capacity installed is $G(x^*(q),q)$. The optimality condition of the equilibrium imposes that for all $q$, $G(x^*(q),q) = 0$ (which can be verified). By pursuing an optimal entry strategy, the best the firm can do is a zero-NPV project. If the firm invests at any other time, it will lose value.

This result can be extended to the Leahy case, where $\delta = 0$, and the value of an asset just being installed is $G(x,q) = x\frac{q^{-\frac{1}{\eta}}}{r-\mu} - \frac{1}{\beta(r-\mu)}\left[\frac{\beta(r-\mu)}{\beta-1}K\right]^{1-\beta} x^{\beta} q^{-\frac{\beta}{\eta}} - K$, which can be rewritten as $G(p) = \frac{1}{\beta(r-\mu)}\left[\beta(p-P^*) + P^*\left(1-\left(\frac{p}{P^*}\right)^{\beta}\right)\right]$.

### 11.1.3. The two-technology model

This section will describe the third and final step of the models considered in this study. The general context is the same as the one considered in the Leahy model and in the Grenadier model.

#### 11.1.3.1. General principle of the model

The new feature of the two-technology model is the possibility to invest in two different types of technology which we will write $G$ and $N$ . A unit of capacity in both technologies will produce one unit of the same output at every period forever. The two technologies are similar in all respects, except for the following attributes:

- Technologies $G$ and $N$ have different costs noted $K_G$ and $K_N$;
- Technology $G$ has no time-to-build: there is instantaneous construction of $G$ capacity;
- Technology $N$ has a strictly positive time-to-build: whenever capacity addition is decided, it takes $\delta$ years for the new capacity to become available for production.

The introduction of two technologies, in combination with time-to-build makes the problem infinitely more complicated to resolve.

In Grenadier with only one technology and time-to-build, the apparent issue stemming from the additional information needed was solved by a trick that proved that the optimization problem was equivalent to the same one with no capacity in the supply pipeline. The solution was made possible by the fact that the cash flows generated during the first $\delta$ years were independent of the pattern with which construction had been previously decided.

However, the situation features two different pipelines of different lengths (in the case we have chosen here, one of the pipelines has an infinitely small length). The cash flows generated during the $\delta$ first years now depends, not on the pattern of capacity addition of technology $N$ , but on the investment pattern of technology $G$ , which directly affects the current price.

### 11.1.3.2. Solving the model analytically

We will write $q_{N,comm}(t)$, $q_N(t)$ and $q_G(t)$ respectively the committed capacity of technology $N$, the installed capacity of technology $N$ and the installed capacity of technology $G$. We will also write $q(t) = q_N(t) + q_G(t)$ and $q_{comm}(t) = q_{N,comm}(t) + q_G(t)$. Like in Grenadier, we have that $q_N(t) = q_{N,comm}(t - \delta)$.

Moreover, the competitive situation between the two types of capacity will be seen as two different and separate groups of firms capable of building either one of the technologies. All firms have the characteristics described in the previous sections, including their being price takers. Thus, for each firm, the strategy is not a choice between investing or not on either one of the technologies but a choice in when to invest in a unit of capacity of their given technology. Consequently, what we are looking for is not one but two separate entry strategies.

The rationale for this assumption is to introduce competition, not only between the individual firms, but between the two technologies. Each strategy will be similar to the strategy in the one-technology equilibriums described earlier.

If we consider $q_{N,comm}(t)$, $q_N(t)$ and $q_G(t)$ continuous, there are two maximization problems being solved simultaneously: the maximization problem of technology $N$ and the maximization problem of technology $G$, both optimal control problems:

$$J_N(\Omega_0) = \max_{[q_{N,comm}(s), s>0]} E\left[\int_0^\infty e^{-rt} p(t) \cdot q_N(t) dt - \int K_N e^{-rt} dq_{N,comm}(t) \middle| \Omega(0) = \Omega_0\right]$$

$$J_G(\Omega_0) = \max_{[q_G(s), s>0]} E\left[\int_0^\infty e^{-rt} p(t) \cdot q_G(t) dt - \int K_G e^{-rt} dq_G(t) \middle| \Omega(0) = \Omega_0\right]$$

The solution used by Grenadier cannot be used here because the sequence of prices in the first $\delta$ periods will depend on the $G$ capacity being installed, and the early cash flow from capacity $N$ depends on the current price pattern. Therefore, it is not possible to modify the terms of the problem in a way that would reduce the information to consider in the investment decision.

There is now an infinitely long vector of committed capacity to take into account in elaborating the strategy. It seems it is not possible impossible to solve the equilibrium analytically in order to reach a closed form.

#### 11.1.3.3. Simplifying assumptions

The option that will be chosen in the following section is to approximate the optimum and to find a measure of how close the approximation from the optimal competitive equilibrium.

So far, in the Leahy model and in the Grenadier model, we have used the concept of a myopic behavior of firms. Leahy proved that taking into account only existing capacity in fashioning expectations of future cash flows was equivalent to a competitive equilibrium strategy and achieved optimality. Similarly, the optimal strategy in Grenadier only considers information on installed capacity and capacity in building, without forming future expectations on capacity additions that would affect cash flows.

I will now introduce a new form of myopic behavior, that I will call extended myopia. When choosing to invest in either one of the technologies, the firms will form expectations on capacity throughout the next $\delta$ years, for both technologies and only for that period. In other words, in order to make an investment decision at time $t$, firms will take into account $\{q_{N,comm}(t-s), 0 \le s < \delta\}$ and $\{E_t(q_G(t+s)), 0 \le s < \delta\}$.

What we note $\{E_t(q_G(t+s)), 0 \le s < \delta\}$ is the expectation one can make based on the form of the demand behavior and the strategy of all actors. Within the time frame between time $t$ and time $t+\delta$, the producer knows the amount of capacity of type $N$ that will come online, and can anticipate the strategy of $G$ based on simulated paths for demand. The only relevant information will be the average value of the capacity at time $t+\delta$.

##### 11.1.3.3.1. Strategy for technology $G$

For technology $G$, we have seen that investment occurred in the Leahy case when the value of the asset at installation reached zero, i.e. in case of a possible zero-NPV investment. The expression of the value of the asset was: $G(\Omega_0) = x\frac{q^{-\frac{1}{\eta}}}{r-\mu} - \frac{1}{\beta(r-\mu)}\left[\frac{\beta(r-\mu)}{\beta-1}K_G\right]^{1-\beta} x^{\beta} q^{-\frac{\beta}{\eta}} - K$

or $G(\Omega_0) = \frac{1}{\beta(r-\mu)}\left[\beta(p - P^*_G) + P^*_G\left(1 - \left(\frac{p}{P^*_G}\right)^{\beta}\right)\right]$.

The first possible strategy for producers of technology $G$ would be to use the same decision criterion as if there was no committed capacity, and to install additional capacity as soon as $\overline{G}(\Omega_0) = x\dfrac{q^{-\frac{1}{\eta}}}{r-\mu} - \dfrac{1}{\beta(r-\mu)}\left[\dfrac{\beta(r-\mu)}{\beta-1}K_G\right]^{1-\beta} x^\beta q^{-\frac{\beta}{\eta}} - K_G$ is positive. This strategy, though probably not far from the optimum in some cases, is sub-optimal. Indeed, it does not take into account the committed capacity that is not installed yet. Since $\overline{G}(\Omega_0)$ is greater than the actual value of the asset, it will reach zero "too soon", thereby leading to suboptimal overinvestment. By using this strategy, the actual NPV of an investment will always be negative.

The second possible strategy for producers of technology $G$ would be to use the same decision criterion as if all the committed capacity was going to come online at the next instant, i.e. to install additional capacity as soon as $\underline{G}(\Omega_0) = x\dfrac{q_{comm}^{-\frac{1}{\eta}}}{r-\mu} - \dfrac{1}{\beta(r-\mu)}\left[\dfrac{\beta(r-\mu)}{\beta-1}K_G\right]^{1-\beta} x^\beta q_{comm}^{-\frac{\beta}{\eta}} - K_G$ is positive. This situation is not optimal either, for it assumes that the capacity will immediately increase and that the price will be brought down instantly instead of progressively between time $t$ and time $t+\delta$. Therefore, there will be underinvestment, investment will occur too late, at a time when the value of the asset is strictly positive.

Under the first strategy, one can verify that the decision criterion is equivalent to a demand trigger strategy with a demand trigger of $\overline{x^*} = \dfrac{\beta}{\beta-1}(r-\mu)K_G q^{\frac{1}{\eta}}$. This means that investment will occur when the demand shock reached the above trigger. Therefore, the quantity installed will be chosen so as to increase the demand trigger to the new level of the demand shock.

Under the second strategy, the decision criterion is equivalent to a demand trigger strategy with a demand trigger of $\underline{x^*} = \dfrac{\beta}{\beta-1}(r-\mu)K_G q_{comm}^{\frac{1}{\eta}}$. The quantity installed will be chosen so as to increase the demand trigger to the new level of the demand shock.

We can notice that $\overline{x^*} = \dfrac{\beta}{\beta-1}(r-\mu)K_G q^{\frac{1}{\eta}} < \dfrac{\beta}{\beta-1}(r-\mu)K_G q_{comm}^{\frac{1}{\eta}} = \underline{x^*}$. The two strategies above being two extremes, it is certain that the equilibrium optimum will lead to investment when the demand shock is between those two values. This corresponds to the intuition that in the first strategy, the trigger will be too low and lead to overinvestment, and with the second strategy, the trigger will be too high and lead to underinvestment.

Moreover, it has the following feature: if there is no capacity in construction at a certain time, then the two demand triggers will be the same, and we will know the optimal strategy at that time for certain.

For the first strategy, similarly to the Leahy case, at the first instant that $x(t)$ reaches the trigger value $\overline{x^*}(q+dq)$, $q_G$ will rise to the level $q_G + dq$.

For the second strategy, similarly to the Grenadier case, at the first instant that $x(t)$ reaches the trigger value $\underline{x^*}(q_{comm} + dq)$, $q_G$ will rise to the level $q_G + dq$.

There is no way to achieve a closed form for the quantity of investment in the optimal strategy. The only thing we know is that the quantity invested will be bound by the quantity that would be invested in the two other strategies.

11.1.3.3.2. Technology $N$

For technology $N$, we have seen that investment occurred in the Grenadier case when the value of the asset at installation reached zero, i.e. in case of a possible zero-NPV investment. The expression of the value of the asset was $G(\Omega_0) = xe^{-(r-\mu)\delta}\frac{q_{comm}^{-\frac{1}{\eta}}}{r-\mu} - \frac{e^{-(r-\mu)\delta}}{\beta(r-\mu)}\left[\frac{\beta(r-\mu)}{\beta-1}e^{(r-\mu)\delta}K_N\right]^{1-\beta} x^\beta q_{comm}^{-\frac{\beta}{\eta}} - K_N$.

Keeping this strategy for the producers of technology $N$ would lead to overinvestment as the investment rule does not take into account the potential additional capacity of technology $G$ coming online in the next $\delta$ years.

For technology $N$, we need to make a simplifying assumption in order to approximate the solution. The entry strategy is the one developed in Grenadier, where investment is triggered when the demand shock hits a demand trigger. The only difference now is that the value of the asset really is $G(\Omega_0) = xe^{-(r-\mu)\delta}\frac{q(t+\delta)^{-\frac{1}{\eta}}}{r-\mu} - \frac{e^{-(r-\mu)\delta}}{\beta(r-\mu)}\left[\frac{\beta(r-\mu)}{\beta-1}e^{(r-\mu)\delta}K_N\right]^{1-\beta} x^\beta q(t+\delta)^{-\frac{\beta}{\eta}} - K_N$. What makes this decision rule non-obvious is the presence of $q(t+\delta)^{-\frac{1}{\eta}}$, which takes into account the expectations of capacity addition for the other technology. The demand shock trigger is no longer exclusively a function of committed capacity as in the Grenadier case, but of function of expected installed capacity. It is equal to $\frac{\beta}{\beta-1}(r-\mu)Ke^{-\mu\delta}E_t(q(t+\delta))^{\frac{1}{\eta}}$.

Once the trigger is hit, the strategy is to maintain the discounted expected price below the trigger level.

Although we have not found a closed form to describe the optimal strategies, the strategies developed above have the advantage of being easily implemented in simulations. The following section will be devoted to simulations.

#### 11.1.3.4. Evaluation of the approximate solution

For the strategy used by the producers of technology $G$, we have managed to construct a lower and an upper bound that will allow us to evaluate how close the approximate solution is from the optimum. Indeed, the NPV foregone in the suboptimal investment rule will necessarily be smaller than the difference of NPV in the upper and lower strategy.

However, we do not have such an opportunity to evaluate the quality of the strategy of producers of technology $N$, except to calculate the value of an asset at any point in time and to check where it is compared to the cost of installing one unit of capacity.

### 11.1.4. Numerical example

In order to better understand the properties of the three models, we will go through a short numerical example with various initial situations for demand shock and capacity.

We will adopt the following numerical values for the example:

- $r = 5\% / year$, $\mu = 2.5\% / year$, $\sigma = 10\%$, $\eta = 1.2$, $\delta = 24\ months$
- $K_N = 100$, $K_G = 150$
- $q_G = 0.5$, $q_N = 0.5$
- $q_{N,comm} = 0.55$ in the Grenadier and two-technology cases, with no capacity to come in the next period
- $x = 1.6$

#### 11.1.4.1. Leahy

In the Leahy case, the price trigger for technologies $G$ and $N$ will be $P_G^* = \frac{\beta}{\beta - 1}(r-\mu)K_G = 1.56$ and $P_N^* = \frac{\beta}{\beta - 1}(r-\mu)K_N = 1.04$. For technology $G$, given the previous capacity, the demand trigger will be $x_G^* = P_G^* \cdot q_G^{\frac{1}{\eta}} = 0.88$. For technology $N$, given the previous capacity, the demand trigger will be $x_N^* = P_N^* \cdot q_N^{\frac{1}{\eta}} = 0.58$.

Since the realized demand shock is above both values, additional capacity will be committed to maintain the price at the trigger level. Consequently, it will be such that $P_G^* = x_G^* \cdot (q_G + \Delta q_G)^{-\frac{1}{\eta}}$ and $P_N^* = x_N^* \cdot (q_N + \Delta q_N)^{-\frac{1}{\eta}}$.

The additional committed capacity for technology $G$ will be $\Delta q_G = \left(\frac{x}{P_G^*}\right)^{\frac{1}{\eta}} - q_G = 0.52$. The additional committed capacity for technology $N$ will be $\Delta q_N = \left(\frac{x}{P_N^*}\right)^{\frac{1}{\eta}} - q_N = 1.17$. Since the price trigger for technology $N$ is lower, more capacity will be needed to maintain the price at that level.

#### 11.1.4.2. Grenadier

In the Grenadier case, the demand trigger for technology $N$ will be $x_N^* = P_N^* e^{-\mu\delta} \cdot q_{N,comm}^{\frac{1}{\eta}} = 0.60$.

Since the realized demand shock is above both values, additional capacity will be committed. However, the additional capacity will have no effect on the current price level. The new price will be $P = x \cdot q_N^{-\frac{1}{\eta}} = 2.85$. We can notice that the price is above the price trigger derived in the Leahy case. In the Grenadier case, the current price in not capped by a trigger price.

The additional capacity committed will be such that the demand trigger is raised exactly to the level of the demand shock. Since the demand trigger is $x_N^* = P_N^* e^{-\mu\delta} \cdot q_{N,comm}^{\frac{1}{\eta}}$, the new committed capacity will be such that $x = P_N^* e^{-\mu\delta} \cdot \left(q_{N,comm} + \Delta q_{N,comm}\right)^{\frac{1}{\eta}}$,

or $\Delta q_{N,comm} = \left(\dfrac{x \cdot e^{\mu\delta}}{P_N^*}\right)^{\frac{1}{\eta}} - q_{N,comm} = 1.23$.

### 11.1.4.3. Two-technology

In the two technology case, the price trigger for the technology $G$ is $P_G^* = \dfrac{\beta}{\beta - 1}(r - \mu)K_G = 1.56$. Demand triggers for technology $G$` for the upper and the lower bounds are now $\overline{x_G^*} = P_G^* \cdot \left(q_G + q_N\right)^{\frac{1}{\eta}} = 1.56$ and $\underline{x_G^*} = P_G^* \cdot \left(q_G + q_{N,comm}\right)^{\frac{1}{\eta}} = 1.63$. Since the demand shock is below $\underline{x_G^*}$, there will be no capacity addition in this case. There will be capacity addition in the upper bound strategy because the demand shock is higher than $\overline{x_G^*}$. The amount of the capacity addition of technology $G$ in this case will be $\overline{\Delta q_G} = \left(\dfrac{x}{P_G^*}\right)^{\frac{1}{\eta}} - q_G - q_N = 0.03$.

