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The Economics of Nuclear Power

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BY STEVE THOMAS

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Introduction

The severe challenge posed by the need to reduce emissions of greenhouse gases, especially in the electricity generation sector, has led to renewed interest in the construction of new nuclear power plants. These would initially replace the ageing stock of existing reactors, then meet electricity demand growth, and eventually replace some of the fossil-fired electricity generating plants. In the longer term, the promise is that a new generation of nuclear power plants could be used to manufacture hydrogen, which would replace the use of hydrocarbons in road vehicles.

The public is likely to be understandably confused about whether nuclear power really is a cheap source of electricity. In recent years, there have been a large number of apparently authoritative studies showing nuclear economics in a good light and most utilities seem determined to run their existing plants for as long as possible. Yet utilities are clearly reluctant to build new nuclear power plants without cost and market guarantees and subsidies. Some of this apparent paradox is relatively easily explained by the difference between the running costs only of nuclear power, which is usually seen as relatively low, and the overall cost of nuclear power—including repayment of the construction cost—which is substantially higher. Thus, once a nuclear power plant has been built, it may make economic sense to keep the plant in service even if the overall cost of generation, including the construction cost, is higher than the alternatives. The cost of building the plant is a “sunk” cost that cannot be recovered and the marginal cost of generating an additional kilowatt-hour (kWh) could be small. However, much of the difference between the economics of existing plants and the forecasts for future plants is explained by detailed differences in assumptions on, for example, operating performance and running costs, which are not readily apparent in the headline figures.

The objective of this chapter is to identify the key economic parameters commenting on their determining factors and to review the assumptions of main forecasts from the past five years to identify how and why these forecasts differ. It will also identify what guarantees and subsidies the government might have to take to allow nuclear plants to be ordered.

1 The world market for nuclear plants: existing orders and prospects

During the past year, there has been increased publicity about an apparent international revival in nuclear ordering, especially in the Pacific Rim countries. The list of plants currently on order (see table 2) suggests this revival is overstated. In October 2005, there were 22 plants under construction worldwide with a total capacity of 17 gigawatts (GW), compared to 441 plants already in service with a total capacity of 368GW (see table 1). Of the units under construction, 16 use Indian, Russian, or Chinese technology—designs that would be highly unlikely to be considered in the West. For 6 of the plants, construction started before 1990 and there must be doubts about whether these plants will be completed. In addition, the units under construction in Taiwan, ordered in 1996 when completion was expected in 2004, have slipped by six years. The Western vendors active in Europe—Westinghouse and Areva—have just one order between them: Areva's Olkiluoto order for Finland.

China is frequently mentioned as a likely source of a large number of nuclear orders. It has forecast it will build a further 30 units by 2020. But for more than twenty-five years, China has been forecasting imminent orders but it has ordered only 11 units in that time, 3 of which were small, locally supplied plants. The most likely outcome for China, given the need for China to use its limited capital resources carefully, is that it will continue to place a small number of nuclear orders on the international market—much fewer than forecast by the Chinese government or by the nuclear industry—while trying to build up its capability through its own nuclear power plant supply industry.

India ordered plants from Western suppliers in the 1960s, but a nuclear weapons test in 1975 using material produced in a Canadian research reactor led to the cutting of all contact with Western suppliers. India has continued to build plants using a 1960s Canadian design. These have a poor record of reliability and frequently take much longer to build than forecast, so the completion dates in table 2 should be treated with skepticism. The United States also broke off cooperation in 1998 after further weapons tests but in 2005, India and the United States were negotiating a deal over technological cooperation in civil nuclear power. Canada also resumed sales of nuclear material in 2005. When or if this will lead to new nuclear orders from Western suppliers remains to be seen.

Table 1. Nuclear capacity in operation and under construction

Country	Operating plants: capacity MW (no of units)	Plants under construction: capacity MW (no of units)	% of electricity nuclear (2004)	Technologies	Suppliers
Argentina	935 (2)	-	9	HWR	Siemens AECL
Armenia	376 (1)	-	35	WWER	Russia
Belgium	5728 (7)	-	55	PWR	Framatome
Brazil	1901 (2)	-	4	PWR	Westinghouse Siemens
Bulgaria	2722 (4)	-	38	WWER	Russia
Canada	12599 (18)	-	12	HWR	AECL
China	6587 (9)	2000 (2)	?	PWR, HWR, WWER	Framatome, AECL, China, Russia
Taiwan	4884 (6)	2600 (2)	?	PWR, BWR	GE, Framatome
Czech Rep	3472 (6)	-	31	WWER	Russia
Finland	2656 (4)	1600 (1)	27	WWER, BWR, PWR	Russia, Asea, Westinghouse
France	63473 (59)	-	78	PWR	Framatome
Germany	20303 (17)	-	28	PWR, BWR	Siemens
Hungary	1755 (4)	-	33	WWER	Russia
India	2983 (15)	3638 (8)	3	HWR, FBR, WWER	AECL, India, Russia
Iran	-	915 (1)	-	WWER	Russia
Japan	47646 (55)	1933 (2)	25	BWR, PWR	Hitachi, Toshiba, Mitsubishi
S. Korea	16840 (20)	-	40	PWR, HWR	Westinghouse, AECL, Korea
Lithuania	1185 (1)	-	80	RBMK	Russia
Mexico	1310 (2)	-	5	BWR	GE
Netherlands	452 (1)	-	4	PWR	Siemens
Pakistan	425 (2)	300 (1)	2	HWR, PWR	Canada, China
Romania	655 (1)	655 (1)	9	HWR	AECL
Russia	21743 (31)	3775 (4)	17	WWER, RBMK	Russia
Slovak Rep	2472 (6)	-	57	WWER	Russia
Slovenia	676 (1)	-	40	PWR	Westinghouse
S. Africa	1842 (2)	-	6	PWR	Framatome
Spain	7584 (9)	-	24	PWR, BWR	Westinghouse, GE Siemens
Sweden	8844 (10)	-	50	PWR, BWR	Westinghouse, Asea
Switzerland	3220 (5)	-	40	PWR, BWR	Westinghouse, GE Siemens
Ukraine	13168 (15)	-	46	WWER	Russia
Un. Kgdom.	11852 (23)	-	24	GCR, PWR	UK, Westinghouse
Un. States	97587 (103)	-	20	PWR, BWR	Westinghouse, B&W, CE, GE
WORLD	**367875 (441)**	**19210 (24)**	**16**		

Source: World Nuclear Association (http://www.world-nuclear.org/info/reactors.htm)

Notes: 1. Plants under construction does not include plants on which construction has stalled.
2. Technologies are: PWR: Pressurized Water Reactor. BWR: Boiling Water Reactor. HWR: Heavy Water Reactor (including Candu). WWER: Russian PWR. RBMK: Russian design using graphite and water. FBR: Fast Breeder Reactor. GCR: Gas-Cooled Reactor
3. Figures for Canada do not include two units with total capacity 1561MW, which were closed in the 1990s but which it was decided in October 2005 would be refurbished in preparation for reopening.

Table 2. Nuclear Power Plants under construction worldwide

Country	Site	Reactor type	Vendor	Size MW	Construction start	Construction stage (%)	Expected operation
China	Tianwan 1	WWER	Russia	1000	1999	70	2006
China	Tianwan 2	WWER	Russia	1000	2000	100	2006
Taiwan	Lungmen 1	ABWR	GE	1300	1999	57	2009
Taiwan	Lungmen 2	ABWR	GE	1300	1999	57	2010
Finland	Olkiluoto 3	EPR	Areva	1600	2005	-	2009
India	Kaiga 3	Candu	India	202	2002	45	2007
India	Kaiga 4	Candu	India	202	2002	28	2007
India	Kudankulam 1	WWER	Russia	917	2002	40	2008
India	Kudankulam 2	WWER	Russia	917	2002	40	2008
India	Tarapur 3	Candu	India	490	2000	73	2007
India	PFBR	FBR	India	470	2005	0	?
India	Rajasthan 5	Candu	India	202	2002	34	2007
India	Rajasthan 6	Candu	India	202	2003	19	2007
Iran	Bushehr	WWER	Russia	915	1975	75	2006
Japan	Tomari 3	PWR	Mitsubishi	866	2004	28	2009
Japan	Higashi Dori 1	BWR	Toshiba	1067	2000	95	2005
Pakistan	Chasnupp 2	PWR	China	300	2005	-	2011
Romania	Cernavoda 2	Candu	AECL	655	1983	71	2007
Russia	Balakovo 5	WWER	Russia	950	1987	?	2010
Russia	Kursk 5	RBMK	Russia	925	1985	70	?
Russia	Kalinin 4	WWER	Russia	950	1986	?	2010
Russia	Volgodonsk 2	WWER	Russia	950	1983	?	2008
TOTAL				17480			

Sources: PRIS Data Base (http://www.iaea.org/programmes/a2/index.html), Nuclear News, World list of nuclear plants
Note: Plants marked * have achieved first criticality

Table 3. Nuclear power plants on which construction has been stopped

Country	Site	Tech	Vendor	Size MW net	Construction start	Construction %
Argentina	Atucha 2	Candu	AECL	692	1981	80
Brazil	Angra 3	PWR	Siemens	1275	1976	30
N. Korea	Kedo 1	PWR	S Korea	1000	1997	33
N. Korea	Kedo 2	PWR	S Korea	1000	1997	33
Romania	Cernavoda 3	Candu	AECL	655	1983	10
Romania	Cernavoda 4	Candu	AECL	655	1983	8
Romania	Cernavoda 5	Candu	AECL	655	1983	8
Slovakia	Mochovce 3	WWER	Russia	405	1983	50
Slovakia	Mochovce 4	WWER	Russia	405	1983	40
Ukraine	Khmelnitsky 3	WWER	Russia	950	1986	15
Ukraine	Khmelnitsky 4	WWER	Russia	950	1987	15
TOTAL				8642		

Sources: PRIS Data Base (http://www.iaea.org/programmes/a2/index.html), Nuclear News, world list of nuclear plants

Table 4. Possible orders in the next two to three years

Buyer	Site	Bidders	Need	Possible order date	Forecast completion
China	Sanmen	Areva (EPR), Westinghouse (AP1000), Russia (WWER-1000)	2x1000MW	2005/06	?
China	Yangjiang	Areva (EPR), Westinghouse (AP1000), Russia (WWER-1000)	2x1000MW	2005/06	?
France	Flamanville 3	Areva (EPR)	1x1600MW	2006	2012
Korea	Shin-Kori 1&2	Korea (KSNP)	2x1000MW	2005	2010, 2012
Korea	Shin-Kori 3&4	Korea (APR-1400)	2x1400MW	2006	2012, 2013
Japan	Tsuruga 3&4	Mitsubishi (APWR)	2x1500MW	2006	2014

Source: Various press reports

Japan is another country that has consistently forecast large increases in nuclear capacity which have not been matched by actual orders. Japanese companies supply these plants using technology licensed from Westinghouse and GE. It may take up to twenty years to get approval to build on sites in Japan, although once construction starts, completion is usually quick (four years typically) and does not usually overrun. A series of accidents at plants in Japan, often badly mishandled, have led to an increase in public concern about nuclear power, and finding sites for further plants is likely to be difficult.

Reliable information from Russia on the status of construction at nuclear plants is difficult to get and the plants listed here may not be actively being built. A particular doubt is the Kursk 5 plant, which uses the same technology as the Chernobyl plant.

Table 3 shows that there are eleven units on which construction started but has not been carried out thusfar. For these, the quoted degree of completion may be misleading. Plants reported to be less than 33 percent complete are likely to have seen only site preparation with no actual reactor construction.

