The Centre for International Governance Innovation

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The Economics of Nuclear Power: Current Debates and Issues for Future Consideration

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Addressing International Governance Challenges

Abstract

Existing nuclear power plants in the United States and Canada have been recovering from the pre-1998 cost overruns, unreliability, and safety concerns. The favourable economics of existing plants (after debt has been written down or otherwise managed) have attracted private sector investment in capacity uprates and life extensions. This improved performance, coupled with claimed construction cost reductions for new nuclear power plant designs, has been heralded as evidence of a "Nuclear Renaissance." Estimates comparing the economics of new nuclear plants with alternatives such as natural gas-fired generation spur debate over the accuracy of the data used. It is clear that the economics of nuclear power vary inversely with interest rates and improve as natural gas prices rise and become more volatile. In competitive electricity markets, new nuclear plants may not be financially attractive to private sector investors without government action to tilt the economics in nuclear's favour, at least for FOAK (first-of-a-kind) plants. Some governments are exploring incentives for the construction and operation of new nuclear designs in order to avoid greenhouse gas emissions and enhance energy security. The industry's response to the incentives enacted in the United States will provide fresh evidence about the economics of nuclear power.

Canadian Centre for Treaty Compliance

CIGI's Nuclear Energy Futures Project is being conducted in partnership with the Centre for Treaty Compliance at the Norman Paterson School of International Affairs, Carleton University, Ottawa.

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Letter from the Executive Director

On behalf of The Centre for International Governance Innovation (CIGI), it is my pleasure to introduce the Nuclear Energy Futures Papers Series. CIGI is a Canadian-based non-partisan think tank that addresses international governance challenges and provides informed advice to decision makers on multilateral governance issues. CIGI supports research initiatives by recognized experts and promising academics; forms networks that link world-class minds across disciplines; informs and shapes dialogue among scholars, opinion leaders, key policy makers and the concerned public; and builds capacity by supporting excellence in policy-related scholarship.

CIGI's Nuclear Energy Futures Project is chaired by CIGI Distinguished Fellow Louise Fréchette and directed by CIGI Senior Fellow Trevor Findlay, Director of the Canadian Centre for Treaty Compliance at the Norman Paterson School of International Affairs, Carleton University, Ottawa. The project is researching the scope of the purported nuclear energy revival around the globe over the coming two decades and its implications for nuclear safety, security and nonproliferation. A major report to be published in 2009 will advance recommendations for strengthening global governance in the nuclear field for consideration by Canada and the international community. This series of papers presents research commissioned by the project from experts in nuclear energy or nuclear global governance. The resulting research will be used as intellectual ballast for the project report.

We encourage your analysis and commentary and welcome your thoughts. Please visit us online at www.cigionline.org to learn more about the Nuclear Energy Futures Project and CIGI's other research programs.

John English
Executive Director

Introduction

This paper was written for the reader who wants to understand the claims and counterclaims on whether the construction of new nuclear reactors to generate electricity is economic or is not. It draws on existing literature; no new economic modelling was performed. The paper provides an elementary introduction to levelized cost analysis and portfolio simulation–methods of estimating the economics of proposed nuclear power plants and comparing them with alternatives, such as hydroelectric stations and natural gas-fired generation. Results of selected cost estimation studies for the UK, Ontario, and the United States are presented and the limitations of the estimates are explained. Because the principal limitations are reliance on data and assumptions that are themselves debatable, the cost studies spur further debate rather than close doors to it. Some findings from the studies are unassailable nonetheless: the economics of nuclear power vary inversely with interest rates and improve as natural gas prices rise and become more volatile. Turning to the future, a levy on emissions of carbon dioxide would improve the competitiveness of nuclear power. Some governments are exploring measures to make the economics of new plants more attractive. The US already has enacted incentives for the construction of new nuclear plant designs in the deregulated, competitive US electricity market. The number and quality of licence applications prompted by the incentives and the decisions by the regulator on the applications will provide fresh evidence about the economics of nuclear. In Ontario, the advice McKinsey and Company are due to give about generating options, and the province's subsequent decisions, may offer clues to new plant economics in this Canadian province. Before turning to economic analysis, this paper begins with the tale of the widely-reported "Nuclear Renaissance."

The Nuclear Renaissance

The story of the Nuclear Renaissance and the difficult years for nuclear power that preceded it provides background for the current debates about nuclear economics. Many US and Canadian nuclear power plant projects initiated in the 1960s and 1970s cost more and took longer to build than predicted, and they operated less reliably than expected. Concerns over safety intensified after the Three Mile Island incident in March 1979. Design and construction problems, stricter safety requirements, and neighbourhood opposition contributed to lengthy delays in the completion of some units then under construction. For example, in June 1978 Ontario Hydro estimated the Darlington Nuclear Power Plant would cost $5 billion and the four units would enter service between November 1985 and February 1988. The actual cost was $14.3 billion, and the units entered service between October 1990 and February 1993. Contributing to the cost overruns were changes to cost estimates to reflect rework and repairs ($1 billion), unplanned schedule and scope changes ($2.1 billion), and accounting changes ($1.3 billion). Government indecision, first delaying the planned completion by three years or so because of reductions in forecast electricity demand and then speeding up the project by six to twelve months as part of a government job-creation program, was responsible for $2.5 billion of the overrun (OPA, 2005: Vol. 2, 217).

The unusually high double-digit interest rates in the 1980s made financing very expensive during the prolonged construction periods, and some projects were not completed. Costs of many plants were passed on to electricity users through rate increases. In the United States, large purchasers of electricity protested that rates were out of line with the cost of electricity from other fuels, particularly natural gas, which was plentiful as a consequence of deregulations in Canada and the US

Author Biography

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during the years 1978-1992. Large electricity users demanded to be unshackled from the local monopoly utilities; they wanted freedom to shop around for electricity. Their calls were heeded by the US Congress, which encouraged competition in wholesale power markets in The Energy Policy Act of 1992. High-cost nuclear plants became "stranded assets," their electricity rates undercut by non-nuclear utilities and independent power producers.

The reliability of nuclear power plants in the early decades of the technology disappointed expectations. In the US, capacity factors averaged 55.9% in 1975, 56.3% in 1980, 58.0% in 1985, and 66.0% in 1990 (EIA, 2007b: 123). (Capacity factor expresses actual generation as a percentage of maximum possible generation.) In Ontario, nuclear power dropped to its nadir in 1997 when Ontario Hydro laid up seven of its 19 operating reactors because it could not operate them safely.

In both Canada and the US the future of nuclear power was being questioned, but the seeds of a turnaround had already been planted. Under pressure from regulators and the marketplace, nuclear power plants improved reliability and cost control. This effort was accelerated by improvements in the quality and depth of management at nuclear utilities. Several utilities, having elected to become more specialized in nuclear power, started to acquire management rights or ownership of other utilities' nuclear assets, at significant discounts to book value. A comparison between 1991 and 2005 indicates the trend toward concentration of ownership in the United States. At the end of 1991, a total of 101 individual utilities had some (including minority) ownership interest in operable nuclear power plants. By late 2005, only 27 companies were involved, and the top ten had 68% of US nuclear capacity (WNA, 2007b). In Ontario, private investors assumed operations at the Bruce Nuclear Power Plant under lease in the year 2001. They rejuvenated the Bruce, restarted two of the units that had been laid up in 1997, and are currently refurbishing the remaining two inoperable units on a schedule that will return them to operation in 2009 and 2010 respectively. In 2006, Bruce Power generated 51% more electricity than in 2001, and the six operable units had a combined capacity factor of 88% (Bruce Power, 2007: 7, 18).

