Highlights

- Recent UK Government (DECC) levelised cost estimates are compiled and scrutinised
- Out-turn, past and present generation costs provide an analytical context
- Uncertainty stemming from the variability in estimation is quantified
- Strangely, estimate variability decreases as the forecast horizon increases
- Imminent (forecasted) cost reductions suggest the timing of deployment is not straightforward

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

A study of cost uncertainty

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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 as an overall picture of how costs and uncertainty vary over time. This study aims to address these two shortcomings. Two analyses are performed using reported DECC LCOE estimates for three important electricity generation technologies for the UK; nuclear, offshore wind and coal with carbon capture and storage. The first analysis composes LCOE estimate trajectories from previous years' DECC estimates and presents them alongside contextual data, including some out-turn costs. The second quantifies the variability presented in the LCOE estimate trajectories for commissioning dates in the decade 2020-2030. Nuclear costs are presented as both the most consistent and lowest in magnitude. An imminently forecast steep fall in the LCOE of offshore wind raises questions about the timing of investment and deployment. In most cases estimate variability decreases over the estimation horizon, strangely suggesting greater levels of certainty for further flung commissioning dates. Further observations and implications for policy stemming from the analyses are discussed.

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. 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. Cost estimation, particularly aspects concerning methodologies, is a topic that is frequently discussed (e.g. Gross et al., 2013). This study differs in its focus, by concentrating on the uncertainty *as it is presented* in the variability of electricity generation cost estimates.

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 allows a range of cost estimates for a given technology to be compared to that of another, on a 'levelised' cost per unit (£/MWh) basis (DECC, 2013a, pp. 4–11, 2013b, pp. 6–7; Mott MacDonald, 2010, pp. 2–22). The LCOE methodology itself is not disputed in this study. However, we assert that the elected presentation of uncertainty is limited in its provision of context, and as an overall picture of how costs and uncertainty vary over time. Without numeric context, the relevance and usefulness of cost estimates is reduced. Without tracking the degree to which estimates vary over time, only a partial picture of uncertainty can be gleaned. The purpose of this study is to address these two shortcomings and discuss the implications resulting from the picture of uncertainty that is presented by DECC.

The first component of the work composes *contextual cost landscapes* which present the DECC 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 alone, which aims to quantify the variability in previous estimation. In other words, it is intended that the analysis captures the degree of variability (or consistency) of the DECC LCOE estimates over time. 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. This quantified measure of variability in estimates over time is hereafter termed *temporal estimate uncertainty*.

Three technology groups – nuclear, offshore wind and coal with Carbon Capture and Storage (CCS) – have been selected for analysis (see Table 1). Contemporary nuclear generation, as represented by Pressurised Water Reactors (PWRs) is a well-established technology. European Pressurised Reactors (EPRs), based on the same fundamental power generation design as PWRs but with enhanced safety features, look to be the chosen design for future deployment in the UK. 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, coal with CCS will be a truly First-of-a-Kind (FOAK) technology in the UK, with initial commercial-scale installations planned for the mid-2020s.

The reasons for prioritising these three technology groups are twofold: Firstly, in the context of the UK they represent a diverse range of scalable, low carbon options for electricity generation. Onshore wind, solar photovoltaic (PV) and hydro-power generation for example, may well be scalable elsewhere, but currently look to be less likely options (at least at the time of the DECC scenarios we focus on) for large portions of additional UK capacity. Secondly, a consistently compiled set of LCOE estimates, with good coverage over a fixed timeframe are needed to undertake the analysis. Numerous other sources of cost estimates are available. However, in order to assess temporal estimate uncertainty from estimation variability, the variability being measured must be that of the estimate values, not the methodologies used to compose them. Furthermore, DECC estimates will be a key source of cost information for many industry professionals, investors and academics, so they comprise an appropriate and relevant set of data with which to conduct the analysis.

The UK has ambitious legally binding targets for the decarbonisation of its economy. These involve a 34% reduction of CO_2 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 coal with CCS plant[a] are forecast to be commissioned.

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 sections 4 & 5 discuss the conclusions and policy implications of the reported cost analysis for each of the three technologies in turn.

[a] The *White Rose Carbon Capture and Storage Project* is currently in the examination phase of the planning process. If granted permission the plant should begin generating electricity in early 2020 (Capture Power, 2014).

2. Methods

2.1 Review of relevant literature

In a comprehensive review of cost estimation methodologies for the electricity sector, a UKERC study broadly characterises the approaches adopted as either 'engineering assessment' methods (bottom-up parametric cost modelling and estimates informed by expert insight) or top-down 'experience curve' (learning) based methods (Gross et al., 2013, p. 22). In highlighting the capabilities and deficiencies of each, across a wide-ranging set of case studies, they conclude that the approaches are complementary, but that decision makers must be aware of the various layers of uncertainty comprised in each.[b]

Variability and trends in out-turn costs can be observed for specific technologies when comparable data are available. This can lead to insights on the cost trend over time on a unit capacity (£/MW) or levelised (£/MWh) basis, such as those gleaned in studies of nuclear (Du and Parsons, 2009; Harris et al., 2013), and offshore wind (Heptonstall et al., 2012; van der Zwaan et al., 2012) generation. The aim is to capture the rate of learning undergone during a technology's development, thereby gaining an insight into future costs. (Jamasb, 2007) explores to what extent learning can be attributed to research (R&D) or doing (deployment) for a range of energy technologies.

