Submission to NERSA on South Africa's proposed nuclear power programme.

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1. Professor Steve Thomas

I am Emeritus Professor of Energy Policy at the University of Greenwich in London. I worked as an energy policy researcher from 1976 till my retirement in 2015. From 1976-2000, I was a member of the Science Policy Research Unit at the University of Sussex and from 2001-2015 I was a member of the Public Service International Research Unit at the University of Greenwich. Since my retirement I have remained active in energy policy debates, continuing to publish articles in academic journals and becoming the Coordinating Editor of Energy Policy, the major policy journal covering energy worldwide. Much of my research has concerned economics and policy on nuclear worldwide and I have been a consultant to the International Atomic Energy Agency and the Brazilian government on nuclear power. I was a member of the Expert Panel appointed by the South African government in 2001 to review the prospects for the Pebble Bed Modular Reactor, writing the section on the economics of the design.

2. Introduction

The basis for the recommendation in the Integrated Resource Plan of 2019 (IRP 2019)[1] that a 2,500MW nuclear power programme be pursued is that it would be a 'no regret option in the long term'. The programme would comprise large reactors and/or small modular reactors (SMRs). IRP does not define a no-regret policy but NERSA[2] offers its own definition and in the absence of clarification from the government, this is the definition we will work on:

> 'those options that generate net social or economic benefits irrespective of whether or not climate change occurs, as well as across a range of possible climate futures. They build resilience to future climate shocks while also delivering near-term benefits.'

The key elements appear to be economic benefits and the most likely of these must be affordable electricity and resilience, primarily security of electricity supply and a perceived need for base-load capacity. It is not clear what social benefits a nuclear programme might have while, given that nuclear capacity would not come on-line till after 2030, nuclear orders would not deliver near-term benefits in terms of resilience.

A Request for Information (RFI) issued in June 2020 by the Department of Mineral Resources and Energy[3] gave more details of the requirements on reactor vendors who would be able to bid in any Request for Proposals for this new capacity. In particular:

> 'vendors of conventional pressurized water reactor [PWR] technology must assure DMRE that their reactors are "currently commercially available," while SMR vendors must boast a design "expected to be under development (matured to at least prototype/experimental designs) for commercialization by 2030." In addition to providing details of their respective technologies, including project data for designs under construction or built, vendors were asked to provide "indicative contracting models," such as "Engineering procurement contract (EPC), engineering procurement contract management (EPCM), build own and

[1] http://www.energy.gov.za/IRP/irp-2019.html
[2] http://nersa.org.za/wp-content/uploads/2020/11/Annexure-D-Consultation-Paper-for-Nuclear-Procurement.pdf
[3] https://www.gov.za/speeches/mineral-resources-and-energy-publishes-request-information-2-500-mw-nuclear-new-build

operate (Boo), build own and transfer (Bot) and build own operate and transfer (Boot)." Vendors aren't expected to provide any binding bids.'

This submission falls into three main sections: in the first we look at the technologies that might be available in the time-frame identified above: in the second, we look at potential economic benefits specifically the record of construction in terms of cost and construction time for the commercially available large reactors and for the SMRs, we review progress with the designs that might be available in the time-frame; in the third, we look at the contribution a nuclear programme, positive or negative, might make to electricity system resilience.

3. The technologies

For large technologies, those with whom South Africa signed or expected to sign Intergovernmental Agreements in earlier attempts to launch a new nuclear programme would appear to be the starting point.[4] This includes the Framatome European Pressurised Reactor (EPR)[5], Westinghouse AP1000, Rosatom VVER-1200, State Nuclear Power Technology Company (SNPTC) CAP1400 and the Korean APR1400. All of these are Pressurised Water Reactors, the same basic type as are installed at the Koeberg site. Another Chinese design, the Hualong One offered by both China General Nuclear (CGN) and China National Nuclear Corporation (CNNC) could be offered instead of the CAP1400. All are commercially available and most have some operating experience but experience with the construction process has been invariably poor. Collectively these are often known as Generation III or Generation III+ designs. The definition of the nuclear design generations is vague but Generation III/III+ covers designs using a PWR (or the closely related Boiling Water Reactor) that were designed after the Chernobyl disaster.

3.1. Large reactors

3.1.1. Framatome EPR

The EPR was designed by a company known as Areva, majority owned by the French state. In 2016, this company collapsed, in large part due to losses from an EPR, Olkiluoto, sold to a Finnish company.[6] Areva was split into a fuel cycle company, known as Orano, and the reactor business renamed Framatome (the previous name of the business up to 2002 and the company that supplied Koeberg). Framatome is now majority owned by the French state-controlled electric utility, Electricité de France (EDF), which itself is in severe financial difficulties and is expected to split into at least two parts.[7] The fate of the reactor business had not been determined by January 2021.

Table 1 shows experience to date with the EPR and it is uniformly extremely poor with construction delays of 5-13 years and as four out of six of the reactors are not complete, it is likely the delays will be even greater.[8] Given that the worst delay and cost over-run is at a plant (Flamanville) being built in its home market by the world's most experienced nuclear

[4] https://uk.reuters.com/article/us-safrica-nuclear-france/south-africa-signs-nuclear-agreement-with-france-idUSKCN0HZ18D20141010
[5] https://www.sa.areva.com/EN/news-10346/intergovernmental-agreement-between-the-french-and-south-african-governments-for-cooperation-in-the-development-of-civil-nuclear-energy.html
[6] https://www.world-nuclear-news.org/C-Areva-outlines-restructuring-plan-1506164.html
[7] Power in Europe 'French strike boosts spot power as nuclear gets Macron backing' December 14, 2020, p 21.
[8] All construction dates and operational experience data are taken from the IAEA's PRIS database. https://pris.iaea.org/PRIS/CountryStatistics/CountryStatisticsLandingPage.aspx

builder/owner/operator, EDF, this suggests fundamental problems with the design. There are many factors behind this experience including poor quality control of on-site work, sub-standard components, and design safety issues.

The Hinkley Point project is early in its construction phase but even before construction started, estimate cost for the two reactors had increased from £14bn to £19.6bn and have since increased even more. In January 2021, EDF announced a further 6 month delay to the project and an increase in cost of £0.5bn. This means the expected cost is £22-23.7bn in 2015 prices. In 2020 prices, this equates to £25.5-27.5bn.

The only prospective orders for the EPR are for India (Jaitapur)[9] and the UK (Sizewell)[10]. The Jaitapur deal was announced in 2007 but by 2020, no firm contract had been signed and there seems little prospect of a deal being signed imminently. For Sizewell, the deal will only go ahead with expected commissioning not before 2034 if the controversial Regulated Asset Base model (see below) is approved by the UK government. So it is likely to be at least 15 years before the design can be proved to be buildable at a predictable price and over a predictable timescale. Areva contracted to build the Olkiluoto plant on a fixed price basis and losses on this plant were a significant factor in its financial collapse in 2016. The fate of the Framatome reactor business following its collapse and the uncertainty about the future of its new owner, EDF, because of its financial difficulties mean there must be doubts as to whether the EPR will continue to be offered.