Demand trigger for technology $N$ is $x_N^* = P_N^* e^{-\mu\delta} \cdot E\left(q_{comm}\right)^{\frac{1}{\eta}}$, with $E\left(q_{comm}\right) = q_{N,comm} + E_{t+\delta}\left(q_G\right)$. The value $E_{t+\delta}\left(q_G\right)$ is calculated by simulating a large number of demand shock paths for the next $\delta$ periods, which entail potential new capacity addition for technology $G$ (and not for technology $N$ because of the $\delta$-month long construction time), and by taking the average value. If we assume in our case that, for the lower bound, the expected new gas capacity committed is close to zero, and for the upper bound there will be only one capacity addition of $0.03$ at this period, then the demand triggers will be $\overline{x_N^*} = P_N^* e^{-\mu\delta} \cdot E\left(q_{comm}\right)^{\frac{1}{\eta}} = 1.06$ and $\underline{x_N^*} = P_N^* e^{-\mu\delta} \cdot E\left(q_{comm}\right)^{\frac{1}{\eta}} = 1.03$.

The additional capacity committed will be such that the demand trigger is raised exactly to the level of the demand shock. In this case, since the demand trigger is $x_N^* = P_N^* e^{-\mu\delta} \cdot E\left(q_{comm}\right)^{\frac{1}{\eta}}$, the new committed capacity will be such that $x = P_N^* e^{-\mu\delta} \cdot \left(E\left(q_{comm}\right) + \Delta q_{N,comm}\right)^{\frac{1}{\eta}}$, or $\Delta q_{N,comm} = \left(\frac{x \cdot e^{\mu\delta}}{P_N^*}\right)^{\frac{1}{\eta}} - E(q_{comm})$. We will have that $\overline{\Delta q_{N,comm}} = \left(\frac{x \cdot e^{\mu\delta}}{P_N^*}\right)^{\frac{1}{\eta}} - E(q_{comm}) = 0.70$ and $\underline{\Delta q_{N,comm}} = \left(\frac{x \cdot e^{\mu\delta}}{P_N^*}\right)^{\frac{1}{\eta}} - E(q_{comm}) = 0.73$.

The additional capacity will have no effect on the current price level. The new price will be $P = x \cdot (q_G + q_N)^{-\frac{1}{\eta}} = 1.6$.

In the two-technology case, we can notice that in the upper bound case, more capacity of technology $G$ is added, while less capacity of technology $N$ is added. This phenomenon corresponds to the intuition that we had initially about the two strategies: the upper strategy builds too much capacity of technology $G$ while the lower strategy builds too little. The optimum capacity addition of technology $G$ is between $0$ and $0.03$.

Also, the total capacity addition in both cases is $0.73$. This is consistent with the intuition that ultimately, the total amount of capacity online will be the same. Time-to-build will result in a shift from a cheaper capacity to a more expensive capacity without time-to-build.

## 11.2. Simulations and discussion of the results

Whereas the models previously discussed were rather general, mentioning only a non-storable good, the following sections will explicitly deal with electricity and electric capacity. When two generation technologies will be compared, $N$ will be nuclear power and $G$ will be gas-fired power.

In the subsequent sections, we will place ourselves in a variety of different contexts relevant to the models described before. The goal will be to gain insight from the simulations.

Ultimately, the purpose of the model is to assess the additional cost from the differences in construction time from different power generation technologies.

### 11.2.1. Numerical assumptions

We have chosen to place ourselves in the context of electricity generation. Therefore, we will need to choose numerical assumptions that are consistent with the characteristics of the technologies considered.

#### 11.2.1.1. Units of time, capacity and output and time frame

The time frame used for the simulations is 360 months or 30 years. In our simulations, the unit of time will be the month, the unit of capacity will be the kW, and the unit of output will be the MWh. The choice is consistent with the levelized costs calculations that have been made throughout this study.

In the theoretical model, at every period, one unit of output is produced by each unit of capacity. If we wish to use the formulas in the model, we have to adjust it to have prices not in $/ (output produced in a period), but $/MWh. The output produced in a month will be $CapacityFactor \cdot Hours / Month / (MW / kW)$ (this includes the conversion from kW to MW). The assumptions on the capacity factor for both technologies will be the same as previously used in this study, 85%.

#### 11.2.1.2. Risk-free interest rate and initial values

The annual risk-free interest rate assumption made to run the simulations is 5%. The initial value for regional capacity will be 1 kW. It will be evenly split among technologies in the case of two technologies. The demand shock will start so that the price would be exactly at the nuclear trigger price.

#### 11.2.1.3. Costs

We have already mentioned that when a unit of capacity is installed, it produces one unit of output indefinitely. While this is obviously not the case for electric power generation, we have to remember this model has more of an explicatory purpose than a predictive purpose, and that a model requires simplifying assumptions.

As a result, production costs will be incurred indefinitely at every period. Since our models do not depend on the ratio of capital costs to production costs, we only need to make an assumption on present lifetime cost that would include both capital and production costs.

For nuclear power, a spreadsheet calculation with assumptions of capital costs at 1,350 $/kW and production costs of 23 $/MWh gives a present lifetime cost of 4,800 $/kW. For gas-fired power, the same spreadsheet calculation with assumptions of capital costs at 500 $/kW and production costs of 45 $/MWh gives a present lifetime cost of 7,200 $/kW. The ratio of those two present lifetime costs comes out to be 3/2. Clearly, the underlying assumption is that, in the long run, after a number of units of advanced nuclear power designs are built in a standardized manner, nuclear power will end up being cheaper than gas-fired power, like is the case in France.

We can also calculate the equivalent of a levelized cost of electricity for both technologies, which is the equivalent of the present lifetime cost, but with the assumption that there is no initial capital outlay, and only production costs. The levelized cost of electricity in the case of nuclear power is 32.07 $/MWh. The levelized cost of electricity in the case of gas-fired power is 48.38 $/MWh. Those results are of an order of magnitude that is consistent with the figures given by previous levelized cost of electricity.

#### 11.2.1.4. Inverse-demand function and demand shock process

For the inverse demand function, the price elasticity of demand $\eta$ was taken to be 1.2.

The geometric Brownian motion describing the demand shock will grow at an annual rate of 2.5%. This drift corresponds to the drift of electricity consumption in developed countries. The volatility is a parameter which will vary in the simulations. Although a figure of 10% could be considered more reasonable, it appears in the simulation that interesting trends appear in the vicinity of 25% to 30%. We will discuss relevant phenomena with 30% volatility but show simulations with a 10% volatility as well to properly assess the actual impact of our conclusions.

11.2.2. Understanding the general features of the various models

11.2.2.1. Impact of uncertainty on investment

The situation we are placing ourselves in during most of the simulations is a context of uncertainty.

However, in order to get a better understanding of the phenomena at hand, we will choose to start with a situation without uncertainty on the demand shock. This will translate into $\sigma = 0$ in the simulations.

Here are the results that we get with the nuclear technology characteristics.

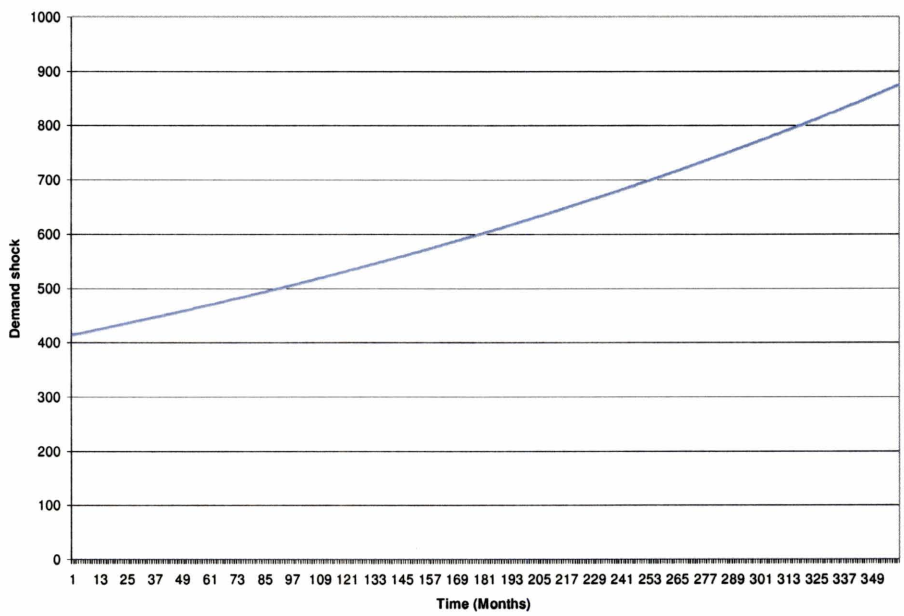


**Figure 57 – Leahy – Demand shock – Gas – No uncertainty**

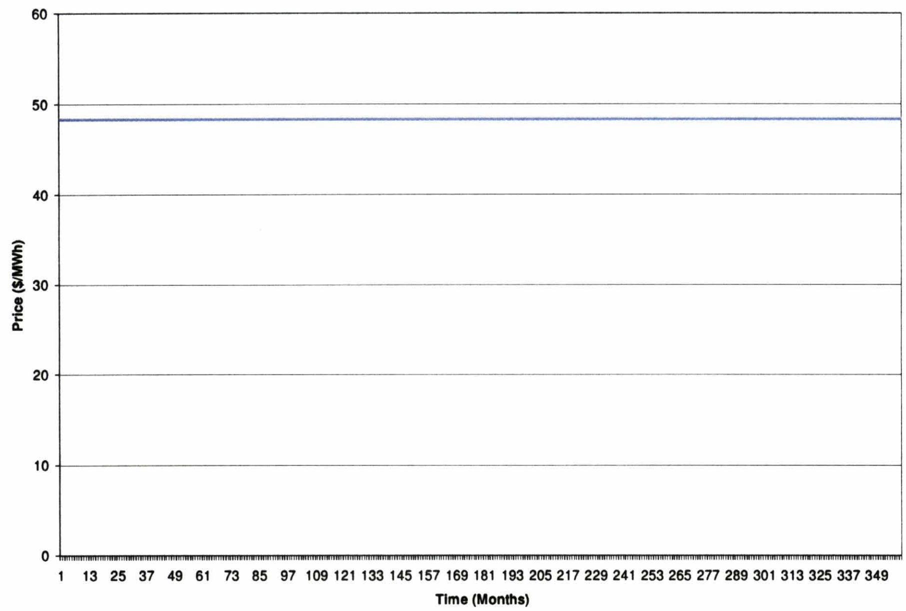


**Figure 58 – Leahy – Price – Gas – No uncertainty**

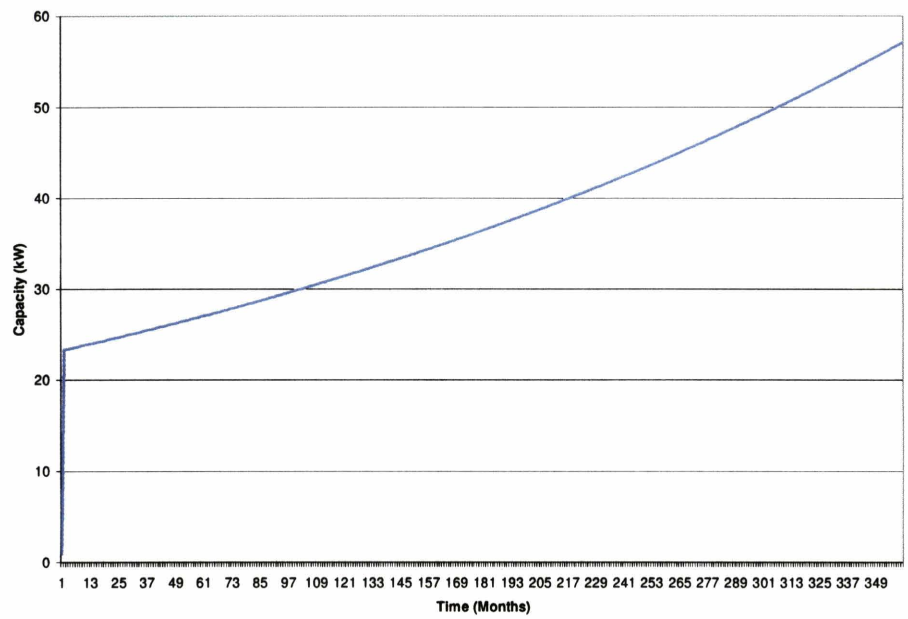


**Figure 59 – Leahy – Capacity – Gas – No uncertainty**

We see that under certainty conditions, when the price for electricity is at the trigger price (which happens to be exactly the levelized cost of electricity), investment starts at a rate that maintains the price at the trigger level indefinitely. Consequently, after the trigger is hit (if the price is initially below the trigger), the price remains constant forever.

Capacity grows smoothly and predictably at a constant rate, following the pattern of demand growing exponentially.

As price will always equal the LCOE, the zero-NPV is clearly shown in this specific case.

### 11.2.2.2. Impact of cost characteristics on investment

The first simulations will be done under the Leahy model. What we first want to do is understand how nuclear power and gas-fired power compare in terms of costs, should there be no time to build for either of them.

The results from the simulations that are displayed below are the path of the demand shock, the path of prices and the path of capacity. The following simulation features uncertainty with a volatility of $\sigma = 30\%$. Gas and Nuclear technologies are places in the exact same situation for the demand shock. The only difference is the initial outlay required to install one unit of capacity.

