Financing low-carbon generation in the UK: The hybrid RAB model[1]

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31 July 2019

Abstract

Decarbonising electricity is a critical first step in mitigating climate damage but low/zero-carbon generation is very capital intensive. Its cost depends critically on the weighted average cost of capital (WACC). Three factors combine to make a low WACC both desirable and feasible in the UK. First, the *Stern Report* argues for a low social discount rate (1.4% real) for investments in climate mitigation. Second, global and UK real interest rates have been falling steadily - UK gilt index-linked 20-year rates have fallen from +4% in 1995 to -2% (negative) in 2019. CCS and nuclear have long lifetimes over which to recover their capital cost, longer than commercial finance would accept without guarantees, in contrast to renewables where off-take contracts have proven sufficient. Nuclear power faces the additional investment challenge of lengthy uncertain construction. No nuclear plant has ever been built privately without substantial regulatory guarantees. The Regulated Asset Base (RAB) model can address these financing problems for long-lived low-carbon assets. The benefits of placing risk on developers to motivate cost control are small compared to the extra costs of a higher weighted average cost of capital (WACC). A hybrid RAB model (like that used for the Thames Tideway Tunnel) – with excess cost sharing and a cost cap – can reduce risk to deliver an adequately low WACC by accessing infrastructure funds that do not require extensive specialised project knowledge. If the risk of excess costs is spread over the 27 million households and other customers taking two-thirds of electricity, each would bear minimal risk and the cumulative cost would be significantly lower. The levelised cost at the WACC (3.5% real) is £53/MWh (in £2018) if on time and budget, which should be compared with a counterfactual in which all the risk is placed on the company requiring a contract-for-difference with a strike price of £96/MWh for the life of the project (equal to the levelised cost). The levelised cost to consumers if on time and budget would be £50/MWh and in the worst case with a 48% cost over-run, £64/MWh.

[1] Paper commissioned by EDF Energy, and with grateful acknowledgement for their comments and support. It was written in anticipation of a government consultation on the *Regulated Asset Base (RAB) model for nuclear*, but before its publication by BEIS on 22 July 2019. The paper solely represents views and analysis by the authors. It should not be taken to reflect EDF Energy positions. : https://www.gov.uk/government/consultations/regulated-asset-base-rab-model-for-nuclear. We are indebted to the thorough responses of three EPRG referees which allowed us to clarify key points in the paper.

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Executive summary

There is a strong case to act on climate change, for action now, and it is appropriate to do this with a low discount rate

1. UK all-party commitment to near zero CO_2 within the average person's lifetime.
2. *Stern Review* "The costs of stabilising the climate are significant but manageable; delay would be dangerous and much more costly." Implies discounting future damage and damage-mitigating investment at a very low discount rate.
3. Stern and others estimated the appropriate real discount rate at 1.4%. HMG's *Green Book*'s same approach proposes low discounting for long-lived projects (2.14%), based on an era of more optimistic growth assumptions and higher real interest rates.

There is a positive macro-economic context in which we are able to take action now

4. Public sector focus on debt not assets has led to underinvestment in infrastructure.
5. Zero carbon projects capital-intensive; require high rates of investment to decarbonise.
6. Global demographic trends led to a savings glut with falling real interest rates.[1] The UK gilt index-linked 20-year real rate of interest has fallen steadily from 4% in 1995 to -2% (negative) in 2019. The cost of public sector finance/support for infrastructure is at an all-time low.
7. Monetary policy is weak, fiscal stimulus for public and private investment now needed.
8. Need for zero carbon investment and potential supply of funds are aligned.

Nuclear is low carbon and, at the right cost, will form a part of the future generation mix, but it has some specific investment challenges

9. Committee on Climate Change: to reduce emissions intensity from current levels of 175 gCO_2 /kWh to near zero by 2050, some combination of nuclear, PV and wind is now cost effective.
10. Nuclear power: lengthy uncertain construction period, high capital cost, low running cost, 60 years delivery of zero-carbon electricity, cost almost proportional to WACC.[2]

[1] e.g. Rachel and Summers (2019) at https://www.brookings.edu/bpea-articles/on-falling-neutral-real-rates-fiscal-policy-and-the-risk-of-secular-stagnation/
[2] Weighted average cost of capital, which for Thames Tideway Tunnel was 2.5% real (linked to RPI).

11. No nuclear plant has ever been built privately without substantial regulatory guarantees.
12. Private sector unwilling to finance lengthy uncertain projects at low interest without credible guarantees and risk mitigation.

The RAB model can align with the characteristics of nuclear to support investment

13. Low WACC requires low risk and assurance of return.
14. The benefits of placing risk on the developer to motivate cost control are small compared to the extra costs of a higher WACC, arguing for the lowest WACC consistent with adequate incentives.
15. The hybrid RAB[3] model (like the Thames Tideway Tunnel) with excess cost sharing and a cost cap can reduce risk to deliver an adequately low WACC by accessing infrastructure funds that do not require extensive specialised project knowledge.
16. Once the project has been de-risked, funding could be secured by a competitive book building exercise, which would set the required return on the money.
17. Payment on RAB during construction increases confidence, reduces risk and WACC.
18. Limiting the risk of cost over-runs and providing a fairly predictable long term return could make this investment attractive to the growing pool of institutional investors who seek such "infrastructure-like" returns, but are put off by construction risk.

The balance of the costs and benefits of introducing a RAB model means that it is worth doing

19. Spreading the risk over the largest number of agents reduces the *total* cost of risk. If spread over the 27 million households and the other customers who took the remaining two-thirds of electricity, each would bear negligible cost of risk.
20. RAB interest paid by domestic customers averages about £4/yr[4] during the construction phase. The levelised cost over the 60 year life could be as low as £53/MWh discounting at the WACC of 3.5% if built on time and budget.
21. Even in a worst case scenario with an 8 year delay and 48% cost over-run the levelised cost to consumers if they bear all the public sector investment cost is £64/MWh discounting at the consumer discount rate of 2% real.

[3] Regulatory Asset Base – accumulated investment less depreciation
[4] Unless otherwise stated, all figures are in £2018.

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1. Introduction
There has been a wide-ranging cross-party commitment to aggressively decarbonise the UK economy in line with the *Climate Change Act* (HoC, 2008) and COP 21. This was reinforced by legislation laid on 12 June 2019 for the UK to become the first major economy to set a net zero emissions target (Priestley, 2019). The easiest and the leading sector to decarbonise is electricity, since here the options lie on the supply side without requiring any change in the final product (electricity). According to the Committee on Climate Change (CCC), 75% of emissions reduction since 2012 have come from the power sector. Emissions intensity has

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fallen from 420 gCO_{2e}/kWh as recently as 2015 to 173 gm CO_{2e}/kWh, by 2018 (BEIS, 2019) but the CCC argues that "A further reduction in the emissions intensity of power generation, to below 100 gCO_2/kWh by 2030 remains the lowest-cost path towards economy-wide decarbonisation." (CCC, 2018, p. 68). The CCC's 2030 electricity target is 77% "low carbon" compared to 52% in 2017. The 2017 capacity of existing nuclear was 9.2 GW but is forecast to fall to 1.2 GW by 2030, to which should be added Hinkley Point C of 3.6 GW.

Zero-carbon generation (wind, solar PV, tidal, nuclear) are notable in having high capital costs and low variable costs. Renewables are variable, nuclear power is best run on base load because of its cost characteristics, although in France it plays a limited load-following role (Nuttall, 2005, p. 63). Low-carbon generation (coal or gas with carbon capture and storage, CCS) and negative-carbon (bio-energy with CCS, or BECCS) also have high capital costs but high variable costs and are flexible. Each technology therefore has specific characteristics, both strengths and limitations, which will influence its potential role in decarbonising electricity.

High capital cost plant faces significant barriers in liberalised markets requiring commercial rates of return. Since the privatization of electricity in the UK, liberalization has favoured gas (mostly combined cycle, but recently some open-cycle turbines) with renewables requiring additional support, most effectively with the recent contracts-for differences (CfDs) with a Feed-in-Tariff (FiT), A standard CfD guarantees the strike price, *s,* for a specified volume of output, *M* MW and time, settled against a reference (usually day-ahead) wholesale price, *p*. The generator receives *pM* from the wholesale market and (*s-p*).*M*, from the CfD, ensuring *sM* provided the generator delivers. The FiT element allows for the variability of the renewables. The *Energy Act 2013* (HoC, 2013) recognised the importance of extending some investment assurance to conventional generation through auctioned capacity agreements, but again this only attracted gas (and small diesel) generation.

This paper argues that a low discount rate is critical for efficient decarbonisation, that such a discount rate is justified (§2), that the private sector can now deliver that with suitable assurances (§3), but that nuclear power faces additional hurdles, possibly comparable to those of fossil generation. Section 5 proposes a possible model for funding such investments, arguing that the two key conditions—regulatory assurance for long-lived low-return assets and efficient risk allocation—can be met with a hybrid Regulated Asset Base (RAB) model. Section 6 shows how this could be implemented in the case of the proposed Sizewell C nuclear reactor, followed by a discussion of whether this could command public support (§7), and the conclusions.

2. The case for a low discount rate

The *Stern Report* (Stern, 2007, p viii) states that "Climate change is the greatest market failure the world has ever seen, and it interacts with other market imperfections." "The costs of stabilising the climate are significant but manageable; delay would be dangerous and much more costly." The *Stern Report* lays out the arguments for a low social discount rate. It logically follows that the social discount rate is used not only to measure the damage caused by releasing CO_2 now, but should also be the rate used to discount the future benefits of zero-carbon generation investments that avoid damaging CO_2 emissions. (There are additional arguments relating to risk and distributional concerns that strengthen the case for a low rate that are discussed below.)

The UK Government and the 2015 Conference of Parties in the Paris Agreement (COP 21) accept that climate change justifies actions to mitigate its effect. The reason that the cost of future damage loom so large today is because Stern and others have convinced us of the importance of low discount rates for future uncertain but potentially catastrophic events. £1 million of damage in 100 years at a discount rate of 6% is worth just under £3,000, but at Stern's discount rate of 1.4% worth almost £250,000, 84 times as much. It follows that long-lived zero-carbon investments should also be appraised and discounted at a low discount rate.

The UK Government's Appraisal Manual (*The Green Book*, HMT, 2018) follows the same utilitarian public economics theory that guided the estimates of the discount rate in the *Stern Report*. It sets out the principles of social cost-benefit analysis for appraising projects whose private returns are likely to understate their social benefits. That is pre-eminently the case with investments in zero-carbon technologies to mitigate climate change.

Stern (2007, p46) derives the social discount rate, denoted ρ, and the same logical approach is followed in the *Green Book* (HMT, 2018, Appendix A). Stern's formula is

$$\rho = \delta + \eta g, \tag{1}$$

where δ is the rate of pure time preference, g is the long-term growth rate of per capita consumption, and η is the elasticity of marginal utility, a measure of the rate at which the utility of an extra increment of consumption falls.[2] In a strictly utility-based approached to risk aversion, η is also the coefficient of relative risk aversion, and as such is relevant when discussing the cost of risk.

For sound ethical reasons Stern takes $\eta = 1$, equivalent to a logarithmic utility function, which would, to quote Stern (2007, p46) "value an increment in consumption occurring when utility was 2*c* as half as valuable as if it occurred when consumption was *c*." It has the appealing ethical force that lives saved are considered equally worthy regardless of the wealth or poverty of the individual.[3] Stern argues for a low value of pure time preference, $\delta = 0.1\%$, on the grounds that it corresponds to a 9.5% probability of the human race not surviving 100 years, while a $\delta = 1\%$ corresponds to a worryingly high 62% probability of the human race not surviving 100 years (Stern, 2001, p47).

[2] We use *social* to contrast with other discount rates such as those used by the private sector. Stern calls ρ the discount rate without qualification, but in the context it is the discount rate to apply to the future damage of climate change. The *Green Book* uses slightly different notation, terming the social discount rate as the Social Time Preference Rate (STPR), r, with the rate of pure time preference confusingly as ρ, with $r = \rho + \mu g$, where g is the "expected growth rate of future real per capita consumption". Goulder and Williams (2012) derive this same, widely accepted formula, which they describe as "the discount rate appropriate for determining whether a given policy would augment social welfare (according to a postulated social welfare function) .." (p. 6).

[3] Social cost-benefit manuals appraise transport improvements in terms of the Value of a Statistical Life (VOSL) Saved, while health benefits are valued in terms of Quality Adjusted Life-years (QALYs) saved. Both are usually taken proportional to per capita consumption, suggesting the VOSL in a poor country is much less than in a rich country. When weighted using the logarithmic utility function ($\eta = 1$) both lives would be equally socially valued.

The final assumption needed to fix the social discount rate is a plausible rate of growth of per capita consumption over long periods of time. The *Green Book* retains its past rather optimistic g of 2% while admitting that over the past 20 years the UK has fallen considerably below this. Looking ahead, g is constrained by global sustainability (water, population pressure, etc. etc.). There is consensus around Stern's value of 1.3% p.a. (accepted by Cline, 1992 and Nordhaus, 2007). Together this gives a social discount rate of 1.4% in (1). The rate used for long-term discounting by the UK Government was reduced after the *Stern Report* from 2.5% after 75 years to 2.14%, and from 1% over 300 years to 0.86%, after setting $\delta = 0$ (HMT, 2018, p104 and HMT, 2008, p5). For a project lasting 31-75 years and taking $\delta = 0.1$, the discount rate would be 2.67%, falling to 2.24% after 75 years. For projects affecting future health, the rate is taken as 0.86% on the argument that "diminishing marginal utility associated with higher incomes does not apply as the welfare or utility associated with additional years of life will not decline as real incomes rise." (HMT, 2018, A6.21).

Greater future uncertainty argues for lower social discounting, as a symmetric outcome of either high (BAU growth) or low (catastrophe) future consumption translates into a greater weight on the low rather than the high outcome. This further lowers the appropriate social discount rate. Low discount rates make solving the problem of carbon emissions cheaper and more attractive. The *Stern Report* and the Government's own *Green Book* argue for a low discount rate when appraising projects with a long time horizon and appreciable future social benefits that may be heavily discounted by the private sector.

3. The macro-economic background of falling real interest rates

Public sector focus on debt while ignoring assets has led to underinvestment in infrastructure. It has also led to doubtful fiscal accounting to transfer what would otherwise appear as public debt onto private balance sheets via initiatives such as the private finance initiative (PFI) and Public–Private Partnerships PPP (popular for hospitals and schools).[4] These often result in creating essentially the same assets but at a higher cost to the public exchequer and an overall worse economy-wide balance sheet.

The need for proper fiscal accounting has been stressed in a recent IMF publication. "Standard fiscal analysis focuses on flows—revenues, expenditures, and deficits—with assessments of stocks largely limited to gross debt. The focus on debt misses large swaths of government activity and can fall victim to illusory fiscal practices. (IMF, 2018, p. 9).

What is particularly notable is that the UK's net worth started negative and has become more negative, while "other assets" (mainly physical assets in infrastructure) have not increased. Instead of inflating financial public corporations' assets (aka bank lending) to stimulate the economy during the global financial crisis of 2008, stimulating infrastructure investment (as was started in the US under the Obama administration) would have resulted in a healthier net wealth position while creating assets that would continue to yield economic

[4] For a comparison of PPP and RAB finance see Makovšek and Veryard (2016) and references therein.

benefits.[5] As the IMF noted "Net worth declined by a similar, although slightly lower, 25 percentage points of GDP, with the difference attributable to public investment.[6] This average marks a wide dispersion, with net worth declining by as much as 49 percentage points of GDP in the United Kingdom, while increasing by 167 percentage points of GDP in Norway, much of this because of strong valuation gains from its equity holdings." IMF (2018, p. 8).

On the positive side "The United Kingdom authorities are at an early stage in the process of balance sheet management. They recently initiated a balance sheet review, intended to improve balance sheet management and fiscal outcomes …" (IMF, 2018, p19).

Not only has the UK balance sheet deteriorated as a result of relying on monetary stimulus rather than raising the rate of investment, but the cost of financing infrastructure investment is at an all-time low, as Rachel and Summers (2019, fig 1) demonstrates. The world real interest rates on inflation-linked bonds fell almost linearly from over 6% at its peak in 1982 to below zero by 2014, where it remained until at least 2018.