Framatome has been developing a new version of the EPR, EPR-2, which it claims would reduce costs, perhaps by 25 per cent and reduce the risk of cost overruns. However, there are no orders for this new design and a decision whether to build this design in France will not be taken until 2022.[11] The restructuring of EDF is being delayed because of concerns at the European Commission that the plan represents illegal state-aid – the French government using taxpayers' money to give a commercial advantage to a company. Until a rescue is approved, EDF and Framatome will be restricted in what projects they are able to take on.[12]

Because of its poor record of construction times and its very high cost, the EPR cannot be regarded as a prudent option for South Africa, while EPR-2 is several years from being commercially available..

3.1.2. Westinghouse AP1000

Development of the AP1000 started in 1997. Westinghouse was soon after bought by the state-owned British Nuclear Fuels Limited, sold on to Toshiba in 2006 and filed for bankruptcy protection in 2017. It was subsequently bought by the Canadian venture capital company, Brookfield, who expect to reform it and sell it on. How far Brookfield is interested in trying to sell more reactors is not known but given that Westinghouse's financial collapse was caused by losses on sales of AP1000s, it must be in doubt. Westinghouse has said it is not interested in taking on Engineering Procurement and Construction (EPC) contracts so if Westinghouse

[9] Nuclear Intelligence Weekly 'Lawmakers Push for Domestic Newbuild' March 20, 2020, pp 6-7.
[10] Nuclear Intelligence Weekly 'Large-Scale Newbuild Ambitions Shrink to Just Sizewell C' December 18, 2020, pp 4-5.
[11] Nuclear Intelligence Weekly 'France Looks to UK for EPR 2 Financing Ideas' Nuclear Intelligence Weekly' January 22, 2021, p 6.
[12] Nuclear Intelligence Weekly 'Debating EDF's Restructuring and Arenh' Nuclear Intelligence Weekly' January 22, 2021, p 5.

technology were chosen, it would have to be provided by another company using Westinghouse as equipment supplier.

Table 2 shows experience with the AP1000 and the picture is similar to that with the EPR, with orders for China being completed five years late and orders elsewhere going catastrophically wrong. The two US projects were both based on being part-financed by an effective surcharge on consumer bills during construction. The Virgil Summer project was abandoned in 2017 with costs running at four times the expected cost.[13] Fraud charges were brought against utility executives and electricity consumers of its owners have paid billions of dollars to fund construction for a power plant that will never operate.[14] The Vogtle plant is still being built and regulators in Georgia have expressed severe doubts that the utility's forecasts of completion in 2022 will be fulfilled.[15]

It was losses on the Summer and Vogtle orders that were the main factor in Westinghouse's bankruptcy. It had fixed price deals for completion of these plants in 2015 and their cost estimates proved to be huge underestimates.[16]

Westinghouse has no prospects for orders for the AP1000, so, as with the EPR, it will be more than a decade as a minimum before the design can be proved to be buildable at a predictable price and over a predictable timescale. The AP1000 cannot therefore be regarded as a prudent option for South Africa.

3.1.3. Rosatom AES-2006

The AES-2006 was announced in 2006 with ambitious plans for sales to Russia but apart from four orders placed in 2007, these plans did not materialise. There are two significantly different versions of the AES-2006, a version designed by the Moscow design studio and one designed by the St Petersburg design studio.[17] In 2010, Rosatom announced the AES-2006 would be superseded by the VVER-TOI with ambitious and implausible claims that this would be cheaper (20% less) and easier to build (only 40 months) and would be available to order by 2012. However, it was not till 2018 that construction of the first VVER-TOI started (in Russia). It is not clear whether new export customers would be offered the VVER-TOI or the AES-2006 and if the latter, which version.

Reliable cost estimates for the reactors built in Russia are not available and the only cost estimates available for exports are those made when the deal was first signed, extrapolated from the loans offered by Russia, typically for 90% of the expected cost. Three of the four reactors in Russia were in commercial operation by end 2019 five or more years late with the fourth still only in the testing phase by January 2021 (see Table 3).

The reactors in Belarus are reported to be close to completion but their construction phase has proved problematic, in particular when the reactor vessel was dropped when it was being

[13] https://www.nytimes.com/2017/07/31/climate/nuclear-power-project-canceled-in-south-carolina.html
[14] Nuclear Intelligence Weekly 'SEC Charge V.C. Summer Project Owner With "Historic" Fraud' March 6, 2020, p 4 & Nuclear Intelligence Weekly 'How to Value Westinghouse' March 17, 2017, p 2.
[15] Nuclear Intelligence Weekly 'PSC Staff Predicts More Vogtle Delays' January 3, 2020, p 4 and Nuclear Intelligence Weekly 'Vogtle's Hot Test Further Delayed' January 15, 2021, p 3-4.
[16] Nuclear Intelligence Weekly 'Dominion Acquiring Scana's Failed Nuclear Project' January 5, 2018, p 4.
[17] For a detailed account of Russia's nuclear export strategy, see: S Thomas, 2018 'Russia's Nuclear Export Programme' Energy Policy, 121, pp 236-247.

installed and had to be replaced.[18] The first unit started generating in November 2020 but has suffered two major problems, the details of which had not been properly reported by January 2021.[19]

The plants in Bangladesh[20] and Turkey[21] are in the early stages of construction and only preliminary reports are available on progress. In both cases, there was a long delay from the deal being announced to buy reactors and construction start. For Turkey, the deal for four reactors was announced in 2010 with construction start in 2012, six and eight years before construction actually started on the first two reactors. The expectation was that Turkish investors would own a significant proportion of the equity but they all withdrew leaving Rosatom owning the whole project. Some serious quality concerns emerged in January 2021 with reports of cracks in the reactor base concrete and an explosion at the site.[22]

For Bangladesh, a deal was signed in 2009 and a foundation stone laid in 2013, but the actual order was not placed until 2015, two years before construction started.

Rosatom claims orders in several other countries including India, China, Iran, Egypt, Hungary, and Finland with some sort of agreements in Nigeria and Uzbekistan. Orders for Jordan and Vietnam have collapsed. In nearly all cases, these orders were won in part because Russia was able to lend money, usually 80-90% of the expected cost. The interest rate is relatively low, 3-4% but problems have occurred because, typically, repayments must start 10 years after the loan is taken out.[23] In Hungary, this was in 2016 but by 2021, construction start was not expected to start until 2024 so loans would have to start being repaid four or more years before the reactor began to produce power. The very large number of orders Rosatom has requiring Russian finance, typically $5+bn per reactor means that there must be doubts about Russia's capability to continue to offer finance.[24]

In Hungary and Finland in particular, the national regulators have not been happy with the documentation provided by Rosatom contributing to delays in construction start.[25] For example, when the deal was signed for the Hanhikivi plant in Finland in 2013, construction was expected to start in 2017, but the earliest dater now is 2022. While for Hungary (Paks), a deal in 2014 was expected to lead to construction start in 2018, but construction start is now expected in 2024.

