Updated Annex to 'Civil Nuclear Energy - An Alternative Perspective' discussion paper
(updated on 30th Jan 2018 to include Aurora report and text refinements)

Introduction

This Annex to the 'Alternative Perspective' discussion paper details the methodology, assumptions and calculations which provides the cost estimates for :

i) a range of nuclear subsidy costs on consumer bills of Hinkley Point C and subsequent projects comprising the planned 'first-tranche' 18 GW nuclear programme (in £ billions over 60 years) compared to an offshore wind deployment counterfactual to 2090
ii) a 'reference case' **additional** 'system' cost (in £ /MWh) of an offshore wind counterfactual to a given nuclear deployment

In this paper the 'additional system costs' essentially comprises cost estimates over 60 years for the additional : gas-fired back-up Capex + 'gas' fuel balancing Opex + electrolyser Capex. An estimate for the cost-benefit of competitive post CfD contract nuclear electricity is also included in the counterfactual.

This additional comparative methodology is different to other back-up, balancing and integration cost methodologies. Some system cost estimates are based on actual (estimates) of extra costs imposed on a conventional fossil-based system by the inclusion of intermittent Renewable Energy Systems (iRES) mainly wind and PV.

This paper's methodology aims to give a first-approximation estimate of the iRES counterfactual system costs minus the nuclear programme's own system cost (which also includes the need to meet peak demands, and probably electrolytic hydrogen production at scale by mid-Century) over a period of 60 years (the operational life of proposed new reactors).

Nuclear system costs are usually overlooked in many analyses to date and in that sense are (another) hidden or forgotten subsidy on consumer bills. For these reasons the additional £ /MWh cost could be denoted NNCASC (non-nuclear counterfactual additional system cost) or similar acronym.

Estimates to date of actual, as distinct to additional, extra intermittent iRES system costs vary considerably. Much can depend on what is deemed a 'system' cost, what time scale and what technologies are considered, what the cost is extra to (eg a future nuclear or existing fossil comparator), and what if any future strategic considerations, eg electrolytic hydrogen production at scale, are included.

A counterfactual to the planned 15.5-18 GW first-tranche new-build nuclear programme

The Government's planned **15.5 - 18 GW new-build nuclear programme** would generate 120 -140 TWh per year of electricity output for an operational life of 60 years starting between 2025-2035 and ending in 2085-2095. Hinkley Point C under construction will generate 25.5 TWh/y if or when commissioned.

For comparison, an additional **deployment of 30-35 GW offshore wind farms**, also generating 120-140 TWh per year (at average 45 % annual capacity factor), built across the 2020s and into the late 2030s, is used as a 'counterfactual' or alternative scenario to the planned nuclear scenario. It is realistic counterfactual as much or possibly all of the capacity could probably be consented, funded and built in the required timescale.

It may be that some additional PV and other renewable schemes would also need to be included in a counterfactual renewable 'mix' at the higher nuclear outputs if construction and delivery constraints in the offshore wind sector were envisaged eg anything totaling over 40 GW by the late 2030s (including up to 14 GW of existing and consented schemes by 2023). However the bulk of the output would be from additional offshore wind projects.

If Hinkley Point C (generating 25.5 TWh/y) is not cancelled and only four further first-tranche schemes were built (generating 96 TWh/y) then the counterfactual offshore wind capacity would fall to **24 GW** (24 x 8.76 x 0.45 = 96).

This offshore wind counterfactual would be an additional offshore wind deployment from about 2024. All existing and auctioned offshore windfarms to date will result in 14 GW deployed by about 2024 (ie about 1 GW per year since 2010) according to Aurora (see link below). All renewables support funds to 2025 eg the Government's announced £ 557 million funding pot, could be used in any scenario to support further onshore wind deployment in Scotland and Wales plus PV and other newer renewable tech deployment across the UK.

So, 24-35 GW of offshore wind built over 15 years starting from 2021 and commencing operation from 2024 to 2035, would be additional schemes and would constitute a realistic buildable 'counterfactual' (ie a build rate of between 1.6 to possibly 2.3 GW per year).

Many or most of the other large inputs and outputs and costs to the UK electricity Grid would essentially be the same or similar in either or any future scenario to 2050 and beyond eg inputs from renewables already built, PV, demand changes, the existing fleet of gas-fired capacity, pumped and other storage capacity. Even the amount of Natural Gas used, decreasing year on year to 2050, would roughly be the same in either scenario for a given climate / GHG emission reduction / intensity policy (ie currently 50-100 grammes/kWh by 2030).

So, given the similar backdrops, a first-approximation of the additional system costs of an equivalent or 'counterfactual' offshore wind deployment, called the 'reference case' cost, compared to the nuclear programme, can be made by comparing the following :

i) Capex cost of additional gas-fired back-up capacity required for the counterfactual wind deployment

ii) Opex cost of additional 'gas' fuel used in 'balancing' intermittent wind (incurred due to combustion inefficiencies in the gas-fired plants during continuous load-following and cold start-stop operations)

iii) cost of additional electrolyser capacity Capex in utilising wind supply excesses (to instantaneous consumer Grid demand) to produce a given annual production of electrolytic hydrogen to supply industry (for low-carbon chemicals production eg fertilizers), transport and heat sector applications

The nuclear subsidy assessment methodology uses the following **assumptions** :

i) the first replacement counterfactual windfarms would be phased in after 20+ years (ie from 2045-2055) which would generate for an additional 15 to 20+ years so probably 40-45 years in total

ii) average CfD cost of 24-35 GW of windfarms commissioning from 2024 to 2035 = £ 60 /MWh (in 2017 prices) for 15 year contracts *

iii) CfD costs (two scenarios) of first replacement windfarms around the late 2040s = £ 55 /MWh and £ 50 / MWh for 15 years (ie a very conservative CfD cost reduction by late 2040s)

iv) Nov 2017 CPI prices (HPC + Sizewell £ 89.50 / MWh in 2012 > £ 95, and HPC alone at £ 92.50 > £ 98 / MWh in Nov 2017)

v) nuclear CfD price reductions (four sample scenarios) for the remaining five first-tranche schemes : £82.50, £80, £75, £70 /MWh for 35 years

vi) additional system costs for offshore wind (back-up, + gas balancing + electrolyser costs) range between £ 5-10 /MWh (ie ranged 33 % above and below a first approximation reference case cost of £ 7.50 /MWh estimated in this Annex)

vii) offshore wind is assumed in the counterfactuals but other renewables of similar 'CfD+ additional system' cost could be mixed in to provide the optimal RE counterfactuals to new-build nuclear projects and or to address scale of deployment practicalities

viii) post 35 year contract nuclear wholesale prices (ie post 2060-65) are pitched to just undercut the then cheapest renewables eg offshore wind (some also post contract) by £ 1 /MWh (and stress tested at £ 2 /MWh) for the remainder of the reactors 60 year operational life (to 2085-90) to maximise profits - this market benefit is included in the offshore wind additional (technical) systems cost in this paper for brevity

ix) an annual electrolytic hydrogen demand of 1 Mt pa consuming 50 TWh/y electricity is required by industry (based on forecast EU H2 production per capita - see Future Hydrogen Demand section below)

* significantly lower CfDs than £ 60 /MWh have been forecast even by 2025 by Aurora (see link below) and may be subsidy-free by 2040 (see National Grid study link below). That said, further cost reductions may be counteracted to some extent by scheme deployment further offshore or deeper water and risk in early floating offshore wind schemes.

Aurora report : estimates a further drop of 25-30 % on 2017 capital cost by 2025 : 'The new economics of offshore wind' Jan 2018 : https://www.auroraer.com/insight/new-economics-of-offshore-wind/

July 2017 scenarios study by National Grid : suggests that offshore wind could be subsidy free by 2040 : https://www.windpowermonthly.com/article/1439381/national-grid-sees-subsidy-free-offshore-wind-2040

Note that some 'additional' windfarms would commission before most of the first-tranche nuclear schemes start generating post 2025 and some may commission just after unless the last nuclear scheme slips beyond 2035. So the overall GHG emission reductions value needs to be compared in that light (eg in $MtCO_2$ avoided x years to 2050).

Estimate of HPC subsidy over renewables (offshore wind) counterfactual

Note that HPC CfD contract price £ 92.50 / MWh was set in 2012 prices and CPI index-linked > £ 98 /MWh in Nov 2017 prices, falling to £ 89.50 /MWh if Sizewell C is contracted > £ 95 /MWh in Nov 2017 prices.