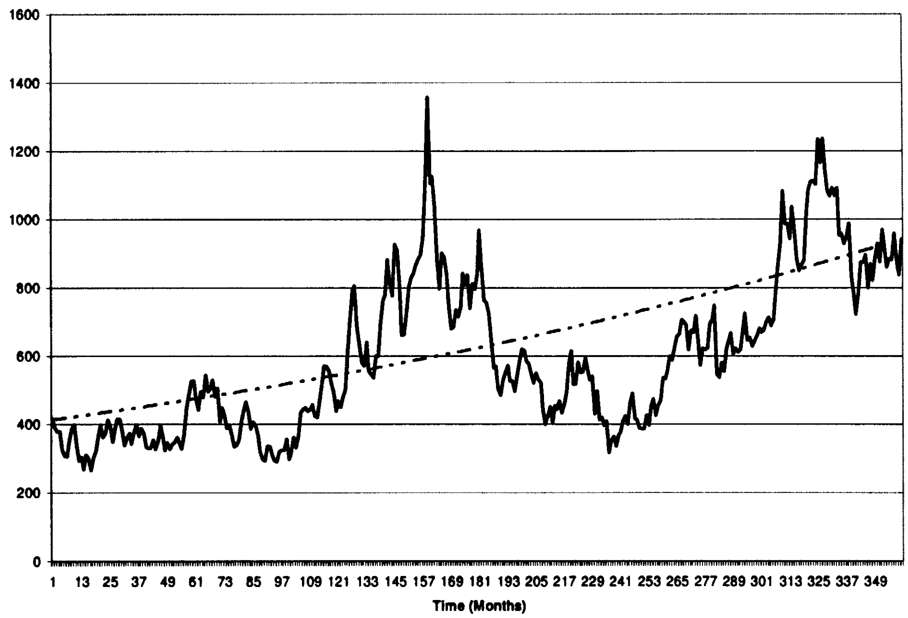


**Figure 60 – Leahy – Demand shock – Uncertainty ($\sigma = 30\%$)**

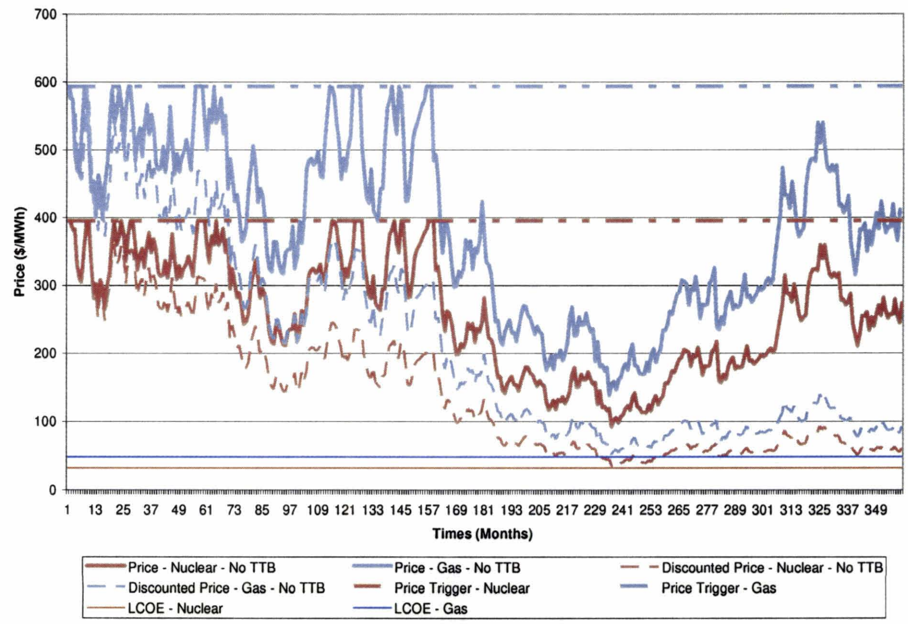


**Figure 61 – Leahy – Price – Nuclear and Gas – Uncertainty ($\sigma = 30\%$)**

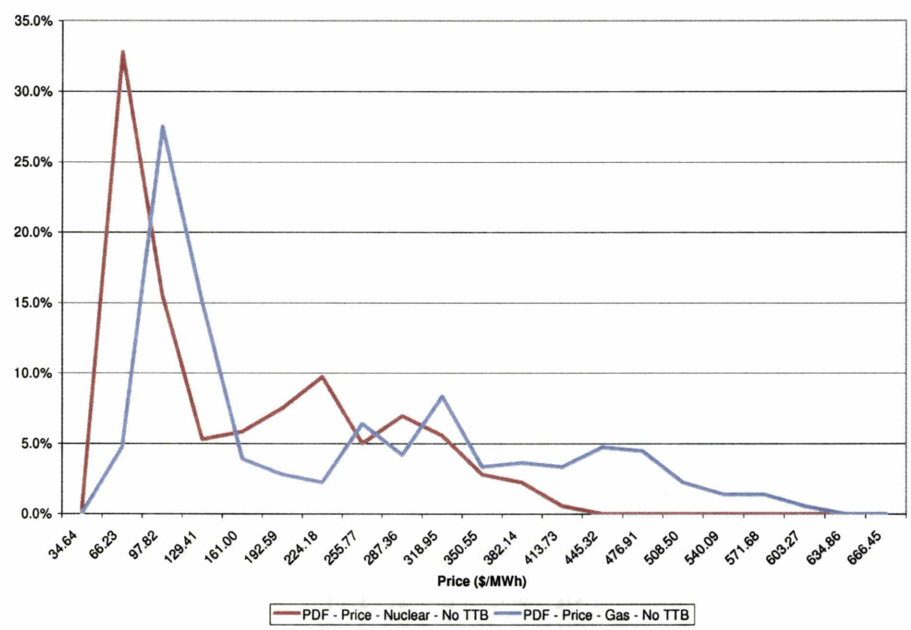


**Figure 62 – Leahy – Distribution of prices– Nuclear and Gas – Uncertainty ($\sigma = 30\%$)**

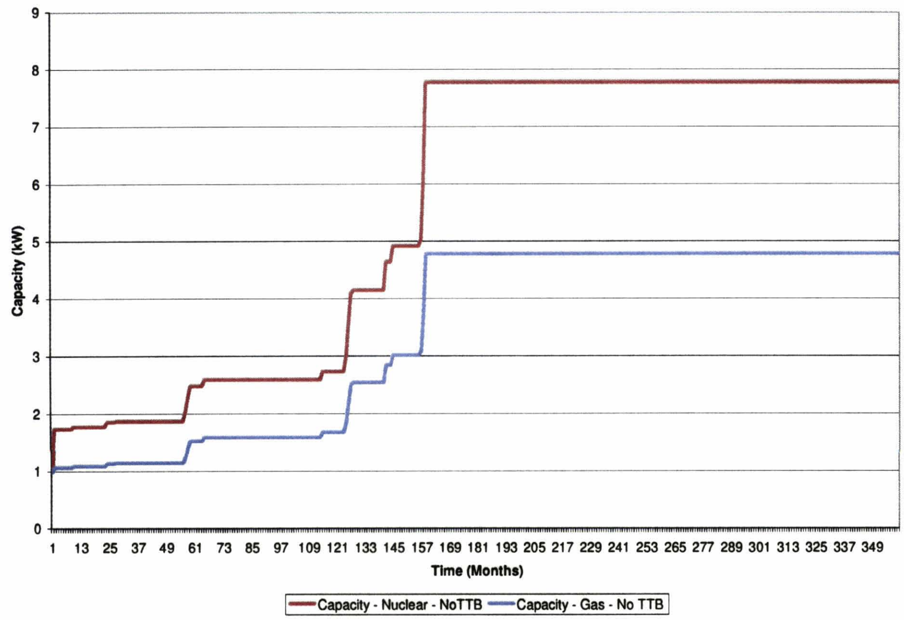


**Figure 63 – Leahy – Capacity – Nuclear and Gas – Uncertainty** ( $\sigma = 30\%$ )

We have added a line representing the values the demand path would take if there was no uncertainty and if the first and last points were the same, i.e. for a certain demand growing at the same compound average growth rate. The compound growth rate that we obtain is 2.75%, which is above the instantaneous growth rate.

The trigger prices are 395.14$/MWh for Nuclear and 592.71 $/MWh for Gas. We can see that the trigger prices are at levels much higher than the levelized cost of electricity. This phenomenon is due to the cost of uncertainty, the premium that the power generation technologies have to pay for uncertainty in demand. For both technologies in this case the ratio of the trigger price to the LCOE is 12.26. The LCOE for the two technologies are the following: 32 $/MWh for nuclear and 48 $/MWh for gas.

The first impression is that, quite predictably, prices have the same general behavior: They follow the demand shock until they hit a trigger level. When they rise to their trigger, capacity is instantly added, and after some time the price drops down to a lower level. The operation is repeated.

Capacity in both cases follows a stepwise increase. During the periods when the price is below the trigger level, the capacity remains constant until the trigger is hit again.

The shape of the price path is similar for some intervals of time. This can be explained by the fact that, when neither gas nor nuclear is investing, the price is simply proportional to the demand parameter. Consequently, prices are proportional for those intervals too.

The difference in costs induces a difference in the level of the trigger. Since the gas price trigger is 1.5 times higher than the nuclear trigger, price will be allowed to reach higher level before new capacity is installed. As a result, the level of prices will on average be lower in the case of nuclear than in the case of gas, while nuclear capacity will grow to a higher level than gas capacity.

For a few months, prices are equal in both cases as the price level has not reached a level at which any investment will be initiated. Then the nuclear trigger is hit, causing the nuclear case to install capacity, while no additional gas capacity comes online. It is only at a later instant that gas capacity starts increasing.

Another notable element is the average discounted price. Although the time period used for the simulation is not infinite, we can see that on average, the price sits at 217 \$/MWh for nuclear and 326 \$/MWh for gas. Those values are higher than their respective LCOE.

Prices in both cases seem to be proportional. The reason is the initial price is at the trigger price in both cases. From that point onwards, the situations for nuclear and gas will just be proportional as well. As a result, the coefficient of variation of prices is the same in both cases: 44.84%.

A calculation of the actualized lifetime consumer surplus indicates a value of \$769,031 for nuclear and \$740,658 for gas. This is not surprising: by maintaining the price at lower levels and bringing capacity to higher levels, nuclear manages to serve more demand than gas. Elasticity being $\eta > 1$, nuclear achieves a higher consumer surplus than gas.

The social welfare is here defined as the actualized consumer surplus minus the actualized costs of installing capacity. When computing the values in our simulation, we get \$748,545 for nuclear and \$693,856 for gas. It is therefore socially preferable to build a cheaper than a more expensive technology. We could use the ratio of the two values to assess a social cost to using a more expensive technology. We would get a value of 93%. This is a measure of the share of social surplus that is sacrificed by using a more expensive technology.

11.2.2.3. Impact of time to build on investment

This section will feature a comparison of the behavior of the nuclear technology with and without time-to-build. The same elements as the previous section will be considered in the analysis.

Displayed below are the path of the demand shock, the path of prices and the path of capacity from the simulations. The volatility is still $\sigma = 30\%$. The two parallel cases of nuclear with and without instantaneous construction are in the exact same situation in all respect except for time to build: the time-to-build chosen in this case will be 24 months.

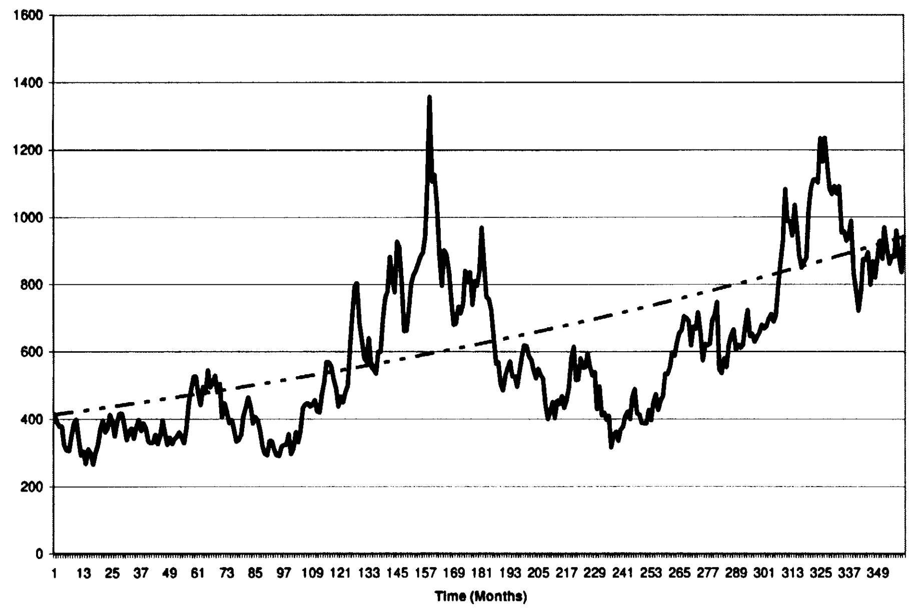


**Figure 64 – Leahy and Grenadier – Demand shock – Uncertainty ($\sigma = 30\%$)**

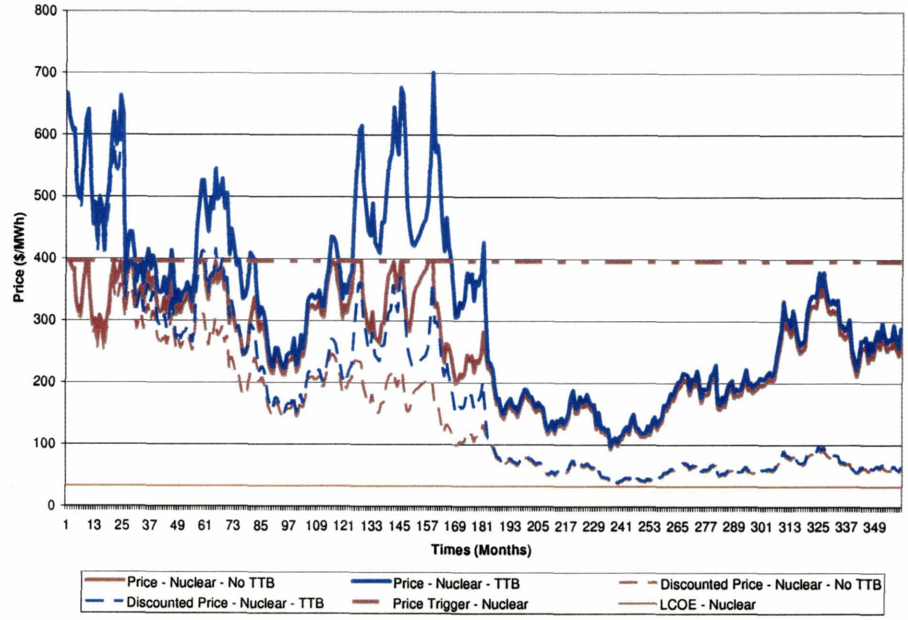


**Figure 65 – Leahy and Grenadier – Price – Nuclear with and without time-to-build**

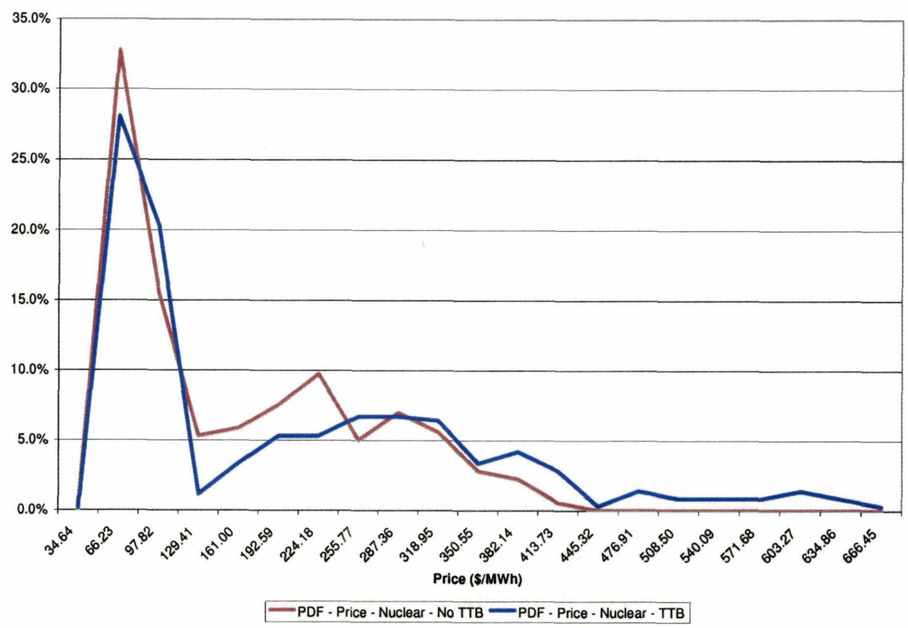


**Figure 66 – Leahy and Grenadier – Distribution of prices – Nuclear with and without time-to-build**

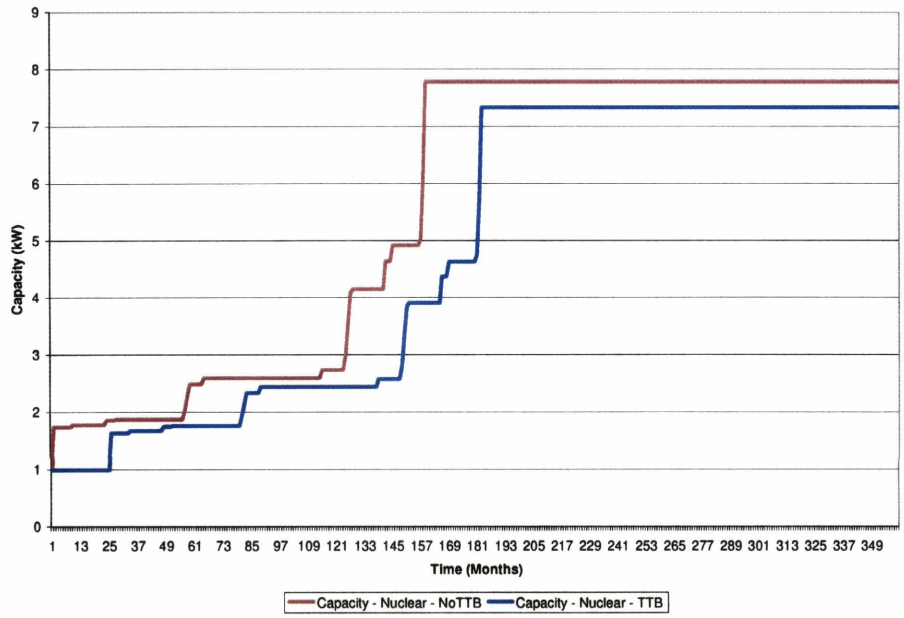


**Figure 67 – Leahy and Grenadier – Capacity – Nuclear with and without time-to-build**

The trigger price is always 395.14\$/MWh for both technologies. However, time-to-build affects the investment optimal strategy. Without time-to-build, investment starts when the current price hits the trigger, whereas with time to build, investment starts when the discounted expected price at the end of potential construction (in $\delta$ months) hits the same trigger.

Comparatively, prices seem to behave in a very different manner. Fluctuations are similar in direction and relative magnitude, but the price path is fundamentally different. The reason for the difference is the absence in the case of time-to-build of a price ceiling. Theoretically, the price is not bound by any limit. Although the probability that the price will grow to very high levels is low, it is strictly positive.

Also, even though the current price with time-to-build is allowed to fluctuate more, fluctuations never exceed a short period of time. This phenomenon is also easily understood: if at a certain point, demand rises sharply due to a shock, while nuclear can react instantly when there is no time-to-build, when a delay in construction is present, the reaction is also immediate, but the effect of that reaction happens 24 months later. Instead of retaining the price instantly, the price is brought back down at the end of construction when the new capacity comes online.

Overall, the process is the same however: when demand rises, some investment may be triggered, and then prices eventually decrease. During times when prices decrease, there is no new investment triggered and the capacity remains flat. This is true of the time-to-build case with a 24 months lag. As a result, in both situations, capacity in both cases follows a stepwise increase.

The shape of the price path is similar for some intervals of time. This can be explained by the fact that, when neither technology has been investing for more than 24 months, the price is simply proportional to the demand shock. Consequently, prices are proportional for those intervals too.

Since the price is not capped when there is time-to-build, the level of prices will be allowed to grow higher. As a result, the level of prices will on average be lower in the case of nuclear without time-to-build than in the case of nuclear with time-to-build. On the other hand, capacity without time-to build will grow slower than capacity with time to build. A graph of discounted expected prices would be more similar to cases without time-to-build, as the strategy is to maintain the discounted expected price below the trigger level. For a few months, prices are equal in both cases as the price level has not reached a level at which any investment will be initiated. Then the nuclear trigger is hit, causing the nuclear case to install capacity, while no additional delayed capacity comes online. It is only at a later instant that delayed capacity starts increasing, although the decision might have been made at the same time.

