What would the RAB model mean for Sizewell C?

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1. Introduction & Summary

Electricité de France (EDF) is making strenuous efforts to promote the Regulated Asset Base (RAB) finance model to build the Sizewell C (SZC), nuclear power station. EDF claims the price of electricity from SZC would be in the range of £40-£60/MWh[1]. EDF's financial condition is so poor it has no hope of being able to finance SZC itself, so new investors have to be found and incentivised if the project is to go ahead.[2] The attractions to EDF of the RAB model, in comparison with the Contract for Difference (CfD) model used for the Hinkley Point C (HPC) project, are clear. EDF is the majority owner of HPC and is locked into a contract that requires it to absorb the risks from escalating costs and construction delays. After only two years of construction, the plant is 52-68% over budget, at least four years late, and, as a result, there is an increasing risk the project will be a loss-maker for EDF.

Under RAB, construction risks would fall on the public - most likely as electricity consumers, but also as taxpayers - in order to make the investment attractive to institutional investors such as pension funds. EDF's role would be to supply the reactor and build, operate, and maintain it under contracts that are, for nuclear projects, typically 'cost-plus', in other words guaranteed to be profitable. In addition, EDF would be able to recover the costs it has already incurred in developing the site, that would be lost if the project did not go forward. By end 2020, EDF reported in its annual Reference Document it had spent €324m on the Sizewell site including €219m in 2020 alone, from a development budget of €458m.

The UK government and EDF are reportedly considering taking small stakes, presumably to send a signal to the market that the project would not be allowed to fail. EDF forecasts a Final Investment Decision might be taken by mid-2022.[3] Given that EDF will at most be a minority investor, it is not clear how EDF can make a Final Investment Decision, all they can do is bring the project to the point when the investors could be brought in and it would be for them to make the investment decision. Nevertheless, the British government announced in December 2020 that it had entered negotiations with EDF on the SZC project.[4] However, the UK government is claiming only that it would aim to achieve a Final Investment Decision for at least one reactor project by the end of the current Parliament (December 2024), subject to clear value for money and all relevant approvals.[5]

This report reviews EDF's analysis of why the purchase price of power from HPC is so high, and uses this information to critically examine the economic case put forward for SZC under the RAB model, based also on the information given in a UK government consultation paper on the scheme published in July 2019.[6] We consider the likely cost to consumers of levies on energy bills to support the construction of SZC and the cost of the power generated, both

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[1] https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/110220-uk-to-approve-new-nuclear-plant-at-sizewell-c-ahead-of-white-paper-report

[2] At the Westminster Energy and Environment Forum 10 October 2020, Humphrey Cadoux Hudson, Managing Director, Nuclear Development EDF Energy said: "We have to get this asset [Sizewell C] off our balance sheet" https://www.youtube.com/watch?v=S74CNa5MVVM

[3] https://www.edf.fr/sites/default/files/contrib/groupe-edf/espaces-dedies/espace-finance-fr/informations-financieres/informations-reglementees/urd/edf-urd-rapport-financier-annuel-2020-fr.pdf

[4] https://www.gov.uk/government/news/government-sets-out-plans-for-clean-energy-system-and-green-jobs-boom-to-build-back-greener

[5] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/945899/201216_BEIS_EWP_Command_Paper_Accessible.pdf

[6] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/943746/rab-model-for-nuclear-consultation-.pdf

under conditions put forward by EDF and under more realistic but still relatively optimistic assumptions.

The challenge EDF and the UK government face is to show that SZC would give consumers Value for Money; in other words electricity that is considerably cheaper than the strike price for HPC, so robustly criticised by the NAO, and competitive with alternative low-carbon generation options. [7] This report considers whether it is possible to reduce the price of SZC's electricity enough to provide Value for Money whilst still giving investors an attractive return.

We find that the minimum cumulative cost to consumers over Sizewell C's 10-year construction period, to deliver a 6% return to investors for a £20 billion capital investment, would be around £300 using EDF's unrealistic assumptions and could be over £500 on more realistic assumptions. If the project goes as badly as all other EPR projects have, the surcharge to consumers during construction would be much higher. On the cost of power, while under the RAB model this would tend to reduce over time, using information provided by EDF on the breakdown of the contract price agreed for electricity from Hinkley Point C we conclude that it would be decades before the cost of Sizewell C's electricity would reduce to the £40-£60/MWhr range EDF is currently claiming, with calculations of at least £100/MWhr in year 1, only falling to below £60 after year 30 of the plant's operation. Using more realistic calculations, which would still require SZC to be completed more efficiently than any of the previous EPRs, we calculate that the cost per MWhr would remain above £70/MWhr even by year 40. Our conclusions are:

- that by removing construction risk from EDF, incentives to control construction costs are reduced, exposing electricity consumers and taxpayers - who are paying all the finance costs during construction - to unquantified liabilities.
- that EDF's cost estimates are too optimistic.
- that even if - eventually - the electricity price for a RAB-funded Sizewell C is lower than Hinkley Point C, it will be much higher than renewables and not offer Value for Money.

As the UK government has acknowledged, many of the details needed to evaluate the RAB model are not specified in the Consultation Paper and will only be determined in commercially confidential negotiations between the government and potential investors. We have therefore had to make assumptions on some of the elements. For an investment of tens of billions of pounds of essentially public money to be shrouded in such secrecy is indefensible.

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[7] We address the issue of the carbon content of nuclear power and whether there is a need for specific base-load power plants in https://stopsizewellc.org/core/wp-content/uploads/2020/10/Hinkley-finance-AMF-CDC-update.pdf.

2. The record of the EPR

None of the five large reactor designs currently on offer worldwide has a good record in terms of costs and construction times but the EPR appears to have the worst. The first EPR ordered was the Olkiluoto 3 reactor on which construction started in 2005 at an expected cost of €3bn with completion due in 2009. The plant is not expected to be in commercial operation before 2022 and the most recent cost estimate was about €10.5bn. Construction on Flamanville 3 started in 2007 at an expected cost of €3.2bn with completion in 2012. This plant is also not complete and it will not be online before 2023. EDF's latest cost estimate is €12.4bn, while the French government's Cour des Comptes estimates the cost as €19.1bn.[8]

The two EPR reactors for Taishan (China) were ordered soon after the Flamanville order and would therefore be expected to have a similar contract price to Flamanville although the contract price has not been published. The Cour des Comptes report states the reactors, which went into operation in 2018 and 2019, were five years late and 60% over budget. If we assume the expected cost when the contracts were signed was the same per reactor as Flamanville 3, the actual cost with the 60% cost escalation would be €10.2bn, still less than half the cost forecast by EDF for SZC. The power purchase price paid is set by the Chinese government at 435 RMB/MWh (about 56 €/MWh or £50/MWh).[9] EDF acknowledges that this price is not sufficiently profitable. This makes EDF's claim that the price of power from SZC would be in the range £40-60/MWh implausible.

3. Why is Hinkley Point C's power purchase price so high?

The HPC project comprises two EPR reactors each of 1600MW supplied by Areva, ordered in 2016 and to be owned by a consortium, NNBG, comprising EDF (66.5%) and China General Nuclear (CGN, 33.5%). After the order was placed, Areva collapsed financially and in 2017 as part of a government driven rescue package, EDF was required by the French government to take a majority stake in its reactor division, Areva NP, which it renamed Framatome.[10]

EDF has presented analysis of the breakdown of HPC project costs purporting to show that two thirds of the HPC power purchase price is accounted for by financing costs, much of which is the 'risk premium' (see Table 1).[11] The conclusion drawn by EDF from this is that with a different finance method, the Regulated Asset Base (RAB) model, the risk premium would be much lower and the power purchase price correspondingly lower.