Case 1 If Sizewell C is not consented then HPC cost would be £ 98 /MWh

(£ [98 - 70] /MWh x 25.5 m MWh/y x 15 years + £ [98 - 65] /MWh x 25.5 m MWh/y x 20 years) = £ m (420 + 660) x 25.5 = **£ 27.5 billion** for Hinkley Point if additional RE system costs are £ 10 /MWh

(£ [98 - 65] /MWh x 25.5 m MWh/y x 15 years + £ [98 - 60] /MWh x 25.5 m MWh/y x 20 years) = £ m (495 + 760) x 25.5 = **£ 32.0 billion** for Hinkley Point if additional RE system costs are £ 5 /MWh or technology costs fall to £ 50 /MWh and additional system costs rise to £ 10 /MWh

(£ [98 - 65] /MWh x 25.5 m MWh/y x 15 years + £ [98 - 55] /MWh x 25.5 m MWh/y x 20 years) = £ m (495 + 860) x 25.5 = **£ 34.5 billion** for Hinkley Point if additional RE system costs are £ 5 /MWh and technology costs fall to £ 50 /MWh

Case 2 If Sizewell C is consented then the HPC deal cost would reduce to £ 95 /MWh, bringing subsidy down by £ 2.7 billion

(£ [95 - 70] /MWh x 25.5 m MWh/y x 15 years + £ [95 - 65] /MWh x 25.5 m MWh/y x 20 years) = £ m (375 + 600) x 25.5 = **£ 24.8 billion** for Hinkley Point C if additional RE system costs are £ 10 /MWh

(£ [95 - 65] /MWh x 25.5 m MWh/y x 15 years + £ [95 - 60] /MWh x 25.5 m MWh/y x 20 years) = £ m (450 + 700) x 25.5 = **£ 29.3 billion** for Hinkley Point C if additional RE system costs are £ 5 /MWh or technology costs fall to £ 50 /MWh and additional system costs rise to £ 10 /MWh

(£ [95 - 65] /MWh x 25.5 m MWh/y x 15 years + £ [95 - 55] /MWh x 25.5 m MWh/y x 20 years) = £ m (450 + 800) x 25.5 = **£ 31.9 billion** for Hinkley Point C if additional RE system costs are £ 5 /MWh and technology costs fall to £ 50 /MWh

Estimates of possible subsidy costs of each subsequent scheme (Moorside, Wylfa B Sizewell C, Oldbury, Bradwell) assuming £ 82.5, £ 80, £ 75 and £ 70 /MWh contract prices for 35 years

Note that the annual nuclear output is assumed at 25.5 TWh/y (3.24 GW Sizewell C) though it would be less for 2.7 GW (23.6 TWh/y) Wylfa B and Oldbury schemes and more for a 3.6 GW (28.4 TWh/y) Moorside scheme. So, for example, multiply by 23.6/25.5 to obtain prices for Wylfa B and Oldbury from cost figures below.

At £ 82.50 / MWh CfD :

(£ [82.5 - 70] /MWh x 25.5 m MWh/y x 15 years + £ [82.5 - 65] /MWh x 25.5 m MWh/y x 20 years) = £ m (187.5 + 350) x 25.5 = **£ 13.7 billion** if additional RE system costs are £ 10 /MWh

(£ [82.5 - 65] /MWh x 25.5 m MWh/y x 15 years + £ [82.5 - 60] /MWh x 25.5 m MWh/y x 20 years) = £ m (262.5 + 450) x 25.5 = **£ 18.2 billion** if additional RE system costs are £ 5 /MWh or technology costs fall to £ 50 /MWh and additional system costs rise to £ 10 /MWh

(£ [82.5 - 65] /MWh x 25.5 m MWh/y x 15 years + £ [82.5 - 55] /MWh x 25.5 m MWh/y x 20 years) = £ m (262.5 + 550) x 25.5 = **£ 20.7 billion** if additional RE system costs are £ 5 /MWh and technology costs fall to £ 50 /MWh

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£ 80 / MWh :

(£ [80 - 70] /MWh x 25.5 m MWh/y x 15 years + £ [80 - 65] /MWh x 25.5 m MWh/y x 20 years) = £ m (150 + 300) x 25.5 = **£ 11.5 billion** if additional RE system costs are £ 10 /MWh

(£ [80 - 65] /MWh x 25.5 m MWh/y x 15 years + £ [80 - 60] /MWh x 25.5 m MWh/y x 20 years) = £ m (225 + 400) x 25.5 = **£ 15.9 billion** if additional RE system costs are £ 5 /MWh or technology costs fall to £ 50 /MWh and additional system costs rise to £ 10 /MWh

(£ [80 - 65] /MWh x 25.5 m MWh/y x 15 years + £ [80 - 55] /MWh x 25.5 m MWh/y x 20 years) = £ m (225 + 500) x 25.5 = **£ 18.5 billion** if RE system costs are £ 5 /MWh and technology costs fall to £ 50 /MWh

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£ 75 / MWh :

(£ [75 - 70] /MWh x 25.5 m MWh/y x 15 years + £ [75 - 65] /MWh x 25.5 m MWh/y x 20 years) = £ m (75 + 200) x 25.5 = **£ 7 billion** if additional RE system costs are £ 10 /MWh

(£ [75 - 65] /MWh x 25.5 m MWh/y x 15 years + £ [75 - 60] /MWh x 25.5 m MWh/y x 20 years) = £ m (150 + 300) x 25.5 = **£ 11.5 billion** if additional RE system costs are £ 5 /MWh or technology costs fall to £ 50 /MWh and additional system costs rise to £ 10 /MWh

(£ [75 - 65] /MWh x 25.5 m MWh/y x 15 years + £ [75 - 55] /MWh x 25.5 m MWh/y x 20 years) = £ m (150 + 400) x 25.5 = **£ 14 billion** if RE system costs are £ 5 /MWh and technology costs fall to £ 50 /MWh

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£ 70 / MWh :

(£ [70 - 70] /MWh x 25.5 m MWh/y x 15 years + £ [70 - 65] /MWh x 25.5 m MWh/y x 20 years) = £ m (0 + 100) x 25.5 = **£ 2.5 billion** if additional RE system costs are £ 10 /MWh

(£ [70 - 65] /MWh x 25.5 m MWh/y x 15 years + £ [70 - 60] /MWh x 25.5 m MWh/y x 20 years) = £ m (75 + 200) x 25.5 = **£ 7 billion** if additional RE system costs are £ 5 /MWh or technology costs fall to £ 50 /MWh and additional system costs rise to £ 10 /MWh

(£ [70 - 65] /MWh x 25.5 m MWh/y x 15 years + £ [70 - 55] /MWh x 25.5 m MWh/y x 20 years) = £ m (75 + 300) x 25.5 = **£ 9.5 billion** if RE system costs are £ 5 /MWh and technology costs fall to £ 50 /MWh

Nuclear subsidies for various 16 GW CfD scenarios (five project first-tranche programme) :

HPC at £ 30 billion + 4 other projects (at £ 70 /MWh) x 5 billion = £ 50 billion
HPC at £ 30 billion + 4 other projects (at £ 75 /MWh) x 9.5 billion = £ 68 billion
HPC at £ 30 billion + 4 other projects (at £ 80 /MWh) x 13.7 billion = £ 85 billion

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Additional offshore wind counterfactual System Costs - Methodology

This section puts forward a transparent, first-approximation methodology (proposed by the author) to assess the additional system costs of an offshore wind deployment (in £ /MWh) counterfactual to a given nuclear programme or deployment. Two counterfactual have been assessed, the first would generate the equivalent annual electricity output (120-140 TWh/year) of a 15.5 -18 GW (five or six project) first-tranche new-build nuclear programme (FTNP) by 2035, the second is a Grid-scale (335 TWh/year) 85 GW offshore wind deployment versus 40+ GW nuclear deployment by mid-Century.

The 'additional costs' methodology below is used because it provides a relatively simple and hence more transparent and accessible way to calculate a first-approximation cost for the purposes of wider scenario analysis in which technology costs and their CfD prices play the dominant comparative role. The assumptions and calculations can be varied or changed rapidly for sensitivity and stress testing.

The problems of different system cost accounting models and methods are acknowledged and evident in this report : http://www.creg.info/pdf/ARCC/161019-KULeuven.pdf

Transparency is key because estimates arising from complex computer programmes (eg BEIS Dynamic Dispatch Modeling or DDM) are anything but transparent. The model's assumptions, methodology, and the modelers choice of options cannot easily be scrutinised by the public (which include consumers, taxpayers and voters).

Estimates by nuclear vendors with £ billions at stake (eg EdF estimate £ 15 /MWh for wind - currently not available for scrutiny ?) can hardly be considered or trusted as independent, objective, or accurate, particularly for a full 60+ year deployment comparison to 2090. EdFs £ 15 /MWh figure appears to be for existing onshore wind including curtailment costs and probably does not include new-build nuclear's system costs, so would not be an 'additional' cost.

Though not strictly a system (ie technical) cost a nuclear post-contract (wholesale competitiveness) benefit cost to consumers has also been estimated below. This nuclear benefit cost has been added into the system costs in the above programme analysis section above for brevity.

Additional 'system costs' for a strategic-scale offshore wind counterfactual compared to a 15.5 -18 GW first-tranche nuclear deployment

In any likely energy scenario to 2060 and beyond, ever improving and lower-cost battery and other electricity storage technologies will have an increasingly significant 'system' role in backing-up the intermittent output from various renewable energy technologies. However, currently foreseeable storage technologies could not replace the need for strategic-scale wind energy deployment to be firmly backed-up by mostly gas-fired generation.

Batteries are now helping provide small levels (tens of MW) of fast (sub one second) back-up and frequency control, including on some windfarm sites. The largest battery scheme in the world, the size of a football field, just built in South Australia has a capacity of just 0.129 GWh. For comparison, the Dinorwic pumped-storage scheme is 11 GWh or 85 times larger. In the coming decades significant battery deployments may well help meet peaks in daily demand (tens of GWh scale).

