Final Report

Electricity Generation Costs and Hurdle Rates

Lot 3: Non-Renewable Technologies

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Prepared for:

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EXECUTIVE SUMMARY

The Department for Energy and Climate Change appointed LeighFisher, in association with Jacobs, to review the parameters that it uses for its analysis of the Levelised Costs of Electricity (LCOE) for all non-renewable technologies. These parameters include the costs of designing, building and operating a power plant and the technical characteristics of the power plant when operating, such as its availability and power output.

We have developed low, central and high estimates for each parameter to reflect the uncertainty inherent in large scale, technically complex projects such as non-renewable generation technologies. We found that the existing parameters were generally in line with our understanding of the cost and technical parameters across the technologies. However, we made adjustments to the existing parameters to reflect changes in technology, the commercial environment and changes to licensing and permitting.

We then used DECC's Levelised Cost Model to develop appropriate ranges for the Levelised Cost of Electricity for these generation technologies. A comparison of our results with those from the previous DECC study carried out in 2013 suggests that overall our parameters drive the following changes in our central case levelised costs. The third column shows the impact of changing parameters and the fourth column shows the total change including changes to parameters and changes to hurdle rates.

Group	Technologies	Change in LCOE from updated parameters	Total change in LCOE since 2013
Gas	H class and F class Combined Cycle Gas Turbine (CCGT) plants	4%	4%
	Combined Heat and Power plant	13%	11%
	100, 299, 300, 400 and 600 MW Open Cycle Gas Turbine plants	9%	10%
Nuclear	First of a Kind nuclear plant	19%	11%
	N^{th} of a Kind nuclear plant	8%	1%
Combined Cycle Gas Turbine (CCGT) Carbon Capture and Storage (CCS)	New build CCGT plant fully fitted with post-combustion CCS	24%	14%
	New build CCGT plant fully fitted with pre-combustion CCS	12%	4%
	New build CCGT plant fully fitted with oxyfuel CCS	3%	-5%
	An existing CCGT plant fully retrofitted with post-combustion CCS	17%	11%
Integrated Gasification Combined Cycle (IGCC) CCS	A new build IGCC plant fully fitted with CCS	8%	-2%
	A new build IGCC power plant partially fitted with CCS	6%	0%
	An existing CCGT plant retrofitted to operate as an IGCC plant fully fitted with CCS	50%	38%
Advanced Super Critical Coal (ASC) CCS	A new build ASC plant fully fitted with post-combustion CCS	23%	11%
	A new build ASC plant partially fitted with CCS	22%	16%
	A new build ASC plant fully fitted with post-combustion CCS using ammonia	19%	7%
	A new build ASC plant fully fitted with oxyfuel CCS	25%	12%
	An existing coal plant fully retrofitted with CCS	15%	8%
Biomass	A new build biomass plant fully fitted with post-combustion CCS	131%	115%

Note that the percentage change in LCOE is from 2012 prices (used in the 2013 report) to 2014 prices (used in this report) and compares central estimates only. However, there has been limited inflation between 2012 and 2014 in the inflation indices we have used[1]. These values are for the medium case. Changes to the high and low case may be different.

Each technology type above is at a different state of development in the UK and the available data means different analytical approaches are required. In this study we have used the following approaches:

- *top-down analysis based on recent empirical evidence of specific transactions and supplier quotes*
- *bottom-up by deriving parameters based on a first principles technical breakdown of plant requirements*
- *comparator analysis from an assessment of comparator technologies and engineering studies*
- *assessment, and validation against, project experience using our extensive project experience across all the generating technologies identified to supplement our top down/bottom up/comparator analysis*
- *using DECC's previous input assumptions, provided by PB power, as a starting point for our analysis*

There is inherent uncertainty in non-renewable power generation technologies. They are large capital projects involving complex technology. Technical and cost assumptions could vary significantly in practice. We have developed appropriate ranges of low, central and high estimates for costs and technical parameters to reflect this uncertainty. In undertaking our analyses, we have made a number of assumptions. We have explained these in the relevant sections for each technology, but there are a number that apply across technologies.

We also developed levelised cost ranges for small-scale, 20 MW reciprocating gas or diesel engines and pumped storage facilities, technologies that DECC did not consider in 2013. The charts below show our levelised cost ranges first for base-load technologies – those that look to operate at all times – and peaking technologies – those that operate when electricity demand is high.

Figure 1 and Figure 2 on the next two pages summarise our LCOE results in full.

[1] The change in these indices over the period was -2.5% for capex and +1.3% for opex. See section 1.2.1 for further details.

Figure 1 – baseload LCOE

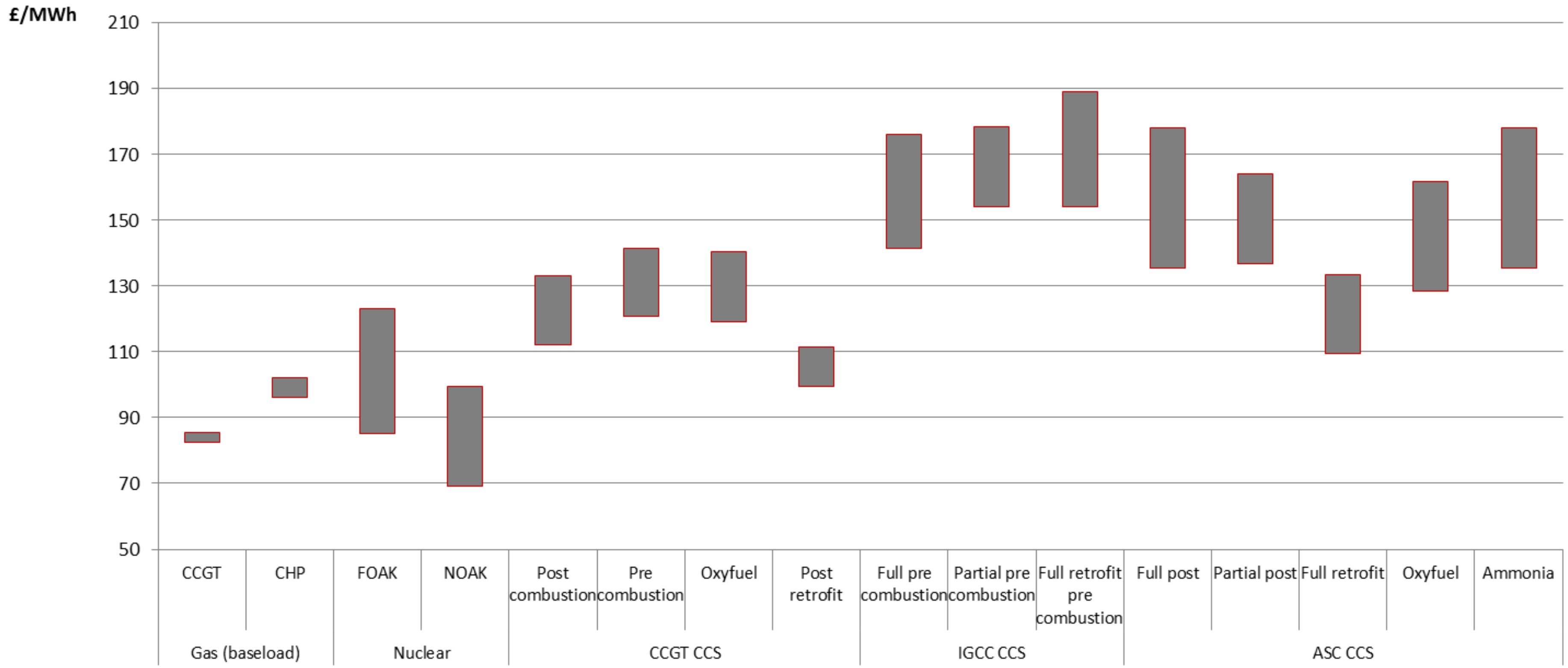
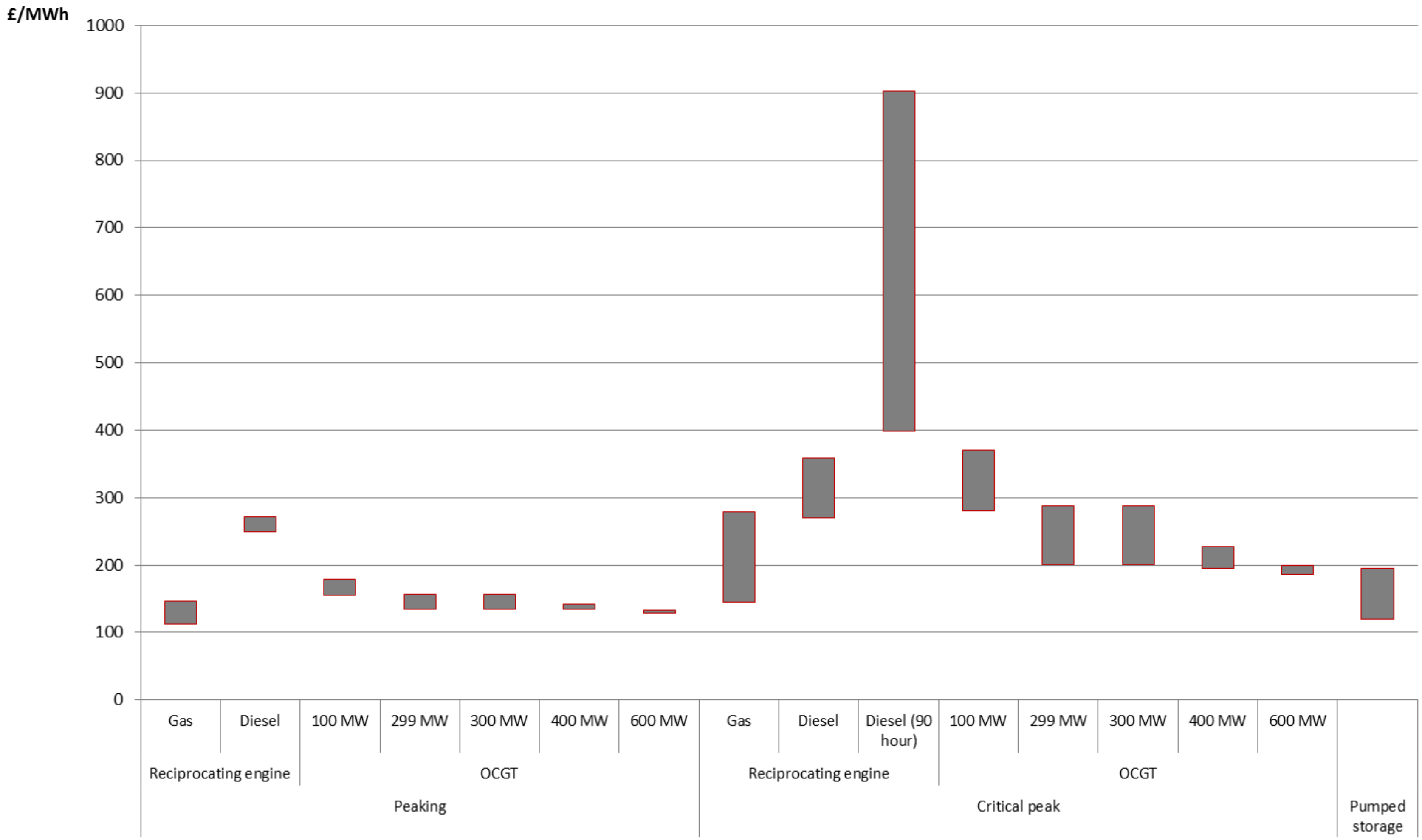


Figure 2 – peaking LCOE



*The open cycle gas turbine (OCGT) range is the maximum and minimum of LCOE for all OCGT capacities (100 MW, 299 MW, 300 MW, 400 MW, 600 MW)
†The Reciprocating engine range is the maximum and minimum of LCOE for diesel and gas engines

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1 Introduction

1.1 Introduction

The Department for Energy and Climate Change appointed LeighFisher to review and update the input assumptions and input data used in its estimates of the Levelised Cost of Electricity (LCOE) for all non-renewable technologies. The LCOE is a measure that allows comparison of the cost of different types of generation technology. In this report we consider the input assumptions and then consider the overall levelised costs for each technology by using DECC's Levelised Cost Model (LCM). Our report covers both cost assumptions and technical assumptions. We have considered assumptions for the following technology types:

- *NOx compliance – various measures to ensure environmental compliance in existing coal plants and existing and future CCGT plants*
- *Gas – new build Combined Cycle Gas Turbines (CCGT), Open Cycle Gas Turbines (OCGT), CCGT Combined Heat and Power and reciprocating engines*
- *Nuclear – new build nuclear generation*
- *Carbon Capture and Storage (CCS) – new build and retrofit pre-combustion, post-combustion and oxyfuel CCS generation*
- *Pumped storage – new build and conversion pumped storage plants*

Our scope is to consider the previous DECC assumptions and update them when we consider there to be evidence that there have been "significant and robust" changes. The previous DECC assumptions are those developed by PB Power in 2013 and 2014. We have referred to these as "previous" assumptions throughout. We have stated these in the report for comparison. Note that these are in 2012 prices as originally presented so that we do not distort the original analysis. However, there has been limited inflation between 2012 and 2014 in the inflation indices we have used[2].

