Hinkley Point C: Value for Money Assessment

1. This report sets out the UK Government's assessment on the value for money of the Hinkley Point C nuclear project.

2. The decision taken by the Secretary of State (SoS) for the Department of Business, Energy & Industrial Strategy on whether to direct the Low Carbon Contracts Company (LCCC) to offer a Contract for Difference (CfD) in relation to the Hinkley Point C (HPC) project was informed by the consideration of this Value for Money (VfM) assessment.

3. This VfM framework comprising four separate tests was developed and agreed by the Department's Chief Economist in 2011.[1] They are summarised below:

   (i) *Test 1* considers whether the CfD package offers a fair return to investors in HPC without overcompensating them given the true costs and risks faced by the project;

   (ii) *Test 2a* considers whether HPC is cost-competitive to other options for delivering power. It compares the Strike Price of HPC with the equivalent cost per MWh of alternative technologies capable of delivering low-carbon generation at scale in the 2020s;

   (iii) *Test 2b* considers whether HPC reduces the total cost of the GB electricity system out to 2050 to bring net social benefits.[2] Social benefits are assessed by comparing total electricity system cost scenarios where HPC goes ahead, to various electricity system cost scenarios where HPC is not delivered or significantly delayed while we continue to work towards our legally required low carbon targets. This test differs to Test 2a in that it considers additional impacts to society such as the limits of alternative technologies, security of supply, balancing & network cost.

   (iv) *Test 3* considers whether HPC is affordable to UK electricity consumers. Affordability is assessed by estimating the impact of HPC on household electricity bills and comparing this to the impact of various counterfactual scenarios where alternative types of generation had been built.

4. Having considered the analysis the SoS for Business, Energy and Industrial Strategy was satisfied that offering a CfD represented value for money.

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[1] The Chief Economist of the formerly titled Department of Energy and Climate Change.

[2] Social benefit is a collective term for all the combined impacts (benefits minus costs) of a policy option from the perspective of UK society as whole. If one policy has a greater level of social benefit (or smaller cost) than another it is said to have 'net' social benefits. These impacts are assessed using HMT Green Book appraisal techniques: https://www.gov.uk/government/publications/the-green-book-appraisal-and-evaluation-in-central-governent

Economic Rationale for Intervention

5. There are several market failures and other barriers to investment which affect investment in low-carbon generation in the UK. A market failure refers to where the market has not and cannot of itself be expected to deliver an efficient outcome. Market failures are present in low carbon investment; and intervention is needed to redress these – in the case of HPC, providing the project with a CfD.

6. Existing market arrangements will not deliver the UK's objectives of an optimal level of security and diversity of supply, decarbonisation, and affordability. The market failures exist both at a broad level – the market for electricity generation, resulting in under-investment in low-carbon generation; and at a narrow level – resulting in under investment in nuclear generation specifically.

7. At the broad level, these market failures include:

   (a) **Residual Carbon Externality** – by itself, the market would not reduce the production of greenhouse gases associated with fossil fuel combustion.

   While the UK Government has partially addressed this issue through the use of the EU Emissions Trading System and the Carbon Price Floor, the price of carbon emissions is neither high nor certain enough to reflect their full cost to society. Because these measures are exposed to political risk and the risk of investment holdup, they have two clear limitations, which result in a 'residual carbon emissions market failure'.

   Current governments cannot commit to the future of these measures, which inhibits efficient long-term private investment in low-carbon generation capacity. Furthermore if these measures are used in isolation to address the carbon externality[3], the carbon price would have to be set very high and therefore be subject to increased political pressure. Fossil fuel generators therefore do not face the full costs of their carbon emissions meaning that investors are not fully incentivised to invest in low-carbon generation, such as nuclear power.

   (b) **Lack of energy diversity and security of supply to GB** - nuclear investors do not get paid by the market for the full benefits of providing diversity in the electricity mix. Nuclear investors also do not get paid by the market for the full benefits of providing electricity security.

   Diversity of electricity supply sources is desirable from a resilience point of view to avoid over-reliance on a particular technology. Greater diversity generally makes the electricity system less susceptible to fossil fuel supply

[3] An externality occurs as a consequence of a transaction whereby a group not party to the activity is impacted. This unintended spill over effect on the group is referred to as the externality.

shocks. The market left to its own devices would likely favour one particular technology and not value energy diversity benefits to GB.

(c) **Insufficient incentives to invest in and develop immature technologies** – nuclear investors do not get paid by the market for the full benefits of reducing the costs of future nuclear power.