Storage at such scale would significantly optimise the use and hence cost of gas-fired back-up schemes by minimising fuel inefficient cold-starts, stand-by and part-loading. Similarly, batteries would help maximise hydrogen output of electrolysers per GW installed. By 2060 a UK-wide battery electric vehicle fleet may have a storage capacity of several TWh, some of which could be used by a smart Grid for system purposes.

Even at TWh scale, batteries could not significantly replace gas-fired back-up, for example, in a very low-wind winter month when wind output may fall over 10 TWh below average and there would be little PV. As both PV and wind output can fall to zero on a cold still winter evening when Grid demand is at its highest (currently 60 GW peaks and 85 GW peaks are forecast) most of that peak would need to be met by gas-fired back-up schemes (gas turbines, engines and fuel cells).

Any back-up adds 'system' costs to any intermittent (or baseload) technology to reach a 'Whole System Cost'. The analysis below aims to provide useful range of estimates, among many unknowns, of how much the ADDITIONAL system cost, compared to a nuclear scenario, that an offshore wind deployment and the firm back-up it would require. The analysis includes gas-fired Capex, gas balancing Opex, electrolyser Capex (electrolyser Opex assumed to be equal), post-35 year contract nuclear pricing and considers transmission link costs.

In both or any likely Grid decarbonisation policy and generation scenario a similar volume of 'gas' (Natural Gas declining year by year, bio-methane and bio-SNG increasing) would likely be used to provide the daily to seasonal supply-demand matching in transition to a low-carbon UK energy system by 2050, irrespective of the installed capacity of gas-fired plant deployed in different scenarios.

A 'Whole System Cost' analysis has been carried out by NERA in Feb 2016 :
http://www.nera.com/content/dam/nera/publications/2016/NERA_Imperial_Feb_2016_Renewable_Subsidies_and_Whole_System_Costs_FINAL_160216.pdf.

It estimates for offshore windfarm schemes built in the 2020s the system costs would be 7% of the levelised cost of energy (LCOE) of the technology. Note that NERA exclude the transmission reinforcement cost and notes (5) that : *Generators pay Transmission*

Network Use of System (or TNUoS) charges, which are reflected as plant operating costs in the LCOE, but there is disagreement about whether these charges accurately reflect the costs imposed by individual generators.

The scenarios comparison below assesses the 'additional system costs' of a 35 GW of offshore wind deployment compared to 18 GW of nuclear capacity which would both generate about 140 TWh per year (offshore wind at 45 % Capacity factor):

Additional back-up (gas-fired capacity) Capex costs

Assuming zero Capacity Credit and no supply via inter-connectors during major low-wind periods over western Europe there would be occasional times of low or zero wind generated electricity supply. Consequently, the offshore wind counterfactual is assumed to need 18 GW of gas-fired back-up capacity to provide the same output as the nuclear 18 GW baseload.

So, the offshore wind scenario would need about 15.8 GW of additional gas-fired back-up capacity (ie 18 - 3.2 + 1) assuming the nuclear scenario requires 3.2 GW of gas-fired back-up to cover outages (Grid in-feed losses) of the two largest units on its Grid system (ie two 1.6 GW EPR reactors) and offshore wind requires 1 GW (ie two 0.5 GW CCGTs).

The additional 15.8 GW of capacity would be relatively cheap to build and, being widely decentralised, would provide a strategic level of Grid resilience with major National Defence benefits. The capacity would comprise a mix of CCGTs, OCGTs / aero-derivatives, gas-engines and fuel cells.

The Capex for the additional 15.8 GW of gas-fired back-up capacity would be about £ 7.1 billion (assuming £ 0.45 billion per GW installed) and could operate for about or over 30 years at low capacity factors. Assuming <u>complete replacement</u> for the remaining 30-35 years the total cost would be **£ 14.2 billion**. Over the first 35 years the share of Capex = **£ 8.3 billion** (14.2 x 35/60) and post-contract 2062-2088 Capex = **£ 5.9 billion** (14.2 x 25/60)

As an 18 GW nuclear programme or 35 GW offshore wind counterfactual would generate 4,900 TWh of electricity over 35 years (140 x 35) then the additional 15.8 GW of wind back-up Capex 2028-2062 = **£ 1.70 / MWh** (8,300 / [140 x 35]). The same deployment would generate 3,500 TWh of electricity over 25 years (140 x 25) then the 15.8 GW of wind back-up Capex 2063-2088 = **£ 1.70 / MWh** (5,900 / [140 x 25]).

The cost of the additional gas-fired Capex = **£ 1.70 /MWh over 60 years** (14,200 / [140 x 60]).

CHECK : assessed as part of a 100% RE scenario with Grid-scale offshore wind counterfactual by 2050-60 (see section 'A 100 % renewable energy system by mid-Century' below) the additional gas-fired Capex costs pre and post 2062 costs could be slightly higher :

Gas-fired Capex 2028-2062 = **£ 1.80 /MWh** and gas-fired Capex 2063-2088 = **£ 1.80 /MWh** and gas-fired Capex **= £ 1.80 /MWh over 60 years**

Additional balancing ‘gas’ Opex cost

It is likely that more ‘gas’-fired capacity will be load-following or 'cycling' more in the offshore wind counterfactual as the cumulative output of intermittent wind and PV sources varies (from seconds to seasons). Note that ‘gas’ refers to any one or more of the following : Natural Gas, bio-methane, bio-Synthetic Natural Gas, electrolytic hydrogen) and is assumed to increasing comprise lower-carbon mixes year on year.

The additional load-following would result in some additional gas fuel costs due lower part-load fuel efficiency and cold-starting. That said, next-generation gas turbines are being design specifically to efficiently load-follow and fast-start, and low-cost batteries can optimise fuel efficiency by minimising part load running (delaying starts and recharging using excess full-load output). Also, Grid demand profile (diurnal and seasonal) is changing as efficient technologies are deployed eg LED's, more homes are built and electric vehicles become commonplace by 2050 and probably ubiquitous by 2060 with a potentially a system transformative 2-3 TWh of 'smart' vehicle battery storage.

Demand Management will further help minimise additional costs. Also there will be prolonged times, perhaps most of the summer season, when supply from PV+wind or PV+nuclear would exceed demand and any supply variability would only seen across the electrolyser fleet. Most of the resulting variable hydrogen output would be stored anyway awaiting subsequent seasonal demands. Inter-connectors, especially via offshore windfarms in the North Sea connecting to mainland Europe and Norwegian pumped-storage schemes, could also minimise balancing gas use towards 2050 and beyond.

The heat sector might also demand significant more electricity but other non-electric heat scenarios are very possible including PV-T with inter-seasonal ground heat storage (GHS) either linked by district heat networks or individual stores. Sweden with a population of 10 million people currently has 20 <u>TWh/y heat</u> of GHS capacity or 2 <u>MWh heat</u> per person, and rising. For a UK population of 70 million that would be equivalent to 150-200 <u>TWh/y heat</u> available in deepest winter. More summer heat could be stored as required. For example, 300 <u>TWh heat</u> of ground heat stores would avoid 100 TWh/y of electricity demand by heat pumps at COP3.

Weather forecasting, which plays a significant role in reducing load-following inefficiencies, is improving all the time and aggregation over the whole UKCS land and sea area out to possibly 100 miles is likely to result in highly accurate forecasting. A study in Finland of 24 windfarms over 3 years estimated a wind balancing cost of € 1-1.4 /MWh and costs down to $ 10 cents have been estimated in the US (page 70-71 of Final Summary Report) : Task 25 .

So, given that other renewables will be on the system too in both RE and nuclear-inclusive scenarios (eg many tens of TWh/y of PV, possibly 10-20 TWh/y of lagoons, hydro 5 TWh/y, and a few TWh/y of marine current, wave and geothermal) it is very difficult to work out a cost for the additional gas used in balancing from hundreds of possible scenarios. So this analysis considers a likely range of additional balancing gas Opex cost scenarios which can then be used in wider analysis including assessing gas Opex cost sensitivity compared to maturing wind / RE technology costs.

Note the term for primary energy content of gas namely TWh thermal should not to be confused with TWh electricity eg 2 TWh thermal of gas would generate 1 TWh of electricity in a gas turbine of efficiency 50 % (2 x 50 % = 1)

It could be that by 2045 sufficient wind, PV and other renewables, batteries, vehicle batteries, other storage, Smart Grids and inter-connectors have or are being deployed to obviate most or all wasteful additional 'gas' burn post 2050. Bio-derived gases (bio-methane, bio-gas, bio-SNG) may well be available only in limited quantities. In the scenarios below only upto around 70 TWh/y thermal of low-carbon bio gases are assumed to be available, generating 30 TWh/y electricity from 2060 to help balance the Grid (eg 67 x 45 % = 30).

Presumably, in the 25 years beyond the nuclear contract periods (ie beyond 2060-65) the nuclear utilities would pitch their power price just below that of wind/renewables inclusive of the latter's additional system costs. So there would be relatively minimal wholesale saving benefitting the consumer at most eg £ 1 /MWh for 140 TWh/y on nuclear electricity would save the consumer over 25 years about £ 3.5 billion 140 x 25 x 1m).

