The South African government's Integrated Resource Plan for the electricity industry

Professor Steve Thomas, Business School, University of Greenwich

Contents

1. General principles of electricity system planning

From a consumer point of view, the objective of any new investment in generating capacity should be to minimise the long-term overall cost of supply of electricity to consumers ***subject*** to meeting all requirements on security of supply and meeting all environmental objectives. Power plants are operated in a so-called 'merit order'. This requires that, as demand fluctuates on a daily basis, the plant with the lowest operating costs (excluding the fixed costs, for example of construction) not already in operation is brought on-line when demand increases, and when demand falls, the plant with the highest operating costs then in operation is the first to be taken off-line. This means that on a day-to-day basis, the cost of meeting demand from a given set of power plants is minimised. The fixed costs must be paid whether or not the plant is operated so play no part in deciding the daily operating regime. The plants at the top of the merit order are not necessarily the cheapest overall, as the merit order only takes account of operating costs.

As a result of merit order operation, a new power plant will have implications for the operating regime of the existing power plants. This means that when deciding on new capacity, the impact on the cost of operating the whole system should be considered. For example, if a new base-load plant is built, adding it to the system will mean that all plants below it in the merit order will be used somewhat less than if the new plant was not built. It also means that building new capacity should not only be considered when old plant is retired and needs to be replaced or when demand has grown sufficiently to require new capacity. It may be cheaper to retire and replace a relatively new plant even though it has plenty of operating life left.

This means that, in theory, when deciding whether to build new capacity, a computer simulation of the cost of operating the whole electricity system over the whole life of the plant should be carried out for each of the options to see which of the options produces the lowest overall cost of meeting demand over the next few decades.

Traditionally, electric utilities examined only the option of building new generating capacity. Integrated Resource Planning (IRP), sometimes known as Least Cost Planning (LCP), built on this by bringing in the option of examining demand-side measures. These methodologies date back about 30 years and were used widely in the USA in the 1980s. The rationale for including demand side measures was that consumers were largely indifferent to how their energy needs were met, provided they met the legal standards for example, for environmental impacts. Their concern was to get a reliable service for the lowest cost. In practice, the two major differences this made to utility planning was that, for the first time, demand side measures were given equal weight to supply side measures on the grounds that consumers cared about the size of their bill not the cost of a kWh. If a consumer used fewer kWh, even if the cost per kWh was more (to finance demand side measures), they would be happy if the overall bill was lower. The other major change was that utilities could not pursue high cost options ahead of lower costs options because of some internal bias in favour of the high cost option. In the USA, use of IRP revealed that utilities were pursuing nuclear power ahead of cheaper options at considerable cost to consumers.

The use of IRP, which was generally seen as successful, declined after the 1980s as electricity systems were increasingly reformed to run on competitive criteria. In a competitive system, it is assumed that market forces will achieve the same as IRP because in a perfectly competitive market, companies that choose expensive options incur high costs, lose market share and, ultimately, go out of business. Whilst this logic was appealing, results with the competitive model were problematic, with spectacular failures in California and Brazil. Even in the UK, the main pioneer of markets and often taken as the model for reforms, the government and the regulator both agreed in 2010 that the competitive market would not give reliability and would not allow the UK to meet its long-term goals for reductions in greenhouse gas emissions. As a result, a process of Electricity Market Reform was started, which, logically, will lead over time to a return to a fully planned electricity system.[1]

South Africa abandoned its attempt some years ago to create competitive electricity markets in favour of retaining a planned system with a strong element of public ownership. In a planned electricity system, IRP methodology remains an appropriate way to plan an electricity system.

2. The nuclear policy background

The South African government chose to impose a programme of new reactors with a total capacity of 9,600 MW to be on-line by 2030 on the IRP. It was assumed that there would be six reactors each of 1,600 MW and the French design, the European Pressurised Water Reactor (EPR), which has this capacity, is used for illustration. It appears no decision on technology has been taken yet and following the revision to the IRP in November 2013 halving the forecast nuclear capacity for 2030, it not clear when a call for tenders would be opened.[2] The first reactor was previously expected on line in 2022 with the next five following at 18 month intervals. This programme was then described as follows[3]:

> 'A commitment to the construction of the nuclear fleet is made based on government policy and reduced risk exposure to future fuel and renewable costs.'

The update of November 2013 suggests that nuclear capacity will not be needed before 2025. The need for a decision on nuclear will not be before 2015 and if other options are pursued such as the Inga hydro-electric project, or a more rapid development of solar options, the need for a decision could be after 2017.

On costs, there is ambiguity. The version of the IRP that predated the November 2013 update assumed nuclear construction costs would be 40 per cent higher than assumed in the original IRP2010, although, the new higher estimate still appears far too low. This new higher estimate is not revised in the November 2013 update. Note that if we assume a general inflation rate of 3 per cent for Europe, the region of origin of the EPR, this would increase nominal prices by about 10 per cent in three years so the original cost estimate of $4,200 from 2010 would be about $4,600 in 2013 money

Yet in the report summary (p 6), it is stated: 'to account for the uncertainties associated with the costs of renewables and fuels, a nuclear fleet of 9,000 MW is included in the IRP' and on p 18, it is stated: If the nuclear costs should turn out to be higher than assumed, this could increase the expected price of electricity. This can be mitigated with a firm commitment to 3,000 MW of nuclear.'

It is hard to see the logic in this. If estimated nuclear power costs are so uncertain that they can be increased by 40 per cent in a short period of time, this suggests nuclear power is highly risky and not a sensible choice to reduce risk. There is no evidence that the costs can be fixed by committing to order just two reactors. Most international tenders are for at least two reactors and real costs are continuing to rise not least as lessons from Fukushima are fed into reactor designs, no vendor is going to fix the price for a decade forward at a price that might well not cover its costs. It is not clear what impact the reduction in forecast nuclear needs and the delay in the start of the programme

---

[1] For more details on Electricity Market Reform, see http://www.decc.gov.uk/en/content/cms/meeting_energy/markets/electricity/electricity.aspx
[2] Q2 2012 Areva CI Earnings Conference Call – Final.
[3] http://www.energy.gov.za/IRP/irp per cent20files/IRP2010_2030_Final_Report_20110325.pdf p 22

would have on the assumption that a large commitment would mitigate any price increases for nuclear power.

However, most relevant is the earlier call for tenders of 2008. Thomas wrote[4]:

> 'By mid-2007, Eskom was targeting construction of 20,000 MW on new nuclear capacity by 2025, although completion of the first unit had slipped to 2014. It expected a construction cost of $2,500/kW. In January 2008, Eskom received two bids in reply to its call for tenders from November of the previous year for 3,200 to 3,400 MW of new nuclear capacity in the near term and up to 20,000 MW by 2025. One bid was from Areva for two EPRs (plus 10 more for the long-term) and the other from Westinghouse for the three AP1000s (plus 17 more in the long term).[5]Both claimed their bids were "turnkey," but whether they were really turnkey in the fixed price sense or whether they were simply for the whole plant is not clear. It was later reported that the bids were for around $6,000/kW – more than double the expected price.[6] It was therefore no surprise when Eskom abandoned the tender in December 2008 on the grounds that the magnitude of the investment was too much for it to handle.[7] This was despite the willingness of Coface, the French government's loan guarantee body, to offer export credit guarantees and despite Areva's claims that it could have arranged 85 per cent of the financing.[8] While Eskom is still claiming it expects to order nuclear plants, it seems unlikely that it will be able to finance these. *Engineering News* reported that the issue was the credit rating of Eskom[9]: 'In fact, ratings agency Standard & Poor's said on Thursday that South Africa's National Treasury needed to extend "unconditional, timely guarantees" across all Eskom's debt stock if it hoped to sustain the utility's current BBB+ investment-grade credit rating. The National Treasury was still to announce the details of the package. The Eskom board had, as a result, decided to terminate the commercial procurement process to select the preferred bidder for the construction of the Nuclear-1 project.'