Between 1994 and 2004, US nuclear plants increased their capacity factor from 73.8% to 90.1% by reducing the duration of outages for refuelling and maintenance and making other improvements (EIA, 2007b: 123). Some plants were uprated to generate as much as 10% more power. These improvements enabled an increase in US output from 640 billion kilowatt hours (kWh) of nuclear electricity in 1994 to 789 billion kWh in 2004. This would be equivalent to bringing 18 new nuclear power plants of the 1,000-megawatt (MW) size into service at the 1994 capacity factor (Fertel, 2005). It was accomplished despite a decline in the number of operable US nuclear power plants from 109 in 1994 to 104 in 2004. Compared to coal- and gas-fuelled power stations, nuclear power plants, although costly to build, are economical to operate, as evidenced by the eagerness of US utilities to renew the original 40-year licences of the plants when they reach the eligibility date for a 20-year extension. According to the US Nuclear Regulatory Commission (NRC), 48 plants have renewed their licenses, starting with Calvert Cliffs, Maryland, which in the year 2000 was issued an extension to 2034; the license would otherwise expire in 2014. Another 14 plants are at various stages in the 30-month license extension process (NRC, 2007a).

The dramatic increase in the efficiency of US nuclear power plants inspired the industry to herald the arrival of the "Nuclear Renaissance." Not only had the operation of existing plants been improved, but the industry stepped up the promotion of new builds to increase electricity supply and energy security while avoiding emissions of greenhouse gases. The industry cited advances in construction and assembly techniques, new reactor designs, and changes to the licensing process. These brought the prospect of lower construction costs and shorter construction periods. Improved project management and construction methods have shortened construction time. GE claims a construction period of approximately 39 months from first concrete to first fuel load for an Advanced Boiling Water Reactor (ABWR) in Japan (GE Hitachi Nuclear Energy, 2007). Atomic Energy of Canada (AECL) reports that Qinshan, China, Phase III Unit 1, a CANDU 6 that entered service at the end of 2002, was built in 54 months from first concrete to full power operation (AECL, 2006). Economies from serial manufacture of components in factories would become achievable by standardizing on a small number of reactor designs and obtaining design certification in advance of construction. This scenario would contrast with the development of the existing US fleet of 104 reactors, which is a hodgepodge of 80 different designs (Smith, 2007). The three potential standard designs attracting the most interest in the United States include GE's ABWR, which the NRC certified in 1997 (NRC, 1997), and the Westinghouse/Toshiba AP1000 for which the NRC issued final design approval in early 2006. NRC design certification confirms the safety of a nuclear power plant design, independent of a specific site (NRC Licensing Reviews, nd). The third design is the Areva

EPR, for which a design certification pre-application review was started in 2005 (NRC Pre-application Review, nd). (The EPR, originally known as the European Pressurized Reactor, was renamed the Evolutionary Power Reactor for the US market.) Site-specific licensing has been streamlined in the US, as the NRC can issue a combined license (COL) "to construct and, with conditions, operate a nuclear power plant at a specific site and in accordance with laws and regulations" (2007b). This should prevent recurrence of delays, responsible for some past cost overruns, in waiting for a license to operate a plant already built pursuant to a construction licence. COL applications have been submitted for two projects: in July 2007 for an EPR at Calvert Cliffs, and in September 2007 for two ABWRs in South Texas. However, construction has yet to start in the US or Canada on the new masterpieces of the Nuclear Renaissance that was proclaimed six years ago.

Cost Analysis

New nuclear plants are expensive construction projects. Olkiluoto-3, an EPR with a capacity of 1600 MW now under construction in Finland, reportedly has a budget of three billion Euros ($4 billion) and is already 25% over budget (Katz, 2007). In the United States and Canada, a natural gas-fuelled plant costs much less to build than a nuclear plant. The construction period is shorter, and the approvals come quickly. On the other hand, the operating cost of a natural gas plant is higher. Fuel amounts to 50-65% of the cost of electricity from a gas plant compared to about 15% of the cost of nuclear electricity. As for hydroelectric projects, they require a large outlay for construction but operating costs are relatively small. Comparisons of the economics of various types of power plants having differences in upfront costs, construction times, fuel costs, and other determinants of economic performance are possible with levelized cost methodology. It is a tool for comparing the different cost profiles of various power plants on a uniform basis. Levelized cost represents the net present value of the average unit of electricity each plant will generate over its lifetime. The lifetime costs of a new power plant, including finance, construction, operation, fuel, maintenance, and decommissioning, are estimated, discounted to a present value using an appropriate rate of return, and totalled. The sum is divided by the total quantity of electricity the plant is projected to generate during its life. The resulting number, expressed in cents (or other currency) per kilowatt-hour (kWh), or dollars per megawatt-hour (MWh, which equals 1000 kWh), is the "Levelized Unit Electricity Cost" or "LUEC" (also known as the "Levelized Unit Energy Cost" and the "Levelized Cost of Electricity"). The LUEC is equivalent to the present value of the price of electricity sufficient for the recovery of all expenses for the power plant including a return on investment. The economics of different power plants under consideration can be compared by comparing their LUECs.

The Nuclear Energy Agency (NEA) and the International Energy Agency (IEA), which have cooperated on a series of studies on projected costs of electricity generation, illustrate the calculation of LEUC with the following formula (2005: 174):

$$LUEC = \Sigma\,[(I_t + M_t + F_t)\,(1+r)^{-t}] \,/\, \Sigma\,[E_t\,(1+r)^{-t}]$$

Where: I_t = Investment expenditures in the year t
M_t = Operations and maintenance expenditures in the year t
F_t = Fuel expenditures in the year t
E_t = Electricity generation in the year t
r = Interest rate used to discount expenses and revenues to a present value

Table 1 is a concrete example of the costs included in a LUEC estimate and the assumptions underpinning it. It is adapted from a consultation document the UK Department of Trade and Industry (UKDTI) issued in May 2007 to seek public input to a decision it plans to take later this year "whether or not to allow energy companies to build new nuclear power stations." (UKDTI, 2007c: 3) This study was selected because the assumptions are conservative and specified carefully. The DTI complained that over-optimistic assumptions and estimates caused previous levelized cost studies to underestimate the expense of new nuclear plants in the UK. The DTI presented nuclear cost estimates that it considered to be conservative compared to other studies and industry estimates (67-69). Table 1 reproduces the assumptions for each of the cost components in the "central-cost case." (Forecasts of future energy costs and supplies often compare different scenarios for the future, such as a high natural gas price case, a low natural gas price case, etc. The scenario considered most probable is usually labelled the "base case" or the "central case"; the term varies from study to study.)

Employing the above assumptions, the DTI estimated the levelized cost of new nuclear in the UK to be £37.7/MWh. If the average electricity price is equal to or greater than this number, the nuclear plant will recover its costs including a 10% after-tax return on investment. The LUEC for nuclear exceeded DTI's estimate of £37.3/MWh for a combined cycle natural gas turbine (CCGT) operated at 85% capacity for baseload.