Table 1 EDF's breakdown of Hinkley Point C price under Contract for Difference

	Cost (£/MWh)
Construction risk premium	36
Financing cost without risk premium	26
Operations & Maintenance cost	19.5
Capital construction cost excluding finance	11

[8] https://www.ccomptes.fr/fr/publications/la-filiere-epr

[9] https://www.edf.fr/sites/default/files/contrib/groupe-edf/espaces-dedies/espace-finance-fr/informations-financieres/informations-reglementees/urd/edf-urd-rapport-financier-annuel-2020-fr.pdf

[10] Areva was created in 2001 from the merger of the fuel cycle company, Cogema, and the reactor company Framatome. The fuel cycle interests were in Areva NC and the reactor division in Areva NP. These companies have been majority owned by public money since the 1980s. Areva NC was renamed Orano in the rescue

[11] Presentation by Humphrey Cadoux-Hudson to a parliamentary meeting 2020.

Total	92.5

Note: These prices are in 2012 money. The strike price is index-linked and in 2020 money is £111.7/MWh.

EDF fails to mention that one of the major differences between the HPC CfD model and the SZC RAB model is that under the latter, consumers would pay a non-refundable surcharge on their bills to finance the plant as soon as it had been approved and these costs are additional to its forecast power price of £40-60/MWh.

The obvious conclusion to be drawn from the high risk premium claimed by EDF is, as the National Audit Office said, *"the Department's deal for HPC has locked consumers into a risky and expensive project with uncertain strategic and economic benefits."*[12] EDF claims that half the financing cost is attributable to HPC being a first-of-a-kind (FOAK) so the risk would be much less with a replica follow-up plant as SZC would be. The claim HPC is a FOAK is highly questionable. HPC represents the fifth and sixth reactor of Framatome's EPR design on which construction has started. The previous four started construction 8-13 years before construction started at HPC, with two reactors in commercial operation. EDF was a major partner in the construction of three out of four of these so there was ample experience with the design, most of which was known to EDF. The UK regulator, the Office of Nuclear Regulation, did require some changes to meet its own requirements but there is no suggestion these changes substantively changed the fundamentals of the design. It is hard to avoid the conclusion that EDF will claim every EPR to be a proven design up till the point of order, but it will become a FOAK when costs start to rise. The HPC deal included a provision that the HPC price would come down by £3/MWh if SZC is built. This appears to be based on a sharing of any FOAK costs between two projects rather than one and the scale of this reduction implies the FOAK costs are small. It has yet to be confirmed whether this reduction would apply if SZC was built under the RAB model,

If, as claimed by EDF, half the finance cost is down to the plant being a FOAK rather than being generic to all nuclear projects, the obvious conclusion is that for a follow-up plant also with two EPRs, at Sizewell C (SZC), the risk premium would be much lower and, hence, the price of power under the CfD model used at HPC would be much lower, £74.5/MWh compared to £92.5/MWh. This begs the question, why is a different finance model needed if such a large part of the risk is due to HPC being a FOAK? The clear explanation is that it is a way for the EDF to continue the project and win profitable contracts, but without the financial risk associated with HPC?

If half the risk is generic to nuclear, that risk for SZC would be no different to that for HPC and the reduced power price using the RAB model would come because, under RAB, the risk is shifted to the British public, either as taxpayers or electricity consumers. RAB would guarantee that whatever costs are incurred in building and operating the plant would be passed on to consumers, and the plant owners would be paid a rate of return on the money invested long before a MWh had been generated. Consumers would pay an increasing surcharge on their electricity bills during the construction period. It is not clear why a different finance model is needed other than because EDF's financial condition is too weak to use CfD. In short, again the problem is EDF, not the finance model. If the risk were shifted to the British public, the price using the CfD model could be made flexible, for example, reset

[12] https://www.nao.org.uk/report/hinkley-point-c/

annually, with whatever costs are incurred being recovered from consumers. We do not recommend this option.

3.1. Evaluation of EDF's analysis of HPC costs

In the Appendix, we present a detailed critique of EDF's cost analysis. This analysis of the breakdown of HPC's costs is not consistent with the conditions that applied when the price was set in 2013. The claim of a huge risk premium on the cost of finance is incompatible with the finance being guaranteed by UK taxpayers as was then expected. The risk would have been borne by UK taxpayers, not the financiers, so there would have been no risk premium on the cost of finance. The estimated operating costs appear much lower than they are likely to be.

If EDF were to attempt to finance the SZC project using the CfD model, the real strike price would have been higher, even if we accept EDF's claim that the construction cost of SZC will be significantly less than the outturn cost of HPC. This is because the HPC strike price was based on an assumed real construction cost 22% lower than the forecast cost of SZC. The widely adopted convention given by the International Atomic Energy Agency for start of construction of a reactor is the pouring of 'first structural concrete', although preparatory ground works will have started well before this point. For example, preparatory work on the HPC site started in 2013 but first structural concrete for the first unit was not poured until December 2018. So, as of early 2021, the lead-time is likely to be about 14 years and the construction time about 9 years. EDF's application for Development Consent states that the construction time for SZC will be 10-12 years (EDF does not specify when first structural concrete is expected to be poured), with an expected start date of 2022 based on a Final Investment Decision being taken in 2022 with the plant being operational by 2034. It is clear this start date of 2022 cannot be met and if a Final Investment Decision is not taken before 2024, even completion in 2036 will be hard to achieve.

4. The RAB model

EDF claims that under the RAB model, the price of power from SZC would be £40-60/MWh compared with £111.7/MWh (in 2020 prices) agreed for HPC. In this section we try to reconcile this forecast with the assumptions EDF appear to have made.

From 2018 when it was clear that EDF did not have the scope to finance the SZC project, it has been promoting the Regulated Asset Base (RAB) model both to the British government and to the British public. In July 2019, the UK government published a consultation paper on the RAB model with an expectation of a response including a decision on the viability of the model by early 2020. The government response was not published until November 2020.[13] However, it did not approve the model as EDF hoped it would, merely saying: *"Having assessed the consultation responses, the government believes that a RAB with the high-level design principles set out in the consultation remains a credible model for large-scale nuclear projects."* The UK government claimed that it would aim to achieve a Final Investment Decision for at least one large-scale nuclear project by the end of the current Parliament

[13] https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future
https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/943762/Nuclear_RAB_Consultation_Government_Response-.pdf

(December 2024).[14] If a Decision is not taken by mid-2022, EDF has said it and CGN would need to come to a new agreement to meet the additional costs.

Under RAB, investors would be paid a guaranteed rate of return on the value of the asset. Institutional investors like pension funds will not be able to justify investing in a RAB scheme if any significant elements of the risk arising, for example from cost escalation, delays, poor reliability etc, falls upon them. The government will doubtless talk about risk-sharing but the reality will be that it will only be possible to attract investors if all the significant risks fall on consumers.

There are two major differences between RAB and CfD. First, under RAB, consumers would pay a surcharge on their bills up to the point the plant entered commercial service, while under CfD consumers do not start to pay until the plant is in service. This surcharge would start to pay investors their finance costs from the point the deal was agreed and money began to be spent, presumably including the cost of getting the deal to Final Investment Decision. This would mean that the value of the asset and the cost of finance would be based on the cost of construction alone, the so-called overnight cost, because consumers would pay the finance charges. This is in contrast to the HPC deal, where the construction cost is the overnight cost plus the cost of finance during construction. EDF claims that finance costs are of the same order of magnitude as the actual construction costs so RAB would essentially halve the price of construction to the plant owners. Consumers would face increased bills long before they received any benefit from the new plant and despite paying for a significant proportion of the plant, this funding would bring them no stake in the plant.

Second, unlike HPC where the real price is constant over the life of the contract, under RAB, the price would be as high as necessary to pay the investors their guaranteed profit.