A number of points emerge from this experience:

- The South African government has a history of unrealistic expectations on nuclear power that predate this experience with a decade wasted trying to commercialise the Pebble Bed Modular Reactor;
- The bids in the previous tender of 2008 (updated for inflation to 2012 prices to $6750/kW) were about 16 per cent higher than the cost assumed in the updated IRP and about 50 per cent higher than the level originally assumed in the IRP2010. It is incomprehensible why the South African government went to international consultants to get an estimate of the cost of a nuclear power plant when it had recent experience likely to be a much more reliable estimate of costs, the results of its earlier tender, than a consultant's cost estimate;
- The price agreed for Hinkley Point in November 2013 of about $8000/kW suggest that nuclear prices have gone up significantly faster than inflation since 2008;

[4] http://www.boell.de/downloads/ecology/Thomas_economics.pdf p 44
[5] Nucleonics Week 'Eskom Gets Bids for Two EPRS, Three AP1000s, Bigger 'Fleet,'' February 7, 2008.
[6] Nucleonics Week 'Big Cost Hikes Make Vendors Wary of Releasing Reactor Cost Estimates' Sep 11, 2008.
[7] Nucleonics Week 'Eskom Cancels Tender for Initial Reactors' December 11, 2008.
[8] The Star 'Nuclear Bid Had Funding – AREVA' January 30, 2009.
[9] Engineering News 'Eskom Terminates Nuclear 1 Procurement Process, but SA Still Committed to Nuclear' December 5, 2008.

- The issue of finance is not considered as an uncertainty in the IRP. Only four years ago in 2008, a programme of two reactors proved to be unfinanceable yet it is not even questioned that a programme of six reactors might not be financeable.

The South African government is not alone in being misled by uncritically accepting over-optimistic cost forecasts made by nuclear proponents. In its White Paper on nuclear power published in 2008, the British government assumed an EPR could be built in the UK for £2bn. In 2013, it agreed to a deal with EDF to build two EPRs in the UK at a cost of £8bn. Over that five year period, general inflation was about 3 per cent per annum and would only have increased the original estimate of £2bn to about £2.3bn.

3. Issues with IRP methodology

There are a number of issues that can make application of IRP methodology difficult.

3.1 Strategic decisions

Prior to use of IRP methodology, many expensive decisions were justified on strategic grounds, often bogus. IRP methodology does increase transparency for strategic decisions but given that the value of strategic objectives are often difficult to quantify, for example, what is the value of reducing dependence on an unreliable fuel supplier, strategic decisions cannot generally be integrated into the IRP methodology but must be imposed on the options. This is of particular relevance to South Africa's IRP 2010 in which the government chose to override cost considerations and force its preferred nuclear programme of adding 9,600 MW of nuclear capacity by 2030.

The IRP stated[10]:

> 'Three policy choice options were identified:
>
> a) Commit to the nuclear fleet as indicated in the RBS;
>
> b) Delay the decision on the nuclear fleet indefinitely (and allow alternatives to be considered in the interim);
>
> c) Commit to the construction of one or two nuclear units in 2022-4, but delay a decision on the full nuclear fleet until higher certainty is reached on future cost evolution and risk exposure both for nuclear and renewables.
>
> The Department accepted option 4.3a, committing to a full nuclear fleet of 9 600 MW. This should provide acceptable assurance of security of supply in the event of a peak oil-type increase in fuel prices and ensure that sufficient dispatchable base-load capacity is constructed to meet demand in peak hours each year.'

In short, the option to choose to build 9,600 MW of new nuclear capacity did not emerge from the IRP process, it was imposed upon it. Imposing options is not wrong *per se*, but if a strategic objective is being pursued, it would be logical that checks be made to confirm that the option chosen is indeed the cheapest way to meet that objective. This does not appear to have been done in the case of the decision to impose 9,600 MW of nuclear capacity on the plan.

In December 2013, the South African government revised the IRP2010 again and cut back the nuclear forecast for 2030 by half to 4.86GW of nuclear power, equivalent to three reactors of the

[10] http://www.energy.gov.za/IRP/irp per cent20files/IRP2010_2030_Final_Report_20110325.pdf p 11.

most likely choice, the French European Pressurised water Reactor (EPR) supplied by Areva. The report stated[11]:

> 'The revised demand projections suggest that no new nuclear base-load capacity is required until after 2025 (and for lower demand not until at earliest 2035) and that there are alternative options, such as regional hydro, that can fulfil the requirement and allow further exploration of the shale gas potential before prematurely committing to a technology that may be redundant if the electricity demand expectations do not materialise.'

3.2 Demand projections

IRP methodology is heavily dependent on demand projections. If the forecast is too high, there will be over-investment leading to higher than necessary energy prices and if it is too low, security of supply will be jeopardised. The IRP is based on an assumption that peak demand will grow by about 75 per cent between 2010 and 2030, an annual rate of about 3 per cent.

While it is intuitively sensible to assume that with many South Africans consuming very little electricity, that demand will grow as living standards increase. However, South Africa already consumes a comparable amount of power per capita as Western European countries because of the existence of large amounts of electric intensive industry such as metal manufacture. Whether it is appropriate for South Africa to support electric intensive industry, which may contribute relatively little to GDP, employment and government income is a political decision. However, if some of this industry, which receives very cheap power, was relocated to other countries, the welfare of South Africans, as measured by their electricity consumption could increase in a scenario of low demand growth. More aggressive demand side measures could also achieve the same. The government acknowledges that its demand forecasts are high[12]:

> 'The forecast demand is at the higher end of the anticipated spectrum. The risk is thus that the actual demand turns out to be lower than forecast. In this case, the effect would be limited to over-investment in capacity. Security of supply is not jeopardised because of the conservative assumptions regarding energy efficiency and thus demand reducing measures.'

The IRP update of November 2013 belatedly acknowledges the unreliability of the demand forecasts that its earlier nuclear plans were based on and identifies that aluminium smelters are now relocating outside South Africa because of high power costs. Given that aluminium consumes a large proportion of South Africa's electricity but contributes little to GDP and to employment, it is not clear that this relocation will have much impact on the South African economy.

3.3 Data requirements

The basis for IRP is that all options should be considered and this places a huge burden to collect accurate demand forecasts and cost data, such as fuel cost and construction cost for all the options so they can be evaluated fairly. Inevitably, in some cases and particularly decades into the future, costs are going to be speculative and subject to a wide margin of error, perhaps sufficient to invalidate the results of the exercise. The electricity industry and government ministries have shown little capability to forecast these variables with any degree of accuracy even only a few years forward. So while in theory, this is the ideal way to plan investment in power plants, in practice, the data requirements mean the results are not always reliable.

---

[11] Nuclear Intelligence Weekly 'South Africa: Paring back nuclear plans' December 6, 2013, p 3
[12] http://www.energy.gov.za/IRP/irp per cent20files/IRP2010_2030_Final_Report_20110325.pdf p 18

Again, this does not invalidate the exercise but it does mean results dependent on highly uncertain variables must be treated with care. In this paper, we examine in detail the cost assumptions made for nuclear power, including the value chosen and the level of uncertainty associated with these variables.

3.4 Other approaches

A number of other measures of the attractiveness of various options are sometimes introduced and these are discussed in more detail in Annex 1. The Levelised Cost of Energy (LCOE) attempts to calculate the average cost of power over the life of the plant but takes no account of system consideration. The South African government has introduced a Cap on the expected construction cost of nuclear power plants as a filtering device rather than as a decision-making tool.