Of the prospective orders over the next year or two (see table 4), China has said it expects to place these orders in 2005, but it would be no surprise if this timetable is not met. The units for Korea will use Korean technology (licensed from BNFL/Westinghouse). Construction start-time has slipped several times and substantive construction is not expected to start now until 2006 for units 1 and 2, and 2007 for units 3 and 4.

The Tsuruga units—the first expected orders for the APWR design—have also slipped by about six years from their original schedule. The Flamanville plant to be built in France cannot be ordered until after an independent committee appointed by the government has completed a public consultation exercise, the conclusion of which is unlikely to come before mid-2006.

1.1 US initiatives

The Bush administration has made a concerted effort to encourage a revival of nuclear ordering under its Nuclear Power 2010 program, launched in 2002. The program focuses on Generation III+ designs (see below). Under the program, the US Department of Energy expects to launch cooperative projects with industry:

> ".. to obtain NRC approval of three sites for construction of new nuclear power plants under the Early Site Permit (ESP) process, and to develop application prepara-

> tion guidance for the combined Construction and Operating License (COL) and to resolve generic COL regulatory issues. The COL process is a ‘one-step’ licensing process by which nuclear plant public health and safety concerns are resolved prior to commencement of construction, and NRC approves and issues a license to build and operate a new nuclear power plant.”[1]

A total of up to US$450 million in grants is expected to be available. Two main organizations have emerged to take advantage of these subsidies. Nustart, launched in 2004, comprises a consortium of eight US utilities including Constellation Energy, Entergy, Duke Power, Exelon, Florida Power & Light, Progress Energy, Southern Company, and the Tennessee Valley Authority (TVA, providing staff time not cash). The French utility EDF and the vendors Westinghouse and GE are also members but have no voting rights. Nustart plans to make two applications—one to build a GE ESBWR at Entergy’s Grand Gulf (Texas) site and one to build a Westinghouse AP-1000 at TVA’s Bellefonte site (see section 3 for more details on these designs).

The other main group is led by the utility Dominion. Dominion was seeking a COL for an advanced version of Atomic Energy of Canada’s CANDU design—the ACR-700—at North Anna (Virginia) where Dominion already operates two power reactors. However, in January 2005, it announced that it was replacing the ACR-700 with GE’s ESBWR mainly because of the expected time for a Candu plant to be licensed in the United States. A Candu design has not achieved regulatory approval in the United States and the NRC forecast that its approval process could take more than sixty months—much longer than would be required for a Generation III+ PWR or BWR.

A number of individual utilities have also announced their intention to investigate whether to apply for COLs to take advantage of federal subsidies. These include a number of members of Nustart operating independently, including TVA, Constellation, Entergy, Duke Power, Progress Energy, and Southern Company, plus South Carolina Electric & Gas. TVA asked the DOE to cover half of the cost (currently estimated at $4 million) of a feasibility study on the building of an Advanced Boiling Water Reactor (ABWR) at the utility’s Bellefonte site in Alabama. The other members of the TVA group are Toshiba, GE, Bechtel, USEC, and Global Nuclear Fuel-Americas. TVA’s feasibility study, released in September 2005, based on the construction of two GE ABWRs at Bellefonte, forecast that the plants could be built in forty months for $1,610/kW. This proposal appears now to be a lower priority than the Nustart initiative partly because the ABWRs would have been the only two of their kind in the United States and the ABWR appears to have been superceded by the ESBWR. Constellation Energy announced in September 2005 that it had formed a joint venture with the Areva Inc. and Bechtel Power to sell Areva’s EPR units in the United States. Entergy announced also in September 2005 that it would put together a COL application for its site.

Although both Nustart and the Dominion group intend to pursue the licensing process, all the way to issuance of a license, neither has committed to building a new plant, and no reactor orders have been placed. It remains unclear whether the utilities in the various initiatives are really committed to building new nuclear plants or whether they are just taking advantage of government subsidies in the hope that further subsidies for construction would be made available and that there would be market guarantees which

[1] http://www.ne.doe.gov/NucPwr2010/NucPwr2010.html

would mean new nuclear plants would not be exposed to any risk from wholesale electricity markets.

The initiatives by Nustart and Dominion are put in perspective by the CEO of Dominion, Thomas Capps. In May 2005, he stated:[2]

> "We aren't going to build a nuclear plant anytime soon. Standard & Poor's and Moody's would have a heart attack [referring to the debt-rating agencies]. And my chief financial officer would, too."

This reflects the reality that decisions on nuclear orders can only be taken with the implicit support of the financial community. No company would place a nuclear order if it was likely to lead to a significant increase in the cost of their borrowing or a significant fall in their share price.

[2] M. Wald, "Interest in Reactors Builds, But Industry Is Still Cautious," *New York Times,* April 30, 2005, p 19.

2 Current designs

The most relevant designs for orders to be placed in the next decade, particularly in the West, would appear to be so-called Generation III and Generation III+ designs, often called Advanced Reactors. The main distinction between Generation II plants and Generation III plants is that the latter incorporate a greater level of "passive" compared to engineered safety. For example, Generation III designs would rely less on engineered systems for emergency cooling and more on natural processes, such as convection. There are a large number of designs that have been announced, but many are not far advanced, do not have regulatory approval, and have limited prospects for ordering. There is no clear definition of what constitutes a Generation III design, apart from it being designed in the last fifteen years, but the main common features quoted by the nuclear industry are:

- A standardized design for each type to expedite licensing, reduce capital cost, and reduce construction time
- A simpler and more rugged design, making them easier to operate and less vulnerable to operational upsets
- Higher availability and longer operating life—typically sixty years
- Reduced possibility of core-melt accidents
- Minimal effect on the environment
- Higher burnup to reduce fuel use and the amount of waste
- Burnable absorbers ("poisons") to extend fuel life[3]

These characteristics are clearly very imprecise and do not define well what a Generation III plant is other than that the design was evolved from existing models of PWR, BWR, and Candu (see Appendix 2 for an account of the technologies and Appendix 3 for a list of the main vendors). The distinction between Generation III and III+ designs is even more unclear, with the US Department of Energy saying only that III+ designs offer advances in safety and economics over III designs. Until there is much more experience with Generation III and III+ plants, any figures on the generation cost of power from these designs should be treated with the utmost caution.

2.1 PWRs

2.1.1 EPR

The only Generation III or III+ PWR to be ordered yet is the Areva European Pressurized water Reactor (EPR) for the Olkiluoto site in Finland. The Finnish government issued a construction license in February 2005 and construction started in summer 2005. The EPR has also been bid for in orders from China, but the result of this tender had not been decided by October 2005. France intends to build at least one EPR and perhaps five successor units, but these plans are far from firm yet. The EPR received safety approval from the French authorities in September 2004 and from the Finnish authorities in January 2005. Areva has asked the US Nuclear Regulatory Commission (NRC)—in collaboration with Constellation Energy—under the Nuclear Power 2010 program to

[3] http://www.uic.com.au/nip16.htm

begin licensing of the EPR in the United States. For the US market, EPR will be an abbreviation for Evolutionary Power Reactor.

The EPR has an output of 1600 megawatts (MW) although this may be increased to 1700MW for orders after Olkiluoto and is expected to be built in fifty-seven months from laying of first concrete to commissioning. The design was developed from the previous Framatome design, N4, with some input from Siemens' previous design, the "Konvoi" plant. A reduction in the refueling time is expected to allow a load factor[4] of about 90 percent.

The Finnish buyers, TVO, have chosen not to publish a detailed breakdown of the construction cost, but the order is described as "turnkey" and company officials stated the cost was about €3 billion. Assuming an output of 1600MW, this represents a cost of about €1,875/kW.[5] However, this cost includes interest charges and decommissioning charges which are not conventionally included in comparisons of nuclear construction costs. The Olkiluoto order is widely seen as a special case and it has been suggested that Areva has offered a price that might not be sustainable to ensure that their new technology is demonstrated, while the buyer, TVO, is not a normal electric utility. TVO is a company owned by large Finnish industry that supplies electricity to its owners on a not-for-profit basis. The plant will have a guaranteed market and will not therefore have to compete in the Nordic electricity market, although if the cost of power is high compared to the market price, the owners will lose money. The real cost of capital for the plant is only 5 percent per annum.[6]

The French utility EDF has not said how much it expects to pay for the Flamanville plant. However, Areva has stated that it would expects an EPR supplied to the US market to cost between US$1,600 and 2,000/kW (not including interest during construction and decommissioning charges). These figure were being described by Areva as not "completely finished," but the US$2,000/kW is a little below the total figure quoted for Olkiluoto.[7]

It is worth noting that while the operating reliability of the "Konvoi" plants has been outstanding, that of the N4 plants is much poorer. The first unit, Chooz B1, began generating in 1996 but suffered serious teething problems and in the next four years, its average load factor was less than 40 percent. Since then, reliability has been much better and load factor has averaged 75 percent. The other three units of this design followed a similar pattern of three to four years of very poor performance (typical average load factor of about 40 percent) followed by reasonable reliability (average load factor of about 75 percent). The N4 design was said to have been built upon the experience of the sixty PWRs built in France and this illustrates that it cannot be assumed that new designs, such as EPR, will be reliable just because they build on past experience.

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[4] Annual (or lifetime) load factor is calculated as the annual (or lifetime) output of the plant as a percentage of the output the plant would have produced if it had operated continuously at full power and is a good measure of the reliability of the plant.

[5] Conversions from € to US$ are made assuming an exchange rate of €1=US$1.2 and from £ to US$ assuming £1=US$1.8.

[6] A complaint to the European Commission by the European Renewable Energies Federation was made in December 2004 that the Olkiluoto plant would receive illegal state aid. This complaint had not been ruled on by October 2005.

[7] *Nucleonics Week*, September 22, 2005, p 12.

2.1.2 AP-1000

The AP-1000 (Advanced Passive) was designed by Westinghouse and was developed from the AP-600 design. The rationale for the AP-600 was to increase reliance on passive safety and also that scale economies (from building larger units as opposed to building larger numbers) had been overestimated. An executive of Westinghouse justified the choice of a unit size of 600MW rather than 1000–1300MW by stating that "the economies of scale are no longer operative."[8] The AP-600 went through the US regulatory process and was given safety approval in 1999. By then, it was clear that the design would not be economical and the AP-600 was never offered in tenders. Its size was increased to about 1150MW in the hope that scale economies would make the design competitive. In September 2004, the US Nuclear Regulatory Commission (NRC) granted a Final Design Approval (FDA), valid for five years, to Westinghouse for the AP1000. The NRC anticipates issuing a standard Design Certification, valid for fifteen years before December 2005. AP-1000 has so far been offered in only one call for tenders, the current call for four Generation III units for China, which had not yet been awarded in July 2005.

The AP-1000's modular design is expected to allow it to be built in thirty-six months at a cost of $1,200/kW. However, until details of actual bid costs are available and until units are built, these figures should be treated with skepticism.

2.1.3 System 80+/APR-1400

Combustion Engineering's System 80+ design received regulatory approval in the United States in 1997 when Combustion Engineering was owned by Asea Brown Boveri (ABB). ABB (including Combustion Engineering nuclear division) was subsequently taken over by British Nuclear Fuel Limited (BNFL) and was absorbed into the Westinghouse division and the System 80+ is not being offered for sale by Westinghouse. However, the Korean vendor, Doosan, has used this design under license from Westinghouse to develop its APR-1400, which is expected to be ordered for Korea in the next year or two. Korea did try to offer the design for the current tender for Generation III plants for China but it was rejected. It seems unlikely that the APR-1400 will be offered in Western markets.