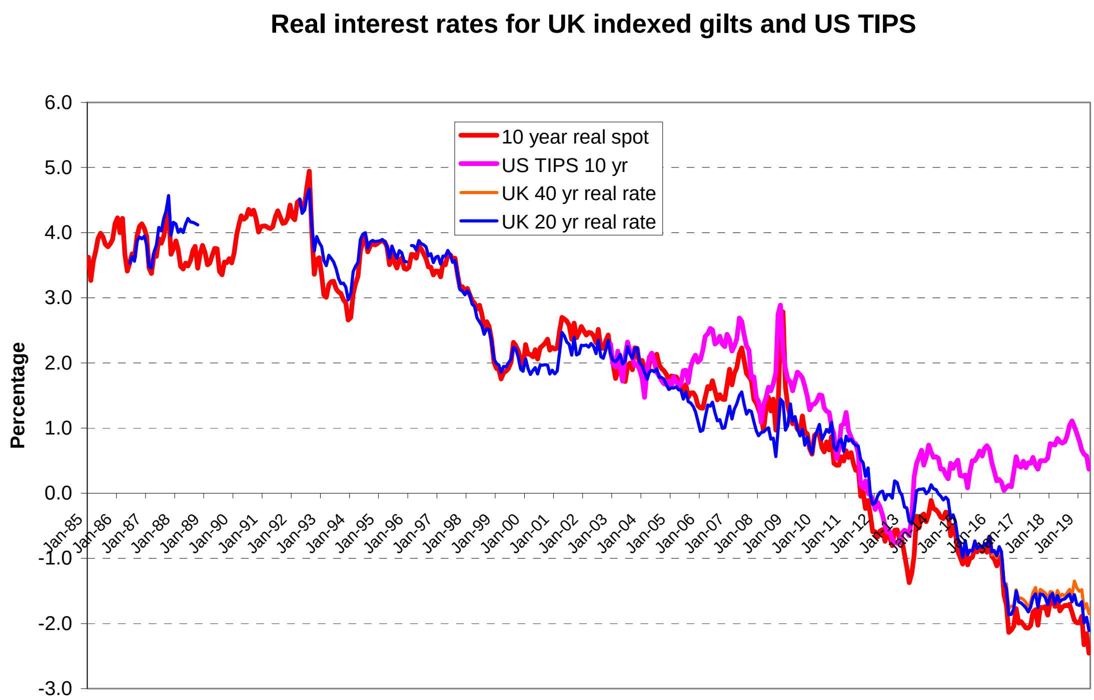

Figure 1 Real spot interest rates for UK index-linked gilts and US TIPS

Source: Bank of England https://www.bankofengland.co.uk/statistics/yield-curves and https://fred.stlouisfed.org

[5] The American Recovery and Reinvestment Act (ARRA) of 2009 allocated $105.3 billion to infrastructure, although the whole package, which included tax cuts, was estimated at $787 billion. According to the Council of Economic Advisors' report "The two established CEA methods of estimating the impact of the fiscal stimulus suggest that the ARRA has raised the level of GDP as of the third quarter of 2010, relative to what it otherwise would have been, by 2.7 percent. These estimates are very similar to those of a wide range of other analysts, including the non-partisan Congressional Budget Office." (CEA, 2010, p. i)

[6] The net worth of 17 countries fell from 43% in 2007 to 18% in 2012, its value in 2016. (Explanation added by authors.)

Figure 1 shows that UK real indexed-gilt rates (both 10 and 20-year maturity) have declined roughly linearly from +4% in early 1994 to its current negative -2.5% real. Even the 40-year maturity rate (for which data are only available from 2016) is only slightly higher than the 10-year maturity. The US real rate has remained (mostly) positive in the recent past but still well below its historic levels.

In their important article, Rachel and Summers (2019, p1) demonstrate "that neutral real interest rates[7] would have declined by far more than what has been observed in the industrial world and would in all likelihood be significantly negative but for offsetting fiscal policies over the last generation. …We show … that neutral real interest rates have declined by at least 300 basis points over the last generation. We argue that these secular movements are in larger part a reflection of changes in saving and investment propensities rather than the safety and liquidity properties of Treasury instruments. We then point out that the movements in the neutral real rate reflect both developments in the private sector and in public policy. …we suggest that the "private sector neutral real rate" may have declined by as much as 700 basis points since the 1970s. Our findings support the idea that, absent offsetting policies, mature industrial economies are prone to secular stagnation. … More broadly, a large share of the decline in risk-free rates has been mirrored in risky asset returns, such as rates of return on corporate bonds and on equites: notwithstanding some volatility, spreads have remained close to long-run historical averages." (Rachel and Summers, 2019, p2; fig 3, p5.)

They show that the US equity risk premium has fallen from around 5% only to around 4½% in 2016, but combined with the fall in the risk-free rate the cost of equity has now also fallen quite dramatically. The reason they give for the fall in the real interest rate is primarily the excess supply of private savings relative to private investment: "on average across the business cycle, equilibration of private-sector saving and private-sector investment may indeed require very low real rate of interest in advanced economies for years to come." (ibid, p7). These arguments "thus underscore the urgent priority for governments to find new sustainable ways of promoting investment to absorb the large supply of private savings and to devise novel long-term strategies to rekindle private demand." (ibid: Conclusions, p. 43).

While there may be debates about the possible causes of the falling interest rate, it is hard to disagree with evidence that it has fallen quite steadily and by a remarkable amount since the early days of electricity liberalization. In addition, monetary policy is now very weak given the low nominal interest rates and high net debt, making fiscal policy and policy-stimulated investment the only way to address future economic downturns, and, in the Rachel/Summers view, avoid pending secular stagnation. This policy point needs underlining. The private sector is reluctant to invest commercially in long-lived assets when the rate of return falls to the currently observed low levels. The reason has been amply explained by Avner Offer (2018). The private sector requires considerable reassurance to undertake investments with a time horizon much longer than 10-15 years, given the rapidly growing uncertainty and vulnerability to at-present unforeseen policy shocks beyond this horizon. Offer terms this the *credit time horizon*, defined as the time to pay back the loan.

[7] The interest rate consistent with stable macroeconomic performance.

With a horizon less than 15 years the required rate of return is 10% or more, hence the growing mismatch between private savings and infrastructure-like investment. If investment is to be stimulated at much lower weighted average costs of capital (WACCs) then policy support to provide investor confidence will be needed. The alternative is that the funds are merely deflected into creating asset inflation in land and real estate that might appear to enjoy greater (tacit) public and therefore political support against expropriation or wealth-reducing tax or rule changes.

Fortunately, the demand for infrastructure investment (notably transport, but also public housing) combined with a more intelligent approach to public sector accounting looking at both sides of the balance sheet can help avoid this stagnation. Even more relevant in the current context, mitigating damaging climate change requires huge levels of investment as zero-carbon projects are very capital-intensive. To conclude this section, the need for zero carbon investment and potential supply of funds are aligned, and the key role of the public sector is to find policies to stimulate private investment.

4. Investment challenges facing nuclear power

The main supply-side options available to decarbonise electricity are nuclear power, renewables (wind, solar PV and biomass), and carbon capture and storage (CCS). Wind and solar PV are variable and hence need back-up from flexible fossil power, at least for the near future. Other flexibility options have high capital costs, and would require a high carbon price to compete with flexible gas, but France has demonstrated that nuclear can load follow (Cany et al, 2016). Advanced nuclear options such as small modular reactors have also been receiving attention for their lower upfront capital costs and their greater flexibility although the economics are still untested (Richards et al, 2017).

CCS systems, particularly based on natural gas plants, could be operated flexibly and would have numerous degrees of flexibility depending on the ability to ramp up and down both the gas turbine and the capture unit, the use of solvent regeneration and the position in the merit order (Mechleri et al, 2017; Schnellmann et al, 2018). Real-world performance of CCS flexibly is unproven both in cost and performance terms. Biomass with CCS may also deliver flexible generation where emissions could even be net negative, depending on the sustainability of the biomass (Bui et al, 2017).

Only storage hydro (a small part of which we could access with an interconnector to Norway) can address shortfalls of more than a day, while pumped storage can handle diurnal fluctuations and batteries only for an hour or so. Their combined contribution over hours is less than 10% of peak winter demand. Nuclear power is a mature technology, whereas CCS has yet to be deployed at scale in the European power sector (although several plants have begun operating in North America). Nuclear and CCS face public acceptance issues, although the UK appears more accepting than many other countries. Nuclear waste disposal, decommissioning and CO_2 storage raise long-term safety and management issues (Kröger & Fischer, 2000; Budnitz et al, 2018).

Variable renewables are modular, come in modest sized units of a few MW, are quick to build (PV is fastest, off-shore wind slowest), have benefited from manufacturing scale economies, but have limited lifetimes (20-25 years). CCS units are large (300+ MW) and might be as durable as coal-fired stations (30-60 years).

Thus, nuclear power is at the extreme of cost, size and relevant lifetime. Hinkley Point C (HPC) entered its present planning phase with the submission by EDF/AREVA NP of the European Pressurised Water Reactor (EPR) design to the Office for Nuclear Regulation in September 2007 (NAO 2017b). Final Investment Decision was taken in 2016, and commissioning is not expected until 2025. Its lifetime may then be 60 years (or more) but decommissioning and waste management will continue for many decades thereafter.

All low/zero-carbon options have high capital cost and low variable costs (except CCS), which implies that their cost of energy is highly sensitive to the Weighted Average Cost of Capital (WACC). Nuclear power is an extreme case of this, as halving the WACC roughly halves the required strike price for any contract (see e.g. NAO, 2017b, fig 20, p68 and Appendix B). If, optimistically, private finance were only twice as costly as public finance, its private pay-back period (simply computed) would be half that of the government. Government guarantees or their regulatory equivalent (such as the US model of rate-of-return regulation underpinned by a Constitutionally-backed rule of law) can provide reassurances, lower the cost of capital and extend this credit horizon.

In any infrastructure project the risks can be divided into construction risk and operating & commercial risk (post-construction). Investors need *ex ante* compensation for these risks, and the higher the risk the higher the expected return.

Nuclear is unusual, if not quite unique, in having a very high proportion of construction risk relative to operating and commercial risk (although political risk of premature closure remains potentially important). Once built, nuclear reactors have a generally good record of operations and face relatively low operating risk: fuel is a very small fraction of cost compared with, say, gas powered stations, and nuclear has been very competitive in bidding into markets so it faces little risk of not running. Nuclear faces price risk that may be higher than for price-setting plant such as CCGT, where prices of gas and of electricity follow each other closely, providing a natural hedge (Roques et al., 2006). As with other renewable generators in a liberalised market, a suitable hedge normally requires an off-take contract. Nobody would build a merchant nuclear plant and take on that risk.

Nuclear's recent and long term construction history makes it difficult to mobilise private capital. Although it might seem there is a price for every kind of risk, the *ex ante* returns needed to compensate for construction risk are for the most part too high to be credible so there is, in effect, a threshold beyond which no level of expected return can practically motivate private investors—the point that Offer (2018) stresses. In this case the risk must be reduced to an acceptable level.

The range of risk-bearing options is illustrated in Table 1, which shows the risk arrangements for a range of recent new nuclear build projects.

Note that the ultimate ownership of the nuclear station does not immediately tell us about risk bearing: the UAE project will belong to the government but the construction contract leaves most of the risk with the South Korean consortium building the four reactors, who are compensated *ex post* by a long-term operating contract.

It is no coincidence that EDF, KEPCO, Areva and CGN are all state-owned companies (with some private share ownership in some cases). No fully private company would normally take on the construction risk and no contractor would be willing to sign a contract with a private company without actual or *de facto* state backing because the counterparty risk is so high and the single project size tends to be large relative to the enterprise value of the firm undertaking it.

Table 1 Risk management in recent new nuclear projects

Reactor	Country	Status	Construction risk	Power price risk	Debt guarantee?
Olkilotuo 3	Finland	Under construction	Contractor (Areva)	Customers	No
Flamanville 3	France	Under construction	Sponsor (EdF)	Customers (via regulation)	No
Vogtle	USA	Under construction	Customers (via regulator)	Customers (via regulator)	Federal government
Barakah	UAE	Under construction	Sponsor (KEPCO-led consortium)	Customers (fixed price contract)	South Korean government
Hinkley Point C	UK	Under construction	Sponsors (EDF and CGN)	Customers (fixed price contract)	UK government

Source: World Nuclear Association; author's estimates

This was illustrated by the Chapter 11 bankruptcy of the Toshiba subsidiary Westinghouse, which took on fixed price construction obligations for US projects which it ultimately could not meet. This demonstrates the limit of allocating all risk to those 'best placed to manage it'. Despite the very strong incentives on Westinghouse to avoid cost overruns (so strong it was a question of solvency, as the evidence showed) the overruns occurred. As a result the half-complete projects in South Carolina have been abandoned (a deadweight economic loss) and Voglte continues – though the transition imposed costs. A more sensible risk allocation (with more risk sharing) could have achieved full incentives on Westinghouse to minimise costs while not exposing them to insolvency, and therefore allowed the South Carolina projects to complete.

Before the oil shock and inflationary burst of the 1970's, the US regulatory model seemed able to provide the necessary credible underwriting from utilities empowered to pass the cost through to final consumers. However, the latter model ran into difficulties when inflation raised electricity costs, requiring a rate review. A rate review requires utility commissions to scrutinise costs and investment plans to ensure they are "just and reasonable". The Washington Public Power Supply System had started on one nuclear plant and had plans for four more, with two units starting in 1977. WPPSS had the right to issue tax-favoured municipal bonds to finance investments without voter approval, but a voter initiative in 1981 denied WPPSS the right to issue more bonds. Construction was suspended and eventually only the first reactor was ever completed (Blumstein, 1983). Joskow (1989) records that perhaps 20% of the final cost of nuclear power plant investments (i.e. tens of billions of dollars) in the US were disallowed by regulators and hence absorbed by private shareholders, in the era of private monopoly generation.

This case has many lessons – that nuclear power plants that suffer cost and time over-runs face the risk that utility commissioners will disallow them as "not used or useful" or "imprudent" (Gilbert and Newbery, 1994). Nuclear power in particular raises public concerns that require government assurance if the regulatory compact is to be credible. This is even more the case in periods of low real interest rates where investors have to wait an improbably long time to recover their investment, if they lack credible guarantees and risk mitigation.

Recent US experience shown in Table 1 reinforces this point. Two new nuclear reactors under construction have been halted in South Carolina following huge cost over-runs. Some other older plants are likely to close early owing to the pressure on power prices. But two reactors at the Vogtle project are under construction in Georgia, sponsored by Southern Company and approved by the Georgia Public Service Commission (the state regulator for telecoms, gas and electricity).

Georgia remains a rate-base regulated state, meaning that the electricity selling price is determined by the GPSC. This covers both operating costs and investment costs. Broadly speaking, the regulator ensures that the utility receives a fair cost of capital on investment. For a new investment project such as Vogtle, which like other projects building the Westinghouse AP1000 reactor has proved highly troublesome, this implies some risk-bearing by the customer (the "rate base"). When costs rise above original estimates, the utility makes a case to the regulator for those costs to be added to the rate base. The regulator may not approve all of them but, if it wants to get the plant built it is under some pressure to concede most costs.

5. The RAB model for long-lived capital-intensive investment

We have argued that long-term investment in zero-carbon technologies like nuclear power is necessary, and that it is justified at, but requires, low financing costs (or WACCs). There is a case for developing new financing models on a technology-neutral approach for all such cases where a simple CfD (with or without a FiT) would not provide adequate investor assurance to sufficiently lower the WACC. For example, the RAB model has been proposed for use with the transport and storage infrastructure needed for CCS plants or for shifting towards hydrogen for heat (CCTF, 2018; SCCS, 2018). Rather than describe the special features of all such technologies, for most of the rest of the paper we concentrate on the next proposed new nuclear power station at Sizewell C, as that is the subject of an impending public inquiry (Ambrose, 2019).

A low WACC requires low risk and a credible assurance of returns to the investors. No western[8] EPR has yet been commissioned, while cost and construction over-runs have plagued the two previous EPR projects in Finland and France. Given Continental (and hence EU) concerns over nuclear power, the "Coalition Government agreement stated there would be no subsidy for nuclear power. This led the Department to negotiate a deal for HPC replicating as far as possible its contracts to support other low-carbon technologies, such as wind and solar. These contracts mean the private sector financing construction and taking all the risk during this phase of the project, in return for a guaranteed price for the electricity generated once completed." (NAO, 2017b, p8),

The Government's *Green Book* appraisal manual states that: "The responsibility for management of risk should be allocated to the organisation best placed to manage it whether

[8] Taishan, China's EPR, was commissioned in December 2018 (https://www.reuters.com/article/us-china-france-nuclear/china-launches-worlds-first-epr-nuclear-project-in-taishan-idUSKBN1OD0Y4)

in the public or private sector. The objective is *optimal allocation of risk, not maximum transfer*, and this is important to deliver Value for Money. Not all risks can be transferred." (HMT 2018, A5.32, emphasis added.)

The workhorse of utility regulation and portfolio valuation is the Capital Asset Pricing Model (CAPM). At its heart, this is based on expected utility theory, in which an equal probability of an increase or decrease in wealth of X is worth less than the certainty of enjoying X (see Appendix E for a mathematical treatment). The cost of that risk can be measured by the risk premium r required to make the risky prospect $X+r$ have the same value or utility as the expected or certain value EX.

Figure 2 illustrates this. The utility of (or value placed on) consumption, $U(C)$, is plotted against different values of consumption. The risky choice is an equal chance of receiving 4 or 8 units of consumption at points **A** or **B**, a deviation of 2 from the mean, with expected value 6. The utility value of a certain level of consumption 6 shown as 42 but the average or expected utility is $\frac{1}{2}U(4)+\frac{1}{2}U(8) = 40 = U(5.528)$. The cost of risk in this case is 6 - 5.528 = 0.472, shown as the distance **MN**. If the risk is shared between two agents with equally likely outcomes **C** or **D**, then the deviation from the mean is halved, and each now has an expected utility of $\frac{1}{2}U(5)+\frac{1}{2}U(7) = 41.5 = U(5.877)$ and the cost of risk is now 0.123. However, there are two agents bearing this cost, so the total cost is twice this, or 0.246, which is half the cost of risk if just one agent bears all the risk.[9] More generally, in this quadratic approximation to the local shape of the utility function,[10] the total cost of risk divided equally

[9] In utility terms the cost of risk is exactly halved, but as Appendix E shows, measured in consumption units the cost is only approximately halved, in this case to 52%. The other main message from CAPM is the cost of a risky project depends not on the absolute risk of the project but on its correlation with the existing portfolio. This is captured by the value of β, a key component of determining the WACC in utility regulation. See Appendix E.

[10] This is equivalent to taking a second order expansion around the mean as in Appendix E, and ignoring higher order terms, which will only be valid for limited risks. Fat tails or extreme events would seriously invalidate this approximation.

among n equally placed agents is $1/n$ the cost of one similar agent bearing all the risk.