4. The nuclear cost estimates in the IRP

Under conventional cost accounting procedures, the majority of the cost of a kWh of nuclear electricity is accounted for by the fixed costs associated with the construction of the plant. These costs are fixed in the sense that they are incurred regardless of whether the plant is operated. This fixed cost has three main components:

- The 'overnight' cost of construction. This excludes the cost of finance (i.e., as if the plant was built 'overnight' but includes the first fuel charge (a relatively small cost);
- The cost of finance. Typically, any large investment is financed by a mixture of borrowing (debt) and use of own resources or sale of shares to a third party (equity). The interest rates should be expressed net of inflation (i.e., 'real' rates). Debt is typically lower cost than equity but financiers are often unwilling to provide finance unless the borrower is prepared to put up some of their own money. If the real cost of borrowing is 8 per cent and borrowing accounts for 60 per cent of the finance and the rest is made up of equity at a real cost of 12 per cent, the Weighted Average Cost of Capital is 9.6 per cent (8*0.6 + 12*0.4);
- The load factor. The load factor (capacity factor in US parlance) is the output of the plant in kWh, typically over a period of a year or over the life of the plant, expressed as a percentage of the output the plant would have produced had it operated uninterrupted at full power for the entire period. The more output the plant produces, the more thinly the fixed charges can be spread.[13]

Other factors are either much smaller (not insignificant) for example, the operating costs, including fuel or the way in which conventional accounting deals with them makes their contribution small, for example, waste disposal and decommissioning costs. The operating costs are not dealt with here in much detail but the waste disposal and decommissioning costs are covered.

4.1 Impact of general inflation

One of the problems of comparing nuclear costs is that they frequently refer to different cost year bases and if distortions due to the impact of general price inflation are to be avoided, some correction is needed, although over 2-3 years, the impact is generally small and within the margin of uncertainty between forecasts. Nuclear construction costs are determined in a global market and the relevant rate of general inflation is that applying in Europe and USA. This fluctuates from year-to-year, but a reasonable assumption is that general price inflation is 3 per cent per year. Table 1

[13] For a more detailed account of the economics of nuclear power, see http://www.boell.de/downloads/ecology/Thomas_economics.pdf

shows the impact of inflation at this level over up to 10 years. This shows that to convert a price of 8 years ago to current levels would require that it be multiplied by 1.23.

Table 1 Impact of general inflation on nominal prices

Year	Correction factor for inflation
1	1.0
2	1.03
3	1.061
4	1.093
5	1.126
6	1.159
7	1.194
8	1.23
9	1.267
10	1.305

4.2 Construction cost

The construction cost is central to the cost of power from a reactor. Conventionally, construction cost is quoted as the 'overnight' cost (excluding finance) in dollars per kW of capacity. So, a reactor costing $5,000/kW with a capacity of 1,500 MW would have a total overnight cost of $7.5bn. Clearly there are still a number of problems of comparison: cost estimates from different years may be difficult to compare because of general price inflation; currency exchange rates can fluctuate by up to 20 per cent over quite a short period of time; and site specific costs might differ, for example, the transmission connection cost might differ and the cost of construction will depend on the coolant method and the local geology. Differences in cost of up to 20 per cent might be accounted for by such factors. Nevertheless, the cost per kW does allow the cost of reactors of different sizes installed in different countries to be compared on a reasonably fair basis.

It is sometimes claimed that costs in developing countries will be significantly lower than in developed countries because of lower labour costs. This is not valid. The labour needed is often highly skilled and specialised and has to be brought in from outside the country and has to be paid internationally competitive rates. For example, for the Olkiluoto plant, the workforce is drawn from about 20 countries and this has led to problems of communication. Finland is a much richer country with a skilled workforce and has substantially more nuclear experience than South Africa.

When the Nuclear Renaissance was being first discussed a decade or more ago, the nuclear industry confidently predicted Gen III+ reactors could be built for $1,000/kW. In retrospect, this claim was never feasible but it did convince governments like those of the USA and UK to start efforts to recommence nuclear ordering. By the time the Olkiluoto bid was placed, the price was about $2,300/kW. Estimate costs continued to rise and as US utilities began to plan their new reactors, their cost estimates were around $5,000/kW. From 2008 onwards, a number of calls for tender were held, for example, in Canada, South Africa and the UAE and the lowest bids, apart from the Korean bid for UAE were at least $6,000/kW.

The updated Integrated Resource Plan[14] assumes a base case of an overnight construction cost of $5,800/kW. The cost is described as 'overnight' as it includes no finance charges during the construction period (i.e., the plant was built overnight) to avoid distortions cause by different companies having different finance costs; is per kW to allow fair comparisons between reactors of different sizes; and is quoted in US dollars to avoid distortions from fluctuations in local exchange

[14] http://www.doe-irp.co.za/content/IRP2010_updatea.pdf

rates. The plan implies that if the expected cost is more than $6,500/kW, the nuclear programme would not proceed. Recent information on costs of nuclear power plants suggests that the estimate of $5,800/kW is hopelessly unrealistic and if South Africa proceeds to a tender, the bids received will far exceed the upper limit of $6,500/kW and the tender will have to be abandoned as was the case in 2009 when the lowest bid received, reported to be about $6000/kW, proved so high as to be unfinanceable. If we assume general inflation of 3 per cent per year, a bid of $6000/kW in 2008 money would be equivalent to about $6750/kW in 2012 money. The lack of expertise on nuclear power is apparent in the material produced by the South African Department of Energy and in Annex 3, we examine a recent call for tenders which illustrates this lack of expertise.

The simplest policy course now would be to immediately abandon the nuclear aspirations as unachievable and concentrate on options that are able to meet South Africa's energy policy priorities. However, if the government wants to obtain a realistic view of the construction cost of nuclear power plants, it should commission an independent study of the construction cost. This should be based on well-documented and verifiable costs or cost estimates. Historic evidence suggests that the reliability of indicators of construction cost, in descending order of reliability is:

- The most recent outturn cost for completed plants. These should be costs that are independently verified;
- Bids to calls for tenders for capacity. These bids are based on what vendors believe costs really will be and vendors' reputations will be damaged if these prove inaccurate. In practice, these bids are often too low, as was the case with the Finnish Olkiluoto plant (see below) but the vendor does bear some responsibility for them; and
- Indicative costs put forward by vendors or interest groups. These have historically been hopelessly inaccurate and are basically worthless. For example, around 2000, the world nuclear industry was confidently claiming the new generation designs, the type South Africa is looking to build would cost only $1,000/kW.

4.3 Recent information on construction costs of nuclear power plants

4.3.1 Construction costs of EPRs

The most recent firm information in the cost of new nuclear power plants comes from three projects, the Olkiluoto 3 plant in Finland; Flamanville 3 plant in France and the Hinkley Point C project for the UK.[15] All involve European Pressurised Water Reactors (EPRs) supplied by the French government controlled company, Areva.

4.3.2 Olkiluoto

Construction work on the Olkiluoto plant (1600MW) started in May 2005 with expected first power in 2009 and a fixed price contract to build the plant for €3bn. At current exchange rates of €1=$1.33, this equates to $2500/kW. From the start the project went badly wrong and the most recent estimate forecasts completion in 2016 at a cost of €8.5bn.[16] This equates to $7000/kW. Areva is refusing to honour the fixed priced contract and the issue of who bears the cost of the cost overruns is being decided in the Stockholm Court of Arbitration.

4.3.3 Flamanville

The problems at Olkiluoto were often attributed to specific conditions in Finland, such as lack of recent experience with nuclear power construction and shortage of local skills and, it was claimed,

[15] For more details on the historic record of the EPR, see: S Thomas (2010) 'The EPR in Crisis' http://www.nirs.org/reactorwatch/newreactors/eprcrisis31110.pdf

[16] Nucleonics Week 'Olkiluoto-3 EPR likely not to operate before 2016: TVO' February 14, 2013

the problems would not recur in a French project. The Flamanville plant started construction in December 2007 and was expected to be complete by 2012 at a cost of €3.2bn, about $2700/kW. However, problems occurred from the start and, as with Olkiluoto, the first structural concrete was not properly poured. Arguably, the project is further off course than Olkiluoto was at the equivalent stage. Like Olkiluoto, completion is expected in 2016 at a cost of $7000/kW.