Whether Rosatom would be politically acceptable as a supplier to South Africa is a moot point. However, the record of the AES-2006 in construction is poor and the first year of operation of all the plants has been marked by poor reliability. The cost of plants for Rosatom's home

[18] Nuclear Intelligence Weekly 'Rosatom Agrees to Replace Dropped Reactor Vessel' August 12, 2016 pp 3-4.
[19] Nuclear Intelligence Weekly 'Ostrovets Shuts Down for a Second Time' December 4, 2020, p 1.
[20] Nuclear Intelligence Weekly 'Kudankulam Units Likely to Miss 2023 Commissioning' December 11, 2020, pp 6-7.
[21] Nuclear Intelligence Weekly 'Akkuyu Work Accelerates Despite Lack of Investor Interest' December 18,2020, pp 5-6.
[22] https://yesilgazete.org/problems-around-akkuyu-npp-is-so-dire-that-even-the-supporters-of-nuclear-energy-must-object/
https://ahvalnews.com/akkuyu/opposition-mp-urges-scrapping-turkeys-akkuyu-plant-citing-crack-foundation
[23] Nuclear Intelligence Weekly 'Legal Battle Over Hungary's Paks Far From Complete' December 9, 2016, pp 6-7.
[24] Nuclear Intelligence Weekly 'Akkuyu Work Accelerates Despite Lack of Investor Interest' December 18,2020, pp 5-6.
[25] Nuclear Intelligence Weekly 'Reactor Vendors Struggling to Stay Afloat' September 18, 2020, pp 2-3.

market is not known, and while the cost at the time the deal is agreed is often known for export plants, the outturn costs are not known.

3.1.4. Korean APR1400

The Korean APR1400 is based on a US design, the Combustion Engineering System 80+ licensed from the parent company of Combustion Engineering, Westinghouse. There has been considerable interest in the Korean APR1400 design because of the very low price bid for the Barakah order for the UAE equating to about US$3600/kW, about 30 per cent lower than the next cheapest bid (for EPRs). At the time the order was placed, there was no nuclear safety regulatory body in the UAE so it must be assumed that the UAE accepted Korea's safety case uncritically (see Table 4). The Areva CEO, Anne Lauvergeon was highly critical of the safety features in the APR1400 claiming it was 'like a car without airbags and seatbelts'.[26] KEPCO acknowledged the design built in Korea and UAE does not contain expensive features such as a double containment to protect against aircraft impact and a core-catcher that would be required in Europe and significant safety upgrades to be licensable in Europe. The design has no realistic order prospects in Europe or the USA and the Korean government is committed to phase out nuclear power so it seems there are unlikely to be orders for this design.

There are also issues of quality. Construction of the first two units of this design in Korea was delayed due to the discovery of large scale falsification of quality control documents for more than 2000 components.[27] The first two reactors took 8-10 years to build, while the two reactors with substantial construction are likely to take up to 12 years to build. The project in the UAE has been plagued by quality control errors and the plants are all at least four years late.[28]

Whether the Barakah price is a realistic one that would be repeated for future orders (plus the cost of upgrades necessary to bring the design to European and US standards) remains to be seen but Korea has no realistic prospects for new orders either for its home market or for exports. Korea did provide finance for the UAE project, but, again, it is unclear whether this was a one-off offer in its first attempt to export its reactors.

3.1.5. Chinese-supplied reactors

There are three Chinese reactor vendors, SNPTC, CGN and CNNC.[29] Unlike most vendors, these companies also own and operate power plants including nuclear. For export markets, these companies do not compete with each other and the Chinese government has allocated South Africa to SNPTC. This company was set up in 2007 with the sole purpose of importing AP1000 technology and producing it under license in China where it was assumed this design would take over orders in China from the old 1970s design it was then using. As noted above, experience with the AP1000 in China has been poor and no follow-up orders have been placed despite forecasts for almost a decade that new AP1000 orders would soon be placed. The AP1000 is the intellectual property of Westinghouse and it is not clear whether Westinghouse would allow SNPTC to export AP1000s. By 2012, SNPTC was developing a scaled up version of the AP1000, the CAP1400, and by 2014, it was said to be ready to be built.[30] However, the IAEA database shows that by January 2021, no reactors of this design were yet under

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[26] Nucleonics Week 'No core catcher, double containment for UAE reactors, South Koreans say' April 22, 2010.
[27] http://www.world-nuclear-news.org/RS-Indictments_for_South_Korea_forgery_scandal-1010137.html
[28] Nuclear Intelligence Weekly 'Newbuild Report 2019' p 6.
[29] For a detailed account of China's nuclear export strategy, see: S Thomas, 2017 'China's nuclear export drive: Trojan Horse or Marshall Plan?' Energy Policy, 101, pp 683-691.
[30] Nuclear Intelligence Weekly 'Briefs', January 14, 2017,p 9.

construction. However, reports from China suggest two reactors of this design had recently started construction (in September 2019 and 2020) at the Shidao Bay site but it is not clear why China has not acknowledged this to the IAEA. There are said to be significant problems at the site and it is unlikely more CAP1400s will be approved until the first two reactors are operating successfully.[31]

Whether SNPTC continues to aspire to be a major reactor vendor is now in doubt. SPIC, the parent company of SNPTC, is the world's largest solar generator and third-largest wind producer, by capacity, with 22.2GW and 20.6GW of capacity respectively compared to only 4.8GW of nuclear capacity.[32] Given that the first CAP1400 is five or more years away from first power, it is very much an unknown quantity. Its roots in the AP1000 design are not encouraging and many of the components that have been problematic with the AP1000 would have to be produced in larger sizes and are likely to be even more problematic.

If SNPTC moves away from nuclear power, it might be that the South Africa market would be allocated to CGN or CNNC. These are longer established companies but also have major holdings in renewables. They both offer the Hualong One design but in their own distinct versions.

After the Fukushima disaster CGN and CNNC began to produce their own advanced designs, ACPR-1000, and ACP-1000 respectively, building on the old technology licensed from Framatome that has been built in large numbers in China. Four of the ACPR-1000 design have started construction in China and two of the ACP-1000 are under construction in Pakistan.[33] However, in 2013, the Chinese government required CGN and CNNC to merge their advanced designs to form a unified one, Hualong One.[34] Since then six reactors designated Hualong One have started construction in China from 2015 onwards two using the CGN variant and four the CNNC but the first Hualong One reactor (CNNC design) generated first power only in November 2020. By January 2021, it was not in commercial operation but it had reached first criticality after 67 months of construction, only 5 months behind schedule.

The first reactor of the CGN version of the Hualong One (1000MW) (Fangchenggang 3) is expected to start generation in 2021 and it has been proposed for construction in the UK at the Bradwell site. The process of gaining approval from the UK safety regulator started in January 2017[35] and it seems unlikely it will be complete before 2022. Whether the UK project will go ahead remains in doubt because of concerns about a range of risks associated with buying key technology from Chinese companies. For example, the Huawei company is being phased out of its role in implementing 5G technology in the UK because of such concerns.