Natural Gas and Bio-methane/bio-SNG costs : Natural Gas prices for 2022 delivery are forecast at £ 0.49 per Therm (29.3 kWh) https://www.statista.com/statistics/374970/united-kingdom-uk-gas-price-forecast/ . That equates to £ 17 per MWh thermal energy (34.13 Therms per MWh) or £ 17 million per TWh thermal by 2022. For the purposes of comparative assessment it is assumed that Natural Gas costs rise to £ 25 m per TWh thermal by 2030. It could also be reasonable to assume that bio-methane and bio-SNG would become an significantly increasing percentage of the balancing 'gas' used from 2040 to essentially 100% use by 2050 (costing possibly twice that of Natural Gas eg £ 50 m / TWh thermal).

Bio-methane may cost £ 0.50 per kWh (£ 50 / MWh or £ 50 m / TWh thermal :
https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/06/Biogas-A-significant-contribution-to-decarbonising-gas-markets.pdf .

Electrolytic hydrogen, generated from excess offshore wind and stored (called ‘power to gas’ or P2G), could also be used in gas turbines, engines and fuel cells to re-generate electricity. There would be round-trip efficiency losses. For example, 1 TWh electricity from 'P2G' would cost about £ 100 / MWh, assuming post 2040 electrolyser efficiency of 80 % and 63 % fuel cell efficiency on pure H_2 + O_2 (round trip efficiency 50 %), using offshore wind at £ 50 / MWh (£ 50 x 100 / 50 = 100). Cheaper bio-hydrogen sources may be available in the next decades.

Below are detailed two scenarios to estimate the costs of additional gas use in an offshore wind counterfactual across the period from 2025 to 2090.

Future gas scenarios

It is assumed gas-fired generation using Natural Gas declines steeply in all scenarios as either more renewables or new nuclear generation is added to the Grid (ie by up to 140 TWh/y by 2035).

It is also likely that increasing volumes of low-carbon gases will be injected into the NTS (National Transmission System) or local gas networks, to meet climate policy and gas security objectives to mid-Century. That said, it may be that bio-derived low-carbon gases are constrained by resource availability (and competing uses) and will potentially cost much more the Natural Gas in 2018 or 2040.

The various assumptions below (some iterative) provide a methodology which attempts to capture the additional (wind) system gas Opex balancing costs, plus an increasing percentage mix of bio-gases between 2040 and 2060 and future higher per-unit gas costs (Gas scenario 1).

An alternative scenario of using electrolytic hydrogen for power generation ('power-to-gas' or P2G) is also modeled as a cost comparator and scenario setter (Gas scenario 2). The cost of the electrolytic hydrogen from offshore windfarms is essentially a well defined figure because post 2040 offshore wind electricity has a modeled price (£ 55 - 50 /MWh) and electrolyser efficiency is probably unlikely to improve much on 80 %. So hydrogen would cost around £ 63 /MWh (50 /0.8) by mid-Century.

Assuming a low-efficiency (LE) fuel cell power station averages 47.5 % efficiency then there would be an additional 3 TWh/y thermal loss in generating 30 TWh/y electricity compared to the 50 % average achieved in the back-up for a nuclear system :

30 TWh/y elec x 50 % eff = 60 <u>TWh/y thermal</u> vs 63 <u>TWh/y thermal</u> = 30 TWh/y elec x 47.5 % eff

This <u>3 TWh/y thermal</u> additional gas consumption is used to assume that in Gas scenario 1 the system balancing efficiency improves from 45 % in 2040 to 47.5 % in 2060. If the balancing efficiency remained at 45 %, resulting in the consumption of an additional 6.7 <u>TWh/y thermal</u> (66.7 x 0.45 = 30 TWh/y) of an increasingly expensive composition of bio gases then additional gas costs in 2060 would be **£ 335 m/y** (6.7 x 50m). This would be much more expensive than a P2G system. The 3 <u>TWh-thermal</u> Hydrogen per year would cost **£ 189 m/y** (3 x 63m). The 3 TWh-thermal bio-gases per year would cost **£ 150 m/y** (3 x 50m)which is £ 39 m/y less than low-efficiency P2G and so a practical cost-competitive mid-century option.

So, two P2G scenarios are modeled, the first using low-efficiency cells at an assumed efficiency of 47.5 % (eg MOFC or hydrogen-fueled gas turbines or gas engines ?). **A second P2G scenario uses High-Efficiency (HE) fuel cells at 66 % (eg alkaline using electrolytic hydrogen AND oxygen, not air).**

Alkaline fuel cells particularly have the ability to ramp up and down at very fast rates and would certainly minimise any inefficient fuel use in cycling and cold starting large gas turbines. Even a few GW of fast ramping fuel cell capacity could buy significant time for system operators to decide if cold gas turbines needed to be warmed up if wind and PV supply continued to fall, or not.

In an iterative process the assumptions made in Gas scenario 1 regarding additional burn (falling from 11 to 3 TWh/y thermal) and possible future costs post 2040 were selected as a function of a best-case and worst-case P2G scenarios. That is, if costs of Gas Scenario 1 exceeded the worst-case P2G alternative then there would be a much reduced rationale for burning bio-methane or bio-SNG (a probably constrained and valuable resources) which could then be used in the gas network or other use. The wind turbines could cost-effectively produce their own balancing and back-up gas (ie hydrogen). If the costs of Gas Scenario 1 were lower than the best case P2G then there would be a much reduced rationale for progressing any P2G.

Gas scenario 1

Assumption 1 : up to 2040 in all scenarios gas-fired generation is at baseload efficiency where possible and that **50 TWh/y** of electricity is supplied via gas-fired turbines in less fuel efficient part-load balancing mode (ie not baseload 60+ % efficiency), declining to and leveling off at **30 TWh/y** balancing electricity from 2060.

Assumption 2 : up to 2040 in the wind counterfactual that 50 TWh/y electricity is generated at an average of just **45 % electrical efficiency**, and the nuclear-inclusive scenario achieves **<u>50 % average efficiency</u>**. In such a scenario the <u>additional</u> gas used in the wind system would be **11 TWh/y <u>thermal</u>** or 11 % more (ie 111 x 0.45 = 50 TWh/y electricity = 100 x 0.5 and 111 - 100 = 11).

Assumption 3 : the year on year additional on low-carbon generation to the Grid plus, inter-connectors, post 2040 wind forecasting across UKCS, long PV-related supply excesses in summer, and other factors reduce gas-generated balancing and back-up supply in all scenarios from **50 TWh/y to 2040 down to 30 TWh/y by 2060** and such factors incrementally decrease the wind cycling fuel inefficiency from 11 % additional in 2040 down to 5 % additional by 2060 by which time it levels off.

So, for 30 TWh/y electricity in 2060 the (bio) gas use at 50 % efficiency in the nuclear scenario would require 60 <u>TWh/y thermal</u> of gas. An additional 5 % of gas in the wind scenario would therefore be an **additional 3 <u>TWh/y thermal</u>** (ie 63 <u>TWh/y thermal</u> from bio-sources) at 47.5 % balancing efficiency.

Assumption 4 : in the period from 2040 to 2060 that the 'gas' cost rises from £ 25 m to £ 50 m /<u>TWh thermal</u> (as bio-gases use increases). So from 2060 additional balancing gas usage falls to 3 <u>TWh/y thermal</u> costing £ 150 m/y (3 x 50 m) from that time.

Assumption 5 : the increasing percentage of bio-methane and bio-SNG in the NTS gas network from 2041 results in 60 % of additional gas used in the wind scenario between 2041 and 2062 is from bio-sources (at £ 50 / <u>TWh thermal</u>).

So, an additional 11 TWh/y thermal of Natural Gas would cost about £ 275 million (11 x 25 m) per year from about 2028 to 2040. The total additional gas used in this period would be about 143 TWh thermal (11 x 13 years) costing **£ 3.6 billion** (143 x 25 m).

In the period from 2041 to 2062 the additional gas used falls year on year from 11 TWh/y to 3 TWh/y. So, the total additional 'gas' use = 20 years x (11 - 3) / 2 + 3 x 22 years = 146 TWh of which 60 % or 88 TWh is from bio-sources.

So the additional 'gas' cost from 2041 to 2062 = (146 - 88) x £ 25 m + 88 x £ 50 m = **£ 5.85 billion** (1,450 + 4,400)

So the total additional 'gas' balancing cost over 35 years between 2028-2062 = **£ 9.45 billion** (3.6 + 5.85).

The additional balancing gas cost over 25 years between 2063 to 2088 = **£ 3.75 billion** (25 x 3 x 50 m)

So the total additional 'gas' balancing cost over 60 years between 2028-2088 = **£ 13.2 billion** (9,450 + 3,750)

First-tranche : total additional balancing 'gas' cost per MWh over the first-tranche nuclear contract period from 2028 to 2062 = **£ 1.93 /MWh (**£ 9,450 m / [140 m x 35]) and post-contract to 2088 = **£ 1.07 / MWh** (£ 3,750 m / [140 m x 25]) = **£ 1.57 /MWh over 60 years** (£ 13,200 / [140 x 60]).

Grid-scale : total additional balancing 'gas' cost per MWh over the Grid-scale nuclear contract period from 2028 to 2062 = **£ 0.81 /MWh (**£ 9,450 m / [335 m x 35]) and post-contract to 2088 = **£ 0.45 /MWh** (£ 3,750 m / [335 m x 25]) = **£ 0.66 /MWh** over 60 years (£ 13,200 / [335 x 60])

Gas scenario 2 : Power-to-Gas (P2G) electrolytic hydrogen

This scenario assumes that 3 **TWh thermal** per year of additional volumes bio-methane or bio-SNG are NOT available for the offshore wind scenario in the period from 2050 to 2088. Consequently, electrolytic hydrogen is used instead. Low-efficiency (LE) fuel cells achieving 47.5 % efficiency are assumed to be used in one scenario and high-efficiency (HE) fuel cells achieving 66 % efficiency in a second scenario.