2.1.4 APWR

Development of the Advanced PWR (APWR) by Mitsubishi and its technology licensor, Westinghouse, was launched at about the same time as the ABWR about fifteen years ago but ordering has fallen far behind that of the ABWR and first orders are not expected until about 2007. It is not clear whether the APWR will be offered in the West. Mitsubishi has never tried to win orders in the West and Westinghouse is concentrating its efforts on the AP-1000.

2.1.5 AES-91 WWER-1000

This is the latest Russian design offered by Atomstroyexport and was one of three designs short-listed for Olkiluoto. Finland has two earlier generation WWERs (at Loviisa) and because of its geopolitical position and previous experience with WWER technol-

[8] *Nucleonics Week Special Report,* "Outlook on advanced reactors," March 30, 1989, p 3.

ogy, Finland considered the latest Russian design. It has also been bid for those orders expected to be placed for four units for China in 2005/06. How far it can be categorized as a Generation III plant is not clear and it seems unlikely it would be considered for any Western market other than Finland.

2.2 BWRs

2.2.1 ABWR

The ABWR was developed in Japan by Hitachi and Toshiba and their US technology licensor, General Electric (GE). The first two orders were placed around 1992 and completed in 1996/97. By mid-2005, there were three ABWRs in service and one under construction in Japan and two under construction in Taiwan. Total construction costs for the first two Japanese units were reported to be $3,236 per kilowatt for the first unit in 1997 dollars and estimated to be about $2,800 per kilowatt for the second. These costs are well above the forecast range.[9] The ABWR received safety approval in the United States in 1997, but may now be considered not advanced enough for orders in the West.

2.2.2 ESBWR

The Economic & Simplified BWR (ESBWR) is a 1500MW design developed by GE. In October 2005, GE applied to the NRC for certification of the ESBWR design. The ESBWR has been developed in part from GE's Simplified Boiling Water Reactor (SBWR) and the ABWR. The SBWR began the process of getting regulatory approval in the 1990s but was withdrawn before the procedure was complete and did not win any orders. GE hopes to gain FDA for the ESBWR by the end of 2006 with certification following about a year later. The NRC had not forecast a completion date by October 2005.

2.2.3 Other BWRs

A number of other designs have been developed, but none has received regulatory approval anywhere and only the SWR has been offered for sale. The main BWR designs include:

- The SWR: a 1000–1290MW design developed by Areva. This was one of the three designs short-listed for Olkiluoto.
- The BWR-90+: a 1500MW design developed by Westinghouse from the Asea BWR design.

2.3 Candus

The Advanced Candu Reactor (ACR) is being developed in two sizes: ACR-700 (750MW) and ACR-1000 (1100-1200MW). The ACR-700 was being reviewed by the US NRC under the sponsorship of the US utility Dominion, but Dominion withdrew its support in January 2005, opting instead for GE's ESBWR, citing the long time-scale of at least five years that NRC said would be needed for the review because of the lack of experience in the United States with Candu technology. Efforts to license the ACR in the United States are continuing but at a slower pace. As a result of Dominion's deci-

[9] K. Hart, "World's First Advanced BWR Could Generate Electricity Next Week," *Nucleonics Week,* January 25, 1996, p. 1.

sion to drop the ACR-700 as its reference design, AECL says it will concentrate on the ACR-1000.

2.4 HTGRs

It is not clear whether the HTGRs under development should be categorized as Generation III or IV plants. The Pebble Bed Modular Reactor (PBMR) is based on designs developed by Siemens and ABB for Germany, but abandoned after poor experience with a demonstration plant. It is now being developed by South African interests. The various takeovers and mergers in the reactor vending business mean that the technology license providers are now Areva (for Siemens) and Westinghouse (for ABB). The technology is being developed by the PBMR Co., which had as partners Eskom, the South African publicly owned electric utility, BNFL, and a US utility, Exelon, as well as other South African interests. The project was first publicized in 1998 when it was expected that first commercial orders could be placed in 2003. However, greater than anticipated problems in completing the design, the withdrawal of Exelon, and uncertainties about the commitment of other partners, including Westinghouse, has meant that the project time-scale has slipped dramatically and first commercial orders cannot now be made before 2012 even if there is no further slippage.

Chinese interests are also developing similar technology with the same technological roots, and while optimistic statements have been made about development there, the Chinese government seems to be backing development of PWRs and perhaps BWRs.

3 Key determinants of nuclear economics

There are several important determinants of the cost of electricity generated by a nuclear power plant. Some of these are intuitively clear whilst others are less obvious. The usual rule of thumb for nuclear power is that about two-thirds of the generation cost is accounted for by fixed costs—that is, costs that will be incurred whether or not the plant is operated—and the rest by running costs. The main fixed costs are the cost of paying interest on the loans and repaying the capital, but the decommissioning cost is also included. The main running cost is the cost of operation, maintenance and repair, rather than fuel. However, as is shown below, there is a huge degree of variance in the assumptions made for these parameters from forecast to forecast, so the broad split between fixed and variable costs should just be seen as indicative.

It should be noted that these forecasts were carried out over a five year period and were denominated in various currencies. The impact of inflation—for example a 2.5 percent inflation rate would inflate costs by 13 percent over five years—and currency fluctuations—for example, since 2000, the dollar-pound exchange rate has fluctuated between £1=$1.40 and £1=$1.93—means that any comparisons have a significant margin for error.

3.1 Construction cost and time

Construction cost is the most widely debated parameter, although other parameters, such as the cost of capital and the operating performance, are of comparable importance to the overall cost. There are a number of factors that explain why there is such controversy about forecasts of construction cost.

3.1.1 Unreliability of data

Many of the quoted construction cost forecasts should be treated with skepticism. The most reliable indicator of future costs has often been past costs. However, most utilities are not required to publish properly audited construction costs, and have little incentive to present their performance in anything other than a good light. US utilities were required to publish reliable accounts of the construction costs of their nuclear plants for the economic regulator (who only allowed cost recovery from consumers for properly audited costs). The cost of the Sizewell B plant is also reasonably well documented because the company building it had few other activities in which the construction cost could be "disguised."

Even where the costs are reliably established, there can be disputes about why the costs were that level. For example, according to the PIU report,[10] the cost of Sizewell B was 35 percent higher in real terms than the price quoted in 1987 when it was ordered. However, of the final cost of about $5,400/kW, British Energy claims £750/kW (25 percent) was first-of-a-kind costs. Bid prices by vendors are also realistic, although equipment purchases may only represent less than half of the total cost (civil engineering and installation are generally a larger proportion). Contract prices may also be subject to escalation clauses which means the final price is significantly higher and therefore bids have limited value.

[10] Performance and Innovation Unit (2002) "The economics of nuclear power," Cabinet Office, London.

Prices quoted by those with a vested interest in the technology, such as promotional bodies, plant vendors (when not tied to a specific order), and utilities committed to nuclear power, clearly must be viewed with skepticism. Prices quoted by international agencies, such as the Nuclear Energy Agency, also must be treated with care, particularly when they are based on indicative rather than real costs. Generally, these costs are provided by national governments, who may have their own reasons to show nuclear power in a good light, and who generally do not base their figures on actual experience.

Capital charges are normally expected to be the largest element of the unit cost of power from a nuclear power plant. The construction cost is therefore crucial in determining the cost of power from a nuclear power plant. Conventionally, quoted construction costs include the cost of the first charge of fuel but do not include the interest incurred on borrowings during the construction of the plant, usually known as interest during construction (IDC). To allow comparisons between reactors with different output capacities, costs are often quoted as a cost per installed kW. Thus, a nuclear power plant with an output rating of 1200MW, quoted as costing £2,000/kW would have a total construction cost of £2,400 million.

Forecasts of construction costs have been notoriously inaccurate, frequently being a serious underestimate of actual costs and—counter to experience with most technologies where so-called "learning," scale economies, and technical progress have resulted in reductions in the real cost of successive generations of technology—real construction costs have not fallen and have tended to increase through time.

There is also some inevitable variability from country to country regarding local labor costs and the cost of raw materials such as steel and concrete.

3.1.2 Difficulties of forecasting

There are a number of factors that make forecasting construction costs difficult. First, all nuclear power plants currently on offer require a large amount of on-site engineering, the cost of which might account for about 60 percent of total construction cost, with the major equipment items—such as the turbine generators, the steam generators, and the reactor vessel—accounting for a relatively small proportion of total costs.[11] Large projects involving significant amounts of on-site engineering are notoriously difficult to manage and to control costs on; for example, in the United Kingdom, the costs of the Channel Tunnel and the Thames Barrier were well above forecasted costs. Some Generation IV designs, such as the Pebble Bed Modular Reactor, are designed to be largely factory-built and costs are expected to be much easier to control in a factory.

For some designs of power plants, it is possible to buy the plant on "turnkey terms," in other words at an agreed price that the vendor guarantees will not increase above the agreed level. Turnkey terms are only possible where the vendor is confident that they can control all aspects of the total construction cost. The current generation of gas-fire power plants, combined cycle gas turbine (CCGT) plants, are often sold under turnkey terms because they are largely factory-built in factories controlled by the vendor which require relatively little on-site work. In the mid-1960s, the four major US nuclear ven-

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[11] As a result of the difficulty of controlling construction costs, the World Bank's long-standing policy is not to lend money for nuclear projects. See: World Bank (1991) "Environmental Assessment Sourcebook: Guidelines for environmental assessment of energy and industry projects, volume III," World Bank Technical Paper 154, World Bank, Washington, DC.

dors sold a total of twelve plants under turnkey terms, but lost massive amounts of money because of their inability to control costs and, since then, it is unlikely that any vendor has risked offering a complete plant on turnkey terms. Note that individual items of equipment may be purchased on turnkey terms but any price for a nuclear plant quoted as being on turnkey terms should be regarded with considerable skepticism. The Olkiluoto order is usually described as "turnkey," with Areva being responsible for management of the construction, but the contract details are confidential and it is impossible to know whether there really are no cost-escalation clauses. For example, if an accident elsewhere led to a regulatory requirement to change the design, would Areva really bear the extra costs resulting?

Second, costs increase if design changes are necessary; for example, if the original detailed design turns out to be poor or the safety regulator requires changes in the design, or the design is not fully worked out before construction starts. In response to these problems, plant constructors now aim to get full regulatory approval before construction starts as with the proposed US combined Construction and Operation Licenses, and they require designs to be as fully worked out as reasonably as possible before construction starts. The risk of design change cannot be entirely removed, especially with new designs where unanticipated problems might be thrown up by the construction process. Experience with operating reactors might also lead to a need to change the design after construction has started. For example, a major nuclear accident would necessarily lead to a review of all plants under construction (as well as all operating plants) and important lessons could not be ignored simply because licensing approval of the existing design had already been given.

3.1.3 Learning, scale economies, and technical progress

The expectation with most technologies is that successive generations of design will be cheaper and better than their predecessors because of factors such as learning, economies of scale, and technical change. How far nuclear technology has improved through time is a moot point, but costs have clearly not fallen. The reasons behind this are complex and not well understood, but factors that are often quoted are increased regulatory requirements (note: the standards have not increased, but the measures found to be necessary to meet these standards have) and unwise cost-cutting measures with first generation reactors.

The paucity of orders for current generations of reactors, especially those with properly documented costs, makes it difficult to know whether costs have stabilized yet, let alone begun to fall. However, "learning," in other words, improvements in performance through repetition, and scale economies are two-way processes. In the 1970s, the major reactor vendors were receiving up to ten orders per year. This allowed them to set up efficient production lines to manufacture the key components and allowed them to build up skilled teams of designers and engineers. How far these economies of number produced reduced costs is difficult to estimate. A Nuclear Energy Agency report from 2000 suggests that the intuitive expectation that economies of number would be large may not be accurate. It stated:[12]

[12] Nuclear Energy Agency (2000) "Reduction of Capital Costs of Nuclear Power Plants," OECD, Paris, p 90.