4.1. The cost of finance

It is implausible that financial institutions, such as the pension funds expected to comprise the investors, would have a lower cost of capital for the SZC project than EDF was expecting when the HPC power purchase price was agreed in 2013. Indeed, it is more likely that their cost of capital, essentially the interest rate they pay their investors, would be higher. In 2013, it was expected that EDF's borrowing for HPC would be backed by UK sovereign credit guarantees making it an exceptionally low risk proposition for those lending to the project with correspondingly low interest rates. An EDF press release in September 2013 said: *"The Government has confirmed that the project is eligible for its UK Guarantees scheme. It is currently assumed that, subject to Infrastructure UK due diligence, Treasury-guaranteed debt will finance 65% of expected total costs prior to operations, backed by an appropriate security package provided by the investors."*[15]

A French regulatory body, Autorité des Marchés Financiers (AMF) criticised EDF and its then CEO for delaying communicating important information to the market about the

14 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/945899/201216_BEIS_EWP_Command_Paper_Accessible.pdf

15 https://www.edf.fr/sites/default/files/contrib/groupe-edf/espaces-dedies/espace-finance-en/investors-analysts/events/special-announcements/agreement_reached_on_commercial_terms_for_the_planned_hinkley_point_c_nuclear_power_station.pdf

decision not to take up these guarantees.[16] AMF claimed that on September 21, 2015, the electricity group indicated that HPC would be financed by equity and that this major transaction would be consolidated by full integration into EDF's accounts, which was not what EDF had previously planned. AMF said that EDF should have communicated this information to the market three months earlier. AMF clearly believed the provision of loan guarantees was a major positive element in the deal and EDF's decision not to take them up was important information of relevance to investors that should have been communicated promptly to the financial market.

Under RAB, the EDF (80%) and CGN (20%) consortium that owns the SZC project would finance it up to the point of a Final Investment Decision by the new owners, the institutional investors. The cost of getting to this point for HPC was claimed by EDF to be £2bn. Some of these costs would go back to 2009 when the additional land needed at their sites was acquired and the UK's Generic Design Assessment process was launched (completed in 2012).[17] Some of these costs would not need to be repeated, for example, the cost of getting the design through the Generic Design Assessment process and of completing the design (assuming SZC actually will be an exact replica of HPC). EDF and CGN would expect to recover this cost from the new owners. We assume the cost would be the €458m budgeted although if the Final Investment Decision is after 2022, additional costs are expected.

4.2. The cost of power under RAB

4.2.1. UK practice with regulation of network assets

The consultation paper draws close parallels between RAB and with the way energy network assets are regulated and prices set so it is useful to summarise this latter process. The price is essentially set as the value of assets multiplied by the allowed rate of return plus the operating costs. Prices are set for eight year periods (recently increased from five years) at which point the rate of return is adjusted to reflect the prevailing market interest rates and the asset base (Regulated Asset Value or RAV) is adjusted up, to reflect new investments to be made during the next eight-year period, and down to reflect depreciation. In the process of setting the additions to RAV, the regulator asks the companies to set out their investment requirements and the associated timings and costs. These are then reviewed by Ofgem and the income set so that these requirements agreed by Ofgem and the network company can be financed. Therefore consumers pay for facilities before they are complete, as is proposed for the RAB model. This model has led to 'gaming', with network companies tending to overestimate their investment needs and how quickly they are needed, leading to companies being paid earlier and for more expenditure than they actually make. The RAV is adjusted to reflect actual spend every eight years but the companies, who claim the shortfall is due to efficiency gains, are not required to repay the unearned income. In theory there are incentives and penalties for the network companies based on their performance, but in practice, few if any penalties are

[16] https://business.financialpost.com/pmn/business-pmn/edf-faces-11-million-fine-over-hinkley-point-c-nuclear-project and https://www.agefi.fr/regulation/actualites/quotidien/20200626/college-l-amf-demande-10-millions-d-euros-d-amende-301611

[17] Design approval under the GDA was for 10 years and would expire in 2022, well before construction of SZC had started. However, the UK Office of Nuclear Regulation has indicated that it would expect renewal to be essentially automatic.

levied and payments are all incentives.[18] For RAB, to reduce the risk of gaming, it would seem sensible that returns are paid on the basis of actual, not forecast, expenditures and timings. This might be done by setting the price based on forecast costs and then recovering any under- or over-spend the following year.

From a regulatory policy point of view, this method of approving investments in advance and paying for them before they are in operation is flawed. Effectively it is the regulator or, in the case of RAB the government, that is making investment decisions. Private companies should be required to make commercial judgements on their needs and back them with their own money so that if the investment proves misconceived, it will be the company that bears the consequences, not the consumers.

4.2.2. The cost of power under RAB

In its Consultation Paper, the government specified few of the details needed to evaluate the scheme. On how electricity would be priced, it identified seven components:

1. Return on capital (WACC x RAB)
2. Depreciation
3. Operating costs
4. Funded decommissioning programme
5. Tax
6. Grid costs
7. Incentives/penalties, other adjustments.

We will focus on the first four, which are likely to be the largest or, in the case of decommissioning, very important. The other three costs are not known but would probably not be major additions to the cost so for the purposes of this exercise we do not consider them. We create two scenarios to illustrate potential costs. Scenario 1 uses the assumptions made by EDF where they are known, while Scenario 2 uses our assumptions based on past experience. The Scenario 2 assumptions are far from a worst case scenario and in our view are closer to a best realistic case.

4.2.3. Funded decommissioning programme

This cost is not dependent on the funding model and should be dealt with separately. We assume that the funded decommissioning programme will also include the cost of spent fuel disposal, as is the case with the Nuclear Liabilities Fund that would fund EDF's UK operating reactors. For HPC, the government estimated this would account for only £2/MWh (£2.4/MWh in 2020 prices) of the strike price. If we assume a plant availability of about 80%, this will yield about £54m per year or £1.9bn over the 35-year life of the plant.

There is minimal experience of decommissioning nuclear power plants to the final stage of 'greenfield site' (available for unrestricted use) worldwide - none at all in the UK - but the minimal experience there is suggests the cost will not be less than £1,000/kW or £3.2bn for HPC.[19] To this must be added the cost of spent fuel disposal and there is absolutely no

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18 https://tarifamoderna.com.br/wp-content/uploads/2020/05/Workshop-3-DIA-2_MESA-4-_presentation_SThomas.pdf

19 https://www.world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-wastes/decommissioning-nuclear-

experience of this worldwide. Indeed, final disposal of spent fuel and other high-level waste in a Geological Disposal Facility (GDF) in the UK is not expected to start before 2075. The waste must stay in temporary above ground stores either at Sellafield or at the reactor sites until then. The high-burn-up fuel to be used at HPC and SZC will be more difficult to handle than existing fuel and will take even longer before it would be ready to be placed in a GDF, if that is the option chosen; perhaps 140 years (around 2200). Preliminary estimates suggest the cost of spent fuel disposal will be of the same order of magnitude as decommissioning, requiring a total of £6.4bn. All experience suggests the actual cost will not be less and is likely to be much more than these preliminary estimates.

While it would be hoped that a decommissioning fund set up to pay these costs, assuming a fund that will survive for about two centuries is credible, would earn a positive real rate of interest, this has not been experience in the UK in recent years. The Nuclear Liabilities Fund has failed to keep pace with inflation in the past 7-8 years. £2.4/MWh is likely to be a gross under-estimate of the actual requirement and since the owners of a plant built using the RAB model are highly unlikely to undertake to pay the shortfall from their own resources (assuming they still existed a century or more from now), it will be an extra charge for the public purse. How any shortfall would be dealt with at HPC is unclear. For SZC, we assume the required contribution will be £2.4/MWh for Scenario 1, but more than three times the amount estimated for HPC or £8/MWh for Scenario 2.

4.2.4. Operating costs

The operating costs - mainly Operations & Maintenance costs, with fuel a much smaller element - are difficult to estimate but would be expected to be much lower per MWh than the return on capital element. For Scenario 1, we use EDF's assumption of £23.4/MWh in 2020 prices. For Scenario 2, international experience suggests £30/MWh would be a minimum so that is the number we will use. It is less than the apparent average cost of the 56 French plants of £44/MWh.[20] These costs would essentially be passed directly through to consumers.