DECC commissioned a separate assessment of the cost and technical assumptions for renewable generation technologies. The work was carried out by Arup.

We have summarised the range of parameters we have considered in Table 1.

Table 1 – parameters considered

Category	Description	Unit
Key Timings		
Pre-development period	Length of time from project inception to Final Investment Decision (FID)	Years
Construction period	Length of time from FID to first operational year	Years
Operating period	Length of time from first operational year to final operational year[3]	Years
Technical parameters		
Power output	The total power produced by the power plant when operating at full capacity. This includes any load deductions relating to the technology, including parasitic load from attached CCS equipment, but excludes transmission losses.	MW

[2] The change in these indices over the period was -2.5% for capex and +1.3% for opex. See section 1.2.1 for further details.

[3] Operational life will depend on various technical and economic factors. Where major refurbishment would be needed for continued operation, this has not been included in the costs or reflected in the operating periods stated in this report

Category	Description	Unit
Efficiency	The percentage of the energy content of fuel that is transformed in to power output[4]	%
Availability	The percentage of time that the power plant is technically capable of operating. We have expressed this as an average over the plant lifetime in the report and availabilities to reflect maintenance cycles. This includes planned maintenance and unplanned outages. We have provided average annual availabilities but not considered whether there are different availabilities based on system demand. For nuclear we have included an initial availability ramp up to cover initial technical issues and plant testing, but we consider this would be covered under the commissioning period for other technologies.	%
Load factor	The percentage of time that the power plant is generating electricity	%
Capital costs		
Pre-licensing, technical and design	Costs incurred in initial plant design before FID	£/MW
Regulatory, licensing and public enquiry	Costs incurred during consenting process before FID	£/MW
Construction	Costs incurred in developing the plant after FID, excluding network connections	£/MW
Infrastructure	Costs incurred by the developer in connecting the plant to the electricity or gas grid based on illustrative assumptions about the length of overhead line and length of pipeline required.	£
Cost reduction profile	Our construction costs are based on assumed first operational date. The cost reduction profile provides an indication of how construction costs may change in future from the base construction costs in terms of % of construction cost	%
Operating costs		
O&M fixed costs	Costs incurred in operating the plant that do not vary based on plant output	£/MW/year
O&M variable costs	Costs incurred in operating the plant that vary based on plant output. Note that in our analysis this includes Balancing Services Use of System charges	£/MWh

The scope of this study did not include fuel prices or decommissioning costs which were provided separately by DECC for the purposes of LCOE analysis.

1.2 Methodology

Each technology type above is at a different state of development in the UK and the available data means different analytical approaches are required. In this study we have used the following approaches:

- *top-down analysis based on recent empirical evidence of specific transactions and supplier quotes*
- *bottom-up by deriving parameters based on a first principles technical breakdown of plant requirements*
- *comparator analysis from an assessment of comparator technologies and engineering studies*
- *assessment, and validation against, project experience using our extensive project experience across all the generating technologies identified to supplement our top down/bottom up/comparator analysis*
- *using DECC's previous input assumptions, provided by PB power, as a starting point for our analysis*

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[4] We have provided Lower Heating Value (LHV) efficiency in the appendices to this report. Higher Heating Value conversions are based on information from DECC document "Energy and commodity balances, conversion factors and calorific values". These are 95.22% for coal, 94.04% for diesel and 89.82% for natural gas.

There is inherent uncertainty in non-renewable power generation technologies. They are large capital projects involving complex technology. Technical and cost assumptions could vary significantly in practice. We have developed appropriate ranges of low, central and high estimates for costs and technical parameters to reflect this uncertainty. In undertaking our analyses, we have made a number of assumptions. We have explained these in the relevant sections for each technology, but there are a number that apply across technologies.

1.2.1 Price base

Values in this report are stated on 2014 basis. The previous assumptions were stated in 2012 prices. When considering historical data we have indexed from 2012 basis to 2014 basis using the European Power Cost Construction index for construction costs[5] and from Price Adjustment Formulae Indices (Specialist Engineering) Series 3[6] for operating, regulatory and licensing costs.

The exception to this is pumped storage. Existing pumped storage projects date back to 1965, so a longer term index is required. In addition, pumped storage projects involve a high proportion of civil engineering costs. To reflect this, we have used the ENR construction index to inflate historical costs of pumped storage projects.

1.2.2 High, medium and low cases

We have provided values for low, central and high scenarios for each parameter. In this context, consideration is given to the potential correlations between the ranges for different items and whether such variations for individual cost elements would be additive when calculating the low, central and high ranges for *overall* LCOE. We have constructed our scenarios to represent the likely developments in the UK. For example, the “high” operating cost will not necessarily correlate with the “high” construction cost or “high” efficiency. Rather, the “high” construction cost scenario will correlate with the other cost and efficiency parameters of that particular plant type. We discuss correlations between individual parameters in the relevant section for each technology.

Although current market sentiment is considered by some to be depressed, our analysis has compared costs derived from bottom-up modelling and analysis against actual historic projects over an extended period and calibrated values accordingly. Such adjustment means that our costs are likely to be representative of longer-term averages over the business cycle

Cost estimates are stated to Class 4 level of accuracy in the AACE International Recommended Practice No. 18R-97: Cost Estimate Classification System shown in Appendix B.

1.2.3 Construction costs

The construction costs stated in this report are assumed to include all capital costs incurred following Final Investment Decision, excluding financing costs, for a commercially constructed plant. These are plants constructed with the aim of generating revenue from electricity sales and other services, rather than a demonstration plant, which is a plant constructed with the aim of testing the commercial viability of a technology.

Costs incurred prior to FID are included in pre-development costs. In practice, there is wide variation in the costs incurred in the pre-development stage depending on the level of detail to which the project developer seeks to develop the project prior to making a Final Investment

[5] Available here: https://www.ihs.com/info/cera/ihsindexes/

[6] Information available here: http://www.rics.org/uk/shop/BCIS-Price-Adjustment-Formulae-Indices-Online-PAFI---2-3-Users-x-19422.aspx

Decision. Some developers may have limited development budgets and would seek to reach a Final Investment Decision at a comparatively early stage in the process whereas other developers may seek to develop project design to a much greater level of detail before letting an Engineering, Procurement and Construction (EPC) contract.

Our capital cost range represents uncertainty around capital costs for any given project, and we have sought to exclude site specific considerations. This has not been possible throughout all analysis. For example, site specific costs are likely to be a driver in variation in nuclear plants given their size and the low number of plants constructed recently. Given the limited data on nuclear plants, it is likely some site specific variation would be included in our cost ranges.

1.2.4 First-of-a-kind (FOAK) and Nth-of-a-kind (NOAK)

For CCS and nuclear we have stated costs as First-of-a-Kind (FOAK) and Nth-of-a-Kind (NOAK) using appropriate assumptions for the timing and magnitude of cost reduction as experience in the different sectors develops. We do not anticipate any future cost reductions for other technologies as they are mature and well understood.

1.2.5 Load factor

In DECC's LCOE modelling, load factor is a parameter rather than derived within the model itself. Load factor can have an impact on other technical parameters. If load factor assumptions for low, central and high cases would be linked to operating cycles, such as peaking, two-shift and base-load operation, then other parameters would need to vary in line with load factor.

In general we have set load factor at the level of availability. When deriving LCOE, the model effectively assumes that plant would run at an availability level reflecting expected levels of planned and unplanned outages over the plant life.

The exception to this is OCGT, reciprocating engines and pumped storage. These are intrinsically peaking operation technologies. For these sectors, we considered two scenarios linked to environmental permitting conditions. Our scope did not include a review of environmental permitting conditions, but we believe the peaking and critical peaking scenarios considered in this study are believed to be indicative of the range of potential operational scenarios under current permitting arrangements:

- *Critical peak – a load factor based on 500 hours p.a., consistent with the limits imposed under environmental permitting (i.e., load factor 5.7%)*
- *Peaking – a load factor based on up to 2,000 hours p.a.*[7] *(i.e., load factor 22.8%)*
- *Pumped storage – load factors of 12% (low), 20% (medium) and 22% (high) based on our analysis of pumped storage operations*

In addition, we have considered another critical peak scenario of 90hr p.a. operation for diesel reciprocating engines following industry feedback that it would be appropriate to also consider a 1% load factor for diesel engines.

[7] The actual operating hours that may be achieved in practice will be constrained by environmental legislation and this is discussed in later sections of the report. We have used 2,000 hours as a general indication of operating hours for peaking plant. The main driver behind the OCGT parameters is likely to be the number of starts, with a 1,500 hours operating regime leading to the same number of starts, but fewer hours of operation per day.

We understand that is possible that diesel reciprocating engines are unlikely to receive local authority permits when operating at up to 2,000 hours p.a. However, we have included them in our analysis for completeness.

We have also considered the impact of running CCGTs at lower load factors than at the level of availability in section 3.4.2.

1.2.6 Network Charges

(a) Transmission Network Use of System Charges (TNUoS)

Large scale generators connected to the high voltage transmission system incur the costs of building, operating and maintaining the transmission network through TNUoS. TNUoS is charged on a locational basis with 27 separate geographical zones in the GB mainland. National Grid publishes forecast tariffs for each zone for four years ahead and provides a tool on its web-site to enable users to determine TNUoS on a site specific basis under the new charging regime following approval of Connection and Use of System Code Modification Proposal 213. We have used National Grid's tool for the purposes of calculating tariffs for this study and, for consistency, have used the assumptions for load factor values as stated elsewhere in this report rather than the generic values included within that tool's data set.

We have made various assumptions about the likely locations of new developments in each sector. This ensures that the values are not unduly skewed by high tariffs for certain zones, for example in the north of Scotland, since non-renewable deployment (other than pumped storage) is unlikely in those. We have therefore calculated costs for expected deployment on the following basis for the central case assessment:

- *CCGT and OCGT – unweighted average of TNUoS for all zones for which there is consented development with capacity on the Transmission Entry Capacity Register and/or existing sites (given the possibility that such sites may be re-planted)*
- *Reciprocating engines - average DUoS tariffs plus embedded benefits (TNUoS triad avoidance) on average basis for same zones as CCGT and OCGT*
- *Coal (retro-fit) – unweighted average of TNUoS for all zones with existing coal-fired capacity*
- *CCS – as for CCGT or coal above as appropriate*
- *Nuclear – unweighted average of TNUoS for all zones where development is planned (EdF, Horizon and NuGen sites)*
- *Pumped storage – an unweighted average of all zones where pumped storage sites have been considered*

The data at individual zone level has also been used to guide the selection of appropriate values for low and high cases. The low case is based on the rate for the second lowest cost zone (aggregate TNUoS plus DUoS) and the high case is based on the rate for the second highest cost zone applicable to each sector. Using the second lowest/highest rates in this manner is considered to give a reasonable indication of the range of potential rates without making an assumption of all prospective developments achieving the lowest/highest possible rates.

TNUoS is charged as a £/kW tariff.

(b) Distribution Use of System Charges (DUoS)

Smaller scale generators connected to the low voltage distribution network are subject to DUoS applicable to the Distribution Network Operator (DNO) zone in which they were connected. We have used an average of the 14 DNO Extra High Voltage[8] (EHV) tariffs published in the current Charging Statements. Such charges comprise p/kWh, p/kVA/day and p/day tariffs which we have converted to equivalent £/kW based on the load factor assumptions.

(c) Balancing Services Use of System Charges (BSUoS)

Unlike TNUoS and DUoS which are ex-ante published tariffs, BSUoS is calculated ex-post at half-hourly granularity on a £/MWh basis and chargeable at the same rate for all generators and offtakers. DECC has previously treated BSUoS as a £/MW/year charge. We recommended that BSUoS is treated as £/MWh, and have therefore included BSUoS as a variable cost. For the avoidance of doubt, the variable opex figures in the summary table set out in the appendices to this report do not include BSUoS. Accordingly the £/kW values for connection and use of system stated in the summary tables do not include BSUoS.

We have used a central forecast value of £1.90/MWh, which is based on a historical average. This value is assumed to apply for all forward years.

Appendix C sets out values of the use of system charges broken down by TNUoS, DUoS and BSUoS on this basis.

1.2.7 Connection and infrastructure costs

Given the shallow connection boundary[9] applicable to most non-renewable developments, wider system reinforcement costs would not be expected to be borne by individual generators (and would fall within TNUoS or DUoS. The direct costs of site sub-station and transformers are included within construction costs. Only overhead line costs directly associated with a project but not included in use of system charges (typically spur connections) are treated as infrastructure costs.