This hydrogen would cost about £ 63 m / TWh thermal assuming an electrolyser efficiency of around 80 % (£ 50 wind x 1/0.8).

If used in low efficiency fuel cells (eg MOFC at 47.5 %) the hydrogen would generate 1.425 TWh/y using 3 TWh/y thermal H2 (ie 3 x 47.5 % = 1.425). The 3 TWh/y thermal H2 would cost **£ 189 m/y** (63 m x 3)

If used in (more expensive ?) high-efficiency fuel cells (eg alkaline at 63 %) such pure hydrogen + the saved oxygen would generate the 1.425 TWh/y using only 2.15 TWh/y thermal H2 (ie 2.15 x 66 % = 1.425). The 2.15 TWh/y thermal H2 would cost **£ 135 m/y** (63 m x 2.15)

Note that reject hot water from the cells at very useful (+80 C) temperatures, and from the electrolysers, would be available for the heat sector. In the alkaline cell the round trip efficiency = 53 % (80 % x 66 %) so up to about 0.5 TWh/y hot water could be available. In the lower efficiency cell the round trip efficiency = 38 % (80 % x 47.5 %) so up to about 1.5 TWh/y hot water would be available.

A P2G system with low efficiency cells from 2050-2062 would INCREASE costs by £ 0.507 billion ([189 - 3 x 50] m x 13 years) to **£ 9,957 m** (9,450 + 507) and INCREASE costs by £ 0.975 billion from 2062 to 2086 (25 years x [189 - 3 x 50] m) to **£ 4,725 m** (3,750 + 975) **ie increasing** Scenario 1 gas costs by £1,482 m to **£ 14,682 m** (13,200 + 1,482) over 60 years.

Gas scenario 2 LEFC First-tranche : the total additional balancing 'gas' cost per MWh over the nuclear contract period from 2028 to 2062 = **£ 2.03 /MWh (**£ 9,957 m / [140 m x 35]) and post-contract to 2086 = **£ 1.35 /MWh** (4,725 m / [140 m x 25]) and **£ 1.75 /MWh over 60 years** (14,682 x [140 x 60])

Gas scenario 2 LEFC Grid-scale : the total additional balancing 'gas' cost per MWh over the nuclear contract period from 2028 to 2062 = **£ 0.85 /MWh (**£ 9,957 m / [335 m x 35]) and post-contract to 2086 = **£ 0.57 / MWh** (4,725 m / [335 m x 25]) and **£ 0.73 /MWh over 60 years** (14,682 x [335 x 60])

A P2G system with high efficiency cells from 2050-2062 would **REDUCE** costs by £ 0.195 billion ([135 - 3 x 50] m x 13 years) to **£ 9,255 m** (9,450 - 195) and **REDUCE** costs by £ 0.375 billion from 2062 to 2086 (25 years x [135 - 3 x 50] m) **to £ 3,375 m** (3,750 - 375) **ie reducing Scenario 1 gas costs by £ 0.57 billion to £ 12,630 m** (13,200 - 570) over 60 years.

Gas scenario 2 HEFC First-tranche : the total additional balancing 'gas' cost per MWh over the nuclear contract period from 2028 to 2062 = **£ 1.89 /MWh (**£ 9,255 m / [140 m x 35]) and post-contract to 2086 = **£ 0.97 / MWh** (3,375 m / [140 m x 25]) and **£ 1.50 /MWh over 60 years** (12,630 x [140 x 60])

Gas scenario 2 HEFC Grid-scale : the total additional balancing 'gas' cost per MWh over the nuclear contract period from 2028 to 2062 = **£ 0.79 /MWh (**£ 9,255 m / [335 m x 35]) and post-contract to 2086 = **£ 0.40 / MWh** (3,375 m / [335 m x 25]) and **£ 0.63 /MWh over 60 years** (12,630 x [335 x 60])

Gas scenarios analysis

In Gas Scenario 1 assuming that the additional systems cost of gas Opex in the offshore wind counterfactual amounted to **£ 13.2 billion** (regardless of the above assumptions about future gas price of £ 50 / TWh thermal cycling fuel efficiency, etc) then the additional 60 year system would amount to **£ 1.57 / MWh** for a first-tranche nuclear programme falling to **£ 0.66 /MWh** if there was a major 85 GW deployment of offshore wind by mid-Century.

The high cost estimate in the FTNP case indicates that the gas Opex assumptions and methodology in the FTNP counterfactual are over-stating the additional gas costs attributable to balancing the 18 GW of windfarms. Much greater accuracy is likely in the Grid-scale counterfactual as wind intermittency would be the major additional gas Opex cost (massed PV would be common to both Grid-scale nuclear and wind counterfactuals and assumed in this analysis not to result in an additional cost).

So, the relatively small (140 TWh/y) programme-scale counterfactuals can be very sensitive to gas Opex assumptions and that such counterfactuals would consequently benefit from Grid-scale long-term counterfactual analysis.

The assumptions in the power-to-gas Gas Scenario 2 suggest that gas Opex could either slightly increase or decrease (+ 11 % or - 4 %) depending on the round-trip-efficiency of the P2G process. The efficiency of the fuel cell may be key, or if offshore wind electricity fell significantly below £ 50 / MWh by mid-Century.

Scenario 1 Grid-scale gas Opex costs increase by **£1.482 billion** at a round-trip efficiency of 38 % and reduce by **£ 0.57 billion** at 53 % efficiency (eg using high-efficiency alkaline cells and stored electrolytic oxygen).

FTNP-scale additional 60 year system costs could either rise by 18 pence from £ 1.57 /MWh to **£ 1.75 / MWh** or reduce by 7 pence to **£ 1.50 /MWh.** Grid-scale additional 60 year system costs could either rise by 7 pence from **£ 0.66 / MWh** to **£ 0.73 /MWh** or reduce by 3 pence to **£ 0.63 /MWh**

Battery Capex cost

Several GWh of battery capacity at least would be needed in both scenarios to optimise system costs. Batteries would be a major feature in strategic-scale PV and PV-T deployments included in their Grid-scale system costs, which would probably built in both wind and any nuclear scenarios being compared here.

It is difficult to assess what additional costs or benefits to an offshore wind counterfactual there may be. Indeed, summer over-production between nuclear and PV could well require additional batteries and inter-seasonal hydrogen storage costs in a large-scale nuclear scenario. Lighter winds in summer will result in less offshore wind output over the summer months than in the nuclear scenario. Offshore wind across the UKCS may generate round 41 % of their annual production in the summer six months and 59 % in the winter six months (author's estimate based on various data)

For example, the 140 TWh/y nuclear programme would generate about 50 % of its annual output ie 70 TWh across the six summer months compared to 57.5 TWh (140 x 41% summer) from the lighter summer offshore winds. As there is likely to be a net supply excess over the summer period in all scenarios (ie lots of PV and lower summer Grid demand) this is when most hydrogen that is needed across the year would be generated. So the extra 12.5 TWh of nuclear electricity, producing 10 TWh of hydrogen, would require additional seasonal storage cost.

Batteries should avoid hot running 3.2 GW of gas-fired back-up for an instantaneous unscheduled double nuclear reactor / site / transmission line outage (requiring around 1 GWh depending on gas-fired start-up times eg 20 mins).

The largest battery globally is 0.129 GWh for comparison so at least 8 such football-field sized battery schemes would be needed to provide just 1 GWh storage. The Dinorwic pumped-storage schemes is about 11 GWh and a typical winter evening peak electricity demand (5 pm to 9 pm) may be roughly 25 GWh. That said, by 2050 there may well be at least tens of GWh of battery storage potentially available in millions of smart battery-electric vehicles. By 2060 there could be hundreds of GWh potentially available.

Consequently, future cost or scale of battery resource is difficult to forecast and would be common to all likely scenarios. So, no additional battery Capex is included in the scenarios comparison or counterfactual.

Integration (electrolysis - hydrogen production) additional system costs

At times a 35 GW wind deployment would generate more than the average 16.2 GW baseload (18 GW x 0.9) of the nuclear programme. Peak offshore wind across the UKCS in the windy winter months may occasionally reach over 80 % of a 35 GW deployment, eg 28.2 GW. So, during peak winds the wind scenario may at times generate **12 GW** (28.2 - 16.2) more than the 18 GW nuclear programme.

In a Grid system currently running at an average of 40 GW annual demand rising to 50-60 GW on winter evening peaks, much of the offshore wind peak supply may simply be consumed by instantaneous consumer demand. Baseload generation after 2030 would probably just be 1.2 GW Sizewell B (excluding new-build nuclear) while annual demand will likely be higher with battery-electric vehicles included. Also, wind peaks are also highest in the windy winter months when PV peaks are at their lowest.

So, post 2030, occasional 28+ GW wind peaks would probably only cause supply excesses on sunny summer days when PV is also peaking, and summer nights when consumer demand is lowest eg reaching just less than 30 GW Grid demand. Inter-connectors could also usefully distribute supply excess wider afield. So, it may be that a few GW of electrolysers, along with some battery/other storage, could capture all or most wind supply excesses annually and convert them to valuable clean electrolytic hydrogen at little or no additional counterfactual cost.

