The economics of nuclear power: analysis of recent studies

by

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1. Introduction

In the past 15 years, the apparent economic fortunes of nuclear power in Britain have fluctuated wildly. In 1990, the nuclear power plants were so unattractive to private investors and so uneconomic that they had to be withdrawn from the privatisation process and required a consumer subsidy of about £1bn per year simply to cover their running costs. Six years later, the efficiency of operation of the plants had improved sufficiently for all except the very oldest plants to be privatised and for 2-3 years, the privatised nuclear company, British Energy, was highly successful. Only three years on in 2002, British Energy had collapsed and was rescued by the government at a cost to taxpayers of several billion pounds. Throughout this period, the nuclear industry was arguing for new orders yet government reviews in 1995 and 2002 found no economic case for new nuclear orders. However, in 2005, after a series of international reports painting an optimistic picture of the economics of nuclear power, ordering new nuclear power plants for the UK is on the political agenda again.

The public is likely to be understandably confused about whether nuclear power really is a cheap source of electricity. Some of this confusion 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. There is also the context of the need to reduce greenhouse gas emissions, which means that the relevant economic comparison is increasingly between nuclear power and other low CO_2 technologies such as wind-power rather than between nuclear power and coal or gas. However, much of the difference between the economics of existing plant and the forecasts for future plant 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 report is to identify the key economic parameters commenting on their determining factors and to review the assumptions in main forecasts of 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 allow nuclear plants to be ordered.

2. The world market for nuclear plants: existing orders and prospects

During the past year, there has been increasing 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 July 2005, there were 24 plants under construction worldwide, with a capacity of 19GW compared to 439 plants already in service with a capacity of 366GW as of May 2005 (see Table 1). Of the units under construction, 16 use either Indian or Russian technology, designs that would be highly unlikely to be considered in the West. For six of the plants, construction started 20 years ago or more 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 and may still not be completed. The Western vendors active in Europe, BNFL/Westinghouse and Framatome/Areva, have just one order between them, Framatome'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 25 years, China has been forecasting imminent orders but it has ordered only 11 units in that time, three 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 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 scepticism.

Japan is another country that has consistently forecast large increases in nuclear capacity not matched by actual orders. Japanese companies supply these plants. It may take up to 20 years to get approval to build at sites in Japan, although once construction starts, completion is usually quick (four years typically) and does not usually over-run. 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 11 units on which construction started, but on which work is not being carried out at present. For these, the quoted degree of completion may be misleading. Plants reported to be less than 33 per cent 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 will be no surprise if this time-table is not met. The units for Korean 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 be before mid 2006.

Table 1. Nuclear capacity in operation and under construction

	Operating plants: Capacity MW (no of units)	Plants under construction: Capacity MW (no of units)	% of electricity nuclear	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	12080 (17)	-	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	2493 (14)	4128 (9)	3	HWR, FBR, WWER	AECL, India, Russia
Iran	-	915 (1)	-	WWER	Russia
Japan	46342 (54)	3237 (3)	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
UK	11852 (23)	-	24	GCR, PWR	UK, Westinghouse
USA	97587 (103)	-	20	PWR, BWR	Westinghouse, B&W, CE, GE
WORLD	**366177 (439)**	**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: Pressurised 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.

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	2005
Taiwan	Lungmen 1	ABWR	GE	1300	1999	57	2009
Taiwan	Lungmen 2	ABWR	GE	1300	1999	57	2010
Finland	Olkiluoto 3	EPR	Framatome	1600	June 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	Tarapur 4*	Candu	India	490	2000	100	2006
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	Shika 2*	ABWR	Toshiba	1304	2001	100	2006
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				19174			

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 2-3 years

Country	Site	Bidders	Need	Possible order date	Forecast completion
China	Sanmen	Areva (EPR), BNFL/Westinghouse (AP1000), Russia (WWER-1000)	2x1000MW	2005/06	?
China	Yangjiang	Areva (EPR), BNFL/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

3. Operating nuclear power plants in the UK

Britain's stock of nuclear power plants is markedly different to that of any other country in the world. All except one of the 12 operating stations use a technology, carbon dioxide cooled and graphite moderated, not used elsewhere in the world (see Table 5).[1] There are two designs, the early plants being of the Magnox design and the later ones Advanced Gas-cooled Reactors (AGR). The reputation of the Magnox plants as 'reliable workhorses' seems over-stated on the basis of their operating record. All are restricted to significantly less than their design rating and, in terms of their lifetime load factors[2], all fall in the bottom quarter of the world's plants (see Table 6).