For the purposes of this report infrastructure costs are derived from unit cost data for overhead lines and pipelines. The following assumptions have been used for the low/central and high cases:

- *CCGT/OCGT:* *5/10/20 km lengths for L/M/H respectively*
- *Reciprocating engines[10]:* *1/ 5/15 km lengths for L/M/H respectively.*
- *Nuclear:* *Relevant benchmarking information*
- *CCS:* *5/10/20 km lengths for L/M/H respectively*
- *Pumped storage:* *10/25/50 km lengths for L/M/H respectively*

The unit costs rates used assume such line and pipeline routes would be over greenfield sites with no adverse geological or topographical conditions and no road or river crossings. Our assumptions for unit costs differ from those stated previously, which explains the difference in infrastructure costs in this report from previous reports.

1.2.8 Foreign exchange rates

Costs have been stated in sterling. Where foreign exchange rates have been applied in this analysis, the rates provided by DECC have been used as shown in Table 2.

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[8] Distribution networks are low voltage relative to transmission networks, but are further divided in to low voltage (below 1kV), high voltage (between 1kV and 22kV) and extra-high voltage (22kV and above).

[9] A shallow connection boundary means that a developer is only charged for new assets that are for the sole use of the power station

[10] We have assumed shorter lengths because reciprocating engines tend to be connected to distribution networks rather than transmission networks and because of the geographic density of such networks, development sites tend to be closer to potential connection points

Table 2 – foreign exchange rates

Year	GBP:USD	GBP:EUR
2005	1.819	1.463
2006	1.843	1.467
2007	2.002	1.462
2008	1.853	1.259
2009	1.567	1.123
2010	1.546	1.166
2011	1.603	1.153
2012	1.585	1.234
2013 onwards	1.564	1.178

Where bottom-up cost estimates have been modelled, the granularity of information needed to break individual cost elements down into different currencies is not available. Even where specific components are quoted in specific currencies, it would still be potentially misleading to present costs in "appropriate" currency without detailed knowledge of Original Equipment Manufacturer (OEM) supply chains; i.e., although an OEM may price its product in EUR for example, prices would not necessarily move pro-rata to EUR foreign exchange rates because the supply chain involved in building such a product could include components sourced from many different currency areas.

Notwithstanding, for CCGT and nuclear a proportional breakdown of costs in percentage terms versus the main cost headings[11] has been provided separately. This will allow DECC to make adjustments to the costs stated in this report based on their own assumptions about FX impacts on different cost elements.

1.2.9 Start-up costs

It is not possible to provide start-up costs on a £/MWh basis since this would depend on assumptions regarding the commercial operating regime. As described above, this study assumes that plants operate at availability with the exception of reciprocating engines and OCGT which operate as peaking and critical peaking plant.

Start-up and shut-down costs would not be material for plants with load factors based on running at availability levels. Therefore, we state the quantities of fuel used per start-up and run-down are the corresponding values for minimum on and off times are considered only for OCGT and reciprocating plant. It has been assumed that all fuel consumed in synchronising each unit and then ramping up to full load would be a direct start-up cost incurred by the generator (i.e., no revenue earned until full-load achieved). Similarly fuel used during the ramp-down from full-load and de-synchronisation period would also be a direct cost with no revenue earned. Additional opex costs arising from increased Equivalent Operating Hours (EOH) due to start-ups are not considered.

1.2.10 Ambient conditions

For gas plant modelling, values for parameters expressed per MW or per MWh are stated assuming prevailing annual average conditions expected for the UK sites under consideration. This would assume a lower average temperature than ISO conditions (11 ^{o}C versus 15 ^{o}C) and GT output would therefore be higher than at ISO conditions. This assumption applies to configurations assumed to run base-load and also for configurations assumed to operate on a peaking basis[12].

[11] Main turbine and generator plant; balance of plant; civils, labour; mechanical and electrical installation work; buildings; etc

[12] In practice the operation of such plants may be skewed towards winter months resulting in higher output relative to annual average conditions

2 Gas assumptions

2.1 Technology types

We have considered the gas generation technology types shown in Table 3, split between Combined Cycle Gas Turbines (CCGT), Open Cycle Gas Turbines (OCGT), reciprocating engines and Combined Heat and Power (CHP).

Table 3 – gas technology types

Technology	Notes
CCGT (1,200 MW) H class	New CCGT in capacity auction[13] is largely in 600 MW units and likely to be built in two-unit plants
CCGT (1,400 MW) F class	For comparison with the H class costs, smaller F class blocks have been analysed to give a typical three-block plant cost.
CCGT CHP	CCGT CHP assessed in "power-only" mode, with no heat offtake, and "CHP mode", with a part loaded steam generator.
OCGT (400 MW)	Supply chain now offering 400 MW units
OCGT (600 MW)	Equivalent of two 299 MW units
OCGT (299 MW / 300MW)	We have considered a range of capacities around the 300 MW range. We have also provided values based on a 299 MW scenario as it falls under the Carbon Capture Readiness threshold, which we discuss in section 4.3.2, but also considered other capacities in a similar range but over 299 MW.
OCGT (100 MW)	100 MW capacity assessed
Diesel reciprocating engine (20 MW)	A 20 MW site installation using 1-2 MW units sizes, in line with capacity market results and developer's plans for future capacity market auctions.
Gas reciprocating engine (20 MW)	A 20 MW site installation using 1-2 MW units sizes, in line with capacity market results and developer's plans for future capacity market auctions.

Further details on these configurations and the methodologies applied in our assessment are provided in Appendix E.

2.2 Scenarios

The analysis has identified ranges of costs for different plant configurations based on using gas turbines from different OEMs. This analysis has been benchmarked against available transactional data to identify appropriate values for high, medium and low cases.

2.3 FOAK and NOAK

CCGT, OCGT, reciprocating engines and CHP are well-understood, established technologies. It is therefore assumed that parameters would be equal for FOAK and NOAK. This assumption is consistent with previous studies.

2.4 Availability

We have assessed appropriate values for each year over the average design life of the reference plant in each case based on internal information. We have taken degradation into account and

[13] The auction for capacity contracts managed by Nation Grid in its role as Electricity Market Reform (EMR) Delivery Body: https://www.emrdeliverybody.com/SitePages/Home.aspx

assumed some recovery following major services, on and off-line washes. We have stated an average availability across all years in the summary data presented in this report.

2.5 Cost adjustment profiles for capital costs

For gas plants (i.e., CCGT, OCGT, reciprocating engines and CHP), the previous cost reduction profile showed 0.5% p.a. reduction in capital costs, down to a maximum decrease of 9% in the low case, a 0.5% increase in capital costs, up to a maximum increase of 9% in the high case and flat costs in the medium case. The base year for our analysis is a gas power plant that reaches FID in 2015.

We have considered a cost reduction profile that reflects the underlying technical drivers faced by gas plants. These are cost changes from improvements in manufacturing processes by OEMs and their supply chains, and ongoing technical improvements or design refinements which might result in minor increases or decreases in OEM costs.

Based on indicative analysis of historical trends (allowing for inflation effects), we consider the ±0.5% per annum cited in previous studies provides a reasonable representation of the potential range of cost adjustment in this respect.

We have applied this cost reduction profile to CCGT, OCGT, reciprocating engines and CHP.

2.6 Technology scenarios

Previously, DECC’s advisors have provided analysis of specific gas plant configurations and separately considered the potential variation in overall LCOE for each type of gas plant across multiple plants deploying concurrently. They approached this latter exercise by assessing the correlation of different parameters across different gas plants.

- *Separate analysis of F and H class CCGTs*
- *Separate analysis of different capacities for OCGT configurations*
- *Separate analysis of OCGTs and reciprocating engines at different load factors*

Therefore the ranges we stated for each individual parameter are generally considered on an individual basis and not necessarily correlated. We have provided a range for parameters that states the range that we would expect a developer to see in tender returns. It may be that low construction cost will align with high operating costs, and high construction costs with low operating costs, but this is not certain.

Our view is that there is a reasonable correlation between construction cost and efficiency (i.e., a higher construction cost would be expected to result in a plant with higher efficiency.

Insurance costs are considered to be a percentage of construction cost value, so would be correlated with construction cost for any given assumption on that percentage (values of 0.3%, 0.4% and 0.5% of construction cost are proposed for low/central and high cases in this respect and have been applied to the corresponding low/central/high cases).

There may be some inverse correlation between design costs and construction costs (i.e., greater effort spent at the design stage may result in a better design with corresponding benefits in costs under the EPC contract). However, there is also a possibility that there may be a direct correlation, if a particularly complex project may result in high design and construction costs, or a simpler project results in lower design and construction costs.

We have aligned the low/medium/high capacities (MW) with low/medium/high efficiencies (%) respectively. In some cases, the values stated for high capacity MW are therefore lower than the corresponding values for low and/or medium capacity MW for example because the highest efficiency configuration produces a lower output than the other configurations considered. While we have considered the medium capacity case for the purposes of our LCOE analysis, DECC should consider capacity and efficiency as correlated parameters if they elect to vary capacities in any subsequent analysis of alternative combinations of parameters. Otherwise, we believe the variations between low/central/high cases are uncorrelated and can therefore be considered independently.

Otherwise, we believe the variations between low/central/high cases are uncorrelated and can therefore be considered independently.

We consider that assessing variation in capital and pre-development costs provides the most appropriate indication of the likely range of gas LCOE. While there may be a correlation between high costs and high efficiency, correlating high cost with high efficiency results in a narrower LCOE range that may not reflect fully the potential range in future costs if a broader range of uncorrelated parameters were to be considered instead.

A further consideration is the extent to which market factors could possibly affect CCGT development if multiple CCGT projects were to be progressed at the same time by a number of different developers. As an indication of potential impact on LCOE, we considered potential variations in construction costs of 30% trough-to-peak (i.e., +/-15% around the average) across the business cycle, our high, medium and low cases assuming the mid-point of the business cycle.

These were used as illustrative indications of limited market activity or where market conditions are buoyant and potential demand may be greater than supply chain capacity. This assessment indicated that any such additional variations on this basis could result in changes to LCOE of ±1% over or below the high and low LCOE values respectively stated in Section 12.1.

3 Combined Cycle Gas Turbines

We have considered the newer larger H class units and smaller F class units separately. This allows us to separate the underlying movement in market costs since the previous 2013 report from the movement in costs attributable to use of new. Our summary tables present F class and H class configurations rather than providing a single set of values based on a fleet comprising an assumed blend of F and H class machines. For the purposes of modelling and analysis LCOE and/or merit order modelling we would recommend that DECC uses separate input tabs for F and H class configurations.

While some costs will be similar, there are differences between the various cost components for each technology. Presenting costs on an assumed average basis for a fleet containing both F and H class plants may give a distorted view of costs. Similar considerations apply to the technical parameters associated with different turbine classes (e.g., efficiency) which would affect the likely dispatch regime. For example, higher efficiency plant is likely to be in merit more often and also likely to have a longer economic life time due to lower fuel costs per MWh.

Our assessment considers F class plants based on three blocks of 450 MW – 490 MW using Alstom, GE, Siemens and Mitsubishi turbines, and H class plants based on two blocks of 600 MW capacity using Siemens and GE turbines. Further details of these reference plants are provided in Appendix E.

3.1 Key timings

We have assumed commissioning dates of 2020 for CCGT plants.

Our assessment of timings for CCGT plant is based on relevant project experience across all stages of power project development, execution, construction and operation. We have summarised these with a comparison against the previous assumptions in Table 4.

Table 4 – CCGT key timings

Parameter	Previous			LF		
	Low	Med	High	Low	Med	High
Pre-development period (years)	2.0	2.3	5.0	2.0	2.3	5.0
Construction period (years)	2.0	2.5	3.0	2.0	2.5	3.0
Operating period (years)	20.0	25.0	35.0	20.0	25.0	35.0

3.1.1 Pre-development

There are no significant changes to pre-development timescales since the 2013 update with pre-development taking between 2-5 years and average plant pre-development taking 2 years 4 months.

3.1.2 Construction

CCGT technology is a mature technology. The construction period for this type of plant has not changed much in recent times with no major advancements in construction techniques. Therefore the construction periods quoted remain the same as in the 2013 report of between 2-3 years with the typical plant taking 30 months to build.

3.1.3 Operating period

The operating period for new-build CCGT has been stable for a long time due to the in-depth understanding of the technology. We note that operating periods can be extended with life extension programmes. Any such programmes would be subject to cost-benefit analysis based on the market economics prevailing at that time, and incur material costs should the economic case support such an investment. The costs of such major refurbishments are not included in this study.

3.2 Technical parameters

We have summarised our assessment of CCGT technical parameters with a comparison against the previous assumptions in Table 5.