4.2.5. Return on capital and depreciation

This will represent by far the largest element of the MWh price. For Scenario 1, we use EDF's optimistic estimate of the 'overnight' construction cost of £20bn for two EPRs, about 35% less in real terms than the expected cost of HPC of £27bn (2020 money), and a lead time of 10 years. However, £20bn is 22% more in real terms than the forecast price for HPC in 2013 when the HPC strike price was set. We assume more realistic but still optimistic costs for Scenario 2. The overnight cost is £30bn and construction overruns by two years making the lead time 12 years. While £30bn is about 10% more than the current assumed price for HPC, there is still six years of construction remaining and there is little to suggest the costs will not continue to escalate and end up significantly higher than £30bn. An assumption of £30bn for SZC is likely to represent a significant reduction over the HPC outturn cost. If SZC were to only overrun by two years, that would make it the EPR closest to achieving its expected construction schedule.

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facilities.aspx#:~:text=For%20nuclear%20plants%2C%20the%20term,is%20permanently%20removed%20from%20operation.

[20] In France, EDF is required to sell 25% of its nuclear output to other electricity retail companies using the ARENH tariff at €42/MWh. It argues that this does not cover its costs and is lobbying for the tariff to be increased to about €50/MWh or £44/MWh.

The government gave an illustration of how the asset value might be depreciated over time with 'straight-line depreciation', although it did not specify the period over which depreciation would take place. We will assume for our illustration of the SZC project that the depreciation period will be the contract life, which, for simplicity, we assume would be 40 years. The overnight construction cost will be £20bn, including the cost of purchasing the scheme from EDF/CGN, assumed to be €458m. The Regulated Asset Value of the plant in the accounts will be reduced (depreciated) at £0.5bn per year in Scenario 1 and by £0.75bn in Scenario 2.

For these purposes, let us assume that the allowed rate of return on assets is similar to that allowed for the electricity network companies, 6% real.[21] The rate of return is influenced by prevailing interest rates and should be approximately the rate of return available in the market for a very low risk investment.

In the consultation paper, the government refers to the Weighted Average Cost of Capital (WACC). If the cost of borrowing is 6%, providing two thirds of the capital and the required rate of return on equity - which would provide the other third of the capital - was 12%, WACC would be 8% (6 x 2/3 + 12 x 1/3). It is not clear how far the financial institutions would finance using their investors' funds, and how far they would also use borrowing.

For network companies, the allowed rate of return is reset when the pricing formula is reset, every eight years. Whether institutional investors would be willing to take the risk that the rate of return would be reset at a significantly lower level or whether they would demand a fixed rate for the life of the power purchase contract, remains to be seen and would be the subject of commercially confidential negotiations between the government and potential investors.

4.2.6. The cost of the surcharge and the price of electricity under RAB

If we assume consumers in Scotland, which long ago chose not to pursue new nuclear projects, and Northern Ireland are not required to pay the surcharge (the government needs to confirm this), that leaves the money to be raised from the approximately 20 million customers in England and Wales. (Note that the government also needs to confirm whether customers with 100% renewable energy suppliers will be required to pay the surcharge.)

We use EDF's assumptions in **Scenario 1** to generate the cost of the surcharge to each consumer during the construction period and the cost per MWh during operation (see Tables 2 and 3). These estimates are highly optimistic. If the construction cost goes up or the construction period is extended, the surcharge will be higher. It is implausible that investors would take this risk especially given EDF's experience with HPC. But based on EDF's assumptions, over a 10 year period from signing of contracts up to commercial operation, every consumer will have to pay more than £300 in surcharges. In short, they would pay for a third of the construction cost but despite this, they would not receive any equity stake in the plant

Table 2 Costs of surcharge to consumers during construction: Scenario 1 (EDF's Assumptions)

[21] The allowed rate of return varies from each re-setting of the price control (now every 8 years) but in the most recent price control for electricity distribution companies, 5 of the 6 companies were allowed 6% and the other one 6.4%. https://www.ofgem.gov.uk/sites/default/files/docs/2014/11/riio-ed1_final_determination_overview_-_updated_front_cover_0.pdf

Year	Cumulative Investment £bn	Return on investment £m	Surcharge per consumer £
1	2	120	6
2	4	240	12
3	6	360	18
4	8	480	24
5	10	600	30
6	12	720	36
7	14	840	42
8	16	960	48
9	18	1080	54
10	20	1200	60
Total	20	6600	330

Source: Authors' calculations

Note: We assume there are 20 million consumers. Costs are in 2020 money.

Table 3 Costs per MWH during operation: Scenario 1

Year	Net asset value £bn	Return on investment £m / £/MWh	Depreciation £m / £/MWh	Income for return & depreciation £m / £/MWh	Operating cost £/MWh	Price per MWh £
1	20	1200 / 53.6	500 / 22.3	1700 / 75.9	25.8	97.4
2	19.5	1170 / 52.2	500 / 22.3	1670 / 74.5	25.8	96.0
3	19	1140 / 50.9	500 / 22.3	1640 / 73.2	25.8	94.7
4	18.5	1110 / 49.6	500 / 22.3	1610 / 71.9	25.8	93.4
5	18	1080 / 48.2	500 / 22.3	1580 / 70.5	25.8	92.0
6	17.5	1050 / 46.9	500 / 22.3	1550 / 69.2	25.8	90.7
7	17	1020 / 45.5	500 / 22.3	1520 / 67.8	25.8	89.3
8	16.5	990 / 44.2	500 / 22.3	1490 / 66.5	25.8	88.0
9	16	960 / 42.9	500 / 22.3	1460 / 65.2	25.8	86.7
10	15.5	930 / 41.5	500 / 22.3	1430 / 63.8	25.8	85.3
20	10.5	630 / 28.1	500 / 22.3	1130 / 50.4	25.8	71.9
30	5.5	330 / 14.7	500 / 22.3	830 / 37.0	25.8	58.5
40	0.5	30 / 1.3	500 / 22.3	530 / 23.6	25.8	45.1

Source: Authors' calculations

Notes:

1. We assume the plants produce 22400GWh per year. Costs are in 2020 money.
2. The operating cost is made up of £23.4/MWh for O&M plus fuel & £2.4/MWh for decommissioning & spent fuel disposal.
3. Price per MWh is the sum of income for return on investment & depreciation plus operating cost

These MWh prices represent a significant reduction over the HPC price of £111.7/MWh in 2020 prices, but this is only achieved by each consumer making an advance, non-refundable, payment of £330. If we assume the price in year 20 is the average price over the whole contract, it would be £76.2/MWh, 32% less than HPC but not taking into account the £330 per consumer that will have been paid in the construction period. They are also based on costs that, on historical experience, are unlikely to be achieved. Nevertheless, it is the promise of MWh prices at this level that will be used to sell any RAB deal to consumers, despite the fact that such figures will only be indicative and the actual price will be whatever is required to meet the owner's costs and rate of return.

For **Scenario 2**, we assume that the same reliability as for Scenario 1 – each MW of capacity generates 7000MWh per year - and we do not assume any increase in operating costs as the plant gets older (see Tables 4 and 5).

Table 4 Costs of surcharge to consumers during construction: Scenario 2

Year	Cumulative Investment £bn	Return on investment £m	Surcharge per consumer £
1	2.5	150	7.5
2	5	300	15
3	7.5	450	22.5
4	10	600	30
5	12.5	750	37.5
6	15	900	45
7	17.5	1050	52.5
8	20	1200	60
9	22.5	1350	67.5
10	25	1500	75
11	27.5	1750	82.5
12	30	2000	90
Total	30	11700	585

Source: Authors' calculations

Note: We assume there are 20 million consumers. Costs are in 2020 money.