4.3.4 Hinkley Point

In October 2013, the British government announced it had reached agreement with Electricité de France (EDF) to build two EPRs.[17] The agreed price for the plants is £8bn per unit. This equates to $8000/kW. This figure is surprisingly high as it implies that the expected cost of a new EPR is now higher than the current forecasts for two projects that have gone catastrophically wrong. The possible explanations for this include: there has been extraordinary escalation in costs since the Olkiluoto and Flamanville orders; the Hinkley Point price includes very large contingencies to cover the cost of construction problems; and the contract is remarkably favourable to EDF. Reports in the South African press that Areva accepts the figures in the updated IPRP. The South African MD for Areva is reported to have said:[18] 'the group is pleased with the "realistic projections" contained in the update regarding the building of nuclear base-load capacity by 2035.' Given that the sum agreed for an EPR reactor supplied to the UK in October 2013 was 38 per cent higher than this, it is hard to see how a figure of $5800/kW can be seen as 'realistic'.

4.3.5 Requirements to finance nuclear power plants

The other features of the contract are also worth noting as they give clear indications of what the requirements to obtain finance for a nuclear power plant are. The initial price for power will be £92.5/MWh. At an exchange rate of £1=R$17, this equates to about R$1600/MWh (R$1.6/kWh). This has been widely reported to be double the prevailing electricity wholesale market price for power. This price will go up in line with general inflation and may be indexed to other cost factors. The contract will not be released in full as the government has stated elements are commercially confidential so it is impossible to identify the escalators. The power will be bought on a 35 year contract to be signed by a new agency of government yet to be set up. The government is giving loan guarantees worth £10bn. This is expected to cover the debt (borrowing) part of the finance with the rest of the cost coming from 'equity' (self-finance. The contract is specifically with a new company, NNB Genco, which will be a consortium expected to include EDF, Areva and two Chinese companies, China General Nuclear (CGN) and China National Nuclear Corporation (CNNC). The shares of the consortium are yet to be determined but the expectation is that it will comprise 50 per cent EDF, 10 per cent Areva and 40 per cent CGN/CNNC. It seems apparent that without the Chinese contribution, EDF would not have been able to finance the project. The loan guarantees essentially mean the banks financing the project are lending to the British government and mean that if the project goes badly (as at Olkiluoto and Flamanville) and the loans cannot be repaid by NNB Genco, British taxpayers will have to repay the banks. The Chinese contribution appears to be purely financial for this project as China has no technologies or supply to offer and it seems unlikely it has human resources that could be usefully used.

---

[17] https://www.gov.uk/government/news/initial-agreement-reached-on-new-nuclear-power-station-at-hinkley
[18] http://www.engineeringnews.co.za/article/areva-welcomes-irp-updates-nuclear-cost-ceiling-proposal-2013-12-11/rep_id:3182?utm_source=Creamer+Media+FDE+service&utm_medium=email&utm_campaign=Areva+welcomes+IRP+update+ per cent7C+Africa+behind+in+financial+inclusion+ per cent7C+Kentz+upscaling+Moz+presence&utm_term=http per cent3A per cent2F per cent2Fwww.engineeringnews.co.za per cent2Farticle per cent2Fareva-welcomes-irp-updates-nuclear-cost-ceiling-proposal-2013-12-11 per cent2Frep_id per cent3A3182

The deal was generally not well received. Liberum Capital, an independent British investment bank, in a report entitled 'Flabbergasted: The Hinkley Point Contract'[19] stated:

- Based on the disclosure so far this looks likely to be an outstanding deal for Edf and its partners. On a leveraged basis we expect Edf to earn a Return on Equity (ROE) well in excess of 20 per cent and possibly as high as 35 per cent.
- Once again, the UK government is taking a massive bet that fossil fuel prices will be extremely high in the future. If that bet proves to be wrong then this contract will look economically insane when HPC commissions. We are frankly staggered that the UK government thinks it is appropriate to take such a bet and under-write the economics of any power station that costs £5m per MW and takes 9 years to build.

The reality may be that the British government has negotiated the best terms it can but these are the terms that are needed to persuade financiers to lend money for nuclear power projects. After spending 7 years' time, effort and resources to get this far, the government was unwilling to face the humiliation of abandoning the nuclear programme despite the massive cost and risks being passed through to electricity consumers and taxpayers. This points to the risks of governments backing themselves into a corner by becoming too heavily committed to a particular technology choice.

4.4 Load factor

The nuclear industry consistently assumed that nuclear power plants would be very reliable and would achieve lifetime load factors of 90 per cent or more. Reliability worldwide has improved since around 1980 when the average load factor worldwide was about 60 per cent and now the average is about 80 per cent. However, over the life of the plant, no more than a handful of reactors with more than a couple of years of operation has achieved a lifetime load factor of more than 90 per cent (most of these are in Germany). The two Koeberg reactors both have life time load factors over their 20 year life of 69 per cent.[20] The IRP assumption of 92 per cent appears hopelessly unrealistic.

The impact of poorer reliability goes much beyond the impact on the fixed costs. Poor reliability is likely to result in higher maintenance and repair costs and, perhaps most important, the power that the plant was expected to produce but did not, has to be produced from other sources. Power systems are usually run on 'merit order' basis under which plants are brought into operation or taken off line as demand rises and falls on a daily basis according to their operating costs. So, if a nuclear power plant breaks down, it must be replaced by a plant that would otherwise have been too expensive to operate. These so-called replacement power costs can be huge.

4.5 Cost of capital

The cost of capital is covered by use of a 'discount' rate. The discount rate is not the same as the cost of capital, but it is clearly related. The main factor determining the cost of capital is the financiers' perception of how risky the project is. The credit rating of the country involved has some impact but, in most cases, mainly it is the riskiness of the project and who that risk falls upon. The record of nuclear power plants seldom if ever being built to time and costs, of operating significantly less reliably than expected and of real cost escalation in all aspects of the product life cycle from construction costs, through operating costs to decommissioning and waste disposal makes nuclear power by far the riskiest commercial generation option. In the past, this riskiness has been of

[19] Liberum Capital (2013) 'Flabbergasted: The Hinkley Point Contract' http://www.liberumcapital.com/pdf/ULkWtp00.pdf

[20] http://www.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=836

limited relevance because the implicit assumption has been that consumers would pay whatever costs were incurred and if things went wrong, the company owning the plant was not at risk.

In the past two decades this assumption has in many cases been broken with the adoption of competitive markets in some cases and the introduction of independent price regulators in others. In a competitive market, a company whose costs are too high goes bankrupt as was the case with the UK nuclear generation company, British Energy, in 2002. Independent regulators may be unwilling to pass on to consumers costs they consider to be 'imprudently incurred'. These imprudently incurred costs had to come from profits and if the amount was high, the utility could be bankrupted. The increased scrutiny of US regulators in the late 1970s led to the end of nuclear ordering there (the last order not subsequently cancelled was placed in 1974) as banks made it clear that it would not lend money for nuclear projects and pressured utilities to cancel existing orders.

The only orders for nuclear power plants in the past two decades have been placed in centrally planned, generally publicly owned systems, such as China, Russia and Korea or in countries where the utility has a dominant market share (for example, EDF in France, or is offering a 'cost-plus' contract to purchase the power (for example, TVO in Finland).

In South Africa, there is now an independent regulatory body and of that body has any rationale, it will be unwilling to pass on large cost overruns for a nuclear project to South African consumers. A nuclear power plant in South Africa must therefore be regarded as a risky investment as was made clear by the views of Standard & Poor's, the credit rating agency, which was asking for unconditional state-backed guarantees on *all* Eskom's debt if it was not to reduce Eskom's credit rating. Reducing Eskom's credit rating would have increased their cost of borrowing for all its debts and would have increased its overall costs (and the price of electricity) substantially.