In fact, in the time-to-build case, when no capacity has been built for more than 24 months, there is no capacity in construction. Then, until the next investment is triggered, the technology with delay will have the same strategy as the no delay technology: they will commit capacity as soon as the nuclear trigger is reached.

We have already commented on the level of prices. This remark confirmed by the average discounted price displayed the graph. Although the time period used for the simulation is not infinite, we can see that on average, the price sits at 217 \$/MWh for nuclear without time-to-build, and 276 \$/MWh for nuclear with time-to-build. Those values are still reassuringly higher than the nuclear LCOE, preserving the expectation of a positive-NPV investment.

Prices in the case of nuclear with time-to-build vary on a larger interval since the current price is not capped. However, it is notable that price volatilities are very similar, lower without time-to build (44.84%) than with time-to-build (52.29%). It is difficult to interpret the way the coefficients of variation are ordered. Moreover, if we look at the same demand shock path with different values of demand volatility (the Wiener process is the same, but the volatility is different), they are always in the opposite order. This is probably the effect of one simulation and the short time frame that does not allow for adjustments. It would be expected that volatility with time-to-build is higher for similar reasons exposed in the previous paragraph. The nuclear with time-to-build PDF is less skewed to the left than the nuclear without time-to-build PDF. This is also explained by the fact that the ratio of the average discounted price over the trigger is larger with than without time-to-build.

A calculation of the actualized lifetime consumer surplus indicates a value of \$769,031 for nuclear with no construction delay, and \$709,985 for nuclear with construction delay. This is still not a surprise. By maintaining the price at lower levels and bringing capacity to higher levels when it is needed, nuclear without time-to-build manages to serve more demand than nuclear with time-to-build. Elasticity being $\eta > 1$, the consumer surplus is higher without time-to-build.

The social welfare for each situation gives \$748,545 for nuclear with no time-to-build and \$723,452 with time-to-build. At equal capital costs, there is a welfare loss with time-to-build from the instantaneous investment case. We could use the ratio of the two values to assess a social cost to using a more expensive technology. We would get a value of 97%.

Subsequent sections will feature variations in time to build. What we can already predict is that the effects described above will be amplified as time to build increases. The costs of time-to-build will prove larger as delays lengthen.

### 11.2.2.4. Impact of the presence of two technologies on investment

The purpose of the coming section is to understand the difference in outcome between the two technology case and the case where there is only one technology on the market. The insight we will get will allow us to assess to what extent it is socially beneficial to have two technologies in competition instead of one. The section will analyze the impact of introducing the gas technology in a "delayed nuclear" market.

Displayed below are the path of the demand shock, the path of prices and the path of capacity from the simulations. The volatility is still $\sigma = 30\%$. The cost characteristics and other assumptions are not altered from the previous sections.

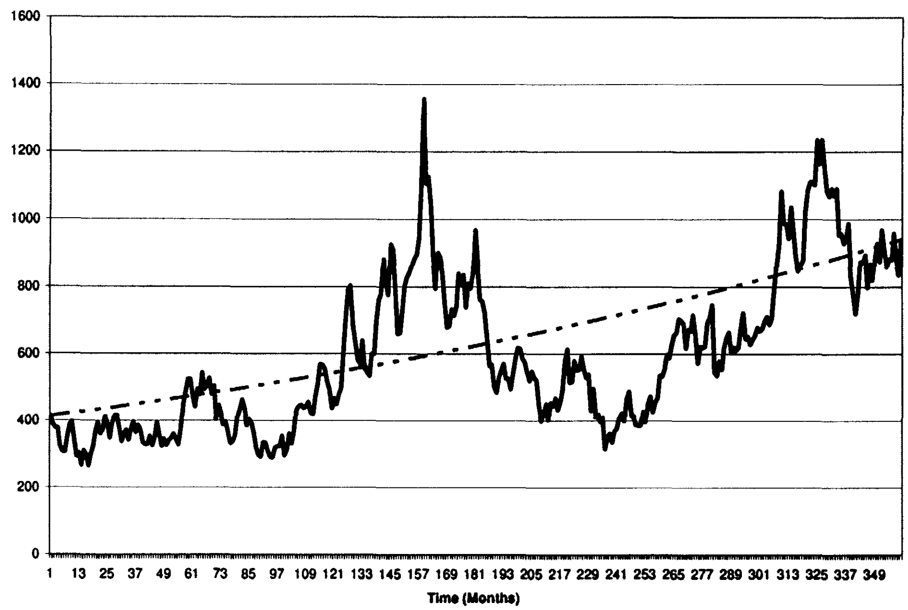


**Figure 68 – Two-technology and Grenadier – Demand shock**

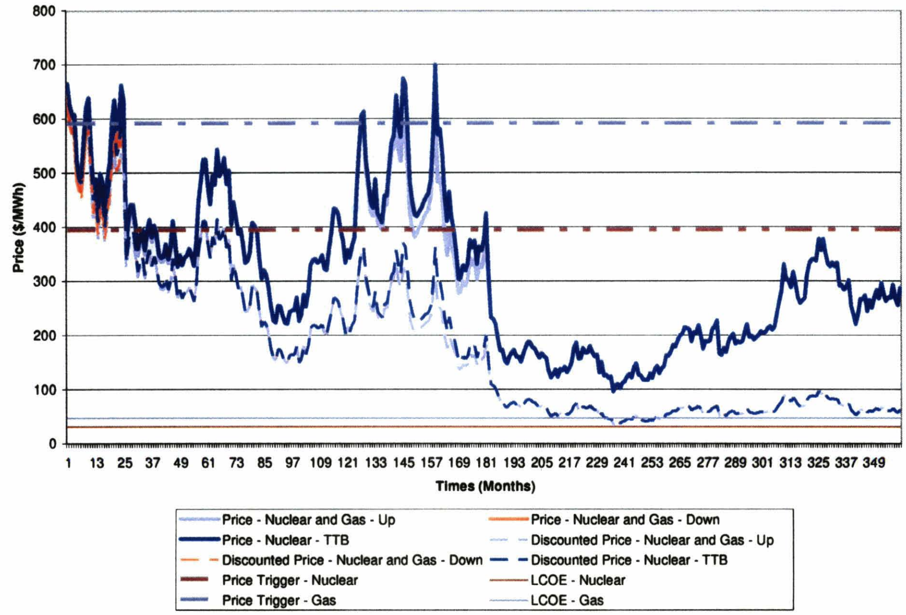


**Figure 69 – Two-technology and Grenadier – Price – Two technologies vs. Nuclear with time-to-build**

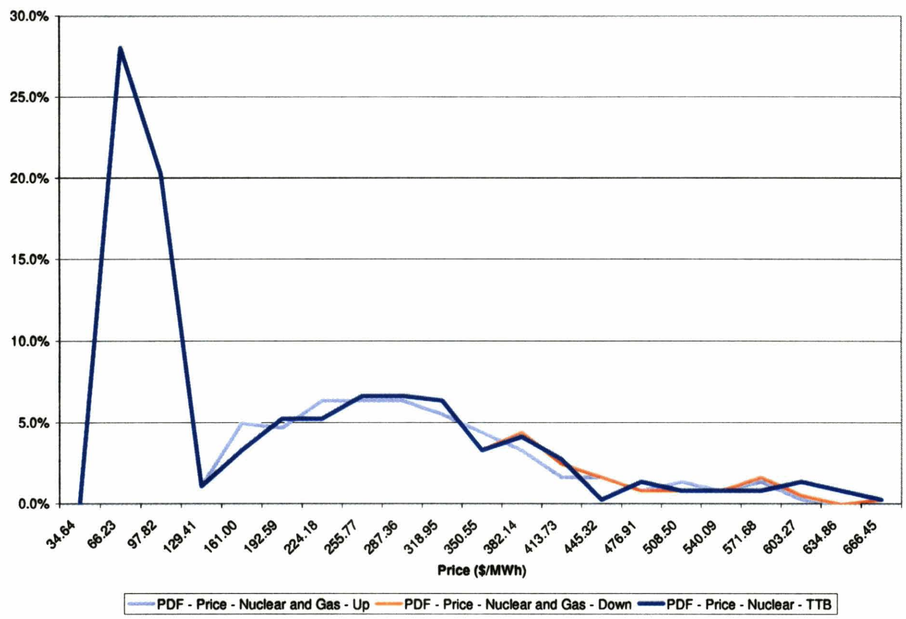


**Figure 70 – Two-technology and Grenadier – Distribution of prices – Two technologies vs. Nuclear with time-to-build**

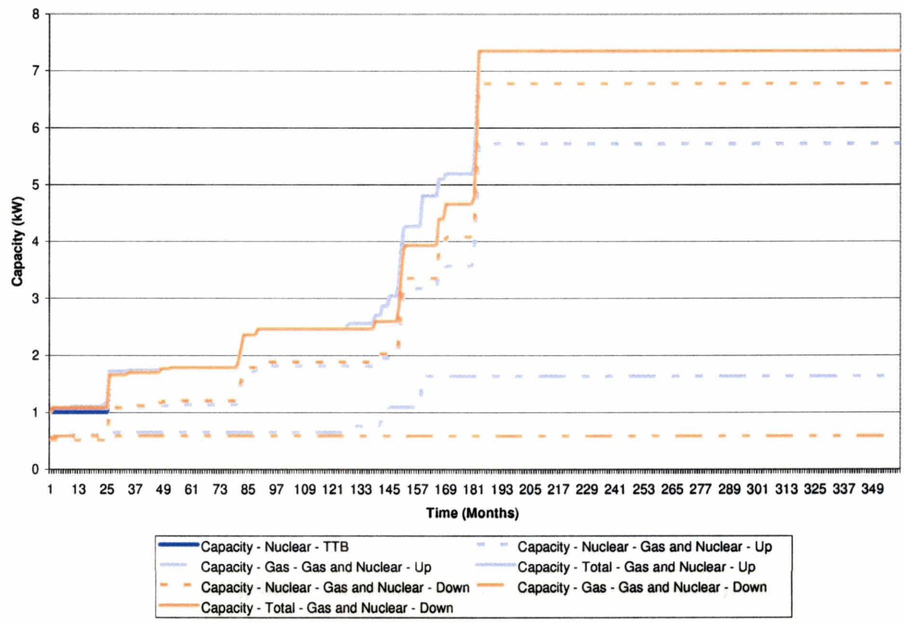


**Figure 71 – Two-technology and Grenadier – Capacity – Two technologies vs. Nuclear with time-to-build**

Similarly to the previous cases, the trigger prices are still 395.14$/MWh for nuclear and 592.71 $/MWh for gas.

In this case we are facing two options where prices tend to fluctuate substantially, because the cheaper (in one case the only) technology has a construction delay. As a result, the price appears to be very volatile.

Yet the difference is the presence of gas capacity in one case. The difference that gas will induce is an effective capping of prices. On the graph, it is apparent that the price hits the price trigger for gas several times. When the price reaches the gas price trigger, gas takes the advantage of an opportunity to invest and brings capacity online, thereby maintaining prices below the ceiling. The consequence will also be to prevent nuclear capacity from making the optimal pattern it would follow if it were alone. In a way, the presence of gas will discourage the installation of nuclear capacity, despite the fact that it is cheaper. This is a common feature of certain types of games: gas gains the advantage of pre-commitment.

Capacity in both cases follows stepwise increases. Some price spikes trigger nuclear investment. In the two-technology case, we can see investment at times when current price is at trigger. Investment periods and fixed capacity periods follow each other repeatedly.

Similarly to previous cases, the shape of the price path is similar for some intervals of time when there is no investment.

The average discounted prices are of course different in this case. The presence of gas technology in the two-technology case maintains the price below a certain level, prevents it from rising.

Consequently, the average discounted price for the two-technology case is lower than in the nuclear with time-to-build case (267 \$/MWh for the upper bound and 273 \$/MWh for the lower bound compared to 276 \$/MWh for nuclear with time-to-build). The prices are of the same order of magnitude: nuclear power being cheaper, it shapes the investment profile to a larger extent. Gas has a small influence on the level of prices for that reason. We will see later that gas has a larger influence as the construction delay increases.

Price patterns are extremely similar in the two cases, and their volatility are very close (52.29% for nuclear alone and 51.11% and 51.15% for the upper and the lower bound of the two-technology situation). Several simulations with different time-to-build will allow us to confirm whether the order of the volatilities is consistent with intuition or is the result of a specific simulation. The same can be said of the PDF in both cases.

Another notable fact is that total capacity and prices end at the same value. This suggests that, despite capacity additions of gas technology, the ultimate target capacity may be the same given a demand shock process. This could also be a consequence of a single simulation, but it seems rather unlikely.

Also, it seems that the lower bound of the two-technology model gives very similar results as the nuclear with time-to-build case. The reason for that is that in the upper bound, gas producers will build less capacity than would be optimal, in fact almost none. When they build none, the situation is that of nuclear alone with time-to-build.

A calculation of the actualized lifetime consumer surplus indicates a value of \$709,985 for nuclear with time-to-build and \$744,841 and \$741,205 for the two technologies. The reason for this is that the total amount of capacity is greater in both of the two-technology strategies, and this compensates the lower level of prices (because $\eta > 1$, since $S(x_t, q_t) = \frac{\eta}{\eta - 1} x_t q_t^{\frac{\eta-1}{\eta}}$). When gas technology caps the price, it prevents some early investment in nuclear, but keeps the price down. This would tend to argue for a beneficial effect of adding gas technology to the market.

Last, social welfare is higher in the two-technology case than in the one-technology case (\$723,452 for one technology and \$725,733 and \$723,794 for the upper and the lower bound with two technologies). This was to be expected: the two technology case installs more expensive capacity than the nuclear alone case, but the increased capacity brings the price to lower levels. The consumer benefits from earlier capacity addition despite the extra cost. If we wanted to calculate the ratio of the two values to assess a social cost, we would get a value of around 97% (almost the same value for the upper and the lower bound of the two-technology case).

In order to evaluate the quality of the approximation of the upper and the lower bound to the value of the asset, we can calculate $W(\Omega_0) = E\left[\int_0^\infty e^{-rt} P(t)dt \middle| \Omega(0) = \Omega_0\right]$ in both cases. For the upper bound, we get \$64,039. For the lower bound we get \$65,558. The error made is lower than 2%.

### 11.2.3. Impact of volatility on the comparative investment decision

It is a relevant question to ask wonder about the sensitivity of the results to the volatility of the demand shock. The following graphs stem from the similar demand shock paths. The only difference between the paths is the volatility of the process, or the magnitude of the stochastic jumps.