Table 1: UK - Assumptions for Central Case for Costs of New Nuclear Build

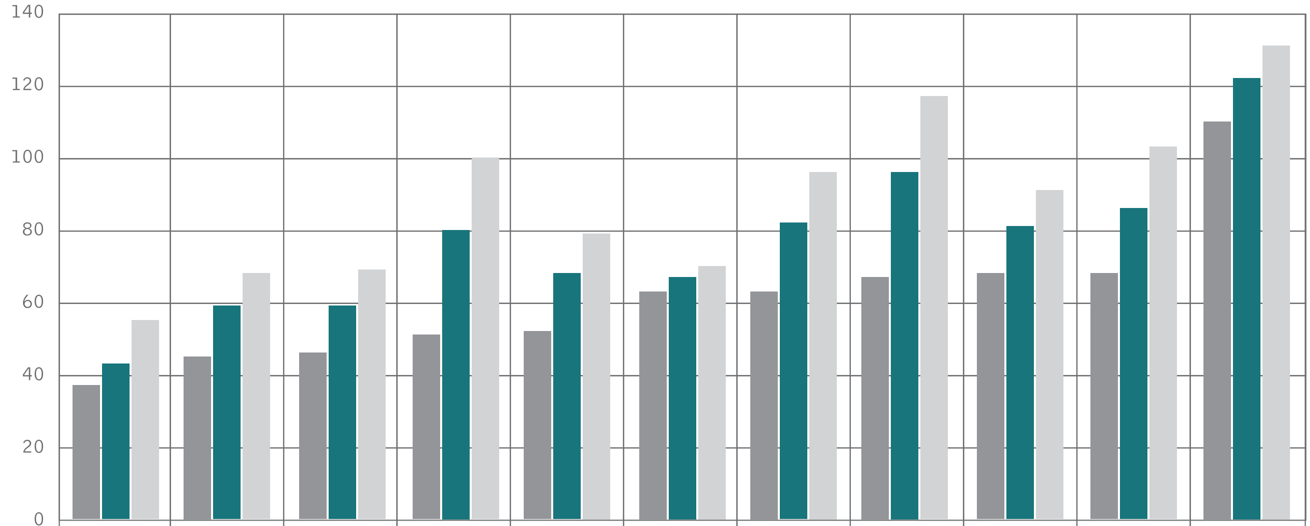
Item	Assumption	Source/Comment
Pre-development cost	£250 million	United Kingdom House of Commons Environmental Audit Committee report, "Keeping the Lights on: Nuclear, Renewables and Climate Change," March 2006
Pre-development period	eight years	Five years to obtain technical and site licence with three-year public inquiry period. Sizewell B pre-development period was seven years. (Sizewell B, completed 13 years ago, is the UK's most recent domestic experience with new nuclear build.)
Construction cost	£1,250/kW plus £500 million IDC (interest during construction) and £10/kW onsite waste storage every ten years over life	Total build cost is £2.8 billion. Compares to estimates of £2.7 billion for Finland EPR (based on recent press which suggest final cost might be ˚4 billion).
Construction period	Six years	Vendors estimate from 5 to 5.5 years. Sizewell B construction period was seven years.
Load (capacity) factor	80% rising to 85% after five years	Vendors expect 90% and over.
Operational life	40 years	Vendors expect 60-year life.
Operations and Maintenance (O&M) cost	£7.7/MWh (or £90 million per annum)	Within range provided by Sustainable Development Commission. Vendors expect O&M to be around £40 million per annum.
Fuel supply cost	£4.4/MWh	Based on raw uranium price of $80/lb, which with enrichment and fabrication costs as published by Uranium Information Centre gives £2,400/kg all-in cost. PB Power (consulting firm that provided cost studies for the 2004 report of The Royal Academy of Engineering) notes that most studies assume a fuel cost of around £4/MWh.
Waste disposal cost	Fund size of £276 million at end of 40 year life or £0.4/MWh	Assumes higher-level waste is disposed in a national deep geological repository together with legacy waste. Fund growth is assumed to be 2.2% in real terms.
Decommissioning cost	Fund size of £636 million at end of 40 years or £0.7/MWh	Cost is assumed to be £400 million/GW. Vendors' estimates are from £325 million/GW for the EPR and £400 million for the AP1000. Fund growth is assumed to be 2.2% in real terms.
Cost of capital	10%	Post-tax real discount rate, used in a number of studies and widely accepted by industry.

Source: UKDTI, 2007c: 68.

Nuclear was cheaper than other low carbon options for new generation. Onshore wind (50MW capacity) was estimated at £56/MWh, and offshore wind (100MW) at £84/MWh. Estimates for coal-fired carbon capture and storage (CCS) generation ranged widely because this technology is in an early stage of development. Levelized costs to retrofit an existing coal plant with CCS ranged from £40 to £48/MWh, while new plants ranged from £43 to £55/MWh (DTI, 2007b: 22-26).

The gap between the nuclear and gas levelized costs may appear narrow, but gas, which requires much less upfront investment and repays the investment more quickly, should be more attractive to private investors than the cost difference alone suggests. In the UK's liberalized energy market, it is the private sector, not governments, that "would decide whether to propose, develop, construct and fund any new nuclear power stations. Private sector financing would also need to

Figure 1: Ontario - Selected Levelized Costs ($Cdn/MWh)



	AP1000	ACR1000	ACR700	Hydro	CANDU 6	Gas Combined Cycle	Biomass	Hydro from Manitoba	Coal Gasification	Wind	Gas Turbine
WACC 5%	37	45	46	51	52	63	63	67	68	68	110
WACC 8.5%	48	59	59	80	68	67	82	96	81	86	122
WACC 11%	55	68	69	100	79	70	96	117	91	103	131

Source: OPA, Vol. 2, 238.

cover the full costs of decommissioning and full share of waste management costs. Therefore, it would be for the private sector to ultimately take a view on the financial viability of any proposal for a new nuclear power station." (UKDTI, 2007c: 59) If new nuclear plants are not economic, and would be built only if they were, why has the government embarked on public consultations on whether to allow energy companies to build them? The reason is the government's belief that under other scenarios for future gas and carbon prices, nuclear power would offer general economic benefits to the UK, reduce carbon emissions, and increase energy security (10). Further on, this paper looks at the effects of climate change policies on the economics of nuclear power as analyzed by levelized cost models.

Estimating the Economics of New Builds in Ontario

The UK's electricity supply mix is gas 38.8%, coal 35.8%, nuclear 18.6%, renewables 4.7%, and other 2.1% (for April 1, 2006 to March 31, 2007; DTI, 2007a). Are the economics of new nuclear builds better in markets that rely on nuclear more? For Ontario, where the electricity supply mix is nuclear 54%, hydro 22%, coal 16%, natural gas and oil 7%, and other 1% (in 2006; IESO: 4), levelized costs were reported in the December 2005 Supply Mix Advice Report the Ontario Power Authority (OPA) submitted to Ontario's Minister of Energy. Figure 1 displays selected LUECs from the report. They show the sensitivity of power plant lifetime costs to different interest rates. The study calculated LUECs at 5%, 8.5%, and 11% interest rates. OPA used the term "Weighted Average Cost of Capital" (WACC), which is particularly appropriate for the 8.5% and 11% discount rates. WACC applies to projects attracting equity investors as well as bond holders. Because equity investors shoulder more risk, they require a higher return. A project with a debt to equity ratio of 40:60 that paid a return on equity of 15% and interest to bondholders of 5% would have a WACC of 11%. Regarding the 5% rate, OPA considered it a "social discount rate," equivalent to the long-term cost of the provincial debt (Vol. 1, 33).

Figure 1 arranges new power plant options from right to left in order of increasing levelized cost at the 5% discount rate. Omitted are OPA's estimates for photovoltaics and fuel cells because they exceeded $100/MWh at the 5% WACC. OPA assumed natural gas and coal prices to be $8/MMBTU and $2.5/MMBTU respectively. Capacity factors were assumed as 85% except for wind 30%, hydroelectric 45%, simple cycle gas 20%, and biomass 50%.

At all three discount rates, the Westinghouse AP1000 pressurized water reactor (PWR) has the lowest expected levelized cost, followed by two AECL designs, the ACR-1000 and ACR-700. As these three designs have yet to be built, the construction cost estimates may be optimistic, an issue that will be discussed later. The other nuclear power plant on the chart, AECL's CANDU 6, has been built in New Brunswick, Quebec, Korea (four units), Argentina, Romania, and China (two units). At the 5% discount rate the LUEC for a new CANDU 6 is $52Cdn/MWh, more than a new hydroelectric installation ($51Cdn/MWh) but less than a new CCGT plant ($63Cdn/MWh). As interest rates (WACC) increase, LUEC increases more for the CANDU 6 than for CCGT. A WACC increase from 5% to 8.5% raises the CANDU 6 LUEC by 30% to $68Cdn/MWh, but the CCGT costs only 6% more ($67Cdn/MWh). A further WACC increase from 8.5% to 11% raises CANDU 6 a further 16% to $79Cdn/MWh but CCGT only another 4% (to $70Cdn/MWh). Natural gas plants are less sensitive than nuclear to interest rates because the capital investment represents only 15-20% of the lifetime cost of a CCGT plant, compared to 50-60% for nuclear (WEC, 2007: 56).