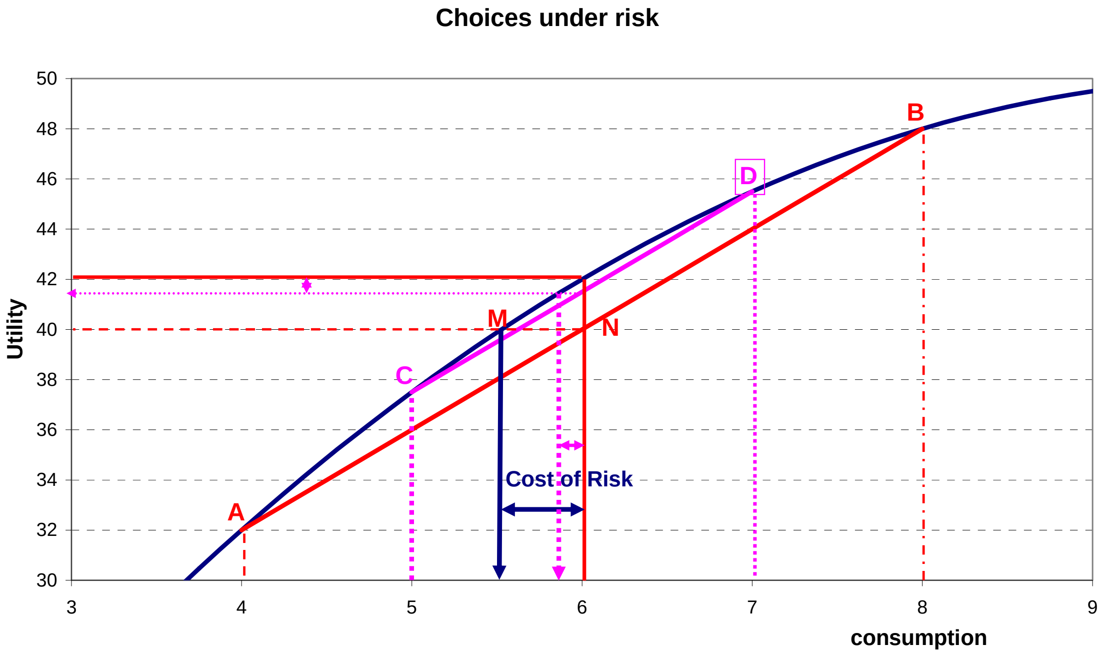

Figure 2 Illustration of cost of risk and risk premium

Note: The utility function is $U(C) = 10C - \frac{1}{2}C^2$

The implication is that placing all the risk of construction on the developer is potentially very large compared to spreading that risk over, for example, all 27 million households who enjoy electricity, and the remaining 70% of industrial, commercial and other consumers who consume higher amounts. This is not a fair comparison, however, as in the case of building nuclear power plants, the construction and operating risks are likely to have a low correlation with GNP, Government income and public sector net assets, and with the stock market. In short, they are largely idiosyncratic risks. That might suggest that they can be widely diversified through the stock market, but we again run into the problems of the time horizon and the perceived risk of political intervention (as in Germany). The problem is that the risks are not considered to be distributed around a known mean value. Especially with construction risk, shareholders take the view that any financial proposal (particularly one coming from a company committed to such projects) is likely to have huge optimism bias.

If all the risk is transferred to consumers, the concern would be that the developer would have little incentive to manage the risk, and might instead be more concerned to avoid adverse outcomes by excessively gold-plating the project. This tendency was widely observed in the US cost-of-service regulation, most notably in the monopoly Bell Telephone Company, where costs could be passed through to final consumers. The result was high prices and low choice of equipment This Averch-Johnson effect (Averch and Johnson, 1962) has been widely documented and lies at the heart of the Principal-Agent problem – how does the principal (the share-holder, the consumer, or the Government) design a contract that provides sufficient incentive to the agent (the developer, construction company, workers) to manage risks, reduce costs and deliver on time and budget, without imposing so much risk that the costs outweigh the benefit. Appendix B shows how this might be done, and demonstrates that the benefits of placing risk on the developer to motivate cost control are small compared to the extra costs of a higher WACC. That implies designing a contract that delivers the lowest WACC consistent with providing adequate incentives for efficient management.

4.1 RAB and hybrid RAB models

The Regulated Asset Base (RAB) approach to utility regulation has been used successfully in the UK since the late 1980s (see Appendix C for more details). The RAB is the amount of capital that the regulator recognises as deserving a return. When combined with a statutory obligation to ensure the utility can fund itself, the RAB becomes a very low risk asset. This means a low cost of capital which in turn means lower prices for customers.

The RAB model was designed for natural monopoly utilities where there is no possibility of competition. Where competition is possible the rate of return should emerge from competitive entry and exit, with the regulator ensuring competition works.

With a fixed allowed rate of return on the RAB, the system would closely resemble the traditional rate of return regulation used for many decades in the USA. That system was criticised for i) lacking incentives to cut costs (since the increase in profit would be clawed back entirely by the regulator, a form of 100% profit tax); and ii) encouraging over-investment in assets (the Averch-Johnson effect). Both adverse effects can be mitigated. In the US as noted above costs can be disallowed if they are “not used or useful” or “imprudent” while in the UK there are incentives to provide accurate assessments of future investment costs and to deliver them efficiently.

The UK system of periodic price reviews encouraged cost saving (in both operating and capital spending) by providing fixed prices for a period followed by a review. So long as there is no retrospective clawback of earlier cost savings, the investor is incentivised to cut costs and economise on capital spending. The RAB approach in the original privatization Acts offered a rolling 25-year contract that could be revisited periodically (typically every 5 years).[11] At that point the regulator had to check that the original terms were fair and not exploitative to current and future consumers, and ensured financeability. If not, prices could be re-set for a further period until the next price review. Over time, the UK RAB model of regulation has created investor confidence and a falling real WACC, proving to be a valuable commitment device (Stern, 2013).

4.2 Hybrid RAB – the Thames Tideway Tunnel

The RAB has been used for a company (though one that can have multiple shareholders). An extension of the concept is to use it for a discrete project, also possibly with multiple shareholders. This might be done because the project is too large relative to the existing company assets for the shareholders to be comfortable holding the risk, or because it has some special characteristics that justify it being treated separately from the rest of the company’s assets.

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[11] This was increased to 8 years with the move from RPI-X to RIIO but Ofgem now considers that was probably too long, see Ofgem (2018).

The Thames Tideway Tunnel (TTT) is an example of what we might call a hybrid RAB. In 2015, the government put in place the Government Support Package, which transfers some potential project risks from customers and investors to taxpayers. The features have both common elements with conventional RAB models and distinctive elements:

i) the project is a discrete, ring-fenced capital investment, though with operating interconnections with Thames Water's existing assets;
ii) the project has external investors that are different from those of Thames Water itself;
iii) the project has explicit construction risk-sharing with customers (through the regulator); and
iv) the project receives financial returns before construction is complete.

Point iii) is most relevant for new nuclear since that is the most salient point for private investors. As discussed above, the more the construction risk is borne by customers, the lower the returns required by the investors, which means lower prices paid by customers.

Point iv) is another way of reducing the required return to investors, since it reduces the period of discounting. All else being equal, the sooner cash is paid, the lower the internal rate of return of the project and the lower the expected return of investors. Investors are ready to accept very long payback periods, e.g. in the oil industry, subject to a compensating higher expected return. Many pension funds invest in private equity funds that are typically tied up for 10 years without any return until the fund is liquidated. They obviously expect a higher return for such investments (including a premium for the illiquidity of the investment, compared with owning publicly quoted shares). The actual deal struck with TTT was for a WACC or regulated return of 2.497% (NAO, 2017a, §3.8.)[12] Initial estimates of the cost of the project to consumers of £70-80 per annum were cut to £20-25 (in 2016-17 prices) with this financing model.

If the goal is to reduce prices paid by customers, then earlier servicing of the return to capital will achieve this. In the case of the TTT, risk was reduced by cost-sharing of any cost over-runs (symmetrically, in that cost under-runs would also be shared). Appendix D examines a possible contract to illustrate the potential risk-reductions, but the final details are best left to negotiations with potential financiers. Once these details are clarified, funding could be secured by a competitive book building exercise, which would set the required return on the money (the WACC). Limiting the risk of cost over-runs and providing a fairly predictable long-term return could make this investment attractive to the growing pool of institutional investors who seek such "infrastructure-like" returns, but are put off by construction risk and the need for specialised industry knowledge in the absence of a regulatory oversight and guarantee of prudent management.

[12] Although the report does not say exactly what this means, regulated returns for utilities are normally real not nominal — Ofwat (2014, 5.2) "In the absence of a fundamental change in policy or methodology by which the industry is economically regulated, our approach to remunerating both debt and equity investors is expected to be to set a real WACC which ensures that an efficient IP is able to finance the proper carrying out of its functions." TTT's WACC is close to the Government's 35-71 year social discount rate of 2.57%. It is indexed to the RPI that is equivalent to 3% CPI-linked.

4.3 Comparing the US and UK approaches

The US approach puts most of the risk onto customers, who are not directly able to influence them, but whose agent is the commissioner (regulator). There is the danger that the investor is insufficiently motivated to manage construction costs but there remains the risk that the regulator will not simply wave through all cost increases, which should discipline the investor to manage costs. The customers bear much of the risk but benefit from the cost of capital being kept low and therefore a lower overall price of electricity compared with more investor risk-bearing which implies a higher cost of capital.

The UK approach for conventional generation investment requires a higher cost of capital to incentivise the investors. So although customers avoid bearing any construction risk, they "pay" for this in the form of costlier power, with a partial cap set by the gain-share mechanism (partial because there is no absolute cap on the investor return). This was less of a problem with cheap gas-fired generation but would be with more costly plant.

Broadly speaking, there is a trade-off between customer risk-bearing (or risk-bearing by the state) and the investor's expected return, which directly affects the contract price. If the contract price is the most visible and important aspect for public policy, the case for at least some risk bearing by customers or the state is strong.

4.4 State versus customers in risk-bearing

From the point of view of investors, it matters little whether construction risks are borne by the state or by customers, so long as in the latter case the legal framework is clear and robust. The state can take on construction risk by i) offering a guarantee; or ii) by taking an equity stake.

i) state guarantee: provided credible risk-bearing, a state guarantee would be a contingent liability on the government's balance sheet and would be highly visible; it acts similarly to the role of a US regulator, meaning that keeping some incentives with the investors is necessary but the benefit in lower cost of capital is maximised.

ii) equity stake: unless 100% (in which case there are no private investors) an equity stake provides only incomplete risk-bearing as it reduces the scale of the private investor commitment but doesn't cap the construction risk; it appears on the state balance sheet and is highly visible.

The government's marginal cost of funding will always be the lowest in the economy (at least for most governments not at extreme risk of sovereign default), so if this is used as the discount rate for any project it will minimise the cost. But the cost of capital for a project (in an efficient capital market with well diversified investors) is driven by the project risk, not by the ability of the investor to borrow. The project risk also includes the risk that the company or the special purpose vehicle will default, and that the government will rule the project unacceptable (as in various governments imposing retrospective nuclear taxes or forcing shut-down or project abandonment). Again, Avner Offer's credit time horizon captures the notion that the longer the duration that the investor is at risk, the greater the perceived risk that the investment will be impaired or expropriated.

If the government takes on risk, that risk has an implicit price, which would crystallise as a flow of public spending if the project costs exceed the level where the guarantee is triggered. In the *Green Book*, this is best handled as optimism bias (HMT, 2018, ch5 and A5).

Merely discounting the original estimated cost at the government's marginal cost of funding fails to capture this risk, which is a genuine risk that should be accepted and included. Indeed what should happen for a new project design is that a maximum reasonable cost overrun should be financed upfront to avoid having to reopen the financing for a project when it is within the range of optimism bias (which might be of the order of 25% in the case of a nuclear power plant).[13] The cost of holding this finance and of incentivising the constructor companies not to use it unless necessary is likely to be small.

6. A possible model for financing Sizewell C

Appendix D sets out a model of funding based closely on the Thames Tideway Tunnel (TTT) model, with all flows in real terms[14] and with sharing of cost over-runs up to a cap of 130% of the agreed construction cost. The RAB would be increased in line with investment until it reached the target construction cost (taken as £5,000/kW), and thereafter would only be incremented by 60% of the cost over-run, with the investors contributing the remaining 40% without a RAB-guaranteed return (up to the cap). The RAB and the agreed WACC paid on the RAB would be subject to periodic reviews by Ofgem. To ensure access to investment grade lending, gearing would be kept no higher than 70%. If the debt rate of interest is as high as 2% real[15] and the equity risk premium is 5%, and setting $\beta = 1$ (thus ignoring the lack of correlation of construction risk with market returns), the return to equity would be 7% real and the implied WACC 3.5% real. Investors would receive a return on the RAB during construction, and would then be awarded a life-time (60-year) contract on commissioning. Ofgem would deliver this flow of funds by setting a strike price at the start of each new review period.

In the base case in which the project is delivered on time and budget, the internal rate of return to the equity participants would be the required 7% (for good algebraic reasons set out in Appendix F). The levelised cost over the life at the WACC is £52.36/MWh and at the social discount rate (SDR) of 2% is £49.24/MWh.[16] However, the levelised cost to consumers at the SDR is slightly higher as they have to prepay on the RAB during construction, and for them it is £49.6/MWh. If the strike price is set at periodic reviews every five years, then over the first period it would be set at £53.72/MWh. At the next review in year 15, the RAB has fallen to £4,583 and the strike price for the next period (years 16-20) would fall to

[13] HMT recommends optimism bias adjustments of 25% for a non-standard engineering project. See https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/191507/Optimism_bias.pdf at p. 2.

[14] Commercial evaluation is done at prices of the day and nominal WACCs to better model tax payments, and possibly front end in real terms a constant nominal flow of depreciation expenditures.

[15] The TTT rate was set at 1.8% above UK 10-year indexed gilts, that are now significantly negative, as figure 1 shows.

[16] This accumulates customer payments during construction at the WACC or SDR to the date of commissioning and then discounts the customer payments thereafter, dividing by the NPV to commissioning of the output over the life (in the base case at the rate of 8 MWh/kWyr for 60 years). It is not the same as levelising the strike prices, which ignores the consumer payments during construction.

£51.90/MWh with the depreciating value of the RAB, and then decreasingly rapidly to £33.67/MWh from year 66 to 70.

This can be contrasted with a counterfactual case in which the entire construction is financed by Sizewell C (SZC) much as in the case of HPC (assuming that it would be possible to find a comparably large source of risky finance). In this case effectively the entire revenue would be at risk and the required return or WACC is assumed to be 8%. The asset value at completion and including interest during construction would be £7,243/kW, even if delivered on time and budget. For ease of comparison in this counterfactual, SZC would have to earn the WACC and cover depreciation over the following 60 years. The constant (real) strike price to deliver this return is £96/MWh, or 194% of the RAB levelised cost (at the SDR). The levelised cost of transferring the asset value into a fund paying just the SDR would be £81/MWh. Assuming that the CfD strike price were held constant (at £96/MWh), the first year clear cash-flow would be £465/kWyr after paying depreciation, or an immediate return of 6.4%, rising as the capital value is depreciated. As SZC bears all the risk, consumers are protected through the pre-agreed CfD price (unless the project went into administration with a renegotiated and presumably more expensive replacement contract).

In the worst case scenario (described in Appendix D) in which the project is eight years late and 48% over budget, but with the cost over-run capped, the value of Ofgem assuring the allowed RAB (which is 80% of the total undiscounted construction cost) is that it provides a remarkably high internal return to SZC's shareholders (of 5.8%). The levelised cost to consumers (including the publicly financed extra capital cost) over its lifetime would be £64/MWh at the social discount rate (2%).

7. Public Support

Any decision to move ahead with a RAB model for nuclear will depend on the wider political economy considerations and support for socialising costs for nuclear power. Nuclear power is a less popular option than other low-carbon options such as offshore wind; nevertheless, the UK public is broadly supportive of nuclear power and, unlike several other major European countries, that support has actually increased in recent years (Kim et al., 2014). Indeed, outside of central and eastern Europe, the UK has the highest levels of support for nuclear power. NGO support (or rather lack of strong opposition) is also notably different from most of western Europe.

There is ample evidence of generalised support for nuclear energy alongside other low-carbon options, or at least what Corner et al. (2011) describe as 'reluctant acceptance'. Since 2012, the quarterly BEIS/DECC tracker surveys have found that the views of the British public have remained quite consistent with roughly 35-40% of the public supportive (less than 10% strongly supportive) and 20-25% opposed (less than 10% strongly opposed) with the remaining 40% or so neutral (BEIS, 2018). The results differ greatly by demographic group – men, older people and those of a higher social grade all tend to be more supportive of nuclear power (Yu et al., 2018).

In terms of financing, there is relatively little evidence of public preferences, but a recent study by the UK Energy Research Centre (Demski et al., 2019) found that although a majority supported a transition to low-carbon energy sources, when asked how to divide up responsibility for paying for that transition, the expectation was that industry would take the lead. Asked to allocate responsibility for funding for new low-carbon generation, respondents believed almost half of the cost should be borne by industry and that government should pay for almost 30% from existing tax revenues, compared with only 10% coming from new tax revenues or and another 10% from future UK residents through government borrowing or debt.

There is the additional issue of whether it is acceptable to spread the risk of low-carbon investments over consumers. The Government clearly considers this valid for financing renewables, even though there is a good public good case for saying that the learning externalities are a global public good that should better be financed from general revenue (Newbery, 2018). Ofgem passes the cost of its Network Innovation Competitions (NIC) (Ofgem, 2019) on to consumer bills, on the grounds that it will benefit future consumers more than the current subsidy, and that is very much the case here although the NIC only costs £70 million/yr. Of course, as outlined at the start, there are many different possible investments, a number of which might be credibly supported using a RAB model (hydrogen, CCS transport and storage, pumped hydro, etc) and so even the most ardent supporter will need to justify why a particular investment should be prioritised using such an approach relative to other possible investments.