Chinese companies therefore represent very much unknown quantities in terms of the technologies they offer and their experience in export markets. The common assumption is that reactors from China would be cheaper than those of their competitors but this assumption is

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[31] Nuclear Intelligence Weekly 'SPIC's Move Away From Nuclear' November 6, 2020, p 5
[32] Nuclear Intelligence Weekly 'SPIC's Move Away From Nuclear' November 6, 2020, p 5
[33] Pakistan has ordered 6 reactors from CNNC dating back to 1993, four using a Chinese 300MW PWR design and two using the ACP-1000 design. Nuclear Intelligence Weekly 'CNNC to Supply Karachi NPP' July 12, 2013, pp 3-4.
[34] Nuclear Intelligence Weekly 'CNNC and CGN Struggle to Work Together On Gen-3 Design — at Beijing's Behest' July 12, 2013, p 3.
[35] http://www.onr.org.uk/new-reactors/uk-hpr1000/index.htm (Accessed May 11, 2017)

not based on any hard data. Buying reactors from China would therefore be a major risk for South Africa.

3.2. Small Modular Reactors

The term SMR encompasses a wide range of technologies.[36] Some are based on existing technology, primarily Pressurised Water Reactors (PWRs), the technology installed at the Koeberg site. The only ones that might come close to meeting the 2030 requirement are scaled down versions of the PWR technology built at Koeberg. Others use technologies that have not been built as commercial power plants or that have not been built even at prototype scale. These fall into the category often known as Generation IV designs. The former category includes Sodium-cooled Fast Reactors and High Temperature Gas-cooled Reactors (HTGR), the technology used in the Pebble Bed Modular Reactor (PBMR) design that South Africa pursued unsuccessfully from 1987-2010.[37] The latter include technologies such as Molten Salt Reactors (MSRs) and Lead-cooled Fast Reactors. The Generation IV International Forum was set up in 2000 by governments of most of the major nuclear using nations to stimulate development of Generation IV designs. When it was set up, it forecast these designs would be available for commercial ordering between 2015-25. By 2019, it assumed they would not be commercially available before 2045. This class of reactors will not meet the 2030 criterion and is not relevant for this discussion. However, because of its history with the PBMR, we do briefly note developments with this technology since 2010

3.2.1. Pebble Bed Modular Reactor

The PBMR was developed by the two large German-based companies Siemens and ABB and their design, HTR-Modul (about 80MW), was completed in 1988 but never marketed, at which time, NECSA began work to develop the design for manufacture and use in South Africa. In 1998, Eskom took over the work taking out a technology license from the German companies. In 1998 output was expected to be 110MW and they anticipated commercial orders would be possible from 2004 and that a large world market for the design would emerge. From 2002 onwards, Eskom did not contribute to the development costs all of which were borne by South African taxpayers. The expected output increased to 125MW, then 137MW and eventually 168MW, without any increase in the physical size of the plant, presumably to try to improve the economics. No firm orders were ever placed and despite the large amount of public money that had gone into the project, no detailed official account of the reasons for its failure were ever published. It seems likely that there were several reasons including poor economics, difficulties developing the innovative helium gas turbine that would generate the power and safety issues arising from the risk of overheating of the fuel 'pebbles'.

China also licensed HTR-Modul technology and in 2012, started construction of a demonstration plant comprising two reactors of their HTR-PM design, connected to one turbine. It is technologically much less ambitious than the South African version being only 105MW per reactor, operating at 750˚C compared to 850˚C for PBMR and using a conventional well-proven steam turbine.[38] Despite this, the project, expected to be completed

[36] For a detailed review of SMRs, see: S Thomas, P Dorfman, S Morris, & M V Ramana, 2019 'Prospects for Small Modular Reactors in the UK & Worldwide' NFLA, Manchester. https://www.nuclearpolicy.info/wp/wp-content/uploads/2019/07/Prospects-for-SMRs-report-2.pdf

[37] For a detailed account of the PBMR history, see: S Thomas, 2011 'The Pebble Bed Modular Reactor: An obituary' Energy Policy, 39, pp 2431-2440

[38] Nuclear Intelligence Weekly 'Plans for Inland HTGR Project' October 18, 2013, pp 4-5.

in 2016/17 has been continually delayed and by November 2020, completion was not expected till 2021.[39] China has plans to build plants in groups of six reactors connected to a single turbine. These plans have been continually delayed and it is far from clear whether they will materialise.

There are still strong and influential advocates of the PBMR in South Africa[40] who would like to return to the technology but it seems unlikely that investing more public money in the technology would be justifiable and, given the technology's poor record, the chances of success, certainly in the time-frame discussed here are negligible.

3.2.2. Pressurised Water Reactors

Throughout the history of nuclear power, as costs have escalated, nuclear designers have sought to compensate by increasing reactor size and output to gain scale economies – in principle, it is cheaper to produce one large piece of equipment than, say 10 small pieces totalling the same capacity. While these scale economies clearly exist, they have been drowned by other cost-increasing factors such as a need for increased safety, the greater difficulty of fabricating large pieces of equipment and the complexity of designs. There has often been a suggestion that these factors are temporary and that as the technology matures, costs will stabilise and perhaps fall. The large amount of site work required for these large reactors is notoriously difficult to manage and the small number of orders placed for reactors in the past 30 years means reactors are typically fabricated on a one-off basis. While predictions of scale economies seem intuitively reasonable, they have not been observable nor are there any signs that costs have stabilised. The rationale for SMR PWRs is that being smaller they could be sold in larger numbers (economies of number) meaning cheaper production line manufacture techniques could be used rather than one-off fabrication, components could be transported to the site already assembled reducing the amount of site-work and their smaller size would mean that safety features required for large reactors would not all be needed.

While these cost-reducing attributes are plausible, it is far from clear that economies of number will be sufficient to more than counterbalance the lost scale economies. This claim will only be tested when the cost of production line reactors is fully established and this will require a large number of orders to be completed. Opting for SMRs is therefore a massive punt and one which, realistically, can only be made using public money.

Most of the PWRs are so-called integral designs, in which, unlike the large designs, all key components, including cooling water, are sealed within containment facilities, and that can quickly be shut down during an emergency. This means they use no pumps or valves.

NuScale

The design with by far the longest history is the NuScale design, under development since 2000. It is designed to be built in clusters of 12 with a central control room. Despite this development and despite backing from its large engineering company owner since 2011, Fluor, NuScale has no firm orders. The reactors were originally expected to produce 40MW but this has subsequently been increased to 45MW, the 50MW, then 60MW and, in November 2020 to 77MW with no increase in the physical size of the plant.[41]

[39] Nuclear Intelligence Weekly 'HTR-PM Commissioning Pushed Back to 2021' June 26, 2020, pp 5-6.
[40] Nuclear Intelligence Weekly 'The PBMR Idea Resurfaces' January 31, 2020, pp 6-7.
[41] Nuclear Intelligence Weekly 'Weekly round-up' November 13 2020, p 1.