In the absence of out-turn costs or learning curves, or when it is thought that future cost trends may not mirror those of the past, expert elicitations can be sought. The insights gained are used to characterise explicitly uncertainty around costs in a probabilistic manner. Difficulties arise when comparing elicitations gathered via differing methods from various sources. (Verdolini et al., 2015) present results from a study that standardises a range of expert elicitations on the costs of solar PV. The authors find differing levels of confidence (range of estimates) and optimism (level of estimates) across the elicitation studies surveyed.

The Bank of England's (BofE) Monetary Policy Committee (MPC) incorporates a probabilistic dimension of uncertainty in its projections (for inflation, GDP etc.) by using Fan Charts (see example in Fig. 1) (Elder et al., 2005). The single most likely

[b] The authors also specifically address variability in estimation, by categorising its various manifestations in the technologies they explore in their case studies, but do not quantify it.

forecast (the mode) is represented by the darkest red band in the centre of the 'fan'. The width of the fan indicates the degree of uncertainty. The degree of symmetry represents the skew – the mean's position relative to the mode. The black data points represent out-turn values plotted on top of previous estimates to track the forecast's accuracy. This probabilistic representation in conjunction with retrospective out-turn reporting demonstrates the state of the art when marshalling uncertainty in forecasting.

2.2 DECC LCOE estimate data

The first analysis presents 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 a series of UK government LCOE estimates, which were first produced in 2010 by a consultant on behalf of DECC. A summary of the sources of the estimates used is provided in Table 2.

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, and one where estimate- rather than methodological-variability is measured, 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, high and low 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, decommissioning costs etc.) were left unaltered in each case, as per the high and low estimates directly provided.

All of the data are adjusted for inflation. An index year of 2012 was chosen, as this is the year to which the strike price for the first next-generation nuclear power plant (Hinkley Point C) is indexed. The latest reference tables (March 2014, at the time of the analysis) were obtained 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.[c] 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 were 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.

2.3 Contextual data

2.3.1 Historic and projected wholesale costs

Historic wholesale price data were not available from a single source due to a modification to electricity trading arrangements in March 2001 (Simmonds, 2002, pp. 2–10). Between January 1990 and March 2001 pool price data were obtained from (Skea (UKERC), 2012). Price data following March 2001, up to March 2014 were obtained from a power exchange company (APX, 2014). In the case of the data compiled by UKERC, pool purchase prices were extracted in half-

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[c] 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.

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.

A second wholesale cost profile was created in order to indicate the hypothetical impact on historic prices of a levy on CO_2 aimed at decarbonising electricity generation. This was done by modifying the historic cost profile to incorporate the cost of CO_2 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.

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. 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 was performed in two phases. In both phases, the emissions 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 tCO_2/GWh (DECC, 2013c, p. 121).

As one EUA is the allowance to emit one tCO_2, multiplying the emissions intensity by the electricity volume yields an approximation of the number of tCO_2 liable for EU-ETS payments. Preceding 2005, this tCO_2 figure can simply be multiplied by £62.30/tCO_2, 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/tCO_2, 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/tCO_2 in order to obtain the correct CO_2 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/tCO_2 in 2020 and steeply on to £70/tCO_2 in 2030, in line with DECC's then projections. The second scenario ('Scenario 3') assumes a price of £40/tCO_2 in 2020 achieved through carbon price support, and a resultant slower rise to £70/tCO_2 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 becoming cheaper, as a result of earlier-prompted low carbon investment reducing EUA liabilities.

2.3.2 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 DECC model[d] 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. For detail on the structure of the original model see (DECC, 2012, p. 17). Some additional assistance was kindly provided by DECC.

For nuclear, six contextual data points are plotted. Two are the agreed strike price for Hinkley Point C (£92.50/MWh), and the reduced price for the two stations following the completion of Sizewell C (£89.50/MWh) (DECC, 2013d). These figures could be plotted directly, as they are in 2012 prices. Three others were calculated in the new LCOE model using cost components (such as CAPEX, OPEX and availability factors) reported in archived records of two public inquiries. The first concerned Sizewell B (Layfield, 1987), the UK's most recent nuclear power station which began generating in 1995; and the second, Hinkley Point C (Barnes, 1990), the plans for which were mothballed until recently. The Layfield inquiry yielded the £65.48/MWh estimate for Sizewell B. The Barnes inquiry yielded the data informing the £58.20/MWh estimate for Hinkley Point C and the £93.15/MWh estimate for Sizewell B. The final contextual data point for nuclear (Sizewell B, £131.79/MWh) is calculated based on the same data from the Barnes inquiry used in the estimate, but with the out-turn CAPEX reported in the press (Toke, 2005) substituted for the CAPEX figure provided in the inquiry documentation.

Similar calculations were performed to provide LCOE approximations for existing offshore wind farms. Reported project costs, peak capacities, commissioning dates and design lives, were obtained for existing UK installations from a database (4COffshore, 2014). An average load factor for the UK offshore wind fleet was used (DECC, 2014, p. 47) along with two OPEX estimates (<100MW and >100MW in £/MW/year) (Arup, 2011, p. 49).

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[d] The term 'original' DECC model is used to distinguish the source of modeling results presented by DECC and their consultants in the reports in Table 2, from any additional 'new' LCOE modeling conducted for this study.