More generally, there has also been increased attention to nationalisation (or renationalisation) in the energy sector, particularly coming from the Labour Party leadership in the UK. Support for interventions such as nationalising energy companies has remained quite high (41% in 2014 and 39% in 2017) even as concerns over energy prices declined significantly over that same period (Rogers de Waal and Reiner, 2017). Although support for nationalisation varies both by industry and across the population (notably by political party affiliation) (Smith, 2017), overall there is widespread support for some state involvement in the energy sector, although there are differences as whether that means local energy firms, a state-owned competitor or renationalisation. This has led to a number of more radical policies gaining currency, for example, the Labour Party has recently suggested bringing National Grid back into state ownership to facilitate the low-carbon transition (Monaghan, 2019). Perhaps more surprisingly, some in the private sector frustrated with the inability to finance their projects, including the Chairman of Hitachi, which recently cancelled their proposed Wylfa project, have suggested nationalisation with regard to nuclear power might be a preferable alternative.[17]

8. Conclusion

The Government has in the past committed to a significant new nuclear construction programme to replace the impending retirement of the existing fleet. Looking further ahead beyond 2030 and providing costs can be contained, nuclear looks to be an important part of the electricity generation mix in the UK. National Grid's only two Future Energy Scenarios for 2050 that meet the UK's 2050 carbon reduction target (*Community Renewables* and *Two*

[17] The Chairman of Hitachi, Hiroaki Nakashini declared : "Nationalisation is the only path" at the World Economic Forum at Davos, Switzerland. AFP (2019). "Hitachi wants nationalisation of UK nuclear project: report", 24 January.

Degrees) both show substantial new nuclear by 2050 (7.9 GW and 16.6 GW respectively) with 2050 carbon intensities of 32 and 20 gm CO_2/kWh respectively (National Grid, 2019). Given the recent cancellations of proposed British nuclear projects, projections for nuclear penetration in the intervening years have been scaled back, nevertheless the recent introduction of a net zero target in the UK raises the ultimate need for baseload zero-carbon technologies even more (to 18.6 GW in the FES 2019 Net Zero sensitivity analysis).

Delivering that new nuclear will require a change in the form government support compared to HPC, but to a model that has been shown to attract private finance for infrastructure projects such as the Thames Tideway Tunnel. This model can deliver an acceptable national and electricity consumer cost, provided there is a regulatory guarantee to enable the RAB to be financed with investment grade debt, which would be passed through to electricity consumers at a cost of slightly higher initial consumer bills, but substantial savings once the stations are commissioned. To encourage non-infrastructure specialist funders such as pension funds, the Government would provide backstop equity funding above an agreed cost over-run, here assumed to be 30%. This hybrid RAB model appears the most promising, and arguably the only feasible way to deliver new nuclear build, which, we have argued, is cost-effective at the appropriate and now low discount rates and a likely essential component of meeting the increasingly challenging decarbonisation target.

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Appendix A Discounting and climate change mitigation

Public economics is concerned to guide the choice of policies, including tax and expenditure. In its modern form (used, e.g. in the UK Government's *Appraisal Manual*, HMT, 2018) it assumes the existence of a social welfare function, that measures the desirability of outcomes in terms of the improvements of welfare/well-being to individuals in the polity now and in the future. The relevant polity may be the country, or, for collective climate change action, the world. Welfare for individual economic outcomes is normally taken to be a function of consumption, $U(c_{ht})$, where c_{ht} is consumption per equivalent adult h at time t. If $U(.)$ is a utility function, then current social welfare, W_0, is the sum over the relevant population:

$$W_0 = \Sigma_h U(c_{ht}). \tag{A1}$$

Mitigating climate change requires actions now, including long-term investment plans with delayed future impacts on welfare, and the relevant inter-temporal measure is the utility discounted sum of future utilities, W:

$$W = \Sigma_{h,t} U(c_{ht})/(1+\delta)^t \text{ or } \int \Sigma_h U(c_{ht}) e^{-\delta t} dt. \tag{A2}$$

The two critical issues to settle are the choice of the utility function, $U(c_{ht})$, and the choice of the utility discount rate or rate of pure time preference, δ. There are attractions in using a constant elasticity utility function of the form

$$U(c_h) = (c_h^{1-\eta})/(1-\eta), \tag{A3}$$

where η is the elasticity of marginal utility. Equation (A3) conveniently has the same functional form as the utility that measures attitudes to risk, with η the coefficient of relative risk aversion. If so, and if consumption per head were to grow on average at rate g so that consumption in year t were $c_0(1+g)^t$ or $c_0 e^{gt}$ then the social discount rate s is

$$s = \delta + \eta g. \tag{A4}$$

From now on we take $\eta = 1$, which is equivalent to taking $U(c_h) = log(c_h)$, also assumed by Stern (2007). Briefly, there are two arguments to be so specific. The first is that most perceptions (seeing, hearing, etc.) are logarithmic (e.g. sound is measured in dB, which is a logarithmic scale). The ethical argument arises when making comparisons between people, as the increase in well-being of a transfer of £1 to person h is measured by the marginal utility of consumption of that person, $dU(c_h)/dc_h \equiv U'(c_h) = 1/c_h$. This means that making a small transfer to someone with an income twice that of another is only considered half as socially valuable as giving it to the other person. A direct implication is that most countries need to put a value on a life saved for allocating medical procedures or investing to reduce traffic accidents, and these are normally related to per capita consumption within the country, as that measures the country's ability to pay for these activities. Call this monetary value $V_k = \alpha c_k$, where c_k is per capita consumption in country k. When making global decisions on climate change with different impacts across the globe, the logarithmic welfare function implies that the (global) social value of a life is the same in all countries, equal to $W_k = \alpha c_{k.}U'(c_k) = \alpha c_{k.}/c_k = \alpha$, the same in every country. With these assumptions

$$s = \delta + g. \tag{A5}$$

The rate of pure time preference is similarly an ethical choice, reflecting the weight we attach to the welfare of future generations. Many have argued that ethically they should be treated equally, so there should be no discounting just because their welfare happens in the future, rather than somewhere else now, so $\delta = 0$. Others including Stern argue that there is some chance of global disaster (asteroids, pandemics, …) and that $\delta = 0.1\%$, equivalent to a 10% chance of extinction in a century, or a 50% chance of the human species surviving for 700 years. The UK Government (HMT, 2018) in its *Green* Book takes $\delta = 1\%$ for short time horizons (which gives humanity only a 33% chance of surviving a century), but considers a rate of zero for long-term projects.

The final assumption is a reasonable rate of growth over long periods of time for per capita consumption, where there is some consensus around Stern's value of 1.3% p.a. (accepted by Cline, 1992, and Nordhaus, 2007). Together this gives a social discount rate of 1.4%. The rate used for long-term discounting by the UK Government was reduced after the *Stern Report* from 2.5% to 2.14% (after 75 years), and from 1% over 300 years to 0.86% (HMT, 2018).

Future inequality

The implicit assumption above is that the consumption of all agents grows at the same rate, g. There are good grounds for considering that climate change will have differential impacts across the planet, and that the coefficient of variation of consumption, σ, might grow. It can be shown that this reduces the social discount rate, although the effect is arguably small. Compared to equation (A5), if σ^2 grows by $\Delta\sigma^2$ over T years, then the social discount rate becomes

$$s = \delta + \eta g - \tfrac{1}{2}\Delta\sigma^2(\eta + \eta^2)/T. \tag{A6}$$

If $\Delta\sigma^2 = 10\%$ over 50 years, and $\eta = 1$, then the social discount rate is reduced by 10%/50 or by 0.2%, lowering the Stern estimate from 1.4% to 1.3%.

Appendix B Risk and Incentives

The main concern with risk sharing is that it blunts the incentives to manage costs. If the company took none of the risk of cost and time over-runs, the worry is that it would have insufficient incentive to manage and reduce that risk. If at the other extreme it bore all of the risk, the resulting weighted average cost of capital (the WACC) would be much higher, even assuming it was financeable. The obvious question is what is the appropriate degree of risk-sharing purely from an incentive viewpoint?

B1. Risk and the cost of capital

One way to model this is to suppose that the degree of risk impacts the equity share, while leaving the interest on debt (at 2%) and the equity risk premium (at 5%) unaffected (although beyond some point, more risk would likely increase the WACC beyond this).[1] Thus if the equity share is α and the debt share $(1- \alpha)$, the resulting WACC is $\alpha.7\% + (1 - \alpha).2\%$ in real terms (all prices and interest rates will be real in this discussion). Thus if $\alpha = 20\%$, the WACC is 3%, rising to a notional 7% at $\alpha = 100\%$, and for $\alpha = 50\%$, the WACC is 4.5%.

B1.1 Assumptions

Suppose that the target cost of constructing Sizewell C (SZC) is £5,000/kW for a construction period of 10 years to commissioning. This is based on the claim that SZC is an almost exact replica of HPC, for which costs are now reasonably well identified, and with a construction team that comes with experience of constructing HPC. For other as yet unbuilt (in the UK) designs a cost and time over-run of 25% would provide a better base case. However, given the implausibility (at least in the eyes of potential investors of no cost over-runs, we consider a 25% and a 50% over-run. Cost and construction time are likely highly correlated, so suppose that the rate of expenditure is £500/kW/yr so the total overnight cost is £500.T/kW for $T \leq 10$ is the construction time in years.

Suppose that the plant life after that is 60 years, and that it averages 8,000 full output operating hours per year. Even if decommissioning costs were as high as £900/kW[2] incurred 20 years after shutdown and even with zero discounting, the average decommissioning costs over the output of the plant, would be £15/kWyr or less than £2/MWh, so it is reasonable to take the total operating costs (O&M, fuel and decommissioning) as £22.50/MWh,[3]

[1] In the counterfactual case considered in Appendix D in which SZC bears all the risk, the WACC is taken as 8%.

[2] Lévêque (2015) gives figures from France estimated at €300/kW but a high-end estimate for Germany of €1,000/kW or £900/kW. OECD (2016) gives estimates for three generic large PWRs with decommissioning costs ranging from \$390-\$1,211/kW, with an average of $\$_{2013}$668/kW or roughly $£_{2018}$800/kW. In practice decommissioning costs would be spread over a longer period.

[3] EIA data 2007-2017, in converted at current £, at constant UK prices is roughly £20/MWh, from https://www.eia.gov/electricity/annual/html/epa_08_04.html, costs from BEIS (2016) at https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016 are £23/MWh, which includes £2/MWh for decommissioning and waste, while £22.50/MWh is EdF's working assumption (also including decommissioning).

B2. Required strike price or levelised cost

Figure B1 shows the relationship between the construction time and associated overnight[4] cost and the levelised cost (or the required real wholesale price) over a 60-year life at different WACCs, which would be covered by a Contract-for-Difference (CfD) with an indexed strike price.[5] If a strike price of less than £70/MWh is taken as the acceptance criterion, then a 10% cost increase on the 10 year construction period, *T*, and a two year over-run (with a 12% increase in overnight cost) are both viable at a WACC of 4.5% (50% gearing) but a five year over-run is only marginally viable at the base WACC of 3.5%.

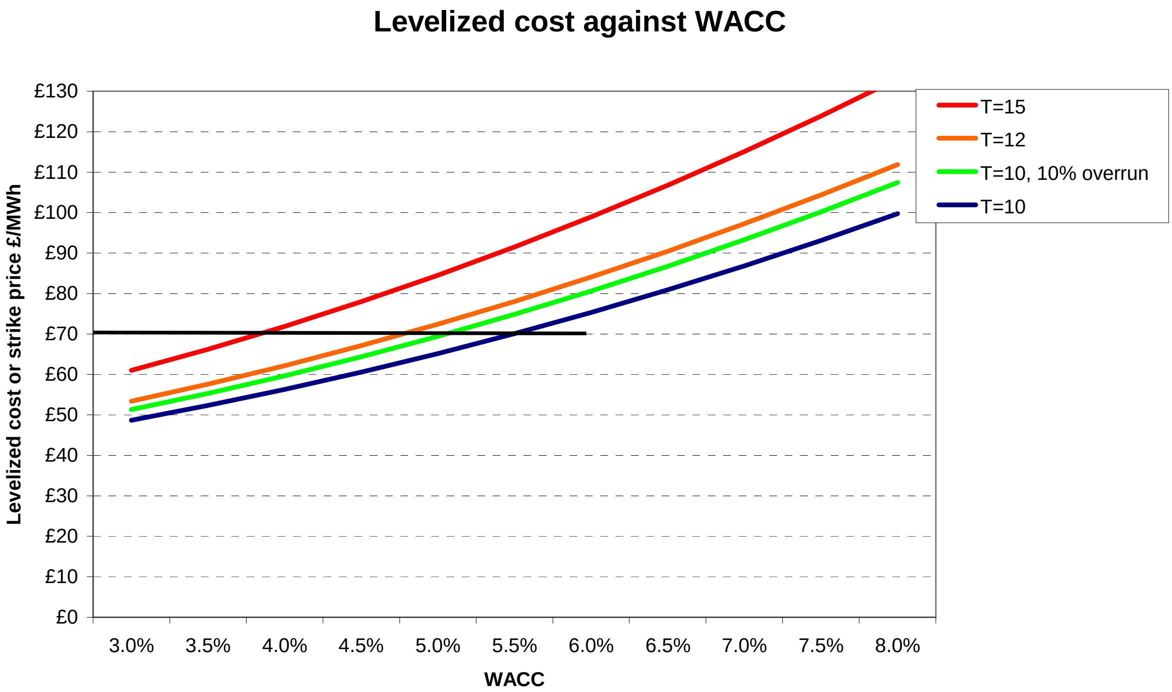

Figure B1 Levelised cost against WACC for different construction periods (*T*)

Figure B2 shows the relationship between the present value of the gross profit (sales revenue less operating costs) discounted date zero (start of construction) and the equity share (which determines the WACC) for different strike prices and construction periods (*T*) of 10 or 15 years. The line labelled "capex" is the cost including interest during construction (IdC) at the WACC that the revenue needs to cover, also discounted to the start of construction. The equity share is shown notionally rising to 120% which corresponds to the higher WACC of 8% needed for SZC to take on all the risk.

The present value of the resulting revenue stream depends on the sales price of electricity. At a wholesale electricity price of £70/MWh, the discounted value of gross profits

[4] i.e. the simple sum of investments ignoring interest during construction (IdC). The graphs discount everything to the start of construction and so include IdC.

[5] The graphs are derived assuming income and expenditure flows and discounting are done in continuous time using the formulae in Appendix F. The spreadsheets are available via links on the EPRG WP site. There will be small differences with annual flows and discount factors. Graph B1 is eq(6) of Appendix F.

over the life of the plant with an equity share of 30% (WACC = 3.5%) is £6,714/kW, to be compared with the discounted cost of construction of £4,219/kW. If, on the other hand the equity share rises to 70% (WACC = 5.5%) the discounted value falls to £4,689/kW (although the construction cost also falls to £3,846). Putting it another way, at an equity share of 70% the required strike price is about £70/MWh, while reducing the equity share to 30% would allow the strike price to be reduced to about £52/MWh, a reduction of about 25% in the cost to the consumer. To deliver a strike price of £52/MWh at an equity share of 70% would require a cost reduction of 37% (from an overnight cost of £5,000/kW to £3,140/kW). It is difficult to believe that increasing the risk such that the equity share had to rise from 30% to 70% would deliver such a massive cost reduction.

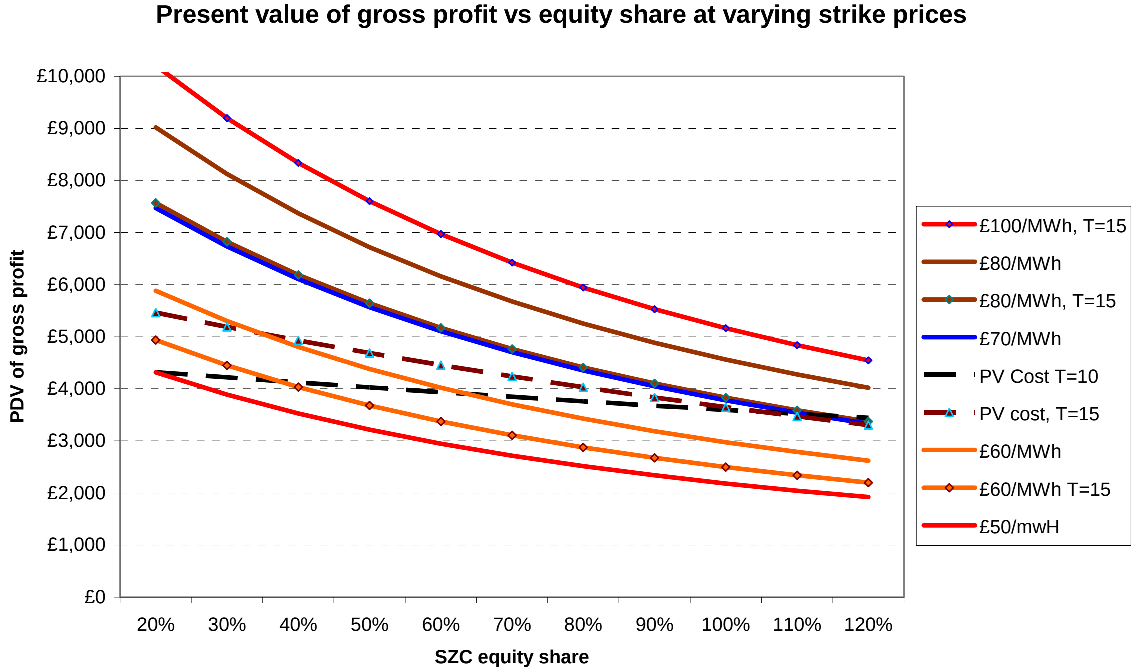

Figure B2 Relationship between present value of gross profit and equity share

We can present the same information as the required percentage saving in cost to compensate for each 10% increase in the equity share (corresponding to a 0.5% increase in the WACC up to 7.5% increasing to 8%), for the two extreme construction periods T = 10 and 15 years. The higher the expected future price of electricity, the more valuable it is discounted to the present, and hence the higher would have to be the incentive saving in construction cost to warrant the higher WACC. Moving from the base case equity share of 30% (WACC = 3.5%) to an equity share of 40% (WACC = 4%) requires a cost reduction of between 9% and 18% (depending on the strike price and construction period) to justify the increase in risk share. The required cost reduction falls as the risk share rises, so the cost reduction required to offset a shift from 70% equity (WACC = 5.5%) to 80% (WACC = 6%) is between 5% and 11%.