Nuclear projects are not favoured by the market, due to their initial cost premium. However, there are positive innovation externalities and learning effects associated with the deployment of First-of-a-Kind ("FOAK") projects or immature technologies that allow for significant cost reductions for future projects. In other words, offering a CfD to HPC would open up a new nuclear pathway. Private investors would not take account of the full option value of this pathway since much of the benefits would accrue to wider society.

Although nuclear is sometimes argued to be a mature technology, the technology of HPC is a new version technology that has been implemented only in a handful of cases. Moreover, no new nuclear plants have been built in the UK since Sizewell B was commissioned in 1995. Therefore, the construction of HPC is expected to bring innovation into the supply chain and technology developments that enable lower costs for future plants, helping to achieve the UK's affordability objective.

These benefits are not exclusive to investors in HPC, as other market participants will benefit significantly. However, without Government intervention developers are unlikely to invest new nuclear projects. .

(d) **Financial market constraints** – these make it difficult to raise very large sums for capital investment, such as that required for nuclear power. The funding market for investments in low-carbon capacity is affected by a market failure due to capacity constraints and by a resulting funding gap.

Since nuclear projects are relatively rare and have unique characteristics, the providers of capital are unlikely to be able to understand fully the details of nuclear projects and their risks, and where they are able to understand there would be large transaction costs associated with gaining such understanding.

8. At the narrow level, these market failures can be exacerbated by other barriers to investment which are particularly acute for new nuclear power:

(i) **Exposure to political risk** – developers face the risk that having made the investment they are prevented by future-government action from realising an appropriate return. This causes barriers to investment pertinent to long term horizon investments, such as nuclear power, which can be alleviated by a binding contract.

(ii) **Exposure to electricity price risk** - Low-carbon technologies, and nuclear in particular, are characterised by high upfront capital cost and low marginal operating costs. This is particularly acute for nuclear projects due to the large scale nature of single projects. Moreover, low-carbon technologies tend to be price-takers, and thus wholesale electricity prices are not correlated with the operating costs of low-carbon technologies, unlike fossil fuel generation, which benefits from a natural hedge (whereby revenues and costs are positively correlated).

Because of these reasons, investors in low-carbon technologies are exposed to significant price volatility risk. This is particularly acute for nuclear projects due to the large scale of single projects. This risk cannot be efficiently transferred, shared or pooled, because there are no markets for the transfer of this type of long-term commercial risks. In the presence of incomplete markets, investors will not be able to transfer or reduce the risk and thus will invest less than it would be desirable from a social welfare perspective.

9. The discussion of market failures above justifies the need for providing support to nuclear power. The following four tests assess whether the support is both proportionate and an appropriate means for delivering affordable, secure, low-carbon in light of alternatives forms of generation.

VfM Test 1 – fair return without over-compensating

10. Test 1 assesses whether the contract provides the developer with a fair return without over-compensating, given the true costs and risks faced.

11. BEIS undertook a Cost Discovery & Verification (CD&V) review. Its purpose was to:

    (a) assess HPC cost estimates prepared by NNB Generation Company HPC Ltd (NNBG[4]) and opine on their reasonableness; and,

    (b) assess NNBG's project delivery capabilities.

12. BEIS appointed expert advisors to perform work in relation to this analysis and assessment by BEIS: Leigh Fisher Limited acted as technical advisors to BEIS; KPMG LLP provided financial advice and a major projects focus; Lazard & Co. Limited provided financial advice in connection with certain matters relating to NNBG's projected return on investment, and; Willis provided insurance expertise.

13. The review was based on documentation provided by NNBG and considered the construction, operation and decommissioning and waste disposal phases of HPC. The CD&V review process has involved continuous engagement with NNBG since the advisors were appointed in 2012.

Cost estimates

14. The advisors concluded that given the cost estimates provided by NNBG at the time, the Strike Price that was agreed in October 2013 was 'reasonable' for a UK first of a kind European Pressurised Reactor (EPR) project.

15. Since the Strike Price was set, NNBG provided: an updated cost estimate and cost profiles based on updated design information, a revised construction schedule, updated pricing information from previous contractors, and updated exchange rate and inflation assumptions. This resulted in a higher total estimated construction cost, the increase being at NNBG's risk, since the Strike Price remains unchanged. NNBG also bears the risk of future changes in exchange rates and inflation rates and their impact on outturn costs.

16. Compared against construction cost benchmarks and detailed cost information provided by EDF from one of its other EPR construction projects at Flamanville, France, our technical advisors concluded that the total HPC construction cost estimate was within the expected range.