> "The ordering of two units at the same time and with a construction interval of at least twelve months will result in a benefit of approximately 15% for the second unit. If the second unit is part of a twin unit the benefit for the second unit is approximately 20%. The ordering of additional units in the same series will not lead to significantly more cost savings. The standardisation effect for more than two units of identical design is expected to be negligibly low."

When the UK Performance and Innovation Unit (PIU) of the Cabinet Office examined nuclear power economics in 2002, it was provided with forecasts of costs from British Energy (the nuclear power plant owner) and BNFL (the plant vendor) that were based on "a substantial learning and scale effects from a standardised program." The PIU was skeptical about the extent of learning, acknowledging that learning was likely to occur but that its impact could be limited. It stated:[13]

> "The pace and extent of learning may however be slower for nuclear than for renewables because:
>
> - relatively long lead times for nuclear power mean that feedback from operating experience is slower;
> - relicensing of nuclear designs further delays the introduction of design changes; and
> - the scope for economies of large-scale manufacturing of components is less for nuclear because production runs are much shorter than for renewables, where hundreds and even thousands of units may be installed."

The major reactor vendors have received only a handful of orders in the past twenty years, their own production lines have closed, and skilled teams have been cut back. Westinghouse has received only one order in the past twenty-five years while even the French vendor Areva received its first order in about fifteen years with its order for Finland. For new orders, large components would generally have to be sub-contracted to specialist companies and built on a one-off basis, presumably at higher costs in countries such as Japan and, for the future, China.[14] Design and engineering teams would have to be reassembled.

The Sizewell B reactor was the most recent plant built in Britain, having been completed in 1995. Its cost is not easy to determine precisely because of disputes, for example, about how far first-of-a-kind costs should be included. However, the overall cost was estimated by the National Audit Office in 1998 as about £3 billion,[15] probably about £3.5 billion in today's money or a cost of £3,400/kW.[16]

3.1.4 Construction time

An extension of the construction time beyond that forecast does not directly increase costs, although it will tend to increase IDC and often is a symptom of problems in the construction phase such as design issues, site management problems, or procurement

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[13] Performance and Innovation Unit (2002) "The Energy Review," Cabinet Office, London, p 195. http://www.strategy.gov.uk/downloads/su/energy/TheEnergyReview.pdf.

[14] For example, if the Flamanville EPR is ordered, the pressure vessel would probably be manufactured in Japan.

[15] National Audit Office (1998) "The sale of British Energy," House of Commons, 694, Parliamentary Session 1997–98, London, HMSO.

[16] British Energy claims that a significant proportion of this cost was non-recurring first-of-a-kind costs.

difficulties that will be reflected in higher construction costs. In a competitive electricity system, long forecast construction times would be a disadvantage because of the increased risk that circumstances will change, making the investment uneconomic before it is completed and because of the higher cost of capital (see below) in a competitive environment.

Overall lead time, from the time of the decision to build the plant to its commercial operation (i.e., after the initial testing of the plant has been completed and its operation handed over by the vendor to the owner) is generally much longer than the construction time. For example, the decision to build the Sizewell B nuclear power plant in Britain was taken in 1979, but construction did not start until 1987 (because of delays not only from a public inquiry but also from difficulties in completing the design). The plant only entered commercial service in 1995, so the total lead-time was sixteen years. The cost of the pre-construction phase is generally relatively low compared to construction, unless the reactor is the "first-of-a-kind" where design and safety approval could prove expensive. However, for a generating company operating in a competitive environment, this long delay and the risks it entails—such as failure at the planning inquiry stage or cost escalation from regulatory requirements—is a major disincentive to choose nuclear.

3.2 Output rating

The maximum output rating of the plant will determine how many kilowatt-hours of saleable power the plant can produce. Particularly for the British plants, problems of corrosion and poor design have meant that most of the plants cannot sustain operation at their full-design rating. For the more widely used designs worldwide, plant "derating" has not been an important issue in recent years and most plants have been able to operate at their design level. Indeed, in some cases, changes to the plant after it has entered service—for example, use of a more efficient turbine or increase in the operating temperature—have meant that some plants are able to operate at above-design rating. For future orders, there is still a small risk for unproven designs that the plant will not be able to operate at as high a rating as planned, but this risk is probably quite small compared to other risks incurred.

3.3 Cost of capital

This is the other element, along with construction cost, in capital charges (see Appendix 1). The real (net of inflation) cost of capital varies from country to country and from utility to utility, according to the country risk and the credit-rating of the company. There will also be a huge impact from the way in which the electricity sector is organized. If the sector is a regulated monopoly, the real cost of capital could be as low as 5 to 8 percent but in a competitive electricity market, it is likely to be at least fifteen per cent.

It is clear that if the largest element of cost in power from a nuclear power plant is the capital charge, more than doubling the required rate of return will severely damage the economics of nuclear power. There is no "right" answer about what cost of capital should be applied. When the electricity industry was a monopoly, utilities were guaranteed full cost recovery, in other words, whatever money they spent, they could recover from consumers. This made any investment a very low risk to those providing the capital because consumers were bearing all the risk. The cost of capital varied according to the country and whether the company was publicly or privately owned (publicly owned companies generally have a high credit rating and therefore the cost of capital is lower for them than for a commercial company). The range was 5 to 8 per cent.

In an efficient electricity market, the risk of investment would fall upon the generation company, not the consumers, and the cost of capital would reflect this risk. For example, in 2002 in Britain, about 40 percent of the generating capacity was owned by financially distressed companies (about half of this was the nuclear capacity) and several companies and banks lost billions of pounds on investments in power stations that they had made or financed. In these circumstances, a real cost of capital of more than 15 percent seems well-justified. If the risks were reduced—for example, if there were government guarantees on the market for power and the price—the cost of capital would be lower, but these would represent a government subsidy (state aid) and it is not clear they would be acceptable under European Union law.

3.4 Operating performance

For a capital intensive technology like nuclear power, high utilization is of great importance, so that the large fixed costs (repaying capital, paying interest, and paying for decommissioning) can be spread over as many saleable units of output as possible. In addition, nuclear power plants are physically inflexible and it would not be wise to start up and shut down the plant or vary the output level more than is necessary. As a result, nuclear power plants are operated on “base-load” except in the very few countries (e.g., France) where the nuclear capacity represents such a high proportion of overall generating capacity that this is not possible. A good measure of the reliability of the plant and how effective it is at producing saleable output is the load factor (capacity factor in US parlance). The load factor is calculated as the output in a given period of time expressed as a percentage of the output that would have been produced if the unit had operated uninterrupted at its full-design output level throughout the period concerned.[17] Generally, load factors are calculated on an annual or a lifetime basis. Unlike construction cost, load factor can be precisely and unequivocally measured and load factor tables are regularly published by the trade press such as Nucleonics Week and Nuclear Engineering International. There can be dispute about the causes of shutdowns or reduced output levels, although from an economic point of view, this is often of limited relevance.

As with construction costs, load factors of operating plants have been much poorer than forecast. The assumption by vendors and those promoting the technology has been that nuclear plants would be extremely reliable with interruptions to service being only for maintenance and refueling (some plant designs such as the AGR and Candu are refueled continuously and need to only shut down for maintenance) giving load factors of 85 to 95 percent. However, performance was poor, and around 1980, the average load factor for all plants worldwide was about 60 percent. To illustrate the impact on the economics of nuclear power, if we assume fixed costs represent two-thirds of the overall cost of power if the load factor is 90 percent, the overall cost would go up by a third if load factor was only 60 percent. To the extent that poor load factors are caused by equipment failures, the additional cost of maintenance and repair resulting would further increase the unit cost of power. In a competitive market, a nuclear generator contracted to supply

[17] Note that where reactors are derated, some organizations (e.g., the IAEA) quote the load factor on the authorized output level rather than the design level. While this may give some useful information on the reliability of the plant, for economic analysis purposes, the design rating should be used because that is what the purchaser paid to receive.

power that is unable to fulfill its commitment is likely to have to buy the "replacement" power for its customer, potentially at very high prices.

However, from the late 1980s onward, the nuclear industry worldwide has made strenuous efforts to improve performance and, worldwide, load factors now average more than 80 percent and, for example, the United States now has an average of nearly 90 percent compared to less than 60 percent in 1980, although the average lifetime load factor of America's nuclear power plants is still only 70 percent.

Only 7 of the 414 operating reactors with at least a year's service and which have full-performance records have a lifetime load factor in excess of 90 percent and only the top 100 plants have a lifetime load factor of more than 80 percent. Interestingly, the top 13 plants are sited in only 3 countries: 6 in South Korea, 5 in Germany, and 2 in Finland.

New reactor designs may emulate the level of reliability achieved by the top 2 percent of existing reactors, but, equally, they may suffer from "teething problems" like earlier generations. The French experience in the late 1990s with the N4 design is particularly salutary. Note that in an economic analysis, the performance in the first years of operation, when teething problems are likely to emerge, will have much more weight than that of later years because of the discounting process. Performance may decline in the later years of operation as equipment wears out and has to be replaced, and improvements to the design are needed to bring the plant nearer current standards of safety. This decline in performance will probably not weigh very heavily in an economic analysis because of discounting. Overall, an assumption that reliability of 90 percent or more seems hard to justify on the basis of historic experience.

3.5 Non-fuel operations and maintenance cost

Many people assume that nuclear power plants are essentially automatic machines requiring only the purchase of fuel and have very low-running costs. As a result, the non-fuel operations and maintenance (O&M) costs are seldom prominent in studies of nuclear economics. As discussed below, the cost of fuel is relatively low and has been reasonably predictable. However, the assumption of low-running costs was proved wrong in the late 1980s and early 1990s when a small number of US nuclear power plants were retired because the cost of operating them (excluding repaying the fixed costs) was found to be greater than the cost of building and operating a replacement gas-fired plant. It emerged that non-fuel O&M costs were on average in excess of $22/MWh (1.5p/kWh) while fuel costs were then more than $12/MWh (0.8p/kWh).[18] Strenuous efforts were made to reduce non-fuel nuclear O&M costs and by the mid-1990s, average non-fuel O&M costs had fallen to about $12.5/MWh (0.7p/kWh) and fuel costs to $4.5/MWh (0.25p/kWh). However, it is important to note that these cost reductions were achieved mainly by improving the reliability of the plants rather than actually reducing costs. Many O&M costs are largely fixed—the cost of employing the staff and maintaining the plant—and vary little according to the level of output of the plant, so the more power that is produced, the lower the O&M cost per MWh. The threat of early closure on grounds of economics has now generally been lifted in the United States.

It is also worth noting that British Energy, which was essentially given its eight nuclear power plants when it was created in 1996, collapsed financially in 2002 because income

[18] For statistics on O&M costs, see: http://www.nei.org/index.asp?catnum=2&catid=95.

from operation of the plants barely covered operating costs. This was in part due to high fuel costs, especially the cost of reprocessing spent fuel, an operation only carried out now in Britain and France (see below). Average O&M costs for British Energy's eight plants, including fuel, varied between about 1.65 and 1.9p/kWh from 1997 to 2004. However, in the first nine months of fiscal year 2004/05, operating costs including fuel were 2.15p/kWh because of poor performance at some plants. The average over the period is about 1.85p/kWh. If we assume the cost of fuel, including reprocessing, is about 0.7p/kWh, this leaves about 1.15p/kWh as the non-fuel O&M cost, about 60 percent higher than the US average.

