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A study of cost uncertainty

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Cost trajectories of low carbon electricity generation technologies in the UK:

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Abstract

Cost uncertainty has latterly come to be presented in the UK's Department of Energy and Climate Change (DECC) Levelised Cost of Electricity (LCOE) estimates using sensitivities; 'high' and 'low' figures presented alongside central estimates. This presentation of uncertainty is limited in its provision of context, and of an overall picture of how costs and uncertainty vary over time. Two analyses are performed using the published DECC cost estimates for three electricity generation technologies – nuclear, offshore wind and Carbon Capture and Storage (CCS). The first analysis analyses cost trajectories from selected DECC LCOE estimates and presents them alongside contextual data, resulting in *contextual cost landscapes*. The second evaluates the associated *temporal estimate uncertainty* in the decade 2020-2030; an approach aimed at capturing the temporal consistency of estimates, alongside variations in magnitude. Nuclear estimates are found to be both the most consistent and lowest in magnitude. Offshore wind and CCS suffer from comparatively large cost and uncertainty premiums. The implications for the direction of policy are then discussed in the context of conflicting past experience and hidden costs.

1. Introduction

As the *energy trilemma* – the need for decarbonisation, security of supply and affordability – looms, policy-makers scramble to identify an energy supply mix that makes sense. The electricity sector is at the heart of this effort, as it is hoped a growing proportion of low carbon supply can be delivered via this energy carrier in the future. Uncertainty is a key factor in determining electricity generation costs. Cost estimation, particularly aspects concerning methodologies, is a frequent topic for discussion [UKERC, 2013]. However, revealed cost uncertainty is rarely placed at the focus of these studies. In advance of investing in a new installation, one can be relatively sure about the degree to which GHG emissions will be abated, or the extent to which it will enhance or diminish energy security. The cost apex of the trilemma on the other hand, remains perennially accompanied by uncertainty.

The relevance and usefulness of cost estimates is increased when their context is understood. The first component of this work composes *contextual cost landscapes* which present the UK’s Department of Energy and Climate Change (DECC) Levelised Cost of Electricity (LCOE) estimates as estimate trajectories, in the context of historic and future estimates, and actual (*out-turn*) costs. The second component is a numerical analysis of the estimate trajectories, which embodies a new approach to measuring and communicating uncertainty. It is intended that this new measure capture the degree of consistency (or variability) of the DECC LCOE estimates over time, alongside variations in cost magnitude. This is premised on the notion that the temporal consistency of an estimate’s magnitude is one indication of the overall levels of certainty embodied in it; something that is often overlooked with conventional uncertainty measures.

Three technology groups – nuclear, offshore wind and CCS (carbon capture and storage) – have been selected, which together constitute a spectrum of cost uncertainty and deployment progress in the UK (see Table 1). Contemporary nuclear generation – principally represented by Pressurised Water Reactors (PWRs) – is a well-established technology, with several years of operational experience accrued to date across several countries (despite well publicised problems at the two plants currently under construction in the EU). Though in its infancy, offshore wind generation is a technology that is gaining momentum, with the UK now the world leader in terms of installed capacity [GWEC, 2012, p.64]. Finally, Carbon Capture and Storage (CCS) is truly a First-of-a-Kind (FOAK) technology in the UK, with initial commercial-scale installations planned for the mid-2020s. Whilst the selected technologies do not constitute the whole gamut of generation options, together they are adequate for exploring a range of uncertainty and demonstrating the methodology.

Table 1

Summary of technology groups and sub-groups.

Technology groups	Technology sub-groups
Nuclear	PWRs
Offshore Wind	Round 2 (R2)
	Round 3 (R3)
CCS	Advanced Super Critical (ASC) Coal + CCS
	Integrated Gasification Combined Cycle (IGCC) Coal + CCS

The UK has ambitious legally binding targets for the decarbonisation of its economy. These involve a 34% reduction of CO₂ emissions by 2020 on 1990 levels extending to almost 50% by 2025 and on to 80% by 2050. The electricity sector is scheduled for approximately 90% decarbonisation by 2030 if these wider targets are to be met. 2020-2030 is therefore a crucial decade for low carbon electricity installations: This is the period when Hinkley Point C and possibly Sizewell C nuclear power stations, several major R2 and R3 offshore wind installations and the first commercially viable CCS plants are forecast to be commissioned. Hence the importance of examining the

published government cost estimates on three of the most promising technologies for decarbonising the electricity sector, in this period.

In section 2 we discuss the methodology we use to examine reported costs in the rest of our study. Section 3 presents the resulting analysis of reported costs, while section 4 discusses the implications of the reported cost analysis for each of the three technologies in turn.

2. Methods

2.1 Review of relevant literature and data sources

The first analysis presents the future cost estimates for each technology group alongside relevant contextual information, including historic and projected wholesale costs and out-turn approximations for existing installations. The core data set is the LCOE estimates which were first produced in 2010 by a consultant on behalf of DECC. A summary of the reports used is provided Table 2.

Table 2

Summary of primary data sources.

Author	Year	Technology data used	Source
Mott MacDonald	2010	Nuclear, Offshore Wind, CCS	[MacDonald, 2010]
Arup	2011	Offshore Wind	[Arup, 2011]
DECC	2012	Nuclear, Offshore Wind, CCS	[DECC, 2012]
DECC	July 2013	Nuclear, Offshore Wind, CCS	[DECC, 2013c]
DECC	December 2013	Nuclear, Offshore Wind, CCS	[DECC, 2013b]

The data in these reports are presented in a number of different ways, and for a number of different scenarios and commissioning dates. To enable a like for like comparison, a consistent set of criteria had to be imposed in the selection process. Firstly, only figures calculated using a 10% discount factor are included. Secondly, where a number of different ‘high’ and ‘low’ estimates were available, only those where the CAPEX portion of the cost varied, were selected.

In the earlier reports, low and high estimates for each technology were not directly provided. DECC kindly provided the authors with assistance in calculating values for the years in which they were omitted, in line with the methodology used to calculate them in the later reports. High and low estimates used in this analysis only take into account a CAPEX variation, whereas the complete range of estimate sensitivities provided by DECC vary in their composition between reports. Therefore, central estimates could be used to calculate high and low values by substituting the central estimate for the CAPEX component, with a high and low CAPEX component estimate respectively. Helpfully, this CAPEX sensitivity range was provided in the earlier publications, where final levelised cost sensitivities were not. The other costs components (such as OPEX and decommissioning costs; depending on the technology) were left unaltered in each case.

All of the data are adjusted for inflation. An index year of 2012 was chosen, as this is the year that the strike price for the first next-generation nuclear power plant (Hinkley Point C) is indexed to. The latest reference tables (March 2014, at the time of the analysis) were obtained from the Office for National Statistics to perform these adjustments [ONS, 2014]. Given that some of the secondary data preceded the implementation of the Consumer Prices Index (CPI), it was decided that the

Retail Prices Index (RPI) was to be used.¹ The LCOE figures selected from the levelised cost reports could be individually adjusted, according to the year in which they were published. Average annual figures were used for the 2010, 2011 and 2012 reports, whereas monthly index values were used to deflate the two sets of figures from the 2013 reports.