Reasonableness

17. Detailed analysis has been undertaken with the assistance of external advisors regarding the **rate of return** based on the risk profile agreed in the CfD, in the context of comparators, and then benchmarking the returns established in the

[4] NNBG is a company set up for the purpose of building HPC to be 66.5% owned by EDF, 33.5% owned by China General Nuclear Corporation.

Financial Model against those comparators in light of such risks. Establishing the risks involved within the project included consideration of both those risks unique to new nuclear, as well as those common to large scale project finance. As such, the rate of return would need to provide compensation for both categories of risk. Finally, benchmarking has been performed against large infrastructure investments made by unlisted funds, other electricity generation/large scale infrastructure projects, and regulated utilities settlements to ensure the rate of return from the project was reasonable.

18. On the bases of the agreed Strike Price, information provided on the costs of the project, the risk/reward allocation and benchmarks based on the latest market data, we consider, after having taken external advice, that the developer's forecast return on investment from the HPC project is reasonable from a financial point of view to the SoS and that reasonable steps have been taken to ensure that the LCCC receives its share of returns in excess of certain prescribed levels that are generated by NNBG.

Project delivery

19. The conclusions from the delivery review were that NNBG has created a project delivery organisation with the right skills and experience, and with appropriately developed delivery strategies that should allow it to deliver HPC to the intended timescales. This is assuming that NNBG can maintain the level of skills and experience within the organisation, demonstrated during the course of the review, and effectively deliver all aspects of the project in accordance with the current plan.

20. If NNBG do not deliver the project, they will not access any support payments. Additionally, if the plant commissions after the agreed commissioning window, the length of the CfD will be reduced by a corresponding number of days. Therefore some of the financial risks to consumers have been mitigated through the design of the CfD.

VfM Test 2a – cost-competitiveness

21. In Test 2a we assess whether the Strike Price for HPC is cost-competitive with the equivalent cost per MWh of alternative low carbon generation technologies which are capable of delivering at scale in the 2020s. Those technologies are: offshore wind, fossil fuel generation equipped with Carbon Capture and Storage (CCS), onshore wind, large-scale solar PV (installations larger than 5MW) and gas CCGT (including the cost of carbon emissions).

22. The test achieves this by comparing the unit cost of generation under the CfD with the equivalent costs for developers of those technologies deploying at the same time as HPC. It is important to note that Test 2a does not fully capture the cost of a like-for-like replacement of HPC as a provider of firm or 'reliable' capacity[5] out from the 2020s to the 2080s, the value of diversity in the generation base, and the option value for further new nuclear that HPC unlocks. These issues are covered and monetised where possible in Test 2b.

23. To create the 'strike price comparator', a levelised cost for each technology has been estimated, with additions for other costs (as shown in table 1) to make the levelised cost more comparable with the cost of the HPC Strike Price under the CfD contract. The costs are for new plant commissioning in 2025, the same year that HPC is expected to commission. A range is given in parentheses for each Strike Price comparator to illustrate the degree of uncertainty for these technology costs.

24. These result in Table 1 show that the cost of HPC is towards the lower end of the comparable cost range of CCS (£77-249/MWh); towards the lower end of the comparable cost range of offshore wind (£81-132/MWh); at the top of the comparable cost range of gas CCGT (£47-96/MWh); and above the comparable cost ranges for both large-scale solar PV (£65-92/MWh) and onshore wind (£49-90/MWh).

25. The cost of HPC has not been compared against the cost of other alternative new nuclear technologies because no robust data on the costs of deploying these technologies in the UK is available. Other new nuclear projects in the UK are intending to use alternative reactor technologies, but these projects are much less developed than the HPC project and it would be premature to provide estimated costs.

[5] Firm capacity refers to generation that can be controlled to match times of high demand.

Table 1: Test 2a results, figures rounded to nearest £1, except where below £1.

Real 2012 £/MWh	Levelised cost of Electricity	Other costs[6]	Strike Price comparator	HPC Strike Price
Gas CCGT	£71 (£47-95)	£0.3 for TLM + £0.1 for land costs = £0.4	£72 (£47-96)	
Onshore wind	£65 (£48-79)	£0.5 for TLM + £6 for extra system costs = £6 (£0-11)	£71 (£49-90)	
Large-scale solar PV	£63 (£55-75)	£0.5 for TLM + £13 for extra system costs = £14 (£11-17)	£77 (£65-92)	£92.50[7]
Offshore wind[8]	£*85*, (£80-120)	£0.8 for TLM + £6 for extra system costs = £6 (£1-12)	£*91* (£81-132),	
Commercial FOAK CCS	£153 (£75-246)	£0.8 for TLM + £2 for land costs = £2	£155 (£77-249)	

Source: BEIS analysis. Totals may not sum due to rounding. Assumed commissioning date of 2025 for all technologies. Neither levelised costs nor the strike price comparators account for CfD duration, wholesale prices or Power Purchase agreements. Note that extra system costs exclude technology or location specific network costs beyond those included in averaged static network charges in the estimated unit cost of electricity – Levelised Cost of Electricity. It also excludes balancing benefits brought about by gas CCGT. These excluded costs are accounted for in Test 2b where possible.