3.6 Fuel cost

Fuel costs have fallen as the world uranium price has been low since the mid-1970s. US fuel costs average about 0.25p/kWh but these are arguably artificially low because the US government assumes responsibility for disposal of spent fuel in return for a flat fee of $1/MWh (0.06p/kWh). This is an arbitrary price set more than two decades ago and is not based on actual experience—no fuel-disposal facilities exist in the United States or anywhere else—and all the US spent-fuel remains in temporary store pending the construction of a spent-fuel repository, expected to be at Yucca Mountain. Real disposal costs are likely to be much higher.

Fuel costs are a small part of the projected cost of nuclear power because uranium supplies are relatively abundant in comparison with current usage. The issue of spent-fuel disposal is difficult to evaluate. Reprocessing is expensive and, unless the plutonium produced can be profitably used, it does nothing to help waste disposal. Reprocessing merely splits the spent fuel into different parts and does not reduce the amount of radioactivity to be dealt with. Indeed, reprocessing creates a large amount of low- and intermediate-level waste because all the equipment and material used in reprocessing becomes radioactive waste. The previous contract between BNFL and British Energy, before its collapse, was reported to be worth £300 million per year, which equates to about 0.5p/kWh. The new contract is expected to save British Energy about £150 to 200 million per year, although this will be possible only because of the underwriting of losses at BNFL by the government. Despite this poor cost experience, the United States was reported to be considering allowing the reprocessing of spent fuel, which has not occurred since a ban was imposed by the Carter administration. The cost of disposing of high-level waste is hard to estimate because no facilities have been built or are even under construction and any cost projections must have a very wide margin for error.

3.7 Accounting lifetime

One of the features of Generation III plants compared to their predecessors is that they are designed to have a life of about sixty years compared to their predecessors which generally had a design life of about half that. For a technology dominated by fixed costs, it might be expected that doubling the life would significantly reduce fixed costs per unit because there would be much longer to recover these costs. In practice, this does not apply. Commercial loans must be repaid over no more than fifteen to twenty years and in a discounted cash flow calculation, costs and benefits more than ten to fifteen years forward have little weight (see Appendix 1).

There is a trend to life-extend existing plants and PWRs are now often expected to be run for more than forty years, compared to their design life of, say, thirty years. However, it should not be assumed that there will be cheap electricity once capital costs have been repaid. Life extension may require significant new expenditure to replace worn out equipment and to bring the plant closer to current safety standards. Life extension is not always possible and, for example, Britain's AGRs which had a design life of twenty-five years are now expected to run for thirty-five years, but life extension beyond that is not expected to be possible because of problems with the graphite moderator blocks.

3.8 Decommissioning cost and provisions

These are difficult to estimate because there is little experience with decommissioning commercial-scale plants and the cost of disposal of waste (especially intermediate or long-lived waste) is uncertain (see Appendix 4). However, even schemes which provide a very high level of assurance that funds will be available when needed will not make a major difference to the overall economics. For example, if the owner was required to place the (discounted) sum forecast to be needed to carry out decommissioning at the start of the life of the plant, this would add only about 10 percent to the construction cost. The British Energy segregated fund, which did not cover the first phase of decommissioning, required contributions of less than £20 million per year equating to a cost of only about 0.03p/kWh.

The problems come if the cost has been initially underestimated, the funds are lost, or the company collapses before the plant completes its expected lifetime. All of these problems have been suffered in Britain. The expected decommissioning cost has gone up several-fold in real terms over the past couple of decades. In 1990, when the CEGB was privatized, the accounting provisions made from contributions by consumers were not passed on to the successor company, Nuclear Electric. The subsidy that applied from 1990 to 1996, described by Michael Heseltine[19] as being to "decommission old, unsafe nuclear plants" was in fact spent as cash flow by the company owning the plant and the unspent portion has now been absorbed by the Treasury. The collapse of British Energy has meant that a significant proportion of their decommissioning costs will be paid by future taxpayers.

Table 5. Liability limits for the OECD countries as of September 2001

Country	Liability limits under national legislation[a]	Financial security requirements[a,b]
Belgium	298 mln €	
Finland	250 mln €	
France	92 mln €	
Germany	unlimited	2,500 mln €[c]
Great Britain	227 mln €	
Netherlands	340 mln €	
Spain	150 mln €	
Switzerland	unlimited	674 mln €
Slovakia	47 mln €	
Czech Republic	177 mln €	
Hungary	143 mln €	

[19] M. Heseltine, President of the Board of Trade, Hansard, October 19, 1992.

Canada	54mln €	
United States	10,937 mln €	226 mln €
Mexico	12 mln €	
Japan	unlimited	538 mln €
Korea	4,293 mln €	

Source: Unofficial Statistics – OECD/NEA, Legal Affairs

Notes: [a] using official exchange rates from 06/2001 to 06/2002, [b] if different than the liability limit, [c] 256 mln € insurance, 2.5 bln € operator's pool, 179 mln € from Brussels amendment to Paris Convention.

3.9 Insurance and liability

This is a controversial area because at present, the liability of plant owners is limited by international treaty to only a small fraction of the likely costs of a major nuclear accident. The Vienna Treaty, passed in 1963 and amended in 1997, limits a nuclear operator's liability to $300 million Special Drawing Rights. At present the British government underwrites residual risk beyond £140 million, though the limit is expected to rise under the Paris and Brussels Conventions to €700 million (£500m). The limit on liability was seen as essential to allow the development of nuclear power but can also be seen as a large subsidy. The German Bundestag's Study Commission on Sustainable Energy[20] compiled figures on the liability limits in OECD countries (see table 5) and this shows the wide range of liability limits from very low sums, (for example, Mexico), to much higher sums, (for example, Germany).

Kommentar [RF1]: empty footnote

The scale of the costs caused by, for example, the Chernobyl disaster, which may be of the order hundreds of billions of pounds (it is invidious to put a cost on the value of loss of life or incapacity but for insurance purposes it is necessary), means that conventional insurance cover would probably not be available and even if it was, its cover might not be credible because a major accident would bankrupt the insurance companies.

There have been proposals that "catastrophe bonds" might provide a way for plant owners to provide credible cover against the financial cost of accidents. A catastrophe bond is a high-yield, insurance-backed bond containing a provision causing interest and/or principal payments to be delayed or lost in the event of loss due to a specified catastrophe, such as an earthquake. Whether these would provide a viable way to provide some insurance cover against nuclear accidents and what the impact on nuclear economics would be will be hard to determine until concrete proposals are made.

[20] Deutscher Bundestag (2002). Nachhaltige Energieversorgung unter den Bedingungen der Globalisierung und Liberalisierung. Bericht der Enquete-Kommission. Zur Sache 6/2002. Deutscher Bundestag: Berlin. Chapter 3.3.2, Table 3.3, Page 232. http://dip.bundestag.de/btd/14/094/1409400.pdf

4 Recent studies on nuclear costs and why they differ

In the past three to four years, there have been a number of studies of the economics of nuclear power. These include:

1. May 2000: "The role of nuclear power in enhancing Japan's energy security," James A Baker III, Institute for Public Policy of Rice University
2. 2002: Lappeenranta University of Technology (LUT). Finnish 5th Reactor Economic Analysis
3. February 2002: "The economics of nuclear power," UK Performance and Innovation Unit
4. September 2002: "Business case for early orders of new nuclear reactors," Scully Capital
5. February 2003: "The future of nuclear power: an interdisciplinary MIT study"
6. March 2004: "The costs of generating electricity," The Royal Academy of Engineers
7. August 2004: "The economic future of nuclear power," University of Chicago, funded by the US Department of Energy
8. August 2004: "Levelised unit electricity cost comparison of alternative technologies for base load generation in Ontario," Canadian Energy Research Institute; prepared for the Canadian Nuclear Association
9. March 2005: "Projected costs of generating electricity: 2005 update," IEA/NEA
10. April 2005: "Business case for early orders of new nuclear reactors," OXERA

Table 6 tabulates the key assumptions made in each of these studies.

4.1 Rice University

The Rice University study examines strategic issues for Japan in ensuring its energy security. It uses a forecast of the overall cost of generation, from plants coming on line in 2010, produced by the Japanese Central Research Institute of Electric Power Industry (CRIEPI).[21] This produces a cost per kWh of 5p/kWh. However, this figure should be seen in the context of the very high price of electricity in Japan, partly attributable to the high value of the yen, and without examining CRIEPI's assumptions in detail, it is difficult to draw strong conclusions.

4.2 Lappeenranta University of Technology

The Lappeenranta study was widely publicized when the decision to go ahead with the Olkiluoto plant was taken. Many of the assumptions are not fully specified, being classified as commercially sensitive, but the very low cost of capital, the low operating costs, and the high load factor inevitably lead to a low generation cost. The Olkiluoto order is discussed in Section 5.1.1.

4.3 Performance and Innovation Unit

The Performance and Innovation Unit (PIU) of the UK Cabinet Office reviewed the economics of nuclear power in 2002 as part of the government's review of energy pol-

[21] Japanese costs are converted to sterling using an exchange rate of £1=200 Yen.

icy leading to the White Paper of 2003. It estimates the cost of generation from Sizewell B, if first-of-a-kind costs are excluded, which is estimated to reduce the construction cost of Sizewell B to £2,250/kW (total cost of £2.7 billion) as about 6p/kWh if a 12 percent discount rate is applied.

It also reports the forecasts provided by British Energy and BNFL and presents them using common assumptions on the discount rate. It is difficult to represent all the information in the PIU report. The table shows the costs for the 8th unit, built as twin units and using AP-1000 technology. The assumption is that by the 8th unit, all set-up and first-of-a-kind charges will have been met and the "settled-down" cost will apply. It uses BNFL's assumptions, but with PIU's assumptions of discount rates of 8 percent (to represent a plant built where there was very low risk, for example, if there was full cost pass-through to consumers), and 15 percent, (to represent a plant subject to much greater commercial risk). The 8 percent case is calculated with a fifteen-year plant life (to represent the likely length of a commercial loan) and a thirty-year plant life, while the 15 percent case is only shown with a fifteen-year life. Given that a cost or benefit arising in twenty years counts as only 6 percent of its undiscounted value and one arising in thirty years counts as only 1.5 percent of its undiscounted value in a DCF calculation, the difference between a fifteen- and thirty-year life is likely to be small. The cost estimates if only one unit is built are 40–50 percent higher reflecting the assumption that first-of-a-kind costs will be about £300 million.

Many of the assumptions, such as for construction cost, are categorized as commercially sensitive and are not published. However, the PIU does state that BNFL's and British Energy's construction cost estimates are less than £840/kW. On load factor, the figures are also confidential although the PIU states the assumed performance is significantly higher than 80 percent.

4.4 Scully Capital

The Scully report was commissioned by the US of Department of Energy and examines the costs of generation from a 1100MW PWR (AP-1000) under four assumptions of construction cost, $1 billion, $1.2bn, $1.4bn, and $1.6bn, equivalent to £500/kW, £600/kW, £700/kW and £800/kW. Unlike other reports, the Scully approach is to forecast the wholesale electricity price and see what rates of return a nuclear plant would yield under their performance assumptions. At a market electricity price of $35/mWh (1.95p/kWh), a nuclear plant would achieve an internal rate of return including inflation of 7.3–10.7 percent, depending on the construction cost. It compares this to the industry norm of 10–12 percent. Only the $1 billion construction cost case is within this range. Sensitivity analyses are carried out on the market price for electricity, the load factor, the price of fuel and the construction time. There are also sensitivities regarding the financial aspects, including the proportion of debt to equity and the cost of borrowing.