Table 5. Britain's nuclear power plants

Site	Reactor type	Design size MW	Authorised size MW	Construct start	First power	Commercial operation	Forecast closure
Dungeness A	Magnox	2 x 275	2 x 225	1960	1965	1965	2006
Dungeness B	AGR	2 x 607	2 x 555	1965	1983, 1985	1989	2008
Hartlepool	AGR	2 x 625	2 x 605	1968	1984	1989	2014
Heysham 1	AGR	2 x 611	2 x 575	1970	1983, 1984	1989	2014
Heysham 2	AGR	2 x 615	2 x 625	1980	1988	1989	2023
Hinkley Pt B	AGR	2 x 625	2 x 610	1967	1976	1978	2011
Hunt'ston B	AGR	2 x 624	2 x 595	1967	1976	1976	2011
Oldbury	Magnox	2 x 300	2 x 217	1962	1967	1967	2008
Sizewell A	Magnox	2 x 290	2 x 210	1962	1966	1966	2008
Sizewell B	PWR	1188	1188	1988	1995	1995	2035
Torness	AGR	2 x 645	2 x 625	1980	1988	1989	2023
Wylfa	Magnox	2 x 590	2 x 490	1963	1971	1971	2010
TOTAL		12802	11852				

Sources: PRIS Data Base (http://www.iaea.org/programmes/a2/index.html), Nuclear News, World list of nuclear plants,
Note: In 2005, British Energy was considering whether to extend the life of Dungeness B beyond 2008 for 5-10 years.

The remaining four Magnox stations (seven have already been retired), which had a design life of 20 years, have now completed nearly double that period. Fuel from these plants has to be reprocessed before final disposal of the waste because of corrosion to the fuel and BNFL has committed to close the reprocessing plant in 2012[3]. Given that it takes a couple of years to remove the fuel, before it is temporarily stored while it cools and then transported to Sellafield for reprocessing, it will be difficult for the remaining Magnox plants to continue in service as long as projected if the 2012 closure date for the reprocessing line is to be met.

It is difficult to know how much weight to put on the performance of the AGRs in considering future orders. The seven stations were of five separate designs and they have a uniquely poor record both in construction over-runs and operating performance. The worst unit, Dungeness B, took 24 years from start of construction to commercial operation. It can only operate at about 90 per cent of its design rating and its lifetime average load factor to end 2004 was 37 per cent. There has been no trend of improvement through time and its best years were 1993 and 1996. The other stations were built somewhat quicker and have performed better (see Table 6), but still fall far short of the levels forecast for them. Eight out of 14 of the reactors fall in the bottom quarter of the table of the operating performance of the world's reactors, and only one is in the top half (Heysham B, 189th out of 414).

The AGRs had a design life of 25 years and all except Dungeness B have had their life extended to 35 years. While British Energy has spoken of extending Dungeness's life by five years, it is not clear that it will be possible to meet even the existing expected lifetimes. The most serious problem concerns the graphite cores, which degrade and develop cracks. In the prospectus for its re-launch in December 2004, British Energy stated: 'We are not aware of any technique for eliminating the cracks. Such cracking can lead to the distortion of the core structure and the reduction of the AGRs' operational capacity' and 'Currently assumed

[1] Plants of similar design were built in France, Italy, Spain and Japan but all have now been retired. Gas-cooled plants were not pursued because it was generally assumed they would be more expensive than the more widely used designs.
[2] 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 full design output level throughout the period concerned.
[3] The only other reprocessing plant for this type of fuel was in France and was closed some years ago.

lifetimes may not be achieved, particularly at Hinkley Point B, Hunterston B, Heysham 2 and Torness, and extensions to station lifetimes at those stations may not be possible.'[4]

Table 6. Lifetime performance of British nuclear power plants

	First power	Lifetime load factor %	World ranking
Dungeness A1	9/65	59.2	366
Dungeness A2	1/66	61.7	349
Oldbury 1	11/67	57.8	313
Oldbury 2	5/68	61.6	351
Sizewell A1	1/66	57.4	375
Sizewell A2	7/66	54.6	384
Wylfa 1	1/71	59.5	363
Wylfa 2	8/71	57.4	374
Dungeness B1	12/85	34.1	409
Dungeness B2	4/83	40.0	406
Hartlepool 1	8/83	56.8	379
Hartlepool 2	10/84	61.5	352
Heysham A1	7/83	58.1	371
Heysham A2	10/84	59.7	362
Heysham B1	7/88	74.0	189
Heysham B2	11/88	72.6	247
Hinkley Point B 1	10/76	68.7	268
Hinkley Point B 2	2/76	65.4	310
Hunterston B1	2/76	67.7	286
Hunterston B2	3/77	66.1	307
Torness 1	5/88	71.1	239
Torness 2	2/89	70.3	247
Sizewell B	2/95	83.5	49

Source: Nuclear Engineering International, June 2005
Note: World ranking is out of 414 reactors with more than a year's service and on which data is available.

The Sizewell B plant should be able, if experience elsewhere in the world is a good guide, to complete a 40 year life-time, provided its economic performance is acceptable. Its operating performance is much better than that of any previous reactor in Britain with an average lifetime load factor of 83.5 per cent. This is still some way below the performance of comparable reactors in Germany and the USA, where the average is now 90 per cent or more and its world ranking in terms of lifetime load factor is only 49 out of 414. Overall, in terms of lifetime load factors, the average for Britain's plants is 64.7, and of the 20 countries with more than four operating units, only India and Bulgaria have a poorer record.