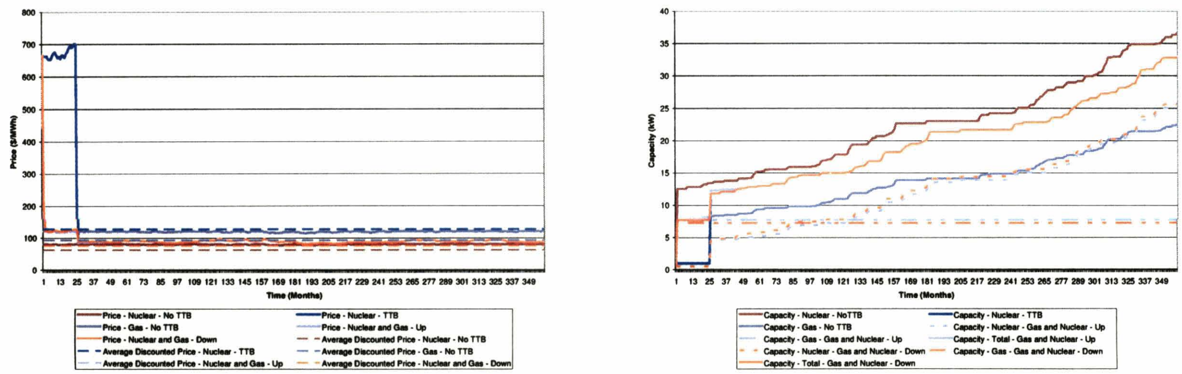


**Figure 72 – Prices and capacities – $\sigma = 10\%$**

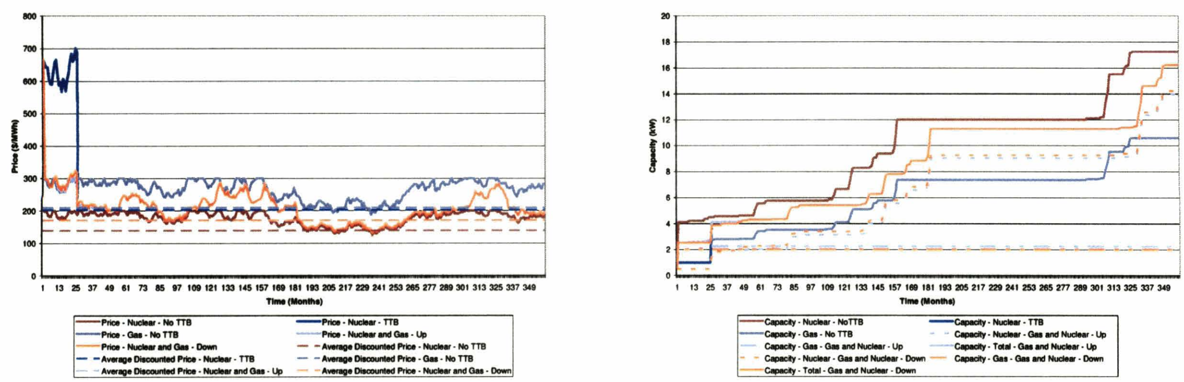

**Figure 73 – Prices and capacities – $\sigma = 20\%$**

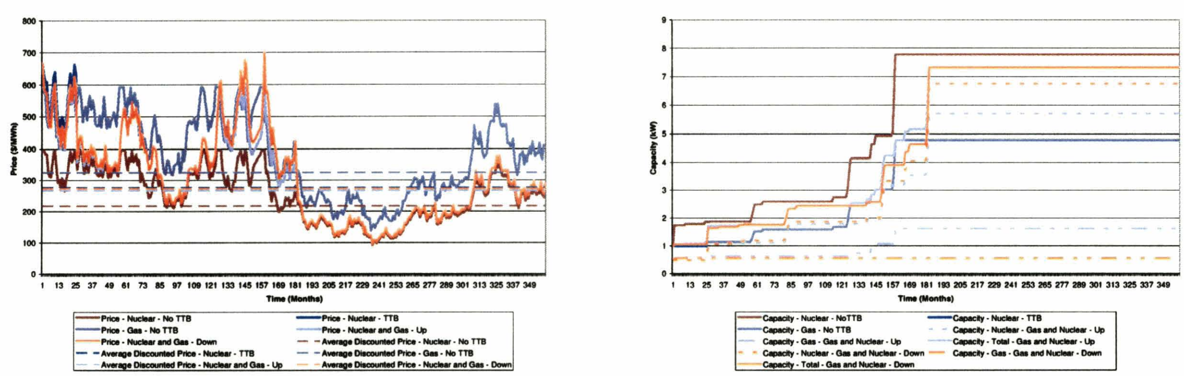

**Figure 74 – Prices and capacities – $\sigma = 30\%$**

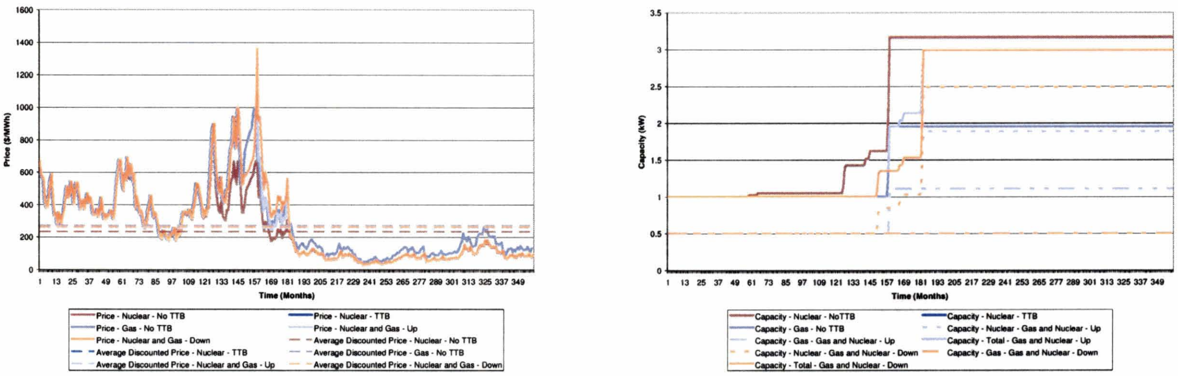


**Figure 75 – Prices and capacities –** $\sigma = 40\%$

The purpose of this section is not to go into detail on the comparisons between situations. This is intended to illustrate the effect of volatility on the price and capacity patterns.

It seems that demand volatility has a direct effect on price volatility: the more volatile demand is the more volatile prices are. This needs no explanation; it is simply a consequence of the chosen inverse demand function.

The capacity path is also smoother when demand is less volatile. This is consistent with intuition: the more predictable demand is, the easier it gets to have a regular capacity path.

Moreover, as volatility increases, the two-technology case progressively becomes closer to the gas without time-to-build. Obviously, when prices fluctuate more, it becomes increasingly profitable to install gas capacity. We will not reach as all-gas situation because high price variations also favor nuclear with time-to-build.

Nuclear with no time-to-build is evidently the situation where prices are lowest and capacity is highest in all volatility assumptions.

Let's consider the share of nuclear capacity in the two-technology case. It is displayed in the figure below.

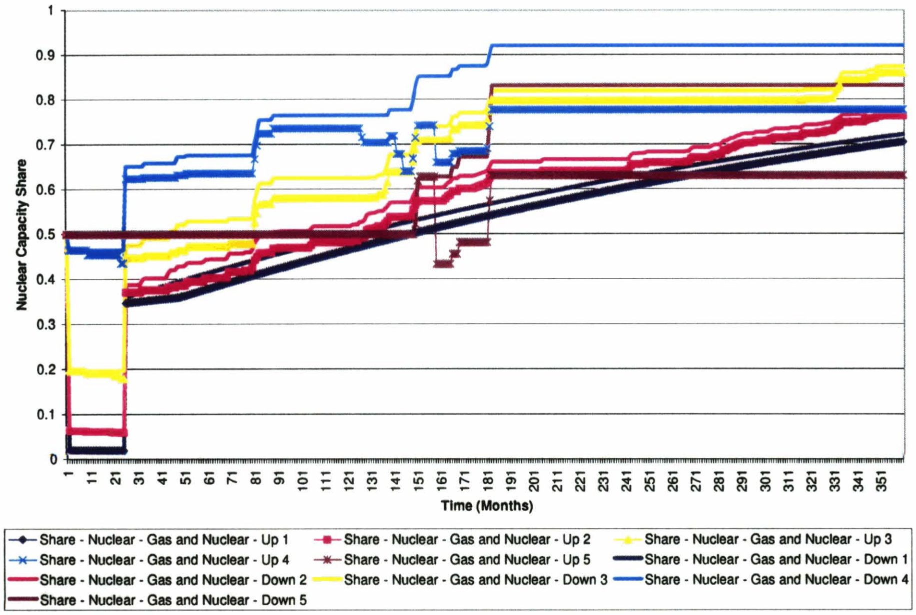


**Figure 76 – Nuclear Capacity Share –** $\sigma = 0\%, 10\%, 20\%, 30\%, 40\%$

The nuclear share continuously increases towards 100% when volatility is low. In cases of higher volatility though, it seems that the share of nuclear capacity will ultimately stop at a level lower than 100%. This is explained by the fact that high volatilities are profitable to gas power too, and that gas capacity will also constantly be installed. Therefore, there will be a non-zero portion of gas capacity when volatility of demand is high. This is one way of explaining the cost of time-to-build. Nuclear power loses market share even though it is cheaper, because of the construction delay.

The following chart summarizes the results analyzed in the preceding sections for various values of volatility.

| | | | | | |
|---|---|---|---|---|---|
| Elasticity | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 |
| sigma | 0 | 0.1 | 0.2 | 0.3 | 0.4 |
| Mu | 2.50% | 2.50% | 2.50% | 2.50% | 2.50% |
| r | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| Construction time | 24 | 24 | 24 | 24 | 24 |
| Knuclear | 4800 | 4800 | 4800 | 4800 | 4800 |
| Kgas | 7200 | 7200 | 7200 | 7200 | 7200 |
| LCOE - Nuclear | $32.23 | $32.23 | $32.23 | $32.23 | $32.23 |
| LCOE - Gas | $48.35 | $48.35 | $48.35 | $48.35 | $48.35 |
| Trigger - Nuclear | $32.23 | $80.58 | $200.48 | $395.15 | $666.45 |
| Trigger - Gas | $48.35 | $120.87 | $300.71 | $592.71 | $999.64 |
| Average Discounted Price - Nuclear - No TTB | $25.09 | $62.08 | $139.85 | $217.15 | $233.61 |
| Average Discounted Price - Nuclear - TTB | $91.91 | $127.07 | $202.98 | $276.12 | $262.53 |
| Average Discounted Price - Gas - No TTB | $37.64 | $93.12 | $209.76 | $325.72 | $270.01 |
| Average Discounted Price - Nuclear and Gas - Up | $31.52 | $74.54 | $169.56 | $266.83 | $255.82 |
| Average Discounted Price - Nuclear and Gas - Down | $31.68 | $74.96 | $170.85 | $273.16 | $262.53 |
| Ratio Average Discounted Price - Nuclear TTB - Mean Nuclear No TTB | 3.66 | 2.05 | 1.45 | 1.27 | 1.12 |
| Ratio Average Discounted Price - Gas NoTTB - Mean Nuclear No TTB | 1.50 | 1.50 | 1.50 | 1.50 | 1.16 |
| Ratio Average Discounted Price - Nuclear and Gas - Up - Mean Nuclear No TTB | 1.26 | 1.20 | 1.21 | 1.23 | 1.10 |
| Ratio Average Discounted Price - Nuclear and Gas - Down - Mean Nuclear No TTB | 1.26 | 1.21 | 1.22 | 1.26 | 1.12 |
| STD Discounted Price - Nuclear - No TTB | 28.39% | 28.49% | 32.11% | 44.84% | 65.68% |
| STD Discounted Price - Nuclear - TTB | 175.41% | 119.94% | 66.86% | 52.29% | 64.07% |
| STD Discounted Price - Gas - No TTB | 28.39% | 28.49% | 32.11% | 44.84% | 61.60% |
| STD Discounted Price - Nuclear and Gas - Up | 112.53% | 54.46% | 40.58% | 51.11% | 64.51% |
| STD Discounted Price - Nuclear and Gas - Down | 112.16% | 54.59% | 41.13% | 51.15% | 64.07% |
| Total Surplus - Nuclear - No TTB | $1,227,088 | $1,094,073 | $1,028,507 | $769,031 | $295,197 |
| Total Surplus - Nuclear - TTB | $1,131,584 | $1,009,034 | $948,832 | $709,985 | $285,022 |
| Total Surplus - Gas - No TTB | $1,158,415 | $1,043,852 | $988,452 | $740,658 | $286,537 |
| Total Surplus - Nuclear and Gas - Up | $1,199,276 | $1,067,685 | $998,121 | $744,841 | $288,582 |
| Total Surplus - Nuclear and Gas - Down | $1,198,489 | $1,066,949 | $997,357 | $741,205 | $286,537 |
| Surplus Ratio - Nuclear TTB/Nuclear NoTTB | 92.22% | 92.23% | 92.25% | 92.32% | 96.55% |
| Surplus Ratio - Gas NoTTB/Nuclear NoTTB | 94.40% | 95.41% | 96.11% | 96.31% | 97.07% |
| Surplus Ratio - Nuclear and Gas Up/Nuclear NoTTB | 97.73% | 97.59% | 97.05% | 96.85% | 97.76% |
| Surplus Ratio - Nuclear and Gas Down/Nuclear NoTTB | 97.67% | 97.52% | 96.97% | 96.38% | 97.07% |
| Total Capital Costs - Nuclear - No TTB | $298,771 | $107,953 | $45,038 | $20,486 | $5,616 |
| Total Capital Costs - Nuclear - TTB | $249,149 | $90,148 | $38,127 | $17,206 | $4,601 |
| Total Capital Costs - Gas - No TTB | $272,739 | $96,783 | $38,768 | $16,129 | $3,536 |
| Total Capital Costs - Nuclear and Gas - Up | $316,474 | $110,720 | $43,101 | $19,108 | $5,493 |
| Total Capital Costs - Nuclear and Gas - Down | $312,738 | $109,252 | $42,459 | $17,411 | $4,601 |
| SWF - Nuclear - No TTB | $928,317 | $986,120 | $983,468 | $748,545 | $289,581 |
| SWF - Nuclear - TTB | $909,266 | $953,704 | $950,325 | $723,452 | $281,936 |
| SWF - Gas - No TTB | $858,846 | $912,251 | $910,064 | $693,856 | $281,486 |
| SWF - Nuclear and Gas - Up | $882,801 | $956,965 | $955,020 | $725,733 | $283,089 |
| SWF - Nuclear and Gas - Down | $885,751 | $957,697 | $954,898 | $723,794 | $281,936 |
| SWF Ratio - Nuclear TTB/Nuclear NoTTB | 97.95% | 96.71% | 96.63% | 96.65% | 97.36% |
| SWF Ratio - Gas NoTTB/Nuclear NoTTB | 92.52% | 92.51% | 92.54% | 92.69% | 97.20% |
| SWF Ratio - Nuclear and Gas Up/Nuclear NoTTB | 95.10% | 97.04% | 97.11% | 96.95% | 97.76% |
| SWF Ratio - Nuclear and Gas Down/Nuclear NoTTB | 95.41% | 97.12% | 97.09% | 96.69% | 97.36% |
| Value of Asset - Nuclear and Gas - Up | $7,565 | $17,890 | $40,693 | $64,039 | $61,397 |
| Value of Asset - Nuclear and Gas - Down | $7,603 | $17,992 | $41,005 | $65,558 | $63,007 |
| Value of Asset - (Down-Up) | $38 | $101 | $312 | $1,519 | $1,610 |
| % decrease in Asset Value | 0% | 1% | 1% | 2% | 3% |

**Figure 77 – Summary Chart –** $\sigma = 0\%, 10\%, 20\%, 30\%, 40\%$

11.2.4. Impact of time-to-build on the comparative investment decision

This section will exclusively consider models featuring time-to-build: the model with nuclear with time-to-build alone, and the two technologies. For a given initial demand path with 30% volatility, we will assess the impact of increasing time-to-build on a number of relevant metrics.

An initial remark is necessary concerning the capital cost assumptions under time-to-build conditions. We have already stressed the fact that in case of a construction delay, the cost was incurred at entry i.e. at the moment the investment decision is made, not at start-up. In order to compare the various alternatives for construction lag, we need to make sure costs are consistent. It is necessary that levelized costs of electricity be equal at start-up for comparison purposes. Therefore, the capital cost at start-up will be discounted to the time of the decision. Consequently, with a longer time-to-build, nuclear capacity will be cheaper.

The following simulations will consider the following time-to-build values: 0, 12, 24, 36, 48 and 60 months. The time-to-build considered is comparative with the construction time for gas-fired capacity. Thus, a 12 months time delay means that it is 12 months longer to build a nuclear plant than a gas-fired plant.

In the figures below, 1, 2, 3, 4, 5 refer to the situation with q time-to-build of respectively 12, 24, 36, 48 and 60 months. 0 is represented by nuclear with no time-to-build.