The implication is that the Government or Ofgem under-writing a large share of the risk (by, for example, allowing a share of cost over-runs to be passed through to consumers so that the company takes only a part) is likely to be very cost effective. Perhaps surprisingly, the benefit of further lowering the risk rises the more risk is removed from the company.

Percentage reduction in capex needed to offset 10% increase in equity share

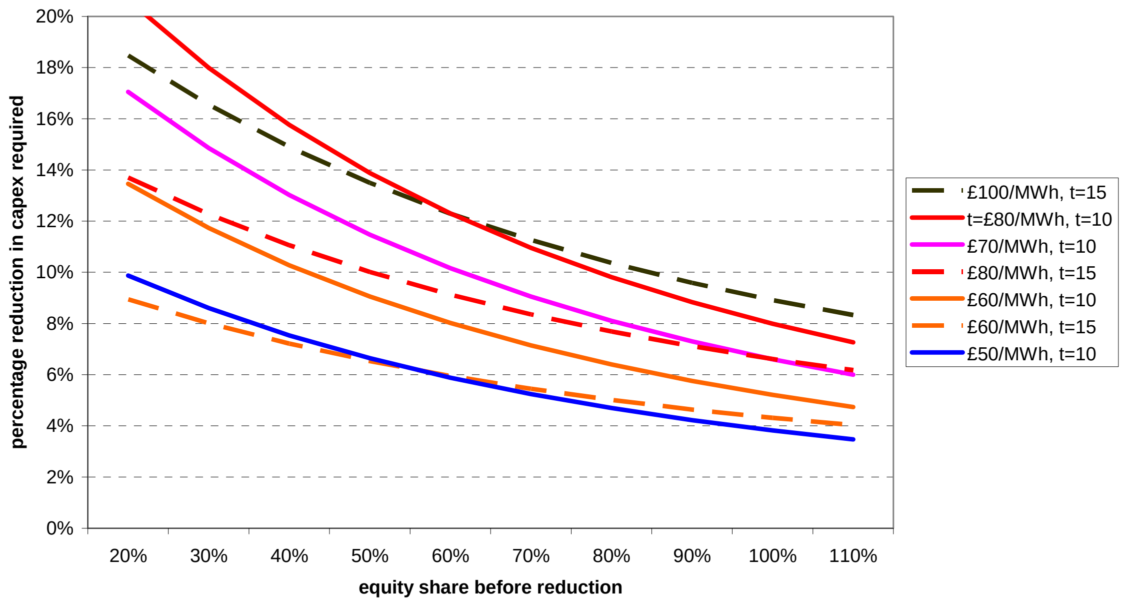

Figure B3 Amount construction cost would have to fall as a result of raising the equity share

Providing incentives for timely delivery, which also on our assumptions keep costs down, is important as delays reduce the present value of future revenues. It may impose additional costs on the industry if it requires more expensive alternatives to make up a period of inadequate supply (e.g. by building more carbon intensive less efficient replacement plant that can be delivered more rapidly, but will then be displaced by the eventual commissioning of the planned nuclear station).

B3. Conclusion on incentives

Incentives matter, but for capital intensive projects with lengthy time periods and a long life, the cost in terms of higher WACCs seem to overwhelm the possible benefits of cost reduction, arguing for very low risks and extensive risk sharing. If incentives to reduce cost can be delivered without putting more financial risk on the company, for example by facilitating site approval, not intervening to require design changes, and encouraging experienced construction teams to be transferred from one site to another with minimal disruption, these would seem to be far more cost effective than a hands-off financial incentive.

Furthermore, there is an additional layer of scrutiny on the project under the RAB model. There is an economic regulator, Ofgem, checking behaviour, governance procedures etc., acting in the interests of customers to ensure costs do not overrun unnecessarily. The regulator provides an additional incentive in that if the investors were not sufficiently incentivised to be efficient, the regulator could disallow costs that were demonstrably the fault of the investor. The *quid pro quo* of sharing risk with customers is that the customers have the regulator overseeing the investors whose job it is to monitor / drive / challenge efficiency.

Appendix C Possibilities for private financing of new nuclear power stations in the UK

C1. Infrastructure as an asset class for institutional investors

Infrastructure is increasingly regarded as an *asset class* (see e.g. G20 et al., 2018) meaning that it has definable investment characteristics that make it suitable for a structured portfolio allocation process. The idea of an asset class is rather loose: arguable the only fundamental asset classes are equity and debt. Proponents of infrastructure as an asset class argue that these assets are typically long term, relatively low risk (meaning low volatility of returns) and possibly well hedged against inflation risk. The low risk is supposed to come from the fact that infrastructure assets are typically either monopolistic or at least have high barriers to entry and usually involve low risk of technical obsolescence. Any given asset may not fully meet these criteria and there are plenty of disaster stories where political risk (which is typically higher for infrastructure assets than conventional commercial assets) more than offsets the lower risk factors.[1]

Infrastructure assets may be invested in through both equity and debt. Equity may be listed (buying shares in a quoted company that owns infrastructure assets, such as an electric utility) or unlisted (meaning it is a form of private equity, shares owned in a company or fund that it not quoted on a stock exchange). The debt may be in the form of loan or a bond, the latter being potentially quoted on a market and/or having transferrable ownership. Infrastructure assets may additionally be classified according to the investment stage. Completed assets that have no development or construction risk are often termed "brownfield" assets and these are the ones that are usually argued to be low risk. But investors can also put money into "greenfield" projects, meaning they take some or all of the development and construction risk. This stage of investment is much riskier than buying a completed, operating asset and has proven less appealing to institutional investors.
Critics (e.g. Inderst, 2010) of the concept of infrastructure as an asset class point to the heterogeneity of infrastructure assets and the lack of any financial theory to justify treating infrastructure as different. Much of the research on this question is from interested parties, either investment managers or investment index providers. But institutional investors do appear increasingly to treat infrastructure as an asset class, separate from real estate and conventional private equity. So even if the theoretical case for thinking of infrastructure as an asset class is dubious, it seems to have an operational importance which means that those seeking to finance infrastructure are encouraged to frame their arguments accordingly.

C1.2 The general case for investing in infrastructure assets

The general case for any asset class is that it contributes portfolio diversification, meaning that it is imperfectly correlated with the other portfolio assets and therefore reduces the overall risk for a given return, or equivalently raises expected return for a given level of risk. A number of studies argue that infrastructure meets this test.

[1] Enron's Dhabol power project in India is a cautionary tale.

Most infrastructure investment is held through private equity, which normally means there is little or no public information. Even when the returns are published, they are subject to the general problem of private equity returns reporting, which is that if the returns are only quoted periodically, they may give the appearance of low volatility relative to for example daily quoted returns from listed financial assets. But this is an artefact of the reporting frequency.

Australian and Canadian institutional investors have been pioneers in infrastructure investing. Two studies (Peng and Newell, 2007, and Newell et al., 2011) draw on data from 1996-2005 on unlisted investments by Australian funds to conclude that infrastructure assets contribute significant portfolio diversification benefits. The authors find that unlisted infrastructure had a Sharpe ratio (a standard measure of investment return per unit of risk) of 1.47 (where anything over 1 is regarded as good) compared with public equities' Sharpe ratio of 0.67.

A variety of index providers now offer investable infrastructure indices, where the constituents are companies that have a high exposure to infrastructure assets. Standard and Poors argue that inclusion of such an index improves the efficiency of a portfolio that otherwise invests in standard asset classes such as public equities, government bonds and corporate bonds.[2] Center Square, a subsidiary of the US bank BNY Mellon, argues that the FTSE Global Infrastructure Index contributes to the efficiency of a standard portfolio.

Many infrastructure assets are utilities which are regulated using price controls. These often give the utility a degree of de facto inflation linkage in its revenue, which offers a partial inflation hedge for investors. Utilities can sell this inflation exposure in the swaps market (they swap an inflation-linked stream of cash flows for an unhedged stream of cash flows, typically mediated by banks) offering an alternative to inflation-linked bonds for investors who seek inflation protection.

By contrast, Standard & Poors claim their inflation index provides partial protection (defined as higher returns than a broader equity index) for a portfolio during periods of high inflation (S&P Dow Jones Indices Research, 2015).

C1.2 The specific case for defined benefit pension fund investors

The case above works for any investor, in principle. But infrastructure assets may be particularly suitable for long term investors seeking modest risk returns. The biggest such class of investors is defined benefit pensions, which have liabilities to pay incomes linked to salaries, meaning their liabilities grow in line with wages, not with prices. (Once their clients have retired, the liabilities usually become indexed to price inflation and bear only that plus longevity risk – see section II for the value of inflation-linked assets to such funds, which make up a large fraction of the UK private sector pension fund universe). Regulation and public scrutiny tend to make such funds fairly risk averse, with trustees under pressure to show that they have very carefully thought through asset decisions.

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[2] S&P Dow Jones Indices Research, 2015. *Approaches to Benchmarking Listed Infrastructure*, April, at https://us.spindices.com/documents/research/research-approaches-to-benchmarking-listed-infrastructure.pdf

If infrastructure assets match the liabilities of pension funds, we might expect to see a lot of investment but that is not the case. The 2018 edition of the annual OECD survey of large pension funds and public pension reserve funds (a mix of private and public sector pension schemes) finds that direct investment (unlisted equity and debt) in infrastructure was only 1.1% of the assets of the 49 schemes surveyed (OECD, 2018). Although many schemes expressed support for the idea of investing in principle, the allocations are dominated by Australia and Canada with a few other countries with higher investment proportions such as Portugal and the Netherlands, both in renewable energy. Many funds have no infrastructure investments at all, even in renewable energy.

The report also shows the continuing attraction of brownfield versus greenfield investments, though some funds indicate a growing willingness to consider greenfield (new build) assets. Pension funds have a slow, careful decision process so these indications may take some time to turn into action.

C1.3 Barriers to pension fund investment

OECD (2018) suggests a number of barriers to pension fund investing including: novelty, lack of knowledge and experience, lack of data and lack of transparency. In sum, pension funds are used to investing in financial assets such as equities and bonds. They typically lack the skills and knowledge to appraise an infrastructure asset, each of which is unique and requires a lot more due diligence than a typical large quoted company share.

The knowledge barrier can be overcome at a cost, either by hiring a team or by buying the expertise of a specialist infrastructure fund, of which there are now many. But pension funds have been unwilling to pay the fees and in most case are too small to justify setting up a dedicated in-house team, especially among the UK's relatively fragmented pension fund sector.

In specific sectors an external solution can work. The Green Investment Bank helped to get investors used to what were initially novel assets (mainly offshore wind turbines) before being privatised in a sale to Macquarie Bank. This has led to suggestions that the UK would benefit from a broader infrastructure bank, particularly in light of the expected loss of access of the UK to the European Investment Bank (EIB). The EIB is available to EU member states and provides both low cost finance and a source of infrastructure investment expertise. It is very likely that the UK will no longer have access to it after leaving the EU.

C1.4 Infrastructure versus private equity: how to get lower expected returns

Many pension funds now invest in private equity (PE), which means unlisted corporate equity. This shows that they are in principle willing to invest in infrastructure type assets but the problem is the mismatch in expected returns.

Typically PE investing is done through a fund run by managing partners, with a ten year life. The fund aims to buy undervalued companies and make them more valuable, then sell them at a profit, with the fund being wholly liquidated. The ten year fund life provides time for this strategy to work, with the assurance to the managers that the external (or "limited" partners) cannot ask for their money back early (though they may be able to sell to new investors). The expected return needs to compensate for the illiquidity of the investment, as well as the risk involved in the strategy.

These investments can include infrastructure (which is confusingly sometimes seen as a separate asset class to private equity, when if in fact largely overlaps with it).

The problem is that private equity expected returns are typically higher than public equity returns, not least because of the illiquidity compensation. But the case for infrastructure investing is that it is low risk and the project sponsors need to attract funds seeking lower returns than those normally associated with private equity.

The challenge then is to harness pension funds' proven willingness to tie up their funds for 10 years or more in illiquid investments, but for lower return investments.

1. The Thames Tideway Tunnel (TTT) model for infrastructure investment

The TTT model for attracting private debt and equity investment into a large infrastructure project has been successful (although the project is not yet complete) and therefore offers a potential model for other major infrastructure projects such as new nuclear.[3]

The TTT model is a successful combination of two key components:

i) harnessing the existing credibility and track record of the regulatory asset base (RAB) approach to regulated utility investment; and

ii) managing risks by using government guarantees to take away extremely remote or "tail" risks.

These two features can be used in other projects and, in principle, for traditionally non-regulated, non-monopoly assets such as nuclear power generation.

TTT is a £4.2 billion[4] construction project to build a large new sewer for London. Thames Water, the regulated water and sewerage utility for London, was unable to finance such a large project on its balance sheet and the government decided that it could be financed instead by a standalone third- party company. The goal was to keep the benefits of private involvement (incentives for efficient delivery) with a minimum of state involvement.

The new asset is owned by a company called (in recognition of a key historic figure in London's sewerage system) Bazalgette Tunnel plc, which has four shareholders, all institutional investors with expertise in infrastructure investment.

The project was developed by Thames Water, which invested £1.1 billion to get it to a fully specified and costed project that just required financing before construction could begin. The asset will interconnect with Thames's existing assets but remain fully owned by Bazalgette.

As with most infrastructure assets, which are very capital intensive and have long construction periods and operating lives, the key cost is the cost of capital. So reducing the cost of capital is key to reducing the costs ultimately borne by customers.

The TTT structure extends the concept of regulatory asset base[5] (RAB) to a separate asset owned, not by a regulated utility company, but by an independent company. The RAB is the book value of the net assets in the regulated business, as recognised by the regulator and therefore eligible for an appropriate rate of return. It may be quite different from the

[3] Data on the TTT model are taken from the presentation to potential bond investors https://www.tideway.london/media/1579/bond-investor-presentation-may-2016.pdf

[4] Unless otherwise specified, figures are in 2014/15 prices.

[5] The term Regulatory Capital Value is also used, we treat them as interchangeable.

normal accounting book value. But so long as investors trust that the RAB will paid a fair return, they can base their investment decision on a comparison of the return with their perception of risk.

Happily, investors are used to, and have confidence in, the way that the RAB is used by the energy regulator (Ofgem) and the water regulator (Ofwat) to pay returns to investors. Under the Water Act of 1989, the regulator is required to make sure that efficient utilities are able to finance their operations. After 30 years of operation, investors trust this approach, which involves the regulator setting water company allowable charges to provide a weighted average cost of capital (WACC), judged according to market information. In the event of a dispute, the Competition and Markets Authority is the court of appeal.

The RAB model has achieved a high degree of legal certainty. It is seen by investors as more robust than either PFI projects (where there is always a risk of revocation of contracts and a potentially costly and messy process of compensation) or the concession approach, where an asset is, in effect, leased to a private investor. All this is despite the fact that, as Stern (2013) points out, the RAB does not appear in any primary legislation in the UK.

(Ofwat has a goal of introducing competition into the water and sewerage industry where possible, so bringing a new third-party company into the industry met that goal, though this was a subordinate reason for using the RAB approach. To the extent that TTT brings additional operating data to the regulator it facilitates yardstick regulation but given the essential simplicity of TTT (it used gravity) this is probably not very significant in practice.)

By treating the TTT asset in the same manner as Thames Water's RAB or National Grid's RAB, the new investment should have the same appeal to investors. But the large scale of the project meant that there was a level of construction risk that might discourage investors who would otherwise be attracted to low operating risk of the asset, once built. So, a second key part of the TTT financing involved a set of risk-sharing arrangements.

First, a portion of the construction risk is shared with customers, which is added to the RAB and attracts the same return. This is set at 60% of cost over-runs, with 70% of underspend shared with customers. This is similar to the pain- and gain-sharing regulatory arrangements for new-build construction adding to water or energy network RABs in general, which are typically set at 50% of cost over- or under-spend.

To remove the small risk of more extreme cost over-runs, which are a feature of many infrastructure projects, there is an upper bound on the investors' total commitment at the level of 30% above the base case. If costs exceed that level, investors can choose to put further funds in, with the return on that incremental investment subject to negotiation with Ofwat. If they choose not to, then the government is committed to providing any additional funding in the form of "contingent equity". This amounts to providing insurance for investors against what is known as "tail risk", referring to the extreme right hand tail of a notional frequency distribution of cost outcomes. The idea is that this risk should be very small so that the government is unlikely to have to put in funds, but by taking away even the remote risks that the project either runs out of funds or investors are forced into unacceptably low returns, it makes the project appealing to institutional investors at a relatively low cost of capital.

The RAB model is also well recognised in the credit markets, where investors and credit rating agencies trust the regulatory regime and can assess creditworthiness relatively easily by comparing total net debt of a company with its RAB. The rule of thumb for achieving investment grade status (BBB or better for Standard & Poors for example) is a debt/RAB of no more than 70%.

This simplicity is important. Infrastructure projects involving construction (as opposed to already built and operating) are quite complex, which is a barrier to investors who lack specialised infrastructure analysis teams. By reducing this risk to the familiar RAB model, a wider range of investors can be mobilised to lend to the project. Lending in traditional project finance, as used in a lot of private infrastructure around the world, is usually much more costly than for utility finance, partly because of the complexity of the project. TTT therefore managed to keep financing costs down compared with a non-RAB project approach.