The estimate dates are not to be confused with the date used as the *x*-axis plotting variable: the proposed (or actual) commissioning date. All LCOE estimates produced in the reports have a corresponding commissioning date, although this is not always presented explicitly in the reports. Often the information is presented relating to a *project start* or *financial close*. In these cases, the pre-development and construction periods needed to be added to these dates as appropriate, in order to determine the commissioning date.

The LCOE data points were plotted together in a continuous data series to form cost trajectories, rather than isolated points in a scatter plot. As there is a varying amount of information available for each technology in each report, these trajectories are formed from a varying amount of data points. For example, in the 2011 Arup report only two estimates were selected for Round 2 (R2) and Round 3 (R3) offshore wind, covering a period of six years. In contrast, both the 2013 DECC reports yielded seven estimates for each of these sub-groups, covering a period of sixteen years. This variation in the estimate coverage may provoke a concern as to the relative weight that is fair to lend to each report, however we wished to make use of as much of the available cost information published by DECC as possible.

2.2 Data: Contextual cost landscapes

2.2.1 Historic and projected wholesale costs

Historic wholesale price data was not available from a single source due to a modification to electricity trading arrangements in March 2001 [Simmonds, 2002, pp.2-10]. Following the New Electricity Trading Arrangements (NETA) of 2001, electricity transitioned from being traded in a ‘pool’ to being traded via electricity exchanges. The aim of this transition was to enable consumers further down the supply chain to participate in the price-setting mechanism, rather than solely the large companies bidding in the price pool, thereby increasing competition [Tovey, 2003]. Between January 1990 and March 2001 pool price data was obtained from the UK Energy Research Centre [UKERC, 2014]. Price data following March 2001, up to March 2014 was obtained from one of the leading power exchange companies [APX, 2014]. In the case of the data compiled by UKERC, pool purchasing prices were extracted in half-hourly intervals for the 11-year period, whereas daily averages were provided directly for the period covered by APX. Quarterly averages of these data were taken and adjusted for inflation to 2012 prices. The middle month of each quarter was used as the inflation reference point.

A second wholesale cost profile was created in order to indicate the hypothetical impact on historic prices of a levy on CO₂ aimed at decarbonising electricity generation. This was done by modifying the historic cost profile to incorporate the cost of CO₂ emissions incurred in generation under a hypothetical scenario envisaged for the future. The hypothetical cost scenario is based upon the European Union Emissions Trading Scheme (EU-ETS), specifically an average of the upper estimates of prices for a European Union Allowance (EUA) in 2020 and 2030.

¹ The Hinkley Point C strike prices are indexed using the CPI, so this would have been preferable to use in the analysis. However, the necessary trade-off would be the inconsistency and complexity of using two indices, leading to confusion. Resultantly, the RPI, with its comprehensive coverage of the analysis period, is used throughout.

In a report for HM Treasury, price scenarios of £20-40/EUA in 2020 and £70/EUA in 2030 are assessed against a baseline [HM Treasury, 2010, p.27]. An average of the £40/EUA and £70/EUA figures was taken, and adjusted for inflation from the 2009 prices in which they were forecast, to the 2012 index year. This resulted in a figure of £62.30/EUA. Since the price of electricity generation has been subject to the impacts of the EU-ETS since 2005, and not previously, the adjustment to the historic cost profile had to be done in two phases. In both phases, the carbon intensity of the price-setting supply source was used to calculate the emissions liability. In the UK, the price-setting supply source is assumed to be natural gas, which has an average emissions intensity for the years 2010-2012 of 401 tCO₂/GWh [DECC, 2013a, p.121].

As one EUA is the allowance to emit one tCO₂, multiplying the emissions intensity by the electricity volume yields an approximation of the number of tCO₂ liable for EU-ETS payments. Preceding 2005, this tCO₂ figure can simply be multiplied by £62.30/tCO₂, and the resultant product is added to the historic cost. From 2005, payments for EUAs were already incorporated within the wholesale cost of electricity. In order to avoid counting EUA liabilities twice, the historic cost of EUAs had to be subtracted from £62.30/tCO₂, following their introduction. Settlement prices of EUAs were obtained from The Intercontinental Exchange [ICE, 2014]. Currency adjustments were performed using historic rates obtained from the European Central Bank [ECB, 2014]. The EUA prices were adjusted to 2012 prices and subtracted from £62.30/tCO₂ in order to obtain the correct CO₂ wholesale cost supplement, following the commencement of the EU-ETS.

Two future wholesale cost scenarios are presented from the same source as the EU-ETS EUA price projections [HM Treasury, 2010, Chart 5.E, p.36]. The baseline projection assumes the EUA price rises unsupported to £16.30/tCO₂ in 2020 and steeply on to £70/tCO₂ in 2030, in line with DECC's then projections. The second scenario (*scenario 3* in the HM Treasury 2010 report) assumes a price of £40/tCO₂ in 2020 achieved through carbon price support, and a resultantly slower rise to £70/tCO₂ in 2030. This second scenario is akin to the modified historic wholesale cost profile, whereas the baseline scenario can be seen as an approximate continuation of the unadjusted wholesale cost profile. The projections intersect in the mid-2020s, with the price-supported *scenario 3* becoming cheaper, as a result of earlier-prompted low-carbon investment reducing EUA liabilities.

2.2.2 Out-turn approximations

A series of isolated out-turn LCOE data points are plotted for nuclear power plants and offshore wind farms in the UK. The original model used to compute the LCOE figures in the annual government reports could not be made available, so a new model, emulating the methodology of the original, was constructed with guidance from DECC. LCOE approximations were computed for Sizewell B & C and Hinkley Point C nuclear power stations, and a number of existing offshore wind farms. The resultant figures are presented in in Table 3, all in 2012 prices, alongside their main data sources.

Table 3 also lists some contextual data for CCS. CCS technology is in its infancy, and there are no commercial scale plants currently operational in the UK. Many have written extensively on the costs of the technology, but these studies tend to be concentrated on regions outside the UK [CCSI et al., 2011]. The inclusion of costs from other countries was considered, but rejected on the basis that this would constitute an inconsistency in the scope of the work. The UK industry-led CCS Cost Reduction Task Force (CRTF), set up by DECC, has produced an analysis of the costs of the technology. In lieu of any out-turn costs, the data from the CRTF seemed a relevant contextual provision. In the interim [CRTF, 2012] and final [CRTF, 2013] reports, the group explores opportunities for reducing the costs of CCS by refining the assumptions and prices used by DECC

in the composition of their annual estimates. Estimates for two coal CCS technologies (post-combustion (ASC) and pre-combustion (IGCC)) are plotted for three prospective commissioning dates. It must be noted that the CRTF values are composed using varying discount rates for each of the principal cost components. The average discount rate is comparable to the 10% figure used in the rest of the analysis, but it is not entirely consistent.

Table 3

Contextual information: LCOE estimates, out-turn approximations and strike prices.