Electrolysers and batteries would also be needed in a nuclear-inclusive scenario too. Very pure low-carbon electrolytic hydrogen will be needed at scale in any likely future scenario for use in a low-carbon chemical industry (non-energy oil/gas demand is around 90 TWh/y thermal). Non-energy products include fertilizers, plastics and an array of hydrocarbon products. Hydrogen would also be needed for bio-SNG production, the transport sector (eg fuel cell vehicles, HGVs, trains) and for back-up electricity generation and the gas network.

For example, based on forecast 2030 EU per capita H2 demand (see Future Hydrogen Demand below) the UK may have a hydrogen demand (from all sources) of around 1 million tonnes per annum (1 Mt pa). The production of low-carbon hydrogen via Steam Methane Reforming (SMR) with CCS may well not be a preferred option due to cost, availability and emission policy constraints about Natural Gas.

Carbon dioxide emissions arising from the steam reformation of Natural Gas for hydrogen production amount to about **10 million tonnes per mega-tonne of hydrogen** : http://www.itm-power.com/news-item/100mw-electrolyser-plant-designs-to-be-launched-at-hannover

So electrolytic hydrogen produced from renewable or nuclear electricity excess-to-Grid supply is likely to see increasing demand.

Every 1 Mt pa of hydrogen would require 50 TWh/y of electricity assuming electrolyser efficiency of 75%.

So, by 2050 a low-carbon hydrogen demand of 1 Mt pa would require **at least 6 GW** (50 / [8.76 x 0.9 baseload]) of electrolysers if electrolysis becomes the main H2 source (ie SMR+CCS not progressed).

However, baseload electrolyser operation is unlikely as Grid supply excesses will be intermittent in any likely scenario (eg 50 : 50). So it may be reasonable to assume around **12 GW of electrolysers** could be needed in any RE or nuclear-inclusive scenario by 2050 as the electrolysers might only achieve an average an annual capacity factor of around 50 %.

If so, wind peak excesses of up to about 12 GW higher than a nuclear 'baseload' supply could be integrated, using the 12 GW of electrolysers needed for hydrogen production anyway, with minimal if any curtailment or loss, especially if inter-connectors are also available.

So, in an programme-scale analysis (ie 18 GW nuclear programme 35 GW offshore wind counterfactual) the additional cost for electrolysers to integrate excess supply peaks in the offshore wind could be deemed minimal or zero if electrolytic hydrogen demand is at or above the 1 Mt pa level by 2050.

However, no scenario or programme-scale analysis is isolated from the wider system in which it is part. So a 24-32 GW offshore wind counterfactual would have to pay its share of additional electrolyser costs in the wider system of which it may well form part. It would be almost certain that a much larger offshore wind deployment would be required to facilitate a 100% renewable energy system and Grid supply by mid-Century. So, a 'Grid-scale' electrolyser counterfactual is set out in the section below comprising 335 TWh/y from an 85 GW of offshore wind deployment (at average annual 46 % Capacity Factor).

The cost of electrolysers in the Grid-scale counterfactual are **£ 0.34 /MWh before 2060** rising to **£ 0.5 / MWh between 2060 and 2090**. The Grid-scale counterfactual costs and the conclusions above, that additional electrolyser costs could be deemed to zero in an 24-35 GW offshore wind counterfactual, are included and considered in the Summary analysis.

Low-carbon Hydrogen Demand by Mid-Century

Future hydrogen production, much of it for the chemicals industry, is forecast to increase, as is demand for hydrogen from low-carbon sources (electrolysis and Steam Methane Reformation with CCS). Assuming EU per capita 2030 forecasts (eg 7.1 Mt pa hydrogen for an EU population of 520 million) the UK would be producing around 950,000 tonnes or about 1 Mt pa in 2030 on a per capita basis.

By 2050, UK hydrogen demand may be considerably greater than 1 Mt pa in which case a greater capacity of electrolysers would be needed. So the additional offshore wind counterfactual costs, even when included in a wider deployment of intermittent renewables, would reduce if more hydrogen were needed. Ex-DECC 2050 team member Simon Counsell was going to include an annual rate of low-carbon / green hydrogen production in the 2050 Calculator (following discussions with the author) but left before a figure materialised.

At 100 % efficiency 1 kg H2 require 39 kWh * so 39 MWh per tonne of H2. Assuming 75 % electrolyser efficiency the electricity required = 50 MWh per kg H2. So 1 Mt pa H2 would require **50 TWh/y of electricity** at 75 % efficiency.

* http://www.renewableenergyfocus.com/view/3157/hydrogen-production-from-renewables/

Post-contract period (2060-65 to 2085-2090)

In the 25 year post-contract period nuclear utilities would presumably just marginally undercut the cheapest renewable price (in this comparison : offshore wind + its system costs) at that time to maximise profits and there would be minimal benefit to consumers.

For example, if prices were pitched £ 1 /MWh below whatever the offshore wind + additional system costs then in a 140 TWh/y scenario the saving would be £ 140 million per year for 25 years = **£ 3.5 billion over 25 years. That equates to £ 0.42 /MWh (3,500 m / [140 m x 60]) over 60 years.**

That said, the higher the post 2060 offshore windfarm costs (CfD / other) plus their post 2060 system charges then the higher the consumer bills (assuming the actual nuclear generation cost would then be very low and that competitive prices would be charged by nuclear utilities). Different approaches could be used to assess the consumer nuclear benefit in the 25 post-contract years.

This analysis assumed £ 1 /MWh benefit in the post-contract 25 years, and this figure was stress-tested to £ 2 /MWh and there is plenty of slack in the reference additional system cost of £ 7.50 /MWh for this benefit to be higher without changing the overall analysis or conclusions in this Annex.

A 100 % renewable energy system by 'mid-Century' and a Grid-scale counterfactual

As a methodology check it is instructive to consider a large 'Grid-scale' scenarios comparison (eg 42 GW nuclear, 85 GW offshore wind) to stress-test if smaller programme scale scenarios (eg 18 GW nuclear, 35 GW offshore wind), which may well be scaled-up significantly, are a good approximation for comparative purposes.

Such a comparison would also provide insights as to what part such programmes would play in a possible UK mid-Century Grid system which is forecast to handle significantly greater annual electricity consumption and higher peak demands. In this section an 85 GW offshore wind counterfactual to a 42.5 GW nuclear deployment, both built by 2060, is examined (both deployments generating 335 TWh over a year).

The National Grid Company's 2017 Future Energy Scenarios report has four distinct 2050 UK energy scenarios : http://fes.nationalgrid.com/media/1253/final-fes-2017-updated-interactive-pdf-44-amended.pdf.

The NGC scenarios indicate that 2050 annual electricity demand may be around the 350 TWh/y mark (excluding transmission losses which comprise about 7 % of current electricity supplied by generators to the HV Grid and LV distribution networks). So a 2050 UK Grid may have around 400 TWh/y of electricity supplied to it. This demand is considerably lower than some recent previous forecasts of 2050 electricity demand eg over 600 TWh/y including electric vehicle use, a highly electrified heat sector (mainly heat pumps), and electrolytic hydrogen production for the chemicals and other sectors. Those scenarios show peak electricity demand ranging between 65 and 85 GW compared to around 60 GW currently.

A 100 % renewable electricity Grid-scale counterfactual by 2050-2060 might have lower additional system costs for gas-back-up Capex (£ per MWh) than the sum of smaller individual programme counterfactuals. This is because only the first 65 - 85 GW (ie whatever the peak winter demand is across the years) needs to have some form of firm back-up.

So for example, in a deployment of 85 GW (335 TWh/y) by 2060 of mainly offshore wind only the first 65-85 GW would need to be backed-up to meet all peak consumer demand (ignoring any wind Capacity Credit claims). Note that some onshore wind capacity decommissioning in the 2050s could be replaced with offshore wind.

The back-up would be mainly gas-fired but batteries and other storage would presumably supply winter evening demand peaks, eg supplying 30-40 GWh over a few hours, thereby flattening short sharp sine-wave shaped demand peaks which currently range from 5 - 10 GW above average daytime demand.

For the purposes of first-approximation Grid-scale counterfactual analysis it is assumed here that 2060 UK electricity demand rises to 550 TWh/y including transmission losses and 50 TWh/y demand for electrolytic hydrogen production (1 Mt pa H2) mainly for the chemicals sector. It is also assumed that the **maximum annual peak rises to 70 GW** (inclusive of any outage margin but excluding the emergency back-up to cover the two largest in-feed losses in a given system scenario eg 3.2 GW in a nuclear-inclusive scenario and 1 GW in a RE scenario).

So, a 'Grid-scale' wind deployment of **85 GW (335 TWh/y)** by 2060 OR **42.5 GW (335 TWh/y)** nuclear deployment + 90 GWe (120 TWh/y) PV / PVT and other renewables is assumed to be deployed to meet the 550 TWh per year electricity demand.

A 42.5 GW (335 TWh/y) nuclear deployment would need **30.7 GW** (70 - 42.5 + 3.2) of firm back-up to meet peak demand assuming ALL nuclear capacity is operational in the peak demand winter months (ie scheduling all refueling etc outside Nov-Feb if possible). In comparison, the 85 GW offshore wind counterfactual would need **71 GW** (or whatever the then peak + 1 GW) of firm back-up to meet peak winter evening demand (because PV and wind can drop to essentially zero output for days) and the other renewables are either small or intermittent themselves (and common to both scenarios).