The equity investors, who still bear most of the risk, in line with the need for incentives to manage costs effectively, are specialists who should have the expertise to appraise the project in detail.

The financing costs of TTT were the result of a competitive process. Two consortia bid for the right to finance the project, on the basis of the lowest WACC they needed to proceed. The winning WACC was 2.5% in real terms (indexed to the RPI). If the project is built on the target cost, the RAB will attract that overall return. This is broadly consistent with 4-5% cost of equity in real terms.

Crucially for investor acceptance, the outcomes cannot deviate too far from that central case. Investors are assured that they will get some positive return even if the cost exceeds the threshold level of 130%. But in the most plausible best case, the returns will not be excessively high.

This cap-and-collar on returns is attractive to institutional investors which seek reasonable, steady returns without too much risk. This includes a lot of pension fund investors and retail investor. It also meets the needs of equity yield funds which offer a combination of income with expected long term capital gains.

By contrast, the project could have tapped into the class of higher return, more risk-taking funds, including the large pool of private equity investors. These investors would not have needed so much risk protection but would have needed a much higher cost of capital as compensation.

Additional risk mitigation features included the government providing £500m of debt in the event of financial markets disruption. Although viewed as unlikely to be needed, this was reportedly important to get investor commitment.

C3. Return on capital during construction

An additional feature of the RAB approach that was important for attracting some (but not all) institutional investors is that the regulator allows a return on the RAB as soon as the capital is invested, amounting to a return on capital invested during construction.

In financial terms, two sequences of financial flows with different timings can easily be compared and the required return calculated. So in theory there is a benefit to earlier financial payments that reduces the expected return, compared to the conventional project case when investors receive a return only when operation starts.

But the investment world is segmented, and income funds will typically not invest in assets with a long gap before returns, no matter how high the return is expected to be. By treating the TTT RAB just like the Thames Water RAB, investor appeal could be increased to include low risk but steady return investor, including institutions whose ultimate customers are retail investors seeking a steady or at least non-volatile cash yield.

Additionally, many infrastructure equity funds are organised as temporary, closed-end private equity-style funds with a ten year life. For long construction period projects, the delay from investing to getting a return would be a barrier to these sorts of investors, even if the expected return was high.

In sum, paying a return on the RAB, whether construction has finished or not, was an important part of the appeal for mobilising funds for TTT.

Other features of the TTT project that helped it get financing were:

i) investors had a lot of comparable information on tunnelling projects both in the UK[6] and abroad, and so had confidence in the costs Thames had estimated and risks around them even if these comparators were not quite as complex as a major new tunnel under London;[7]

ii) the project used a bespoke version of the RAB approach, for example the WACC is fixed for 15 years (the construction period)[8] and only once operation starts will it be reset periodically in line with normal RAB assets;

iii) Ofwat reportedly consulted debt rating agencies as well as commercial finance experts to ensure that the structure would be acceptable to private investors as well as meeting the regulator's goals.

As well as helping ensure sufficient private financing for the project, mobilising capital helped increase the level of competition to set the cost of capital. Increased competition thus helped reduce the cost of finance, to the benefit of consumers.

C4. Application of the TTT model to new nuclear: institutional investor attitudes

The TTT project is potentially applicable to any large, discrete infrastructure investment which is too big for the existing regulated utility companies to manage. It would be a further extension to use it for non-monopoly regulated assets such as electricity generation, since these are usually seen as taking part in a competitive market. State support for renewable generation typically takes the form of a contract for differences (CFD) which provides ex-post revenue certainty while leaving construction and operating risks with investors. That is also the approach used for Hinkley Point C but nuclear is arguably different in two respects:

i) the sheer scale of investment is far larger than most other utility investment; and

[6] The TTT finance marketing presentation cites Crossrail, another Thames Water project in the Lee Valley and a National Grid tunnelling project as evidence of tunnelling being a well understood practice.

[7] This was before the much-publicised problems of the Crossrail project, though those were not particularly related to tunnelling.

[8] We understand WACC is adjusted in construction so that it partially tracks changes in the market cost of debt. This provides a reduction in financing risk and also helps make the project more attractive for investors.

ii) the technology is proven in operation but lacks a recently proved construction record, to put it mildly.

The UK offshore wind industry is a highly successful example of private design, construction, investment and operation under the umbrella of fixed price contracts, which may not even be needed for very much longer, as costs continue to fall. But nuclear is some way off meeting those conditions. Since the cost of capital is the key influence on nuclear electricity costs, it is worth considering how the TTT model might be applied.

In principle, a new nuclear station (taking Sizewell C, SZC, as the most likely case) could be set up as a RAB project. Investors would bid a required return to finance the project, a range of cost outcomes would be established, and some threshold ("worst case") level set, above which the state would provide contingent equity. The regulator Ofgem would charge customers an amount sufficient to pay the WACC during the construction phase, with a conventional five year periodic review thereafter.

Conversations with a range of debt and equity investors suggest that all of this is feasible in principle.[9] There are some important differences, but mostly not of principle.

Scale: SZC construction costs are likely to be in the range of £15-18 billion, of which EDF is unlikely to be willing to fund more than 20%, leaving some £12-14 billion to be funded.[10] It is not clear how much of this could come from the other current project owner CGN.

Construction risk: unlike TTT, there are few direct precedents for SZC's construction and most are discouraging; but there is, or will be, one very specific precedent, namely the construction of Hinkley Point C. If, as planned, SZC is an exact replica of Hinkley, with the same construction team and supply chain, then confidence in the construction risk should be very much higher than for HPC itself, which is the fifth of a kind EPR in the world but first in the UK. Depending on what stage of construction HPC has reached by the time of a financial decision on SZC, the construction risk should be much better known, though there will still be a tail risk that needs to be covered. Clearly, any setbacks at HPC would affect confidence in the SZC process. However, a critical point is that exact replication is only possible if construction of each stage of SZC follows on closely from the equivalent stage at HPC. Any decision to delay the start of construction at SZC – to 'increase confidence' by completing HPC first – will actually have the opposite effect, as it makes it more likely that design changes and equipment requalification will be required.

ESG: a number of investors point to the need for all investment now to be approved by their internal Economic, Social and Governance (ESG) risk committee. These committees have mostly never had to consider a nuclear-related investment and so there is real uncertainty as to what they will say. New nuclear can make a strong claim to being consistent

[9] The author (ST) interviewed a small number of UK institutional investors in debt (two insurance companies and a pension fund) and equity (two specialist infrastructure investment funds) plus a legal corporate advisor and two investment banking corporate advisors. The results are clearly indicative rather than statistically significant.

[10] We understand EDF wishes to have no more than 20% of the equity long term, which would be a much lower figure than the total share of financing, assuming the project had a long term 65/45 debt/equity financing ratio.

with environmental goals in respect of climate change but the matters of nuclear waste and of safety would need to be considered. Most investors were fairly confident that this would not be a significant barrier, but pointed out that some infrastructure investment funds explicitly exclude nuclear from their scope.

Credit rating agency views: similarly, credit rating agencies would need to consider whether being in the nuclear sector would make any important difference to their evaluation. It is probably essential for the project to have an investment grade rating to attract the debt investors on the scale needed (though some larger UK institutions are now quite happy to lend without ratings, having their own in-house credit rating teams). The majority investor view was that the rating agencies would look at the credit risk on its merits and would not apply any nuclear-specific additional terms, but this is not certain.

C4.1 Tapping UK debt markets: the mature pension fund sector

An important feature of the UK institutional funds industry is the large proportion of mature pension funds, meaning that most of their members are retired and the fund's key obligation is to pay them pensions which are usually indexed (to some extent) to inflation, usually the RPI. Unlike in the growth phase of pension funds, the key risks to be managed are inflation and longevity risk (the risk that people die later than forecast). This creates a demand for inflation-linked assets at a time when such assets are in limited supply.

There is already a swaps market for inflation-linked cash flows, mostly supplied by regulated utilities that have natural inflation exposure. But mature pension funds need new inflation linked assets, so any project that can issue inflation linked debt, particularly at long maturities, should find ready demand. This provides an opportunity for SZC to tap the UK debt markets at some scale. Although UK inflation indexing is moving towards CPI as a benchmark, there remain many outstanding RPI-linked liabilities which require hedging with RPI-linked assets, so it may be best to issue both types of index-linked debt.

Other points arising from investor conversations include:

- the need for "skin in the game" from the major project sponsors, chiefly EDF; but a 20% equity stake (and a 25% interest in the supply chain) would amply meet this need, since the key thing is for the sponsor to face a material financial incentive, which need not mean a large equity share so long as the absolute amount is material. EDF's key role is seen in the operating phase.

- foreign investor demand, hitherto likely to be large for good quality UK credit risks, is now in doubt because of the combination of Brexit-related uncertainty and the unquantifiable threat of a new Labour government pledging to renationalise utility assets, possibly below market or even RAB values; whether that pledge would extend to projects such as SZC is very unclear but the wider damage amounts to a higher risk premium for any UK investment and a decision by more risk averse foreign investors to avoid the UK altogether for the foreseeable future.

- given the lack of familiarity with nuclear investment, an "education" programme would be needed to build confidence among investors (including but not limited to the ESG committees).

- there is a large pool of equity infrastructure funds, many of which have "dry powder" (uninvested funds) owing to a lack of suitable projects; many of these funds exclude greenfield (construction) projects but are very keen to find suitable operating assets, and could provide demand for the equity of the project, but only after operation has started; that means it may be harder to find the initial equity but those early investors could probably sell at a profit once construction has finished.

- the scale of SZC's financing needs makes it unlikely that the TTT model of competing consortia would work; but other methods, including book-building (an auction-based approach routinely used in securities issuance) could offer a way to bring competition into the process.

- the credibility of the construction plan was critical to TTT's ability to achieve investor financing on competitive terms; likewise it will be essential for SZC to be able to offer a credible plan.

-compared with TTT, the need for equity at the construction phase is probably larger because the construction risk will almost certainly be perceived as larger. This implies a higher cost of capital. But once the project is completed that cost of capital will fall. This is true for any construction project but much more so for nuclear build. The question of whether the *ex ante* cost of capital that investors would bid initially might appear unduly favourable ex post once construction is completed needs addressing. This problem is familiar from the PFI world and was addressed through a combination of ex post gain-sharing on the refinancing after construction and in PFI2 the idea that the client (local or central government) would put in a share of the equity. As the NAO (2017a) noted, putting in equity was somewhat in conflict with the point of using private finance in the first place.

- TTT is a relatively simple operating asset compared with a nuclear power station; those investors familiar with nuclear are confident that the typical operating record of PWRs and of EDF is very good, and that investors can become comfortable with the operating risk in the same way that they have in a relatively short time got used to the operating risk of offshore wind turbines (where wind risk was a new concept for most investors, for example). Some UK investors will have the unhappy memory of the operating performance of the UK AGRs but this is a matter that needs to be differentiated from the wider nuclear operating record, through education; by the time SZC faces a financial decision there should be three or possibly four operating EPRs in the world.

- although the overall TTT structure provides a workable template, the detail of the equivalent risk-sharing in construction and the "threshold" for government-provided contingent equity will be the nub of any viable structure; anecdotally it appears the TTT equity investors believed there was a reasonable chance of beating the construction costs of the TTT central case, which was perceived to be somewhat conservative (risk-averse); for SZC it is rather less likely that the risks will be seen to be symmetrical around a central case, unless of course the central case is chosen to be very pessimistic; in essence, there will be less information on which to base a rational analysis of the SZC construction outcomes and so more room for differences of opinion.

- a key part of the early financing for TTT came from the European Investment Bank (EIB) (£0.7 billion); building early momentum is important for financing large projects and the EIB role was very helpful; assuming EIB financing is no longer available to the UK after Brexit, lining up one or more initial "anchor" lenders would be very helpful to building confidence among other potential lenders.

C5. Conclusion

TTT offers an encouraging precedent for other infrastructure financing, including a new nuclear power station. It is not surprising that investors will want to finance a project with de facto guaranteed returns, so the practical question is what balance of risk protection and incentive will satisfy investor demands and the government's need for value for money?

The argument for using private finance is that it brings expertise (mainly in the construction phase) and frees up state resources for other purposes (at a time when the state debt level is likely to face continued pressure from elsewhere).

There is a good case in principle for institutional investors with long time horizons to invest in infrastructure projects. This is particularly true of mature pension funds seeking inflation-linked assets to hedge their liabilities.

There are reasonable grounds for believing that even a project of the scale of SZC could achieve the funding needed, if the terms are right.

Investors are likely to back a similar project structure of sharing cost over-runs and under-spends with the customer, and with an upper bound on investment, above which the state provides contingent equity. Replicating the TTT state debt facility back up, on a materially larger scale, would probably be necessary, and having as explicit and automatic a pass through from market interest rates to the allowed cost of debt would help assure debt investors.

There may be a bigger challenge to find equity investors on the scale needed, as the pool of infrastructure equity funds, although large, is not all available for new build projects. Once the project is completed these funds would probably be ready to buy the (by that stage de-risked) equity.

Appendix D The financial model

There are a variety of possible funding models for Sizewell C (SZC) but the one considered here follows the Thames Tideway Tunnel approach closely (see Appendix C). The counterfactual against which to compare this RAB model places all the risk on SZC, which would in effect rule out debt finance, and require a rate of return (the WACC) of 8% real.[1]

D1. Assumptions

The base case cost of constructing SZC is £500/kW per year for a construction period of 10 years to commissioning, which if completed on time would have an undiscounted cost of £5,000/kW, or for 3.2 GW, a total cost of £16 billion. This is based on the claim that SZC is an almost exact replica of HPC, for which costs are now reasonably well identified, and with a construction team that comes with experience of constructing HPC. Cost and time over-runs are likely highly correlated, so suppose that the rate of expenditure after 10 years falls to £300/kW per year of over-run (all prices are in £2018). The undiscounted (over-night) cost is £500.Min(T,10)/kW + £300.Max(0,T-10) where T is the construction time in years.

Total operating costs (O&M, fuel and decommissioning costs) are assumed to be £22.50/MWh,[2] and the plant life is 60 years. Some of these assumptions will be varied in the worst case. This should also include the cost of the risk of a major accident. Lévêque (2015, p81) argues that this is low, drawing on upper-case assumptions that the chance of a disaster is 1 in 100,000 years of reactor operation with the cost of the damage of €1,000 billion, given a cost of €1/MWh. We assume that is included in the total operating costs.

D2. The RAB model

The RAB model for utilities such as National Grid essentially guarantees that investors will earn an agreed Weighted Average Cost of Capital (WACC) on the Regulatory Asset Base (RAB), and that the WACC will be based on a financing structure that assures investment grade debt. In effect this limits the debt-to-equity ratio to 70:30. Both the WACC and RAB will be revisited at periodic (normally 5-yearly) reviews. The revenues available to reward the debt and equity holders will be projected forward at each review allowing for efficient investment additions and operating costs. The RAB model will continue to be applied until shut-down, 60 years after commissioning, and that is the period over which the depreciation and debt are written down (to preserve the 70:30 split).

Applied to Sizewell C (SZC), which has a lengthy construction period before commissioning, the regulator (presumably Ofgem) would agree the time profile of investment and the other financial details such as the length of time over which the project is depreciated and the WACC based on an acceptable financial structure. In this example the contract length will be the life of the asset, 60 years. SZC would then put up 30% of the agreed final projected cost (estimated to be £$_{2018}$16 billion or £5,000/kW) as equity to fund the early construction stages. This amount of £1,500/kW would be injected at the rate of £150/kW/yr

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[1] A commercial analysis would do everything in nominal values and take account of tax, but this complicates and obscures the results.

[2] See footnote 23 above

until the predicted date of construction in year 10.[3] Debt would be issued simultaneously at a rate of £350/kW/yr, keeping the debt-to-equity ratio no higher than 70:30. The first periodic review at year 5 would provide an update to all these numbers, which for the moment we assume are unchanged.

During construction SZC would receive the WACC on the evolving RAB, which would be paid for by electricity customers as pre-funding (as with other monopoly regulated assets and airport projects such as Heathrow Terminal 5).

If the project is completed ahead of schedule and budget, then at the second review in year 10 70% of the cost savings would be clawed back, leaving SZC with 30% of the savings. So if the project came in at the end of year 9 at a cost of £4,500/kW, the revised RAB at year 10 would be (£4,500 + 0.3x £500)/kW = £4,650/kW.

If the project were running above budget at the review then SZC would bear 40% of the cost-over-run, and this 40% would be added to the previously agreed RAB, until the cost reached 130% of the original budgeted cost. At that point, the shareholders (SZC) would be asked whether they wished to fund this excess cost at an agreed WACC, failing which the Government would take equity in the excess cost (possibly passing that back to customers). We assume that is the default outcome, noting that adding £300/kW for five years reaches this ceiling of 130% of the budgeted cost. The stress case is discussed below.

On completion, Ofgem would set the strike price at a level to provide the required payments over the next review period. This would be a combination of the operating costs (opex) and the capex (the return on the RAB and depreciation of the RAB over the agreed life of the project, taken as 60 years). The WACC would be reset in light of the now presumably assured evidence of satisfactory commissioning, and each subsequent review would reset the strike price in light of the depreciated RAB, the appropriate market determined WACC, and updates on forecast opex. Over the modest length of the review period (5 years) the predicted constant gross profit would initially fall short of the full return on the RAB and depreciation, but later would over-pay, giving the same present value over the period as the declining full value of the return on and of the RAB. This would be borne by retained equity profits.

In addition, to give a comparable cost to the levelised cost of electricity often used for base-load comparisons across technologies, we also calculate the constant (real) strike price that would recover all costs over the entire lifetime of SZC.

D2.1 Assumptions on the WACC and social discount rate

In the run-up to almost every price control, the regulator consults on the building blocks of the WACC ─ the real debt interest rate, the equity risk premium and the gearing. All are contested, with the utilities' consultants criticising the regulator's consultants.[4] In particular,

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[3] Another mode of financing would be for SZC to put all its equity in over the first three years and raise debt gradually over the remaining construction period, but this lowers the internal rate of return to SZC.