	Installation (proposed/actual commissioning date)	LCOE ^a £/MWh	Data description	Source(s)
Nuclear	Sizewell B (1994)	93.15	CEGB net effective cost estimate	[Layfield, 1987, Vol. 5, C55, p.8]
	Sizewell B (1996)	65.48	CEGB central cost estimates	[Barnes, 1990, Vol. 3, C29, p.825]
	Sizewell B (1995)	131.79	Out-turn using reported CAPEX	[Toke, 2005]
	Hinkley Point C (1994)	58.20	CEGB central cost estimates	[Barnes, 1990, Vol. 3, C29, p.825]
	Hinkley Point C (2023)	92.50	Strike price	[DECC, 2013d]
	Sizewell C (2023)	89.50	Strike price	[DECC, 2013d]
Offshore Wind	Blyth Offshore (2000)	90.57	Out-turn approximations derived from reported project costs, average OPEX estimates and the latest UK average offshore wind load factor	Reported project costs: 4COffshore Database [4COffshore, 2014] OPEX estimates: Arup Generation Costs Report [Arup, 2011, p.49] Average load factor: DECC Energy Trends [DECC, 2014, p.47]
	North Hoyle (2003)	108.49		
	Scroby Sands (2004)	103.77		
	Kentish Flats 1 (2005)	101.42		
	Barrow (2006)	109.29		
	Burbo Bank (2007)	106.79		
	Lynn (2009)	111.44		
	Inner Dowsing (2009)	111.44		
	Rhyl Flats (2009)	132.21		
	Gunfleet Sands 1/2 (2010)	153.73		
	Robin Rigg A&B (2010)	145.54		
	Thanet (2010)	164.98		
	Walney 1 (2011)	185.14		
	Walney 2 (2012)	171.57		
	Ormonde (2012)	169.48		
Sheringham Shoal (2012)	190.04			
London Array 1 (2013)	165.48			
Greater Gabbard (2013)	190.10			
Gunfleet 3 (2013)	194.61			
CCS	Post-comb. coal (2018)	166.50	Projected levelised costs based on optimised financial, technology advancement and policy conditions	[CRTF, 2013]
	Post-comb. coal (2025)	114.70		
	Post-comb. coal (2033)	95.30		
	IGCC coal (2019)	169.30		
	IGCC coal (2026)	123.80		
	IGCC coal (2034)	100.80		

^a Note: Colours correspond to the contextual data points plotted in Fig. 2 & 3.

2.3 Calculations: Temporal estimate uncertainty

A bespoke method was devised to evaluate the temporal estimate uncertainty in the published estimate trajectories composed in the previous component of the work (see section 2.3). Whereas the contextual cost landscapes were composed in technology groups, this analysis was performed separately for each sub-group.

The results of this analysis give an overall picture of the uncertainty embodied in the published figures. There are many layers of uncertainty embedded within the methodology used to construct the figures, which are acknowledged by the authors of the DECC cost reports. This analysis is not targeted at any of these specific aspects of methodological uncertainty, and is not meant as a critique of the methodologies themselves.

The analysis comprised a number of mathematical operations explained in Eq. (1), (2) & (3) and Fig. 1.

$$x_1, x_2, y_1, y_2, y_3, y_4 \xrightarrow{\text{yields}} U(t), L(t) \xrightarrow{\text{yields}} \text{Area} \quad (1)$$

$$\text{Area} = A = \int_{t_1}^{t_2} U(t) dt - \int_{t_1}^{t_2} L(t) dt \quad (2)$$

$$\text{Temporal Estimate Uncertainty} = U_T = A/(t_2 - t_1) \quad (3)$$

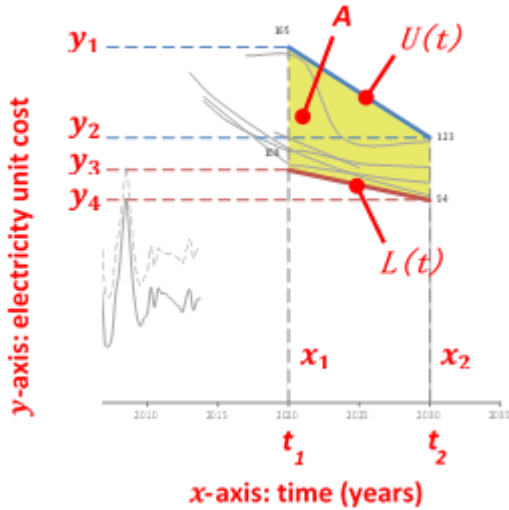


Fig. 1. Construction of temporal estimate uncertainty analysis.

Construction lines $\{x_1, x_2, y_1, y_2, y_3, y_4\}$ were plotted, the intersections of which form the corners of a closed boundary around the estimates. The lines forming the upper $\{U(t)\}$ and lower $\{L(t)\}$ bound functions are then integrated with the limits 2020 $\{t_1\}$ and 2030 $\{t_2\}$. The shaded area contained within the complete boundary could then be computed by subtracting the integral result of the lower bound function from that of the upper. The area is then divided by the time span $\{t_2 - t_1\}$ in hours, in order to normalise the measure and yield meaningful units. This final figure $\{U_T\}$ is the magnitude of temporal estimate uncertainty in £/MWh. This process was performed for each technology sub-group and each estimate sensitivity.

3. Results

3.1 Contextual cost landscapes

The results of the first analysis are presented as contextual cost landscapes (Fig. 2, 3 & 4) for the central estimates of each technology group. These figures show the core LCOE estimate data set in the context of the historic and projected wholesale cost profiles and out-turn approximations, described in section 2.

Nuclear (Central)