26. Around £17/MWh of the CCGT comparator cost is made of the market cost of carbon, and discarding it would reduce the strike price comparator to £54/MWh. However, if carbon was priced at its social value, the strike price comparator rises to £86/MWh.[9] Separately, as CCGTs can provide flexible generation, they are likely to

[6] Other costs include: the transmission loss multiplier (TLM) i.e. the cost of lost output during network transmission; extra system costs including additional balancing costs for onshore and offshore wind, and system integration costs for large-scale solar PV; and land costs.
[7] A Strike Price of £92.50/MWh applies if Sizewell C does not go ahead. £89.50/MWh will apply if Sizewell C does go ahead.
[8] Offshore Wind estimates are a combination of two sets of strike price comparators: the first consistent with our independent evidence from ARUP and NERA (see Annex 1); the second where a higher learning rate for cost reduction is applied to these costs so that the central estimate is consistent with the government's CfD auction strike price cap as set out in the March 2016 Budget (Para 1.246 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/508193/HMT_Budget_2016_Web_Accessible.pdf) The auction Strike Price cap for 2025 is given in italics and set at £85 in 2025.
[9] The social cost of carbon encapsulates the full cost of damage that an incremental unit of carbon emitted today will impose over the whole of its time in the atmosphere. It is a measure of the unaccounted cost that needs to be incorporated into our decisions on policy and investment. This is different to the market price, which reflects the value of traded carbon emissions. See https://www.gov.uk/government/collections/carbon-valuation--2

bring larger balancing benefits to the system than nuclear.[10] By taking this into account the CCGT strike price comparator would appear further cheaper relative to HPC.[11] However, by relying on CCGT it would be difficult to reach current carbon ambitions as set out in Test 2b.

27. The extra system costs of intermittent technologies (in addition to levelised costs) could be lower than the central scenarios presented here for Test 2a, should for example further storage or DSR technologies be deployed cheaply at large-scale over and above that assumed. However, system costs could also be significantly higher; system costs added for wind do not account for extra capacity costs, nor location specific network costs beyond those included in averaged static network charges in the levelised cost of electricity (LCOE) estimates for example.

28. Approximately 9GW of onshore wind would be required to produce the same average annual generation as HPC. BEIS considers this scale of onshore wind to be technically feasible in the 2020s, but it would require significant developments to the grid, incurring upgrade costs, as well as appropriate planning regulation, policy support and public acceptability to ensure the fast rate of deployment of this decade continues into the next. However, it is considered unlikely that the 27GW of additional large-scale solar needed to replace HPC could be deployed in the 2020s due to planning and grid constraints. That noted, as deployment levels towards the upper end of the deployment potential band cannot be ruled out, and as large-scale solar PV could form part of a mixed counterfactual to HPC, large-scale solar PV has been included as a comparator.

29. On the basis of the preceding analysis, it can be said that the costs of HPC are competitive with those costs of alternative low-carbon large-scale technologies in the mid-2020s. As explained in Test 2a, technology or location specific network costs beyond those included in averaged static network charges also need to be taken into account. If such impacts were included, HPC is expected to become more competitive particularly against onshore and offshore wind as these technologies are often located in more remote locations to harness higher wind speeds and are therefore associated with higher network costs.

[10] Load factors for CCGT could be higher than the central case here, e.g. if fossil fuel prices and/or the Carbon Price Support are lower than assumed or there is less low-carbon capacity in the market. However, they could also be lower, e.g. if fossil fuel prices were higher or there is more low-carbon capacity. Arguably, the conservative approach taken to choosing CCGT load factors means there is more risk of them being lower than the central case than there is of them being higher.

[11] Arguably in relation to extra system costs, there is more potential upside for the HPC VfM case than downside, because test 2a analysis does not account for all aspects of extra system costs. In addition, the gas CCGT comparator costs could be lower, as test 2a does not account for the potential extra system benefit compared to nuclear due to the extra flexibility it provides.

VfM Test 2b – social cost-benefit analysis

30. This section uses BEIS's Dynamic Dispatch Model (DDM) to test the total electricity system costs of a scenario where HPC goes ahead against the electricity system costs of various counterfactual scenarios where the nuclear programme is delayed, by either three or ten years.