Britain's nuclear generating capacity will decline in the next decade with about two thirds of the capacity expected to be retired by 2015 (see Table 7). If Magnox closure has to be accelerated, and fears about the graphite cores are fulfilled, the rate of decline could be even quicker. Currently, Britain gets about a quarter of its power from nuclear power plants and this could fall to less than 10 per cent by 2015. Unless there is strong government action to either replace this plant with new nuclear build or renewables or substantial improvements in energy efficiency, this capacity will be replaced by gas-fired plant, seriously damaging Britain's attempts to meet its targets on greenhouse gas emissions. Given the likely lead-time for new nuclear plant, including technology selection, planning approval, safety regulatory approval and construction, it seems unlikely that even the first replacement plant could be in service by the end of 2015 even if the process was started immediately. This may explain the increased pressure from some quarters for decisions to be urgently taken to allow new nuclear orders to be placed in Britain.

Table 7. Nuclear generating capacity in UK: 2005-2025

Year	Capacity at year end (MW)
2005	11852
2010	8458
2015	3688
2020	3688
2025	1188

Source: Author's calculation

[4] Utility Week, December 10, 2004, p 3.

4. Current designs

For the UK, the most relevant designs would appear to be so-called 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 for emergency cooling less on engineered systems and more on natural processes, such as convection. There are a large number of designs said to be under development, 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 15 years, but the main common features quoted by the nuclear industry are:

- a standardised 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 60 years,
- reduced possibility of core melt accidents,
- minimal effect on the environment,
- higher burn-up to reduce fuel use and the amount of waste,
- burnable absorbers ('poisons') to extend fuel life.[5]

These characteristics are clearly very imprecise and do not define very well what a generation III plant is. Generation III reactors are evolved from existing designs and are based on existing designs of PWR, BWR and Candu (see Appendix 2 for an account of the technologies and Appendix 3 for a list of the main vendors). Until there is much more experience with these technologies, any figures on the generation cost of power from these designs should be treated with the utmost caution.

4.1. PWRs

4.1.1. EPR

The only Generation III PWR to be ordered yet is the Framatome EPR, for the Olkiluoto site in Finland. Construction was due to start in summer 2005. The Finnish government issued a construction license in February 2005. The EPR has also been bid for orders in China, but the result of this tender has not been decided yet. France also intends to build the 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, from the Finnish authorities in January 2005 and Framatome has asked the US Nuclear Regulatory Commission (NRC) to begin licensing in the USA.

The EPR has an output of 1600MW although this may be increased to 1700MW for orders after Olkiluoto and is expected to be built in 57 months from 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 refuelling time is expected to allow a load factor of about 90 per cent.

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 €3bn. Assuming an output of 1600MW, this represents a cost of about £1250/kW.[6] The Olkiluoto order is widely seen as a special case and it has been suggested that the Framatome has offered price that might not be sustainable to ensure 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 per cent per annum.

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 per cent. Since then, reliability has been much better and load factor has averaged 75 per cent. The other three units of this design followed a similar pattern of 3-4 years of very poor performance (typically average load factor of about 40 per cent)

[5] http://www.uic.com.au/nip16.htm
[6] Conversions from € to £ are made assuming an exchange rate of £1=€1.50.

followed by reasonable reliability (average load factor of about 75per cent). The N4 design was said to have built on experience with the 60 PWRs built in France and this does illustrate that it cannot be assumed that new designs will be reliable just because they build on past experience.

4.1.2. AP-1000

The AP-1000 (Advanced Passive) was designed by Westinghouse and was developed from the AP-600 design. It was given regulatory approval by the US NRC in autumn 2004 and 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 rationale for the AP-600 was to increase reliance on passive safety and also that scale economies had been over-estimated. A Westinghouse official claimed that the scale economies 'simply were not there'. 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 economic and the AP-600 was never offered in tenders. It was scaled up to about 1100MW in the hope that scale economies would make the design competitive. The AP-1000 received safety approval in September 2004.

The AP-1000 will have an output of about 1100MW and its modular design is expected to allow it to be built in 36 months at a cost of $1200/kW (£666/kW).[7] However, until details of actual bid costs are available, these figures should be treated with scepticism.

4.1.3. System 80+/APR-1400

Combustion Engineering's System 80+ design received regulatory approval in the USA in 1997 when Combustion Engineering was owned by ABB. ABB was subsequently taken over by BNFL and the System 80+ is not being offered for sale by BNFL/Westinghouse. However, the Korean vendor, Doosan, has used this design under license from BNFL/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.

4.1.4. 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 15 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.