A levelized cost study for one electricity market cannot be assumed to apply elsewhere. OPA's analysis reflects the limited resources available to Ontario for new power plants. The province already has developed most of its inexpensive hydro potential. Coal, an abundant resource in the US, Australia, and elsewhere, is not found in Ontario, and the provincial government promised in electoral campaigns to shut down existing coal plants. Power plants are large construction projects, and costs vary with differences among countries in wage rates, productivity, industrial and labour market structures, regulations and regulators, and climate-related construction and design requirements. CERI reports a cost engineer's view that the cost of building a nuclear power plant in Canada could be 14% higher than an estimate derived by converting the average cost for one built in the US into Canadian dollars (Naini et al., 2005: 11). Accordingly this paper will also look at levelized cost estimates for the US, which generates more nuclear electricity than any other nation.

MIT Estimates of New Build Costs in the United States

The generation mix in the US electric power sector was coal 50.4%, nuclear 20.2%, natural gas 18.8%, conventional hydro 7.3%, other renewables 1.7%, and oil 1.5% in 2006 (EIA, 2007b: 104). The 2003 MIT study, The Future of Nuclear Power, although not the most recent for the US, raised a number of important issues, including the realism of the assumptions and data used by levelized cost studies, the extent to which carbon taxes would tilt levelized cost comparisons to favour nuclear, and the national interest in subsidizing the "first-of-a-kind" (FOAK) costs of the initial nuclear plants built to new designs.

The 104 nuclear power plants now operating in the US were developed by publicly-owned or regulated investor-owned utility monopolies. The risks of these projects, such as construction cost overruns and unanticipated outages, were largely passed on to customers rather than borne by the plant vendors and utilities. Knowing this, investors gave less weight to these risks. Subsequently the US wholesale electricity market was deregulated. The MIT study assumed future nuclear plants will have to compete as merchant plants with other energy technologies in a deregulated market.

> While some of the risks associated with uncertainties about the future market value of electricity can be shifted to electricity marketers and consumers through forward contracts, some market risk and all construction cost, operating cost and performance risks will continue to be held by power plant investors. Thus, the shift to a competitive electricity market regime necessarily leads investors to favor less capital-intensive and shorter construction lead-time investments, other things equal. (MIT, 2003: 37-38)

Believing that the traditional levelized cost model did not reflect how private investors would finance power plants in competitive markets, the MIT researchers developed and employed a "Merchant Cash Flow" model. It "provides flexibility to specify more realistic debt repayment obligations and associated cash flow constraints, as well as the costs of debt and equity and income tax obligations that a private firm would assign to individual projects with specific risk attributes, while accounting for corporate income taxes, tax depreciation and the tax shield on interest payments" (Ibid.,39). The study made stringent assumptions about levelized cost components. For example, it assumed a WACC of 11.5% for nuclear plants but only 9.6% for CCGT, as the latter technology was less risky for investors (Ibid.,132).

The MIT modellers ran a number of simulations corresponding to various plausible scenarios about future fuel prices, construction costs, government policies, and other factors. Table 2 displays the results for the base case and the effects of different assumptions about nuclear plant costs and natural gas prices.

Table 2: United States - Levelized Costs of New Generating Plants, 2003 MIT Study

Real (2002 US$) Levelized Costs in Cents/kWh

Assumptions: 85% capacity factor, 40-year plant life, nuclear plant is light water reactor (LWR) with overnight capital cost of US$2,000/kW, O&M costs include fuel, and gas costs reflect real, levelized acquisition cost per thousand cubic feet (Mcf) over the economic life of the project.

Base Case	LUEC
Pulverized Coal	4.2
CCGT - low gas prices, US$3.77/Mcf	3.8
CCGT - moderate gas prices, US$4.42/Mcf	4.1
CCGT - high gas prices, US$6.72/Mcf	5.6
Nuclear	6.7

Reduced Nuclear Cost Cases. Effects on LUEC accumulate going down the list.	
• 25% reduction in construction cost	5.5
• Construction time shortened from 5 to 4 years	5.3
• O&M reduced from 1.5cents/kWh to 1.3cents/kWh	5.1
• Cost of capital reduced to be equivalent to coal and CCGT	4.2

Source: MIT, 2003: 39-42.

Note: The "overnight capital cost" is the total of all the costs that would arise if the plant could be built in one day; in other words, it excludes interest during the construction period. It includes engineering, procurement and construction (EPC) costs, site preparation, and licensing.

In the base case, nuclear was more expensive than coal and CCGT, even at high natural gas prices. At high natural gas prices it was coal, not nuclear, that would attract new plant investment.

The reduced nuclear cost cases reported in Table 2 modelled the economic effects of various claims about the latest nuclear plant designs:

- The 25% construction cost reduction case modelled the claim that experience acquired by building the FOAK units will bring the construction cost down for subsequent units.
- The shortened construction time case simulated the assertion that plants built to standardized designs using modular, factory-assembled components and advanced project-management techniques will be quicker to build.
- The reduction of O&M cost to 1.3cents/kWh reflected the performance of the plants in the lowest-cost quartile of operating US nuclear plants. The 1.5cents/kWh figure in the base case reflected the O&M costs of plants in the second-lowest cost quartile.
- If investors could be persuaded that nuclear was no more risky than gas and coal plants, the cost of capital for nuclear could be expected to drop to the level of the other technologies.

The cumulative effect of these reductions would bring the cost of new nuclear plants into line with coal, and with natural gas under the medium and high natural gas price scenarios. However, the reductions do not give nuclear an advantage over coal. The MIT study summed up its finding about the reduced nuclear cost claims in the following words:

> *The cost improvements we project are plausible but unproven.* It should be emphasized that the cost improvements required to make nuclear power competitive with coal are significant: 25% reduction in construction costs; greater than a 25% reduction in non-fuel O&M costs compared to recent historical experience (reflected in the base case), reducing the construction time from 5 years (already optimistic) to 4 years, and achieving an investment environment in which nuclear power plants can be financed under the same terms and conditions as can coal plants. Moreover, under what we consider to be optimistic, but plausible assumptions, nuclear is never less costly than coal. (41)

Debates over Levelized Cost Estimates - Construction Cost

The MIT study and the recent UK DTI consultation document were explicit about their efforts to avoid alleged flaws of some previous LUEC studies. Issues that have given rise to debate include reliance on cost data supplied by vendors, uranium price increases, and selection of discount rates.

Little data is available about actual recent costs of building nuclear power stations (MIT, 2003: 38) Because the AP1000 and the EPR have not yet been built, their actual costs are unknown. Four ABWR units have been built in Japan, but it would be complex to estimate costs in North America and Europe based on Japanese cost experience as the structures of the Japanese economy and construction industry are different. The turnkey contract for the EPR under construction in Finland and the nature of the fixed price provisions have not been made public (SPRU/NERA, 2006: ii). Without hard cost data, many LUEC studies make do with estimates. For example, the 2005 update of the NEA/IEA study, Projected Costs of Generating Electricity, relied on paper estimates submitted by member countries, not on orders for plants, for the costs of most power plants, particularly 11 of the 13 nuclear plants reported. Construction cost data supplied by vendors may be optimistic and not subject to independent evaluation. A report for the UK Sustainable Development Commission cautions, "Vendors of reactor systems have a clear market incentive, especially ahead of contractual commitments, towards 'appraisal optimism'-in other words to underestimate costs. This means that the risks attached to cost estimates are 'asymmetrical'-the chances of actual costs turning out to be higher than forecast costs are much higher than actual costs turning out to be lower" (Ibid.). Reactor vendors forecast that construction costs for their newest models will be much less than plants completed during the 1980s and early 1990s. Memories of the past gap between promises and performance invite skepticism about the cost estimates for the latest models. To quote from the MIT study:

> The reasons for the poor historical construction cost experience are not well understood and have not been studied carefully. The realized historical construction costs reflected a combination of regulatory delays, redesign requirements, construction management and quality control problems. Moreover, construction on few new nuclear power plants has been started and completed anywhere in the world in the last decade. The information available about the true costs of building nuclear plants in recent years is also limited. Accordingly, the future construction costs of building a large fleet of nuclear power plants is necessarily uncertain, though the specter of high construction costs has been a major factor leading to very little credible commercial interest in investments in new nuclear plants. (MIT, 2003: 38)

Debates over Levelized Cost Estimates - Uranium Price

The run-up of the uranium price in recent years should not deter the deployment of nuclear power. The volatile spot price of uranium has captured the attention of the media, but most uranium is transacted at lower and predictable prices under three- to five-year contracts. Uranium accounts for less than half the cost of nuclear fuel, and nuclear fuel is 15-20% of the lifetime cost of a nuclear reactor. There is no reason to believe uranium will be an exception to the general historical pattern whereby price increases for natural resources induce increases in supply and efficiencies that moderate prices. Turning to the first of these points, the EIA reports that US nuclear power plants purchased a total of 67 million pounds of U3O8e (uranium oxide equivalent) during 2006. A full 90% of the purchased uranium involved long-term contracts, and the remaining 10% involved spot contracts. The average price for long-term contracts was US$16.38 per pound of U3O8e, but for spot contracts it was US$39.48 per pound. The weighted average price paid was US$18.61 per pound of U3O8e (an increase of 30% compared with the 2005 price; EIA 2007a).