31. The counterfactuals used here represent two of the many possible reactions of new nuclear developers of a decision not to proceed with HPC. The three-year delay counterfactuals represent scenarios where the Government does not offer HPC a contract but developers remain relatively confident in the Government's policy framework and commitment to new nuclear. The 10-year delay represents a scenario where Government needs to agree a new process/framework for nuclear if the CfD framework failed for HPC, and investors in nuclear power lose a significant degree of confidence, leading to a substantial delay in the new nuclear programme.

32. The scenario where HPC goes ahead is considered the reference case.[12] The counterfactuals in the table below generally focus on meeting decarbonisation targets through deploying additional low-carbon technologies. This requires CfD Strike Prices to be increased from what they are in the reference case. The exception to this is the counterfactual where gas generation fills the nuclear generation gap, which is unable to meet the same level of decarbonisation out to 2050.

The **Dynamic Dispatch Model** (DDM) is a comprehensive fully integrated power market model covering the GB power market over the medium to long-term. The model enables analysis of electricity dispatch from GB power generators and investment decisions in generating capacity from 2010 through to 2050. It considers electricity demand and supply on a half hourly basis for sample days. Investment decisions are based on projected revenue and cashflows allowing for policy impacts and changes in the generation mix. The full lifecycle of power generation plant is modelled, from construction through to decommissioning. The DDM enables analysis comparing the impact of different policy decisions on generation, capacity, costs, prices, security of supply and carbon emissions, and also outputs comprehensive and consistent cost-benefit analysis[13].

The DDM is also able to endogenously model the Balancing Mechanism (BM), some of the most important System Balancing services and network costs and their feed-through to charges. The BM functionality procures generation bids and offers to smooth out supply and demand uncertainty, while the System Balancing functionality does the same to meet certain system requirements (e.g. sufficient inertia or reserve), thereby offering additional revenues to participating

[12] The reference case represents a plausible diversified and economic pathway for decarbonising the GB power sector out to 2050, given the latest fossil fuel price, carbon price, and technology cost, hurdle rate, and deployment assumptions. Strike Prices increased to ensure additional deployment can be supplied through the market. The role of battery storage is included in the reference case.

[13] For more information see: https://www.gov.uk/government/publications/dynamic-dispatch-model-ddm; and Annex A of the EMR Delivery Plan Impact Assessment: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/288463/final_delivery_plan_ia.pdf

plants. The network cost functionality determines the overall length of the network by measuring system dispersion of generation and demand[14].

Table 2: Test 2b summary, estimates rounded to 3 significant figures.

£m in real 2012 prices, discounted to 2012 Counterfactual – what delay to nuclear, and what alternative generation	Net social benefit of no delay to HPC, cumulative to 2030	Net social benefit of no delay to HPC, cumulative to 2040	Net social benefit of no delay to HPC, cumulative to 2050
Three-year delay – more offshore wind and CCS *offshore wind costs consistent with announced CfD auction price cap*	**£7,300**	**£18,000**	**£19,400**
Ten-year delay – more offshore wind and CCS *offshore wind costs consistent with announced CfD auction price cap*	**£17,000**	**£43,700**	**£52,300**
Three-year delay – more gas plant	**-£3,200**	**-2,900**	**-£830**
Three-year delay – more onshore wind and large-scale solar PV	**£3,600**	**£10,900**	**£11,700**

Source: BEIS analysis. See ***Annex*** *for details of underlying assumptions.*

33. The first row of the table above uses a counterfactual of a three year delay in the nuclear programme with increased generation from offshore wind and CCS[15] filling the gap. Enough offshore wind and CCS is brought forward to ensure the counterfactual scenario reaches the same falling level of electricity grid carbon intensity in 2040 and in 2050, as the scenario with HPC.[16] The net social benefit of bringing forward HPC compared to this counterfactual is calculated to be £7.3bn cumulatively to 2030, £18bn to 2040 and £19.4bn to 2050 (real 2012 prices, discounted to 2012). Offshore wind has higher associated network and balancing costs and CCS has higher generation costs, which drive the increased cost of this counterfactual compared to the scenario with HPC.

[14] The model allows for negative wholesale prices, meaning the model can assign dispatch/curtailment in periods when there is an excess of supported low-carbon generation in a more appropriate way. It is, however, worth noting that there are modelling limitations and there is considerable uncertainty about which plants/technologies would reduce their generation and by how much. In addition, the model cannot model locational curtailment.

[15] It assumed that Carbon Capture and Storage is available to be deployed in the UK from 2035 onwards and is able to provide around 21GW of capacity in 2050.