4.1.5. 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 technology, Finland considered the latest Russian design. How far it can be categorised as a Generation III plant is not clear and it seems unlikely it would be considered for any other Western market.

4.2. BWRs

4.2.1. ABWR

The ABWR was developed in Japan by Hitachi, Toshiba and its US technology licensor, General Electric (GE). First orders were placed around 1992 and the first units completed in 1996. By mid-2005, there were three ABWRs in service in Japan, one under construction in Japan and two under construction in Taiwan. The ABWR received safety approval in the USA in 1997.

4.2.2. 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 Economic & Simplified BWR (ESBWR), a 1500MW design developed by GE;
- The SWR, a 1000-1290MW design developed by Framatome. This was one of the three designs short-listed for Olkiluoto;

[7] Conversions from US$ to £ are made using an exchange rate of £1=$1.80

- The BWR-90+, a 1500MW design developed by Westinghouse from the Asea BWR design

4.3. 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 USA with Candu technology. Efforts to license the ACR in the USA are continuing but at a slower pace.

4.4. HTGRs

It is not clear whether the HTGRs under development should be categorised 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 Framatome (for Siemens) and BNFL (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 publicised in 1998 when it was expected that first 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 BNFL, has meant that the project time-scale has slipped dramatically and first commercial orders cannot now be 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 concentrating on developing and using PWRs and perhaps BWRs.

5. 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 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 per cent inflation rate would inflate costs by 13 per cent over five years, and currency fluctuations, for example, since 2000, the dollar-pound exchange rate has fluctuated between £1=$1.40-1.93 means that any comparisons have a significant margin for error.

5.1. 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. There are a number of factors that explain why there is such controversy about forecasts of construction cost.

5.1.1. Unreliability of data

Many of the quoted construction cost forecasts should be treated with scepticism. 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 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[8], the cost of Sizewell B was 35 per cent higher in real terms than the price quoted in 1987 when it was ordered. However, of the final cost of about £3000/kW, British Energy claims £750/kW (25 per cent) was first-of-a-kind costs. Bid prices by vendors are also realistic, although given that they may not cover the whole plant or may be subject to escalation clauses that mean the final price is significantly higher, they have some limitations.

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 treated with scepticism. 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.

Capital charges are normally expected, rightly, 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 or 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 £2000/kW would have a total construction cost of £2400m.

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 reflecting local labour costs and the cost of raw materials such as steel and concrete.

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

5.1.2. 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 per cent 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.[9] Large projects involving significant amounts of on-site engineering are notoriously difficult to manage and to control costs on, for example, the Channel Tunnel, the Thames Barrier etc. 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 plant, 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 plant, combined cycle gas turbine (CCGT) plants, are often sold under turnkey terms because they are largely factory built in factories controlled by the vendor and require relatively little on-site work. In the mid-1960s, the four major US nuclear vendors sold a total of 12 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 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 scepticism. The Olkiluoto order is usually described as 'turnkey', with Framatome 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 Framatome 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 was not fully worked out before construction starts. In response to these problems, plant constructors now aim to get full regulatory approval before construction starts and they require designs to be as fully worked out as reasonably 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.

5.1.3. 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 stabilised 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 10 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.

The major reactor vendors have received only a handful of orders in the past 20 years, their own production lines have closed and skilled teams have been cut back. Westinghouse has received only one order in the past 25 years while even the French vendor, Framatome received its first order in a decade with its order for Finland. For new orders, large components would generally have to be sub-contracted to specialist

[9] 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.

companies and built on a one-off basis, presumably at higher costs in countries such as Japan and, for the future, China. Design and engineering teams would have to be reassembled.

The Sizewell B reactor was the most recent plant built in Britain, being 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 £3bn[10], probably about £3.5bn in today's money or a cost of £2900/kW.[11]

5.1.4. 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 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 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 completing the design). The plant only entered commercial service in 1995, so the total lead-time was 16 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.

5.2. Output rating

The maximum output rating of the plant will determine how many kWh 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 safely operate 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.

5.3. Cost of capital

This is the other element with construction cost in capital charges (see Appendix 1). The 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 organised. If the sector is a regulated monopoly, the real cost of capital could be as low as 5-8 per cent but in a competitive electricity market, it is likely to be at least 15 per cent.

It is clear that if the largest element of cost in power from a nuclear power plant is the capital charges, 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 to them than for a commercial company). The range was 5-8 per cent.

[10] National Audit Office (1998) 'The sale of British Energy' House of Commons, 694, Parliamentary Session 1997-98, London, HMSO.
[11] British Energy claims that a significant proportion of this cost was non-recurring first-of-a-kind costs.

In an efficient electricity market, the risk of investment would fall on the companies, not the consumers and the cost of capital would reflect this risk. For example, in 2002 in Britain, about 40 per cent 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 per cent seems well justified. If the risks were reduced, for example, 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.