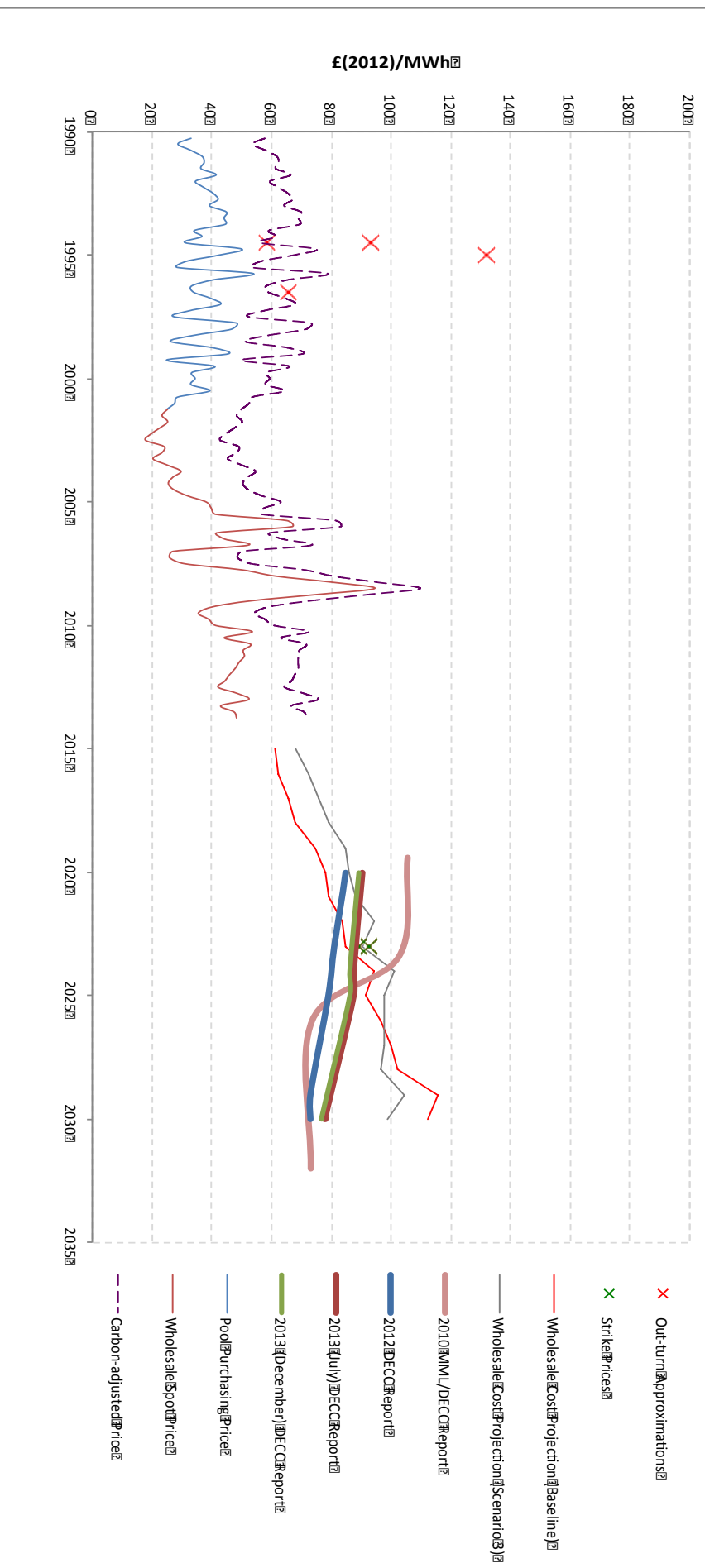


Fig. 2. Cost landscape for nuclear central LCOE estimates.

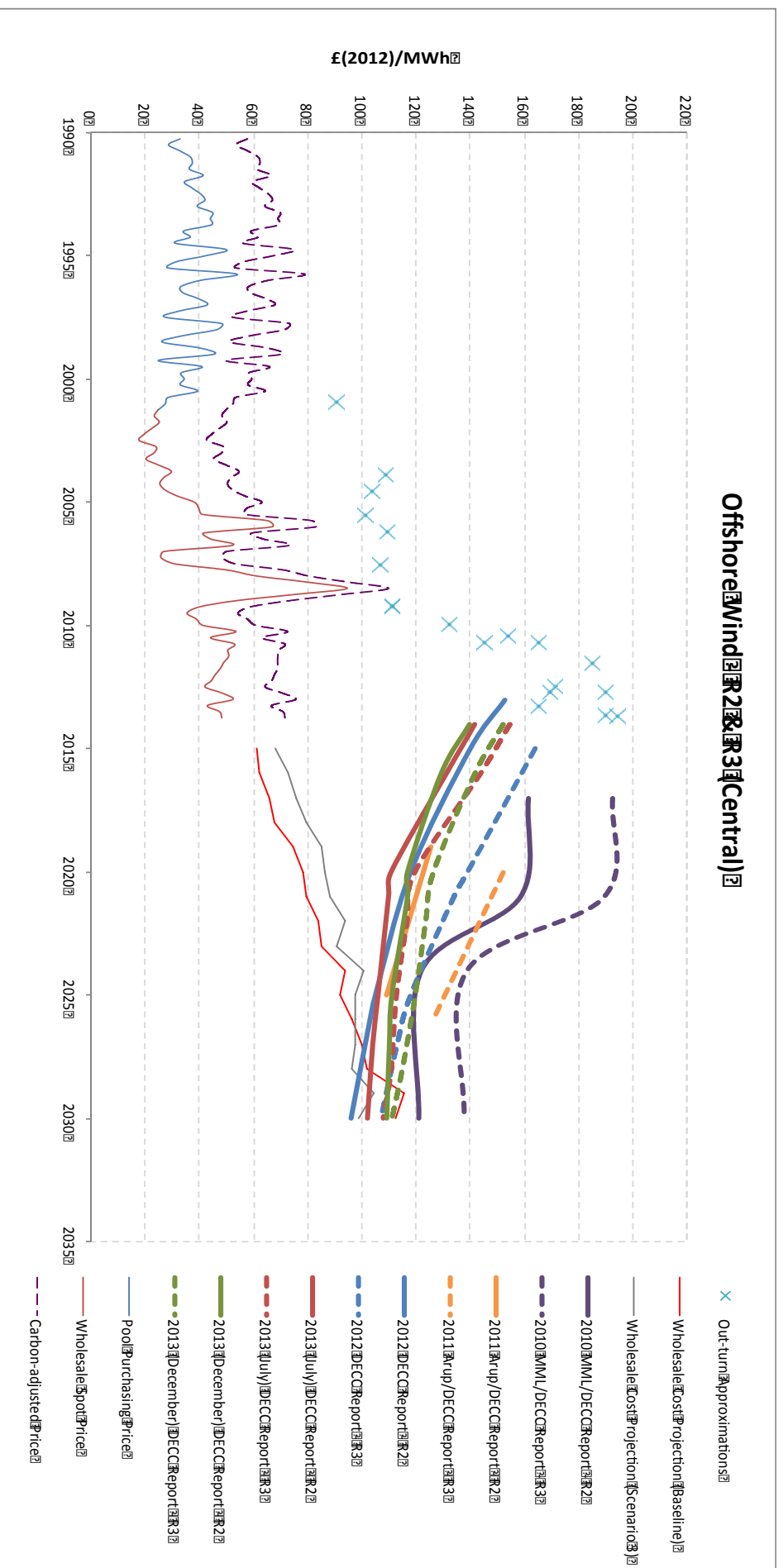


Fig. 3. Cost landscape for offshore wind central LCOE estimates.