In 2008, NuScale forecast it would submit its design to the US Nuclear Regulatory Commission (NRC) in 2010 with certification of the design allowing it, in principle, to be built anywhere in the USA by 2015. The safety review was undertaken in the USA by the Nuclear Regulatory Commission and caried out between from 2017-2020 but in 2017, the reactor was rated at 50MW and it was this version that was reviewed. It was subsequently uprated to 60MW and then 77MW. Major technology issues remain from the completed review[42] (the reactor was not going to be sold in that form so they did not need to be resolved) and the uprating of nearly 50% will require a full reassessment. NuScale does not expect to submit the revised design to NRC until 2022. There is one prospective order, the Utah Associated Municipal Power Systems (UAMPS) project for a cluster of 12 reactors. However, it does not have enough investors to go ahead and existing investors are dropping out.[43] It is unlikely to be completed before 2030 if it goes ahead. If it does go ahead, the reactors will be fabricated on a one-off basis, not using production lines so the economics will not be properly tested. The cost estimates for the UAMPS projected have increased alarmingly from US$2.895bn in 2015[44] to US$6.124bn in 2020.[45]

The US Department of Energy (USDOE) has provided funds for reactor development since 2000. In 2013, it provided US$213m for reactor development. In 2018, a further US$40m was provided and in 2020, USDOE gave a further US$1355m.[46]

Rolls Royce

A much larger (450MW, half the output of a Koeberg reactor) UK Rolls Royce PWR design is also gaining some publicity but it is at a much earlier stage of development only being announced in 2016. Unlike most of its PWR SMR competitors, the design is not an ‘integral’ design making it much more a scaled-down version of existing PWRs. Rolls Royce say the first reactor will be in operation 10 years after an order is placed. It is unwilling to go ahead with completing the design without a firm order backed by the UK government for 16 reactors.[47] It remains to be seen whether the UK government is prepared to gamble a very large amount of taxpayers’ money on a totally unproven design. The design cannot therefore be proven until after 2030.

Holtec

The Holtec SMR is a 160MW integral PWR. It is undergoing a preliminary safety review in Canada, but it has no immediate prospects of a sale.

4. Economic benefits

There is no realistic prospect of South Africa developing a nuclear industry that would generate significant benefits for South Africa through export sales. The case that a nuclear programme would bring economic benefits will therefore depend on the cost of power the reactors would produce. Because of their high construction cost, the cost of power from a nuclear power plant

[42] https://www.nrc.gov/reactors/new-reactors/smr/nuscale/review-schedule.html
[43] Nuclear Intelligence Weekly ‘Weekly Round-up’ November 6, 2020, p 1.
[44] Nuclear Intelligence Weekly ‘NuScale Pegs SMR at $3 Billion’ February 20, 2015, pp 3-4.
[45] UAMPS, 2020 ‘Carbon Free Power Project Amended Budget & Plan of Finance.’ Utah Associated Municipal Power Systems, Salt Lake City
[46] Nuclear Intelligence Weekly ‘Weekly Round-up’ October 16, 2020, p 1.
[47] For a list of the conditions Rolls Royce is asking the UK government to agree to if it is to go ahead with its SMR, see: https://www.parliament.uk/business/committees/committees-a-z/lords-select/science-and-technologycommittee/news-parliament-2015/nuclear-research-technology-report-published/

depends heavily on two factors, the construction cost, and the cost of financing construction, the cost of capital.

4.1. Construction cost

Construction costs are nearly always presented as so-called 'overnight' costs (as if the plant were built in a day) and exclude the cost of finance during construction. This cost will vary according to the interest rate at which loans are taken out and on the construction time (the longer the construction period, the greater the interest charges) but EDF has claimed for the UK, interest charges could represent half the total cost, or in other words, the interest charges could be as high as the construction costs. There are analytical reasons to present the overnight cost rather than the total cost if the objective is to compare costs between countries or over time without the distortion that varying interest rates would bring. However, using overnight costs does seriously underestimate the costs of reactors, perhaps only half the cost consumers would have to bear. Construction costs are generally expressed in US$/kW of installed capacity, so a 1000MW reactor costing US$5000/kW would have an overnight cost of US$5bn. Using US$ as a stable currency does reduce the distortion from varying exchange rates for comparisons but a fall in a local currency would tend to increase costs to consumers without necessarily increasing the dollar cost. It is also important to identify the time of the estimates so that differences just due to general inflation are not seen as real cost changes. These factors mean that using foreign costs for plants completed earlier as an indicator of costs in another country is necessarily imprecise, albeit on the basis of experience, the best indicator.

IRP 2019 states its assumptions are based on the 2013 Ingerop report[48] commissioned by the South African government as an input to an earlier version of the IRP. This report is not only badly out of date, but it was also of highly questionable quality bringing in data of dubious quality and for old reactors using designs that would be unacceptable today. It found an average value of construction cost of ~US$5000/kW (see Table 5). This appears to be based on cost estimates for 15 projects which had a range of US$2750-6700/kW. The size of this range – a factor of 2.5 for essentially the same item - for a technology that had then been commercially exploited for 50 years is troubling in itself. It would be expected that the cost of a mature technology would be stable and would vary comparatively little according to location.

At the time of the estimates, seven of the projects had not started construction and, in fact three of these were abandoned before construction started. Two of the projects in Korea use old technology no longer offered. Cost estimates made before construction starts are notoriously a very poor indicator of actual costs. Two of the projects are in China and are little more than half the average but it is questionable whether data from China can be relied upon or whether they are a good guide for elsewhere.

If we discount abandoned projects, projects using old technology, and projects where up to date cost estimates are not available, for the ones where construction has actually started, the average is about US$9300/kW, 85% higher than the Ingerop estimate. These four projects are still at least 1-7 years from completion and all experience suggests final costs will be even higher. The 2500MW programme would cost $23bn or R350bn (at US$1=R15).

Ingerop repeats the nuclear industry's mantra over the past 50 years that standardisation, learning and ordering in relatively large numbers will reduce costs. The experience in France

[48] Ingerop, 2013 'Study of the cost of nuclear power' Department of Energy, Republic of South Africa

where more than 50 reactors were built in a period of little over a decade using a large degree of standardisation, bulk ordering and with apparently ideal conditions was that, far from falling, real costs more than doubled.[49] Two recent studies found evidence that contradicts these assumptions. 'We observe that nth-of-a-kind plants have been more, not less, expensive than first-of-a-kind plants.'[50] 'The study also finds that, contrary to what those in the industry seem to expect, focusing on standardized designs doesn't really help matters, as costs continued to grow as more of a given reactor design was built.'[51]

Despite the unrealistically low construction cost estimate derived by Ingerop, new nuclear was never part of the least cost solution in the various versions of the IRP that used it and a nuclear programme was only in the plan as a result of policy interventions or adjustments. In short, according to the IRP, choosing nuclear would have made electricity prices higher than they would have needed to be.