The figures described above are plotted in relation to their expected (in the case of estimates) or actual (in the case of out-turn approximations) commissioning dates. Numerous rudimentary adjustments for inflation, interest accrued during construction and currency exchange rates had to be made. It should be noted that all the contextual data provided are calculated based on reported data from the sources referenced above. There are a number of potential sources of imprecision, such as average figures used for load and availability factors. Perhaps most significantly, the 10% discount factor used is unlikely to reflect project-specific financing conditions. They should therefore be treated as approximations to provide an analytical context, not precise reported out-turn costs from operators.

Table 3 also lists some contextual data for coal with CCS from the CCS Cost Reduction Task Force (CRTF). CCS technology is at an early stage in its development, and there are no commercial scale plants currently operational in the UK. As a result, no out-turn costs could be approximated, as they were for nuclear and offshore wind. Many have written extensively on the costs of CCS 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 CCS CRTF has produced an analysis of the costs of the technology, resulting in a *best-case* set of estimates for various technology options. In their reports (CRTF, 2013, 2012), 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. Their estimates for the two coal with CCS technologies included in this study (post-combustion (ASC) and pre-combustion (IGCC)) are plotted for three prospective commissioning dates, constituting the contextual provision for coal with CCS. 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.

2.4 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. Whereas the contextual cost landscapes were composed in technology groups, this analysis was performed separately for each technology sub-group.

The results of this analysis provide an overall picture of the uncertainty presented by the published figures, by quantifying their variability over time. There are many layers of uncertainty embedded within the methodology used to construct the figures, which are acknowledged in the DECC LCOE reports. As stated, 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. (1-3) and Fig. 2.

$$x_1, x_2, y_1, y_2, y_3, y_4 \xrightarrow{yields} U(t), L(t) \xrightarrow{yields} A \qquad (1)$$

$$A = \int_{t_1}^{t_2} U(t)\, dt - \int_{t_1}^{t_2} L(t)\, dt \qquad (2)$$

$$Temporal\ estimate\ uncertainty = U_T = A/(t_2 - t_1) \qquad (3)$$

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. 3-5) 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.

3.2 Temporal estimate uncertainty

Fig. 6 shows the application of the temporal estimate uncertainty methodology outlined in section 2.4, 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 upper and lower bound functions were adjusted iteratively until the enclosed area was minimised.[e] This was achieved graphically in a spreadsheet. 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).

As a contrasting example – in terms of magnitude – the same process is shown for R3 offshore wind in Fig. 7. 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).

The process shown in these two examples constitutes the intermediate graphical step required to obtain the full set of temporal estimate uncertainty results. The process was applied to each set of estimate sensitivities for R2 offshore wind, ASC coal with CCS and IGCC coal with CCS in the same manner. The collated numerical results of this analysis are displayed in Fig. 8.

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[e] One reviewer correctly highlighted that an iterative graphical adjustment did not guarantee minimisation. The sensitivity of the uncertainty measure to a deliberate misplacement of one of the bounding functions was tested, by introducing a visible gap between the extremity of an outermost trajectory and the function. The visible gap had a <£1/MWh impact on the results. As the conclusions we draw from the results do not hinge on this degree of precision, the method was deemed satisfactorily accurate for these purposes.

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.

Further caveats relate specifically to the temporal estimate uncertainty method proposed in this study. Firstly, simply tabulating the ranges – between the highest and lowest estimate trajectory – in each commissioning year would produce similar results to the method proposed. However, the single value achieved with the temporal estimate uncertainty measure eases comparability. Secondly, the measure proposed quantifies the range between the highest and lowest estimate trajectories, but takes no account of how many trajectories lie in between.[f] A weighting procedure was considered, by which a greater number of trajectories would have the effect of diminishing the measure of temporal estimate uncertainty value, for a given range between the highest and the lowest trajectory. This was rejected, as it would introduce a degree of arbitrariness. Furthermore, in the case of the DECC LCOE estimates the varying consistency of estimate coverage for each technology is potentially due to a number of factors (different consultants producing the earlier reports for instance), which do not necessarily indicate greater uncertainty.

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[f] One reviewer correctly highlighted that: the measure is determined by the range between the highest and lowest estimate trajectories and; that if one of these 'extremes' were omitted, the measure would alter significantly. However, unlike a standard statistical analysis, none of these trajectories (each consisting of several point estimates) can be classified as 'outliers', unless they were to be retracted by DECC. Therefore, disregarding – arbitrarily – any portion of the portfolio of figures would result in a selective interpretation of the estimates available.

The best way to address this deficiency would be to generate estimates on a consistent basis for each technology. This could be achieved by making a public version of the model available, allowing users to generate estimates for each commissioning year, thereby providing consistent estimate coverage. This would be a challenge as the model contains proprietary information in its input data.

In addition to those caveated, there are some costs that are omitted from LCOE estimates altogether, such as balancing costs (Gross et al., 2006). 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 (so called 'green jobs') 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 difficult to quantify meaningfully even after they have been accrued, let alone in the process of forecasting.

A comprehensive literature study on the subject of green jobs finds that renewable energy (and energy efficiency) investments can contribute to greater increases in short-term employment than equivalent investments in fossil-fuel capacity – i.e. they tend to be more labour-intensive (Blyth et al., 2014). However, the authors note two important caveats. Firstly, increasing labour intensity in the electricity sector – or in the wider economy for that matter – is not necessarily always practical or desirable, especially in times of high-employment or low productivity. Secondly, if during some period a Keynesian increase in labour intensity was a desirable end in itself, sectors such as domestic building construction may yield greater gains per unit invested. It is clear – as the report concludes – that the discussion of green jobs adds little clarity to decisions concerning electricity sector investment.