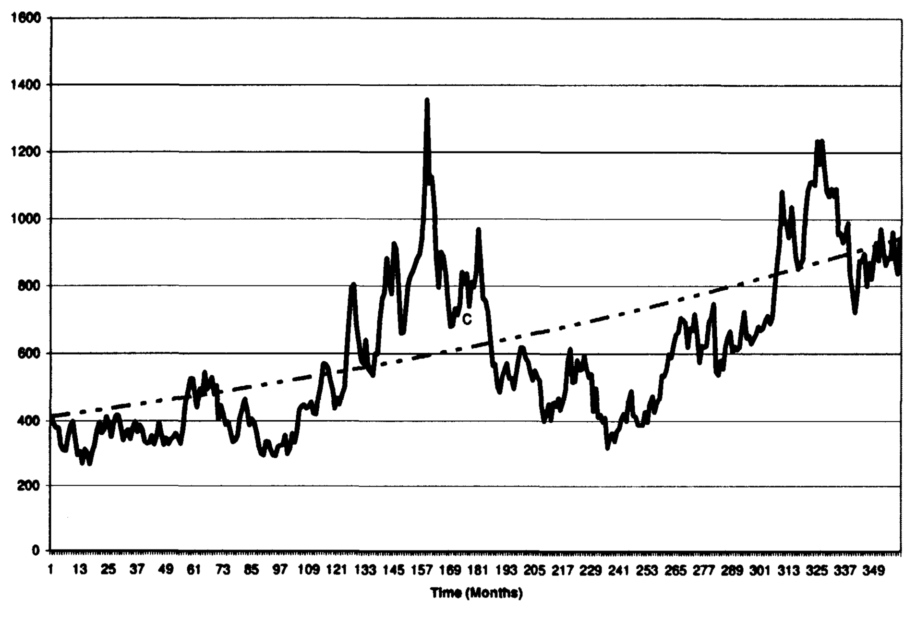


**Figure 78 – Demand Shock**

| | | | | | |
|---|---|---|---|---|---|
| **Elasticity** | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 |
| **sigma** | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| **Mu** | 2.50% | 2.50% | 2.50% | 2.50% | 2.50% |
| **r** | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| **Construction time** | 12 | 24 | 36 | 48 | 60 |
| **Knuclear** | 5046 | 4800 | 4566 | 4343 | 4132 |
| **Kgas** | 7200 | 7200 | 7200 | 7200 | 7200 |
| **LCOE - Nuclear** | $32.23 | $32.23 | $32.23 | $32.23 | $32.23 |
| **LCOE - Gas** | $48.35 | $48.35 | $48.35 | $48.35 | $48.35 |
| **Trigger - Nuclear** | $415.41 | $395.15 | $375.88 | $357.55 | $340.11 |
| **Trigger - Gas** | $592.71 | $592.71 | $592.71 | $592.71 | $592.71 |
| **Average Discounted Price - Nuclear - No TTB** | $105.31 | $105.31 | $105.31 | $105.31 | $105.31 |
| **Average Discounted Price - Nuclear - TTB** | $172.96 | $182.72 | $191.87 | $198.06 | $205.15 |
| **Average Discounted Price - Gas - No TTB** | $216.80 | $216.80 | $216.80 | $216.80 | $216.80 |
| **Average Discounted Price - Nuclear and Gas - Up** | $170.92 | $178.35 | $183.69 | $188.03 | $190.36 |
| **Average Discounted Price - Nuclear and Gas - Down** | $172.70 | $182.40 | $191.40 | $197.46 | $204.42 |
| **Ratio Average Discounted Price - Nuclear TTB - Mean Nuclear No TTB** | 1.64 | 1.74 | 1.82 | 1.88 | 1.95 |
| **Ratio Average Discounted Price - Gas NoTTB - Mean Nuclear No TTB** | 2.06 | 2.06 | 2.06 | 2.06 | 2.06 |
| **Ratio Average Discounted Price - Nuclear and Gas - Up - Mean Nuclear No TTB** | 1.62 | 1.69 | 1.74 | 1.79 | 1.81 |
| **Ratio Average Discounted Price - Nuclear and Gas - Down - Mean Nuclear No TTB** | 1.64 | 1.73 | 1.82 | 1.88 | 1.94 |
| **STD Discounted Price - Nuclear - No TTB** | 67.42% | 67.42% | 67.42% | 67.42% | 67.42% |
| **STD Discounted Price - Nuclear - TTB** | 72.18% | 72.16% | 72.61% | 71.28% | 70.96% |
| **STD Discounted Price - Gas - No TTB** | 67.42% | 67.42% | 67.42% | 67.42% | 67.42% |
| **STD Discounted Price - Nuclear and Gas - Up** | 72.34% | 73.01% | 74.23% | 73.62% | 74.24% |
| **STD Discounted Price - Nuclear and Gas - Down** | 72.07% | 72.00% | 72.44% | 71.11% | 70.78% |
| **Total Surplus - Nuclear - No TTB** | $345,282 | $345,282 | $345,282 | $345,282 | $345,282 |
| **Total Surplus - Nuclear - TTB** | $300,129 | $300,129 | $300,129 | $300,129 | $300,129 |
| **Total Surplus - Gas - No TTB** | $314,579 | $310,991 | $308,015 | $306,081 | $304,120 |
| **Total Surplus - Nuclear and Gas - Up** | $315,671 | $313,340 | $312,391 | $311,122 | $310,576 |
| **Total Surplus - Nuclear and Gas - Down** | $314,652 | $311,049 | $308,100 | $306,188 | $304,251 |
| **Surplus Ratio - Nuclear TTB/Nuclear NoTTB** | 86.92% | 86.92% | 86.92% | 86.92% | 86.92% |
| **Surplus Ratio - Gas NoTTB/Nuclear NoTTB** | 91.11% | 90.07% | 89.21% | 88.65% | 88.08% |
| **Surplus Ratio - Nuclear and Gas Up/Nuclear NoTTB** | 91.42% | 90.75% | 90.47% | 90.11% | 89.95% |
| **Surplus Ratio - Nuclear and Gas Down/Nuclear NoTTB** | 91.13% | 90.09% | 89.23% | 88.68% | 88.12% |
| **Total Capital Costs - Nuclear - No TTB** | $24,542 | $23,345 | $22,207 | $21,124 | $20,093 |
| **Total Capital Costs - Nuclear - TTB** | $12,798 | $12,065 | $11,368 | $10,708 | $10,081 |
| **Total Capital Costs - Gas - No TTB** | $10,566 | $10,566 | $10,566 | $10,566 | $10,566 |
| **Total Capital Costs - Nuclear and Gas - Up** | $13,906 | $13,763 | $14,354 | $13,925 | $13,990 |
| **Total Capital Costs - Nuclear and Gas - Down** | $12,859 | $12,091 | $11,399 | $10,742 | $10,118 |
| **SWF - Nuclear - No TTB** | $320,739 | $321,936 | $323,075 | $324,158 | $325,188 |
| **SWF - Nuclear - TTB** | $301,781 | $298,926 | $296,647 | $295,374 | $294,039 |
| **SWF - Gas - No TTB** | $289,563 | $289,563 | $289,563 | $289,563 | $289,563 |
| **SWF - Nuclear and Gas - Up** | $301,766 | $299,578 | $298,037 | $297,197 | $296,586 |
| **SWF - Nuclear and Gas - Down** | $301,794 | $298,957 | $296,701 | $295,446 | $294,133 |
| **SWF Ratio - Nuclear TTB/Nuclear NoTTB** | 94.09% | 92.85% | 91.82% | 91.12% | 90.42% |
| **SWF Ratio - Gas NoTTB/Nuclear NoTTB** | 90.28% | 89.94% | 89.63% | 89.33% | 89.04% |
| **SWF Ratio - Nuclear and Gas Up/Nuclear NoTTB** | 94.08% | 93.05% | 92.25% | 91.68% | 91.20% |
| **SWF Ratio - Nuclear and Gas Down/Nuclear NoTTB** | 94.09% | 92.86% | 91.84% | 91.14% | 90.45% |
| **Value of Asset - Nuclear and Gas - Up** | $41,022 | $42,804 | $44,085 | $45,126 | $45,686 |
| **Value of Asset - Nuclear and Gas - Down** | $41,447 | $43,776 | $45,935 | $47,391 | $49,060 |
| **Value of Asset - (Down-Up)** | $426 | $972 | $1,850 | $2,265 | $3,374 |
| **% decrease in Asset Value** | 1% | 2% | 4% | 5% | 7% |