There are two options other than guaranteed cost pass-through that would reduce the risk on banks. A 'turn-key' (fixed price) contract would place the risk of cost escalation on the vendor. Such contracts have been extremely rare for nuclear power plants because the vendors do not have the financial resources to take that risk. A turn-key contract was signed for the Olkiluoto plant but when costs began to escalate, Areva, the vendor refused to honour the contract blaming the utility and the case about who pays the extra costs (now more than €3bn) will be settled in the Stockholm Court of Arbitration. For these purposes, it is irrelevant who is to blame, the consequence is that a fully fixed price contract to supply a nuclear power plant is highly unlikely to be offered and even if it is, financiers are likely to assume it is not worth the paper it is written on.

The other option is for state guarantees to cover the loans, for example, offered by the government of the country of the vendor. Under this, if the utility went bankrupt and could not repay the bank, the taxpayers of the country offering the guarantee would repay the banks. This would mean the bank was, essentially, lending to a national government and the interest rate would be commensurately low. This has attractions, but there are serious problems: First, if the costs do overrun, the utility will have to go to the market to borrow money to finance a project going badly wrong; second, this will be extremely expensive. If the utility does fail, the banks will be repaid but consumers and or taxpayers will be faced with large costs to bail out the utility or make alternative provisions; third, in today's economic climate government Treasury's are going to be reluctant to take on large potential liabilities and will be unwilling to offer loan guarantees; and finally, under OECD guidelines, loan guarantees should attract an fee that reflects the riskiness of the project. This fee should be an economic one and if it truly reflects the risk, this fee might well counterbalance the advantages of the lower interest rate.

For the IRP, a standard real discount rate of 8 per cent for all options is used. In practice, and unless an explicit risk analysis is done, this implicitly assumes all options are equally risky. The problems with this assumption are alluded to on page 22 of the IRP where it states: 'The possibility of different discount rates for technology to factor in different risk profiles for the technologies should also be investigated.' This has not been done. It is difficult to know what an appropriate cost of capital for a nuclear power plant exposed to risk would be. It could well be double the assumed rate.

4.6 Impact of changes to the fixed costs on the cost of power

To measure the impact of alternative assumptions on construction cost, load factor and cost of capital would require a full re-running of the IRP but some idea of the impact can be gained by making some very simple assumptions. Let us assume, purely for illustration, that with IRP assumptions, the cost of power from a nuclear power plant was ZAR100/MWh and that was made up of two thirds fixed costs associated with construction and one third running costs. Let us assume that the construction cost is 50 per cent higher than assumed, bringing it into line with most current estimates. This would increase the cost of power to ZAR133/MWh. If the cost of capital was 12 per cent rather than 8 per cent, this would also increase the cost of power to ZAR133/MWh. If we assume the load factor was 70 per cent instead of the 92 per cent assumed, this would increase the cost of power to ZAR121/MWh. A lower load factor would lead to other increases in cost, such as replacement power costs and higher maintenance and repair costs. These extra costs are not estimated here. If all three alternative assumptions were applied, the cost of power would increase to ZAR230/MWh.

These assumptions are far from worst cases. For construction cost, the alternative assumption only brings it into line with international estimates and the cost of capital could also be double the assumed level. This would mean the cost of power from a nuclear reactor would be about three times the expected level. If more realistic assumptions were applied to running costs and the cost of decommissioning and waste disposal were properly factored in, the costs would be even higher.

4.7 Decommissioning and waste disposal

In absolute terms, the cost of waste disposal and decommissioning are of the same order as the cost of construction. For example, in the 2007/08 annual report and accounts of British Energy, the British nuclear power generator, it was estimated the cost of decommissioning its eight plants was £9.4bn and the cost of disposal of the spent fuel was £5.5bn.[21]

However, these liabilities fall due far into the future. For example, in the UK, the most difficult stage of decommissioning, cutting up and disposing of the contaminated equipment and cleaning the site so it can be released for unrestricted use is not expected to take place until about 60-80 years after plant closure. So, if it is assumed that a nuclear plant operates for 40-60 years, on the day of its commissioning, it will 100-140 years before most decommissioning funds are needed. Current UK government plans foresee that a disposal site for spent fuel will not be available until 2125. If we assume a fund is created and it earns a real interest rate of 2.5 per cent, such a fund will grow in real terms by a factor of about 12, so even though estimated costs for decommissioning are very high, this process of 'discounting' means that a liability of, say, £5bn that falls due in 100 years, can be shown in the company accounts and fed into the cost estimates as a discounted liability of only £420m. This means that these large costs can effectively be made to 'disappear' from cost estimates of a kWh of nuclear electricity.

[21] http://www.british-energy.com/documents/Annual_report_2007_2008.pdf. Note, more up to date data is not available because the company was taken over by Electricité de France and no longer publishes this data.

Best practice for decommissioning funds is that they be 'segregated' from other company funds so that they cannot be affected by changes to the company, at worst, for example bankruptcy.

The Integrated Resource Plan is not very explicit on how decommissioning costs are accounted for and how funds are collected and dealt with (see Annex 2 for details of world experience of nuclear power plant decommissioning). In its first revision, it states:[22]

> 'The capital costs for nuclear were increased by 40 per cent to accommodate inputs from numerous sources that the EPRI costs under-estimated the capital costs for newer nuclear technologies. The costs for decommissioning and waste management were also not fully incorporated in the original EPRI cost estimates and this adjustment allowed some accounting for these important elements.'

Some more information on how provisioning for decommissioning is planned were released in a document released in January 2014.[23] In 5.1.1 of this document and elsewhere, there is a conspicuous absence of any requirement for segregated funds. This is worrying as it leaves a risk that there will be no money available for decommissioning when it is required. For example, in the UK, consumers contributed money for decommissioning from 1979-90 but this money was not segregated and when the company was privatised, this money was lost, effectively taken by the UK Treasury. While, for example, there are no plans for privatisation of Eskom currently, in 100 years' time when decommissioning might take place, the picture is likely to have changed many times over.

Decommissioning for Koeberg is assumed to take place in only 16 years which, by international standards is exceptionally fast - the average expected time in UK is 90 years. Given that no large nuclear power plant has been decommissioned anywhere in the world apart from six reactors in the USA, it is not clear whether the plans for South Africa are realistic and whether this difference is significant.

5.2 of this document states the estimate for Koeberg is R8.69 billion, which equates to about $817m or $450/kW. That estimated cost is a discounted cost. If it is discounted at, say, only 2.5 per cent real for 16 years, the undiscounted price would be about 50 per cent higher ($675/kW). If we look at the plans for Hinkley Point C, the assumed decommissioning cost appears to be not less than $900/kW with a cap at $1,350/kW. This makes the South African estimate look very low.

5. The technology options

When the programme of 9,600 MW of new nuclear capacity was announced, there was a great deal of speculation about potential suppliers in addition to the two companies Areva with the EPR and Toshiba/Westinghouse with the AP1000 that participated in the 2008 call for tenders. These included suppliers from China, Russia and Korea. It seemed that the conclusion of the government and Eskom was that the reason the bids were so high was that the tender had been done wrongly so that the bids were higher than they should have been and that other suppliers, not included in that process would offer much cheaper prices. This attitude was quickly shown to be naïve.

It seems that South Africa is interested only in Pressurised Water Reactors (PWRs) not their close relative, the Boiling Water Reactor (BWR). The two reactors at Koeberg are PWRs so this has some logic. If BWRs were included, one or two more options would emerge but there is no evidence the costs would be lower. There was also speculation that earlier generation designs, so-called Generation II, that would not meet current Western safety requirements, assumed to be cheaper,

[22] http://www.energy.gov.za/files/irp_frame.html, p 39
[23] Eskom 'Status of decommissioning strategy and plans for Koeberg nuclear power station' Eskom

would also be considered. This option now appears to have been discounted and South Africa is only interested in Generation III or III+ designs.