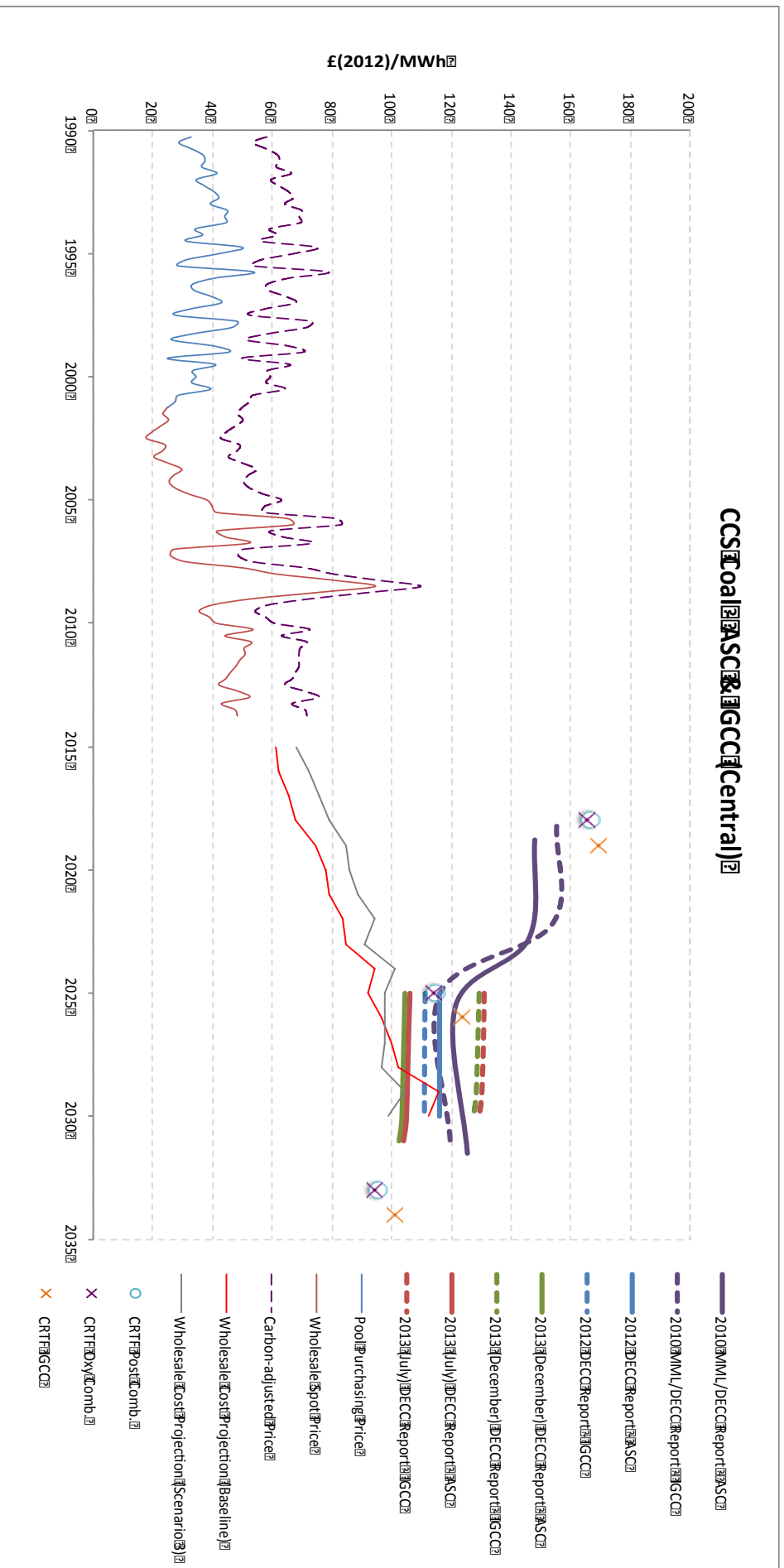
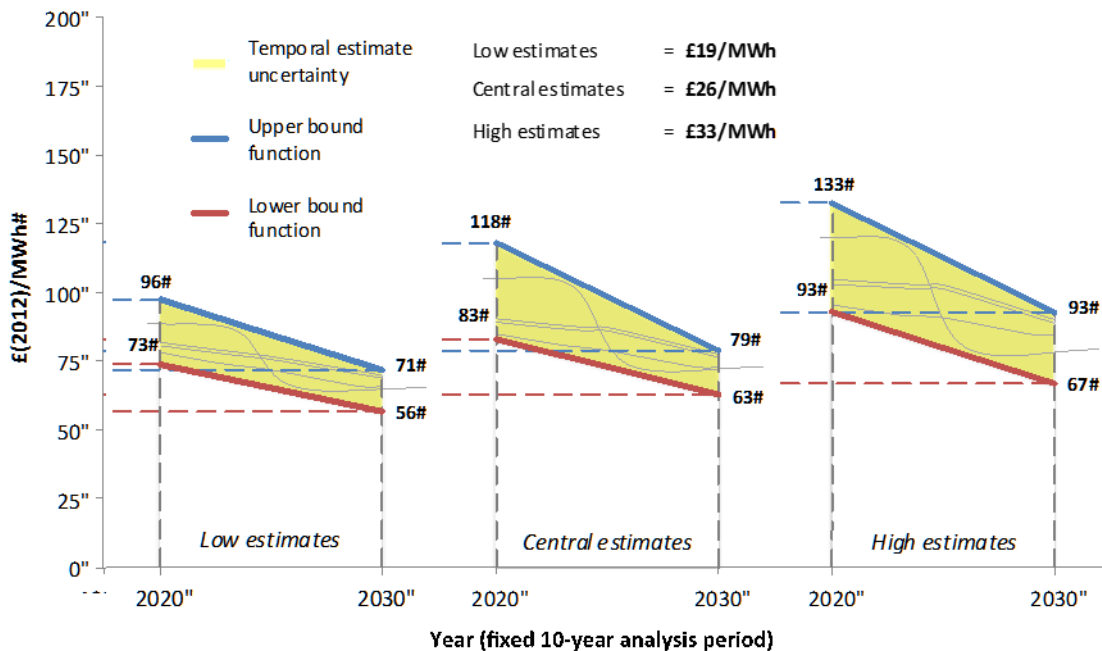


Fig. 4. Cost landscape for CCS central LCOE estimates.

3.2 Temporal estimate uncertainty

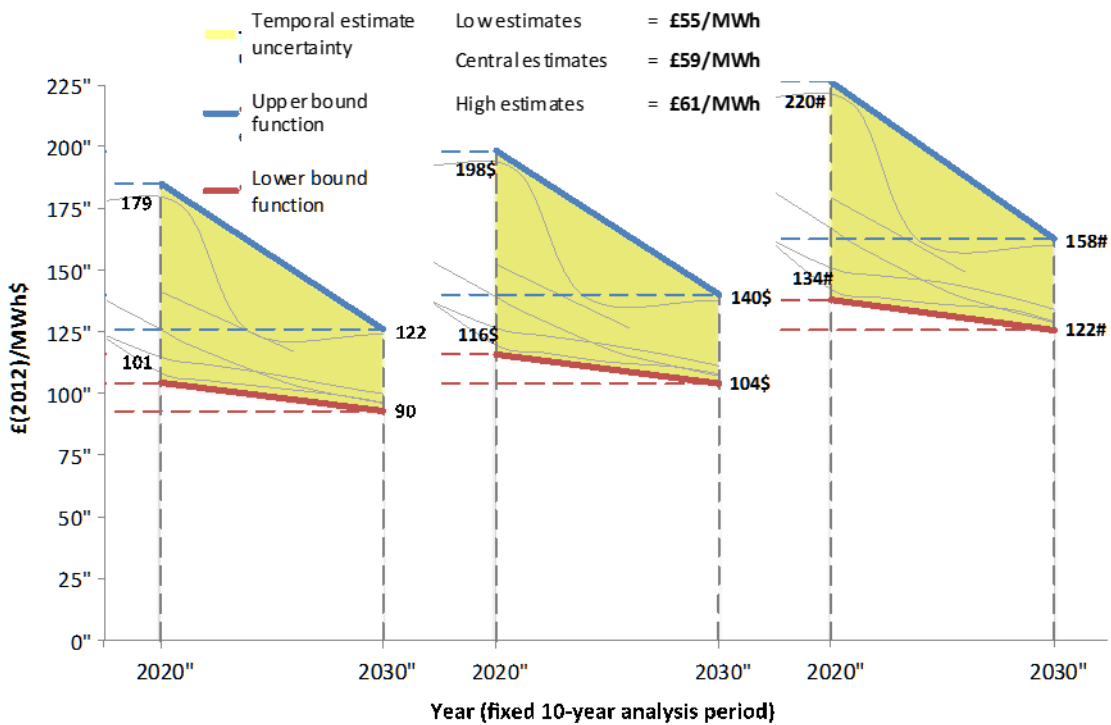
Fig. 5 shows the application of the temporal estimate uncertainty methodology outlined in section 2.3, using the sets of trajectories formed for the low, central and high estimates for nuclear, as an example. The estimate trajectories are now shown undistinguished from each other, as fine line-weight, grey curves. This has been done to highlight the new functions on the graph, and because the chronology of the estimate trajectories (the year of the report from which they are constructed) is of no consequence to this measure. The upper $\{U(t)\}$ and lower $\{L(t)\}$ bound functions have been plotted tightly up against the highest and lowest estimate curve extremities respectively. In order to keep the methodology consistent between applications across technologies and sensitivities, the positioning of the upper and lower bound functions was done iteratively; with the intention of minimising the enclosed area. Once the boundary had been formed around the estimates the yellow shaded area was produced, enabling the calculations outlined in Eq. 2 & 3 to be performed. These operations resulted in the values of temporal estimate uncertainty for nuclear to be obtained (low = £19/MWh, central = £26/MWh, high = £33/MWh).