**Figure 79 – Simulation Summary Chart**

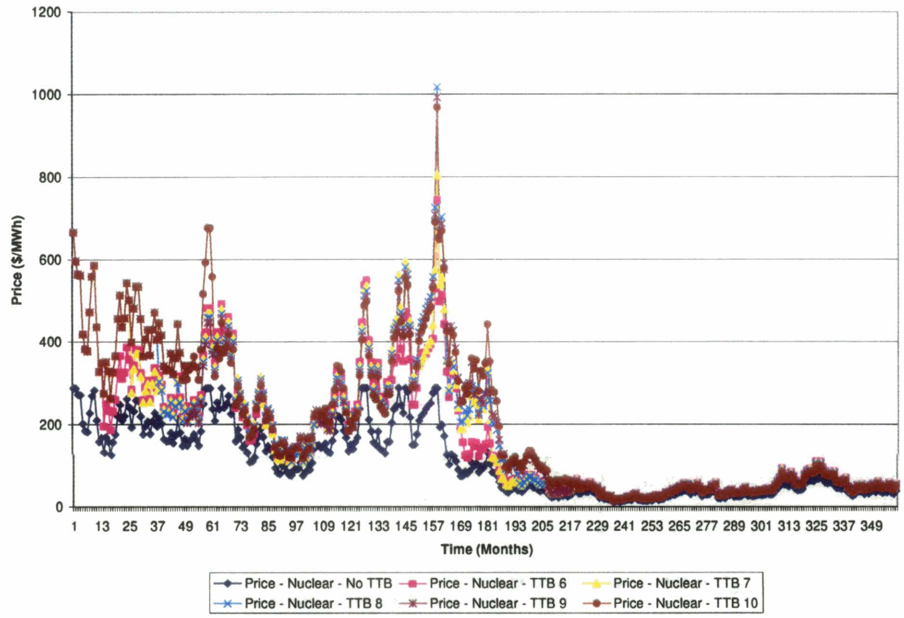


**Figure 80 – Grenadier – Price**

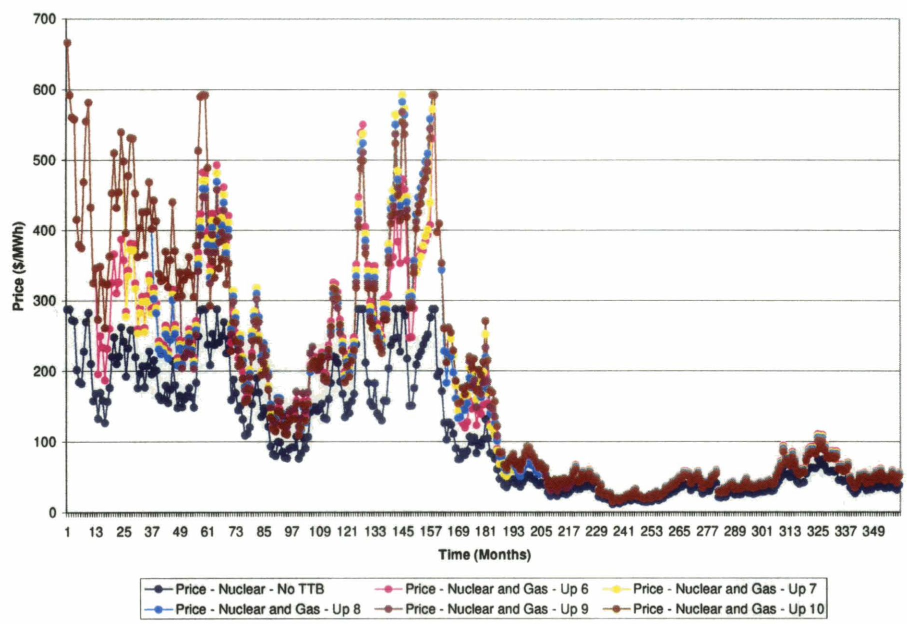


**Figure 81 – Two-technology – Upper bound – Price**

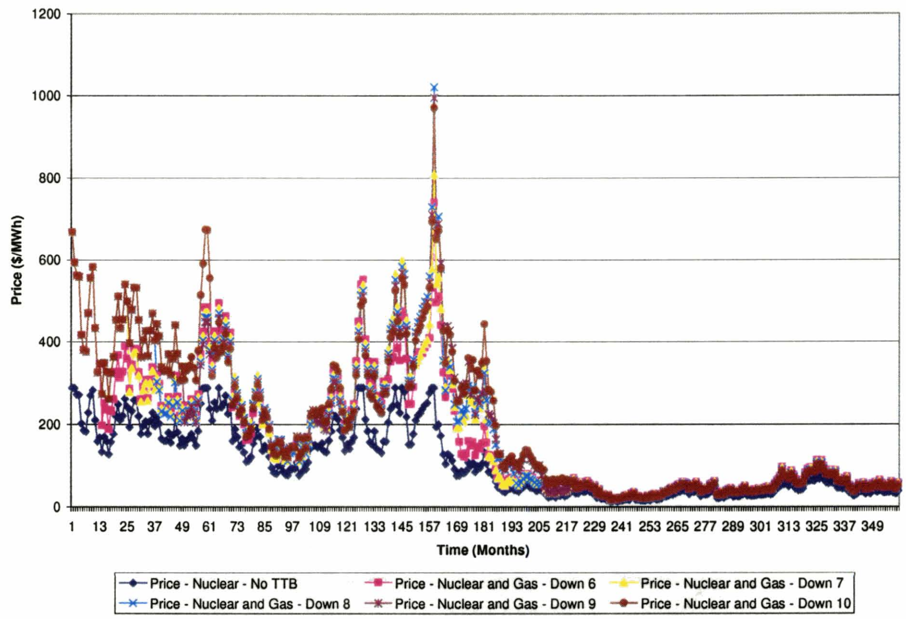


**Figure 82 – Two-technology – Lower bound – Price**

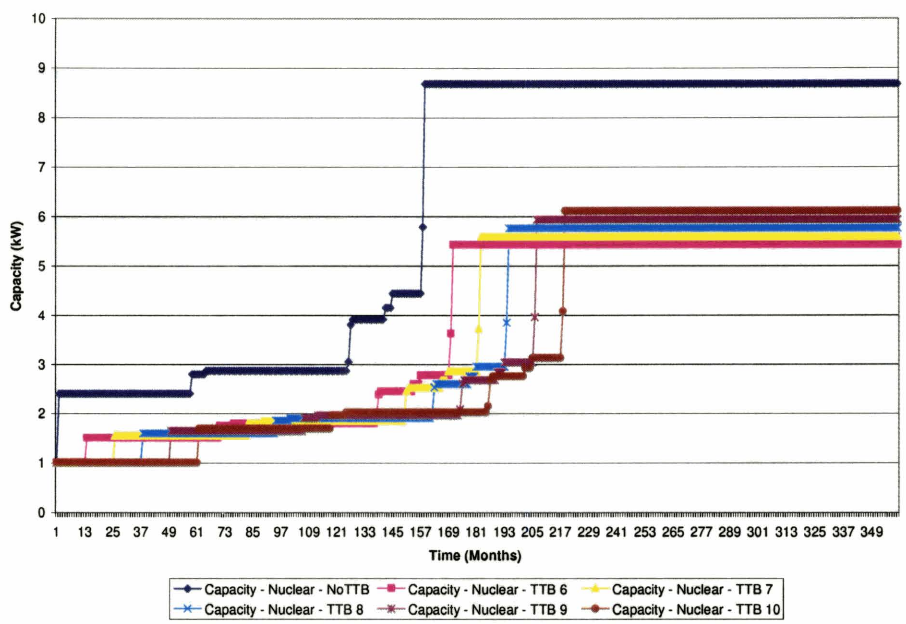


**Figure 83 – Grenadier – Nuclear Capacity**

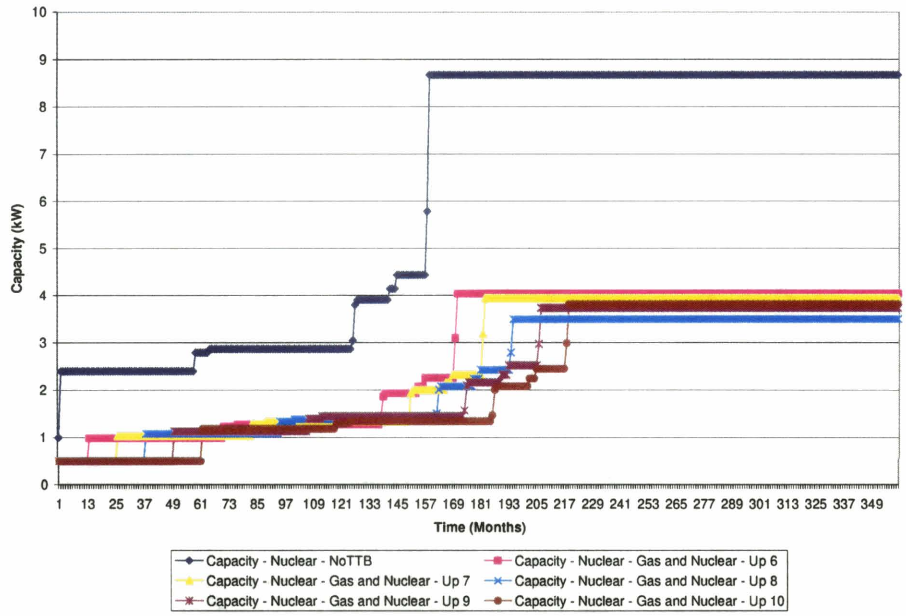


**Figure 84 – Two-technology – Upper bound – Nuclear Capacity**

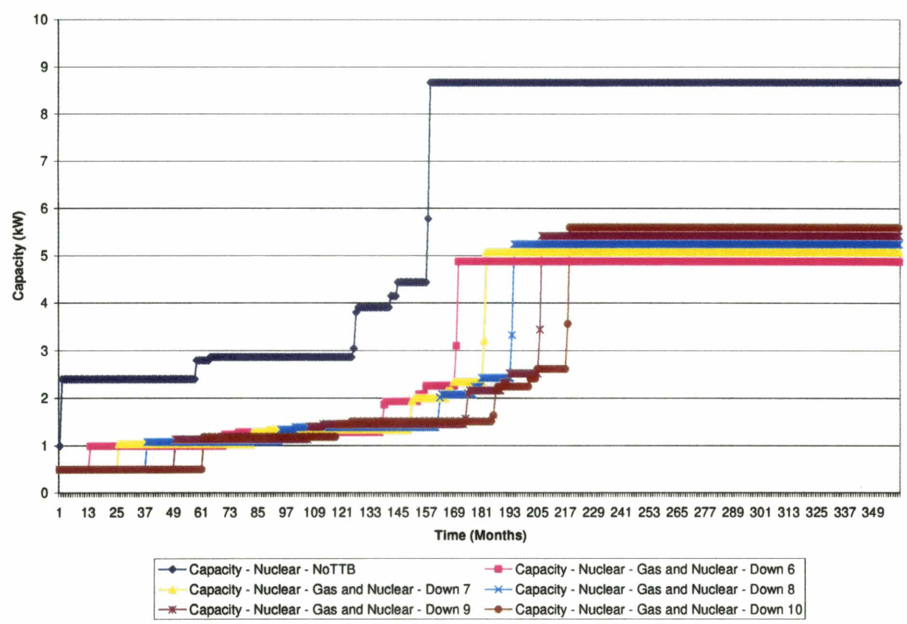


**Figure 85 – Two-technology – Lower bound – Nuclear Capacity**

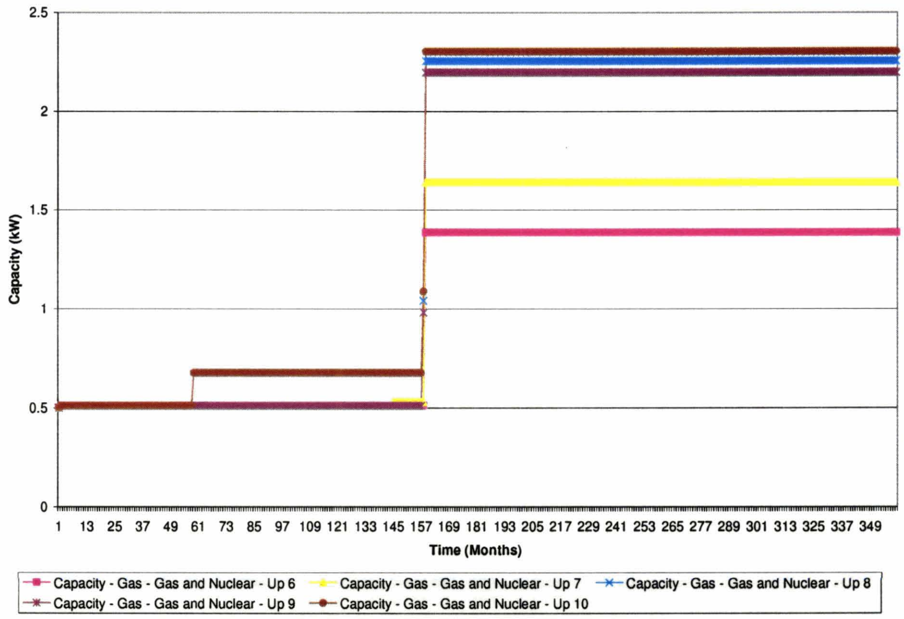


**Figure 86 – Two-technology – Upper bound – Gas Capacity**

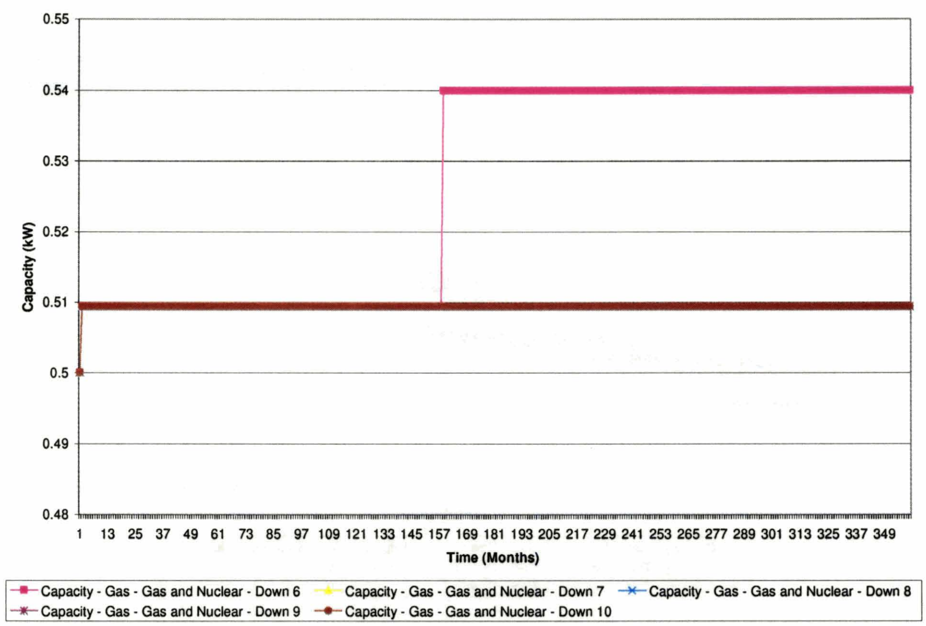


**Figure 87 – Two-technology – Lower bound – Gas Capacity**

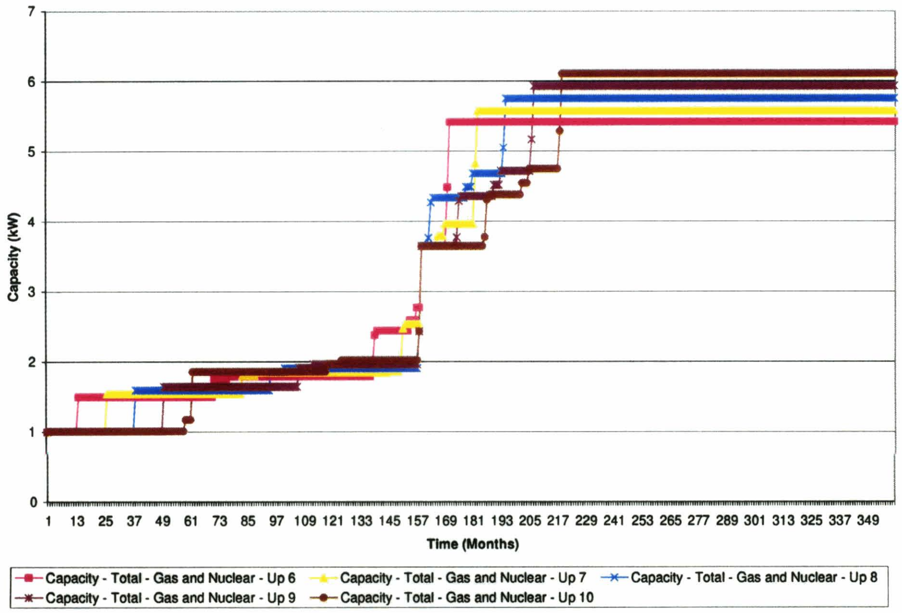


Figure 88 – Two-technology – Upper bound – Total Capacity

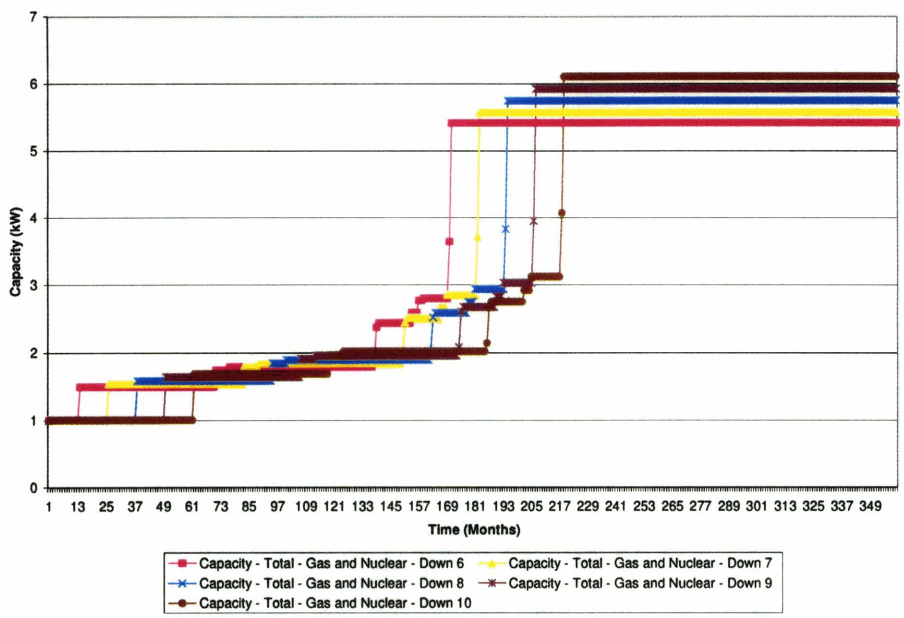


Figure 89 – Two-technology – Lower bound – Total Capacity

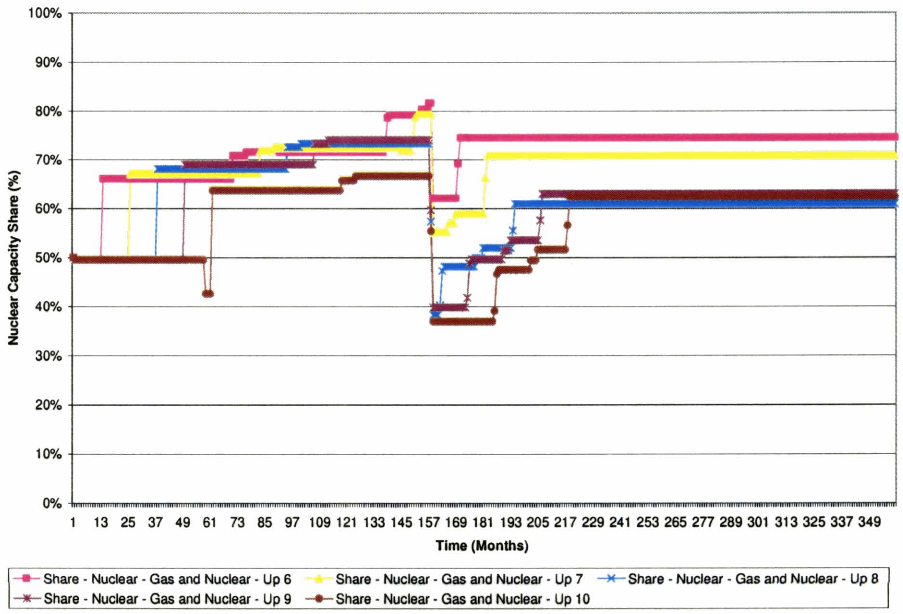


**Figure 90 – Two-technology – Upper bound – Nuclear Capacity Share**

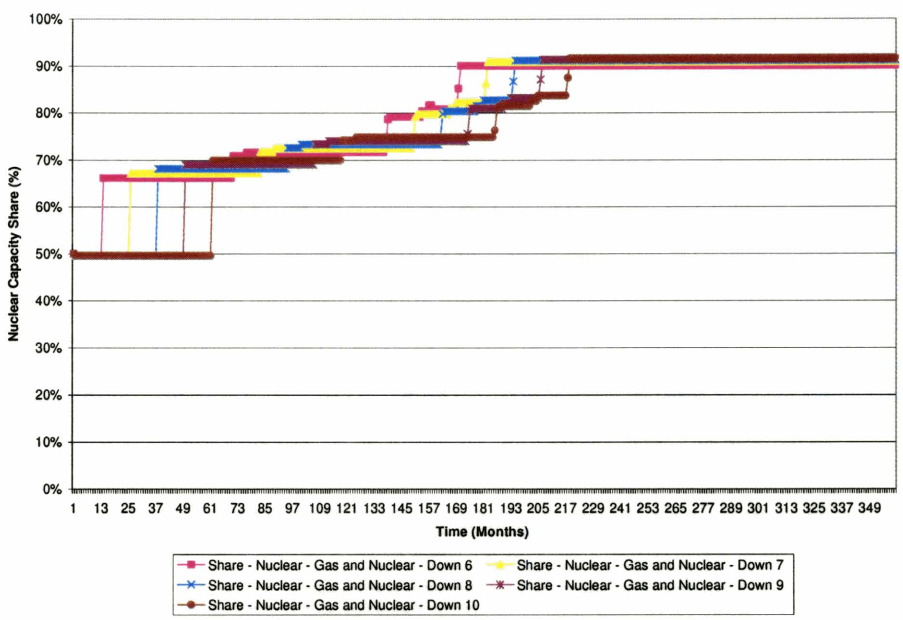


**Figure 91 – Two-technology – Lower bound – Nuclear Capacity Share**

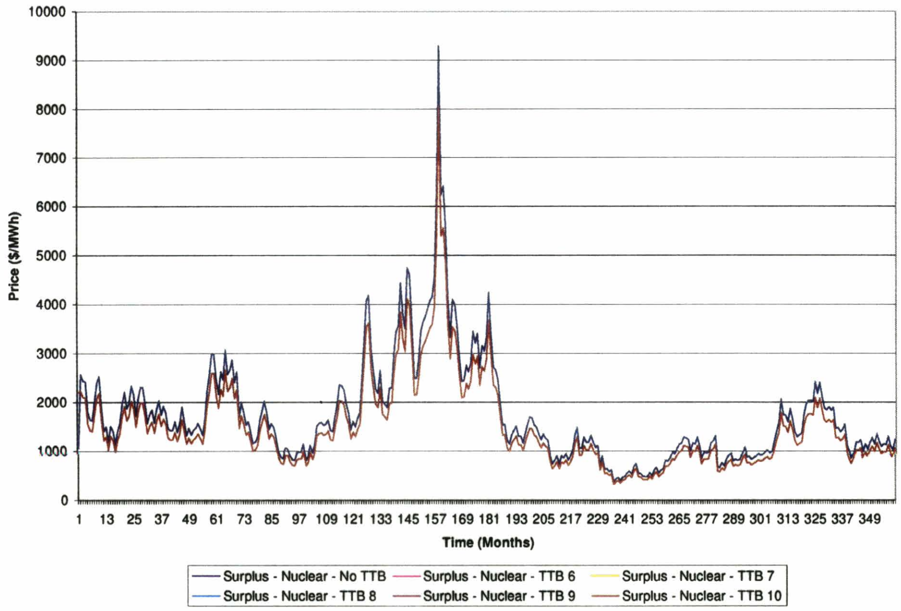


**Figure 92 – Grenadier – Consumer Surplus**

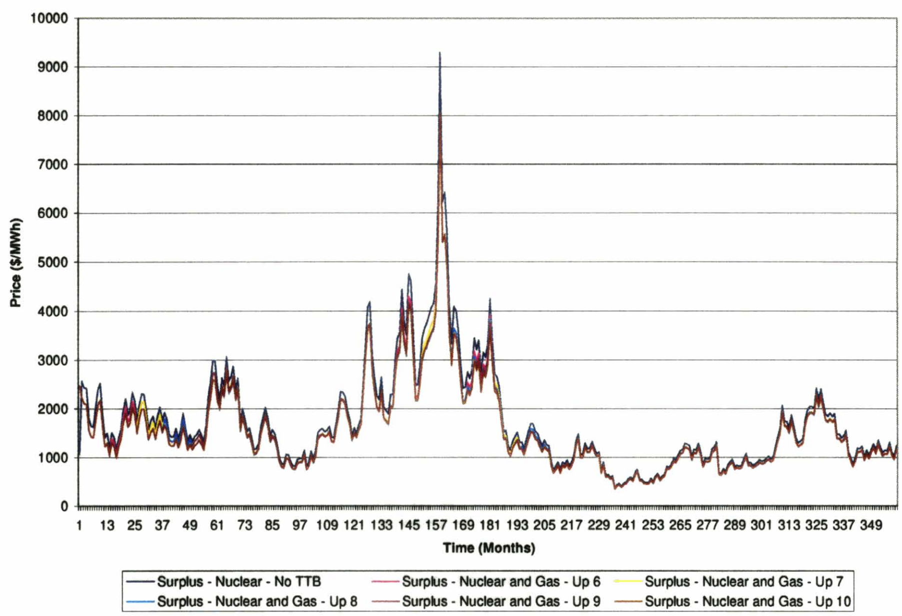


**Figure 93 – Two-technology – Upper bound – Consumer Surplus**

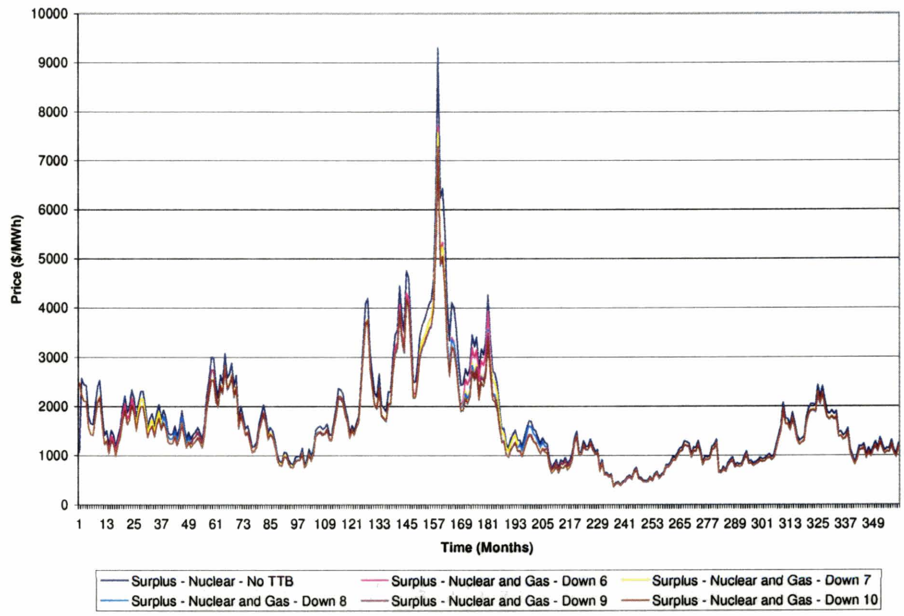


**Figure 94 – Two-technology – Lower bound – Consumer Surplus**

11.2.4.1. Analysis of general trends

First, it seems that the remarks made earlier about time-to-build are confirmed by this set of simulations.