Table 5 – CCGT technical parameters summary

Parameter	Previous			LF F Class			LF H Class		
	Low	Med	High	Low	Med	High	Low	Med	High
Power output (MW)	900	900	900	1,340	1,405	1,370	1,190	1,200	1,210
Net efficiency (LHV) (%)	57.4	58.8	60.0	57.4	58.8	60.0	58.8	59.8	60.7
Availability (%)	91.9	92.8	93.7	91.7	92.6	93.6	92.3	93.0	93.6

3.2.1 Power output

F class machines have a typical output of 450-490MW per block. We have modelled a three block configuration to provide a comparable configuration to the two x 600 MW H class configuration base case. Our F class medium case is a higher capacity than the low and high case as we consider this to be the most likely configuration. As such, our low case is the lowest capacity, medium case the highest capacity and high case the middle capacity.

3.2.2 Efficiency

While there have been some marginal gains on the top end efficiencies with the introduction of the H class CCGT machines, the lower efficiency F class machines are still available on the market. The F class efficiencies remain the same as shown in the 2013 report. The H class efficiencies are slightly higher (up to 60.7%).

The figures stated reflect expected levels of degradation during the operating lifetime of the plant. The degradation profile of a gas turbine is attributed mainly to blade fouling which cause the blade profiles to change over time. This has an effect on the gas turbine performance. Some of the loss in performance can be regained by online washing and much more can be regained by offline washing. Both online and offline washing take the gas turbine out of service for a period of time. An offline wash requires the gas turbine to be fully cooled (i.e., offline for a period of 8-10 hours prior to the wash). The online wash cannot be done on-load, but it can be done when the turbine is warm. Therefore there is less disruption to the plant as a result.

The most effective way of recovering performance is a major overhaul. During an overhaul, blades are either mechanically cleaned or replaced. Following an overhaul the gas turbine is returned into service with an increase in performance to a nearly new condition. As-new performance of the gas turbine is not possible. This is known as non-recoverable degradation.

3.2.3 Availability

Availability figures for CCGT remain the same as figures quoted in 2013. Our analysis is based on in house and reported data and operational experience of F Class plants, and in house and reported data on likely availability of planned CCGT plants. Main plant outages are planned for every 48,000 hours. Other outages are typically scheduled annually and require less down time. The profile presented assumes 8,000 hours operation (base load) although the actual availability profile would be subject to operating hours and the operation regime. A change to this operation would alter the availability profile. For example, a change to two-shifting or peak loading would result in changes to the time taken to reach equivalent operating hours limits.

Between outages, availability would be affected by the need for on- and off-line washing. As explained above, this is required periodically to maintain turbine compressor condition and hence performance levels.

Typical availability figures for CCGT plant range between 92% - 94% for H class and F class technologies. The figures stated reflect expected levels of degradation during the operating lifetime of the plant.

3.3 Capital costs

We have summarised our assessment of CCGT capital costs with a comparison against the previous assumptions in Table 6.

Table 6 – CCGT capital costs summary

Parameter	Previous 2012 prices			LF F Class 2014 prices			LF H Class 2014 prices		
	Low	Med	High	Low	Med	High	Low	Med	High
Pre-licensing (£/kW)	6.0	12.0	15.0	4.8	10.0	11.5	5.3	10.8	13.6
Regulatory (£/kW)	0.4	0.4	4.0	0.3	0.3	3.3	0.3	0.4	3.6
Capital cost (£/kW)	490	569	648	403	475	546	439	516	593
Infrastructure (£m)	7.0	17.5	36.0	7.5	15.1	30.2	7.5	15.1	30.2

3.3.1 Pre-licensing costs, technical and design

Pre-licensing costs, technical and design varies from project to project based on the complexity of the site and the information available. A typical cost has been provided based on confidential project information and PEACE[14] data[15].

3.3.2 Regulatory, licensing and public enquiry

Regulatory, licensing and public enquiry costs will vary depending on location and sensitivity of a specific site. We have provided basic costs associated with these activities to give a typical overview of the costs. The regulatory and licensing regime has not changed significantly since the previous review.

3.3.3 Construction cost

We used PEACE software to derive a bottom-up costing for a typical F class CCGT plant using the database of 2012 prices and the database of 2014 prices. This allowed us to evaluate the impact of market price changes since the previous report. We then validated these prices using confidential project data for historic projects. There are limited recent projects so up-to-date comparators are

[14] PEACE is a software module that provides cost estimations ("Plant Engineering And Cost Estimation" for gas power plant specifications http://www.thermoflow.com/combinedcycle_PCE.html

[15] PEACE suggests 3% of construction costs for pre-licensing and 2% for regulatory

not widely available. We therefore rebased historical project references to take account of recent market trends and fluctuations.

Historic projects modelled using the 2014 PEACE database showed a drop in the CCGT price from the 2012 price. Actual project data suggests such a drop in prices may not actually be seen in practice. Equipment accounts for a large proportion of the total construction costs, so when demand is high the price would tend to reflect such conditions. Conversely, discounts may be available in a depressed market providing that a well-structured competitive tender process is employed by the developer. Discounts may also be available when manufacturers attempt to place new turbines into operation to establish reference plants for future sales growth. The current market situation is considered to be challenging for manufacturers with there being few new projects in recent years and quoted OEM prices reflect this situation. In addition, manufacturers are seeking to get new H class machines deployed and proven in the market.

As well as the above factors the largest contribution to the apparent reduction in costs observed in the PEACE analysis is seen to derive from the relationship between different currencies. This has the largest impact on equipment sourced from Europe. Given the large swing in Euro Sterling exchange rates over the last 15 years there is uncertainty as to whether such prices would be experienced in practice given that current spot rates may not endure over the extended time horizon required to develop a project.

For F class we have estimated construction costs of £360 to £487 per kW, although analysis of previous actual projects would suggest a figure above £500 per kW. We have adjusted therefore the costs calculated using PEACE to take account of some of the difference identified between actual project costs versus calculated costs. On this basis, we would expect to see construction costs of £403 to £546 per kW if previous trends are to be seen. However the points discussed above in relation to prevailing market conditions could have a greater impact on the price rather more than historic trends.

There is very little in the way of historic data for the H class technology but applying a similar uplift figure to calculated costs as that for F class projects would result in construction costs in the region of £439 to £593 per kW.

As an indication, Table 7 shows how construction costs, excluding pre-development and infrastructure costs, may be approximately proportioned.

Table 7 – CCGT construction cost proportions

<table>
<tr><th>Category</th><th>Proportion</th><th>Currency impact</th></tr>
<tr><td>I Specialized equipment</td><td>48%</td><td>Likely to be in denomination of turbine supplier ($/€/¥)</td></tr>
<tr><td>II Other equipment</td><td>4%</td><td rowspan="7">Likely to largely be delivered in UK.

If delivered by supplier in non-GBP denomination, GBP supplier likely to become more competitive and thus overall price unlikely to change.</td></tr>
<tr><td>III Civil</td><td>9%</td></tr>
<tr><td>IV Mechanical</td><td>10%</td></tr>
<tr><td>V Electrical</td><td>3%</td></tr>
<tr><td>VI Electrical assembly and wiring</td><td>5%</td></tr>
<tr><td>VII Engineering & Plant setup</td><td>3%</td></tr>
<tr><td>VIII contractor's soft & misc cost</td><td>19%</td></tr>
<tr><td>Total</td><td>100%</td><td></td></tr>
</table>

(a) Infrastructure cost

The low, central and high cases for gas pipeline and overhead lines are based on our assessment of costs for 5 km, 10 km and 20 km connection lengths respectively, and remain similar to those applicable in 2013.

3.4 Operating costs

3.4.1 Operations and maintenance

We have identified a wide range of potential Long Term Service Agreement (LTSA) costs, in terms of overall costs and the basis for allocation between fixed and variable costs. This depends on the contractual arrangements achieved in negotiation between developers and providers.

There are various O&M packages available from several suppliers which are structured differently. The fixed costs vary between 25%–75% of the total annual share of the O&M costs. We have taken the midpoint of the 25%–75% range. Actual LTSA cost data for H class turbines is extremely limited given the limited deployment of such configurations. Therefore we have costs on a variety of data for other comparable units and manufacturers. The costs can also vary according to when LTSAs are negotiated. LTSAs negotiated during the bid phase are part of the selection criteria for the EPC contractor so priced more competitively.

The previous costs for the O&M fees in the 2013 report are similar to those costs we have seen on other projects. However the proportion of variable costs is higher in most of the cases reviewed in our review of confidential data. Therefore we have adjusted the split accordingly to the mid-point of the 25%–75% range highlighted above.

We have summarised our assessment of CCGT operating costs in Table 8 with a comparison against the previous assumptions. Assuming operation at availability load factor, this would result in F Class operating costs that a broadly in line with the previous assumptions and H Class operating costs that are higher.

Table 8 – CCGT operating costs summary

Parameter	Previous 2012 prices			LF F Class 2014 prices			LF H Class 2014 prices		
	Low	Med	High	Low	Med	High	Low	Med	High
Fixed fee (£/MW/yr)	18,026	21,954	25,882	9,131	11,440	13,710	9,770	12,240	14,670
Variable fee (£/MWh) excluding BSUoS	0.00	0.08	0.15	1.14	1.43	1.71	1.22	1.43	1.83
Insurance (% capex/yr)	0.2%	0.4%	0.5%	0.3%	0.4%	0.5%	0.3%	0.4%	0.5%
Connection (£/MW/yr)	6,842	6,842	6,842	(9,000)	3,280	23,010	(9,000)	3,280	23,010

3.4.2 Operating regime

The operating costs stated in this report are based on a standard 8000 hours base load operation per annum. O&M contracts are usually based on Equivalent Operating Hours (EOH) (or equivalent schemes as offered by the various OEMs). Although the specific arrangements vary between individual contracts, in most cases manufacturers attribute a number of hours to a start, trip and other associated events.

Under an operating regime with greater frequency of starts and stops (e.g., two-shifting) the number of occasions when CCGT plants are brought on and off would increase the EOH. Hence there would be an increase in the £/MWh variable cost element of the O&M cost. In recent years design changes for newer machines allow CCGT plant to be started and stopped with less impact on EOH, so the impact may be lower than in the past.

A CCGT running 7 am to 7 pm, 5 days a week (total 60 hours) would accrue an additional 40 EOH per week for corresponding starts, assuming 8 EOH for a start. For a 1400 MW plant this may result in variable costs of £10.6m rather than £6.2m for operation at base load. There would be no additional output with respect to the additional 40 EOH per week and therefore the cost of operation per MWh output would increase from of £1.43 per MWh for base-load stated in the summary tables in this report to £2.43 per MWh.

The above is based on the assumption of a generic OEM O&M package and these can vary between projects so the figures stated should be considered as indicative.

3.4.3 Start-up fuel consumption

Start-up time and fuel consumption can vary considerably depending on the design and configuration of the CCGT plant. Table 9 provides values based on typical start-up curves for F and H class configurations for two scenarios:

- *Start-up after a weekend (i.e., shutdown period up to 48 hours)*
- *Start-up under a two-shift cycle (i.e., 12hr off time)*

Table 9 – CCGT start-up fuel consumption

Scenario	F class		H class	
	Warm start (<48 hours)	Hot start (<12 hours)	Warm start (<48 hours)	Hot start (<12 hours)
Average (MJ/MWe at base load)	5,800	4,300	5,300	3,650
High (MJ/MWe at base load)	6,950	5,150	6.350	4,400
Low (MJ/MWe at base load)	4,650	3,450	4,200	2,900

3.4.4 Shut-down fuel consumption

Figures for fuel consumption during shut-down from base-load are given in Table 10.

Table 10 – CCGT shut-down fuel consumption

Scenario	F class	H class
Average (MJ/MWe at base load)	2,648	2,276
High (MJ/MWe at base load)	3,177	2,731
Low (MJ/MWe at base load)	2,118	1,821

3.4.5 Insurance

From review of various confidential reference projects we note that insurance typically amounts to a figure in the range of 0.3% to 0.5% of the construction cost. We have set values of 0.3%, 0.4% and 0.5% which are used for the low, central and high cases respectively.

3.4.6 Connection and use of system charges

We have taken an unweighted average of TNUoS tariffs for all zones for which there is consented development with capacity on the Transmission Entry Capacity Register and/or existing sites, given the possibility that such sites may be re-planted. We have derived an average of forecast tariffs for the next four years using National Grid’s model at a load factor assumption of 100% of availability. Further details of the applicable tariffs are provided in Appendix C of this report.

4 Open Cycle Gas Turbines

We have examined four different capacity sizes within the OCGT technology group to represent the different options available to developers in the market. In varying the capacity of an OCGT plant, an operator is looking to capture different opportunities by utilising different aspects of the technology such as ramp rate, efficiency, emissions or capital cost. The capacities are 100 MW, 299, 300 MW, 400 MW and 600 MW. These are in line with common offerings from the major gas turbine manufacturers.

The 100 MW OCGT configurations consider a variety of large frame, industrial and aero-derivative gas turbines to represent options available to developers in this capacity range. The low case is represented by a less advanced but cheaper large-frame machine, whereas the high case is a high efficiency, highly flexible aero-derivative industrial machine. The central case is representative of a typical plant which sits in the middle of the trade-off between high cost and high performance.