Fig. 5. Temporal estimate uncertainty analysis formation: low, central and high nuclear estimates example.



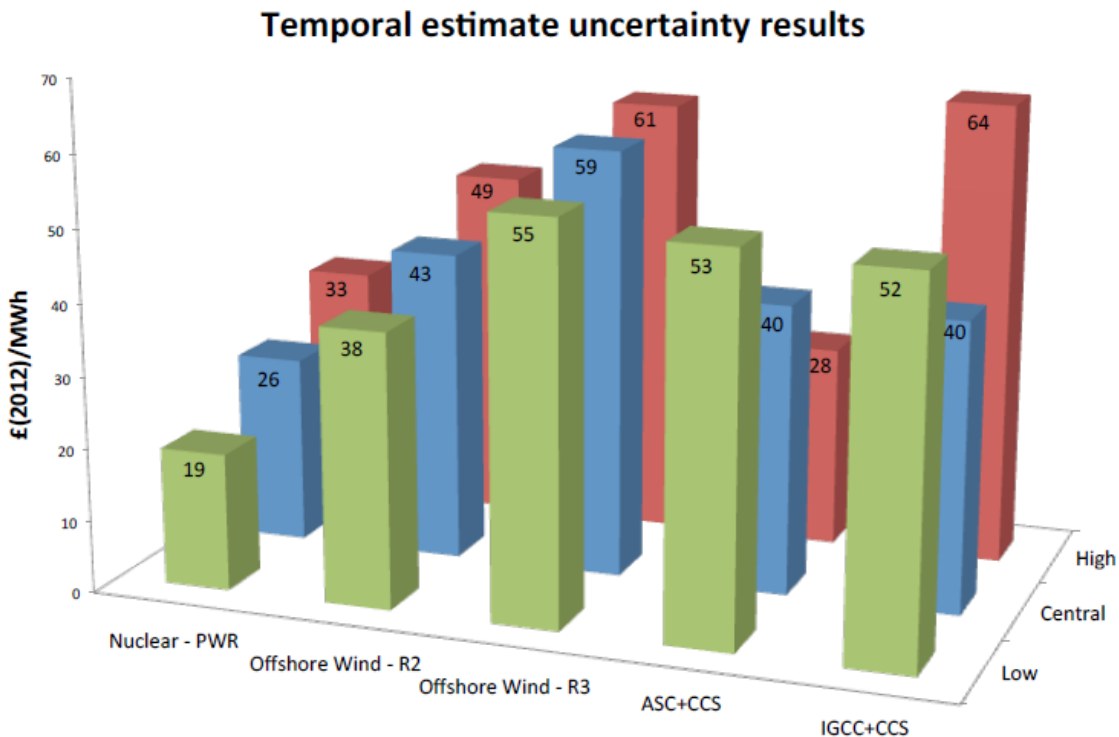
As a contrasting example – in terms of magnitude – the same process is shown for R3 offshore wind in Fig. 6. This comparison illustrates the proportionality of the spread of the grey estimate curves, the size of the yellow shaded area and the magnitudes of temporal estimate uncertainty (low = £55/MWh, central = £59/MWh, high = £61/MWh).

Fig. 6. Temporal estimate uncertainty analysis formation: low, central and high R3 offshore wind estimates example.



The process shown in these two examples constitutes the intermediate graphical step required to obtain the full set of temporal estimate uncertainty results. The demonstrated process was also applied to each set of estimate sensitivities for R2 offshore wind, ASC coal CCS and IGCC coal CCS in the same manner. The collated numerical results of this analysis are displayed in Fig. 7.

Fig. 7. Temporal estimate uncertainty results: low, central and high estimates for each technology.



4. Discussion

4.1 Analysis limitations

In analyses of this type, where data is subject to some degree of simplification through quantification, it is important to make a distinction between the various layers of uncertainty when considering the corresponding limitations. As the analyses are principally constructed from published DECC LCOE estimates, all of the caveats that apply to them also apply to this work [see DECC, 2012, p.5]. Particularly important to note is the method by which the high and low estimates are calculated. As mentioned previously, these values are generally based on an adjustment of the CAPEX component of the LCOE only. This leads to a conservative quantification of uncertainty, as there are several other sources of variability; such as, OPEX, load factors etc. Even though the approach is consistent for each technology, technologies with a higher proportion of CAPEX relative to other cost components will see a wider cost spread between their low and high estimates when this method is used.

In addition to those caveated, there are some costs that are omitted from LCOE estimates altogether. These mainly comprise indirect costs that are technology-specific. Perhaps the most glaring of these are standby power costs, particularly for renewables [Economist, 2014a]. Commonly referred to as *externalities*, many environmental and social costs are also excluded from LCOE calculations. As an example in nuclear generation, there is a concern that discounting the costs of waste storage may be flawed [Napoleon et al., 2008, p.84]. This is because they are bound to accrue to some degree, over an approximately infinite timespan.

It is important to note that there are also positive externalities that are not accounted for in LCOE estimates. Macroeconomic effects such as GDP growth and derived employment are also frequently heralded when decisions about investing in new installations arise. However, with regards to the *green economy* these are increasingly thought to be marginal at best, for countries such as the UK [Constable, 2011, p.xiv]. Moreover, they often prove problematic to quantify accurately even after they have been accrued, let alone in the process of forecasting.

Underlying these potential pitfalls is a broader tension between the desire to simplify and the need to account for complexity in economic comparison. Some would argue that the requisite simplification in quantifiable comparison methods (LCOE being one example) renders the process futile and the results arbitrary. However, this scepticism could also be seen as capitulating to complexity. In the absence of absolutes, some form of metric for comparison is required. It is hoped that modifications such as those proposed in this analysis expand the scope of complexity considered, whilst not inhibiting comparative capacity.