Table 5 Prices per MWH during operation: Scenario 2

Year	Net asset value £bn	Return on investment £m / £/MWh	Depreciation £m / £/MWh	Income for return & depreciation £m / £/MWh	Operating cost £/MWh	Price per MWh £
1	30	1800 / 80.4	750 / 33.5	2550 / 113.9	38	151.9
2	29.25	1755 / 78.3	750 / 33.5	2505 / 111.8	38	149.8
3	28.5	1710 / 76.3	750 / 33.5	2460 / 109.8	38	147.8
4	27.75	1665 / 74.3	750 / 33.5	2415 / 107.8	38	145.8
5	27	1620 / 72.3	750 / 33.5	2370 / 105.8	38	143.8
6	26.25	1575 / 70.3	750 / 33.5	2325 / 103.8	38	141.8
7	25.5	1530 / 68.3	750 / 33.5	2280 / 101.8	38	139.8
8	24.75	1485 / 66.3	750 / 33.5	2235 / 99.8	38	137.8
9	24	1440 / 64.3	750 / 33.5	2190 / 97.8	38	135.8
10	23.25	1395 / 62.3	750 / 33.5	2145 / 95.8	38	133.8
20	15.75	945 / 42.2	750 / 33.5	1695 / 75.7	38	113.7
30	8.25	495 / 22.1	750 / 33.5	1245 / 55.6	38	93.6
40	0.25	15 / 0.7	750 / 33.5	900 / 34.2	38	72.2

Source: Authors' calculations

Notes:

1. We assume the plants produce 22400GWh per year. Costs are in 2020 money
2. The operating cost is made up of £30/MWH for O&M plus fuel & £8/MWh for decommissioning & spent fuel disposal.
3. Price per MWh is the sum of income for return on investment & depreciation plus operating cost

Note that significant numbers of old US reactors, that were long ago fully depreciated and which have already been approved for life-extension by the US safety regulator, are being closed (or given subsidies to allow them to remain in operation) because their operating costs alone are too high to justify their continued operation so again, this assumption is very favourable. If we put in the cost escalation and delays that have occurred at Olkiluoto, Flamanville and HPC, the costs below would be far higher.

Under Scenario 2 assumptions, consumers must pay, on average, nearly £600 in non-refundable surcharges before any power is produced. So, in this Scenario, consumers would pay 40% of the construction cost but with no equity stake in return. Despite this, it is not till year 20 that the MWh price falls to about the HPC level. So on average, the MWh price would be no lower than HPC but we would have to wait for 10 years of construction and more than 20 years of operation to reach this level. This is in addition to nearly £600 per customer surcharge consumers would have had to pay during the construction phase. To put this surcharge of £90/year in the final year of construction in perspective, a typical consumer uses about 3MWh/year costing about £1000, so the surcharge would increase the MWh charge by about £30/MWh and increase bills by about 9%.

Under the assumptions of Scenario 2, consumers must pay, on average, nearly £600 in non-refundable surcharge payments before any power is produced and, despite this, it is not till year 20 that the MWh price falls to about the HPC level. So on average, the MWh price would be no lower than for HPC but they would have to wait for 10 years of construction and 20 years of operation to reach this level. This is in addition to the nearly £600 per customer surcharge consumers would have had to pay during the construction phase.

Table 6 shows a comparison of power prices in Scenario 1 and 2 and also compared to the Hinkley Point C prices. For comparison, the most recent (2019) capacity auction for offshore wind projects produced a bid of £47.9/MWh (adjusted to 2020 prices).[22]

Table 6 **Comparison of Scenario 1, Scenario 2, and Hinkley Point C (price per MWh £)**

Year	Scenario 1	Scenario 2	Hinkley Point C
1	101.7	151.9	111.7
5	96.3	143.8	111.7
10	89.6	133.8	111.7
20	76.2	113.7	111.7
30	62.8	93.6	111.7
40	49.4	72.2	111.7

Notes: Prices are in 2020 money. Hinkley Point price is calculated from £92.5/MWh in 2012 money

How can EDF claim prices would be as low as £40-60/MWh? We take the assumptions for construction cost, operating cost, construction time used in Scenario 1, EDF's assumptions. Operating, fuel, decommissioning and spent fuel disposal costs are £25.80/MWh, which means that what remains must cover depreciation and return on asset value: £14.2/MWH to achieve £40/MWh and £34.2/MWh to achieve £60/MWh. By year 20, the value of the asset will have been depreciated to £10bn. With a power price of £40/MWh, income would not be enough to cover depreciation, operating costs, and costs of decommissioning and spent fuel disposal. In short, income would not even be sufficient to repay the invested capital let alone a return on investment and the return on asset value would be negative. If the power price was £60/MWh, after operating costs (£25.8/MWh) and depreciation (£22.3/MWh) had been paid, only £11.9/MWh would be left to pay the return on assets. It is implausible that institutional investors would invest for such a poor rate of return.

4.3. Implications for power prices

The only positive factors in the HPC deal from a consumer point of view are that the price of power is known and constant in real terms and that if construction costs escalated over the 2013 estimates, these costs would be borne solely by the plant owners, EDF and CGN, assuming the price was not renegotiated as the NAO feared it would be.[23] In project appraisals, companies weigh benefits earned at an early stage higher than a benefit of the same real monetary value earned later so companies would prefer income to be front-end

[22] https://home.kpmg/uk/en/home/insights/2019/09/contract-for-difference-subsidiary-auction.html

[23] There is scope to review the operating cost element of the price after 15 years of operation.

loaded as would be the case with RAB but not CfD.[24] These advantages for consumers of a constant known price and risk bearing by the plant owner are equally, therefore, disadvantages for the plant owners.

A particular risk for consumers is relying on EDF's unrealistic forecast of an overnight cost of £20bn for the two reactors. There are few examples, especially in recent years, of nuclear plants being built that do not end up costing far more than forecast and taking significantly longer to build (see section 2). For example, HPC was forecast to cost £14bn in 2013. Estimates from the end of 2018, at the point when construction actually started, were that costs would be £21.5-23.2bn (2015 prices). In January 2021, the cost estimate was increased again to £22-23.7bn, a 67% real increase over 2013 estimate. With at least 5-7 years of construction left, it is highly unlikely there will not be more cost increases for HPC. Inevitably, under RAB, it will be consumers who pay for these excess costs both before and after plant completion.

As with the HPC deal, the SZC power would be sold to the government's Low Carbon Contracts Company (LCCC), which in turn would oblige electricity retailers to buy a share of the output at the price paid by LCCC. Electricity retail companies offering renewables-only deals and consumers wanting such deals would be forced to buy output from HPC and plants like SZC built under RAB and consumers would have the option of choosing green energy taken away from them.

4.4. Will there be investors?

We have so far focused on what it would take to produce a deal that would be financially attractive to investors. EDF's financial advisers, Rothschild & Co, has confirmed SZC is seeking "in excess of GBP20 billion...at low cost", which requires "the deepest pools of capital to be available".[25] However, even before serious negotiations have started and the elements of a deal specified, three large potential investors, Legal & General, Prudential and Aviva have indicated they have no interest in SZC.[26] Rothschild admitted that funds "are worried about what their ultimate investors think, what their pensioners think (if it's a pension fund) or their savers. They're worried about what their employees and their customers think. These are going to be big, high-profile investments that investors do not want to be controversial". In letters to pensioners, Aviva stated "nuclear's ESG [environmental, social and corporate governance] impact was far from clear at this time".[27] EDF's claim that the ownership would be majority UK based is no more than a pious hope and some potential investors will have no interest in investing in nuclear whatever the terms.