The additional 40.3 GW (71 - 30.7) of gas-fired capacity Capex would cost around £ 18.1 billion (at £ 0.45 billion per GW installed). This capital cost equates to **£ 1.80 /MWh** (£ 18.1 b / [335 TWh/y x 30 years]). In comparison, the 18 GW nuclear 'baseload equivalent' comparison with the 35 GW by 2035 offshore wind counterfactual, the gas-fired Capex = £ 1.70 /MWh (see gas-fired Capex section above). Over 60 years and a full back-up replacement after 30 years the Capex would rise to £ 36.2 billion and would still cost £ 1.80 / MWh (36.2 / [335 x 60]).

The higher offshore wind cost in the Grid-scale analysis reflects the slightly lower relative cost of providing the same 3.2 GW of gas-fired back-up (to cover a double 1.6 GW in-feed loss) for a 40+ GW nuclear deployment compared to an 18 GW first-tranche programme.

Note that the actual peak output (70 GW in this example) and the extra cost of back-up capacity required could be much higher and have no effect on the additional cost because the cost difference between the nuclear deployment and the offshore wind counterfactual would remain the same.

Gas scenario 1 Grid-scale : the additional 'gas' balancing cost over 35 years between 2028-2062 in delivery 50 TWh/y electricity to 2040 reducing to 30 TWh/y by 2060 would probably remain around £ 9.45 billion. That equates to about **£ 0.80 /MWh** (9,450 / [335 x 35]). Similarly, post 2060 additional gas use may remain around £ 3.75 billion. That equates to about **£ 0.45 /MWh** (3,750 / [335 x 25]). The 60 year additional gas Opex system cost would be **£ 0.66 /MWh over 60 years.**

The Grid-scale power-to-gas counterfactual Gas scenario 2 suggests that the Opex costs could vary between **£ 1.20 /MWh** to **£ 1.42 /MWh** depending on the round-trip efficiency of the electrolysers and fuel cells.

Post-contract nuclear consumer benefit (ie nuclear pricing pitched to be £ 1 / MWh competitive) would be £ 335 million per year for 25 years = £ 8.375 billion or **£ 0.42 /MWh** factored over 60 years (8,375 / [335 x 60]).

Grid-scale counterfactual integration costs

As regards integration costs (of supply excesses of wind and PV to produce hydrogen), it is mainly the level of Grid-scale electrolyser capacity and Capex that may differ from a small programme deployment and its counterfactual. The electrolyser Opex to produce 1 Mt or whatever of hydrogen per year would be similar in both scenarios unless possibly significantly more hydrogen is stored inter-seasonally for power generation in a nuclear scenario compared to an offshore wind counterfactual.

Winter winds are stronger and so offshore wind turbines capture a significantly greater proportion of their annual yield in the winter six months (eg 59 % winter vs 41 % summer). Conversely, PV outputs in the summer six months may be about double that of the winter six months (eg 67 % summer vs 33 % winter).

Note that a significant nationwide battery deployment would store summer daytime PV excess production for use that night with any night time excesses used for hydrogen production. So, batteries and other storage would help optimise the installed capacity of electrolysers required in either scenario.

For the purposes of a first-approximation cost comparison any differences in inter-seasonal storage of hydrogen for subsequent power generation (eg in winter) would result in higher Opex costs and storage infrastructure costs but such nuclear additional costs are assumed to be minimal.

So, assume 85 GW of mainly offshore wind capacity deployed by around 2060 and spread across the UKCS would average 37 GW (85 x 43 % Capacity Factor). The deployment would occasionally peak at above 68 GW (85 x 80 %) probably in winter which could be well above Grid demand at a given instant. 2060 annual electricity demand is assumed at 550 TWh/y in this scenario (supplied by 335 TWh/y wind, 120 TWh/y PV, 30 TWh/y Gas, 65 TWh/y other RE). So, the average annual electricity demand would be around 63 GW (550 / 8.76).

So assuming batteries could soak-up and reduce wind peaks from 68+ GW to 60 GW and a minimum of 30 GW of Grid demand is likely (ie on a summer night) then 30 GW of electrolysers would be needed to capture the remaining supply (60 - 30) if no other ways to reduce capacity were available. However, there would be potentially over 10 GW of inter-connectors available to mainland Europe to electrolysers abroad and Norwegian pumped storage.

For comparison, a nuclear scenario may need more like 12 GW (assuming an annual capacity factor of 50 % and 1 MT pa hydrogen production requiring 50 TWh/y electricity). Assume inter-connectors reduce electrolyser capacity by a further 8 GW.

Under such assumptions the additional electrolyser capacity of the Grid-scale offshore wind counterfactual would be **10 GW** (30 - 8 - 12) by 2050. Such an additional deployment may ramp up from near 0 GW in 2030 with about 5 GW installed by 2040 to 10 GW by 2050. Replacement electrolysers would be needed from 2060 to 2090 assuming a 30 year life (regardless of level of use).

For comparative purposes it would be simpler to consider electrolyser.years across the 60 year scenario and counterfactual period. Assuming electrolyser Capex = £ 0.5 billion per GW installed and operational life is 30 years then **60 GW.y of electrolyser use would cost £ 1 billion**.

Cumulative additional GW.years = from 2030-2040 (0 to 5 GW) + from 2040-2050 (5 to 10 GW) + 2050-2060 (10 GW) + 2060-2090 (10 GW) = 25 + 75 + 100 + post contract 300 GW.y = 200 GW.y (pre-2060) + 300 GW.y (post 2060)

So the additional electrolyser Capex for the 2030-2060 period would be £ 200 / 60 = **£ 3.4 billion** and from 2060-2090 Capex = 300 / 60 = **£ 5 billion** amounting to **£ 8.4 billion** over 60 years.

That equates to **£ 0.34 /MWh** (3,400 / (335 x 30) in electrolyser pre-2060 Capex + **£ 0.50 /MWh** (5,000 / (335 x 30) in electrolyser post-2060 Capex and **£ 0.42 /MWh over 60 years** ([3,400 + 5,000] m / [335 / 60]).

Electrolyser Capex Analysis

The discussion above estimates that 10 GW of additional electrolyser capacity would be needed, costing **£ 0.42 /MWh over 60 years** in the Grid-scale offshore wind counterfactual. This counterfactual could be included in the first-tranche nuclear programme (FTNP) analysis as part of the 'Whole (additional) System Costs' calculations. However, it could be claimed that the electrolyser capacity needed to generate 1 Mt pa of hydrogen in the nuclear scenario too would result in little or zero additional electrolyser Capex would be needed.

As part of a Grid-scale offshore wind counterfactual the inclusion of the £ 0.42 /MWh electroloyser Capex would be reasonable in any likely 100 % RE counterfactual scenario to any new-build nuclear. If it were the case that more electrolyser capacity were needed to utilise excess offshore wind supply eg because there were fewer inter-connector capacity or very high peaks occurred due to PV in summer, then an extra 10 GW of capacity, on top of the additional 10 GW capacity estimated above, would cost a further £ 0.42 /MWh.

Whole (additional) System Costs Analysis for the offshore wind counterfactual

The whole (additional) system cost is assumed in this Annex to comprise the Capex and Opex factors detailed and estimated in the sections above. An additional market factor (consumer benefit of post-contract nuclear pricing) is also considered. Each of technical factors is calculated on a pre 2060 and post 2060 basis for comparison. The various costs of the counterfactual scenarios are summed below. The acronym FTNP stands for ‘First-Tranche Nuclear Programme’ (ie between 96 - 140 TWh/y by 2035), and GS stands for ‘Grid-Scale’ (around 335 TWh/y by 2060) :

Whole additional system cost = gas-fired capacity Capex + 'gas' fuel balancing Opex + electrolyser Capex

In Gas scenario 1 FTNP, the total additional system costs for a 35 GW / 140 TWh/y wind deployment over a nuclear deployment = **£ 3.69 /MWh** (1.70 + 1.57 + 0.42)

In Gas scenario 2 FTNP LEFC, the total additional system costs for a 35 GW / 140 TWh/y wind deployment over a nuclear deployment = **£ 3.87 /MWh** (1.70 + 1.75 + 0.42)

In Gas scenario 2 FTNP HEFC, the total additional system costs for a 35 GW / 140 TWh/y wind deployment over a nuclear deployment = **£ 3.62 /MWh** (1.70 + 1.50 + 0.42)

Grid scale counterfactuals :

In Gas scenario 1 Grid-scale, the total additional system costs for a 35 GW / 140 TWh/y wind deployment over a nuclear deployment = **£ 2.88 /MWh** (1.80 + 0.66 + 0.42)

In Gas scenario 2 Grid-scale LEFC, the total additional system costs for a 35 GW / 140 TWh/y wind deployment over a nuclear deployment = **£ 2.95 /MWh** (1.80 + 0.73 + 0.42)

In Gas scenario 2 Grid-scale HEFC, the total additional system costs for a 35 GW / 140 TWh/y wind deployment over a nuclear deployment = **£ 2.85 /MWh** (1.80 + 0.63 + 0.42)

In all scenarios the post-contract nuclear benefit to consumers = **£ 0.42 / MWh (for a £ 1 /MWh under-cut) not to be confused with the electrolyser Capex also £ 0.42 /MWh over 60 years.**

It is clear that the cost of the gas-fired back-up (£ 1.80 /MWh) is the major component in this additional systems cost counterfactual analysis, particularly at Grid-scale. This gas back-up Capex cost estimate is also likely to be the most accurate of the three component estimates (ie back-up Capex, gas Opex and electrolyser Capex) as its based on the most certain assumptions. The annual capacity factor would be very low too perhaps 5 % eg 71 GW delivering 30 TWh/y (71 x 8.76 x 5 %cf = 30).