The 299/300 MW OCGT configurations are based on large frame and industrial gas turbine configurations. Plant configurations marginally above 299 MW Carbon Capture Threshold were examined based on F class and E class gas turbines.

The 400 MW OCGT configurations are based on a single unit H Class machines and multiple unit smaller machines (E Class and F Class). We note that H class machines have not been deployed in OCGT arrangement at the time of publication, but have been considered in this report to provide context of potential future opportunities going forward.

The 600 MW OCGT values are based on dual unit F class machines available in the market. The single OCGT reference plant considered in the 2013 Update was based on a large frame F class machines and therefore the 600 MW OCGT plant in this report is the most comparable to those in the 2013 Update.

Values for all configurations are in Appendix G.

4.1 Key timings

We have assumed commissioning dates of 2020 for OCGT plants.

4.1.1 Pre-development

Timings for OCGT plant are based on relevant project experience across all stages of power project development, execution, construction and operation. There are no significant changes since the 2013 update in construction and operating life timings and therefore these remain the same.

The pre-development period for 400 MW and 600 MW OCGT plant remain the same as the OCGT figures from the 2013 Update, since these were representative of the same type of plant.

For 299 MW OCGT plant, the low capacity case (but high capital cost case) represents a plant that falls under the 300 MW Carbon Capture Readiness (CCR threshold). For 100 MW plant, all three cases will fall under the 300 MW threshold. Our experience of the CCR development process suggests there is unlikely to be a material increase in timings. Therefore for some individual cases there may be pre-development periods that are moderately less than the other OCGT plant types, but this is unlikely to be material.

Table 11 compares our 400 and 600 MW OCGT assumptions with the previous 600 MW OCGT assumptions, as the previous assumptions only considered a 600 MW OCGT. The remaining OCGT assumptions are in Appendix G.

Table 11 – OCGT key timings

Parameter	Previous			LF (400 & 600 MW)		
	Low	Med	High	Low	Med	High
Pre-development period (years)	1.5	1.8	4.5	1.5	1.8	4.5
Construction period (years)	1.5	2.0	2.5	1.5	2.0	2.5
Operating period (years)	20.0	25.0	35.0	20.0	25.0	35.0

4.1.2 Construction

OCGT technology is a mature technology and the construction period for this type of plant has not changed much in recent times, with no major advancements in construction techniques. Therefore the construction period remains the same as in the 2013 report.

4.1.3 Operating period

The operating period for new build OCGT has been stable for a long time due to the in-depth understanding of the technology. We note that operating periods can be extended with life-extension programmes. As with CCGT, these depend on business cases and will incur material cost increases and are therefore excluded in this study.

4.2 Technical parameters

As discussed above, we have considered four output capacities that reflect typical offerings from the gas turbine market and sizes likely to be developed as OCGT plant. These capacities are 100 MW, 299 MW, 300 MW, 400 MW and 600 MW. All OCGT plant power outputs are based on internal data sources and PEACE modelling. Our 300 MW medium case is a higher capacity than the low and high case as we consider this to be the most likely configuration. As such for 300 MW our low case is the lowest capacity, medium case the highest capacity and high case the middle capacity.

For OCGT plants we have considered the capacity for each size of reference plant at the prevailing UK average ambient conditions rather than ISO standard conditions. However, the actual achieved average output could vary considerably according to the assumed despatch regime. For example, if operation were assumed to be skewed towards the winter months, then output would be greater because of the lower temperatures prevailing during the winter season compared to the annual average. For summer operation, output would be lower on average. It is outside the scope of this study to consider the forecast despatch regime of such units. We have reported any costs elements that need to be apportioned on a £/MWh basis on an assumption of output at annual average ambient conditions. We have not made assumptions as to the time of year in which plant would be dispatched in the chosen critical peaking and peaking load factor scenarios.

4.2.1 Efficiency

New build efficiency figures are based on PEACE modelling which uses manufacturer's technical data. We have applied lifetime degradation factors in line with typical LTSAs used in the market, which state the maximum allowed degradation after each major inspection. The figures presented in the summary tables are the lifetime average efficiency figures (taking account of degradation as described in 3.2.2) and not the new build efficiency.

4.2.2 Availability

The core technology and operating strategy for OCGT is independent of capacity size and therefore material differences in availability figures are unlikely for the ranges being analysed. We have applied the same availability for all OCGT plant types.

OCGT technology is well understood by plant operators with maintenance programmes having been refined based on operational experience. Therefore the availability of OCGT plant remains very high. The availability of an OCGT plant compared to a CCGT plant operating on the same regime is often higher due to the relative simplicity of the design, leading to fewer outages and less maintenance.

The central case for availability remains at 94.7% given the strong understanding of the basic technology and no major developments in availability improvement since the 2013 update. The low and high cases have been widened based on market data and project experience.

The timing of major and minor gas turbine overhauls are based on operating hour and number of starts. As with CCGTs, this is often represented as equivalent operating hours (EOH). Therefore at very low load factors of 500 hours of operation a year where the plant has a peak loading operating profile, the time availability of OCGT plant can be extremely high since major maintenance overhauls are further apart, leading the average annual availability to be higher.

At regular peaking load factors of up to 2,000 hours of operation per year, the high number of starts and longer operating time per start leads to overhauls being needed earlier.

Our analysis indicates that very low load factors lead to an increase in availability in the order of 1.5% compared to regular loads. We have applied this adjustment factor to the critical peak availability figures.

4.3 Capital costs

Table 12 compares our 600 MW OCGT technical parameter estimate with the previous 600 MW OCGT estimate. Our remaining estimates are available in Appendix G.

Table 12 – OCGT capital costs summary

Parameter	Previous 2012 prices			LF OCGT Peaking 2014 prices			LF OCGT Critical Peak 2014 prices		
	Low	Med	High	Low	Med	High	Low	Med	High
Pre-licensing (£/kW)	16	19	25	15.4	17.5	21.8	15.4	17.5	21.8
Regulatory (£/kW)	2.0	2.4	3.1	2.1	2.4	3.1	2.1	2.4	3.1
Capital cost (£/kW)	218	274	330	283	291	294	283	291	294
Infrastructure (£m)	7.0	9.1	11.1	7.6	15.1	30.2	7.6	15.1	30.2

4.3.1 Pre-licensing costs, technical and design

There have been no significant developments in the pre-licensing, technical and design costs in the UK since the 2013 Update. Our analysis shows that the central case for these costs is £17.5m based on market knowledge and recent project experience, which is approximately in line with the 2013 Update figure for a similar plant.

These costs are mostly independent of the output of the plant. Our analysis indicates some reduction in cost as the plant capacity becomes smaller, which is due to the decrease in complexity. Therefore we have applied the base case to the 600 MW OCGT plant and applied discount factors of

10%, 20% and 30% to the 400 MW, 299 MW and 100 MW plant respectively. While costs decrease overall, the £/kW figure increases owing to the smaller plant capacity.

4.3.2 Regulatory, licensing and public enquiry

We have taken the same approach for OCGT as CCGT due to their highly similar nature.

We have widened the capacity range to include OCGT projects which fall under the 300 MW carbon capture readiness (CCR) requirement for new build plant in the UK.

This is relevant to OCGT types of 100 MW and 299 MW since some 299 MW plant will be very close to, but under, the threshold. Based on our experience in the sector, the need to meet the CCR requirement for new plant does not materially affect the overall regulatory, licensing and public enquiry cost. While the development time may be longer (although unlikely to be materially longer), it is unlikely to affect the overall cost. The CCR requires the developer to demonstrate that:

- *there is sufficient land available for CCS conversion;*
- *CCS conversion is technically and economically feasible; and*
- *a feasible storage site and pipeline exists.*

We believe that a greater consideration for a developer is likely to be delivering the configuration that delivers the most economic outcome. The most economic are usually those over 300MW.Therefore we concluded that the medium case should be above the CCR threshold.

4.3.3 Construction cost

We have used PEACE to analyse reference plants to produce low, central and high cases for each OCGT plant type. The high case represents a plant with better design and components to increase thermodynamic efficiency to the highest achievable in its class. The low case is typically the least efficient model in the class, which in turn leads to the lowest capital cost.

We have benchmarked the PEACE modelling against market data at a high level to verify the accuracy of the costs presented.

The same approach has been undertaken for all OCGT plant types. For a 600 MW OCGT, our capital cost range is narrower than other OCGT types. This is because of the limited range of configurations provided by PEACE modelling and market data for 600 MW units.

4.3.4 Infrastructure cost

Infrastructure costs are costs incurred outside the site boundary which are required to connect the plant to the necessary grids. As with CCGT plant these are overhead lines for transmission grid connection and an overground pipeline for fuel gas connection. The diameter of the required gas pipeline has been determined for each OCGT plant type based on power output.

The low, central and high cases are based on a 5 km, 10 km and 20 km connection lengths, respectively.

4.4 Operating costs

4.4.1 Operations and maintenance

Fixed and variable O&M costs are based on UK CCGT O&M costs, pro-rated with respect to the cost of construction contracts for OCGT versus those for CCGT. The majority of O&M costs for an OCGT plant are associated with long term service agreements (LTSA) or similar contracts for the gas turbine.

We have validated the OCGT O&M costs normalised in this way through benchmarking against LTSAs for gas turbines in the UK and globally. As discussed above, lower load factors lead to lower EOH for gas turbines and hence longer periods between overhauls.

To evaluate the impact of this on fixed O&M costs, we have modelled the higher load factor scenario using the change in expected number of starts as the key driver. A direct reduction pro-rata to operating hours is unlikely as under such an agreement the gas turbine would be unlikely to reach its first major overhaul threshold and hence a service provider or plant operator is unlikely to accept such terms.

We derive variable O&M costs based on assumptions of 167 starts per annum for the critical peaking scenario and 250 starts per annum for the peaking scenario.

The previous costs for the O&M fees in the 2013 report are similar to those costs we have seen on other projects. However the proportion of variable costs is higher in most of the cases seen in the confidential data reviewed. Therefore we have adjusted the split accordingly.

Table 13 compares our 600 MW OCGT technical parameter estimate with the previous 600 MW OCGT estimate. Our remaining estimates are available in Appendix G.

Table 13 – OCGT operating costs summary

Parameter	Previous 2012 prices			OCGT Peaking 2014 prices			OCGT Critical Peak 2014 prices		
	Low	Med	High	Low	Med	High	Low	Med	High
Fixed fee (£/MW/yr)	8,112	9,879	11,647	5,465	6,846	8,205	3,643	4,564	5,470
Variable fee (£/MWh) excluding BSUoS	0.00	0.03	0.07	0.68	0.88	1.02	0.68	0.88	1.02
Insurance (% capex/yr)	0.2%	0.4%	0.5%	0.3%	0.4%	0.5%	0.3%	0.4%	0.5%
Connection (£/MW/yr)	3,440	3,440	3,440	(4,790)	2,530	14,450	(5,100)	2,350	12,370

4.4.2 Start-up fuel consumption

Fuel consumption during start up for an OCGT is between 1.8 GJ/MW and 2.2 GJ/MW depending on the machine type, class and manufacturer. Estimates are based on a start up with the following characteristics:

- *Cold start*
- *20 minute start up time*
- *Fuel consumption at full speed no load is 30% of full load operation*
- *Ambient conditions specified in 1.2.10*

The figures for fuel consumption during a shut-down from base-load are provided in Table 14.

Table 14 – OCGT start-up fuel consumption

Start-up fuel consumption (GJ/MWe)	Low	Central	High
Open cycle GT	1.8	2.0	2.2

4.4.3 Shut-down fuel consumption

The figures for fuel consumption during a shut-down from base-load are provided in Table 15.

Table 15 – OCGT shut-down fuel consumption

Shut-down fuel consumption (GJ/MWe from base-load)	Low	Central	High
Open cycle GT	1.4	1.5	1.7

4.4.4 Insurance

There has been no significant change in the cost of insurance since the 2013 Update and a percentage of construction cost has been used to determine insurance costs. The low, central and high cases are based on construction cost proportions of 0.3%, 0.4% and 0.5%, respectively.

4.4.5 Connection and use of system charges

We have taken an unweighted average of TNUoS tariffs has been taken for all zones for which there is consented development with capacity on the Transmission Entry Capacity Register and/or existing sites (given the possibility that such sites may be re-planted). The average of forecast tariffs for the next four years derived from National Grid's model using load factor assumptions described in Section 1.2.5. Further details of the applicable tariffs are provided in Appendix C of this report.

5 Reciprocating Engines

Reciprocating engine plants are based on internal combustion, four stroke engines each connected to a generator. Units are connected in series to produce the overall output of the plant. The engines assumed for this study are high-speed type which range in output capacity of 1,000 kW – 2,000 kW for a single unit. We have reviewed both gas-fired and diesel-fired engines and noted any differences in parameters that were found between the two types. Although Selective Catalytic Reduction (SCR) is available for small high speed reciprocating units it is very rarely installed or used and at the current time it is therefore unclear what the market and/or vendors would do to meet the introduction of any future Medium Combustion Plant Directive (MCPD) requirements. On this basis we have not considered configurations with SCR.