If we look at technologies currently offered, as is required by the RFI, the problem for estimating cost is that, without exception, every project has gone badly wrong, being at least 4 years late and, where reliable costs are known, far over budget. Costs do still seem to be rising steeply, unlike renewables which are falling steeply. For example, the Framatome EPR being built at Flamanville (France) at an expected cost of €3.2bn when construction started in 2007 and expected to be complete by 2012 is not expected to be complete before 2023 and with the latest cost estimate after 13 years of construction, €12.6bn. The French Cour des Comptes estimates the final cost will be €19.1bn, a figure not disputed by EDF.[52] The cost estimate for each EPR at the Hinkley site (UK) when construction started in December 2018 was £10.8-11.6bn (€11.8-12.8bn). This estimated cost has already escalated significantly and is likely to increase more before the plant is completed. The price the government would buy the power from this plant at[53] was set in 2013 at £92.5/MWh (2012 money) when the estimated cost was only £7bn per reactor and the power purchase price remains at that level, so the owner, EDF, itself in serious financial difficulties and requiring a major government rescue effort, is likely to lose money on this plant.[54]

4.2. Cost of capital

The issue of finance remains one of the biggest barriers to nuclear investment. No bank will lend money for a nuclear project unless they are insulated from the huge project risk of cost and time overruns. This might be through a cast-iron guarantee that consumers will repay whatever costs are incurred so the project cannot fail. The UK is investigating using a Regulated Asset Base (RAB) model for the next UK nuclear project.[55] Under this, the owners

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[49] A Grubler, 2009 'An Assessment of the Costs of the French Nuclear PWR Program 1970-2000' IIASA, Laxenburg. http://pure.iiasa.ac.at/id/eprint/9116/

[50] https://www.cell.com/joule/fulltext/S2542-4351(20)30458-X

[51] https://arstechnica.com/science/2020/11/why-are-nuclear-plants-so-expensive-safetys-only-part-of-the-story/

[52] Nuclear Intelligence Weekly, Weekly Round-up, July 10, 2020

[53] A UK government agency buys all the power the plant produces (or could produce if, for some reason the grid cannot accept it) at a fixed price (£92.5/MWh (2012 prices) indexed to inflation and sells it on to the companies that sell power to final consumers and these are obliged to buy at that cost.

[54] For an analysis of EDF's financial position and of the economics of the Hinkley Point C plant, see: S Thomas 'Financing the Hinkley Point C project' NFLA, Manchester. http://wp.tasizewellc.org.uk/wp-content/uploads/2020/06/Financing-the-Hinkley-Point-C-project-%E2%80%93-an-analysis-by-Professor-Steve-Thomas-January-202016072.pdf

[55] The UK government's proposals are published at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/943746/rab-

of the plant would be guaranteed to recover their costs and make a guaranteed rate of return on the money they invested. The risks that this imposes on consumers have made this model highly controversial. Consumers would be required to pay a surcharge on their electricity bill during its construction to part-fund it. This is against a basic principle of regulation, that consumers should only start paying for a facility when it is operating and when it has been established that it was needed, was the cheapest way of meeting the need and that its costs were well-managed. If it fails these tests, the consequences should fall on the company. Consumers should not be made to pay for bad decisions by the company building the facility.

In a 9 December 2015 presentation to cabinet (declassified as part of the Zondo Commission hearings), the Ministry of Energy proposed that the cost of building new nuclear plants could be part-funded by consumers. It stated: 'We estimate that 60% of the total investment cost could be funded through the regulated revenue generated during construction.' It stated: 'NERSA support will be required.' This should not be given.

A decision on the use of the RAB model has been expected for about a year now and is long overdue. A variant of the RAB model could be proposed for South Africa but the risks it imposes on consumers are unjustifiable.

An alternative is sovereign loan guarantees so that if the project fails, taxpayers from the country offering the loans, likely to be the government of the country the vendor is based in, repays the bank. The references to the 'Boo', 'Boot' and 'Bot' finance models (b = build, o = own, o = operate, t = transfer), none of which has been tested for a nuclear project illustrate the need for new methods to try to overcome this issue. The Akkuyu plant in Turkey, supplied by Rosatom, uses the Boo model but this only started construction about a year ago. It was expected to be about 50% owned by Turkish investors but they all withdrew.[56] The price agreed in 2010 that the power would be bought at was US£123/MWh. Eskom is not credit-worthy so the government is expected to carry out the tender process.

Of the vendors listed above, Rosatom and SNPTC would expect finance backing from their governments, Russia, and China, respectively. The Trump government talked about backing US vendors (Westinghouse is Canadian owned but US-based) but it is not clear what the Biden government will offer. France has talked about offering loan guarantees for reactor exports but it has only granted them once (Olkiluoto in Finland) and this was only for less than 20% of the expected cost and experience with Olkiluoto has been so bad that the guarantees could yet be called on at the expense of French taxpayers.

The Request For Information suggests a 'turnkey' or fixed price contract would be an option, under which the risk of cost escalation is borne by the reactor vendor. However, turnkey contracts have almost invariably lost reactor vendors large amounts of money when the vendors had to meet the cost escalation themselves rather than passing it on to their customer. They are thus seldom offered. It was losses turnkey contracts that were the main factor in the financial collapse of Areva NP/Framatome and Westinghouse. This experience will mean that it is highly unlikely that any vendor will offer a genuine turnkey contract, that is, one in which there is no

model-for-nuclear-consultation-.pdf . For a critique, see S Thomas, P Bradford, T Burke & P Dorfman, 2019 'The Proposed RAB Financing Method' NCG https://www.nuclearconsult.com/wp/wp-content/uploads/2019/10/NCG_RAB_submission.pdf

[56] Nuclear Intelligence Weekly 'Akkuyu Work Accelerates Despite Lack of Investor Interest' December 18,2020, pp 5-6.

scope for the buyer to bear increased costs. Vendors like to describe contracts as turnkey when they is actually scope in them to pass on costs, so the small print of contracts needs to be read (if it is publicly available).

5. Resilience

The most unreliable power station is the one that was planned to operate but has been delayed and is still under construction. If power systems planners in Finland and France were relying on the EPRs under construction in those countries to ensure reliable operation to be on-line by 2009 and 2012 respectively the systems in those countries would be suffering the sort of power cuts (euphemistically known as load-shedding) that South Africa has for nearly a decade.

The experience in South Africa with the coal-fired stations, a technology that typically does not suffer from major construction delays and technology problems, at Kusile and Medupi, long-delayed and unable to operate at their design output levels must have contributed to power shortages. In addition there were the failed attempts to launch nuclear power programmes through the PBMR programme, the unsuccessful 2009 tender for new nuclear and the various fruitless IRPs, all having a 9600MW nuclear programme imposed on them by the government. These have consistently diverted attention over more than two decades from options that are cheaper and would have had a much higher chance of bearing fruit.