Such low capacity factors may facilitate the deployment of back-up hardware that could be maintained for 60 years rather than replaced after 30 years, which may result in significant back-up Capex cost reductions.

In terms of stress-testing the gas Opex is doubled in the period from 2050-2090 in the counterfactual immediately below and then quadrupled to model the effects of considerably more gas-fired electricity supplied in the period 2050-2090 eg 60 TWh/y and at up to twice the marginal gas burn (6 TWh/y) due to lower relative balancing efficiency

The electrolyser Capex has been been doubled in both stress-tests below.

post-contract gas cost £ 3.75 billion over 25 years = £ 6 billion over 40 years between 2050-2090
* £ 6 billion + £ 13.2 billion = £ 19.2 billion or **£ 0.96 /MWh over 60 years**
** £ 6 billion x 3 = £ 18 billion and £ 18 billion + £ 13.2 billion = £ 31.2 billion or **£ 1.55 /MWh over 60 years**

Stress Test 1 : Gas scenario 1 Grid-scale : additional system costs for a 35 GW / 140 TWh/y offshore wind counterfactual to a nuclear deployment = **£ 3.60 /MWh** (1.80 + 0.96 * + 0.84)

Stress Test 2 : Gas scenario 1 Grid-scale : additional system costs for a 35 GW / 140 TWh/y offshore wind counterfactual to a nuclear deployment = **£ 4.19 /MWh** (1.80 + 1.55** + 0.84)

If the post-contract nuclear consumer benefit (£ 0.42 /MWh) is added in then the stress test scenarios add to £ 4.02 /MWh and £ 4.61 /MWh respectively rising to **£ 4.44 / MWh and £ 5.03 /MWh** if the nuclear benefit were doubled to £ 0.84 /MWh. Costs would be slightly higher in a stress-tested P2G scenario.

The highest stress-test came to about £ 5 /MWh. To provide a further measure of confidence, and to include any system costs not included (eg Frequency Reserve, inertia provision) this figure is increased by 50 % to **£ 7.50 /MWh as a ‘<u>reference</u>’ additional system cost.**

This reference figure is then used to provide the £ 5-10 /MWh cost estimate range scenarios which are used in the programme cost calculations in the first section of the Annex.

So the total additional system costs of an offshore wind counterfactual (as part of a 100 % RE Grid by 2050-2060) could be about £ 7.50 /MWh assessed between 2025 and 2090. It could be much lower at around £ 5 /MWh IF the assumptions and systems in the modeled scenarios in this Annex are representative.

Transmission link / network considerations

The HPC VfM assessment concluded that the cost of renewable counterfactuals offshore and onshore wind would incur higher 'network' and 'transmission' costs which mitigate against such counterfactuals. Yet project developers/operators are responsible for and bear the cost of grid connection in the UK. **So transmission link costs are included in the auction bid and reflected in the CfD strike price**. The developer builds the transmission links and then must sell the links to an OFTO (Offshore Transmission Operator) who owns and operates the assets (substation and export cables). The developer then pays to use these assets. So transmission inks are not an additional 'system' cost to a nuclear or renewable development and its CfD.

As the transmission infrastructure costs are significant for strategic-scale programmes the various issues are examined below to test cost sensitivity.

35 GW of offshore wind would require a significant capacity of cabling both sub-sea and underground to substations attached to the existing Grid system. New much larger nuclear schemes on existing nuclear sites would also need significant transmission lines upgrades to transmit about three times the electricity from each site and a double route would be useful for security purposes. The line capacity upgrading proposals for HPC, Wylfa B and Moorside are causing some public opposition. So both scenarios would require costly transmission line upgrades.

The HPC link over 30 miles may cost over £ 0.7 billion : http://www.telegraph.co.uk/business/2017/08/30/ofgem-balks-national-grids-840m-hinkley-point-plans/
A Moorside link over 100 miles is costed at £ 2.8 billion : http://www.world-nuclear-news.org/NN-National-Grid-puts-Moorside-plans-on-hold-16051701.html
A Wylfa B link over 20 miles could be placed in a 4km tunnel costing £ 0.1 billion : https://wcnwchamber.org.uk/wylfa-newydd-power-tunnel-menai-strait-cost-100m/

It may be that 18 GW of projects could cost about £ 5 billion in transmission link reinforcement.

In comparison, Round 3 offshore windfarm transmission links may cost £ 0.5 billion per GW installed : £ 400 m per GW (in 2008 prices x 1.25 CPI) page 86, Table 23 : https://www.thecrownestate.co.uk/media/451005/ei-km-in-gt-grid-012009-round-3-offshore-wind-farm-connection-study.pdf . Transmission line costs at £ 0.5 billion/GW offshore wind would amount to £ 17.5 billion for a 35 GW deployment, though HVDC technology is improving rapidly and prices are coming down by the year.

The longevity, costs or benefits of maintenance or replacement of sub-sea transmission links from offshore windfarms, eg after 25 years, 35 years or longer, is difficult to assess. It may be that a substantive GW capacity of links and or any replacement links may be incorporated (at relatively much lower initial and or replacement cost) into much larger strategic plans and infrastructure by 2030.

For example, the Dogger Bank artificial island proposal by German and Danish developers with a potential of 70-100 GW could cut the cost of wind output and transmission link costs per GW significantly, hence late 2020s CfDs, and provide an inter-connector link to mainland Europe (literally a wider benefit) : http://www.independent.co.uk/environment/artificial-north-sea-island-energinetdk-tennet-dogger-bank-danish-dutch-german-firms-bid-wind-farms-a7622371.html

Assuming 18 GW of new nuclear costs £ 5 billion in transmission links and 35 GW of windfarms cost £ 15 billion (assuming a 15 % technology and economies-of-scale cost reductions by the late 2020s) then the additional system cost would be around £ 10 billion. That figure could rise significantly if replacement links were necessary in the 60 year comparison period. So link costs could equate to an additional offshore wind infrastructure cost = £ 1.20 / MWh (10,000 / [140 x 60]) or perhaps double that figure over 60 years. However, link costs are already incorporated into the auction bid and the counterfactual's CfD contracts.

A critique of the HPC Value for Money (VfM) assessment issued in Sept 2016

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/621400/Detailed_value_for_money_assessment.pdf

Test 2b - which was 'developed and agreed by the DECC Chief Economist in 2011' ('considers whether HPC reduces the total cost of the GB electricity system out to 2050 to bring net social benefits.') : A 35 year contract for HPC can only now end in 2060 or later and the largest cost differentials between HPC and maturing renewable technologies are likely to be in the 2050-2062 period. The Department's 'DDM' (Dynamic Dispatch Model) computer model also only ran or still runs to 2050. This is hardly convincing or transparent (complex computer models may even have software faults).

BEIS has stated that the benefits of HPC lie in the later years, but how ? Post-contract nuclear utilities will presumably just marginally undercut the cheapest renewable price at that time to maximise profits and there would be minimal benefit to consumers (and lots of Spent Fuel accumulating).

Test 2a ('*compares the Strike Price of HPC with the equivalent cost per MWh of alternative technologies capable of delivering low-carbon generation at scale in the 2020s')* : This is contestable because offshore wind contracts for 2022 delivery (let alone 2027) are as low as £ 57.50 /MWh. Did not BEIS have any indication during PM May's review in September 2016 that bid prices for the Sept 2017 offshore wind auction were possibly or likely to be that low ? In summer 2016 a scheme off the Dutch coast had received a contract in the € 70's / MWh. The VfM considered offshore wind at an average of £ 106 / MWh in 2025 with an £ 85 / MWh target (in 2012 prices).

Regarding delivery at scale in the 2020s, HPC and the whole first-tranche 16-18 GW (125-140 TWh/y) nuclear programme has slipped at least 7 years from originally Xmas 2017-2025 to 2025-2030 or even later. Yet, an offshore wind construction programme averaging 3.5-4 GW per year across the 2020s could deliver 35-40 GW generating 125-140 TWh/y by 2030. Also there would then be a large offshore wind industrial capacity to deliver at scale in the 2030s, particularly if SMRs do not become viable for any reason. The UK would also have the innovation and capacity for major export opportunities.

Test 3 (*comparing this to the impact of various counterfactual scenarios*) : This was unconvincingly addressed. Not only does it state that PV and onshore wind electricity were lower cost but it then dismissed them for weak constraints, then mentioned, but did not appear to seriously consider, a mix of PV offshore wind and onshore wind.

Detailed criticisms of the non-transparent and unconvincing BEIS VfM assessment (HPC being one of the most expensive structures in history) were made in Oct 2016 by the Institute for Government and could now been acted on in any future VfM assessments : https://www.instituteforgovernment.org.uk/blog/hinkley-dubious-value-value-money-assessment

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