5.1 Key timings

The key timings for both the gas-fired and diesel-fired reciprocating engine plant are equivalent, and hence this section covers both types. We have summarised these in Table 16.

We have assumed commissioning dates of 2020 for reciprocating engines.

Table 16 – reciprocating engines key timings

Parameter	LF		
	Low	Med	High
Pre-development period (years)	1.0	2.0	3.0
Construction period (years)	0.3	0.5	0.7
Operating period (years)	10.0	15.0	17.0

5.1.1 Pre-development

The development times for reciprocating engine power plants are shorter compared to more complex technologies such as gas turbines or large boiler-based plant. The key timing figures are based on recent project experience of developing projects in the UK and globally. Factors affecting the development time of a plant include site location, tender evaluation and ease of planning and permitting, which leads to the differential between the low, central and high cases.

We estimate reciprocating engine pre-development times to be 12 (low), 24 (medium) and 36 (high) months.

5.1.2 Construction

Construction times for small, modular reciprocating engine plant are well understood. Times are much shorter than gas turbine based plant due to the lighter foundations, simple commissioning practices and reduced onsite assembly.

We estimate reciprocating engine construction times to be 4 (low), 6 (medium) and 8 (high) months.

5.1.3 Operating Period

The potential operating life for a new build reciprocating engine power plant is approximately 100,000 operating hours (albeit some maintenance requirements would be based on time intervals rather than operating hours) though it is unlikely that such number of hours would be reached within the economic life of an asset operating at low load-factors. A plant operating under normal conditions will reach its economic design life, on average, at 10 years. We note that many reciprocating engine proposals in the capacity auction have sought 15 year agreements. Plants with advanced asset management strategies and fewer operating hours could reach an operating life of up to 20 years, and it may be that these proposals include an allowance for future refurbishment capital expenditure.

5.2 Technical parameters

There are no significant differences in technical parameters between gas-fired and diesel-fired reciprocating engine plant other than the fact that for the same output, a gas engine generator set will be slightly larger (physically) than the diesel generator set.

We have summarised our assessment of reciprocating engines technical parameters in Table 17.

Table 17 – reciprocating engines technical parameters summary

Parameter	LF reciprocating engine (peaking, up to 2,000 hours p.a.)			LF reciprocating engine (critical peak, up to 500 hours p.a. including 90 hours p.a. scenario)		
	Low	Med	High	Low	Med	High
Power output (MW)	18.0	20.0	22.0	18.0	20.0	22.0
Net efficiency (LHV) (%)	35.0	36.0	37.0	35.0	36.0	37.0
Availability (%)	92.2	94.3	95.7	92.6	94.7	97.0

5.2.1 Power output

The power output range is based on high speed modular engines in the range from 1,000 kW to 2,000 kW connected in series to generate an overall output of 20 MW. Based on our knowledge of the market, this is the most common configuration for plant in this capacity range as it leads to the most economically and technically feasible solution.

5.2.2 Efficiency

We have based efficiency figures on manufacturing information found in the public arena for common engine models used in the market. The data has been verified against in-house data from recent plant specifications for projects in various locations.

Reciprocating engines do not suffer from output degradation between scheduled outages. Efficiency degradation is minimal with a loss of only 1%–2% in efficiency usually observed in the final period leading up to a major outage. This pattern is reflected in the efficiency profile.

5.2.3 Availability

The availability of reciprocating engines is very high with the technology being very well understood and robust across a wide range of operating conditions. The robustness of internal combustion technology leads to very few trips, contributing to a low degree of unplanned outages and high availability. Environmental permitting considerations may constrain the allowed running hours per annum.

For reciprocating engines, the key driver of maintenance schedules is the running hours. This determines the requirement for major maintenance. Hence lower load factors leads to lower running hours and therefore longer time periods between outages. Our analysis suggests that for plant operating at critical peak (less than 500 hours p.a.) the availability can be approximately 0.4% - 1.3% greater than normal peak loading (up to 2,000 hours p.a.). Our experience of other low-hours projects is that the installations often switch to a maintenance regime which is mostly condition based as the accumulated hours can be very low over a number of years.

We would expect to see major outages every 8 to 10 years for the peaking load profile and every ten to twelve years for the critical peaking 90 hours and 500 hours load profiles. These outages are reflected in our availability profile for reciprocating engines.

5.3 Capital costs

We have summarised our assessment of reciprocating engines capital costs in Table 18.

Table 18 – reciprocating engines capital costs summary

Parameter	Gas 2014 prices			Diesel 2014 prices		
	Low	Med	High	Low	Med	High
Pre-licensing (£/kW)	8	10	14	8	10	14
Regulatory (£/kW)	2.0	3.0	4.0	2.0	3.0	4.0
Capital cost (£/kW)	276	300	324	230	250	270
Infrastructure (£m)	0.7	3.4	10.3	0.4	2.2	6.5

5.3.1 Pre-licensing costs, technical and design

Pre-licensing, technical and design figures for reciprocating engine plant are based on market knowledge and recent project experience and knowledge. Costs for this stage of the project are lower than other plant because modules are designed to be connected in series and require little site-specific engineering.

There is no notable difference in pre-licensing, technical and design costs between diesel and gas fuelled reciprocating engine plant.

5.3.2 Regulatory, licensing and public enquiry

Development costs for reciprocating engine plant are based on market knowledge and recent project experience / knowledge. This stage of a new build project in the UK is similar to a small-scale OCGT plant and therefore these costs have been benchmarked to ensure consistency between these figures.

Costs incurred at this stage are often incurred per project and therefore independent of capacity. This leads to marginally higher unit costs for reciprocating engine plants of 20 MW than a 100 MW OCGT plant.

There is no notable difference in regulatory, licensing and public enquiry costs between diesel and gas fuelled reciprocating engine plant.

5.3.3 Construction cost

We have based construction costs for reciprocating engine plant on market knowledge, discussions with developers and recent project experience. Due to the number of suppliers of reciprocating engines units in the market, the market is highly competitive which leads to low differentiation between market prices. However this can also allow developers to gain significant price reductions through well executed competitive bidding tenders in a depressed market. Conversely, a developer looking to rush the purchase of a plant may incur higher costs if the necessary due diligence is not undertaken.

For diesel-fuelled plant the construction cost includes liquid fuel handling systems and liquid fuel storage infrastructure. These are not required for a gas fuelled plant. However a gas receiving station and associated gas safety systems would be required to process the gas from the transmission network. Feedback from the market and consultees has highlighted that there is a cost premium for a gas fuelled site when taking into account fuel handling systems and the modular engine units. We therefore suggest that a construction cost premium of 20% over the cost of diesel-fuelled sites is appropriate.

5.3.4 Infrastructure cost

We have based infrastructure costs for reciprocating engine on connection to the distribution network at 33 kV.

The site options available to developing a 20 MW reciprocating engine plant are numerous due to the small footprint needed. The 33 kV distribution network is also more expansive than the transmission network. Hence the length of cable required to connect a plant of this size will be less than a CCGT or OCGT plant.

The low, central and high cases for infrastructure costs are based on connections lengths of 1 km, 5 km and 15 km and assume that the plant is connected directly to a local substation via a 33 kV underground cable.

For a gas fuelled plant there is an additional infrastructure cost to connect the site to the gas transmission network. We have assumed the same connection lengths as diesel for the electricity connection and calculated the likely pipe diameter for a 20 MW plant in line with the methodology used for CCGT and OCGT.

5.4 Operating costs

5.4.1 Operations and maintenance (O&M)

We have based operating costs on market knowledge and confidential transactional advice, both in the UK and internationally.

Natural gas is a “cleaner” fuel than diesel and therefore combusting natural gas should in practice lead to a lesser amount of deterioration of components within the engine.

As a result of this there is likely to be a lower O&M cost associated with burning gas compared to diesel. Based on our engineering experience in the operation and analysis of reciprocating engine plant, this reduction in cost could typically be 25% of the overall variable O&M cost. Fixed O&M costs will be equivalent for both fuel types as the basic operation, manning requirements and other rigid costs are independent of fuel type. We have summarised our assessment of reciprocating engine O&M costs in Table 19.

Table 19 – reciprocating engine operating costs summary

Parameter	Gas 2014 prices			Diesel 2014 prices		
	Low	Med	High	Low	Med	High
Fixed fee (£/MW/yr	8,000	10,000	12,000	8,000	10,000	12,000
Variable fee (£/MWh) excluding BSUoS	0.05	0.07	0.08	0.07	0.09	0.11
Insurance (% construction cost/yr)	0.3%	0.4%	0.5%	0.3%	0.4%	0.5%
Connection (£/MW/yr) 90hr p.a.	(34,570)	(27,990)	(14,170)	(34,570)	(27,990)	(14,170)
Connection (£/MW/yr) critical peak	(35400)	(28,500)	(14,330)	(35,400)	(28,500)	(14,330)
Connection (£/MW/yr) peaking	(39,990)	(31,940)	(15,830)	(39,990)	(31,940)	(15,830)

5.4.2 Start-up costs

The fuel cost to start a reciprocating engine and bring it to maximum power is negligible in the context of this study. Both gas and diesel reciprocating engines typically take 2 – 3 minutes to reach maximum power from a cold start and during this time would consume less than 10 GJ of fuel. This cost is therefore immaterial to the overall operation of the plant.

5.4.3 Insurance

The required level of insurance for reciprocating engine plant is similar to CCGT and OCGT, therefore we have applied the same percentages of construction cost. The low, central and high cases are based on construction cost proportions of 0.3%, 0.4% and 0.5%, respectively.

There is no notable difference in insurance costs between diesel and gas fuelled reciprocating engine plant.

5.4.4 Connection and use of system charges

An average DUoS tariffs plus embedded benefits (TNUoS triad avoidance) has been used on an unweighted average basis for same zones as CCGT and OCGT. Further details of the applicable tariffs are provided in Appendix C of this report.

6 CHP

CCGT CHP is a mature technology. It uses the same equipment as conventional CCGT but normally on a smaller scale CCGT CHP operation is mainly driven by heat demand. Because it is less efficient to transport heat than electricity, CCGT CHPs are sized typically to satisfy local heat demands. Suitability of CHP systems is therefore dependent on the proximity of the heat demands to the plant.

Heat uses range from hot water and space heating to process heat. Demand of space heating and hot water is seasonal and is typically supplied with low grade heat (80°C–95°C) by means of hot water. Demand of heat for industrial processes is typically at specific heat conditions and constant through the year, but the amount of heat may vary. Heat conditions and mediums of heat transport delivered to the diverse processes range from low grades in the form of hot water (80°C–90° C), medium and high grade of steam of a very wide range of temperatures and pressures, hot oil at about 160°C and hot air for drying applications requires temperatures up to 550°C.

Some large industrial process users could substitute steam boilers on site with gas turbines and Heat Recovery Steam Generators (HRSG) to obtain revenue for electricity sold to the grid; or reduce total energy purchased by using it internally. This is either by extraction direct from the HRSG or from the turbine depending on the configuration.

When industrial process users consistently take a portion of steam as an extraction from the HRSG this enhances the economics of the CHP. By doing this it is possible to reduce the steam turbine size, relative to the equivalent pure CCGT which would not experience any steam off-take. This may reduce capital costs for the steam turbine.

Users with more intermittent demand may look at sizing the steam turbine to take the full steam output so the plant could run in various modes of operation. For example, if there were no heat loads available a 200 MW CHP plant could convert 49%–55% of energy input to produce electricity with no heat off-take (i.e., closed-cycle Power only mode). This operation mode would not be classed as CHP – a certain amount of steam extraction would be required to achieve CHP status. In CHP configuration there would be a loss of electrical power and electrical efficiency at the steam turbine as a result of the trade-off between heat extraction and electricity generation so it would not be operating at its optimum electrical efficiency.

Because of the variety of possible configurations it difficult to give a meaningful representative value for the costs of this technology without making some assumptions. In this study, the following cases are considered:

- *Electrical output is full-load, at the nameplate output of the gas turbine and steam turbine*
- *We have considered two options: (i) Power only* mode and (ii) CHP mode (with steam turbine part-loaded)
- *Minimum total efficiency of 72%–73% must be obtained to be classed as CHP*[16]
- *Steam offtake at 50bar(g) and 425°C and condensate returns from process users at 80°C in CHP mode (not applicable Power only mode) – this would correspond to a Z ratio*[17] *of 2.5*
- *100% condensate return*

16 Table GN10-1 QI Formulae for Various Sizes and Types of existing CHP Scheme (will be applied by the CHPQA programme from 1st January 2014). The formula shown on page 6 for >200 is 73% and <200 is 72% http://www.chpqa.com/guidance_notes/GUIDANCE_NOTE_10.pdf

17 the ratio of usable heat to the equivalent quantity of electrical output that would otherwise have been produced

- *Heat users' systems are limited in complexity and located in close proximity to plant*[18]

6.1 Key timings

We have summarised our assessment of CHP key timings in Table 20 with a comparison against the previous numbers.