Table 3: Estimated share of the cost components of low-enriched uranium (LEU) fuel, January 2007

Component	Quantity & Unit Cost in US$	Cost US$	Percentage
Uranium	8.9 kg U3O8 x $53	472	26.4
Conversion	7.5 kg U x $12	90	5.0
Enrichment	7.3 Separative Work Units (SWU) x $135	985	55.1
Fuel fabrication	per kg	240	13.4
Total		1787	99.9

Source: Based on WNA, 2007a)

The World Nuclear Association (WNA) estimated that in January 2007, U3O8e purchased at probable contract prices represented 26% of the cost of a kilogram of nuclear fuel. WNA's estimate assumed a contract price per kg of U3O8e of US$53. This is equivalent to US$24/lb, which is 47% higher than the long-term contract price of US$16.38/lb the EIA reported for 2006. Hence WNA's estimate appears to be conservative. Table 3 shows the components of the cost of nuclear fuel.

Fuel accounts for 15-20% of the lifetime cost of a nuclear power plant. For a representative CANDU 6 plant, nuclear fuel was "less than 15% of the operation, maintenance and administration costs of operating Point Lepreau." This figure appeared in the 2002 decision by the New Brunswick Board of Commissioners of Public Utilities on the proposed refurbishment of the Point Lepreau nuclear power station. The board compared nuclear fuel favourably with "the variability in the cost of natural gas and the difficulty in obtaining a long-term supply" (New Brunswick Public Utilities, 2002: 14).

In commodity markets, large price increases eventually induce additional supply, which brings price down. The large supply of previously mined uranium restrained price throughout the 1990s. The history is interesting. After peaking in 1976, the uranium price declined significantly as supply expanded (from new mines as well as stockpiles held by utilities and governments) while demand fell short of forecasts (because many planned nuclear power plants were not completed). The price decline prompted the closure of marginal uranium mines (Mollard et al., 2006: 8). By the end of 2002, mining provided only 54% of world reactor requirements. The gap was filled, as it had been since 1990, by secondary sources, such as excess commercial inventories, low-enriched uranium (LEU) derived from highly-enriched uranium (HEU) warheads, re-enrichment of tails, and spent fuel reprocessing. These secondary sources are expected to decline in availability, particularly after 2020. Reactor requirements will have to be met increasingly by mining. The lead time for the discovery and development of new uranium production facilities has been one to two decades. Such long lead times could potentially create uranium supply shortfalls (Price, Blaise, and Vance, 2004). Growing realization of this possibility led to a sharp increase in uranium prices starting in 2003, which in turn has led to the development of new supply. Kazakhstan, for example, which produced 4,357 tonnes of uranium in 2005, is opening many new mines and plans to produce 18,000 tonnes a year in 2010 (Australian Uranium Association, 2007). The deposits of uranium that can be mined for less than US$130/kg (US$59/lb) are enough for 85 years at the 2004 rate of demand for nuclear electricity, according to a 2005 study (IAEA, 2006). (The spot price of uranium on 8 October 2007 was US$75/lb.) This is longer than the 63 years the world's proved reserves of natural gas at the end of 2006 would last at current rates of production (BP, 2007: 26). Proved reserves of oil would last 41 years (6).

Debates over Levelized Cost Estimates - Interest Rates

The selection of the interest rate for levelized cost comparisons has a great influence on whether nuclear power is estimated to be economic or not. Models of a competitive electricity market use a discount rate around 10% on the assumption that private companies investing in power plants seek a return that equals the interest rate on a safe investment (such as a government bond) plus a premium for the risk of investing in the electricity business. A paper for the UK Sustainable Development Commission assumed the risk premium could be small:

> A good starting point for the cost of capital is the rate of return that the economic regulator Ofgem allows utilities to earn on regulated (low risk) assets. This is currently 6.5% and it seems probable that a first-of-a-kind nuclear project would require a premium of 2 to 3 percentage points above this. This would imply a discount rate of around 9%, assuming that all other uncertainties (especially cost or time overruns) have already been allowed for elsewhere in the analysis. (SPRU/NERA, 2006: iii-iv)

The MIT study started with a higher return on equity and added a risk premium for nuclear. It assumed the investor in a fossil fuel plant earned a return on equity of 12%, while the investor in a nuclear plant would require a higher return-15%-as compensation for the greater business risks associated with nuclear. Assuming both types of plants were financed by a mix of debt and equity, MIT arrived at a WACC of 11.5% for nuclear and 9.6% for CCGT (MIT, 2003: 132).

OPA tested three discount rates in its LUEC analysis, as reported above, but OPA's portfolio simulations, which were relied on heavily for advice to the Ontario government, as shall be explained below, employed only the 5% "social discount rate." This rate is seen in levelized cost studies for markets where the utility has access to government financing or is government-owned and electricity prices are regulated (MIT, 2005: Vol. 1, 33). In Ontario, the electricity market was curtailed in 2002, and central supply planning has been restarted. However, the consistency of a social discount rate with private sector participation in Ontario's electricity supply is unclear. Bruce Power, the investor-owned company that leases the Bruce Nuclear Power Station and generated 23% of Ontario's electricity in 2006, has a WACC in the range of 10.6% to 13.8%, according to CIBC World Markets, which in October 2005 gave the Ontario Deputy Minister of Energy an opinion on the fairness of the transaction to refurbish the four CANDU units at Bruce A (CIBC, 10). Bruce Power's cost of debt is 6.2% before tax and 4.1% after tax. Its cost of equity is in the range of 13.7% to 18.0%. (CIBC: 9)