4.2 General observations

An almost entirely consistent trend exposed by the analyses is the decreasing spread of estimates with an increasing time horizon. This is well exhibited in Fig. 6-7, by the fact that the shaded areas bounding the estimate trajectories are consistently 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. In this regard, the estimates present an unintuitive and unrealistic picture of cost uncertainty. The convergence of further flung estimates does not necessarily point to a flawed estimation methodology, but it is remarkable. Modelling inputs for later commissioning dates will be based on fewer and lower quality items of information. This may explain the lesser variation in the annual estimates for the later commissioning dates, as there might be less evidence on which to base adjustments to a 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. 6) are taken as an example, the values in Table 4 can be compiled.

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 DECC 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 technology, but also the one least laden with uncertainty. This is perhaps not surprising as nuclear fission technology for power generation has been in development for several decades. Despite this, especially in the early report estimates, considerable FOAK premiums are forecasted initially due to a new design being used. The new EPR will indeed be the first of its kind in the UK, although the fundamental power generation concept is a PWR design – its manufacturers tout its proven track record 'based on 87 PWR designs throughout the world' (Areva, 2015). The EPR design does have an array of enhanced safety features that presumably demand its FOAK premium. However, if the appetite for increased safety is not abating after several decades of technological development, then why should it in the future? If it does not, and this leads to a constantly evolving design, this implies that FOAK premiums will endure.

A recent econometric study of the nuclear fleets of the US and France concludes that in contrast to other forms of generation (particularly other low carbon modes), technological progress has lead to increases in construction periods and costs (Berthélemy and Escobar Rangel, 2015). The authors find that cost reductions resulting from learning-by-doing are achieved when the same designer and model of reactor are used. When discussing the implications of the their conclusions for the future development of nuclear generation in the UK, they note that cost reductions are more likely to be gained in the same nuclear consortium. Therefore, they suggest, the benefits of competition between different designers and designs needs to be weighed against those of standardisation. On the one hand, given the evidence of escalating costs, the UK government's approach to shift risk to the private sector with the latest nuclear power agreement, at least partially, seems sensible. On the other hand, this means relinquishing the ability to standardise and ensure learning is conveyed between designers.

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 most conservative years' high estimates, parity is achieved well before 2030. It is hard to resist the conclusion that, economically, nuclear seems to 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 2.3.2 for the UK's most recently constructed nuclear plant – Sizewell B – yield the results in Table 5.

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 estimated, even whilst leaving all other quantities as forecast. 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 and magnitude of LCOE estimates presented is realistic. In a comprehensive study of UK nuclear costs, (Harris et al., 2013) also find that cost escalations and construction times are understated in government estimates, when compared to previous experience from European and US projects.

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 CO_2 price scenario imposed (see Fig. 3-5). However, it correlates well with current wholesale forecasts and central LCOE estimates. As well as the magnitude of recent estimates, the chronology appears convenient, given that the strike prices and LCOE estimates emanate from the same central source. 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 forecast wholesale cost.

We note that not all the associated costs of nuclear are included in the DECC LCOE estimates, nor could they be without difficulty. 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 decommissioning fund contribution cost accrued during the years of operation in the DECC LCOE 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. In the UK 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, 2014a). 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 unaccounted 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. 4). None of the central estimate trajectories reach wholesale price parity before 2025, and estimates for early R2 installations commissioning in 2015 are approximately three times the current wholesale cost. In terms of cost uncertainty, the picture remains bleak (see Fig. 8). 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 expediently and economically 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. 4) 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.

A study by The Crown Estates presents a more optimistic view of costs (Arwas et al., 2012). It forecasts an average LCOE declining to £89-115/MWh (in 2011 prices) for projects reaching FID in 2020, in the four scenarios it explores. In the three scenarios that achieve the feasibility threshold the report imposes (LCOE below £100/MWh by 2020) operational capacity and that reaching FID is assumed to comprise more than 25GW in 2020, and more than 35GW in 2025 (Arwas et al., 2012, pp. 40–44). An important input assumption in their modeling is that 'the move to deeper water and/or further from shore sites in Round 3 and Scottish Territorial Waters is not likely to result in a material LCOE penalty once the greater energy production due to higher wind speed is taken into account' (Arwas et al., 2012, p. viii). Here the study appears to diverge from the DECC view. R3 sites remain at a premium over R2 in DECC LCOE estimates made after the Crown Estates study was published (highlighted by the persistent gap between R2 and R3 estimate trajectories in Fig.4).

The Offshore Wind Cost Reduction Task Force (CRTF), echoes the findings of The Crown Estates study in its report (Jamieson, 2012). This report also stresses the need for costs to be reduced now, 'faster than would otherwise occur naturally' (Jamieson, 2012, p. 3). The recommendation for early intervention and investment is clear.

This raises two questions. Firstly, alongside the potential benefits of doing so, is any significant premium incurred by hastening deployment? Secondly, will cost reductions – either those forecast by DECC or the steeper declines forecast by The Crown Estates study – materialise in the absence of experience derived from hastened deployment in the UK? To explore the first question, Table 6 shows the minimum premiums (R2 central DECC LCOE estimate trajectories from Fig.4 used) over wholesale cost, approximated for the years 2015 and 2025.