We have assumed commissioning dates of 2020 for CCGT CHP plants.

Table 20 – CHP key timings

Parameter	Previous			LF CHP power only and CHP mode		
	Low	Med	High	Low	Med	High
Pre-development period (years)	2.0	2.3	5.0	2.0	2.3	5.0
Construction period (years)	2.0	2.5	3.0	2.0	2.5	3.0
Operating period (years)	20.0	25.0	35.0	20.0	25.0	35.0

6.1.1 Pre-development

This is broadly similar to that for the CCGT plant above. The reduced capacity of CHP compared with a larger CCGT plant does not lead to simplification of the pre-development stage. However, the complexity of matching a project to heat off-take requirements can add complexity at this stage of project development.

6.1.2 Construction

Construction periods are in line with the CCGT plant in Table 20.

6.1.3 Operating period

This is in line with the CCGT plant in Table 20.

6.2 Technical parameters

We have summarised our assessment of CHP technical parameters in Table 21.

Table 21 – CHP technical parameters summary

Parameter	Previous			LF CHP mode			LF power only mode		
	Low	Med	High	Low	Med	High	Low	Med	High
Power output (MWe)	206	215	224	146	168	190	198	227	255
Net efficiency (LHV) (%)	38.2	38.4	38.6	37.9	38.2	38.5	51.6	51.7	51.7
Availability (%)	91.9	92.8	93.7	92.3	93.0	93.6	92.3	93.0	93.6
Steam output (MW thermal)	210	220	224	163	182	200	-	-	-

6.2.1 Power output

For the CHP configuration we have considered one or two blocks depending on output. CHP configurations are bespoke relating to how much steam the users need and the steam conditions

18 This means we have assumed a very straight forward configuration with the heat users. CHP heat users can have a very wide range in complexity of requirements making the interfaces with their systems bespoke. This can make the interfaces a costly part of any project. For example, process users tend to be the most costly with district heating at the lower end of the spectrum. Food and pharmaceutical industries may also have additional requirements such a system separation and material and chemicals usage constraints. Hence there is not a one size fits all approach for this type of system and we have therefore assumed an industrial-user configuration with limited complexity and single offtaker.

required for each user. This project variability makes configurations difficult to benchmark with any accuracy. Based on previous Combined Heat and Power Quality Assurance (CHPQA) guidelines the plant must convert approximately 72%–73% of its fuel energy into useful energy to be classed as CHP[19].

A typical CCGT of 200MW converts 52% of its fuel energy to electricity.

We have modelled two scenarios based on 200MW capacity, where capacity relates to equivalent electrical capacity in Power only mode: The first is Power only mode, with no steam offtake. This approach allows costs to be stated on a £/kW installed full CCGT capacity basis.

The second is with the following configuration:

- *steam offtake at 50 bar(g) and 425oC and*
- *condensate return at 80°C 1 bar(g)*
- *steam turbine sized at capacity capable of operation at equivalent CCGT capacity*

Such a configuration would correspond to an industrial heat off-taker such as a refinery.

In this approach costs are stated as £/kWe where kWe reflects the reduced electrical output

6.2.2 Efficiency

We stated in section 3.2.2 of this report that there have been some marginal gains on the top end efficiencies of newer technologies and gas turbines. However, the smaller and older E class units used in smaller plants such as a CCGT CHP still use older technology making them less efficient. Gas turbine OEMs have typically invested more time and money on the larger frame units to maximise efficiency gains and outputs of the larger machines.

The electrical efficiencies for the two cases differ because of the steam extraction from the steam turbine in CHP mode, which means a reduced steam flow is seen across the steam turbine. This means **electrical** efficiencies of 49%–55% can be achieved in Power only mode and approximately 37-38% when running in CHP mode.

The figures stated in this report reflect expected levels of degradation during the operating lifetime of the plant. As with CCGT, the degradation profile of a gas turbine is attributed mainly to blade fouling which causes the blade profiles to change over time. This has an effect on the gas turbine performance. As with a standard CCGT, some of the loss in performance can be regained by on-line washing and much more can be regained by offline washing. The factors affecting CCGT efficiency as described in section 3.2.2 of this report also apply to CHP installations.

6.2.3 Availability

Both configurations of CHP considered would follow a similar availability profile as stated in the 2013 version of the report.

[19] Table GN10-1 QI Formulae for Various Sizes and Types of existing CHP Scheme (will be applied by the CHPQA programme from 1st January 2014). The formula shown on page 6 for >200 is 73% and <200 is 72%
http://www.chpqa.com/guidance_notes/GUIDANCE_NOTE_10.pdf

6.2.4 Steam output

Steam output is assumed to be the amount of steam offtake required to qualify for good quality CHP plant. In basic terms this is to use a minimum of 72%–73% of the input fuel energy. We assume all steam provided from the CHP plant to the user is fully utilised and all condensate is returned at 80°C.

6.3 Capital costs

We have summarised our assessment of CHP capital costs with a comparison against the previous assumptions in Table 22.

Table 22 – CHP capital costs summary

Parameter	Previous 2012 prices			LF CHP mode 2014 prices			LF power only mode 2014 prices		
	Low	Med	High	Low	Med	High	Low	Med	High
Pre-licensing (£/kW)	26	50	60	33	64	78	27	52	63
Regulatory (£/kW)	1.6	1.7	16.1	0.2	0.2	0.2	0.1	0.2	16.7
Capital cost (£/kW)	482	559	637	614	722	830	493	580	667
Infrastructure (£m)	4.5	7.0	15.5	6.8	13.6	27.1	6.8	13.6	27.1

6.3.1 Pre-licensing costs, technical and design

The pre-licensing costs associated with this smaller plant do not vary from those assumed on the CCGT. However, the lower capacity will lead to a marginally higher £/kW cost for the project.

Due to the loss in electrical output when in CHP mode the £/kW rates are higher for the CHP mode.

6.3.2 Regulatory, licensing and public enquiry

Licensing costs associated with this smaller plant do not vary much from those assumed on the CCGT. However, the lower capacity will lead to a marginally higher £/kW cost for the project. Due to the loss in electrical output when in CHP mode, the stated £/kW rates are proportionately higher for the CHP mode basis.

6.3.3 Construction cost

There is limited real project data for CCGT CHP projects built in the UK or Europe in recent years. Projects of the nominal size of 200 MW–220 MW would typically need a very large industrial user or users to justify the steam demand associated with a plant of this size. As there are very few projects of this type and size to benchmark against the figures provided are from the 2014 PEACE database.

With the various options described above there is a range of prices in each case. Also in the second case (CHP mode), this range would be expressed with respect to a reduced kWe output in CHP mode giving higher £/kW costs for the same nominal construction cost:

- *493-667 £/kW based on the CCGT full name plate output*[20]
- *614-830 £/kWe when expressed with respect to only electrical (rather than electrical plus thermal) output. This is due to the reduction in electrical power output when in CHP mode.*

[20] It is noted that this range is materially higher than the corresponding range for large-frame CCGT – this reflects actual costs of smaller machines

6.3.4 Infrastructure cost

As with CCGT, the infrastructure costs for CCGT CHP plant are overhead lines for a transmission grid connection and a pipeline for fuel gas connection. The diameter of the required gas pipeline has been determined for the CCGT CHP plant type based on power output.

The low, central and high cases are based on a 5km, 10km and 20km connection lengths, respectively.

Steam infrastructure is considered in the construction costs for the plant and is therefore excluded from this cost.

6.4 Operating costs

6.4.1 Operations and maintenance

As with CCGT and OCGT, we have identified a wide range of potential LTSA costs depending on the contractual arrangements achieved in negotiation between developers and providers. There are various O&M packages available from multiple suppliers which are structured differently. The fixed costs vary between 25%–75% of the total annual share of the O&M costs. Costs have been based on a variety of different units and manufacturers. The costs also vary according to when LTSAs are negotiated. LTSAs negotiated during the bid phase are part of the selection criteria for the EPC contractor so priced more competitively.

The previous costs for the O&M fees in the 2013 report are similar to those costs we have seen on other projects. However the proportion of variable costs is higher in most of the cases seen in the confidential data reviewed. Therefore we have adjusted the split accordingly. The costs of operations and maintenance vary more for CHP than OCGT and CCGT due to varying complexity in the steam user interfaces.

We have summarised our assessment of CHP operating costs with a comparison against the previous assumptions in Table 23.

Table 23 – CHP operating costs summary

Parameter	Previous 2012 prices			LF CHP mode 2014 prices			LF power only mode 2014 prices		
	Low	Med	High	Low	Med	High	Low	Med	High
Fixed fee (£/MW/yr)	23,000	46,250	69,500	12,459	28,222	42,719	11,650	23,565	35,670
Variable fee (£/MWh) excluding BSUoS	0.00	0.11	0.23	1.87	3.53	5.34	1.46	2.95	4.45
Insurance (% capex/yr)	0.2	0.4	0.4	0.3	0.4	0.5	0.3	0.4	0.5
Connection (£/MW/yr)	6,655	6,655	6,655	(9,000)	3,280	23,010	(9,000)	3,280	23,010

6.4.2 Insurance

As with CCGT, insurance typically amounts to a figure in the range of 0.3%–0.5% of the construction cost and values of 0.3%, 0.4% and 0.5% are used for the low, central and high cases respectively.

6.4.3 Connection and use of system charges

The same assumptions as for CCGT have been used and further details of the applicable tariffs are provided in Appendix C of this report.

7 Nuclear

7.1 Technology types

We have considered the cost and technical parameters for the three types of nuclear plant currently planned to be constructed in the UK:

- *European Pressurised Reactor (EPR) – EDF is proposing to build Areva EPR plants at Hinkley Point and Sizewell*
- *Advanced Boiling Water Reactor (ABWR) – Horizon Nuclear Power is planning to build Hitachi ABWR plants at Wylfa and Oldbury*
- *AP1000 – NuGeneration is planning to build a Westinghouse AP1000 plant at Moorside.*

There is limited information available on these plants at the moment as they are all in the regulatory and pre-construction processes. Therefore it is difficult to differentiate between the technology types.

7.2 Key timings

We have assumed commissioning dates for 2025 for FOAK and 2030 for NOAK.

We have summarised key timings with a comparison against the previous assumptions in Table 24.

Table 24 – nuclear key timings

Parameter	Previous FOAK			LF FOAK		
	Low	Med	High	Low	Med	High
Pre-development period (years)	5.0	5.0	7.0	5.0	5.0	7.0
Construction period (years)	5.0	6.0	8.0	5.0	8.0	12.0
Operating period (years)	60	60	60	60	60	60

7.2.1 Pre-development

The previous pre-development time assumptions are five (low and medium) and seven years (high), and a construction period of five (low), six (medium) and eight (high) years. This appears appropriate based on our understanding of UK and international pre-development periods.

7.2.2 Construction

In DECC's analysis, the construction period is defined as the time between Final Investment Decision (FID) and the commercial operation date (COD). This differs from other measurements of nuclear construction, including the time between the first pouring of nuclear concrete (FNC) and COD. While a medium construction period of six years appears generally appropriate for the time between FNC and commercial operation, it does not necessarily represent the time between FID and commercial operation. There is usually a period of mobilisation and site preparation between FID and FNC. We estimate this to be around two years. Based on this, we consider 8 years an appropriate medium case for the construction period.

In addition, recent EPR experience in Europe and China and AP1000 experience in the USA and China demonstrate the possibilities of significant delays to nuclear power plant developments. Based on this experience, we have estimated an extended construction period of 12 years under the high case. We anticipate that there will be significant learning from construction and this extended construction period will only apply for FOAK developments.

We anticipate that the construction high cases will fall at NOAK following lessons learnt in the construction and planning process. There is no data available on this timing, but we consider 8 years appropriate as developers are likely to learn lessons through development of plants in the UK and internationally. While a significant delay would still be a possibility, it is less likely than in the FOAK case and therefore 8 years is a more appropriate high case.

7.2.3 Operating Period

The previous operating period assumption is 60 years for a modern nuclear plant. This is in line with our understanding of the specifications for the AP1000, ABWR and EPR and we consider it appropriate.

7.3 Technical parameters

We have summarised our assessment of nuclear technical parameters with a comparison against the previous assumptions in Table 25.

Table 25 – nuclear technical parameters summary

Parameter	Previous FOAK			LF FOAK		
	Low	Med	High	Low	Med	High
Power output (MW)	3,300	3,300	3,300	3,300	3,300	3,300
Availability (%)	89.1	91.1	92.0	83.0	90.2	91.1

7.3.1 Power output

The previous net power output assumption is 3,300 MW. We consider this appropriate for a 2 unit EPR. It is also appropriate for a 3 unit AP1000 (3,300 MW). An ABWR is likely to be 2,700 MW to 4,000 MW, depending on whether it is a two or three unit plant.