[4] See, for example, NERA (2018), *Review of Ofgem proposed WACC for Competition Proxy Model of delivering new onshore capacity investments*, October; and Cambridge Economic Policy Associates Ltd (CEPA) (2018), *Review of Cost of Capital Ranges for New Assets for Ofgem's Networks Division*, 23 January

there is disagreement as to whether the Total Market Return (TMR, to equity) or the Equity Risk Premium is more stable, and if so, at what levels. In practice, this is largely irrelevant as the plan would be for competitive book-building to determine the initial WACC, although Ofgem would likely revisit this at each periodic review. The approach taken here is classic, in that the assumed WACC to SZC is built up as follows. The debt interest is taken as 2% real (which is high compared to the TTT, which was set at 180 base points, or 1.8%, above the 10-year indexed gilt rate, that figure 1 shows is now negative). The equity risk premium is taken as 5% (see e.g. Rachel and Summers, 2019, fig 3, p5), which gives a WACC of 3.5%.[5] The discount rate used for evaluating the cost to consumers is taken as 2% real.[6]

D2.2 Assumptions about cost and time over-runs

A more comprehensive study would examine a probability distribution of outcomes. We approximate this by considering the benchmark on time and budget, a worst case of eight years over-run, and an expected case. With a triangular distribution the expected over-run would be 2.67 years, which we approximate as commissioning in year 13. Clearly over-run costs, duration and probability are uncertain, so these calculations are illustrative rather than certainty-equivalent estimates, and are chosen to err on the side of pessimism. The key parameters are the expected return to shareholders and to test whether the maximum plausible over-run is still viable (i.e. leaves at least a positive real rate of return to the shareholders). As a worst case stress test, SZC is assumed to have a time over-run of 8 years and a cost over-run of 48%, with SZC putting in the required debt and equity finance for its 40% cost share up to a cap of 140% of the base cost of £5,000/kW.

D3 Financial analysis and levelised costs[7]

D3.1 The RAB base case – everything delivered on time and budget

Plant availability is set high, averaging 8,000 full output operating hours per year (91% availability). With the financial injections described in the base case, the RAB will earn the WACC during construction, the debt will just receive interest, and shareholders will receive the residual. Upon completion the RAB will have risen to the full construction cost of £5,000/kW, as all the WACC on the rising value will have been paid out as interest and return to the shareholders. After completion debt will be gradually retired over the life of the

[5] NERA (2018, p. iii) criticised the CEPA (2018) report to Ofgem of a real vanilla WACC for the construction phase of the onshore project Hinkley Seabank of 1.58 - 3.45% real (RPI linked) and suggested 3.88 - 4.27% real when arguing for the company, with a gearing of 30% (and a negative risk-free rate). CEPA's ERP was 7.1 - 7.5% while NERA's was 8.9% - 9.3% (implausibly high). NERA's real TMR was 6.5% - 7.1% while CEPA's was 4.7% - 5.3% (a central value for the past 30 years in the US).

[6] Although this is below the Treasury *Green Book* rate the thrust of the earlier argument is that social discount rates should be reduced for two reasons: world real rates have trended down and are now (and expected to remain) low; while discounting for climate change mitigation justifies an even lower rate.

[7] Caveat: the calculations reported here are based on spreadsheet analysis and are subject to the normal caveat that there may be errors still to be corrected. The formulae for continuous time discounting are given in Appendix F and the key spreadsheet calculations are available on the EPRG website.

plant (60 years) to maintain the gearing near but no higher than 70%, leading to a change in the cash flows paid to debt holders and hence to equity. In the base case in which everything is delivered on time, by completion total debt issued has a value of £3,500/kW, with a gearing of 70%. To remain below the ceiling, debt will be repaid each year until the debt reaches zero near the time when the RAB has fallen to zero at year 70. The simplest way to do this is to retire debt at its share of depreciation each year. Amortising the debt of £3,500/kW over 60 years reduces its value by £83.33/kW/yr.

The levelised cost over the life at the WACC is £53/MWh[8] and at the SDR of 2% is £43/MWh.[9] However, the levelised cost to consumers at the SDR is slightly higher as they have to prepay on the RAB during construction, and for them it is £49.6/MWh.[10] If the strike price is set at periodic reviews every five years, then over the first period it would be set at £53.72/MWh. At the next review in year 15, the RAB has fallen to £4,583 and the strike price for the next period (years 16-20) would fall to £51.90/MWh with the depreciating value of the RAB, and then decreasingly rapidly to £33.67/MWh from year 66 to 70. The internal rate of return received by shareholders is 6.9%, marginally below the return assumed in computing the WACC, probably due to timing of cash flows.

The cost of pre-financing borne by electricity consumers averages £308 million/yr (for the 3.2 GW plant), which averaged over 300 TWh annual consumption is about £1/MWh. For a household consuming 4 MWh/yr this amounts to £4/household/yr.

Another alternative is that the RAB is written down over a contract period of 35 years (and the plant depreciated over this period), with SZC free to sell its output at the market price after the end of the contract. Forecasts for electricity wholesale prices after 2070 (at the end of the 35 year contract) are lacking. The BEIS *Updated energy and emissions projections: 2018* give the low (baseload) wholesale price for 2035 (the latest year) as £50/MWh, compared to their figure of £52.4/MWh for an average of 2017-18. The ENTSO-E day-ahead hourly average for 2017-18 is £51.4/MWh, in reasonable accord. Similarly, the EU publishes forecasts to 2050[11] suggesting that the price in 2050 will be almost identical to the 2015-2020 price. A defensible assumption is therefore that the post 2070 price might be £$_{2018}$50/MWh.

In this case because debt is retired more rapidly, and because consumers pay the higher market price and not the then lower RAB-based price after the end of the contract, the levelised cost at the WACC rises to £52.2/MWh, or nearly 11% higher than a whole-life contract (at the SDR to £51.2/MWh). The IRR to shareholders rises to 7.7% because of the more rapid write-down of the RAB which accelerates customer payments, and after paying debt leaves more to equity. From the consumers point of view a life-time RAB model is preferable, if not necessarily for the shareholders.

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[8] Equation (5) of Appendix F

[9] This takes the full capital cost plus interest at the WACC or SDR during construction and computes the resulting levelised cost that recovers this sum. It is not the same as levelising the strike prices, which ignore the consumer payments during construction.

[10] Equation (7) of Appendix F

[11] DG-Energy, Energy modelling - EU Reference Scenario 2016 – EU and EU Country Results, http://data.europa.eu/euodp/data/dataset/energy-modelling

D3.2 Counterfactual: HPC CfD model, base case

In this case the entire construction is financed by SZC, paying notional WACC on the accumulating investments, to deliver at a WACC of 8% an asset value of £7,243/kW, on which it would have to earn the WACC and cover depreciation over the following 60 years. The levelised cost at the WACC is £96/MWh, or 181% of the RAB levelised cost. The levelised cost of transferring the asset value into a fund paying just the SDR would be £81/MWh. If the CfD strike price were held constant at the WACC-levelised price, the clear cash-flow would be £465/kWyr after paying depreciation, or an immediate return of 6.4%, rising as the capital value is depreciated. As SZC bears all the risk, consumers are protected through the pre-agreed CfD price (unless the project went into administration with a renegotiated and presumably more expensive replacement contract).

D3.3 The worst case, eight year delay, 64% over budget, lower availability

In this case SZC has to raise 40% of the annual over-run cost taken as £300/kW for eight years, with a cap at 130% of the target overnight cost. This cap is reached in year 15 at which date the Government starts injecting equity to cover the cost over-run and after which SZC injects no more money, nor is the RAB further incremented. At commissioning in year 18 SZC's debt is £4,550/kW (assuming that lenders are willing to continue lending at the original rate despite the cost over-run) and the book value of equity issued is £1,9500/kW. After year 10 and until year 15 the RAB is only incremented by the 60% of the extra investment, reaching £5,900/kW, where it remains until commissioning. The return on (but not depreciation of) this rising RAB is paid by customers until completion, and thereafter depreciation of the RAB would be added). Depreciation of the RAB over the life of the plant is £98/kWyr, added to the return on the RAB and paid for by customers. Of the overnight cost of £7,400/kW, £900/kW is government equity, assumed to be passed on to consumers, who bear £1,500 /kW to be recovered as an addition on electricity prices. In this case the return to equity is just over 4.9% (using the continuous time formulae (14-17) in Appenedix F). The levelised cost at the target RAB of 3.5% is £76/MWh.[12] The levelised cost to consumers is £64/MWh at the SDR of 2% (assuming that they also pay for the publicly funded excess cost of investment).[13]

D3.4 The expected case

Investors contemplating the worst and base case may conclude that the expected time to completion is 13 years. In the standard case (cost over-runs at £300/kWyr, availability 8,000 hours, then with a life-time contract and the same cost sharing as before (the RAB only incremented by 60% of the over-spend) then the IRR to shareholders is 6.17%. (The continuous time check gives a reassuringly close value of 6.23%.) The continuous time check gives a reassuringly close value of 6.23%. If the over-run costs are also higher than expected at £350/kWyr and availability only 7,000 hrs, then with a life-time contract and the same cost

[12] Equation (6) in Appendix F.

[13] Equation (20) of Appendix F

sharing as before (the RAB only incremented by 60% of the over-spend) then the IRR to shareholders is 5.4%. The levelised cost to consumers is £57/MWh, allowing for the reduced output over which the costs are levelised. Thus the main impact of the RAB assurances on cost sharing and capping fall on consumers, not the shareholders.

D3.5 Costs of offshore wind

Offshore wind costs have been falling sharply over recent years as investors become more confident in their performance, lowering the cost of finance. Construction costs have also fallen sharply to €2,450/kW (£2,750/kW).[14] With a life-time capacity factor of 38%,[15] that would be equivalent to £6,550/kW "firm", i.e. 90% availability that a new nuclear power station could achieve. Operating costs are currently high but could fall to £62/kWyr or £18/MWh by 2030, according to industry sources,[16] although they are currently nearly twice that level. Connection charges (which require expensive off-shore DC links), and systems cost for intermittency would further increase operating costs, while the life-time would be less than half that of a new nuclear station. Offshore wind would therefore be comparably costly to the worst case considered here.

D3.6 Assessment

The financial structure and incentive regime would appear to assure SZC shareholders of their equity return of 7% real if SZC is built on time and budget, and even in the worst case the capping and cost sharing produce an equity return of 4.9% real. The levelised cost of electricity delivered (discounting at the WACC) could be as low as £53/MWh and not higher than £76/MWh in the worst case considered. The levelised cost to consumers discounting at a consumer discount rate of 2% real would give £53/MWh and £64/MWh respectively.

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[14] D. Weston (2019). Europe's offshore wind costs falling steeply, *WindPower Offshore*, 11 February. https://www.windpoweroffshore.com/article/1525362/europes-offshore-wind-costs-falling-steeply

[15] http://energynumbers.info/uk-offshore-wind-capacity-factors

[16] K. Chamberlain (2017). Offshore wind opex set to fall 40% by 2030 as suppliers dig deep, *NewEnergyUpdate*, 25 October. https://www.newenergyupdate.com/wind-energy-update/offshore-wind-opex-set-fall-40-2030-suppliers-dig-deep

Appendix E Valuing risk

The standard theory of risk taking (for example, that underlies the Capital Asset Pricing Model) assumes that agents experience less benefit from an equal increment in wealth to an equal decrement in wealth. Algebraically, if $U(W)$ is the utility of wealth level W, then U is convex, or $U'' < 0$. The value of risky outcomes is then determined by expected utility, $\mathrm{E}U(W)$, where W is now a random variable. This can be expanded around its mean value, $\mathrm{E}W$:

$$U(W) \approx U(\mathrm{E}W) + (W - \mathrm{E}W)U'(\mathrm{E}W) + \tfrac{1}{2}(W - \mathrm{E}W)^2 U''(\mathrm{E}W), \qquad \text{(E1)}$$

$$\mathrm{E}U(W) \approx U(\mathrm{E}W) - \tfrac{1}{2}\,\mathrm{Var}(W).(-U''(\mathrm{E}W)). \qquad \text{(E2)}$$

If r is the risk premium (i.e. the extra amount needed to compensate for the risk in W, so that $\mathrm{E}U(W) = U(\mathrm{E}W - r)$, then expanding around $\mathrm{E}W$:

$$\mathrm{E}U(W) = U(W - r) \approx U(\mathrm{E}W) - r.U'(\mathrm{E}W). \qquad \text{(E3)}$$

Equation (C1) can be combined with (C2) to give

$$r.U'(\mathrm{E}W) = \tfrac{1}{2}\,\mathrm{Var}(W).(-U''(\mathrm{E}W)), \qquad \text{(E4)}$$

The coefficient of absolute risk aversion, A, is defined as $A = -\, U''(\mathrm{E}W)/U'(\mathrm{E}W)$, hence

$$r = \tfrac{1}{2}\,A\mathrm{Var}(W). \qquad \text{(E5)}$$

The coefficient of relative risk aversion is R, defined as $R = -\,\mathrm{E}W.U''(\mathrm{E}W)/U'(\mathrm{E}W) = \mathrm{E}W.A$, so the relative risk premium, $r/\mathrm{E}W$, is

$$r/\mathrm{E}W \approx \tfrac{1}{2}\,R\mathrm{Var}(W)/(\mathrm{E}W)^2 = \tfrac{1}{2}\,R.\ \sigma(W)^2, \qquad \text{(E6)}$$

where $\sigma(W)$ is the coefficient of variation of W. It is clear from the definition of R and equation (A3) that $R = \eta$, the elasticity of marginal utility, which is important for studying future climate change risks in the context of determining the risk-adjusted social discount rate.

The cost of risk and the benefits of sharing risk

Suppose that the risky prospect is shared by n agents, each of whom takes on W/n. The total cost of risk from (E5) is

$$\tfrac{1}{2}\,An\mathrm{Var}(W/n) = \tfrac{1}{2}\,An\mathrm{Var}(W)/n^2 = \tfrac{1}{2}\,A\mathrm{Var}(W)/n. \qquad \text{(E7)}$$

The total cost of the risk has been reduced to $1/n$ by sharing it across n agents. This is particularly relevant when considering the balance of risk and cost in choosing between imposing more risk and hence cost on EDF compared to transferring much of the risk but at much lower cost of that risk to electricity consumers (or taxpayers).

The treatment of correlated risk

If the Government, consumers and/or shareholders hold equity in a nuclear power station, they add that equity and its risk to an existing portfolio of risky assets. If that existing portfolio is W, and the new project (Sizewell C) is the risky asset, X, then from (E2) but now measuring utility in cash terms (by dividing through by $U'(\mathrm{E}W)$):

$$\mathrm{E}U(W) \approx \mathrm{E}W - \tfrac{1}{2} A\mathrm{Var}(W)..$$

$$\mathrm{E}U(W+X) \approx \mathrm{E}(W+X) - \tfrac{1}{2} \mathrm{A}[\mathrm{Var}(W) + 2\,\mathrm{Cov}(X,W) + \mathrm{Var}(X)], \tag{E8}$$

so

$$\Delta\mathrm{EU} \equiv \mathrm{EU}(W+X) - \mathrm{E}U(W) \approx \mathrm{E}X - \tfrac{1}{2} A[\mathrm{Var}(X) + 2\,\mathrm{Cov}(X,W)] \tag{E9}$$

$$\Delta\mathrm{EU}/\mathrm{E}X \equiv \mathrm{B} \approx 1 - R[r.\sigma_W\, \sigma_X + \tfrac{1}{2}\, \sigma_X^2(\mathrm{E}X/\mathrm{E}W)], \tag{E10}$$

where r is the correlation coefficient between X and W, and σ_W and σ_X are the coefficients of variation of W and X. If the risk is widely spread (e.g. over the entire economy, all electricity consumers, or all shareholders) then $\mathrm{E}X/\mathrm{E}W$ will be small, so the relative benefit of the project is just $1 - Rr.\sigma_W\, \sigma_X$. To give some sense of how large this might be, if $R = \eta = 1$, $\sigma_W = 10\%$, $\sigma_X = 40\%$, $r = 25\%$, then B $\approx 99\%$. The lower the correlation of the risks of the particular project with the relevant portfolio, the lower is the cost of that risk.

Future catastrophic risk

Suppose that the initial level of consumption is 100, but after 50 years there is a 75% probability that consumption will have grown at 1.65% p.a. to 227, a 20% chance that it will have fallen back to its initial value of 100, but a 5% chance that it collapses to 10. The simple expected value of these outcomes in 50 years' time is 191, equivalent to an average growth rate of 1.3% (Stern's value). However, the expected utility is 75%log(227) + 20% log(100) + 5%log(10) = log(164.8) which is equivalent to all consumers experiencing an equivalent growth rate of g^*=1.1%, lowering the social discount rate from 1.4% to 1.2%. Small chances of catastrophic risk reduce, and possibly considerably reduce, the risk-adjusted social discount rate.

This is very much Weitzman's (1998, 2012) argument that a small chance of bad outcomes count very heavily. Specifically, rare events (disasters) happen by definition to infrequently for an accurate estimate of their probability, so that we cannot reject the hypothesis that the distribution of outcomes is "fat-tailed", and is not normally distributed but at best like the t-distribution.

Appendix F

August 1, 2019

1 Equations for the RAB

It is standard regulatory practice in the UK when setting price controls to pay a return on and of the Regulatory Asset Base (RAB). There have been disputes in the past about determining the initial value of the RAB after privatization where the sales value may have been considerably below the replacement cost of the assets (Newbery, 1997). In the case of a new asset, this problem does not arise. We first consider the simplest case of a new asset that springs into life instantly and has a well-defined initial value (and initial RAB) of R_0. Newbery (1997) establishes the central result of RAB accounting, that if the initial RAB is written down by its agreed rate of depreciation, which cumulatively recovers the initial value, then the present value of the stream of payments of depreciation plus the return on the current written-down RAB will exactly recover the initial RAB. This applies to any form of depreciation but can be readily demonstrated for the normal straight line depreciation formula as follows.