The difference between the premium over wholesale cost in 2015 and 2025 is £59/MWh. Assuming an average load factor of 40%, 1GW of installed offshore wind produces approximately 3.5TWh/year. Multiplying by the LCOE premium difference of £59/MWh, these 3.5TWh cost £206.7m/year more when generated from a 1GW installation built in 2015 as opposed to 2025 – that is a £2.07bn/GW premium over the 10 years, in 2012 prices. Operational offshore wind capacity as of early 2015 is just over 4GW (RenewableUK, 2015). Under the 'Gone Green' scenario of the official National Grid projections, offshore wind capacity reaches approximately 25GW (of 100GW planned total capacity) by 2025 (Smith, 2014, p. 36). Using the £2.07bn/GW premium calculated above, the additional cost above wholesale of investing in this additional 21GW at 2015 LCOE prices rather than those of 2025, is £43.4bn or just over 1.5% of UK GDP, in 2012 prices. Moreover, the premium is likely to be larger because there is only a fraction of this resource available on R2 sites; around 7GW (RenewableUK, 2015). More expensive – according to DECC, but not The Crown Estates – R3 sites would have to be used for a considerable portion of new supply. This is a crude estimate, as not all of this capacity could be added instantaneously in either 2015 or 2025. However, even if the figure calculated is halved to account for a steady addition to capacity at linearly declining prices, it remains sizeable. Precision aside, it illustrates that substantial costs can be incurred if investments are ill timed, and that the decision over whether to hasten deployment is not straightforward.

If waiting for costs to decline *naturally* is to be contemplated, the second question raised above concerning the learning derived from experience, needs to be addressed. A recent empirical study of 41 offshore wind installations across Europe finds no evidence of country-specific or industry-wide learning effects, or increasing returns to scale thus far (Dismukes and Upton, 2015). An earlier study did find evidence of learning in the industry, but at very low rates (van der Zwaan et al., 2012).

(Jamasb, 2007) find that the importance of learning by research (R&D) relative to learning by doing (deploying installations) is greater for less developed technologies and declines as they mature. Boaz Moselle notes that although offshore wind is no longer an immature technology, there is still considerable potential for cost reduction to be delivered via R&D (Moselle, 2011). This is potentially much cheaper than learning derived via deployment. Moselle also notes that learning is likely to be local rather than global – that learning derived in the UK will only partially translate to other locations. Implied in this observation is that the corollary is true; lessons learnt elsewhere will be of only partial relevance in the UK context.

Implicit in the modeling scenarios in The Crown Estates' study, is the assumption that offshore wind deployment will drive down costs. This assumption entails large additions to capacity during a period when they – and to a greater extent, DECC – forecast prices to be high. The study also notes the importance of R&D-led learning, identifying Government-encouraged

R&D, and demonstration project support as cost saving prerequisites, although this is given much less emphasis. It is acknowledged in the literature above – and also by us – that some learning by deployment is likely to occur. How much, both in absolute terms and relative to that derivable via cheaper R&D, and under what conditions; is less clear. One encouraging sign is that the first competitive auction for Offshore Wind CfDs gave rise to strike prices of £119.89 in 2017/18 and £114.39/MWh in 2018/19 (2012 prices), suggesting some scope for cost reduction (DECC, 2015).

5.3 CCS

The contextual cost landscape for coal with CCS (see Fig. 5) 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 coal with 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 coal with 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. Coal with 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 coal with CCS is vested with considerable amounts of uncertainty; approaching double the levels of nuclear in the case of the low estimates for both coal with CCS sub-groups (see Fig. 8). Given this, and the fact that the first commercial-scale coal with CCS plant is yet to emerge from the planning process (HM Government, 2014b), it is questionable whether there is much of a degree of contention between coal with CCS and nuclear, at least in terms of significant generation capacity investment in the next 10-15 years.

These factors point to the likelihood that coal with 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 coal is 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, with both coal and gas CCS technologies. In early 2014, £100m of funding was allocated to take the White Rose (oxy-fuel CCS applied to coal with biomass co-firing at Drax power station) and Peterhead (gas with CCS at Peterhead power station) projects through to the design phase (BBC, 2014). Given this, CCS technologies are currently more akin to some tidal demonstration concepts (SPR, 2014), or the new 10MW AMSC SeaTitan turbine (AMSC, 2014), despite being presented alongside major technologies – such as offshore wind and nuclear – in DECC's annual reports examined in this work.

5.4 Conclusions

A richer picture of uncertainty can be gleaned if current estimation is tracked against what has been estimated previously. The analyses outlined in this study add a dimension to the consideration of LCOE uncertainty by including a backward looking reflection of the estimates of future costs, and quantifying the revealed variability. In its implementation the methodology highlights a number of irregularities in the current presentation of cost uncertainty, not readily exposed in the current temporally isolated approach. The richer picture of uncertainty proposed could lead to enhanced insight in the process of policy-making.

The concept proposed could be developed and refined in a number of ways to yield further policy insights. Firstly, the methodology presented here can be applied more generally to technologies aside from the three selected in this study, were sufficient data made available or generated. These include some other core generation technologies aside from nuclear, such as unabated coal and gas. Beyond this, the proposed analyses could be used to examine the presentation of uncertainty in a variety of LCOE estimate data for other countries and regions.

Secondly, the overall precision of the analyses in this study 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 DECC LCOE 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.