5. Conclusions

In our earlier report,[28] we argued that there would be little or no CO2 emissions to replace in the electricity generation system by 2034, when we assumed SZC would come online. If, as the government is implying, a Final Investment Decision is not taken until 2024, completion

[24] Under discounted cash flow calculations, under the process of discounting, it is effectively assumed that money earned earlier will earn interest and will therefore be worth more than a benefit of the same real monetary value earned at a later stage.
[25] https://www.world-nuclear-news.org/Articles/New-nuclear-needs-positive-taxonomies-says-Rothsch
[26] https://www.telegraph.co.uk/business/2021/02/06/aviva-fears-environmental-fallout-backs-new-nuclear-reactors/ and https://www.telegraph.co.uk/business/2021/02/20/sizewell-c-proves-aturn-off-city-giant-legal-general/
[27] ibid
[28] https://stopsizewellc.org/core/wp-content/uploads/2020/10/Hinkley-finance-AMF-CDC-update.pdf

of the plant is not likely before 2036 so the probability that SZC would save any emissions, a key element in the government's case for new nuclear capacity, is even smaller.

EDF's forecasts of timings are notoriously unreliable going back to the often quoted claim by EDF from 2007 that we would be cooking our Christmas turkeys using Hinkley Point C power in 2017[29] and that without Hinkley Point C at that time, the lights would go out. In June 2019, Humphrey Cadoux-Hudson claimed construction of SZC could start in 2021 and in less than two years, this forecast appears to be at least five years out.[30]

EDF's analysis of the breakdown of the HPC price is not credible and appears to be a post-rationalisation rather than being based on the figures used for the actual deal. Their purpose is to make the case for a finance model that would allow EDF to retain the profitable parts of the SZC deal, and not lose the money spent so far on the SZC project, while passing the risks that have made the HPC deal such a financial liability on to consumers. Its claims of lower construction costs for SZC over HPC neglect to point out that even with the substantial cost reductions claimed for SZC over HPC, SZC is still expected to cost substantially more in real terms than EDF expected for HPC in 2013.

A characteristic that increases the attractiveness of RAB to investors is that they can recover their finance costs from consumers during the construction phase, covering all their borrowing requirement in that period and the income is front-end loaded with the highest prices paid at the start of operation. This is equally unattractive to consumers. Our findings show that consumers will have to pay at least £300 up front, even using EDF's implausible figures, before they receive a single MWh, and it will be about 20 years before the price falls to the levels projected by EDF. For SZC this would be after 2050, and for any subsequent projects probably after 2060. Given the serious problems of fuel poverty in Britain, this would represent an unwelcome burden for consumers already struggling to pay their energy bills.

While the impact on bills of the RAB model applied to SZC would be noticeable, the RAB proposal is meant to provide a basis for future large nuclear power stations with the hope that collapsed projects (e.g., Moorside, Wylfa and Oldbury) could be revived and successors launched, multiplying the costs and risks of RAB for consumers several fold. If Moorside, Oldbury and Wylfa were revived, the contribution of nuclear would be about 35% of British electricity supplies rather than the 7% SZC is expected to provide.

It appears that most of the claimed gain of the RAB model is illusory, with the forecast reduced MWh price only possible because of large upfront non-refundable payments made by consumers long before they receive any power from the reactors and with no equity stake given. Consumers would also be shouldering major risks such as cost and time escalation and plant unreliability that under the CfD model EDF has undertaken. These risks could easily result in the increase of the MWh price by 50%. This is not a recommendation to use the CfD model, merely an illustration that under the RAB model, the claim that consumers would get cheaper electricity than under CfD is misleading.

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29 https://www.theguardian.com/uk-news/2017/jul/03/hinkley-point-c-is-22bn-over-budget-and-a-year-behind-schedule-edf-admits

30 Power in Europe 'Sizewell C 'could begin in 2021'' Power in Europe, June 17, 2019 p 5.

It is a widely agreed principle of risk management, including by the nuclear industry, that risks should primarily be borne by those able to influence the outcome.[31] If there are no consequences for those building the plant if costs overrun, they will have little incentive to control the costs. Consumers clearly have no way to influence nuclear costs so the RAB model fails to follow this basic principle. However, following this principle at Olkiluoto with Areva's fixed price contract was a major factor in the collapse of Areva. The cost of the HPC contract, which required EDF to bear the risks of cost escalation, construction delay and poor reliability, is a significant element in the poor financial condition of EDF. Any company taking on such risks is putting its survival in jeopardy and that is why EDF will not repeat a CfD, and Areva/Framatome will not risk a fixed price contract to supply and build a nuclear power plant. So, if the principles of risk allocation are followed, no nuclear plant would ever be built.

With the government refusing to give more details about the specific design of the RAB model, saying *"further details will be developed in discussion with developers of specific projects"* we are concerned that such details will only be known to those involved in commercial negotiations and we will not see the project-specific details - if ever - until a deal has been signed and it is too late. Consumers and probably tax-payers would be paying for the SZC project for half a century or more and it should only go ahead with the informed consent of those who will foot the bill, the public.

The balance of power in the negotiations will be very much with the investors. If a deal that gives a good rate of return with low risk to them is not available, the government will have to offer concessions, or investors will have no hesitation in walking away. The risk is that the government would accept what it believed to be the best deal available rather than walk away with no deal. The HPC deal gives little confidence in the UK government's ability to negotiate a good deal for consumers. It would sell the deal to the public on the basis of an indicative power price based on unrealistic assumptions. The HPC deal was a poor one but at least the price of power could not be hidden.

The government should issue another consultation paper with much more detail on risk allocation and how costs would be allocated. It may be that if these details are specified investors would judge the investment was not attractive. So specifying much more fully how RAB would work might well avoid government and investors wasting time on negotiations that were bound to fail and would allow government to focus on climate change policies that would work.

Even with this illusion of RAB reducing the price of nuclear power, SZC's power is likely to be more than double that of offshore wind, even if we accept EDF's highly optimistic cost estimates for SZC and ignore the surcharge payments.

The UK National Audit Office in its investigation into the HPC deal concluded: *'the Department's deal for HPC has locked consumers into a risky and expensive project with*

[31] At a Webinar on financing nuclear power plants hosted by the OECD's Nuclear Energy Agency, the participants: 'agreed a core economic principle to follow is that each risk should be borne by the parties best placed to reduce it *ex-ante* and most capable to absorb any incompressible residual *ex-post* in the context of their overall strategies of diversifying.'
https://www.world-nuclear-news.org/Articles/Webinar-examines-issues-in-financing-new-nuclear

uncertain strategic and economic benefits.'[32] This verdict came too late to save consumers from the HPC deal, and with the deal for SZC to be agreed in commercially confidential negotiations, this experience is likely to be repeated.

In the light of this analysis, it is clear that the rationale for the RAB scheme is not to reduce the price of power from nuclear sources. For the UK government, that excuse is a fig leaf to bring in a new source of investment in nuclear power after all the expected investors have fled, with little regard for the interests of consumers or its manifesto pledge to lower energy bills.[33] For EDF, it is a way to retain the profitable elements of a nuclear deal, recovering costs already incurred, while passing on the costs and risks to British electricity consumers.

In our introduction we asked whether it was possible to reduce the price of SZC's electricity enough to provide Value for Money whilst still giving investors a sufficiently attractive return. The answer would appear to be a categoric "no".

[32] https://www.nao.org.uk/report/hinkley-point-c/

[33] *"For many families, energy costs are a major source of financial pressure. We will keep our existing energy cap and introduce new measures to lower bills."* Available from https://www.conservatives.com/our-plan p15

Appendix EDF's analysis of the price of power from Hinkley Point C

Inflation and Exchange Rates

To evaluate EDF's claims, we must take account of two factors, price inflation and exchange rates, to ensure fair comparisons are being made. For inflation, there are a number of measures, none of which is ideal, but given that the power purchase price is indexed to the UK Retail Price Index (RPI), this is the index we use (see Table A). The power purchase price for HPC of £92.5/MWh was set in 2012 money, while the latest cost estimates for HPC are in 2015 money. Where costs are given without explicit identification of the base date, we assume it is in money of the day.