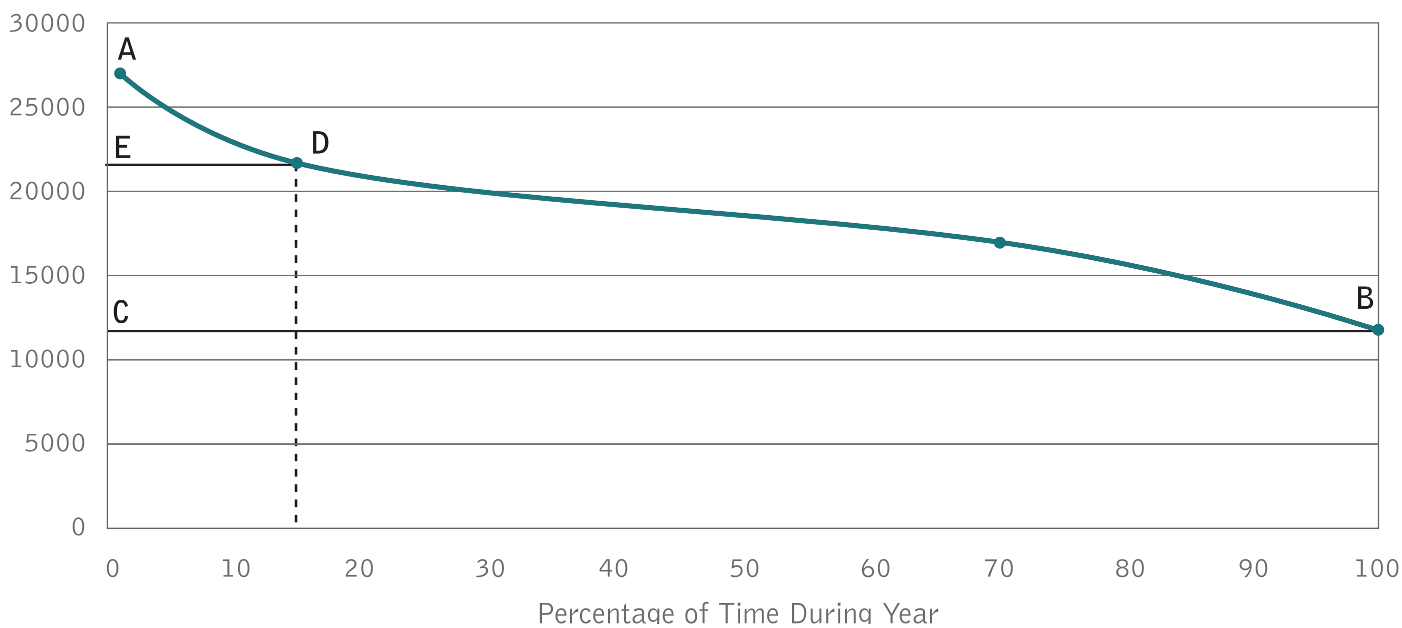
Electrical System Balancing

OPA's portfolio models simulate the requirement that an electricity system balance supply with demand every moment of the day. Unlike most industrial outputs, electricity is not stored; it is produced on demand. Generators are started up and shut down to meet demand for electricity (referred to as "load"). Load varies with the time of day, starting to ramp up around 5:00 am, peaking during the 3:00-6:00 pm period, and subsiding after 8:00 pm in Ontario. Load varies also with the season, being greater in both summer (for air conditioning) and winter (for heating and longer hours of artificial lighting) than in spring and fall. The maximum Ontario load, to date, was 27,005 MW, reached on Tuesday, 1 August 2006. The minimum Ontario demand that same year, on Monday, 9 October was 11,621 MW, or 43% of the maximum load reached on August 1 (IESO, 2007). Hence, 43% of the generating capacity Ontario needed to meet its peak load in 2006 could have been left operating the year round, and the rest of the generating capacity turned on and off as demand dictated. (To keep this discussion simple, reserve margins, exports and imports are ignored.) If the loads and their durations over the course of a year are graphed, the resulting curve has a shape similar to that in Figure 2. The starting point of the curve on the vertical axis, A, represents the 27,005 MW load that lasted for a fraction of a percent of the year. The last point on the curve, B, represents the 11,621 MW load that lasted 100% of the year. The latter demand is called base load and is represented by the line CB. For 15% of the time during the year the load was within 20% of the peak; loads above the line ED are peak loads. Between base load and peak load is intermediate load.

The various loads match some generating technologies better than others:

- A nuclear plant's long start-up time usually limits it to base load. A hydro plant with a reservoir can ramp up generation quickly, making hydro effective for intermediate and peak loads as well. Both types of plants are most economical when operated for base load.
- An intermediate load plant is one that can increase output in response to predictable daily demand cycles. For example, in the morning hours as people wake up, Ontario's demand increases 5,000 MW or more within several hours (OPA, 2005: Vol. 2, 164). Intermediate load plants have greater flexibility than

Figure 2: Hypothetical Load Duration Curve for One Year



base load plants. Examples are coal and CCGT plants. Their higher ratio of marginal cost (for fuel) to fixed cost makes them more economical than nuclear when operated for short durations but their cost advantage diminishes as they are operated for longer periods of time.

- An example of a peaking plant is the simple-cycle gas turbine which can increase output very quickly to meet brief spikes in demand or replace a generator which fails. Simple-cycle gas turbines have high levelized costs because they use gas inefficiently, and are economical only as peaking plants.
- For completeness, technologies which cannot be classified as base, intermediate or peak load should be mentioned. Wind power, run of the river hydro, and some cogeneration resources are used whenever they are available, such as when the wind blows, when the river runs, or when steam is required from the cogeneration facility (OPA, 2005: Vol. 2, 164).

In the real world a utility would install baseload generation capacity exceeding its minimum load, maintain reserve capacity of about 14-18% of the anticipated maximum load, and operate some generating stations as both peak and intermediate plants. (For more detail about how the necessity to balance electricity supply with demand constrains the selection of generating technologies, see OPA, Vol. 2: 162-171.) The above example has been kept simple as the objective was to explain that an electrical grid supplied by a diverse portfolio of generating plants is able to balance supply with demand and is equipped to apply each type of generation to the load it serves most economically. The choice of power plant for a complex electrical system cannot be based on a single criterion, such as levelized cost, in isolation from others. The report to the Australian government by the Uranium Mining, Processing and Nuclear Energy Review Taskforce made the point clearly:

> A comparison of technologies based only on cost per MWh would be misleading, given that a portfolio of generating technologies will form the basis of any national electricity supply system. The most flexible and efficient system is likely to include numerous technologies, each economically meeting the portion of the system load to which it is best suited. In a well functioning system, a diversity of sources can also provide greater reliability and security of electricity supply. (Australia, 2006: 48)

Ontario Analysis of Portfolios of Generating Stations

For this reason, the Ontario supply mix advice went beyond LUEC analysis by simulating and comparing alternative portfolios of generating plants. Some portfolios had more nuclear plants than others. The target common to all portfolios was to have 36,000 MW of generating capacity in place by 2025, of which 63% would be baseload and 37% peak and intermediate. (OPA, 2005: Vol. 2, 171). This represents an increase of 17% from the 2005 installed capacity of 30,662 MW, but the task is much larger than that percentage suggests. Ontario plans to phase out 6,434 MW of coal-fired generation and must either retire or refurbish 10,882 MW of nuclear generation by 2025 (116, 140). The study developed five pairs of portfolios of generating plants. A Portfolio Screening Model developed by Navigant Consulting was used to simulate the operation of the Ontario power system over the period 2006-2025. "Simulation involves the selection of supply resources, hour-by-hour for the 20 year period, based on the marginal cost of the available resources. Simulations were used for sensitivity analysis, as well as for the examination of alternative scenarios, and to produce probability distributions of key variables" (OPA, 2005: Vol. 2, 180).

Of the five scenarios, this paper shall report Scenario 1, which is a base case inasmuch as it "illustrates a future in which all expected procurements, new renewable and conservation resources, and out-of-province purchases materialize" (OPA, 2005: Vol. 2: 254). Scenario 1 compares the cost of a portfolio that relies significantly on nuclear for baseload, with a portfolio in which aging nuclear plants are replaced by natural gas generation. In Scenario 1, Portfolio 1A, most of Ontario's nuclear units, with the exception of two at Pickering, are refurbished or replaced with new nuclear plants as they reach the end of their service lives between 2013 and 2025. Ontario's coal-fired plants are removed from service and replaced by 2009. In Scenario 1, Portfolio 1B, nuclear units are retired as they reach the end of their service lives, leaving only Bruce A Units 1-4 and one unit at Pickering in operation by 2025. The retired nuclear capacity is replaced by approximately 9,300 MW of natural gas-fired generation and approximately 500 MW of coal gasification. The composition of the portfolio is otherwise the same as Portfolio 1A; for example, all coal plants are taken out of service by 2009. Table 4 presents the capacity that was in place in 2005 when the study was written and snapshots at five-year intervals of the evolution of Portfolios 1A and 1B from their common 2005 starting point until 2025. By 2025, Portfolio 1A has 29% nuclear capacity and 28% gas, while Portfolio 1B has

Table 4: Ontario - Installed Capacity (MW) to 2025 under Scenario 1
Portfolio 1A (Nuclear renewed) and Portfolio 2B (Nuclear retired)

Year	2005	2010	2015	2020	2025
	Actual	Portfolio 1A			
Conservation & Demand Management	n/a	1,551	2,073	2,288	2,098
Renewables including hydro	7,756	10,680	12,685	14,635	16,465
Natural gas & oil	4,976	10,802	11,142	12,322	12,462
Coal gasification	0	0	0	250	250
Nuclear	11,397	12,127	11,017	10,338	12,897
Coal	6,434	0	0	0	0
Other	99	n/a	n/a	n/a	n/a
Total	30,622	35,161	36,918	39,834	44,173
	Actual	Portfolio 1B			
Conservation & Demand Management	n/a	1,551	2,073	2,288	2,098
Renewables including hydro	7,756	10,680	12,685	14,635	16,465
Natural gas & oil	4,976	10,802	11,392	17,672	20,762
Coal gasification	0	0	0	250	750
Nuclear	11,397	12,127	9,985	5,832	3,555
Coal	6,434	0	0	0	0
Other	99	n/a	n/a	n/a	n/a
Total	30,622	35,161	36,136	40,678	43,631

Source: OPA, 2005: Vol. 2, 116, 260, 266.