Thirdly, introducing a probabilistic component to the presentation of uncertainty could greatly enhance the picture provided by government LCOE cost estimates. The fan chart presentation of the BofE MPC's projections discussed above (see Fig. 1) could present the framework for integrating uncertainty-focused elicitations with the traditional LCOE modelling methodology.

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 analyses proposed here accordingly. As an example, varying system costs, such as those stemming from the intermittency of renewables or the inflexibility of nuclear installations, are absent in the LCOE estimates considered here. Quantifying and incorporating system costs constitute significant areas of research in themselves (Hirth et al., 2015; Katzenstein and Apt, 2012), and are yet to be incorporated in mainstream LCOE modelling.

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Tables

Table 1
Summary of technology groups and sub-groups.

Technology groups	Technology sub-groups
Nuclear	PWR/EPR
O shore Wind	Round 2 (R2)
	Round 3 (R3)
CCS	Advanced Super Cri cal (ASC) coal with CCS
	Integrated Gasi ca on Combined Cycle (IGCC) coal with CCS

Table 2
Primary data sources: DECC LCOE reports.

Author	Year	Technology data used	Source
Mo MacDonald	2010	Nuclear, O shore Wind, CCS	(Mo MacDonald, 2010)
Arup	2011	O shore Wind	(Arup, 2011)
DECC	2012	Nuclear, O shore Wind, CCS	(DECC, 2012)
DECC	2013 (July)	Nuclear, O shore Wind, CCS	(DECC, 2013a)
DECC	2013 (December)	Nuclear, O shore Wind, CCS	(DECC, 2013b)

Table 3

Contextual informa on: LCOE es mates, out-turn approxima ons and strike prices.

	Installa on (proposed/actual commissioning date)	LCOE[a] £/MWh	Data descrip on	Source(s)
Nuclear	Sizewell B (1994)	93.15	CEGB[b] net e ec ve cost es mate	(Barnes, 1990, Vol. 3, C29, p.825)
	Hinkley Point C (1996)	65.48	CEGB[b] central cost es mates	(Barnes, 1990, Vol. 3, C29, p.825)
	Sizewell B (1995)	131.79	Out-turn using reported CAPEX	(Toke, 2005)
	Sizewell B (1994)	58.20	CEGB[b] central cost es mates	(Lay eld, 1987, Vol. 5, C55, p.8)
	Hinkley Point C (2023)	92.50	Strike price	(DECC, 2013d)
	Sizewell C (2023)	89.50	Strike price	(DECC, 2013d)
Offshore Wind	Blyth O shore (2000)	90.57	Out-turn approxima ons derived from reported project costs, average OPEX es mates and the latest UK average o shore wind load factor	Reported project costs: 4CO shore Database (4CO shore, 2014) OPEX es mates: Arup Genera on 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		
	Ken sh 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		
	Gun eet 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		
	Gun eet 3 (2013)	194.61		
CCS	Post-comb. coal (2018)	166.50	Projected levelised costs based on op mised nancial, technology advancement and policy condi ons	(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		

Table 4

Ver cal uncertainty boundary spread in 2020 and 2030: Nuclear central es mates.

Sensi vity	Es mate Spread	
	2020, £(2012)/MWh	2030, £(2012)/MWh
Minimum low	73	56
Maximum high	133	93
Range	60	37

Table 5

Various CAPEX and LCOE es mates for Sizewell B nuclear power sta on.

Es mate	Es ma on year	CAPEX, £(2012)m	LCOE es mate, £(2012)/MWh
Sizewell B inquiry	1987	-	58
Hinkley Point C inquiry	1990	3,157	93
Es mated out-turn	1995[c]	4,969	132

[a] Note: Colours correspond to the contextual data points plo ed in Fig. 2 & 3.
[b] Central Electricity Genera ng Board
[c] Note: In the case of the es mated out-turn cost it is not the es mate year, but the year of comple on of the plant.

Table 6
LCOE premiums in 2015 and 2025: R2 o shore wind central es mates.

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

Figure(s)

Figures

Fig. 1. Example of Bank of England Monetary Policy Committee 'Fan Chart' (Elder et al., 2005).

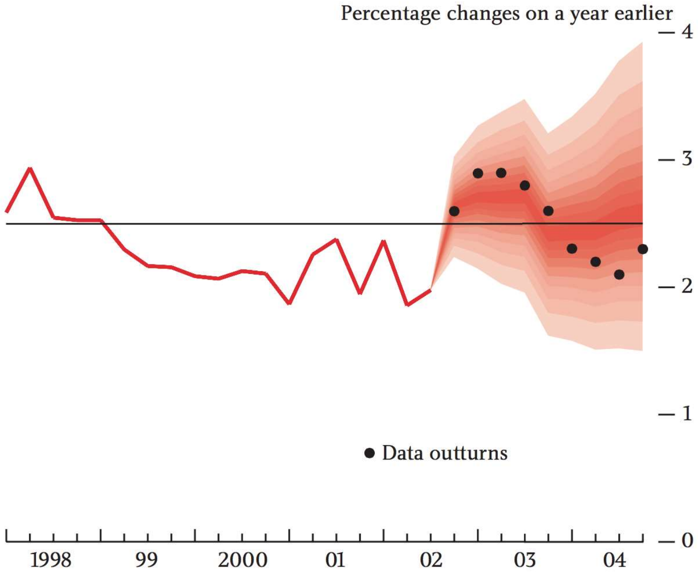

Fig. 2. Construction of temporal estimate uncertainty analysis.