For exchange rates, the costs announced for HPC are in pound sterling but some comparative costs are in Euro. The pound/Euro exchange rate has varied widely in the period since 2012 from £1=€1.09 to £1=€1.42. We use the exchange rate that prevailed in January 2021 of £1=€1.13 and where conversions are required this will introduce some inevitable degree of approximation although this will not affect the main analysis

Table A Retail Price Index 2012-2020

	Index (Jan 1987=100)	Index (2012=100)
2012	242.7	100
2013	250.1	103.0
2014	256.0	105.5
2015	258.5	106.5
2016	263.1	108.4
2017	272.5	112.3
2018	281.6	116.0
2019	288.8	119.0
2020	293.1	120.8

Source: https://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/chaw/mm23

The 2013 deal

To have any value, a breakdown of the £92.5/MWh strike price must be based on the assumptions that went into the deal done in 2013 that set this price. Several factors have changed since then (expected cost, completion date, partners in the consortium, method of finance). Few details of the breakdown of the strike price were published in 2013. The main elements known then were:

1. The power purchase price would be £92.5/MWh (2012 prices), £111.7/MWh in 2020 money, indexed to inflation via the RPI. The price would go down to £89.5/MWh if SZC went ahead, a loss of income to EDF of about £70m per year.
2. The contract would run for 35 years from start of operation, then expected to be 2023.
3. The expected construction cost was £14bn (2013 money) or £16.4bn in 2020 money.
4. 65% of the construction cost would be guaranteed by UK government guarantees;[34]

[34] An EDF press release in September 2013 said: 'The Government has confirmed that the project is eligible for its UK Guarantees scheme. It is currently assumed that, subject to Infrastructure UK due diligence, Treasury-guaranteed debt will finance 65% of expected total costs prior to operations, backed by an appropriate security package provided by the investors.'

5. The investors in the plant would bear the risk of any increases in costs;[35]
6. The other investors in the consortium, NNBG, that would build the plant were not finalised then but EDF was expected to take 45-50% with other companies such as Areva (10%) and two Chinese companies, CGN and CNNC (up to 40%) and other companies not identified taking minority stakes.

Since 2013, a number of these elements have changed. Completion date has slipped to 2026-28. Construction cost has gone up in a number of steps to £22-23.7bn (2015 money) or £25-26.9bn in 2020 prices, a real increase of 52-68% on the 2013 estimate. EDF decided, apparently in 2015 before the contract was signed, not to take up the offer of credit guarantees because of the requirement that borrowing would need to be 'cash collateralised', in short, EDF would have to identify cash assets that could be drawn on in the event of the project failing. It is highly unlikely that HPC could have been financed by loans specifically for the project without guarantees because lenders would have seen the project as far too risky. As a result, rather than being funded by project loans, EDF consolidated its share of the HPC project into its general accounts in 2015 so that any borrowing would be provided from the pool of EDF borrowing. While this will have reduced the cost of borrowing for HPC in the short term, in the longer term, it will increase EDF's net indebtedness (this began to happen in 2019) reducing its credit rating and increasing the cost of much of EDF's total borrowing (across the company). The decision to reject the credit guarantees has never been acknowledged by the British government, and the National Audit Office report on HPC of June 2017 was based on an assumption that credit guarantees would be taken up.[36]

In 2016, EDF said the initial phases would be financed using equity, EDF's and CGN's own funds, but EDF did not specify how it would fund construction after this initial phase. By the end of 2018, little borrowing had taken place and it appears EDF had financed its share from foregone profits and from proceeds of asset sales, for example a 50% cent stake in the French transmission company, RTE. However, since then borrowing to fund HPC has increased.

The final composition of NNBG, determined in 2016, is EDF, 66.5% and CGN 33.5%. The contract duration, the power purchase price (£111.7/MWh in 2020 prices) and the condition that NNBG would bear the construction cost risk remain unchanged. Binding contracts were signed in October 2016 with construction (pouring of first structural concrete) starting for the first reactor in December 2018, the second following on a year later.

Construction cost

While the construction cost, excluding the finance cost, represents only a small direct proportion of the total MWh cost (12% according to EDF's calculations), it drives the finance cost - the higher the cost, the greater the borrowing need. EDF claims SZC would cost £20bn (we assume this is in 2020 prices) claiming about a 20% saving over HPC. With the latest cost increases for HPC, this actually represents a 25-35% real reduction. EDF claims the savings would arise partly because SZC would be a carbon copy of HPC, saving some design costs and benefiting from 'learning' in construction of HPC, and partly because experienced

[35] The risk of constructing the power station to budget is borne by the investors and gainshare mechanisms mean that consumers will share the benefit if costs are less than expected.
https://www.edfenergy.com/energy/nuclear-new-build-projects/hinkley-point-c/news-views/agreements-in-place
[36] https://www.nao.org.uk/report/hinkley-point-c/

construction crews would move from HPC to SZC and complete their work more efficiently based on their expertise. EDF stated:[37]

> *"Project development is based on a replication strategy from HPC which should enable costs to be driven down thanks to a decrease in construction costs combined with lower risks. The Sizewell C project will also be based on EPR technology and will benefit from feedback and experience from HPC."*

These claims are unconvincing. If the feedback from construction of HPC (not to mention Flamanville and Olkiluoto) and operation of all six previously-ordered EPRs reveals that a design change would be desirable (or essential for some safety-related elements), EDF will either have to change the design or forego the benefits of the change. The history of the EPR gives no confidence that all the design problems that have led to the huge delays have been identified and remedied. Indeed, Areva NP/Framatome have been developing a successor design for a decade, with EDF in control since the takeover of Areva NP in 2017, EPR 2, which they claim would be about 25% cheaper and simpler therefore easier to build, based on experience with Olkiluoto and Flamanville. EDF is not offering this apparently cheaper design for SZC.

The first two orders for EPRs (Olkiluoto, 2005, and Flamanville, 2007) were priced at €3 and €3.2bn respectively when construction started, yet the HPC order was priced at £7bn (~€8bn) 6-8 years later (the price of the two Chinese EPRs is not in the public domain). The £20bn forecast for SZC is 22% more in real terms than the HPC 2013 price, so expecting a reduction in price is against all historic experience. The HPC and SZC projects are about seven years apart (EDF does not expect SZC to be complete before 2034). EDF also expects workers to be employed at the site for, on average, only one year. So this smooth transfer of skills from one site to another simply cannot happen, there will be a gap of about seven years between workers finishing their job at HPC before they are needed at SZC. If a Final Investment Decision is not taken in 2022 as EDF hopes it will, the completion date for SZC will be delayed and the gap will be even longer.

Financing cost

The 2013 deal was based on the majority of the finance needed being guaranteed by the UK government with sovereign credit guarantees. These mean that if the project failed and the developer was unable to repay the loans, the lending institution would be repaid by taxpayer money. This effectively shifted the project risk from the lender to taxpayers and there should have been no risk premium in the borrowing cost, so the £36/MWh risk premium could not have applied, at least in terms of a higher cost of borrowing. One interpretation is that because EDF and its partners undertook to shoulder the risk of construction cost escalation, they simply added in a very large contingency element for unexpected cost increases, although categorising this as finance cost would be inappropriate. In addition, the point of contingencies is that they get used when unexpected events occur, yet when this has happened, EDF has increased the expected construction cost rather than drawing down the contingencies. EDF has increased the cost estimate on five separate occasions since 2013 with the expected rate of return to EDF falling each time from about 10% in 2013 to about 7% in 2021.

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[37] https://labrador.cld.bz/EDF-2019-Universal-registration-document/66/ p 64.