8% nuclear and 47% gas. (At the beginning, in 2005, nuclear capacity is 37% of both portfolios.)

Sensitivity studies were run for each portfolio to assess costs and risks. Revenues and cash flows were estimated using the Portfolio Screening Model and discounted at 5% to present values (Ibid., 320). Table 5 compares the estimated costs of the two portfolios.

The portfolio that would be 29% nuclear (installed capacity) in 2025 was estimated to cost $157 billion, discounted to the present, which is less, by $2 billion or 1.3%, than the portfolio that would be 8% nuclear. The cost advantage of Portfolio 1A widened to $4 billion after the OPA used Monte Carlo simulations to assess risks around costs, because the volatility of the natural gas price had more impact on Portfolio 1B, which relies more on natural gas generation (Ibid., 326-7). After performing analogous simulations with the other four pairs of portfolios, OPA concluded that there were economic and environmental advantages to a diverse generating portfolio that included nuclear:

The analysis of the five scenarios, and

Table 5: Present Value (C$ Billions) of Cash Flow Components of Cost under Scenario 1
Portfolio 1A (Nuclear renewed) and Portfolio 2B (Nuclear retired)

	Portfolio 1A	Portfolio 1B
Costs charged after 2025	71	75
Capital charged to 2025 and earlier years	20	18
Fuel & variable operating, maintenance, & administration costs (OM&A)	28	35
Fixed OM&A	34	29
Conservation & Demand Management	3	3
Total Present Value of Cost	157	159

Source: OPA, 2005: Vol. 2, 323.

> sensitivities around them, confirms the merits of a diversified and flexible portfolio including conservation, nuclear generation for base load, natural gas-fired generation for selected uses such as peaking, and renewables for energy production. This analysis suggests, at a minimum, keeping nuclear capacity at its current level through refurbishments and "new-build," and adopting a "smart gas" strategy that takes advantage of the attractive features of natural gas while minimizing price risk. Adding renewables to the extent that is economically achievable will reduce environmental impact and risk. (366)

Would this conclusion be warranted at a higher discount rate-one that reflected commercial risk? At 5%, the present value of the total capital expenditures for Portfolio 1A (nuclear renewed) is $42.7 billion, higher than the $36.9 billion for Portfolio 1B (nuclear retired; 322). At a higher weighted average cost of capital, say, 11.5%, I would expect the cost of the more capital-intensive portfolio to increase more than the other, narrowing the gap between the total costs of the two portfolios. When the total costs of two portfolios are similar, investors are likely attracted to the option that requires less investment up front and offers more flexibility to adapt to changing market conditions. That would be Portfolio 1B, which retires nuclear plants instead of replacing them. The NEA and IEA, in their study Projected Costs of Generating Electricity described the value of flexibility in the following words:

> The introduction of liberalisation in energy markets is removing the regulatory risk shield. Investors now have additional risks to consider and manage. For example, generators are no longer guaranteed the ability to recover all costs from power consumers. Nor is the future power price level known. Investors now have to internalise these risks into their investment decision making. This adds to the required rates of return and shortens the time frame that investors require to recover the capital. . . .
>
> When the level of the electricity price becomes uncertain it is of relatively greater value to be flexible. It is more important to commit capital only when needed. The flexibility of being able to build smaller plants and adjust them in smaller incremental steps is valuable. The flexibility of being able to adjust quickly with short construction times is of value. Prices in an electricity market tend to be volatile in response to the inherent volatility of electricity. There is a significant value of being able to adjust the production easily to the prices in the market. A minimum of capital commitment also makes the profitability less exposed to lower utilisation that may result from volatile prices. With its short construction time, modularity and low capital commitment, CCGT has been a preferred technology in many markets due to its flexibility. (NEA/IEA, 2005: 74)

I interpret the results of Ontario's Portfolio Screening Model as making a case that nuclear power is economic as part of a diverse portfolio of generating plants in a public power environment assuming a 5% social interest rate applies. The results do not make the case that nuclear power would be financially attractive to private capital as an equity investment when the annual return on the Toronto stock index has averaged 9.2% over the past 20 years.

Conclusions about Economics

Based on the studies and industry history reported above, the following conclusions appear reasonable:

1. The economics of nuclear plants vary from one country to another, depending upon energy resource endowments, government policies, and other factors that are country-specific.
2. Existing nuclear plants are economic and attractive to investors, as evidenced by the money the investors continue to put in for the purpose of increasing output and extending operating life. In the US and Canada this is particularly true of plants that have been relieved of some of their original debt through write-downs, ownership changes, or transfer of debt to separate entities. Worldwide there are about 435 nuclear reactors in service, generating 16% of the world's electricity.
3. The economics of new nuclear plants vary inversely with interest rates and improve as natural gas prices rise and become more volatile.
4. New nuclear plant projects to produce electricity for general distribution would be economic at social discount rates of 5% in some countries, according to levelized cost models, but there is no evidence they would be financially attractive to private sector equity investors in competitive electricity markets absent incentives such as those the US Energy Policy Act of 2005 provides, as shall be outlined below. (Note: The analyses reviewed for this paper did not cover the

economics of nuclear plants producing electricity for their owners' industrial processes, such as the EPR being constructed in Finland.)

Issues for Future Consideration

In the US, natural gas has been the "fuel of choice" for the majority of new generating units since the late 1990s. From 1999 to 2006, gas fired power plant capacity increased 99%, reaching 39.4% of net US generating capacity (EIA 2007c). Natural gas demand is forecast to grow by about 1.3% per year through 2010 due mostly to increased demand from electricity generators (Navigant, 2005: 11). Compared to uranium, natural gas has more uses in society (home heating, petrochemicals), may be more limited in long-term supply, and appears more subject to price volatility. The methane that constitutes 97% of natural gas and the carbon dioxide created by the combustion of natural gas are greenhouse gases. Such concerns motivate the search for energy policies to improve the economics of nuclear and its financial attractiveness for investors. Possible policies include carbon taxes and subsidies for FOAK plants. These issues are likely to receive increasing consideration in the future.

Is Nuclear Power Low Carbon?

Implementation of anticipated climate change policies is expected to require significant action by the electricity industry, which was responsible for 40% of global CO2 emissions in 2003. Of this, 70% was from coal-fired plants, 20% from natural gas fired plants, and 10% from oil-fuelled generation. (Australian Uranium Association, 2007: 89, attributed to International Energy Authority, 2006, Energy Technology Perspectives). Nuclear power's claim to be a low-carbon method of electricity generation has been questioned. Although nuclear generation itself does not release greenhouse gases, other necessary steps such as uranium mining and nuclear power plant construction do. Life cycle assessments of nuclear power and other technologies for generating electricity have been performed. A life cycle assessment evaluates, to the extent data are available, the environmental effects at each stage in electricity production, including resource extraction, processing, transport, construction, operation, and decommissioning. In November 2006, the Integrated Sustainability Analysis group at the University of Sydney produced a life cycle study for the Australian Government. Table 6 presents the comparison of the greenhouse gas intensity of various methods of generating electricity, ranked in ascending order.