5.1. Time from policy decision to go nuclear to first power

The delays during construction are well documented (see section 2.1) but there are typically also significant delays between a government decision to launch new nuclear orders. Governments invariably underestimate how long it will take from announcement of an intention to launch a new nuclear programme to first power and also the volume of orders that can be placed. In the USA, in 2002, the Bush administration announced its 'Nuclear 2010' programme under which large-scale nuclear ordering would re-start in the USA (no surviving order had been placed after 1974) with a handful of subsidised plants, the first in 2010 after which ordering would be self-sustaining. Only four subsidised reactor orders were placed (two each at the Vogtle and Summer sites) with construction starting in 2013. Two were abandoned in 2016 with costs and completion times out of control (at great expense to consumers) and the other two are far over budget and at least three years from completion (see section 2.1.2). Losses on these plants were a major factor in the financial collapse of Westinghouse. A similar picture applies to the Olkiluoto EPR in Finland and losses there were a major factor in the collapse of Areva/Framatome (see section 2.1.1).

In the UK, Blair announced in 2006 that nuclear power was 'back on the policy agenda with a vengeance'[57] and plans for 16000MW of new capacity (five projects, eleven large reactors) on-line by 2030 given. At most, only one project for two reactors will be built by 2030, with first power not before 2027. So experienced nuclear countries with determined government support will take more than 20 years to get first power and with far fewer reactors built than expected. South Africa is far from being the only country to fail repeatedly to launch a new nuclear programme with countries like Czechia and Poland also repeatedly failing to order new reactors.

[57] http://webarchive.nationalarchives.gov.uk/20040105034004/http://num ber10.gov.uk/

5.2. Need for base-load generation

At the centre of the IRP plans is the need to replace a net 3800MW of coal capacity by 2030. Most of the closed coal capacity will be replaced by 7800MW of new coal capacity, much of it already under construction (but long-delayed). Since no new nuclear will be complete by 2030, nuclear is irrelevant to that. Beyond 2030, a further 24,000MW of coal plant is expected to be closed by 2050. This raises two issues: is there a need for base-load generation; and, if we assume base-load capacity is needed, can nuclear play an important role in achieving this.

The idea of a need for base-load capacity is a misunderstanding. Clearly there is a base-load demand, a level of demand below which demand never goes, but it is a *non sequitur* to assume that base-load can only be met by base-load plants. It makes no more sense than assuming a factory operating round the clock seven days a week requires a set of workers who will also work round the clock every day. What is required is that generation resources are available when needed. In the past, 'peaking capacity', that is, the plant that operates relatively infrequently and only to meet demand peaks could be oil fired gas turbines or diesel plant.

In the future, if fossil fuels are to be phased out, this will have to replaced, most likely by a combination of resources such as batteries, demand side response (consumers reducing demand at peak times) and peaking plant using non-fossil fuels. Peaking plant will be required whether nuclear or renewables are pursued. These will fill in when the sun does not shine or the wind does not blow in the renewables case or when demand is more than base-load in the nuclear case (in practice, all the time).

The former Chief Executive Officer of the UK National Grid Company, a company responsible for ensuring security of electricity supply in the UK with agenda in favour of renewables or against nuclear, Steve Holliday, said:

> 'The idea of baseload power is already outdated. I think you should look at this the other way around. From a consumer's point of view, baseload is what I am producing myself. The solar on my rooftop, my heat pump – that's the baseload. Those are the electrons that are free at the margin.'[58]

5.3. Are nuclear and renewables complements?

It is often said by nuclear proponents that nuclear power complements variable renewables with the implication that nuclear can fill gaps left by renewables. This is wrong. Nuclear and renewables like wind and solar are both inflexible. Wind and solar are limited by weather conditions while nuclear cannot vary its output on an hour-by-hour basis, much less on the minute-by-minute basis needed to ensure grid stability. Suggestions that new nuclear can 'load-follow' make no sense from either an economic or technical point of view.

6. Climate Change and Environmental Issues

While some assert nuclear power is zero carbon, this is false even though the routine operation of a nuclear power reactor does not directly produce CO_2 (there are some emissions from worker transport and back-up power facilities). Emissions of CO_2 occur in the fuel cycle – the various steps from mining of uranium to disposal of spent fuel - and are embodied in the inputs – the huge amount of material and labour, far larger than other forms of generation – to the

[58] https://energypost.eu/interview-steve-holliday-ceo-national-grid-idea-large-power-stations-baseload-power-outdated/

construction of the plant. There are also emissions from back-up diesel generators, a back-up CHP plant and from vehicle journeys during the operating life of the plant.

The main emissions from the construction phase are from the manufacture of the materials used, such as concrete and steel, with some emissions from worker and materials transport. Other forms of low carbon generation and energy efficiency require materials that will result in the production of CO_2 but the volumes of material are far lower than for a nuclear plant.

The fuel cycle[59] accounts for the vast majority of CO_2 emissions associated with operation of a nuclear plant. These stages take place in a range of countries and will not be reflected in South African emissions, but given that climate change is a global problem, it would be wrong to discount these emissions simply because they do not occur on South African soil. Estimates of the carbon content of the fuel cycle vary massively depending on assumptions made on the quality and depth of the uranium ore deposits and on the composition of the national electricity system in which the highly electric intensive process of enrichment[60] takes place. Experience of reactor decommissioning is minimal and the final stage of the fuel cycle, disposal of spent fuel, has not been carried out anywhere in the world and is probably decades away from being demonstrated. It is therefore not possible to estimate the carbon content of decommissioning and disposal of spent fuel but it will not be zero.

In 2008, Sovacool[61] surveyed the various estimates of the CO_2 content of the nuclear fuel cycle finding a range of 1.4-288g of carbon dioxide equivalent per kWh (g CO_2e/kWh) with a mean value of 66g CO_2e/kWh. In 2012, Warner & Heath[62] carried out a similar survey and found a range of 4-220g CO_2e/kWh with a median of 13g CO_2e/kWh. The range of subsequent estimates has not got smaller since these estimates were published. The Intergovernmental Panel on Climate Change (IPCC) assumes 12g CO_{2e}/kWh[63] and UK's Committee on Climate Change (CCC) estimated the carbon content as 6g CO_2e/kWh, at the lower end of Sovacool's and Warner & Heath's range.

As the world's uranium reserves are depleted, it might be expected that poorer quality ore at deeper depths will have to be mined increasing the emissions from this stage, although historically, this does not always appear to have been the case because much of the world has yet to be explored for uranium. The enrichment process will tend to lead to less emissions as electricity systems are decarbonised.

While it is now widely believed that there is a climate emergency requiring concerted and extensive measure, this does not mean that other environmental issues must be forgotten. The risk of catastrophic accidents at nuclear power plants has been proved to be real, albeit with a

[59] Emissions occur in the mining of the ore, the processing of the ore to separate the uranium, the shipping of the ore to the location of enrichment, the shipping of the enriched uranium to the fuel fabrication plant, shipping of the fuel to the reactor, storage and cooling of the spent fuel for decades, packaging of the spent fuel ready for disposal, transport of the spent fuel to the disposal site and disposal and eventual sealing of the disposal site. The last two stages are not demonstrated and alternative options are possible.

[60] Only 0.7% of naturally occurring uranium is fissile, able to sustain a nuclear chain reaction, U235, with the majority the non-fissile U238. For the majority of reactor types the U235 content much be increased to 3.5-5% via process such as centrifuging to separate the lighter isotope from the heavier.