5.4. Operating performance

For a capital intensive technology like nuclear power, high utilisation is great importance, so that the large fixed costs (for example, repaying capital 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.[12] 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 cost, load factors of operating plant 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 the only interruptions to service being for maintenance and refuelling (some designs of plant such as the AGR and Candu are refuelled continuously and need only shut down for maintenance) giving load factors of 85 per cent or more. However, performance was poor and around 1980, the average load factor for all plants worldwide was about 60 per cent. 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 per cent, the overall cost would go up by a third if load factor was only 60 per cent. To the extent that poor load factors were 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 power that is unable to fulfil its commitment is likely to have to buy the 'replacement' power for its customer, potentially at very high prices.

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

Only 7 of the 414 operating reactors with at least a year's service and which have full performance records have a life-time load factor in excess of 90 per cent and only the top 100 plants (out of more than 400) have a life-time load factor of more than 80 per cent. Interestingly, the top 13 plants are sited in only three countries, six in South Korea, five in Germany and two in Finland. The Sizewell B nuclear plant has the best performance record of any UK reactor with a lifetime load factor of 83.5 per cent. By contrast, the worst, the Dungeness B plant completed in 1983, has a lifetime load factor of 37 per cent.

New reactor designs may emulate the level of reliability achieved by the top 2 per cent of existing reactors, but, equally, they may suffer from 'teething problems' like earlier generations. 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 will tend to decline in the later years of operation as equipment wears out and has to be replaced, and improvements to

[12] Note that where reactors are derated, some organisations (e.g., the IAEA) quote the load factor on the authorised 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.

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 per cent or more seems hard to justify on the basis of historic experience.

5.5. 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 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 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).[13] 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 USA.

It is also worth noting that British Energy, which was essentially given its eight nuclear power plants when it was created in 1996, came close to bankruptcy in 2002 because income 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 1.65-1.9p/kWh from 1997-2004. 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 per cent higher than the US average. This may reflect the poorer reliability of the British plants and AGRs may have higher O&M costs than PWRs, although since British Energy does not provide a breakdown of costs by plant it is impossible to tell if this is the case.

5.6. Fuel cost

Fuel costs have fallen as the world uranium price remains low. 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 USA 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. 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 £300m per year, which equates to about 0.5p/kWh. The new contract is expected to save British Energy about £150-200m per year, although this will be possible only because of underwriting of losses at BNFL by the government. 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.

5.7. 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 60 years compared to their predecessors which generally had a design life of about half that. For

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

a technology dominated by fixed costs, it might be expected 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 15-20 years and in a discounted cash flow calculation, costs and benefits more than 10-15 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 40 years, compared to their design life of, say 30 years. However, it should not be assumed that this is necessarily cheap electricity because 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 25 years are now expected to run for 35 years (except perhaps Dungeness B), but life extension beyond that is not expected to be possible because of problems with the graphite moderator blocks.

5.8. 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 per cent to the construction cost. The British Energy segregated fund, which does not cover the first phase of decommissioning, requires contributions of less than £20m per year and this equates 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 life-time. 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 privatised, the accounting provisions made from contributions by consumers were not passed on to the successor company, Nuclear Electric. The subsidy that applied from 1990-96, described by Michael Heseltine 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.

5.9. 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 300m Special Drawing Rights. At present the British government underwrites residual risk beyond £140 m, though the limit is expected to rise under the Paris and Brussels Conventions to €700m (£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 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.

6. Recent studies on nuclear costs and why they differ

In the past 3-4 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; and
10. April 2005: 'Business Case for Early Orders of New Nuclear Reactors. OXERA.

Table 8 tabulates the key assumptions made in each of these studies.

6.1. 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).[14] 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.

6.2. Lappeenranta University of Technology

The Lappeenranta study was widely publicised 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.

6.3. 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 policy 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 £2250/kW (total cost of £2.7bn) as about 6p/kWh if a 12 per cent 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 s 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 per cent, to represent a plant built where there was very low risk, for example if there was full cost pass-through to consumers and 15 per cent, to represent a plant subject to much greater commercial risk. The 8 per cent case is calculated with a 15 year plant life (to represent the likely length of a commercial loan) and a 30 year plant life, while the 15 per cent case is only shown with a 15 year life. Given that a cost or benefit arising in 20 years counts as only 6 per cent of its undiscounted value and one arising in 30 years counts as only 1.5 per cent of its undiscounted value in a DCF calculation, the difference between a 15 and 30 year life is likely to be small. The cost estimates if only one unit is built are 40-50 per cent higher reflecting the assumption that first-of-a-kind costs will be about £300m.

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

Many of the assumptions, such as for construction cost, are categorised 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 per cent.

6.4. 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, $1bn, $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 per cent, depending on the construction cost. It compares this to the industry norm of 10-12 per cent. Only the $1bn 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 on the financial aspects including the proportion of debt to equity and the cost of borrowing.