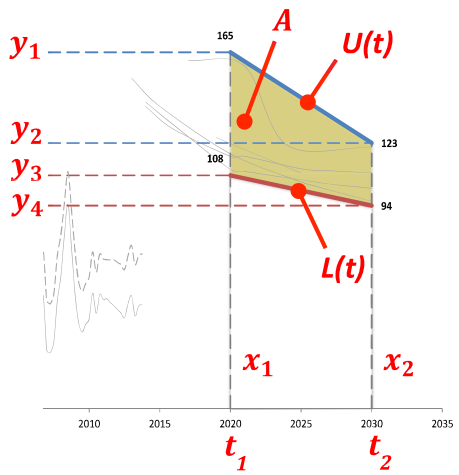

Fig. 3. Contextual cost landscape for nuclear central LCOE estimates.

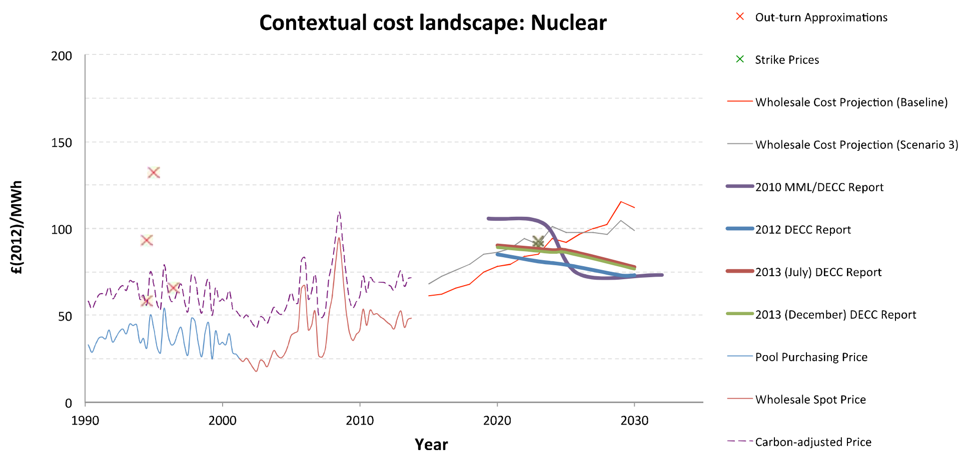

Fig. 4. Contextual cost landscape for offshore wind central LCOE estimates.

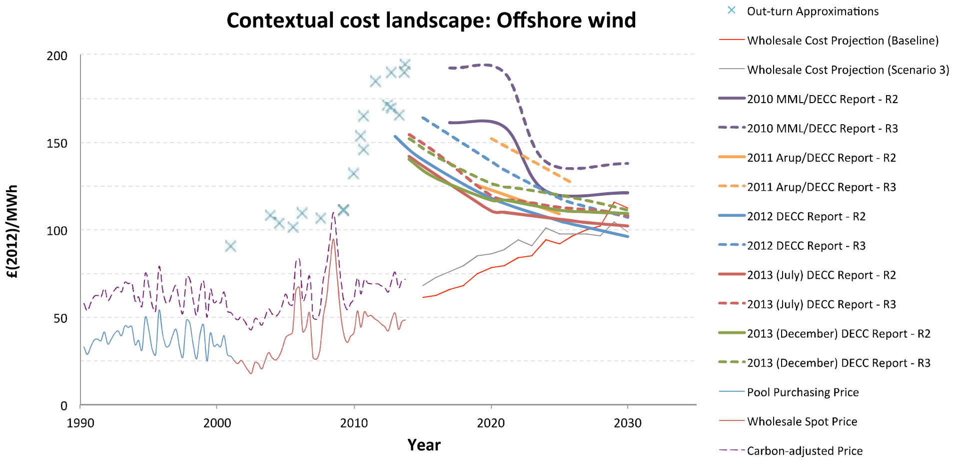

Fig. 5. Contextual cost landscape for CCS central LCOE estimates.

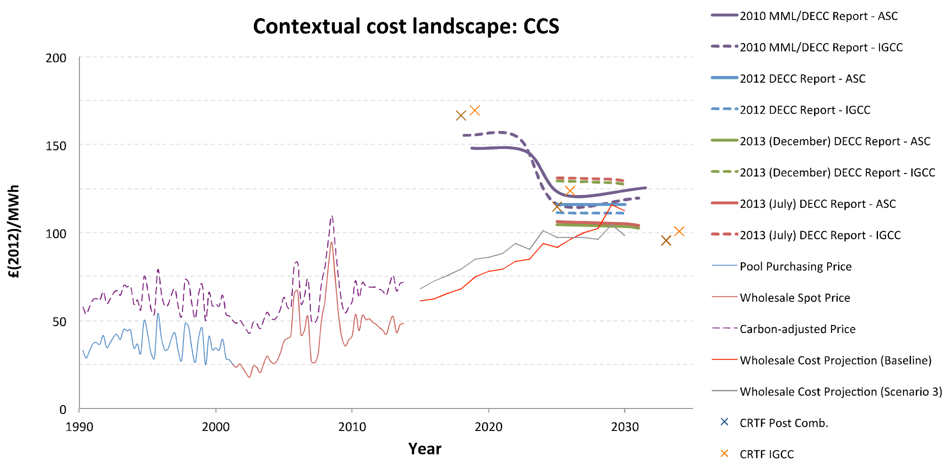

Fig. 6. Temporal estimate uncertainty analysis formation: Low, central and high nuclear estimates example.