4.2 General observations

An almost entirely consistent trend exposed by the analyses is the decreasing spread of the estimates with an increasing time horizon. This is well exhibited by the nuclear example in Fig. 5, by the fact that the shaded areas bounding the estimate trajectories are mostly taller on the left-hand-side than on the right. This trend is even more acute in some of the other sub-groups. With the assumption that variability in estimates is an indication of uncertainty levels, this suggests reduced uncertainty for estimates with commissioning dates further in the future. This is unintuitive and unrealistic. This convergence of further flung estimates does not necessarily point to a flawed estimation methodology, however it is remarkable. Modelling inputs for later commissioning dates will be based on fewer and lower quality items of information. It is therefore easy to explain less

variation in the annual estimates for the later commissioning dates, as there might be less evidence on which to base adjustments to an already poorly-informed quantity. Poor quality input information may explain the convergence of estimates for a given sensitivity. However, this does not address the general narrowing in range between the high and low values observed over time. If the minimum low and maximum high estimates for nuclear (from Fig. 5) are taken as an example, the values in Table 4 can be compiled.

Table 4
Vertical uncertainty boundary spread in 2020 and 2030: nuclear central estimates.

Sensitivity	Estimate Spread	
	2020, £(2012)/MWh	2030, £(2012)/MWh
Minimum low	73	56
Maximum high	133	93
Range	60	37

The considerably larger range between high and low estimates in 2020 than in 2030 is difficult to justify. There should be a mechanism within the LCOE model to ensure the range calculated above *increases* with the estimate horizon. This would correct the current implausible impression derived from the estimates; namely, that there is less cost uncertainty overall, further in the future.

5. Conclusions and policy implications

5.1 Nuclear

The results show nuclear to be forecast not only as the cheapest sub-group, but also the one least laden with uncertainty. This is perhaps not surprising as this technology has been in development for several decades, and there is considerable experience accrued. Despite this, especially in the early report estimates, considerable FOAK premiums are forecasted initially. In the case of the central estimates, the technology reaches wholesale price parity with the projected baseline cost in the period 2020-2025. Even for the high estimates, parity is achieved well before 2030, even by the most conservative years' figures. It is hard to resist the conclusion that, economically, nuclear seems to be the best option of the three, based on these results.

However, do these relatively narrow uncertainty bounds and low costs seem credible in the context of past experience? The LCOE model operations described in section 2.2.2 for the UK's most recently constructed nuclear plant – Sizewell B – yield the results in Table 5.

Table 5
Various CAPEX and LCOE estimates for Sizewell B nuclear power station.

Estimate	Estimation year	Total CAPEX, £(2012)m	Unit CAPEX £(2012)m/MW ^a	LCOE estimate, £(2012)/MWh
Sizewell B inquiry	1987	-	-	58
Hinkley Point C inquiry	1990	3,157	2.66	93
Estimated out-turn	1995 ^b	4,969	4.18	132

^a Note: Unit costs based on originally designed power rating of 1,188MW.

^b Note: In the case of the estimated out-turn cost it is not the estimate year, but the year of completion of the plant.

This shows more than a doubling in the LCOE from the plant in real terms, from first estimate to out-turn cost. These figures are based on several assumptions outlined in section 2, and should be treated as approximations. However, even when allowing for a considerable margin of error in each figure, the disparity remains considerable. The main reason for the large variation is the fact that LCOE estimates are highly CAPEX-sensitive. The capital cost over-run on Sizewell B causes the LCOE out-turn cost to be much higher than initially forecast, even whilst leaving all other quantities as forecasted. Given this high sensitivity, and recent experience of cost over-runs with similar size infrastructure projects, it is questionable as to whether the small range of LCOE estimates presented is realistic.

Given this seemingly unavoidable risk, the government's approach to shift risk to the private sector with the latest nuclear power contract, at least partially, seems sensible. The CfD strike price of £92.50 agreed for Hinkley Point C in 2012 looks costly compared to current wholesale prices, even with an elevated EU-ETS CO₂ price scenario imposed (see Fig. 2-4). However, it correlates well with current wholesale forecasts and central LCOE estimates. Given that all of these figures emanate from the same central source, the chronology of the LCOE estimates looks convenient. In the projected commissioning year for Hinkley Point C, 2023, the 2010 LCOE estimate trajectory is considerably above the strike price. In 2012 it is considerably below, and then the 2013 estimates, following the Hinkley C contract agreement, are very close to both the agreed strike price and forecasted wholesale cost.

We note that not all the external costs of nuclear are included in the DECC cost estimates. Nuclear is almost certainly the technology with the greatest degree of externalised cost and indirect support, of the three explored here. Perhaps only fossil fuels receive more subsidy (estimated at \$544bn globally in 2012 [IEA, 2013, p.55]). Defence applications and research into nuclear fusion are just some of the ways extra money is funnelled to support the technology [Black, 2012]. On the cost side, environmental impacts tend to be large, especially compared with wind turbines, which can be upgraded or removed relatively unobtrusively. Waste storage has costs that will endure long-term and are still unknown in magnitude (though there is a fixed cost allowance for these in the DECC cost estimates). Direct cost is also incurred in funding various bodies to oversee and regulate the technology, although in many cases the nuclear industry is required to meet these costs. These organisations include the Office for Nuclear Regulation, the Nuclear Decommissioning Authority, elements of DECC, the Department for Environment Food and Rural Affairs and the Environment Agency [HM Government, 2014]. Externalities are by no means unique to nuclear energy. However, given their number and potential magnitude, the alluringly low cost estimates and uncertainty results for the technology should be viewed in the context of these potentially omitted costs.

5.2 Offshore wind

What is immediately apparent about offshore wind is that both R2 and R3 installations demand significant cost premiums over most other sub-group estimates, and over projected wholesale costs (see Fig. 3). None of the central estimate trajectories reach wholesale price parity before 2025, and estimates for early R2 installations (generally cheaper and nearer shore) commissioning in 2015 are approximately three times the current wholesale cost. In terms of cost uncertainty, the picture remains bleak (see Fig. 7). R2 and R3 sub-groups exhibit approximately 50% and 100% higher levels than nuclear respectively.

Externalities are generally considered to be minimal when compared with nuclear. Wind turbines can be uninstalled rapidly and cheaply compared to the time and costs associated with decommissioning a nuclear plant, even more so for onshore installations. Shorter design lives

(typically less than half the length of those for nuclear plants) and lower load/availability factors (typically 20-40% compared with 60-90% for nuclear) are resolute structural impediments to cost competitiveness.

As with nuclear, it is important to assess these estimates in the context of past experience. The LCOE trajectories consistently forecast a steep cost decline in the near future. In contrast, the LCOE out-turn approximations for existing installations (see Table 3 and Fig. 3) constitute more than a decade of experience of increasing costs, and diminishing returns to scale. Given this, it is questionable as to whether the imminently forecast reversal in cost trend is realistic.

If the current increasing cost trend *does* reverse as predicted, should investment be delayed? To explore this question, Table 6 shows the minimum premiums (R2 central estimate trajectories used) over wholesale cost, approximated for the years 2015 and 2025.

Table 6

LCOE premiums in 2015 and 2025: R2 offshore wind central estimates.