Operations & Maintenance cost

EDF's forecast Operations & Maintenance cost plus fuel of £19.50/MWh (£23.4/MWh in 2020 money) for HPC appears too low. It is not clear whether this includes the contribution to external funds to pay for reactor decommissioning and spent fuel disposal.[38] The real power sale price is fixed for the first 15 years with scope for a review of the operating cost then and a further review after 25 years.[39] The £19.50/MWh forecast must therefore be the expected average operating cost for at least the first 15 years of operation. In France, EDF has been forced to sell 25% of its nuclear output to competing electricity retailers at €42/MWh or £37/MWh (ARENH tariff). EDF is complaining vociferously that this does not cover their costs and is lobbying for this to be increased to €50/MWh (£44/MWh). Given that nearly all France's 56 reactors are more than 30 years old and their construction cost long since paid off, the €50/MWh must represent almost entirely their operating cost. It is hard to see how the operating cost of an EPR would be only about 40% of the operating cost of the 56 French reactors.

Reliability

Reliability of the plant will be key. Most of the costs are fixed in total and poorer than expected reliability will mean there are fewer MWh over which to spread these fixed costs. Poor reliability is also likely to result in increased overall operating costs to pay to remedy the factors behind poor reliability. The expected reliability of the plant in terms of load factor[40] was not specified in EDF's and the government's accounts of the deal.

Profitability

The European Commission investigation into whether the HPC deal involved unfair state-aid reported that EDF's target internal rate-of-return was 9.75-10.25%.[41] The September 2019 cost increase reduced this to 7.6-7.8%[42] while the January 2021 cost increase reduced this to 6.8-7.2%. With at least 6-7 years of construction remaining, it would be remarkable if more cost increases did not happen eroding further any profitability. Once the plant is operating, there is a risk that any remaining profit will be eaten up by higher than expected operating costs.

There is also uncertainty about how EDF will fund construction from this point on. By 2018, it was clear that EDF's business was not sustainable and the French government launched a restructuring, known as Opération Hercule, under which the nuclear assets of EDF would go into a new company, provisionally known as EDF Bleu, and fully re-nationalised.[43] This plan was still under negotiation with the European Commission in April 2021 to ensure it did not include unfair state-aid. Negotiations are reportedly not going well.[44] Until they are concluded, EDF's future remains uncertain.

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[38] In 2013, the government claimed that the decommissioning and waste management costs would make up only about £2 of the £92.5/MWh strike price

[39] https://www.gov.uk/government/speeches/agreement-reached-on-new-nuclear-power-station-at-hinkley

[40] Load factor is the output of the plant in MWh over a given period, usually either a year or a cumulative average, as a percentage of the output that would have been produced had the plant operated uninterrupted at full power.

[41] https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:L:2015:109:FULL&from=EN pp109/69

[42] https://www.edfenergy.com/media-centre/news-releases/update-on-hinkley-point-c-project

[43] EDF is 83% owned by the French state with the rest held by private shareholders

[44] Nuclear Intelligence Weekly 'Debating EDF's Restructuring and Arenh' January 22, 2021, p 5

EDF's net indebtedness has been increasing sharply, by nearly a quarter to €41bn between end 2018 and end 2019, leading to a fall in its credit rating.[45] The net indebtedness increased again to €42.3 by end 2020 and EDF's projections for 2021 imply indebtedness could increase to about €50bn by end 2021.[46] EDF's contribution to the remaining cost of construction of HPC is of the order of £10-12bn. If it funds this from its general borrowing, this will increase its debt further and risks reductions to its credit rating, in turn increasing the cost of finance for all EDF's borrowing.

Construction cost risk

The decision by EDF to take on the construction cost risk was extraordinary given the adverse consequences in the past to plant vendors and utilities taking on this risk rather than passing it to consumers, not to mention the poor record of EPR projects. The National Audit Office was sceptical whether, if things did go seriously wrong, the price would be fixed. It said:[47]

> *'These factors [the unproven nature of the EPR design and EDF's weak financial position] mean there is a risk that NNBG will seek further financial support from the government, notwithstanding the contractual terms of the deal.'*

At the time of the HPC deal, much of the reporting concerned the very high strike price, seen by some as so high that EDF was bound to make a profit. However, as costs have continued to escalate, EDF's agreement to the terms looks increasingly reckless, and the deal is a poor one for both EDF and consumers. Areva NP supplied the Olkiluoto EPR on so-called 'turn-key' or fixed price terms with any cost escalation to be paid by Areva NP and these losses were a major factor in the collapse of Areva in 2016. By 2013 when the HPC deal was agreed, it was clear the Olkiluoto project was going badly wrong and that huge losses would fall on Areva in fulfilling the turn-key contract. Similarly, Westinghouse agreed fixed price terms to complete two nuclear projects in the USA in 2015 and it soon emerged it had grossly underestimated the completion costs, leading to Westinghouse being forced to file for Chapter 11 protection against bankruptcy.

HPC project risk

EDF's strategy for HPC was indeed extremely risky and led to the resignation of its finance director, Thomas Piquemal, in 2016[48] because of the risks entailed in the project. EDF's French unions also expressed opposition in 2016 because it jeopardised EDF's future.[49] HPC is only one element in EDF's financial problems but it is not an insignificant element. Given the need to life-extend EDF's 56 French reactors (expected to cost in the order of €100bn) and to reduce the large deficit in the fund to pay for French decommissioning and spent fuel disposal, undertaking such a risky but discretionary project as HPC rather than concentrating on its core business is hard to understand.

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[45] https://www.edf.fr/en/the-edf-group/dedicated-sections/investors-shareholders/reference-documents

[46] https://www.edf.fr/sites/default/files/contrib/groupe-edf/espaces-dedies/espace-finance-en/financial-information/publications/financial-results/2020-annual-results/pdf/20210218-annual-results-2020-pr-en.pdf

[47] https://www.nao.org.uk/wp-content/uploads/2017/06/Hinkley-Point-C.pdf p 11

[48] https://www.reuters.com/article/uk-edf-britain-nuclear-idUKKCN0W80ZI

[49] https://www.theguardian.com/uk-news/2016/may/27/hinkley-point-c-french-union-opposition-casts-fresh-doubt-on-project

Many of the risks inherent in the HPC project predated the signing of the contract in October 2016 and would not have been relevant to the finance cost. These include:

- The record of the EPR, even as early as 2010,[50] gave little confidence that it would be anything other than liable to large cost escalation and construction delays.
- Spending large sums of money to take the project to Final Investment Decision by EDF and signing of contracts. EDF has estimated a cost of about £2bn borne wholly by EDF (CGN only started to contribute when contracts were signed). If agreement could not have been reached, these costs would have been losses falling solely by EDF.
- Major components such as the reactor vessel were ordered and manufactured as early as 2011, five years before a contract had been signed to build HPC.
- Groundwork at the site started in 2013, three years before the HPC contract was signed.
- The poor record of Areva NP in quality control including the supply of sub-standard reactor vessel parts to Flamanville 3 imposing large extra costs on EDF (the parts manufactured for HPC suffered the same defect and had to be scrapped and re-manufactured) and falsification of quality control records over decades was apparent.
- The risk that the European Commission would judge that the 2013 deal represented unfair state-aid and require changes, likely to make it less attractive to EDF. Ironically, one of the few changes required by the Commission was an increase in the fee required for the granting of credit guarantees. The offer of credit guarantees was subsequently declined, although there is no suggestion that the increase required by the Commission was a factor in the rejection of these guarantees.

These issues apply almost as much to SZC as they did to HPC. The record of the EPR appears worse now than then and EDF is liable for 80% of the costs to take the SZC project to Final Investment Decision (CGN is expected to bear the rest) and if no investors can be found, it will have to take this as a loss. Whether the issues with Areva's (now Framatome) quality control have been remedied remains to be seen.

On top of these risks, EDF chose to bear the risk of cost and time overruns and of poor reliability for HPC. Declining the credit guarantees means there is a serious risk of damage to EDF's credit rating by financing the project from its own resources, not from project funding.

[50] S D Thomas 'The EPR in Crisis'
https://gala.gre.ac.uk/id/eprint/4699/3/(ITEM_4699)_THOMAS_2010-11-E-EPR.pdf