6.5. MIT

The 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 on the important elements. On O&M costs, it assumes that these can be 25 per cent 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 USA (albeit these were completed about 20 years ago). On capacity factor, the report considers two cases with 85 per cent as the upper case and 75 per cent as the lower case. It bases these assumptions on the good recent performance of US plants for the upper case, but the many years it took to achieve this level for the lower case. 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 life-time extension makes only a small difference to the overall cost (about 5 per cent), while the load factor assumption change makes much greater difference (about 10-15 per cent). In all cases, the gas and coal-fired options are substantially cheaper than nuclear, up to 45 per cent for gas and about 35 per cent for coal. Even reducing nuclear construction costs by 25 per cent, construction time by 12 months and the cost of capital to 10 per cent does not close the gap between nuclear and coal or gas.

6.6. 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 10-30 per cent 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 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 per cent lower than MIT.[15] 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.

6.7. 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 summarise the results of the study, which presents a wide

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

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.

6.8. 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.[16] 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 £3.6m per year over 30 years or 0.03p/kWh. The overall cost is relatively low and most of the assumptions are similar to those used in other studies.

6.9. International Energy Agency/Nuclear Energy Agency

The IEA/NEA study is based on questionnaire responses from national authorities on the cost of various 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.

6.10. 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.[17] The OXERA report includes very detailed financial analysis of the economics but it relies on mainly on other reports for its assumptions on technical performance. For example, an extremely high assumption on load factor of 95 per cent 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 per cent more than British Energy is currently receiving, the internal rate of return would be 8-11 per cent for a single reactor (depending on the proportions of debt and equity). For a programme of 8 units, the return would be more than 15 per cent 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 on the current generation of plants.

On the basis of these cost projections and on the cost of the government's current programme on renewables, which OXERA estimates to be £12bn, OXERA estimates that a nuclear programme would achieve a similar impact in terms of carbon dioxide emissions reductions at a cost of only £4.4bn plus the cost of public insurance risk. The £4.4bn is made up of £1.1bn in capital grants and £3.3bn in loans guarantees. OXERA does not estimate the cost of public insurance risk.

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

[17] OXERA (2005) 'Financing the nuclear option: modelling the cost of new build'

Table 8. 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	2250 3000	86	-	84	1.15	0.7	40	Part segregated, part cash flow	6 ?
Rice University									5.0
Lappeenranta Univ	~1300		5	91	0.5	0.2	60		1.6
Performance & Innovation Unit	<840	-	8 8 15	>80			30 15 15		2.31 2.83 3.79
Scully Capital	500 600 700 800	60		90	0.55	0.28	40	£260m accrued over 40 year life of plant	
Massachusetts Institute Technology	1111	60	11.5	85 75	0.83	-	40 25		3.7 4.4
Royal Academy of Engineers	1150	60	7.5	90	0.45	0.4	40	Included in construction cost	2.3
Chicago University	555 833 1000	84	12.5	85	0.56	0.3	40	£195m	2.9 3.4 3.9
Canadian Nuclear As	1067	72	10	90	0.49	0.25	30	Fund. 0.03p/kWh	3.3
IEA/NEA	1100-2500	60-120	5 10	85	0.38-0.90	0.15-0.65	40	Included in construction cost	1.2-2.7 1.8-3.8
OXERA	1625 first plant 1150 later unit			95	0.35	0.3	40	£500m in fund after 40 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.

7. How might a new British programme of nuclear power plants be carried through?

7.1. Need for and extent of public subsidies

Successive studies by the British government in 1989, 1995, and 2002 have come to the conclusion that in a liberalised electricity market, electric utilities will not build nuclear power plants without government subsidies and government guarantees capping costs.

In 1989, when the electricity industry was being privatised, the nuclear plants were not attractive to private investors and the government was forced to withdraw them from sale and had to create two new publicly owned companies, Nuclear Electric and Scottish Nuclear, to own and operate them. The energy minister of the time, John Wakeham, stated: 'unprecedented guarantees were being sought. I am not willing to underwrite the private sector in this way'.[18]

The government promised a review of its nuclear power policy to be concluded at about the time the Sizewell B plant was finished and when there was time to assess the performance of the nuclear plants in the new competitive environment. This review, in 1995, led to the privatisation of the more modern plants in a new company, British Energy in 1996.[19] However, the review found no case for new nuclear orders. It found that nuclear power would not be economically attractive to the private sector because of the high cost of capital and that only with government support would new reactors be built. It said that this support was not justifiable.

The British government launched a review of government energy policy in 2001, which resulted in publication of a White Paper on energy policy in 2003.[20] British Energy proposed the construction of new nuclear power plants to replace the Magnox plants, but it stated these would not be feasible without government subsidies and guarantees. While the White Paper was careful to affirm that nuclear power should remain a viable option for Britain, no practical steps were taken, for example, R&D support, to retain the option and no case for new orders was found. Subsequently, British Energy abandoned all plans to build new nuclear power plants. The White Paper stated: 'While nuclear power is currently an important source of carbon-free electricity, the current economics of nuclear power make it an unattractive option for new generating capacity and there are also important issues for nuclear waste to be resolved. However, we do not rule out the possibility that at some point in the future new nuclear build might be necessary if we are to meet our carbon targets.'