4.5 MIT

The Massachusetts Institute of Technology (MIT) study was a very detailed and prestigious study of nuclear generation costs compared to other generation options such as CCGT plants. It has detailed assumptions about the important elements. On O&M costs, it assumes that these can be 25 percent less than the average for existing plants because of competitive pressures on generators. On construction costs, the report acknowledges that its assumed costs are far lower than those incurred in the most recent plants in the

United States (albeit these were completed about twenty years ago). On capacity factor, the report considers two cases with 85 percent as the upper case and 75 percent as the lower case. It bases these assumptions on the good recent performance of US plants for the upper case, but the lower case is based on the many years it took to achieve this level. The detailed assumptions on decommissioning do not appear to be specified but it can be assumed they follow current practice of requiring a segregated fund. The cost of decommissioning is not specified.

The main sensitivities reported are on load factor and on project lifetime, although reflecting the relatively high cost of capital, the lifetime extension makes only a small difference to the overall cost (about 5 percent), while the load factor assumption change makes a much greater difference (about 10 to 15 percent). In all cases, the gas- and coal-fired options are substantially cheaper than nuclear, up to 45 percent for gas and about 35 percent for coal. Even reducing nuclear construction costs by 25 percent, construction time by twelve months and the cost of capital to 10 percent does not close the gap between nuclear and coal or gas.

4.6 The Royal Academy of Engineers

The Royal Academy of Engineers' report compared a range of generating technologies and found that the cost of power from a nuclear plant was very close to the cost of power from a gas-fired plant, about 10 to 30 percent cheaper than coal (depending on the coal technology used) and about a third of the cost of renewables. It assumed there were three likely reactor choices: the EPR, AP-1000, and the ACR. It drew heavily on the MIT study for its estimates of the cost determinants, although it did not follow them in all cases, citing "engineering judgement" where it differed. For example, on O&M costs, it forecast costs nearly 50 percent lower than MIT.[22] The report states that an allowance for decommissioning cost is included in the capital cost, but it does not specify the cost assumptions. Its assumptions seem consistently optimistic for all parameters and the overall low cost of generation is therefore not surprising.

4.7 University of Chicago

The University of Chicago study reviews a range of estimates of nuclear costs, but does not produce its own cost estimates. In its "no-policy" scenario, it calculates the levelised cost of electricity (LCOE) for three different cases of plants of 1000MW—the most expensive representing the EPR ordered for Olkiluoto, the middle case representing a plant on which first-of-a-kind (FOAK) costs would be incurred (e.g., the AP-1000), and the lowest, one on which the FOAK costs had already been met (e.g., the ABWR or ACR-700). The results shown in the table do not adequately summarize the results of the study, which presents a wide range of sensitivities, but they do illustrate that even with extremely low construction costs, a relatively high discount rate does have a severe impact on overall costs.

[22] The MIT forecasts themselves represented a significant reduction on current cost levels (25 percent) brought about by competitive forces. However, the discount rate chosen by the RAE is consistent with there being full cost recovery.

4.8 Canadian Energy Research Institute

The Canadian Energy Research Institute study compares the forecast costs of generation from coal- and gas-fired generation with the cost of generation from a pair of Candu-6 units (1346MW total), the current generation of Candu, and a pair of ACR-700 units (1406MW total), the Generation III Candu design.[23] We focus on the ACR-700 option, which is forecast to be cheaper than the Candu-6. Decommissioning costs are assumed to be about £250/kW and payments are made into a fund through the life of the plant, amounting to £3.6 million per year over thirty years or 0.03p/kWh. The overall cost is relatively low and most of the assumptions are similar to those used in other studies.

4.9 International Energy Agency/Nuclear Energy Agency

The IEA/NEA study is based on questionnaire responses from national authorities on the cost of generation options. It is difficult to evaluate this report because of the huge range of national assumptions, with Eastern European countries often providing very low costs and Japan very high. The key factor is the very low discount rate used, which with relatively optimistic performance assumptions gives low generation costs.

4.10 OXERA

OXERA's report of April 2005 was followed up by a second report in June giving more details on the assumptions behind their cost estimates.[24] The OXERA report includes very detailed financial analysis of the economics but it relies mainly on other reports for its assumptions on technical performance. For example, an extremely high assumption on load factor of 95 percent is included with no justification. The OXERA report follows the same approach as the Scully report of calculating the rate of return that would be achieved at a given electricity price. With a base-load electricity price of £27–33/MWh, about 50 percent more than British Energy is currently receiving, the internal rate of return would be 8–11 percent for a single reactor (depending on the proportions of debt and equity). For a program of eight units, the return would be more than 15 percent for the last units. It should be noted that while the construction costs are higher than some forecasts, they are much lower than for Sizewell and lower than the reported cost of Olkiluoto. Its assumptions on load factor and operating cost—drawn partly from the IEA/NEA report and the Scully Capital report—require a huge improvement in the current generation of plants.

On the basis of these cost projections and on the cost of the government's current program on renewables—which OXERA estimates to be £12bn—OXERA estimates that a nuclear program would achieve a similar impact in terms of carbon dioxide emissions reductions at a cost of only £4.4 billion plus the cost of public insurance risk. The £4.4 billion is made up of £1.1billion in capital grants and £3.3 billion in loan guarantees. OXERA does not estimate the cost of public insurance risk. How might a new British program of nuclear power plants be carried through?

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[23] Canadian dollar amounts are converted using an exchange rate of £1=C$2.20

[24] OXERA (2005) "Financing the nuclear option: modelling the cost of new build."

5 Need for and extent of public subsidies

Successive studies by the British government in 1989, 1995, and 2002 came to the conclusion that in a liberalized electricity market, electric utilities would not build nuclear power plants without government subsidies and government guarantees capping costs. In most countries where the monopoly status of the generating companies has been removed, similar considerations would apply. The recent order in Finland clearly does not follow this expectation, but, as argued above, the special status of the buyer as a not-for-profit company owned by the industrial companies contracted to buy the output of the plant means that the special conditions in Finland mean this is not an example other countries are likely to follow.

The areas where subsidies and guarantees might be required would be particularly those which are not fully under the control of the owner. These include:

- Construction cost. The construction cost of a new nuclear power plant would be high and there would be a significant risk of cost overruns. The government might therefore have to place a cap on the cost a private investor would have to pay.
- Operating performance. There would be a significant risk that performance would be poorer than forecast. Reliability is largely under the control of the owner and it is not clear whether developers would be sufficiently confident in their abilities to take the risk of poorer than expected reliability.
- Non-fuel operations and maintenance cost. Similarly, this is largely under the control of the owner and they may be willing to bear this risk.
- Nuclear fuel cost. Purchasing fuel has not generally been seen as a risky activity. Uranium can easily be stockpiled and the risk of increasing fuel purchase cost can be dealt with. The cost of spent-fuel disposal (assuming reprocessing is not chosen) is, however, much more contentious and nuclear owners might press for some form of cap on disposal cost similar to the US arrangements.
- Decommissioning cost. The cost of decommissioning is very hard to forecast, but the costs will rise well into the future. Contributions to a well-designed segregated decommissioning fund appear relatively manageable, although if experience with decommissioning and waste disposal does reveal that current estimates are significantly too low, or if returns on investment of the fund are lower than expected, contributions might have to be increased significantly. Private developers might therefore seek some “cap” on their contributions.

Guarantees would be particularly extensive and high for the first units built, which would bear the set-up costs for a new technology. If a series of plants are built and experience with them is good, it is possible that the market would be willing to bear more of the risk, although a political commitment to promote nuclear power is by no means sufficient to ensure the completion of a program. It should be remembered that the Reagan and Thatcher administrations, which promised a strong revival in the nuclear industry, presided over steep declines in the fortunes of nuclear power.

6 Conclusions

Worldwide, the ordering rate for new nuclear power plants has been at a low ebb for at least twenty years. The reasons behind this are complex and include public opposition to new nuclear power plants and over-capacity of power plants in many potential markets. However, the poor economic performance of many existing plants has also been an important factor. This has been exacerbated by the moves in the past decade to competitive electricity markets, which favor low capital cost-generation options that are quick to build and for which the performance can be guaranteed—characteristics that current nuclear designs do not possess. The few plants under construction are often of old designs that would not be acceptable for new orders in the West and are being built in countries where electricity reforms are still at a very early stage.

Around Europe and North America, there is renewed interest in new nuclear power plants. Nuclear generation capacity in Britain will inevitably fall sharply in the next decade, reducing its contribution from about 25 percent of power needs to less than 10 percent. This has led to concern that the plants will—if there is no government intervention—be replaced by gas-fired plants, significantly increasing Britain’s emissions of greenhouse gases. However, a number of the major countries have actual or de facto nuclear phase-out policies, including Sweden, Italy, Belgium, Germany, the Netherlands, Spain, and Switzerland. There is likely to be some slippage in the closure timetables in these countries, but it is a long step from a policy of phasing-out to one that allows new orders. So, none of the countries in Europe seems likely to face such a steep decline in nuclear capacity in the next decade.

In the United States, the Bush administration is attempting to deal with one of the economic risks—uncertainties about the length and cost of licensing—by offering federal subsidies. It remains to be seen whether this will be sufficient to overcome the financial community’s distrust of nuclear power. The utilities cannot build nuclear plants without the implicit support of credit rating agencies and investment analysts.

This renewed interest in nuclear power is despite the poor economic record of nuclear power in many countries and has been fueled by a number of national and international studies in recent years that have much lower projected generation costs from new nuclear plants than has been the case so far. However, these studies are controversial and many of their underpinning assumptions are implausible.

There are three reasons why forecasting the cost of power from a nuclear plant is difficult and controversial:

- Several of the variables relate to processes which have not been proven on a commercial scale, such as decommissioning, waste disposal, especially for long-lived low-, intermediate-, and high-level waste. All experience of nuclear power suggests that unproven processes could easily cost significantly more than expected. There is therefore a strong risk that forecasts of these costs could be significantly too low.
- For some of the variables, there is no clear “correct” answer. For example, the discount rate could vary widely whilst there is no clear consensus on how provisions to pay for decommissioning should be arranged.

- Perhaps most important, there is a lack of reliable, up-to-date data on actual nuclear plants. Utilities are notoriously secretive about the costs they are incurring, while in the past two decades, there has been only a handful of orders in Western Europe and none since about 1980 in North America. All the modern designs are therefore more or less untested.

Over the past four decades, there has consistently been a wide gap between the performance of existing nuclear plants and the performance forecast for new nuclear plants. These expectations have almost invariably proved overoptimistic. The gap in expected performance is as wide as ever between current forecasts of the economic performance of the next generation of nuclear power plants and that of the existing plants. While the fact that in the past, such expectations have proved wrong, it is not a guarantee that current forecasts would prove inaccurate; it does suggest that forecasts relying on major improvements in performance should be treated with some skepticism.

The most important assumptions are on construction cost, operating performance, running costs, and the cost of capital/discount rate.

The conventional wisdom in the nuclear industry over the past decade or more has been that nuclear construction costs must be about $1,000/kW for nuclear to be competitive with combined cycle gas-fired generation (which has construction costs of about $500/kW). Even the most optimistic studies do not forecast construction costs as low as $1,000/kW. Nevertheless, the clustering of costs around the $2,000/kW mark does suggest that designs are being produced to a target cost. The rise in gas prices in the past couple of years, if sustained, will increase the level of construction cost nuclear would still be competitive at, although it seems unlikely that it would be enough to pay for a doubling of expected nuclear construction cost.

Clearly, designs should not be made in the absence of an economic framework. However, the main issues in evaluating these projections are how realistic these forecasts are. Particularly, there must be concern about the extent to which the huge cost reductions forecast, compared to the cost of the current generation of plants, have been achieved by rationalization of the designs, and how far it is through cost-cutting measures that in the long run will prove unwise. It should be remembered that in the 1960s when the economics of nuclear power were found to be poorer than forecast, cost reductions were made by savings on materials and by rapid scaling-up, measures which in retrospect now appear imprudent because of the impact they had on the performance of plants. For example, steam generators in PWRs had to be replaced at great expense and requiring a shutdown of about a year, sometimes after only fifteen years, because the material used was not durable enough.