The results show that nuclear power is a low-carbon technology and differentiate it clearly from fossil-fuelled generation. The study used data specific to Australia. For example, assuming that nuclear fuel originating as uranium in an Australian mine was transported overseas for conversion and enrichment before being returned to Australia for use in a reactor, the study estimated the CO2 emitted by that international journey (168). The results, nonetheless, correspond to the results of life-cycle assessments done elsewhere. For example, OPA retained SENES Consultants in 2005 for a life-cycle evaluation of greenhouse gas emissions and other environmental impacts of electricity generation. The study confirmed nuclear power to be low carbon, placing it in the same

Table 6: Greenhouse gas intensity of Electricity Generation Options in Australia (grams of CO2-equivalent/kWh)

Electricity Technology	Greenhouse Gas Intensity	
	Estimate	Likely Range
Hydro (run-of-river)	15	6.5 - 44
Wind turbine	21	13 - 40
Light water reactor (reference plant is APR 1400)	60	10 - 130
Heavy water reactor	65	10 - 120
Photovoltaics	106	53 - 217
Combined cycle natural gas	577	491 - 655
Natural gas (open cycle)	751	627 - 891
Black coal (supercritical)	863	774 - 1046
Black coal (new subcritical)	941	843 - 1171
Brown coal (new subcritical)	1175	1011 - 1506

Source: ISA, 2006: 8.

Table 7: United States - Levelized Costs with Carbon Taxes, 2003 MIT Study
Real (2002 US$) Levelized Costs in Cents/kWh

Assumptions: Same as Table 2 plus carbon taxes

	LUEC		
Carbon Tax Cases	$50/tC	$100/tC	$200/tC
Pulverized Coal	5.4	6.6	9.0
CCGT - low gas prices, US$3.77/Mcf	4.3	4.8	5.9
CCGT - moderate gas prices, US$4.42/Mcf	4.7	5.2	6.2
CCGT - high gas prices, US$6.72/Mcf	6.1	6.7	7.7
Nuclear. Costs unchanged from Table 2.	6.7	6.7	6.7

Reduced Nuclear Cost Cases. Effects on LUEC accumulate going down the list.	
• 25% reduction in construction cost	5.5
• Construction time shortened from 5 to 4 years	5.3
• O&M reduced from 1.5cents/kWh to 1.3cents/kWh	5.1
• Cost of capital reduced to be equivalent to coal and CCGT	4.2

(MIT, 2003: 42)

category as hydro, wind, biomass, and photovoltaics (OPA, 2005: Vol. 2, 173-76).

Climate Change Levy

A December 2006 Australian government report estimated that adding a price for carbon emissions in the range of Australian dollars (A$)15-40/tCO2 to the price of fossil fuel-based generation would make nuclear power competitive with conventional coal-fired electricity in Australia (Australia, 2006: 55). Without a charge for CO2 emissions, nuclear power probably would cost 20-50% more than power from a new coal-fired plant at current fossil-fuel prices in Australia (Australia, 2006: 2). The UK government's 2007 consultation document on nuclear power estimated that an average carbon price of °25/tCO2 would raise the levelized cost of gas- and coal-fired generation to £44/MWh in the UK, making nuclear power the form of generation with the lowest levelized cost (UKDTI, 2007c: 72). The UK paper takes the argument further by considering the welfare benefit of nuclear generation. The theory is that the CO2 emissions avoided by adding a nuclear power plant would benefit society by reducing the costs the rest of the economy incurs to meet a carbon reduction target (2007b: 27). If the avoided CO2 emissions are valued at a carbon price, even a price as low as °10/tCO2, the benefits of nuclear power outweigh the cost disadvantage against gas-fired generation in the central nuclear cost/central gas price case (2007c: 73).

MIT modelled the impact on nuclear power's competitiveness of hypothetical government constraints on carbon dioxide (CO2) emissions. The MIT analysts recalculated the levelized costs of fossil-fuel generation (reported in Table 2) to reflect three carbon tax rates: $50, $100, and $200 per ton of carbon (tC). $50/tC was consistent with a US Environmental Protection Agency (EPA) estimate of the cost of reducing US CO2 emissions by about 1 billion tons per year. The $100/tC and $200/tC values bracketed the range of estimates of the costs of carbon sequestration. The results are presented in Table 7.

With the carbon tax rate at $50/tC, nuclear is not competitive in the base case (for nuclear cost). If all the nuclear cost reductions can be achieved, nuclear costs 4.2 cents/kWh, giving it a cost advantage over coal (5.4 cents/kWh) and CCGT in the moderate (4.7 cents/kWh) and high (6.1 cents/kWh) gas price cases. With the carbon tax rate at $100/tC, nuclear in the base case is still not competitive with coal, but nuclear power improves at higher carbon-tax rates and with reductions in the costs of nuclear power.

Policies to Improve the Economics of Nuclear Power

Appreciating the carbon-free nature of nuclear power, the MIT team urged three government actions to improve its economic viability: government cost sharing with industry on selected regulatory requirements; recognition of nuclear power as "carbon-free" and eligible for inclusion in any mandatory renewable energy portfolio standard; and a production tax credit of up to $200 per kW of the construction cost of up to 10 "first mover" plants, to be paid out at about 1.7 cents per kWh, over 18 months of full-power plant operation. The credit of 1.7 cents per kWh is equivalent to a credit of $70 per avoided metric ton of carbon if the electricity were to have come from coal plants (or $160 per avoided metric ton of carbon if the electricity were to have come from natural gas plants; 2003: 8). All three actions would assist the nuclear industry to overcome impediments it has blamed for standing in the way of new builds in the United States. In particular, the production tax credit would challenge the industry to construct nuclear plants to prove its claim that experience building the initial units will bring the cost of subsequent ones down enough to be competitive.

The MIT recommendations possibly were part of the inspiration for provisions in the US Energy Policy Act of 2005 to encourage construction of "advanced nuclear facilities" defined as nuclear power plants built to designs approved by the NRC after 31 December 1993. One incentive is "standby support" to cover cost overruns due to regulatory delays. The support is capped at $500 million for each of the first two new builds and half of the overruns caused by regulatory delays for the next four reactors (up to $250 million each; EPA, 2005: Section 638). Another incentive is a production tax credit of 1.8 cents per kWh for the first eight years of operation, subject to a $125 million annual limit per 1000 MW of "national megawatt capacity" allocated to the facility. (A maximum of 6,000 MW of new nuclear plant capacity is eligible for the tax credit. The Secretary of the Treasury will allocate this national megawatt capacity among the advanced nuclear facilities that are built (Ibid., Section 1306).

The number and quality of COL applications to take advantage of these incentives and the NRC's actions on these applications will provide a clearer picture of the likelihood of new builds in the United States. The NRC received the first application in 2007, and as of 11 October 2007, it expects to receive five more for a total of nine nuclear power units in 2007, and another 14 applications for 20 units in 2008 (NRC, 2007b). In Ontario, the province has engaged McKinsey & Company to assess nuclear technology options and economic considerations (Ontario Ministry of Energy, 2007). The report was expected to be completed later in 2007 and may give clues to the likelihood of new builds in Ontario.

Conclusion

The economics of nuclear plants vary from one country to another, depending upon energy resource endowments, government policies, and other factors that are country specific. Existing nuclear plants are economic and attractive to investors, as evidenced by the money investors continue to put in to increase output and extend operating life. The economics of new nuclear plants vary inversely with interest rates and improve as natural gas prices rise and become more volatile. New nuclear plant projects to produce electricity for general distribution would be economic at social discount rates of 5% in some countries, according to levelized cost models, but there is no evidence they would be financially attractive to private sector equity investors in competitive electricity markets without inducements such as the US Energy Policy Act of 2005. Some governments are considering incentives for construction of new nuclear plant designs in order to avoid greenhouse gas emissions and enhance energy security. The response to the US incentives will provide fresh evidence about the economics of nuclear power.

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