The amount to depreciate each year under straight line depreciation over M years is $D = R_0/M$. The written-down RAB at date $t \leq M$ is $R_t = R_0 - Dt$. The present value of the pay-outs will be

$$
\begin{aligned}
V_0 &= \int_0^M [r(R_0 - Dt) + D]e^{-rt}dt, \\
&= (rR_0 + D)\int_0^M e^{-rt}dt - rD\int_0^M te^{-rt}dt, \\
&= (rR_0 + D)\frac{1 - e^{-rM}}{r} - D(\frac{1 - e^{-rM} - rMe^{-rM})}{r}), \\
V_0 &= R_0(1 - e^{-rM}) + R_0 e^{-rM} = R_0. \qquad (1)
\end{aligned}
$$

Therefore paying interest on and depreciation of the RAB over time does indeed repay the full initial RAB.

2 Funding an investment that takes time to construct

Suppose the period of construction is T years during which the expenditure rate is $k = K/T$ per year, where K is the total construction cost. It is standard practice to pay interest on work in progress ("interest during construction", IDC) and suppose that is at the agreed weighted average cost of capital (WACC), r. (Note discounting as here in continuous time is equivalent to discounting from the middle, rather than the end of the year. The difference is quantified in the appendix.) If the funders receive a return r on the RAB, R_t at date t, then the RAB will just accumulate at rate k, so that $R_t = tk$. The investors will then receive rtk during construction while at the same time paying in k for T years. After commissioning they will receive returns on and of the declining RAB over the amortization period of M years (also the length of the contract). From (1) the post commissioning flow of funds will exactly recover the RAB at commissioning, which will be the full construction cost as all 'interest during construction' will have been paid out as the return on the growing RAB. On commissioning, therefore, $R_T = Tk = K$.

The net present discounted value of this flow of payments (negative) and receipts (positive) will be

$$\begin{aligned} V_0 &= -k\int_0^T e^{-rt}dt + rk\int_0^T te^{-rt}dt + e^{-rT}K, & (2)\\ &= -k\frac{1-e^{-rT}}{r} + k\frac{1-e^{-rT}-rTe^{-rT}}{r} + e^{-rT}K, & (3)\\ &= 0. & (4)\end{aligned}$$

Thus paying a return on (but no depreciation of) the RAB during construction ensures that the project earns just its WACC.

2.1 Levelized cost

The accumulated cost of the project including interest during construction at the date of commissioning is just $k(e^{rT}-1)/r$, and if the station then produces μ MWh/yr per kW capacity for L years, the NPV of this output is just $\mu(1-e^{-rL})/r$. If the operating cost is c/MWh, the levelized cost is

$$p = \frac{k(e^{rT}-1)}{\mu(1-e^{-rL})} + c. \tag{5}$$

This can be used to examine the relationship between the levelized price (the constant strike price in any contract-for difference over the life of the station) and either the overnight cost, K, or the WACC, r.

If the project runs over time and budget, suppose the annual cost to completion after date T is k' per year and the project takes a further O years to complete. In this case the accumulated cost at commissioning is $ke^{rO}(e^{rT}-1)/r + k^{'}(e^{rO}-1)/r$. The levelized cost will now be

$$p = \frac{ke^{rO}(e^{rT}-1) + k^{'}(e^{rO}-1)}{\mu(1-e^{-rL})} + c. \tag{6}$$

3 The Thames Tideway Model

The RAB model has also been applied to the Thames Tideway Tunnel (TTT) project, even though this is a privately financed stand-alone project. Ofwat, the water regulator guarantees that investors will earn an agreed WACC on the RAB, and that the WACC will be based on a financing structure that assures investment grade debt. In effect this limits the debt:equity ratio to 70:30. Both the WACC and RAB will be revisited at periodic (normally 5-yearly) reviews. The revenues available to reward the debt and equity holders will be projected forward at each review allowing for efficient investment additions and operating costs. For the TTT, as there is no obvious benchmark sales price for the output, the contract (and RAB payments) lasts for the life of the asset.

Applied to Sizewell C (SZC), which has a lengthy construction period before commissioning, the regulator (presumably Ofgem) would agree the time profile of investment and the other financial details such as the length of time over which the project is depreciated and the WACC based on an acceptable financial structure. SZC would then put up 30% of the agreed final projected cost (estimated to be $£_{2018}$16 billion or K = £5,000/kW) as equity to fund the early construction stages. With a debt:equity ratio of 70:30 the total equity of £1,500/kW would be injected at k = £150/kW per year, and £350/kW per year debt would be issued until the planned completion and commissioning date in year $T = 10$. The first periodic review at year 5 would provide an update to all these numbers, which for the moment we assume are unchanged.

During construction SZC would receive the WACC on the evolving RAB, which would be paid for by electricity customers as pre-funding (as with other monopoly regulated assets and airport projects such as Heathrow Runway 3). Debt holders would receive debt interest at rate i, and the shareholders would receive the residual, earning a rate of return s. The WACC, $r = \alpha i + (1-\alpha)s$, where α is the allowed gearing (in this case no higher than 70%).

If all returns on the RAB are paid out continuously, the RAB at completion will just be K. The simplest financing structure to model in continuous time would be for bond-holders to invest steadily at rate αk and equity investors at rate $(1-\alpha)k$. Return on the RAB during construction will be rkn after n years, divided into bond interest, αikn, and the residual providing the return to shareholders of $\{\alpha i + (1-\alpha)s\}kn - \alpha ikn = (1-a)skn$, as required by the shareholders.

After commissioning, the RAB will decline at rate D, so that t years after commissioning, the RAB is $R_t = K - Dt$, with $D = K/M$, where M is the period over which the investment is amortized and the length of the contract. Total predicted payouts will determine the strike price that provides the necessary regulatory returns. (After that presumably SZC will continue to sell into the wholesale market, just as renewable projects do at the end of their contracts.)

The project will now pay out $rR_t + D$ and the strike price will be set to deliver this revenue (in practice the strike price would likely be set at a constant value at each 5-yearly periodic review but here we are treating this as a continuous review process). If K is measured per kW capacity, and if SZC operates for $8,000$ hrs per year, and if the O&M cost (the opex) is c/MWh, then the strike price will be $p = c + (rR_t + D)/8$, where the $8 = \mu$ is $8,000$ hours per year divided by $1,000$ to convert kW into MW. As the RAB decreases with depreciation, debt will need to be retired to stay below the gearing limit. Outstanding debt at any date will therefore be (at most) αR_t, and debt will be repaid at rate $\alpha dR/dt = -\alpha D$. Discounting at r to the commissioning date the stream of payments is worth K from (1). Outstanding debt at date t will be $\alpha(K - Dt)$ and total payments to debt-holders will be $\alpha i(K - Dt) + \alpha D$, leaving $(1 - \alpha)[s(K - Dt) + D]$ to share-holders, exhausting the total payment stream.

3.1 Post-contract value

If the contract ends before the expected lifetime, L, of SZC (60 years), then SZC would enjoy the full market price, not the RAB-based price, so after the end of the contract the residual revenue could be considerable. The wholesale price, P, is likely to be at least twice the O&M cost, c, so the annual revenue will be $8(P-c)$ per kW capacity, and is value today will be $8(P-c)\int_{T+M}^{T+L} e^{-st}dt = 8(P - c)e^{-sT}(e^{-sM} + e^{-sL})/s$. Thus if $P =$ £50/MWh and $c =$ £22.5/MWh, $s = 6.5\%$, $T = 10$ years, $M = 35$ years and $L = 60$ years, then the present value is £146/kW, or just under 3% of the capital cost.

3.2 The cost to consumers

Consumers pay the WACC on the RAB before they receive any output, and then pay the return on and of the RAB until the end of the contract (taken here as the life of $L = 60$ years). The levelized cost of the capital (to which must be added the operating cost) discounted at the social discount rate (SDR) of ρ can be determined by first computing the accumulated payment to commissioning, A, and then discounting the return on and of the RAB after commissioning, F. This gives the total discounted capital payments to be spread over the discounted future output. The accumulated value to commissioning is

$$A = rk\int_0^T te^{\rho t}dt = \frac{rK}{\rho T}\frac{1 - (1 - \rho T)e^{\rho T}}{\rho}. \tag{7}$$

The NPV of future payments will be

$$\begin{aligned} F &= K\int_0^L [r+1/L]e^{-\rho t}dt - \frac{rK}{L}\int_0^L te^{-\rho t}dt, \\ F &= K(r+1/L)\frac{1-e^{-\rho L}}{\rho} - \frac{rK}{\rho L}\frac{1-(1+\rho L)e^{-\rho L}}{\rho}. \end{aligned} \tag{8}$$

The sum of the two will be spread over the discounted future output, which at μ MWh/yr per kW capacity, is $\mu(1-e^{-\rho L})/\rho$ to give the levelized capital cost, to which must be added the operating costs to give the levelized cost to consumers, ℓ:

$$\ell = \frac{\rho}{\mu}\frac{A+F}{1-e^{-\rho L}} + c. \tag{9}$$

4 Cost over-runs

The TTT contract (taken here as a model for a possible SZC contact) specifies that if the project exceeds the agreed cost, the RAB will only be incremented by β of the cost over-run ($\beta = 60\%$, with a higher share, 70% of the benefits of cost under-runs accruing to the shareholders). Only a smaller part of the additional investment cost can be funded by issuing bonds without breaching the gearing share ceiling, $\alpha\beta$, so shareholders will be called to put in a fraction $1-\alpha\beta$ of the extra investment needed. This will be capped when the construction cost exceeds $(1+\gamma)K$, where for TTT $\gamma = 30\%$. After the cap is reached, all additional finance will be supplied by the government (perhaps passing this on to customers), if the original shareholders are unwilling to finance it (in return from some assured revenue stream).

If the project is O years late, and if late investment occurs at rate k' and if $ok^{'}/K = \gamma$, with $o < O$, then the project will reach the cap o years after the planned date and before commissioning. Until the cap is reached, debt and equity will continue to be raised but only a fraction β will be added to the RAB to produce an income flow to shareholders, and the remaining $(1-\beta)$ will be borne by shareholders, who will also have to pay out interest on the non-RAB backed debt. The allowed RAB at various dates will be

$$\begin{aligned} R_t &= kt, \quad 0 \le t \le T, \\ R_t &= K + \beta k^{'}(t-T), \quad T < t \le T+o, \\ R_t &= K(1+\beta\gamma), \quad T+o \le t \le O, \\ R_t &= K(1+\beta\gamma)(1-x/M), \quad x = t-O-T, \;\; 0 < x \le M. \end{aligned}$$

The resulting flow of receipts by the shareholders (contributions shown negative) in successive periods up to the date of commissioning will be

$$
\begin{aligned}
f_{1t} &= k((r-\alpha i)t-(1-\alpha))=(1-\alpha)k(st-1), \qquad 0\le t\le T, & (10)\\
f_{2t} &= (r-\alpha i)\{K+\beta k^{'}(t-T)\}-(1-\alpha\beta)k', \quad T\le t\le T+o, & (11)\\
f_{3t} &= (r-\alpha i)(1+\beta\gamma)K, \quad T+o\le t\le T+O. & (12)
\end{aligned}
$$

The first line is the flow of returns to and cost of the approved investment (noting that $r-\alpha i=(1-\alpha)s$ from the definition of the WACC), the second line is the return of the allowed share β of the cost overspend and the residual cost to shareholders after raising debt for the approved share up to the date when further investment is paid by the government, while the final line is the income less interest payments on the capped value of the RAB, which remains constant until commissioning. The RAB at that date will be the capped value $R=(1+\beta\gamma)K$, and this will be recovered over its remaining life at the agreed WACC, r. The resulting flow of funds to shareholders (out of which they need to repay debt) is equivalent to a permanent income stream of rR. The accumulated debt $\alpha(1+\gamma\beta)K$ (on which interest has already been paid to commissioning) can also be amortized over an infinite life and discounted to give an equivalent annual cost to shareholders of $\alpha i(1+\gamma\beta)K$. The term $(r-\alpha i)=(1-\alpha)s$ from the formula for the WACC, where s is the target real equity return and $K=kT$.

The internal rate of return to shareholders, σ, is value that makes the present discounted outlays equal to the PDV of receips (equations (15) to (17)) plus the discounted subsequent income stream net of debt (equation (13)) equal to zero:

$$
\begin{aligned}
0 &= \int_0^{T+O} f_t e^{-\sigma t}dt + e^{-\sigma(T+O)}\frac{(1-\alpha)s}{\sigma}(1+\beta\gamma)kT, \quad \text{where} & (13)\\
\int_0^{T+O} f_t e^{-\sigma t}dt &= \int_0^{T} f_{1t}e^{-\sigma t}dt + e^{-\sigma T}\int_0^{o} f_{2t}e^{-\sigma t}dt + e^{-\sigma(T+o)}\int_0^{O-o} f_{3t}e^{-\sigma t}dt & (14)\\
&= k(1-\alpha)\left((\frac{s}{\sigma}-1)\frac{(1-e^{-\sigma T}}{\sigma}-\frac{s}{\sigma}Te^{-\sigma T}\right) & (15)\\
&\quad +e^{-\sigma T}\left(\begin{array}{c} (1-\alpha)s\beta k^{'}\{\frac{oe^{\sigma o}}{\sigma}-\frac{e^{\sigma o}-1}{\sigma^2}\}+ \\ \{(1-\alpha)sTk-(1-\alpha\beta)k^{'}\}\frac{1-e^{-\sigma o}}{\sigma}\end{array}\right) & (16)\\
&\quad +(1-\alpha)s(1+\beta\gamma)kT\frac{e^{-\sigma o}-e^{-\sigma O}}{\sigma}. & (17)
\end{aligned}
$$

These expressions can be simplified by dividing through by k given a value for k'/k. Equation (14) can be solved for σ once $k^{'}/k$ and the other parameters r, i, α, β, T, and O are specified. If the over-spend does not reach the cap then only the first two lines of the RAB equations need to be integrated, or, equivalently, set $O=o$.

As a check, set $o=O=\beta=\gamma=0$, to confirm that setting $\sigma=s$ makes the equation zero. The second term in (13) is just $(1-\alpha)Ke^{-sT}$, which is the present value of equity, while the first term is (15) or

$$-k(1-\alpha)Te^{-sT} = -(1-\alpha)Ke^{-sT},$$

as required.

4.1 The worst-case cost to consumers

Cost over-runs impact consumers more heavily and raise their levelized cost. If all the Government equity support is allocated to consumers, the worst case can be evaluated as follows. The accumulated cost up to commissioning will an additional term (the investment over-run not borne by shareholders) of $Ok^{'} - \gamma K$, as well as the return on the RAB. If this process of meeting the publicly funded investment shortfall starts o years after the target date, T, this accumulated additional investment cost will be $k'(e^{\rho(O-o)} - 1)/\rho$, so the total accumulated cost will be:

$$\begin{aligned} A^* &= r\int_0^{T+O} R_t e^{\rho t} dt + \frac{k'(e^{\rho(O-o)} - 1)}{\rho}, \\ &= Ae^{\rho O} + r\int_0^{o} (K + \beta k^{'} x)e^{\rho x} dx + \{rK(1+\beta\gamma) + k^{'}\}\frac{e^{\rho(O-o)} - 1}{\rho}, \\ &= Ae^{\rho O} + \frac{rK(e^{\rho o} - 1)}{\rho} + \frac{r\beta k^{'}}{\rho}\frac{1-(1-\rho o)e^{\rho o}}{\rho} + \{rK(1+\beta\gamma) + k^{'}\}\frac{(e^{\rho(O-o)} - 1)}{\rho}. \end{aligned} \tag{18}$$

The post-commissioning discounted payments, F^*, are

$$F^* = (1+\beta\gamma)F, \tag{19}$$

while the discounted future output is the same as before, $\mu(1-e^{-\rho L})/\rho$, to give the worst case levelized cost to consumers as

$$\ell^* = \frac{\rho}{\mu}\frac{A^* + F^*}{1 - e^{-\rho L}} + c. \tag{20}$$

Other cases can be computed similarly using subsets of the RAB elements.

Symbol	Definition	example
α	debt share	70%
β	RAB increment	60%
γ	cap as fraction	30%
ρ	social discount rate	2%
μ	convert from kw to MWH/yr	8
σ	IRR to equity	calculate
c	variable cost	£22.50/MWh
D	depreciation/kWyr	R/M
i	debt interest	2%
k	investment rate	£500/kW
k'	over-run investment	£300/kW
K	target overnight cost	£5,000/kW
L	lifetime	60 years
M	contract length	35 years
o	over-run at cap	3 years
O	max over-run	8 years
p	strike price	calculate
P	wholesale price	£50/MWh
r	WACC	3.5%
ℓ	levelized consumer cost	calculate
s	equity return	calculate
T	plan construction	10 yrs

Table 1 Symbols and their definition

References

Newbery, D. M. (1997) 'Determining the Regulatory Asset Base for Utility Price Regulation', *Utilities Policy*, 6(1), 1-8.

Appendix Adjusting for payments at the end of the year

Continuous discounting as in the text effectively discounts from the middle of the year, while conventional accounting discounts payments made at the end of the year. For a continuous flow of funds a over T years at discount rate r the PDV is $a(1 - e^{-rT})/r$ but receiving the funds at the end of the year has present value $a(1 - (1 + r)^{-T})/r$. The ratio of the discrete flow to the continuous flow for $r = 5\%$ and $T = 30$ years is 0.99, so the difference is slight over longer time periods and modest discount rates. If $r = 10\%$, $T = 10$ years, the ratio falls to 0.97.