Amongst the forecasts examined in this report, the typical construction cost projected is about $2,000/kW. The one forecast that appears to be based on an actual contract cost, the Lappeenranta study, uses a significantly higher construction cost forecast. It should be noted that the Olkiluoto bid, which is the basis for the Lappeenranta study, is often seen as being below the economic price.

Another area where large improvements in performance are expected is in the non-fuel O&M costs, where forecasts are often only about 40 percent of current UK costs and about 70 percent of current US costs. Operating performance forecasts typically suggest load factors of 90 percent, far above the level achieved so far and in line with the performance achieved by only the most reliable plants worldwide.

However, the most difficult and important assumption is arguably over the cost of capital. In some cases, such as the RAE and the IEA/NEA forecasts, the assumptions chosen would only be credible if the owners of the plant were allowed full cost recovery. The US forecasts use more sophisticate methods of determining the cost of capital, but given the lack of progress in most of the United States with introducing competition into electricity, it is not clear that these studies fully reflect the impact of opening electricity generation to competition. Unless there was a return to a monopoly electricity industry structure—a measure that in current circumstances seems almost inconceivable—this would mean the owners would effectively be subsidized by taxpayers (if there was government underwriting) or electricity consumers (if a consumer subsidy was reintroduced). It is questionable whether such arrangements would be politically viable or whether they would be acceptable under European Union law which proscribes (except in specific cases) state aids.

If the owner of the plant is going to be required to bear significant economic risk, a real discount of at least 15 percent, as used by the PIU, is likely to be imposed, and even with very optimistic assumptions of construction and O&M costs (e.g., the PIU or Chicago University forecasts) this would result in generation costs probably in excess of about 4p/kWh.

If nuclear power plants are to be built, it seems clear that extensive government guarantees and subsidies would be required. These might be required for:

- construction cost
- operating performance
- non-fuel operations and maintenance cost
- nuclear fuel cost
- decommissioning cost

There might also need to be commercial guarantees that the output of the plants would be purchased at a guaranteed price. It seems doubtful that such an extensive package of “state aids” would be acceptable under EU competition law.

Table 6. **Comparison of assumptions in recent forecasts of generation costs from nuclear power plants**

Forecast	Construction cost ($/kW)	Construction time (months)	Cost of capital (% real)	Load factor (%)	Non-fuel O&M p/kWh	Fuel cost (p/kWh)	Operating life (years)	Decommissioning scheme	Generating cost (p/kWh)
Sizewell B	4050 5400	86	-	84	2.07	1.26	40	Part segregated, part cash flow	6 ?
Rice University									5.0
Lappeenranta Univ	~2340		5	91	0.9	0.36	60		1.6
Performance & Innovation Unit	<1500	-	8 8 15	>80			30 15 15		2.31 2.83 3.79
Scully Capital	900 1080 1260 1440	60		90	1.0	0.5	40	£260m accrued over forty-year life of plant	
Massachusetts Institute Technology	2000	60	11.5	85 75	1.5	-	40 25		3.7 4.4
Royal Academy of Engineers	2070	60	7.5	90	0.80	0.72	40	Included in construction cost	2.3
Chicago University	1000 1500 1800	84	12.5	85	1.0	0.54	40	£195m	2.9 3.4 3.9
Canadian Nuclear As	1920	72	10	90	0.88	0.45	30	Fund. 0.03p/kWh	3.3
IEA/NEA	2000–4500	60–120	5 10	85	0.68–1.6	0.27–1.17	40	Included in construction cost	1.2–2.7 1.8–3.8
OXERA	2925 first plant 2070 later unit			95	0.63	0.54	40	£500m in fund after forty years life	

Notes:
1. Sizewell B operating costs are the average for all eight of British Energy’s plants including seven AGRs as well as the Sizewell B PWR.
2. The MIT O&M cost includes fuel.

Appendix 1: Discounting, cost of capital, and required rate of return

A particularly difficult issue with nuclear economics is dealing with and putting on a common basis for comparison, the streams of income, and expenditure at different times in the life of a nuclear power plant. Under UK plans, the time from placing of the reactor order to completion of decommissioning could span more than 200 years.

Conventionally, streams of income and expenditure incurred at different times are compared using discounted cash flow (DCF) methods. These are based on the intuitively reasonable proposition that income or expenditure incurred now should be weighted more heavily than income or expenditure earned in the future. For example, a liability that has to be discharged now will cost the full amount but one that must be discharged in, say, ten years can be met by investing a smaller sum and allowing the interest earned to make up the additional sum required. In a DCF analysis, all incomes and expenditures through time are brought to a common basis by “discounting.” If an income of $100 is received in one year’s time and the “discount rate” is 5 percent, the “net present value” of that income is $95.23—a sum of $95.23 would earn $4.77 in one year to make a total of $100. The discount rate is usually seen as the “opportunity cost” of the money, in other words, the rate of return (net of inflation) that would be earned if the sum of money was invested in an alternative use.

Whilst this seems a reasonable process over periods of a decade or so and with relatively low discount rates, over long periods with high discount rates, the results of discounting can be very powerful and the assumptions that are being made must be thought through. For example, if the discount rate is 15 percent, a cost incurred in ten years of $100 would have a net present value of only $12.28. A cost incurred in 100 years, even if the discount rate was only 3 percent, would have a net present value of only $5.20, while at a discount rate of 15 percent, costs or benefits more than fifteen years forward have a negligible value in an normal economic analysis (see table 7).

Table 7. Impact of discounting: net present values

Discounting period (years)	3%	15%
5	0.86	0.50
10	0.74	0.25
15	0.64	0.12
20	0.55	0.061
30	0.41	0.015
50	0.23	0.00092
100	0.052	-
150	0.012	-

Source: author’s calculations

If we apply this to nuclear plants operating in a competitive market where the cost of capital will be very high, this means that costs and benefits arising more than, say, ten years in the future will have little weight in an evaluation of the economics of a nuclear power plant. Thus, increasing the life of a plant from thirty years to sixty years will have little benefit, while refurbishment costs incurred after, say, fifteen years will likewise have little impact.

For decommissioning—for which, under UK plans, the most expensive stage is not expected to be started until 135 years after plant closure—this means very large decommissioning costs will impact only slightly even with a very low discount rate consistent with investing funds in a very secure place with a low rate of return, such as 3 percent. If we assume a Magnox plant will cost about $1.8 billion to decommission and the final stage accounts for 65 percent of the total (undiscounted) cost ($1,170 million), a sum of only $28 million invested when the plant is closed will have grown sufficiently to pay for the final stage of decommissioning.

The implicit assumption with DCF methods is that the rate of return specified will be available for the entire period. Give that even government bonds—usually seen as the most secure form of investment—are only available for 30 years forward, and that a period of 100 years of sustained economic growth is unprecedented in human history, this assumption seems difficult to justify.

So, with nuclear power, there is the apparent paradox that at the investment stage, a very high discount rate (or required rate of return) of 15 percent or more is likely to be applied to determine whether the investment will be profitable, while for decommissioning funds, a very low discount rate is applied to determine how much decommissioning funds can be expected to grow.

The key element resolving this paradox is risk. Nuclear power plant investment has always been risky because of the difficulty of controlling construction costs, the variability of performance, the risk of the impact of external events on operation and the fact that many processes are yet to be fully proven (such as disposal of high-level waste and decommissioning). In a competitive environment, there are additional risks because of the rigidity of the cost structure. Most of the costs will be incurred whether or not the plant is operated. Thus while nuclear plants will do well when the wholesale price is high (as was the case with British Energy from 1996 to 1999), they will do poorly when the wholesale price is low (as was from 2000 to 2002). The fact that a plant has made good profits for a decade will not protect it from bankruptcy in the bad years, and financiers will therefore see investment in nuclear power as extremely risky and will apply a very high interest rate, reflecting the risk that the money loaned could easily be lost.

Appendix 2: Nuclear reactor technologies

Nuclear power reactors can be broadly categorized by the coolant and moderator they use. The coolant is the fluid (gas or liquid) that is used to take the heat from the reactor core to the turbine generator. The moderator is a medium which reduces the velocity of the neutrons so that they are retained in the core long enough for the nuclear chain reaction to be sustained. There are many possible combinations of coolant and moderator, but amongst the reactors currently in service or on offer, there are four possible coolants and three moderators.

The most common types of nuclear plant are the pressurized water reactor (PWR) and boiling water reactor (BWR). These are derived from submarine propulsion units and use ordinary water ("light water") as coolant and moderator. The advantage of water is its cheapness, although it is not the most efficient moderator (some of the neutrons are absorbed by water molecules rather than "bouncing" off the water). As a result, the proportion of the active isotope of uranium has to be increased from about 0.7 percent found in natural uranium to more than 3 percent. This process is expensive.

As a coolant, the disadvantage of water is that it is designed to work as a liquid. If there is a break in the coolant circuit, the water will boil and will cease to be as effective as expected. Avoiding the possibility of so-called "loss of coolant accidents" is therefore a major priority in reactor design. The main difference between a PWR and a BWR is that in a BWR, the coolant water is allowed to boil and passes directly to the turbine generator circuit where the steam generated in the reactor core drives the turbine. In a PWR, the coolant water is maintained as a liquid by keeping it under pressure. A heat exchanger (steam generator) is used to transfer the energy to a secondary circuit where water is allowed to boil and drives the turbine. BWRs are therefore less complex than PWRs but because the coolant water goes direct to the turbine, radioactive contamination of the plant is more extensive. Most of the Russian-design plants, WWERs, are essentially PWRs. Britain has one operating PWR, Sizewell B, but no BWRs.

Some plants use "heavy water" as coolant and moderator, the most common of which are the Candu reactors designed in Canada. In heavy water, the deuterium isotope of hydrogen replaces the much more common form of the atom. Heavy water is a more efficient moderator and Candu plants can use natural (unenriched) uranium. However, its greater efficiency is counterbalanced by the cost of producing heavy water.

All of the British plants except Sizewell B are cooled by carbon dioxide gas and moderated by graphite. The first generation plants, the Magnoxes, use natural uranium but most were unable to operate long-term at their full-design rating because the carbon dioxide coolant becomes mildly acidic in contact with water and causes corrosion of the piping. The second generation plants use enriched uranium and improved materials were used to prevent corrosion. Graphite is an efficient moderator, but is quite expensive compared to water. Its disadvantages are its flammability and its tendency to crack and distort with exposure to radiation.

The design used at Chernobyl, the RBMK, uses graphite as the moderator and light water as the coolant.

There has been consistent interest in reactors that use helium gas as the coolant and graphite as moderator: so-called high temperature gas-cooled reactors (HTGRs). Helium is entirely inert and is an efficient, albeit expensive coolant. The use of helium and graphite means the reactor operates at a much higher temperature than a light water or carbon dioxide cooled reactor. This allows more of the heat energy to be turned into electricity and also opens the way to use some of the heat in industrial processes while still being able to generate power. However, despite research in several countries, including Britain, going back more than fifty years, no commercial design of a plant has ever been produced and the demonstration plants built have a very poor record.

Recently, use of HTGRs as a means of producing hydrogen as a fuel which could, in turn, replace petroleum through use in fuel cells has led to renewed interest in HTGRs. One of the most advanced programs is that of South Africa's, which has adapted an old German design to make the Pebble Bed Modular Reactor (PBMR), so called because the fuel is in the form of tennis ball sized "pebbles." However, the South African program has suffered severe delays and it is unlikely that the design will be available to order on a commercial basis before about 2015.