[16] It was not possible under assumed build rates for any of the scenarios to achieve the same level of emissions intensity in 2030 that would have been achieved with nuclear under the reference case.

34. Compared to a counterfactual following the same principles but assuming a 10-year delay to new nuclear, the net social benefits cumulatively to 2050 of no delay to HPC is estimated at £52.3bn.

35. The offshore wind and CCS counterfactual analysis in Table 2 incorporates a high implied learning rate for offshore wind cost reduction, consistent with the Government's CfD auction strike price cap as set out in the March 2016 Budget. In an alternative scenario, where we have applied our independent cost estimates for offshore wind, consistent with our approach for modelling other technologies, bringing forward HPC compared to the three year delay counterfactual met by offshore wind and CCS will lead to greater net social benefits of £10.5bn cumulatively to 2030, £25bn to 2040, and £25bn to 2050.

36. Compared to a counterfactual scenario where gas plant is assumed to fill the gap caused by a three-year delay to the nuclear programme, there is a net social cost of building HPC to 2050 of around £0.8bn. Meeting security of supply with new build, more flexible gas in the absence of nuclear is potentially more cost effective as system balancing costs are lower. However, a gas counterfactual would not deliver as much decarbonisation as the HPC scenario. This undermines the decarbonisation efforts of sectors outside the EU ETS, and thus the UK's ability to meet its legally binding carbon targets potentially leading to a more costly overall means of achieving economy wide decarbonisation.[17] Additionally, the analysis does not take into account some significant un-monetised benefits to HPC beyond 2050, including the avoided capital cost of replacing the gas fleet (HPC is expected to operate until 2084) and avoiding the rising carbon costs of gas over time.

37. The analysis uses BEIS's central fossil fuel price projections although there is considerable uncertainty over future long-term fossil fuel prices.[18] Under BEIS's high fossil fuel price projections gas CCGT generation is more expensive and the net social cost of HPC to 2050 turns into a net social benefit of £5.2bn. Under BEIS's low fossil fuel price projections, the gas CCGT generation counterfactual scenario is cheaper by around £4bn to 2050.

38. Compared to a counterfactual where onshore wind and large-scale solar PV fill the gap, there is a net social benefit of bringing forward HPC which cumulatively reaches £11.7bn by 2050. Onshore wind has higher associated transmission costs and both onshore and solar attract higher costs in the balancing market which accounts for the uncertainty in their generation. The results of the analysis against this counterfactual

[17] See the 'Committee on Climate Change, The Fifth Carbon Budget – the next steps towards a low-carbon economy (2015).

[18] Draft BEIS fossil fuel price projections as of May 2016. It is important to note that fossil fuel price sensitivities are presented to illustrate the particular uncertainty around gas fuel prices, carbon prices and renewable costs. Higher fossil fuel prices would strengthen the case, while lower fossil fuel prices would weaken it. On the basis of BEIS's projections this can be considered a symmetrical risk. However, this does depend on the view of future global gas prices trends and the future of shale gas, for example.

also need to be assessed in light of the constraints on onshore wind and large-scale solar PV deployment in the 2020s mentioned under test 2a above.[19]

39. Up until 2035, we do not expect to see significant changes in electricity demand. However, beyond 2035, electricity demand will be highly dependent on how we choose to decarbonise the economy as a whole. In our central modelling analysis we have assumed that demand rises substantially beyond 2035, reflecting one possible pathway for decarbonising the wider economy and being a prudent basis for retaining decarbonisation options. Alternative pathways might suggest a more gradual increase in electricity demand than in our central analysis. To test the materiality of demand uncertainty we looked at a state-of-the-world where long-term electricity demand remains flat at its 2035 level, and compared a scenario where HPC is built on time to a three-year delay scenario with generation met by offshore wind. This showed there remains a significant large cumulative net social benefit of around £16.6bn out to 2050 (around £2.8bn lower under the central analysis) within a low-demand environment.

40. In addition, there are significant potential un-monetised benefits relating in particular to: HPC's impact on the UK nuclear supply chain and the associated wider economic impacts that these jobs create; avoiding air quality costs associated with fossil fuel generation; and macroeconomic benefits of lower electricity prices and bills. The probability of nuclear liabilities arising, particularly in relation to the risks of a catastrophic accident, is estimated to be very small by EDF/Areva in their probabilistic safety analysis for the EPR reactor's Generic Design Assessment, analysis which the Office for Nuclear Regulation found acceptable.