In June 2005, there was unconfirmed speculation that a new Green Paper on energy policy might be produced within six months leading to a new White Paper in 2007.[21] It is difficult to see how circumstances now are significantly different to those of only two years ago. Essentially, the Treasury would have to give unlimited guarantees, for example, on cost, for new nuclear orders to be commercially feasible. 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 over-runs. 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 & 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;

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[18] J Wakeham (1989) House of Commons Debates. HC Debates, 1988/89, vol 159, 9, November 1989.
[19] Department of Trade and Industry and the Scottish Office (1995) 'The prospects for nuclear power in the UK: Conclusions of the government's nuclear review' Cm 2860, HMSO, London.
[20] Department of Trade and Industry (2003) 'Our energy future - creating a low carbon economy' Cm 5761, HMSO, London.
[21] Utility Week, June 24, 2005, p 18.

- Decommissioning cost. The cost of decommissioning is very hard to forecast, but the costs will arise far 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 programme. The Thatcher government's commitment of 1979 to build 10 PWRs ordering the first in 1981 shrank to a 'small family of four by the mid-80s and in fact just one unit, ordered in 1987 was built.

It is also worth noting that, whereas in the past, nuclear vendors have been part of large groups, such as Westinghouse, GE, ABB etc, vendors are now often much smaller and the risk they can bear is correspondingly less. For example, the Westinghouse nuclear business owned by BNFL and including the Westinghouse, ABB and Combustion Engineering businesses is expected to be sold for about £1bn, significantly less than the cost of one nuclear power plant.

7.2. Who would own and operate the plants?

Before the electricity industry was privatised, the issue of who would carry out a programme of nuclear orders was not a major problem. The CEGB could essentially be instructed to carry out the programme and its monopoly status meant that any economic risks would be borne by the consumer. Now, the electricity industry is fragmented and privately owned and there is no natural home for a nuclear programme. There are six major generation companies now. These are:

- NPower, owned by the private German company, RWE;
- Powergen, owned by the private German company, E.ON;
- Electricite de France, the publicly owned French electric utility;
- Scottish Power;
- Scottish & Southern Energy; and
- British Energy.

The two Scottish companies are relatively small and have no experience in the nuclear sector, while British Energy's rescue package means it would be unlikely to be able to take on new and risky commitments. This leaves the three foreign owned companies and, perhaps BNFL as the possible developers. BNFL would have an interest in building new plants while it still owns the Westinghouse business, but all its major assets were transferred to the Nuclear Decommissioning Authority and it is questionable whether it would be allowed to acquire new ones. The three foreign-owned companies have skills in nuclear construction and operation from their home markets, but, even if foreign ownership was acceptable when the plants were so extensively subsidised and guaranteed, it is not clear whether these companies would see any commercial benefit in taking on a major nuclear programme. In addition, ownership of eight nuclear plants on top of their existing plants would give a company an uncomfortably large market share, which would tend to compromise efforts to make electricity generation a competitive market.

8. Conclusions

Worldwide, the ordering rate for new nuclear power plants has been at a low ebb for at least 20 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 favour 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.

These economic factors have been particularly important in the UK, partly because the economic performance of the nuclear plants built so far has been worse than in most countries - it seems clear that none of the nuclear power plants built in Britain has ever represented an economic source of power. And partly because the UK has been a pioneer in introducing competitive electricity markets - the bankruptcy of British Energy and other British generation companies has graphically illustrated the risks in investing in new generation of any type in the British market. However, despite the poor economic performance, increases in nuclear output in the 1990s have been an important factor in allowing Britain to meet its acid and greenhouse gas emission targets.

However, nuclear generation capacity in Britain will inevitably fall sharply in the next decade, reducing its contribution from about 25 per cent of power needs to less than 10 per cent. 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. There is therefore renewed discussion about the construction of new nuclear plants in Britain, if only to replace the existing capacity. This would require the construction of about 7-10 units (depending on the design chosen).

Around Europe, there is also renewed interest in new nuclear power plants. 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 time-tables 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. If Britain did embark on a programme of 7-10 new nuclear power plants, it would be in the position of pioneering new and unproven technology, and would have to meet many of the additional costs that new designs incur. First of a kind costs are very high, for example estimated in the PIU report as £300m or about 25 per cent of the first unit's cost.

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

There are three main reasons why forecasting the cost of power from a nuclear power 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-level, 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; and
- 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 unproven.

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 over-optimistic. 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 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 scepticism.