When looking at the market with nuclear capacity only, it appears that time-to-build allows the price to reach higher values because it is not bound by an upper cap. It has an obvious impact on the volatility of prices which increases as time-to-build increases. For the same reason, the average discounted price sits higher for higher values of the construction time. This is already one step towards assessing the cost of time-to-build in a nuclear-only environment.

In the two-technology market situation, for the upper bound, the price is capped by the presence of gas capacity which has no construction lag. Therefore, prices are always below the gas trigger. In this situation and except for short periods, when one considers two price paths for two time-to-build values, the price will always be higher in the case of the highest time to build. The consequence of this is that the average discounted prices are ordered likewise. The presence of a cap does not allow reaching any satisfactory conclusion as to the impact of time-to-build on price volatility. Intuition would suggest that time-to-build increases volatility, yet the higher the time-to-build, the higher the gas response to volatility: those two conflicting effects seem to almost compensate.

In the Grenadier situation, time-to-build causes less capacity construction. The phenomenon is not simply that capacity is built at a later time: less capacity is built overall because of demand uncertainty. This is consistent with prices being higher for longer construction delays.

In the two-technology situation, an increase in construction delay results in less nuclear capacity to be built and of course more gas capacity to be built. This phenomenon is the opportunity given to gas producers to build capacity as new nuclear capacity is slowed down by the construction lag. It is more and more important as the window given to gas producers increases. Ultimately, the installation of more expensive capacity will result in social welfare losses. Overall, an equal amount of capacity is being built, but capacity is being built at later times. As a result, on average, at any point in time there is less capacity when nuclear takes longer to come online. This is also the reason for the average discounted price to be higher for longer construction lags.

In terms of capacity share, obviously the opportunity given to gas producers to build more capacity while less nuclear capacity is being installed results is a lower share of nuclear capacity on the market. As time to build goes to infinity, the share of nuclear power will go to zero.

As far as consumer surplus, in both cases, the impact of time-to-build is to cause a surplus loss. This loss is carried to social welfare and amplified, because consumer surplus is lower and the cost of building capacity is larger.

If we consider the calculation of the value of the asset, it appears that a larger time-to-build introduces more uncertainty in the approximation we are making between the lower and the upper bound. However, the uncertainty remains at level below 10%, which induces that the upper and lower bounds capture most of the information in spite of the absence of an exact solution.

All the remarks that have been made so far describe general trends about the effect of time-to-build on key metrics. It is however relevant to conduct a more quantitative analysis

### 11.2.4.2. Quantitative analysis of the impact of time-to-build

| Construction time | 12 | 24 | 36 | 48 | 60 |
|---|---|---|---|---|---|
| $e^{-\mu\delta}$ | 0.98 | 0.95 | 0.93 | 0.90 | 0.88 |
| **Ratio – Average Discounted Price Nuclear with time-to-build / Average Discounted Price Nuclear without time-to-build** | 164% | 174% | 182% | 188% | 195% |
| **Ratio – Average Discounted Price Nuclear and Gas – Down / Average Discounted Price Nuclear without time-to-build** | 162% | 169% | 174% | 179% | 181% |
| **Ratio – Average Discounted Price Nuclear and Gas – Down / Average Discounted Price Nuclear without time-to-build** | 164% | 173% | 182% | 188% | 194% |
| **Ratio – Social Welfare Nuclear with time-to-build / Social Welfare Nuclear without time-to-build** | 94% | 93% | 92% | 91% | 90% |
| **Ratio – Social Welfare Nuclear and Gas – Up / Social Welfare Nuclear without time-to-build** | 94% | 93% | 92% | 92% | 91% |
| **Ratio – Social Welfare Nuclear and Gas – Down / Social Welfare Nuclear without time-to-build** | 94% | 93% | 92% | 91% | 90% |

**Figure 95 – Ratio comparisons**

The table above displays the calculation of a number of ratios that are relevant measures of the investment model.

In order to quantify the effect of time-to-build, it is useful to remember an element previously mentioned: when no nuclear capacity is being constructed, the investment decision is equivalent to a no time-to-build decision with a price trigger multiplied by a factor of $e^{(r-\mu)\delta}$. Moreover, the demand trigger is multiplied by a factor of $e^{-\mu\delta}$. This can be assimilated as the cost of time-to-build, like the trigger premium over the levelized cost of electricity.

To confirm the idea that $e^{-\mu\delta}$ is a measure of the cost of time-to-build in our model, we are plotting it versus a number of ratios: ratios of average discounted prices over average discounted prices without time-to-build, and ratios of social welfare over social welfare without time-to-build.

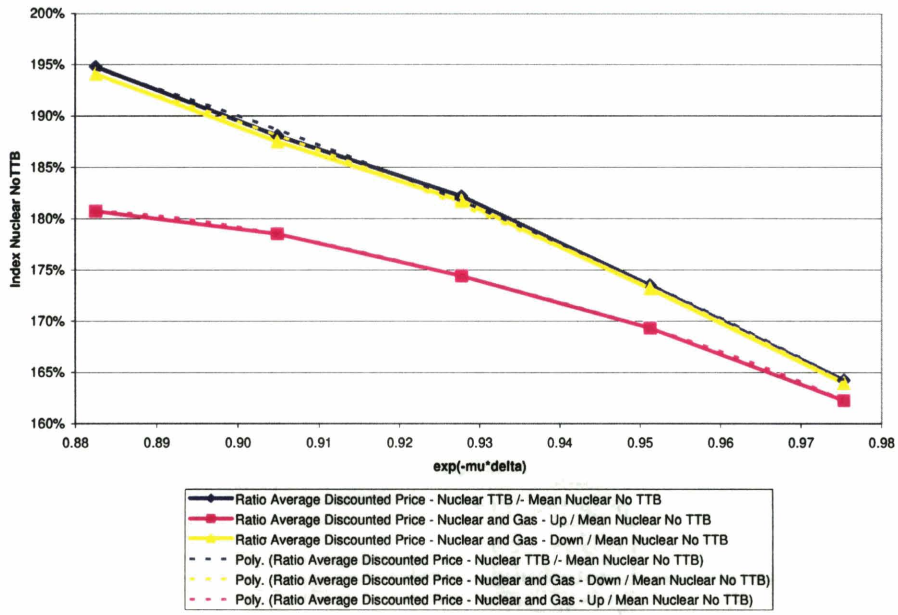


**Figure 96 – Impact of Time-to-build on Average Discounted Price**

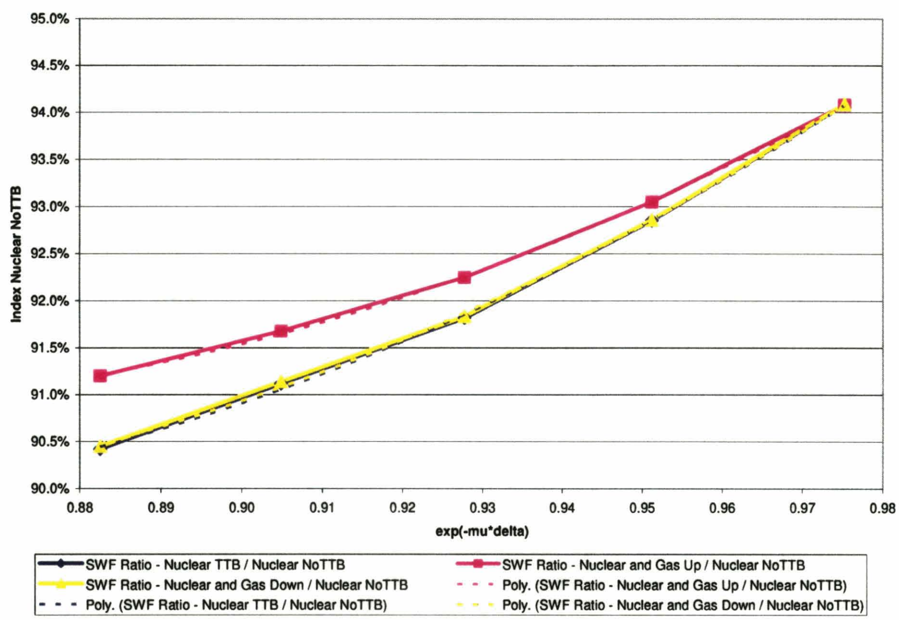


**Figure 97 – Impact of Time-to-build on Social Welfare**

The curves in the graphs above appear to be polynomial, which would suggest that both in the nuclear-alone case and in the two-technology case, the impact of time-to-build on price and social welfare is a polynomial function of the quantity $e^{-\mu\delta}$. These trends are not absolutely obvious with such a small set of data. More data would be required in order to assess the exact shape of the curve.

11.2.5. A closer look at the impact of time-to-build

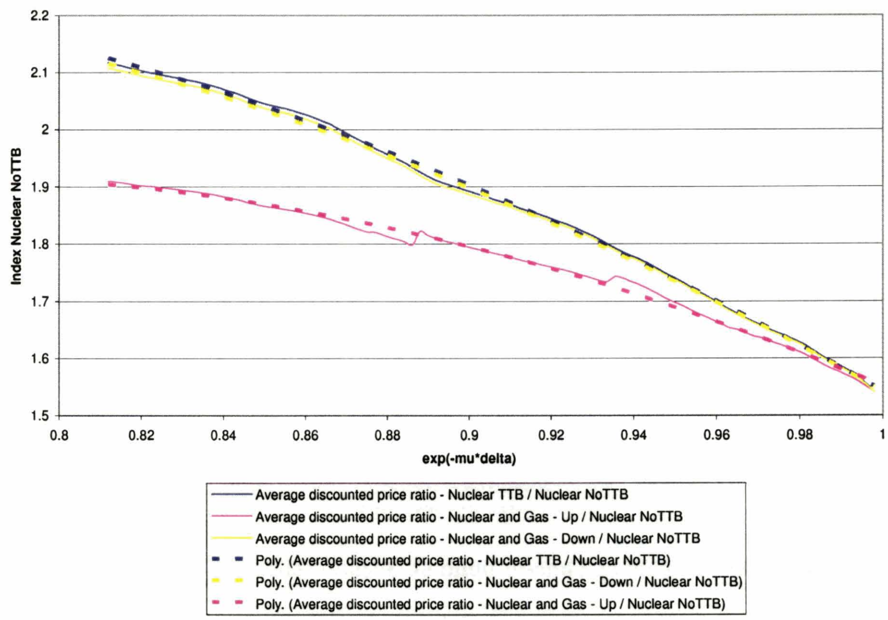


**Figure 98 – Impact of Time-to-build on Average Discounted Price –** $1 \leq \delta \leq 100$

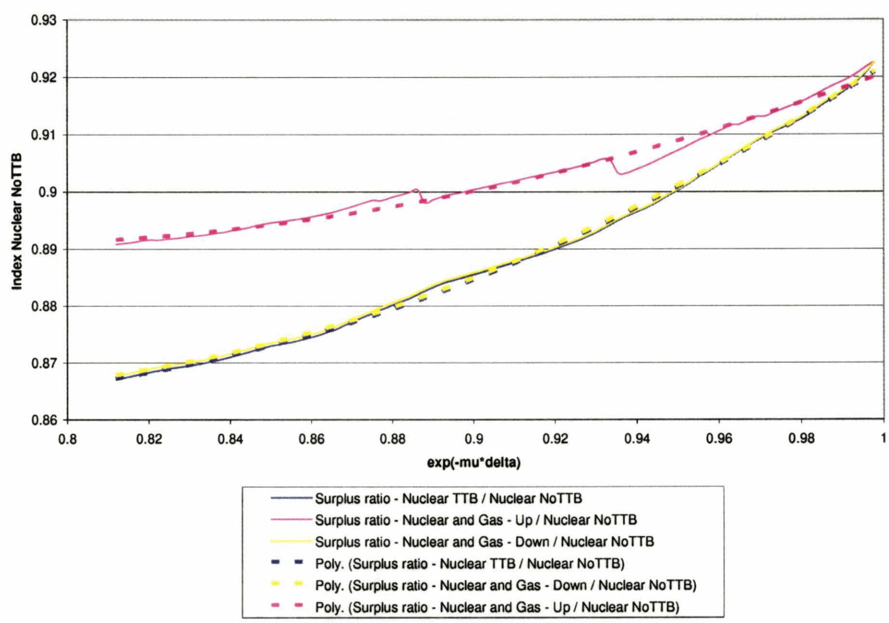


**Figure 99 – Impact of Time-to-build on Surplus –** $1 \leq \delta \leq 100$

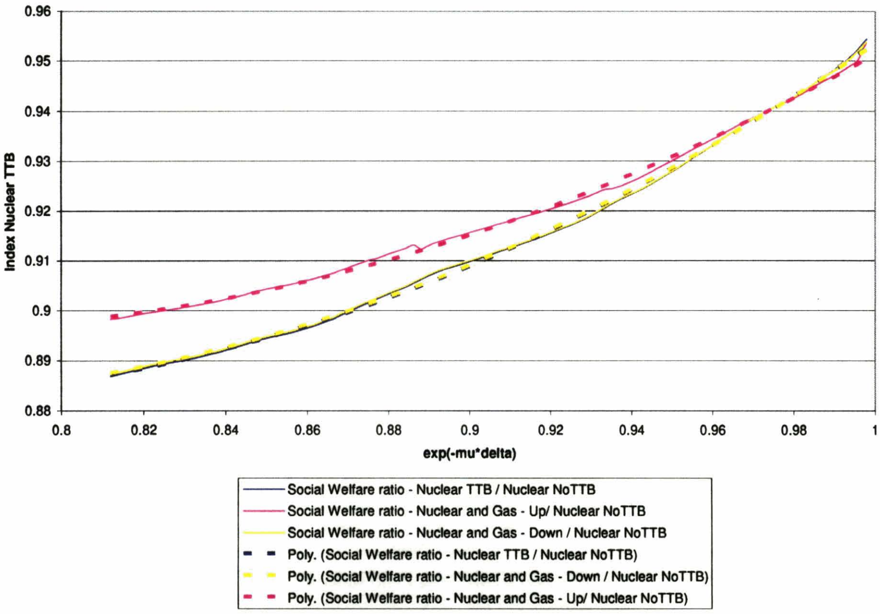


**Figure 100 – Impact of Time-to-build on Social Welfare –** $1 \leq \delta \leq 100$

The figure above confirms a number of remarks elaborated in the previous section. There is a polynomial relationship between what has been identified as the cost of time-to-build and the ratios in the both the Grenadier context and the two-technology context.

Another remark is that the lower bound for the two-technology case has a cost of time-to-build very close to the nuclear alone case. The reason is still that very little gas capacity is being constructed in the lower bound case.

In any case, we have managed to identify the cost of time-to-build as the quantity $e^{-\mu\delta}$, and the relationship between that time-to-build and various metrics of evaluation of an investment strategy given a set of market conditions.

## Conclusions and recommendations for future work

In this study, we have analyzed the main factors driving potential new investment in nuclear power. Some factors are general to electricity generation and some are specific to nuclear power.

The conclusion is that the new NRC licensing process and the nuclear provisions of the Energy Policy Act of 2005 should allow for new investments in nuclear power. By the time the financial support from the federal government has been used, new nuclear reactor designs should be cost-competitive with other sources of baseload generation. The introduction of environmental constraints on emissions of greenhouse gases would confirm the comparative economics of nuclear power.

Financing options will not be an easy undertaking, but this arduous task will be undertaken by a number of multi-utilities consortia, and the Finnish example suggests that financing nuclear power is possible in a competitive electricity market.

The financial investment model developed also shows that the long construction time for nuclear power has other implications than the temporal value of money. In a context of uncertain demand for electricity, there is an additional cost in not being able to react instantly to evolution of demand. Average prices for electricity increase as the construction delay becomes more important, and social welfare incurs losses by a few percent depending on the length of construction time. Traditional financial analysis fails to account for this impact of construction time, though it appears to have a significant effect according to the model calculations.

This study starts with a very broad analysis of the nuclear industry, and of the factors that directly impact investments in nuclear power plants. Yet each of the items analyzed would deserve a separate study, especially the issues classified as "unresolved". It would be useful to develop an investment model that would factor in elements such as environmental constraints over CO2 emissions. A closer look at capital costs and operating costs for new designs, and for the most recent nuclear investments in Asia would prove valuable to gain in the accuracy of the investment model.

In the investment mode, we have chosen to analyze the impact of time-to-build on the competitiveness of nuclear power. I recommend the study of other relevant items in the model, such as the impact of the ratio of investment costs to production costs. The model does not allow interruption of service for power plants. Adding such a feature would be a better approximation of the functioning of the electric power sector, and would also contribute in explaining regional choices in electricity mix.

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