41. The characteristics of nuclear power are different from those of conventional fossil fuel and provide specific advantages with regards to energy security. An interruption in the supply of gas or coal is unlikely to affect the supply of uranium. Consequently, including new nuclear power stations in the generating mix increases the diversity of the fuels on which we rely to generate electricity. Unlike gas, fluctuations in fuel prices do not significantly affect the cost of electricity from nuclear power stations, and the power stations themselves can continue to operate for long periods of time without refuelling. New nuclear power stations will therefore reduce exposure to the risks of fossil fuel supply interruptions and of sudden and large spikes in electricity prices that can arise when a single technology or fuel dominates electricity generation.

42. In turn there may be deliverability risks associated with the EPR technology. Recent experience in construction of EPRs in Flamanville, France and Olkiluoto, Finland has shown repeated delays to the anticipated first operational date of the respective reactors, which could be replicated with HPC. We expect some degree of learning to

[19] Innovation and learning could be higher or lower than the central assumptions presented with respect to the emerging technologies of offshore wind, solar PV and CCS.

have been taken into account in both construction schedules and the manufacture of components intended for the planned new reactor at HPC. Additionally, as test 2b demonstrates, if it is possible to build gas in the event of delays to retain security of supply, there may be wider system benefits from this although it may undermine decarbonisation efforts

43. In summary HPC was found to deliver net social benefits out to 2050 against all low-carbon counterfactuals and a small net social cost when compared to a gas counterfactual. The benefit from HPC to these counterfactual ranges from around £-0.8bn to over £52bn out to 2050.

VfM Test 3 – affordability

44. Under the CfD, HPC will receive top-up payments accounting for the difference between the contract strike price of £92.50/MWh[20] and the reference (wholesale electricity) price. The CfD for HPC insulates consumers from construction cost risk as the developer will pay if the cost of building the plant goes over budget. If the plant comes in under budget, then consumers stand to gain through the construction gain-share by means of either a lump sum or a downwards adjustment to the Strike Price.

45. The appropriate means for testing affordability impacts on consumers is by comparing the whole consumer electricity bill under different scenarios. By contrast, a comparison of the top-up payments for the HPC project under different scenarios is an inferior measure of affordability; support costs are only one part of a consumer's electricity bill and only partially reflective of the costs of decarbonisation.[21]

46. If Hinkley is delayed by three years and we need offshore wind and CCS to fill the gap, it would lead to a £24 annual increase on average household electricity bills from 2026-2030 (2012 prices). Similarly, if we need onshore wind and large-scale solar PV to fill the gap, consumer bills would increase annually by £21. Gas CCGT coming on to fill the gap would see bills £6 cheaper per year, but this would undermine the UK's ability to meet legally binding decarbonisation targets. [22]

Table 3: Consumer Bill Impacts (2012 prices, average impact from 2026-2030).

Scenario	Consumer Bill Impact
3yr delay gas	**-£6**
3yr delay offshore/CCS	**+£24**
3yr delay PV/onshore	**+£21**

Source: BEIS analysis

47. Top-up payments for the Hinkley Point C CfD paid by consumers will depend on what happens to wholesale prices. In the first three years of the plant's operation, from 2025/26, top-up payments are expected to be approximately £580m, £860m and £860m, respectively (in 2012 prices, undiscounted, to two significant figures), using a

[20] Real 2012 prices. Figure reduced to £89.50/MWh if a final investment decision is reached on Sizewell C.

[21] The wholesale market (from which support costs are derived) is not a market for costing investment in future low-carbon electricity; the wholesale market enables generation technologies to dispatch in an efficient order (in terms of their marginal cost) and forms just one *revenue* stream for investors. The wholesale market price largely reflects these short-term, marginal costs of existing generation whose investment costs have been sunk. Generators can and will seek to cover the *costs* of their investment through other means, whether this is through participating in balancing market services, seeking renewable support contracts or Capacity Market agreements amongst other means. All these costs are recovered through consumer electricity bills. The particular project costs of future low-carbon generation that developers seek to recover are set out in Test 2a.

[22] We have omitted 2025 in the calculation of bill impacts as the two reactors from HPC will not operate throughout the full year given their staggered commissioning dates.

central scenario for wholesale prices. These support payments up to 2030 would make up around £12 of an average annual household electricity bill.[23]

48. There is significant uncertainty over future wholesale prices, which feed directly into the level of top-up payments for HPC (or payments back to the LCCC). Table 4 below shows the lifetime top-up payments under different wholesale price scenarios. In addition, as HPC would be eligible to receive payments through the Capacity Market if it was not getting a CfD, Table 4 below shows support payments net of capacity payments.

Table 4: Support payments for HPC, estimates rounded to 3 significant figures (2012 prices).