Year	Approximate wholesale cost under 'Scenario 3', £(2012)/MWh	Approximate R2 LCOE estimate, £(2012)/MWh	Premium, £(2012)/MWh
2015	68	135	67
2025	97	105	8
		Difference:	59

The difference between the premium in 2015 and 2025 is £59/MWh. If this figure is multiplied by a third (given three technologies are considered in the analysis) of the annual UK electricity demand [DECC, 2013a, p.111] over the ten-year period, the resulting figure described in Eq. (4) is substantial.

$$£59 \text{ per MWh} \times 365 \text{ TWh per year} / 3 \times 10 \text{ years} = £71.8\text{bn} \quad (4)$$

Therefore, if this portion of demand were to be met from premature building of offshore wind, the overall premium resulting from doing this in 2015 as opposed to 2025 is £71.8bn, or approximately 4% of UK GDP. Assuming an optimistic average load factor of 40% this would mean installing approximately 35GW of capacity. This is a crude estimate, as no increase in electricity demand is factored-in over the 10-year period, either from mode-switching (space/water heating and transport being two major targets for this) or overall demand increase. Additionally, the premium will in fact be larger because there is only a fraction of this resource available on R2 sites – around 7GW [RenewableUK, 2014]. More expensive R3 sites would have to be used for a considerable portion of new supply, thereby incurring even higher premiums. On the other hand, getting such a high proportion of electricity from offshore wind may be neither sensible nor economic. With technology as it stands, the amount of storage or back-up capacity needed to account for intermittency would also be costly.

The saving accrued from waiting is dependent on the LCOE decreasing without investment in the meantime. It would be helpful to investigate what portion of the LCOE is subject to *learning*. Learning rates and predicting technological progress are rich and diverse topics for publication in the literature. Technology-specific case study approaches are sometimes used [UKERC, 2013], as well as broader numerical approaches aimed at isolating and attributing *learning by research* and *learning by doing* [Jamash, 2007]. No matter the components or mechanisms of the cost reduction, in the instance that learning is required in order for the premiums to reduce, then waiting will not avoid the premiums discussed above. This concept is also relevant to nuclear and CCS technologies. If investment is required at higher costs for offshore wind to reduce in price, it is questionable as to whether it will be financially or politically feasible for the UK to provide adequate support.

However, given it is the current world-leader in offshore wind capacity; it is hard to see another country being more likely to do so.

On the other side of the *holistic balance sheet* are the environmental costs of waiting. Even if another country did provide the initial investment, or the costs reduced for another reason, delaying installations by ten years may have considerable non-economic costs. It would be interesting as part of a wider study, for the costs resulting directly from delaying ten years to be evaluated, and if possible, comprehensively quantified in monetary terms.

5.3 CCS

The contextual cost landscape for CCS (see Fig. 4) shows the LCOE estimates for the technology reaching parity with wholesale cost from 2025 onwards, depending on the sensitivity viewed. The CCS Cost Reduction Task Force (CRTF) estimates show only modest reductions in cost, if any, below the initial portions of the DECC LCOE estimate trajectories. However, the CRTF estimates do show continuing reductions in cost over the period 2018-2034; whereas the more recent DECC estimates show costs plateauing and remaining high (>£100/MWh for the central estimates) through to 2030.

The key finding of the uncertainty results for CCS is that they resonate with the fact that it is a technology in the conceptual stages of its development. The disparate results in the temporal uncertainty analysis – for both CCS sub-groups – confirm the unknown nature of the costs. Additionally, due to the limited estimate coverage presented in the source reports, the specific results should be interpreted with caution. The broad impression is an *unknown-unknown* characterisation.

This characterisation provokes an interesting question of viability in the face of interchangeability with nuclear generation. CCS, like nuclear, provides consistent base-load supply. Both technologies are therefore relatively interchangeable methods of providing seasonably reliable, low carbon electricity. Despite being less effectively quantified in the uncertainty analysis than the other two technology groups, the results show CCS is vested with considerable amounts of uncertainty; approaching double the levels of nuclear in the case of the low estimates for both CCS sub-groups (see Fig. 7). Given this, and the fact that the first commercial-scale CCS plants will not be operational until the late 2020s, it is questionable whether there is much of a degree of contention between CCS and nuclear, at least in terms of investment in the next 10-15 years.

These factors point to the likelihood that CCS will be unable to compete commercially with nuclear in the near future. But this does not mean that it should not receive financial support. Although not an economically viable electricity source in the short-term, given the enhanced access to gas reserves being facilitated by unconventional extraction techniques, and with coal the fastest growing fossil fuel [BP, 2013, p.5], it remains a promising one for the long-term. However, it must be considered as a design concept, and be funded accordingly. Research is still required, and a number of funded demonstration plants would be likely to spur progress. The UK Carbon Capture and Storage Demonstration Programme is dedicated to doing just that. In early 2014, £100m of funding was allocated to take the Drax White Rose (oxy-fuel coal at Drax power station) and Peterhead (gas at Peterhead power station) projects through to Front-end Engineering Design (FEED) phase [BBC, 2014]. Given this, CCS is more akin to some tidal demonstration concepts [Renewables, 2014], or the new 10MW AMSC SeaTitan turbine [AMSC, 2014], despite being presented alongside major technologies – such as offshore wind and nuclear – in the annual reports examined in this work.

5.4 Further work

This work challenges the conventional approach towards presenting cost uncertainty in this field, and proposes a new method for quantifying and communicating it. The resulting proposition could be developed and refined in a number of ways. Firstly, the methodology presented here can be applied more generally to technologies aside from the three selected in this study. These include some other core generation technologies aside from nuclear, such as unabated coal and gas. Looking to other countries, it may be valuable to see how consistency in estimation varies across countries, and investigate the causes behind any discrepancies.

Secondly, the overall precision of the analysis in this work could be enhanced by generating LCOE estimates at more frequent time increments, with which to form the cost trajectories. This could be done directly using the original model, if it were made available. The outcome would eliminate the interpolation needed to form continuous trajectories from sometimes relatively dispersed, discrete data points. Ideally, the trajectories would be formed from estimates for commissioning dates in every year of the time period being analysed.

Finally, it would be valuable to address some of the criticisms that are levelled at LCOE as a metric, and attempt to adapt the uncertainty methodology accordingly. A previously mentioned article in a recent issue of *The Economist* cites Paul Joskow of MIT when stating, “levelised costs do not take into account the costs of intermittency” [Economist, 2014a]. This is because the costs of the extra back-up power that must be kept on standby to support intermittent generation are not taken into account in the LCOE metric. The Brookings Institution has conducted a cost-benefit analysis of various generation technologies, which take into account these standby costs [Frank, 2014]. Surprisingly, with carbon savings priced at \$50/ton (approximately £34/tCO₂), the analysis finds solar and wind generation to be of net *cost* rather than benefit, when compared with coal base-load generation in the US. Further work could be undertaken to incorporate these standby costs into the uncertainty analysis developed in this work.

5.5 Close

As has been shown by the modified approach applied in this work, there are a number of ways in which to analyse and present cost uncertainty. DECC’s methodology – and the modified approach – leads to nuclear being presented favourably compared to other technologies, yielding figures with relatively narrow cost uncertainty. If technologies with narrow uncertainty bounds are prioritised when investing, their cost uncertainty range is likely to shrink further. This seems to be what has happened with nuclear in the UK. Conversely, technologies that exhibit broader cost uncertainty are likely to attract less investment, and remain cost-uncertain – for example, CCS in the UK. To compound this effect, there are obvious political incentives to validate previous estimates and maintain a constant policy thrust, thereby simplifying future investment decisions. This self-reinforcing loop, if present, would lead to an unwelcome systematic bias with regards to investment and policy-making.

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