The designation of design generation is not precise but, broadly, Gen I includes demonstration and early commercial plants. Gen II includes most of the approximately 450 commercial reactors in operation in the world, including Koeberg. Theses reactors were designed in the late 1960s and the 1970s but pre-date the Three Mile Island accident of 1978. Gen III designs take account of Three Mile Island but do not take full account of the Chernobyl disaster, while Gen III+ are the latest designs. Few reactors of Generation III design are in service yet and no reactors of Gen III+ are in service yet. Only two Gen III+ designs have received orders. The EPR has four orders, two for China, one for Finland and one for France. The AP1000 has eight orders, four for China and four for the USA, although main construction work on the four US units has yet to start. So if South Africa wants proven technology, that is, a design with significant operating experience, it will need to go back to designs made 30 or more years ago.

Amongst the PWR suppliers there five obvious options: the Areva EPR, the Toshiba-Westinghouse AP1000, the Korean AP1400, Chinese designs and the Russian AES-2006.

5.1 Areva EPR[24]

This option was the lowest bidder for the 2008 tender albeit far too high to be financeable. It was the first Gen III+ design to receive an order, with construction starting on a reactor in Finland (Olkiluoto) in May 2005 followed by an order for France (Flamanville) on which construction was started in December 2007. Two EPRs are under construction in China (Taishan), starting in 2009. The Olkiluoto project has gone disastrously wrong and the plant which was expected to take four years to build and cost €3bn is now going to take at least 10 years and cost more than double the estimate. Things have gone no better at Flamanville, which is also now four years late and 100 per cent over-budget. There is no clear cause for these delays, a large number of design issues, construction errors etc. seem the main culprits. Reports from China claim the Taishan plants are on schedule but it is hard to get independent verification of this.

One of the issues with the Olkiluoto and Flamanville plants was that the design had not been fully reviewed by the safety authorities before construction started, as was normal practice up to then. In the USA and the UK, full 'generic' design reviews are now required before construction can start to avoid the sort of problems encountered at Olkiluoto and Flamanville. This process is not expected to be complete in the UK till 2013 or later and in the USA by 2014 or later. There is still a major issue to be resolved in the Instrumentation and Control system (the 'brain' of the reactor). This was flagged up by regulators in 2009, but the solution to the issue is still some way from being established.

This means the EPR design is not yet finalised – the designs for Olkiluoto, Flamanville and Taishan will all differ from this final design. Areva and EDF are now reviewing the design again to reduce the cost and this means the design that is approved in the UK and the USA may be changed again before orders for South Africa could be placed. China seems unlikely to pursue the EPR option, although it is possible that China could partner an EPR bid for South Africa.

5.2 AP1000

The AP1000 has orders for China and the USA but independent information on the progress of the Chinese sites is hard to establish. It appears construction is running up to a year late.[25] Construction

[24] For more details on this design, see S Thomas (2010) 'The EPR in crisis', PSIRU, University of Greenwich http://gala.gre.ac.uk/4699/3/ per cent28ITEM_4699 per cent29_THOMAS_2010-11-E-EPR.pdf
[25] Nuclear Intelligence Weekly 'CHINA: AP1000s Delayed by 6-12 Months, SNPTC Says' January 17, 2012, p 4.

work is expected to start in 2013 for the four US reactors. The generic review of the AP1000 has been completed in the USA but the process has been suspended, incomplete, in the UK until Toshiba-Westinghouse has a UK customer.

The AP1000 was expected to take over as the main choice for China but concerns over its high price have put this in doubt. It is not clear whether the AP1000 would be bid again in South Africa. It is possible that China could partner Toshiba for a bid for South Africa.

5.3 Korea

Korea has been building reactors for decades with increasing local content, although the designs it has built have all been under license to US vendors. Its latest design, the AP1400, was licensed from the US company, Combustion Engineering, now part of Toshiba-Westinghouse. Toshiba Westinghouse does allow it to offer the design for export. It received generic design approval in the USA in 1997, but that approval expired in 2012. Construction work in Korea on the first two units of this design (Shin-Kori 3 & 4) started in 2009 with a third (Shin-Ulchin) starting construction in 2012. Korea emerged as a potentially significant exporter of nuclear technology with its winning of a competitive tender in UAE in 2009.

In December 2009, the UAE ordered four nuclear reactors from Korea using AP1400 technology beating opposition from consortia led by EDF with the EPR and GE-Hitachi (ABWR).[26] The contract is with Korean Electric to build and operate the plants, the first coming on line in 2017 and the last by 2020. KEPCO will provide design, construction and maintenance for the nuclear reactor and will subcontract some of the work to equipment suppliers such as Hyundai, Doosan and Samsung. The terms of the deal and what is included are not clear although the contract is reported to be worth $20.4bn. The Korean bid was reported to be $16bn lower than the French bid and the GE-Hitachi bid was reported to be significantly higher.[27] It appears not to be a whole project 'turnkey' (fixed price) deal. Korean companies will hold an equity stake in a joint venture with UAE public companies, which will operate the plants after their completion. Construction work on the first of these at the Barakh site started in July 2012.

The design being built in Korea and UAE, without a 'core-catcher' and a 'double containment', probably would not be licensable in Europe. Areva was particularly bitter about losing the tender to a design it claimed had much lower safety standards than their EPR. Their then CEO, Anne Lauvergeon likened the APR1400 to "a car without seat belts and airbags".[28] It is unclear whether the AP1400 would meet South Africa's requirement that it order only Gen III designs. In 2010, Korea claimed it would submit the AP1400 to the US NRC for generic design review in 2012.[29] By November 2012, the target date for submission was March 2013. Even if that date was met, the process typically takes at least six years so would not be complete by the time the first South African orders were placed

5.4 China

In the period 2008-10, China saw a remarkable spurt of construction with construction work starting on 25 reactors in that period. This compares to only 17 ordered in the 25 years up till then. Since December 2010, no new construction starts have taken place. In part this is due to reviews following

[26] Korea Herald 'Korea wins landmark nuclear deal' December 28, 2009.
[27] Right Vision News 'UAE: Middle East leads rally in nuclear plant orders' January 12, 2010.
[28] Nucleonics Week 'No core catcher, double containment for UAE reactors, South Koreans say' Apr 22, 2010, p 1.
[29] Inside NRC 'Kepco to submit APR1400 design for NRC review in 2012' April 26, 2010.

the Fukushima disaster with a desire, increased by Fukushima to move away from the old designs that made up most of these orders.

None of the reactors ordered from 2008-10 is yet in service. Of these, four were AP1000s and two EPRs. Of the other 19, two were smaller reactors and the other 17 were supplied by Chinese vendors under license to Areva. This design, M310, was built in France in the 1970s and France itself licensed it from Westinghouse around 1970. So while this design has been updated, it is fundamentally a very old design. France is unwilling for China to export it so, even if such an old design was acceptable in South Africa, it is not a feasible option.[30]Nucleonics Week reported: 'The French nuclear safety authority has said it will not condone French nuclear companies participating in construction of reactors abroad that would not be licensable in France.'[31]

There are a number of Generation III/III+ under development in China: ACPR1000, ACP1000 and CAP1400, the latter in collaboration with Toshiba. However, the designs on all of these are some way from being ready to order. Until China restarts its nuclear programme after the halt called following the Fukushima disaster, it will not be clear which design China will pursue. Even then, the design will not have been reviewed by Western safety authorities so unless South Africa was prepared to rely on the Chinese authorities' assessment, these would not be an option for South Africa.

5.5 Russia

Like China, Russia started ordering nuclear power plants again about 5 years ago. Apart from two export orders for plants to China and India, the Russian nuclear industry had not received an order since the mid-80s prior to the Chernobyl disaster. The Chernobyl technology has been abandoned and Russia now only offers its own version the PWR, the VVER. Its latest design is the AES-2006, a 1 200 MW design which Russia claims should be seen as Gen III+. Five reactors of this design are under construction in Russia, but not yet in service. Russia has won orders for this design for Turkey and Vietnam but construction has not started yet. There appear to be a couple of variants on this design (V-392M and V-491), although it is not clear how far these differ. Russia has shown some interest in getting into Western reactor markets but it has not bid yet in the West and its new designs have only been reviewed by the Russian authorities. Whether this review is comparable to a US/UK full generic review is not known so it is impossible to say whether the AES-2006 would be licensable in the West.