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 $1000/kW (£550/kW) for nuclear to be competitive with combined cycle gas-fired generation (which has construction costs of about $500/kW (£280/kW). Even the most optimistic studies do not forecast construction costs as low as £550/kW. Nevertheless, the clustering of costs around the £1100/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 rationalisation 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 shut-down of about a year, sometimes after only 15 years, because the material used was not durable enough.

Amongst the forecasts examined in this report, the typical construction cost projected is about £1100/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 per cent of current UK costs and about 70 per cent of current US costs. Operating performance forecasts typically suggest load factors of 90 per cent, far above the level achieved in Britain 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 on 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 USA 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 being subsidised by taxpayers (if there was government underwriting) or electricity consumers (if a consumer subsidy was re-introduced). It is questionable whether such arrangements would be politically viable or whether they would be acceptable under European Union law which proscribes (except in a 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 per cent, 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 in Britain, it seems clear that extensive government guarantees and subsidies would be required. These might be required for;

- Construction cost;
- Operating performance;
- Non-fuel operations & maintenance cost;
- Nuclear fuel cost; and

- 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.

9. 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 nuclear power plant. Under UK plans, the time from placing of 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, 10 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 per cent, 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 per cent, a cost incurred in 10 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 per cent, would have a net present value of only £5.20, while at a discount rate of 15 per cent, costs or benefits more than 15 years forward have a negligible value in an normal economic analysis (see Table 9).

Table 9. 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 10 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 30 years to 60 years will have little benefit, while refurbishment costs incurred after, say 15 years will equally 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 little impact 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 per cent. If we assume a Magnox plant will cost about £1bn to decommission and the final stage accounts for 65 per cent of the total (undiscounted) cost (£650m), a sum of only £12m 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 per cent 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 1996-99), they will do poorly when the wholesale price is low (2000-2002). The fact that 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.

10. 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 pressurised 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 (water molecules absorb some of the neutrons rather than them 'bouncing' off the water. As a result, the proportion of the active isotope of uranium has to be increased from about 0.7 per cent found in natural uranium to more than 3 per cent. 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 50 years, no commercial design of 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 programmes is that of South Africa, 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 size 'pebbles'. However, the South African programme has suffered severe delays and it is unlikely that the design will be available to order on a commercial basis before about 2015.

11. Appendix 3 Nuclear reactor vendors

11.1. 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 25 years (Sizewell B) and its last order in the USA (not subsequently cancelled) was more than 30 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 per cent 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 Pressurised 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 60) and has exported plants to South Africa, Korea, China and Belgium. Siemens supplied ten out the 11 PWRs built in Germany and exported PWRs to Netherlands, Switzerland and Brazil.

Mitsubishi supplies PWR technology to Japan where it has built 22 units, but it has never tried to sell plants on the international market. Its most modern design is the APWR, but ordering of this has been continually 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 USA. Outside the USA, 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 BNFL/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 USA 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.

11.2. BWRs

The main designer of BWRs is the US company, General Electric (GE), which has supplied a large number of plants to the USA and international markets such as Germany, Japan, Switzerland, Spain and Mexico. Its licensees include Siemens, Hitachi and Toshiba. Siemens (now part of Framatome) 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 32 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 plant 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.

11.3. Candus

The main heavy water reactor supplier is the Canadian company, Atomic Energy of Canada Limited (AECL), which has supplied plants more than 20 units to 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 40 year old design. Argentina has built three heavy water plants, one Candu and two plants of a 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 operating eight of Canada’s nuclear power plants.

12. 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 taken 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 shut-down of a few weeks. Reactors that refuel on line (e.g. AGRs and Candus) take much longer because the refuelling 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 and phase I is invariably completed as quickly as possible consistent with safety. In technological terms, phase I is simple, it represents largely just 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 leaving essentially 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 stage II until 40 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 over 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 per cent). 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 Nuclear Decommissioning Authority in April 2005, is publicly owned and Treasury policy is not to allow segregated funds for publicly owned companies. British Energy assumed a discount rate of 3 per cent for the first 80 years and zero after then, while BNFL assumed a discount rate of 2.5 per cent indefinitely. In 2003/04, British Energy increased its discount rate to 3.5 per cent.

If we assume a total cost of decommissioning of £1bn, 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 10.

Table 10. Illustrative costs of decommissioning (£m)

	Undiscounted	British Energy (3%)	British Energy (3.5%)	BNFL (2.5%)
Phase I	167	167	167	167
Phase II	333	102	84	124
Phase III	666	63	42	23
Total	1000	342	293	314

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 £300m.

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 20 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 in being 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 privatisation in 1990 was privatised. About £1.7bn 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, 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 minimise the risk of loss of the funds. Such investments might yield no more than 3 per cent 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 of provisions being 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 30 years and a discount rate of 3 per cent, the required sum would be about 40 per cent of the undiscounted sum. Thus, if the undiscounted decommissioning cost is about 25 per cent of the construction cost, the sum that would have to be placed in the fund would be about 10 per cent of the construction cost. Even this scheme would be inadequate of 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.