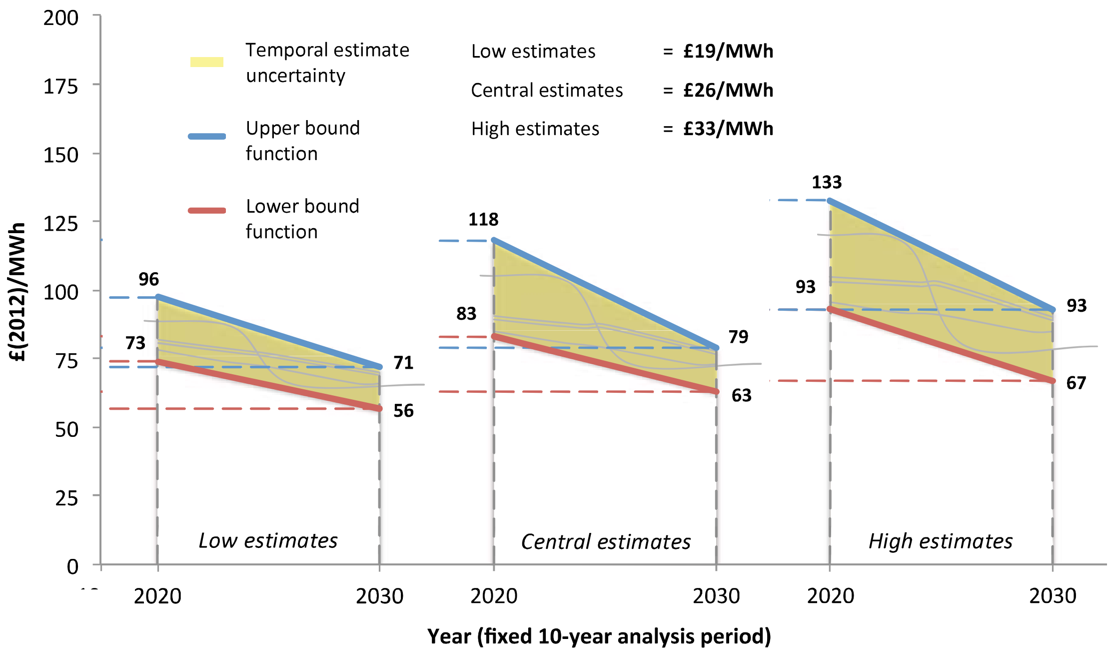

Fig. 7. Temporal estimate uncertainty analysis formation: Low, central and high R3 offshore wind estimates example.

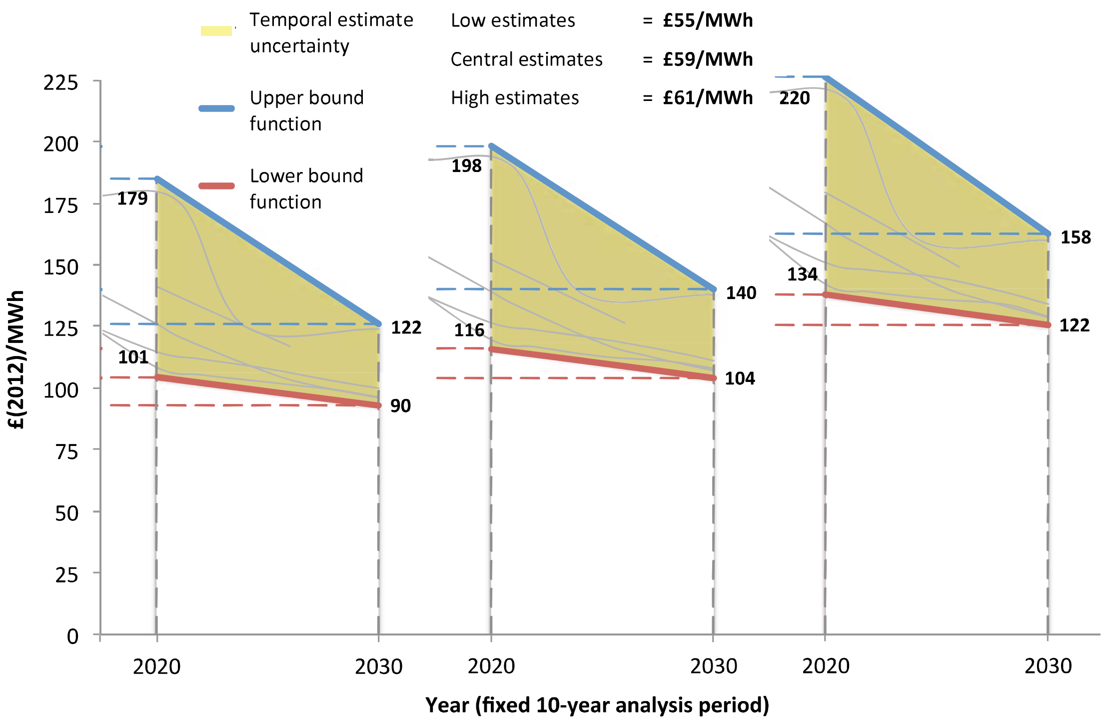

Fig. 8. Temporal estimate uncertainty results: Low, central and high estimates for each technology.