6. Conclusions

In a centrally planned electricity system, integrated resource planning is an excellent tool to ensure that consumers' pay the lowest price possible, consistent with a reliable and 'clean' electricity supply. However, the outcome that South Africa should install 9 600 MW of new nuclear plants by 2030 has nothing to do with the use of IRP. It is an assumption imposed by government. The IRP is based on what is acknowledged to be a demand forecast at the high end of the likely outcomes.

The key assumptions determining the cost of a nuclear kWh are the construction cost, the cost of capital and the load factor. An earlier iteration of the IRP was based on a hopelessly unrealistic forecast of construction costs, about half the level actually bid in 2008 when South Africa carried out an ill-fated call for tenders for nuclear capacity. For the final iteration, this estimate was increased by 40 per cent to $5800 but this still leaves the estimate about 40 per cent lower than most current estimates of about $8000/kW.

[30]Nucleonics Week 'EDF executive seeks joint ventures in China' October 14, 2010.
[31]Nucleonics Week 'Chinese companies look to become nuclear export force with own designs' Dec 2, 2010.

The cost of capital used, 8 per cent, is the same for all options, implying that all are equally economically risky. This is blatantly not the case and, based purely on its past record worldwide, nuclear power is by far the most risky option. If this was reflected in the cost of capital, the cost might double and is unlikely to be less than 50 per cent higher than assumed. The load factor assumed, 92 per cent, is almost unprecedented worldwide for the lifetime of a reactor and is far higher than the two Koeberg reactors have achieved, less than 70 per cent. Poorer load factors than assumed would also lead to other significant extra cost in terms of repair and maintenance and replacement power costs not here estimated.

If more realistic assumptions on construction cost (50 per cent higher), cost of capital (50 per cent higher) and load factor (reliability similar to reactors at Koeberg) were applied, this would double the expected cost of power and if things did not go smoothly, for example, construction cost and cost of capital double the expected level, the cost of power from a new reactor could be two and a half times that expected.

The IRP acknowledges that decommissioning and waste disposal costs are not properly estimated. If provisions were made that properly embodied our moral obligation not to impose financial costs to clean up our environmental damage on a future generation, this would add significantly to the cost, although no estimate of these extra costs is made here. Other assumptions, for example on reactor life-time are also optimistic. Using more realistic assumptions throughout and accounting properly for decommissioning and waste disposal could easily lead to a cost per kWh about three times the level expected.

The government imposed the nuclear programme on the IRP on grounds of its assumed positive impact on security of supply. It is hard to understand how such a blatantly risky option can be seen as a positive contributor to security of supply. Equally, it is hard to believe that with more realistic cost estimates, building nuclear power plants would be the cheapest way to achieve that desired improvement in security of supply.

There has been a lot of ill-informed discussion of the technology options available to South Africa since the failed tenders of 2008. It seemed that the conclusion of the government and Eskom was that the reason the bids were so high was that the tender had been done wrongly so that the bids were higher than they should have been and that other suppliers, not included in that process would offer much cheaper prices. Five options have been mooted: Areva's EPR; Toshiba-Westinghouse's AP1000; a Korean design AP1400; Chinese-supplied reactors; and Russian-supplied reactors. None of these options is proven in the sense of having operating reactors in service yet.

The EPR is the design with the most experience but most of this is appallingly bad. Reactors in Finland and France are running 4-6 years late and at least double the expected cost. There are still major unresolved regulatory issues with the design that were identified at least three years ago.

The AP1000, which has never underbid the EPR in a tender has less experience of construction with no experience outside China, but does have regulatory approval in the USA. Like the EPR, in the previous tender, it proved unfinanceable and it is highly unlikely the price bid in a new tender will be anything other than higher than in 2008.

China is seen as an attractive assumption on the basis of the large number of reactors ordered there in recent years and on the tacit assumption, with no evidence to support it, that because it is Chinese, a reactor would be cheap and of good quality. In practice, the reactors that made up most of the recent burst of orders could not be exported because of license restrictions and would probably be of too early a design generation to meet current safety standards. It has advanced reactor designs under development but these are still some way from being orderable and they have not undergone a comprehensive safety review so are not a realistic option.

Russia has also emerged on the reactor market in the past five years with orders for its home market using a new design that it claims meets current Western standards. These claims have not been tested and no Western regulatory body has undertaken a thorough review of the design.

Overall, there is a risk that South Africa will commit itself to order a large number of reactors that will impose huge additional costs on consumers. However, the more likely risk is that, as in 2008, the nuclear programme will prove impossible. Since 1998, when the Pebble Bed Modular Reactor programme was launched, the South African government has operated on the assumption that nuclear power plants would make up a significant proportion of generation. The result has been that other options, that could have met South Africa's electricity demand needs reliably and cost effectively have been neglected – South Africa, like any other country, has limited resources and cannot pursue all options. If the nuclear programme is not abandoned now, the risk is that efforts to make it happen will continue for several more years, wasting government time and money and leading to more neglect of alternatives, before the government again, as it did with the PBMR and the failed tender of 2008, has to admit defeat.

Annex 1 Other approaches to electricity system investment planning

LCOE approach

A simpler way to decide on new capacity is to calculate the Levelised Cost of Energy (LCOE) from each of the options. This requires that all the costs over the entire life-time of the plant are calculated to provide an average kWh cost over the whole life of the plant. The plant with the lowest LCOE would then be chosen. Such a decision does need to take account of the state of the system. The system should have a balance of 'base-load' plants and 'peaking' plants. Base-load plants, such as nuclear power plants, tend to have high fixed costs and low operating costs and are operated all the time. Peaking plants tend to have low fixed costs and high operating costs and are vital to ensure security of supply but may be operated for only a few hours per year.

Some of the renewables, such as wind and solar, are not available at all times but they have much lower running costs than, say, nuclear power plants, and, in theory should be operated in preference to nuclear power plants. In practice, nuclear power plants are too inflexible to allow this but in some European systems, such as Germany and Spain, there is now a conflict between whether to operate nuclear plants or renewables. In short, this means that systems with inflexible sources, such as nuclear and some renewables require flexible plant to complement them.

There is a common perception that systems need to cover base-load, i.e., the lowest level of demand in the year with base-load plants. This is not true, all that is required is that there be plants to meet demand at all times and base-load could be meet by a mixture of renewables and flexible plant to cover the periods when the renewables are not available.

The data requirements of LCOE are less than for whole system simulations but are still extensive and, for nuclear power, governments and electric utilities have shown little capability to forecast this data accurately. For example, before the call for tenders in South Africa for nuclear capacity in 2008, Eskom had forecast that the construction cost of nuclear would be about \$2500/kW. In the event, the lowest bid received was reported to be \$6000/kW.[32] Similarly, in 2008, the British government forecast that a new nuclear power plant could be built for £2bn. In 2013, the deal to build a new plant was based on a construction cost of £8bn (\$8000/kW).

The nuclear construction cost cap

The South African government has been reported to have placed a cap of \$6500/kW on expected nuclear construction costs, which if exceeded, would mean nuclear was not considered. Whilst this is not a precise way to determine the cheapest way to meet demand, it is a useful way of avoiding unnecessary work with an option that cannot be economic above a certain level of construction costs. Given that the agreement between the British government and EDF was based on construction costs of \$8000/kW and there is no reason to assume nuclear construction costs in South Africa will be any lower than in UK, it seems highly likely that the cap will disqualify nuclear from consideration.[33]

One proviso is that the record of the nuclear industry in forecasting costs is abysmal. 15 years ago, the nuclear industry confidently forecast that a new generation of nuclear designs (so-called Generation III+), the type chosen for UK and which South Africa is considering could be built for only

---

[32] S Thomas (2010) 'The EPR in Crisis' University of Greenwich. http://www.nirs.org/reactorwatch/newreactors/eprcrisis31110.pdf

[33] Note, it is far from certain that the UK will build new nuclear capacity. The agreement has been referred to the European Commission to see if it violates European Union laws on state-aid. If it does, the project will not be allowed to proceed.