NPV, £m (discounted to 2012 at social discount rate)	Top-up payments	Net support payments (top-up payments minus foregone capacity payments
High fossil fuel prices and rising carbon prices post-2030	**£10,600**	**£9,900**
Central fossil fuel prices and rising carbon prices post-2030 (the reference case)	**£12,200**	**£11,500**
Low fossil fuel prices and flat carbon prices post-2030	**£21,400**	**£20,700**

Source: BEIS analysis

[23] The average support cost for consumers is calculated by taking the difference between the HPC Strike Price and the central projection of the wholesale price and attributing this to the share of electricity consumed by each household (i.e. the division of household electricity demand into total electricity demand). Note that collectively all households consume less than half of all electricity generated in the UK.

Annex 1: The Evidence Base

	Renewable technologies	Non-renewable technologies
Capital costs	Arup	LeighFisher
Operating costs[24]	Arup	LeighFisher
Fuel costs	N/A	BEIS draft fossil fuel price projections
Carbon prices	N/A	For gas and coal, the total carbon price is the sum of BEIS's 2016 EU-ETS carbon price projections (forthcoming) and the level of Carbon Price Support. This latter is assumed at £18/t to 2019/20, and then the total CPF remains constant in real terms. The projected rising EU ETS price exceeds the CPF from the mid-2020s, and reaches around £35/t in 2030 (in 2012 prices).[25] [Beyond 2030, two scenarios are considered: one, where the total carbon prices remain flat in real terms at roughly £35/t; and the other where they increase to reach around £200/t in 2050.[26]]
Efficiencies	Arup	LeighFisher
Capacity Factors	National Grid, EMR Electricity Capacity Report May 2016.[27]	
Technology specific hurdle rates	NERA Economic Consulting and BEIS (forthcoming)	
Net load factors	Availabilities28 from Arup, gross load factors from Arup and BEIS analysis using the Dynamic Dispatch Model	Availabilities from LeighFisher, gross load factors from BEIS using the Dynamic Dispatch Model
Transmission Loss Multiplier	0.81%, National Grid	
Land costs	N/A	LeighFisher
Extra system costs	Additional balancing costs from Redpoint[29] (2013) used for onshore wind and offshore wind. System integration costs from	

[24] Includes Transmission Network Use of System charges and Balancing Service Use of System charges.
[25] HM Government is currently reviewing the Carbon Price Support policy.
[26] The rising carbon price scenario to from £35/t in 2030 to £200/t in 2050 assumes there is a global deal on climate change mitigation and a global carbon market emerges. As cheaper greenhouse gas abatement opportunities are progressively used up, the carbon price is expected to rise. The flat carbon price scenario is an illustrative alternative scenario.
[27] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/47/Electricity%20Capacity%20Report%202016_Final_080716.pdf
[28] Availability is defined as the proportion of a year that a power station is available to generate (i.e. net of planned and unplanned outages). The gross load factor is the proportion of that available time in which the plant generates, which is determined in the wholesale electricity market (which BEIS models through its Dynamic Dispatch Model). The net load factor is the product of availability and gross load factor.
[29] Redpoint, 2008, *Implementation of the EU 2020 Renewables Target in the UK Electricity Sector: Renewables Support Schemes*, pp 83-84

	Imperial (2013) used for large-scale solar PV.[30]	

- Note all analysis is presented in real 2012 prices.
- The low and high ranges for the comparators in test 2a use high and low capital cost estimates (including pre-development cost ranges) from the Leigh Fisher, Jacobs and Arup publications, as well as high and low fuel costs from BEIS's 2016 fossil fuel price projections.
- The CCGT comparator is run slightly differently to the other comparators in test 2a. Its central value is an average of 18 different scenarios, consisting of all combinations of:
    - 3 different net load factor scenarios (running at full availability, 93%; running according to the DDM load factors in the plant's first two maintenance cycles (2025 to 2036: 50%); and running according to the DDM load factors over its 25-year lifetime (2025 to 2049: 38%); and,
    - 2 different carbon price scenarios after 2030 (see table above); and,
    - 3 gas fuel price scenarios (BEIS's 2016 low, medium and high gas fuel price projections), with the low, central and high scenarios combined with the respective low, central and high capex costs.
- Its low and high values are the lowest and highest of the 18 different scenarios.
- The Offshore Wind Strike Price comparator is a combination of two ranges - one consistent with our independent evidence from ARUP and NERA; another with a higher applied learning rate for cost reduction such that the central estimate is consistent with the government's CfD auction strike price cap as set out in the Government's March 2016 Budget.

[30] Imperial College, London, 2013, *Grid integration cost of photovoltaic power generation*