Appendix 3: Nuclear reactor vendors

PWRs

There were four main independent vendors of PWR technology: Westinghouse, Combustion Engineering (CE), Babcock & Wilcox (B&W) and the Russian vendor (producing the WWER).

Westinghouse technology is the most widely used and has been widely adopted using technology licenses, the main licensees being Framatome (France), Siemens (Germany), and Mitsubishi (Japan). Westinghouse plants have been sold throughout the world although it has had one order in the past twenty-five years (Sizewell B) and its last order in the United States (not subsequently cancelled) was more than thirty years ago. In 1998, BNFL took over the nuclear division of Westinghouse, although in July 2005, BNFL confirmed it had appointed N M Rothschild to handle the sale of the Westinghouse division. A large number of companies have been spoken of as potential bidders. Westinghouse's main current design is the AP-1000, although it has yet to sell any units.

Both Framatome and Siemens became independent of Westinghouse and, in 2000, they merged their nuclear businesses with 66 percent of the shares going to Framatome and the remainder going to Siemens. Framatome is now controlled by the Areva group, which is owned by the French government. Its main current design is the EPR (European Pressurized water Reactor) of which it has sold one unit (to Finland) and expects to sell another to EDF (France). Framatome supplied all the PWR plants in France (about sixty) and has exported plants to South Africa, Korea, China, and Belgium. Siemens supplied ten out of the eleven PWRs built in Germany and exported PWRs to the Netherlands, Switzerland, and Brazil.

Mitsubishi supplies PWR technology to Japan where it has built twenty-two units, but it has never tried to sell plants on the international market. Its most modern design is the APWR, but ordering has continually been delayed and the first units will probably be ordered in the next year or two.

Combustion Engineering produced its own design of PWR, which is installed in the United States. Outside the United States, its technology was licensed by Korea. The nuclear division of Combustion Engineering was taken over by ABB in 1996 and in turn taken over by BNFL in 1999. It is now part of the Westinghouse division and would be sold with the Westinghouse division if the sale of Westinghouse proceeds. The newest Combustion Engineering design is the System 80+, but Westinghouse is not actively trying to sell plants of this design. However, the Korean vendor, Doosan, has adopted and developed the design for its future plants as the APR-1400. It has made tentative efforts to sell plants to China, but it seems likely that most future orders will be for its Korean home market.

Babcock & Wilcox (B&W) supplied PWRs of its own design to the US market but the Three Mile Island accident, which involved B&W technology, effectively ended their interest in reactor sales. The only plant of B&W design built outside the United States was built under license in Germany, but this was closed in 1988 due to licensing problems soon after its completion in 1986 and will not be restarted.

BWRs

The main designer of BWRs is the US company General Electric (GE), which has supplied a large number of plants to the United States and international markets such as Germany, Japan, Switzerland, Spain, and Mexico. Its licensees include Siemens, Hitachi, and Toshiba. Siemens (now part of Areva) offered the SWR design for the Olkiluoto tender but otherwise does not seem actively to be trying to sell BWRs.

The Japanese licensees continue to offer BWRs in Japan. There are now thirty-two BWRs in operation or under construction in Japan. A few first-of-a-kind plants in Japan were bought from GE but the rest were split between Hitachi and Toshiba. Their current design is the ABWR—the first Generation III design to come on line. The first unit was completed in 1996 and there are two more units in service and one under construction. There are also two ABWRs under construction in Taiwan, supplied by GE. However, like Mitsubishi, Toshiba and Hitachi have not tried to sell plants on the international market. Apart from the ABWR, GE has developed the SBWR but no sales seem likely in the next few years.

Asea Atom (Sweden) produced its own design of BWR, nine of which were built in Sweden and two in Finland. Asea Atom merged with Brown Boveri to form ABB, which in turn was taken over by BNFL in 1999. BNFL no longer actively promotes this design.

Candus

The main heavy water reactor supplier is the Canadian company Atomic Energy of Canada Limited (AECL), which has supplied more than twenty units in Canada as well as exports to Argentina, Romania, Korea, and China. It also sold plants to India but because of proliferation issues, it has had no contact with the Indians since 1975, although India continues to build plants of this forty-year-old design. Argentina has built three heavy water plants: one Candu and two plants of German design (one of which is incomplete and no work is currently being carried out on it). The main future design for AECL will be the Advanced Candu reactor (ACR), which is expected to be produced in two sizes: 750MW (ACR-700) and 1100–1200MW (ACR-1000).

British Energy did contribute funds to the development of the ACR-700 but this ended when British Energy collapsed in 2002 and sold its interests in the operation of eight Canadian nuclear power plants.

Appendix 4: Decommissioning

Decommissioning of nuclear plants has attracted considerable public interest in recent years as reactors get near the end of their life, forecast decommissioning costs escalate, and weaknesses in the schemes that were meant to provide the funds to do the job become apparent.

Conventionally, decommissioning is split into three separate phases. In the first, the fuel is removed and the reactor is secured. The time it takes to remove the fuel varies, with plants that refuel off line taking much less time (e.g., PWRs and BWRs). These are designed for about a third of the fuel to be replaced in an annual shutdown of a few weeks. Reactors that refuel on line (e.g., AGRs and Candus) take much longer because the refueling machine is designed to constantly replace small proportions of the fuel while the reactor is in operation. This requires precision machinery that moves slowly and removing the entire core may take several years. Once the fuel has been removed, the reactor is no longer at risk of a criticality and the vast majority of the radioactivity and all the high-level waste has been removed. Until this phase has been completed, the plant must essentially be staffed as fully as if it was operating. There is thus a strong economic incentive to complete phase I as quickly as possible consistent with safety standards. In technological terms, phase I is simple—it mostly represents a continuation of the operations that were being carried out while the plant was operating. Note that dealing with the spent fuel is not included in the cost of phase I.

In the second phase, the uncontaminated or lightly contaminated structures are demolished and removed, essentially leaving the reactor. Again, this is relatively routine work requiring no special expertise. In economic terms, the incentive is to delay it as long as possible to minimize the amount that needs to be collected from consumers to pay for it—the longer the delay, the more interest the decommissioning fund will accumulate. The limiting point is when the integrity of the buildings can no longer be assured and there is a risk they might collapse, leading to a release of radioactive material. In Britain, it is planned to delay phase II until forty years after plant closure.

The third phase, the removal of the reactor core is by far the most expensive and most technologically challenging, requiring remote robotic handling of materials. As with phase II, the economic incentive is to delay the work until it is no longer safe to do so and in Britain, this is expected to result in a delay of 135 years.

At the end of phase III, the ideal is that the land can be released for unrestricted use, in other words, the level of radioactivity is no higher than in uncontaminated ground. In practice, this is not always going to be possible, and at some “dirty” sites such as the Dounreay site in Scotland where a demonstration fast reactor operated, use of the land is expected to be restricted indefinitely because of the high level of contamination.

Very few commercial-size plants that have operated beyond a full life have been fully decommissioned, so the cost is not well established. The operations required are said to have been demonstrated successfully on a small scale but until they are applied to a large scale plant, the process cannot be seen as proven—many processes that worked on a small scale in this area have suffered problems when scaled up to commercial size.

Much of the cost of decommissioning is accounted for by disposal of the radioactive waste generated. The cost of waste disposal in modern facilities is also not well established, especially for intermediate-level waste and long-lived low-level waste because of the lack of experience in building facilities to take this waste.

This uncertainty is reflected in the way that estimates of nuclear decommissioning costs are quoted. Typically, they are quoted as a percentage of the construction cost (perhaps 25 percent). Given that the cost of decommissioning clearly only bears a limited relationship to the cost of construction, this illustrates how little is known of the costs.

A typical breakdown of the expected undiscounted cost of decommissioning might be one sixth for phase I, one third for phase II, and a half for phase III. British Energy was required to operate a "segregated" fund to pay for decommissioning of its plants, although phase I was expected to be paid for out of cash flow. BNFL, which owned the Magnox plants until they were transferred to the Nuclear Decommissioning Authority in April 2005, is publicly owned and treasury policy is not to allow segregated funds to be used for publicly owned companies. British Energy assumed a discount rate of 3 percent for the first eighty years and zero after then, while BNFL assumed a discount rate of 2.5 percent indefinitely. In 2003/04, British Energy increased its discount rate to 3.5 percent.

If we assume a total cost of decommissioning of \$1.8 billion, split between phases as above with phase I carried out immediately after closure, phase II after 40 years and phase III after 135 years, the undiscounted and discounted costs will be as in table 8.

Table 8. Illustrative costs of decommissioning (£m)

	Undiscounted	British Energy (3%)	British Energy (3.5%)	BNFL (2.5%)
Phase I	300	300	300	300
Phase II	600	184	151	223
Phase III	1200	113	76	41
Total	1800	597	527	574

Source: author's calculations

British Gas-cooled reactors are expected to be very expensive to decommission because of their physical bulk, which produces a large amount of waste. PWRs and BWRs are much more compact and are expected to cost perhaps only a third as much, (e.g., Sizewell B might be expected to cost a total of about \$540 million).

Various means are used so that, as required by the "polluter pays principle," those that consume the electricity produced pay for the decommissioning. Under all methods, if the cost of decommissioning is underestimated, there will be a shortfall in funds that will inevitably have to be paid for by future taxpayers. In Britain, the forecast cost of decommissioning the Magnox plants has grown by a factor of about four in the past twenty years, even before any of the most challenging work has been carried out.

The least reliable method of collecting the funds is the unfunded accounting method, under which the company makes accounting provisions for the decommissioning. The provisions are collected from consumers but the company is free to invest them in any way it sees fit, and these provisions exist as a proportion of the assets of the company. This method will only be reliable if it can be assumed the company will continue to exist until decommissioning is completed and that the assets it builds make at least the rate of return assumed. The weakness of this method was illustrated when the Central Electricity Generating Board (CEGB)—the company that owned the power stations in England and Wales until privatization in 1990—was privatized. About £1.7 billion in accounting provisions had been made by consumers, but the company was sold for only about a third of its asset value, so effectively two-thirds of the provisions were lost. The government did not pass on any of the sale proceeds to the company that inherited the nuclear power plants, thereby losing the remainder of the provisions.

A more reliable method appears to be the segregated fund. Under this method, consumers make provisions through the life of the plant which are placed in a fund that the plant owner has no access to and which is independently managed. The funds are invested only in very secure investments to minimize the risk of loss of the funds. Such investments might yield no more than 3 percent interest. When decommissioning is required, the company owning the plant can draw down the segregated fund. Again, there are risks as illustrated by British experience. The British Energy segregated fund did not cover stage I, by far the most expensive stage in discounted terms (about half), while the company collapsed long before the plants had completed their operating life and the company had to be rescued by government, and much of the burden of decommissioning will be borne by future taxpayers, who will be required to provide the funds when decommissioning is carried out.

Perhaps the lowest risk against provisions becoming inadequate would be if a segregated fund was set up at the time the plant entered service with sufficient funds to pay for decommissioning after the design life of the plant had been completed. If we assume a life of thirty years and a discount rate of 3 percent, the required sum would be about 40 percent of the undiscounted sum. Thus, if the undiscounted decommissioning cost is about 25 percent of the construction cost, the sum that would have to be placed in the fund would be about 10 percent of the construction cost. Even this scheme would be inadequate if the plant had to be retired early, or if the decommissioning cost had been underestimated, or if the funds did not achieve the rate of return expected.

Overall then, the sums required to decommission nuclear plants are likely to be high. But even under the schemes that provide the lowest risk that there will be insufficient funds to pay for decommissioning, if the costs are estimated accurately, the impact on overall costs would appear to be limited because of the impact of discounting.

Heinrich Böll Foundation

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For 2005, the Foundation had almost 36 million € public funds at its disposal.

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