$1000/kW. General inflation would have only increased costs by about 50 per cent, so it appears the nuclear industry underestimated costs by a factor of about five. How far this under-forecasting, which has been a feature throughout the 50-year life of the nuclear industry, is deliberate to mislead investors into choosing the nuclear option and how far it is simply inability to forecast accurately is hard to know. However, throughout the world, these low forecasts had the desired effect of making governments and utilities adopt pro-nuclear policies. This has happened, for example, in the UK, the USA and South Africa. The actual costs, or at least the costs expected at start of construction which are generally an underestimate of final costs, are only acknowledged when bids are actually placed. By this time, it may be very difficult or, at least, politically embarrassing to abandon the pro-nuclear policy, even though it might no longer make economic sense.

This means while the cap might be a useful way to filter out options that are prohibitively expensive, care must be taken to take independent estimates of the costs, not rely on the word of the proponents of nuclear power.

Annex 2 Experience of nuclear decommissioning worldwide

Worldwide, there is no experience of siting a high-level waste disposal site, much less actually building and operating one, so the costs must be seen as extremely speculative and, unless experience here is completely different to experience so far with nuclear power, the actual cost is likely to be substantially higher than current forecasts. Similarly, there is very little experience of the most challenging part of decommissioning, cutting up and disposing of the reactor vessel. In the UK, the first reactor (retired more than 20 years ago) is not expected to start this process before 2070. Worldwide, no more than a handful of commercial nuclear reactors have been fully decommissioned and this experience is of limited value. Some of these plants are very small, some use different technologies to those considered here and most have had a short operating life so are much less contaminated than a reactor that had operated for, say 40 years or more. So, as with high-level waste disposal, there is huge uncertainty about what the costs will be and a strong likelihood that the actual costs will turn out to be much higher than currently estimated.

Under conventional accounting procedure, liabilities that must be met in the future should be 'discounted'. Effectively this means that a sum of money (or assets of that value) is set aside now and it is assumed that money will earn interest and grow to meet the liability. So if a liability of $105 falls due in a year and an interest rate of 5 per cent can be earned, the 'discounted' value of the liability is $100 because in one year, it will grow sufficiently to meet the liability.

In the short term this sounds a sensible procedure, but over longer periods, the operation of compound interest rates mean that sums of money can grow remarkably. For example, a sum invested for 100 years earning an interest rate (net of inflation) of only 3 per cent, will grow 19 fold. So even if the cost of decommissioning a nuclear plant is, say a quarter the cost of building it, in the accounts, the liability will show as, perhaps, 1.3 per cent of the construction cost, in short, a trivial amount. However, if things go wrong, a future generation of taxpayers will have to meet the full cost of decommissioning a facility that they have derived no direct benefit from.

This is not just a theoretical possibility. In the UK, consumers paid money for decommissioning from 1979 onwards only to find that, by 2002, none of that money was available. It had been lost for example, by the Treasury using it for general government expenditure and investment in assets that proved worthless (a nuclear power plant). As a result, future UK taxpayers will have to meet a liability over the next century or more of more than £100bn.

UK experience is worse than most but as a result of issues such as these, best practice has evolved and now, typically, a decommissioning fund has the following characteristics:

- Consumers pay into the fund through their electricity charges;
- The company owning the plant has no access to the fund so if it goes bankrupt, the fund is not lost;
- It is invested in low risk investments (earning a commensurately low rate of return);
- The cost estimates are frequently updated so contributions can be increased to meet this cost escalation.

This represents a substantial improvement on past practice but it is still far from sufficient to provide a high degree of certainty that no financial burden (there is no way to avoid them having to carry out the hazardous task) will fall on future generations to clean up our mess.

To reduce the risk further, all major risks must be taken into account. These include the risk that:

- The fund will be lost or invested in assets that earn a lesser rate of interest than expected. After the current financial crisis, it is clear that few if any investments can be regarded as 'safe' in the long-term and that the assumption of a positive real rate of interest is hard to justify. Real interest rates are negative and decommissioning funds are losing value currently;
- The plant operates for less time than expected. This would mean that less money could be collected from consumers and the time for the fund to grow would be less;
- The cost estimate proves too low. Especially if this discovery comes late in the life of the plant or after it has closed, it will be too late to make up the shortfall through larger contributions. In the UK, the estimated cost of decommissioning has increased about 6 fold in only 20 years;
- The company owning the plant goes bankrupt. In the UK, British Energy, the UK nuclear company, went bankrupt in 2002 and as part of the rescue package, future taxpayers took over the financial burden of paying for decommissioning.

These risks can probably be dealt with by means of financial instruments, effectively insurance policies to cover these contingencies, but the cost will not be low if the current generation is to meet its ethical obligation to provide a very high degree of certainty that the 'polluter will pay'.

Annex 3 Terms of reference for appointment of a service provide for advisory services on financing options, models, and solutions for new build nuclear fleet

The Terms of Reference for the above tender published in October 2013, which calls for information on international models for financing nuclear investment, reveal the lack of expertise in the South African Department of Energy.

The following, text from the call in bold, author's commentary following illustrate the lack of knowledge on the nuclear sector in the Department of Energy.

'At least the following country programmes must be studied: Turkey, Russian Federation, South Korea, Japan, China, United States of America, Vietnam, France, Brazil, India, Taiwan, Germany, Finland, Sweden, Poland, Lithuania, Canada, Switzerland and Spain.'

Some of these countries are problematic. There is no publicly available information on financing of nuclear power plants in Russian Federation, China and India and minimal information from South Korea.

Brazil, Germany, Canada, Sweden, Switzerland and Spain have not ordered reactors for 30 years or more so there is no useful information that can be gathered from these countries. The most recent order for Taiwan was placed 16 years ago and has limited relevance

Poland and Lithuania have yet to place orders and it is far from certain they will, so the details of finance have not been determined.

Few details for Turkey and Vietnam are known and finance details for reactors supplied by Russia are not publicised. Some useful information can be gleaned.

Some information about finance is available from France, USA and Finland

Some details of finance for UK, Czech Republic and UAE, not mentioned in the list, are available and could be usefully reported, but any experience more than 10 years old is not relevant to South Africa's current programme.

A comparative assessment of each of the various financing structures derived from the benchmarking and options phase, as it relates to their impact on the South African environment with regards to:

a) Localisation

b) Cost effectiveness

c) Tenor

d) Drawdown and repayment flexibility

e) Risks (including refinancing risk, foreign exchange risk)

f) Time to deploy

g) Implementability

It is totally unrealistic to expect these details to be made public. The parties to the contracts would regard them as totally commercially confidential.

An assessment of the differences in financing of a fleet strategy versus procurement of individual units should also be given. A detailed risk analysis is to be submitted for each scenario as well as the pros and cons for each.

No country has ordered a 'fleet' of nuclear power plants since France in 1975 so this question cannot be answered

The Service Provider must provide a description of the international experience to address the regulatory tariff risk that may occur during construction, operation and decommissioning. By extension, this should be based on previous scenarios and incorporate the lessons learned, successes and failures and the reasons thereto, and recommend solution/s.

It is not clear what is meant by regulatory tariff risk. Does it mean the price setting process by the Energy Regulatory body? The only worthwhile experience is in the USA 35 years ago

Based on this, an assessment must be done of the impact of the nuclear programme (single plant and fleet) on the South African country financials such as balance of payments, trade deficit, currency, contingent liabilities, fiscal deficit and other relevant financial ratios. The impact on the ownership company financials and credit rating should also be assessed.

It is totally infeasible to model these impacts with any useful degree of accuracy.