[61] B Sovacool, 2008, Valuing the Greenhouse Gas Emissions from Nuclear Power: A Critical Survey *Energy Policy* 36(8):2940-2953.

[62] E Warner & G Heath, Life Cycle Greenhouse Gas Emissions of Nuclear Electricity Generation *Journal of Industrial Ecology*, **16**, S73, (2012)

[63] https://www.ipcc.ch/site/assets/uploads/2018/02/ipcc_wg3_ar5_annex-iii.pdf#page=7

low probability and the measures needed to deal with nuclear waste, especially spent fuel, are unproven and probably decades from being demonstrated anywhere in the world.

7. Conclusions

NERSA's consultation paper on the government proposal to build 2500MW of nuclear capacity asks for comments on it. The law setting up NERSA requires it to ensure:

1. The efficient, effective, sustainable, and orderly development and operation of electricity supply infrastructure in South Africa.
2. The interests and needs of present and future electricity customers and end-users are safeguarded and met, having regard to the governance, efficiency, effectiveness, and long-term sustainability of the electricity supply industry within the broader context of economic energy regulation in the Republic.
3. Investment in the electricity supply industry is facilitated.
4. Universal access to electricity is facilitated.
5. The use of diverse energy sources and energy efficiency is promoted.
6. Competitiveness and customer and end-user choice are promoted.

In terms of these duties, this submission gives overwhelming evidence that:

1. A nuclear programme would not contribute to the effective sustainable and orderly development and operation of the South African electricity sector;
2. It would raise electricity prices above the level needed to meet electricity demand efficiently and while meeting other policy objectives particularly environmental objectives;
3. Nuclear power programmes are notoriously difficult to finance and this is generally only possible if the high risks involved fall either on taxpayers or electricity consumers rather than financiers. Proposals to part-finance construction using a consumer levy should not be approved;
4. The nuclear programme would not facilitate universal access;
5. Diversity is not a useful end in itself, it is useful if it improves security of supply and the uncertainties inherent in a nuclear programme would, as demonstrated in the past, reduce supply security;
6. The nuclear programme would lead to prices being higher than they need be so competitiveness would be damaged.

As a result and given that the objectives listed above are not met, NERSA should not concur with the Minister's decision to commence the process to procure the new nuclear energy generation capacity of 2,500MW.

Table 1 **Experience with EPR**

Project	Date order	Construction start	Forecast completion at construction start	Completion estimate in 2020	Cost estimate at construction start	Cost estimate in 2020
Olkiluoto	2003	8/05	2009	2022	€3bn	€10.5bn
Flamanville	2006	12/07	2012	2023	€3.2bn	€12.4bn
Taishan 1, 2	2007	11/09, 4/10	2013/14	12/18, 9/19	?	?
Hinkley Point C 1,2	2016	12/18, 12/19	2025/26	2028/29	£19.6	£25.5-27.5bn

Source: IAEA PRIS database and author's research
Note: The French Cour des Comptes estimated the completion cost of Flamanville to be €19.1bn in 2020, a figure that EDF has not disputed. Nuclear Intelligence Weekly, Weekly Round-up, July 10, 2020

Table 2 **Experience with AP1000**

Project	Date order	Construction start	Forecast completion at construction start	Completion estimate in 2020	Cost estimate at construction start	Cost estimate in 2020
Sanmen 1,2	2007	4/09, 12/09	2013	9/18, 11/18	?	?
Haiyang 1,2	2007	9/09, 6/10	2013/14	10/18, 1/19	?	?
Summer 2,3	2009	3/13, 11/13	2017/18	Abandoned 2017	$5.2bn	$25bn (2017)
Vogtle 3,4	2009	3/13, 11,13	2017/18	2022+	$6.65bn	$19bn

Source: IAEA PRIS database and author's research

Table 3 **Experience with AES-2006**

Project	Date order	Construction start	Forecast completion at construction start	Completion estimate in 2020	Cost estimate at construction start	Cost estimate in 2020
Novovoronezh 2 1,2	2007	6/08, 7/09	2012/13	2/17, 10/19	?	?
Leningrad 2 1,2	2007	7/09, 4/10	2012/13	10/19, 2021	?	?
Ostrovets 1,2	2012	11/13, 4/14	2018/19	2021/22	$11.1bn	?
Akkuyu 1,2	2010	4/18, 4/20	2023/25	-	?	?
Roopur 1,2	2015	11/17, 10/18	2023/24	-	$12.65bn	?

Source: IAEA PRIS database and author's research
Notes

1. Leningrad 2 1 first grid connection 10/20.
2. Ostrovets 1, first grid connection 11/20.
3. Two further reactors ordered for Akkuyu had yet to start construction by January 2021.

Table 4 Experience with APR1400

Project	Date order	Construction start	Forecast completion at construction start	Completion estimate in 2020	Cost estimate at construction start
Shin Kori 3,4	?	10/08, 8/09	?	12/16, 8/19	-
Shin Kori 5,6	?	4/17, 9/18	?	-, -	-
Shin Hanul 1,2	?	7/12, 6/13	?	-, -	-
Barakah 1-4	2010	7/12, 4/13, 9/14, 7/15	2017+	2021+	$20bn

Notes

1. Barakah 1 generated first power in August 2020 but was still in testing in January 2021.
2. No completion costs are available

Table 5 Ingerop's sample construction costs ($/kW)

Project	Technology	Ingerop estimate	2021 estimate	Comments
Olkiluoto 3 Finland	Framatome EPR	5945	7945	In 2013, completion estimate 2014, in 2020, 2022
Flamanville 3 France	Framatome EPR	6700	9385	In 2013, completion estimate 2015, in 2020, 2023
Hinkley Point C UK	Framatome EPR	6454	10900-11800	Construction start 2018-19, expected completion 2026-28
Taishan China	Framatome EPR	2900	?	In 2013, completion expected 2015, actual completion 2018/19
Vogtle, USA	Westinghouse AP1000	6280	8500	Construction start 2013, expected completion 2017-18. In 2020, 2022+
Sanmen, China	Westinghouse AP1000	2750	?	In 2013, completion expected 2015, actual completion 2018
Shin Kori 3,4 Korea	Korea APR1400	6400	?	Completed 2016, 2019
S U 3, 4 Korea	Korea OPR-1000	4900	?	Technology does not meet current standards
Barakah 1-4, UAE	Korea APR1400	3820	?	Construction start 2013, expected complete 2017-18. 2020, estimated complete 2021-??
Akkuyu 1-4, Turkey	Rosatom AES-2006	4300	?	Construction start unit 1 2018, unit 2, 2020
Vietnam	Rosatom AES-2006	4700	-	Project abandoned before construction
Hanhikivi, Finland	Rosatom AES-2006	4900	?	Construction start 2022
Sinop 1-4, Turkey	SNPTC AP1000	4300	-	Project abandoned before construction
Jordan	Rosatom AES-92	4500	-	Project abandoned before construction
Korea	Korea OPR-1000	3695	-	Technology does not meet current standards

Source: Ingerop Report and author's research