7.3.2 Availability

The previous availability assumptions are 89.1% (low), 91.1% (medium) and 92% (high).

We have considered availability figures from the International Atomic Energy Agency for a range of comparable reactor types that have been constructed in the last 25 years. We have presented our analysis on the range of power plant availability in Table 26. Note that this excludes certain reactors that were achieving availability of up to 99.9% as they had not yet reached their first refuelling cycle and are not representative.

Table 26 – nuclear plant availability

Percentile	Availability
10th percentile	82.2%
20th percentile	83.8%
30th percentile	84.8%
40th percentile	85.6%
50th percentile	86.7%
60th percentile	87.3%
70th percentile	88.7%
80th percentile	90.2%
90th percentile	92.0%
Max	93.6%

We consider that new nuclear build will operate at the higher end of this scale because of advances in technology and lessons learnt on operational techniques. Therefore we consider the medium and high cases set an achievable standard for a new state-of-the-art plant to achieve. However, there is limited operating experience for the new generation of nuclear reactors and there is uncertainty over what can be achieved. To reflect this uncertainty we propose considering a P20 availability of 83.8% as the low case. There is still a chance that availability would be below this number, but the analysis above suggests this is unlikely for a modern plant and we consider that 83.8% represents an appropriate low case.

We have also created an availability profile based on a ramp up rate in early years of operation, expected refuelling cycles, maintenance cycles and unplanned availability. The figures of 83.8% (low), 91.1% (medium) and 92% (high) represent the long term average following ramp up. Our estimated lifetime average is 83.0% (low), 90.2% (medium) and 91.1% (high).

7.4 Capital costs

There is no transactional evidence for new build nuclear power plants in the UK as none have been built since Sizewell B in 1995. There are some cost estimates available for projects under construction in the USA and the EU. Where these cost estimates are available, they have not distinguished between the three cost areas considered by this report (.

We have summarised our assessment of nuclear capital costs in Table 27 with a comparison against the previous assumptions. Note that while we have considered the previous medium and low scenarios to be appropriate, our medium and low numbers have reduced as the power capital cost index we have used has seen a reduction from 2012 to 2014.

The costs stated below are for plants commissioning in 2025.

Table 27 – nuclear capital costs summary

Parameter	Previous FOAK 2012 prices			LF FOAK 2014 prices		
	Low	Med	High	Low	Med	High
Pre-licensing (£/kW)	110	207	462	110	233	635
Regulatory (£/kW)	2.2	2.9	3.8	2.2	2.9	4.1
Capital cost (£/kW)	3,741	4,206	4,653	3,682	4,099	5,114
Infrastructure (£m)	-	11.5	23	-	11.5	50

7.4.1 Pre-licencing costs, technical and design

The previous pre-licencing costs, technical and design assumptions are 3% (low), 5.5% (medium) and 12.5% (high) of construction costs.

We are not aware of any changes to pre-licensing or design requirements since the previous report that would change this proportion and there is limited available data to challenge the original assumptions. Therefore we consider them appropriate.

7.4.2 Regulatory, licencing and public enquiry

The previous regulatory, licencing and public enquiry estimates are 0.06% (low), 0.07% (medium) and 0.08% (high) of construction costs.

We are not aware of any changes to regulatory, licencing and public enquiry requirements since the previous report that would change this proportion and there is limited available data to challenge the original assumptions. Therefore we consider them appropriate.

7.4.3 Construction cost

In our analysis we are considering FOAK plants as all new plants in the UK will be FOAK for those reactor types. We consider FOAK to NOAK impacts in the section.

Our analysis considers multi-unit plants rather than single unit plants. This reflects the current plans of nuclear developers.

Publicly available estimates for construction costs rarely state the cost elements that are included and the cost elements that are not included. Without this information it is difficult to compare estimates on an even basis. Therefore we have considered as wide a range of estimates as possible, the results of which are shown in Table 28. Based on our review of recent cost evidence and our engineering experience, we consider the previous low estimate to be an appropriate lower bound for considering the full scope of costs incurred in developing a new nuclear plant.

Table 28 – nuclear construction costs

Measure	Construction cost (£/kW)
Minimum	3,771
Median	4,262
Mean	4,341
Maximum	5,591

Based on the analysis above, we consider the previous low and medium cases to be appropriate. While the maximum is higher than the previous high case, this may partly be because of scope differences. Given the significant difference, it may be that this estimate includes items that are not in the scope of this cost category, for example land and grid connections. However, recent experience demonstrates that nuclear power plants are prone to delays and major cost overruns. Therefore we recommend increasing the high case to our approximate P90 cost estimate, £5,114/kW.

7.4.4 Nth of a Kind

There is potential for significant savings moving from FOAK to NOAK in new nuclear build. Certain work will not need to be replicated, including elements of design work and regulatory approvals. We estimate this to be around 5.5% of the FOAK cost. In the UK, significant work may be required for a new reactor type to pass the Generic Design Assessment requirements set by the Office of Nuclear Regulation. Therefore some of this FOAK cost will be in the pre-development period. We estimate this at 1.5% (low), 2.5% (medium) and 3.5% (high) of the combined FOAK pre-development and construction costs.

Aside from the one-off work, there are savings to be made following learning from the construction process. Our estimate, based on construction experience of large scale infrastructure projects, is in the range of 5% to 15%. A study by the University of Chicago[21] estimates a learning-by-doing impact range of 3% to 10%, with a midpoint of 5%. Given the uncertainty and lack of UK experience, we consider a conservative 5% impact to be appropriate. This is a cumulative impact of a 10.2% cost reduction. Currently there are no developers considering more than two sites and therefore we do not foresee further savings.

This results in NOAK pre-licensing costs of £53/kW (low), £125/kW (medium) and £434/kW (high) and construction cost estimates of £3,352/kW (low), £3,765/kW (medium) and £4,729/kW (high).

7.4.5 Single unit plants

There are no single unit plants planned in the UK. However, for completeness we have considered the cost impact of developing a single unit plant. Data from the OECD implies a saving of around 15% on the second unit. That is, the overall cost of a two unit plant would be around 185% of the cost of a single unit plant. A single unit plant loses the opportunity for economies of scale from shared infrastructure and design savings. These include site specific design considerations, use of temporary works during construction, shared buildings and spares. There is limited available data on actual costs or detailed plant cost breakdowns to verify this estimate. However, we consider this appropriate based on our understanding of the shared infrastructure requirements of nuclear reactors.

Our estimates are based on multiple unit plants. Based on the above, a single unit plant pre-development and construction costs would be more expensive by around 11%.

7.4.6 Infrastructure cost

The previous infrastructure cost assumptions are £0 (low), £11,500,000 (medium) and £23,000,000 (high). We consider the medium and low cases to be appropriate. However, we recommend increasing the high case to £50,000,000 based on our analysis of relevant benchmark data. This is higher than the infrastructure costs for other technologies considered in this report, but this represents the larger scale and potentially more remote locations of nuclear plants

7.4.7 Currency variation

A proportion of a nuclear plant construction cost is likely to be denominated in foreign currency. Therefore changes to foreign exchange rates could have an impact on costs. As an indication, Table 29 shows how construction cost as set out in 7.4.3, excluding predevelopment and infrastructure costs, may be approximately proportioned against each major cost element and the likely currency impact within each category.

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[21] THE ECONOMIC FUTURE OF NUCLEAR POWER, A Study Conducted at The University of Chicago, 2004

Table 29 – nuclear construction cost proportions

Cost category	Approximate proportion	Currency impact
Reactor	25%	Likely to be in denomination of reactor supplier ($/€/¥). Some local installation costs may be in GBP, between 10% to 30% depending on contracting strategy
Turbine	15%	Likely to be in denomination of turbine supplier ($/€/¥). Some local installation costs may be in GBP, between 10% to 30% depending on contracting strategy
Design and engineering	7.50%	May be in home denomination of developer ($/€/¥)
Electrical	10%	May include equipment supplied overseas (50%) ($/€/¥)
Heat rejection	5%	Likely to largely be delivered in UK. If delivered by supplier in non-GBP denomination, GBP supplier likely to become more competitive and thus overall price unlikely to change.
Balance of plant	5%	
Civil works	15%	
Other (inc owners)	10%	
Indirects (other than design)	7.50%	

7.5 Operating costs

We have summarised our assessment of nuclear operating costs with a comparison against the previous assumptions in Table 30.

Table 30 – nuclear operating costs summary

Parameter	Previous FOAK 2012 prices			LF FOAK 2014 prices		
	Low	Med	High	Low	Med	High
Fixed fee (£/MW/yr)	60,000	72,000	84,000	60,784	72,940	85,097
Variable fee (£/MWh)	2.24	2.86	3.79	2.62	2.62	2.62
Insurance (£/MW/yr)	8,000	10,000	12,000	6,000	10,000	12,000
Connection (£/MW/yr)	7,449	7,449	7,449	(3,540)	490	3,060

We have considered two types of operating cost benchmarking data, those where fixed and variable fees are separate and those where there is a combined fee. We have calculated an overall £/MWh operations and maintenance fee based on the relevant plant availability to compare all costs on an equal basis. We have then benchmarked the fixed variable proportion. We have presented the previous estimates against our benchmark ranges in Table 31.

Table 31 – nuclear fixed and variable total operating cost benchmarks

Estimate (£/MWh)*	Low	Medium	High
Previous estimate (2012 prices)	10.40	11.75	13.17
Benchmark (2014 prices)	9.79	11.88	15.18

*total, including fixed and variable with fixed allocated over assumed availability level of output

Based on these, we consider the low and medium estimates to be appropriate. The high case is based on information from North America, and as such is not necessarily applicable to the UK. It is also unclear whether the operating cost estimates include grid costs and insurance. Therefore we do not consider there to be significant evidence to move from the previous estimates for the high case.

The proportion of overall costs between fixed and variable in our benchmarks is in line with those proposed previously, and we consider them appropriate.

7.5.1 Operations and maintenance – fixed fee

The previous fixed fee assumption is £60,000 (low), £72,000 (medium) and £85,000 (high) per MW per year. Based on the above, we consider these appropriate.

7.5.2 Operations and maintenance – variable fee

The previous variable fee assumption is £2.86/MWh. Based on our benchmark described in section 7.5, we consider an appropriate variable fee assumption to be £2.62/MWh.

7.5.3 Insurance

The previous insurance cost assumption is £8,000 (low), £10,000 (medium) and £12,000 (high) per MW per year. There are limited benchmarks available on insurance costs for nuclear power plants.

Nuclear power plants can have higher insurance costs than conventional power plants. Beyond standard insurance, nuclear power plants have obligations to compensate parties for damage following the release of radiation and may have additional considerations concerning terrorism.

Our benchmark falls below the low case, so we have estimated a new low case of £6,000. Given the uncertainty around new build, it is prudent to consider a wide range of insurance costs. Therefore we consider our proposed insurance costs to be appropriate. This equates to 0.15%, 0.25% and 0.3% of EPC costs per annum.

7.5.4 Connection and use of system charges

An unweighted average of TNUoS tariffs for all zones where development is planned (EdF, Horizon and NuGen sites) has been taken. Further details of the applicable tariffs are provided in Appendix A of this report.

7.6 Cost reduction profile for capital costs

Beyond the move from FOAK to NOAK, there may be opportunities to reduce capital costs for nuclear power plants through cross-industry learning and expansion of the supply chain.

The previous cost reduction profile results in cost reductions of between 5.3% (low), 13.1% (medium) and 20.9% for plants commissioning in 2032. While 5.3% appears an achievable saving, 20.9% appears ambitious.

We have considered a more conservative cost reduction profile based on the current nuclear build programme and likely timing of supply chain expansion. This results in cost reductions of between 2.5% (low), 5% (medium) and 7.5% (high) by 2030.

7.7 Technology scenarios

The ranges stated for each individual parameter are generally considered on an individual basis and not necessarily correlated.

Our view is that there is a reasonable correlation between construction cost and construction time. In nuclear projects a large driver of cost overruns is delay costs. As such, it would be appropriate to consider a long construction period correlated with high construction costs.

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8 CCS

8.1 Technology types

In this chapter we consider the cost and technical parameters of a range of CCS technologies. This range comprises combinations of CCS technology (pre-combustion, post-combustion or oxyfuel combustion) and generation technology (CCGT, OCGT, Advanced Super Critical coal (ASC), Integrated Gas Combined Cycle (IGCC) and biomass).

CCS is a newer, less tested technology than other technologies considered in this report, which generally have a proven track record in the UK. CCS costs also depend on a factor beyond the configuration of individual plants as the process relies on how transport and storage infrastructure is shared between them. Some FOAK plants may be able to adapt existing oil and gas facilities, but others may have to build new infrastructure for transport and storage.

Costs are therefore inherently more uncertain than the other technologies we have considered. The cost and technical assumptions in in this chapter should be considered in this light.

A number of these options are available for new build plants and retrofits to existing plants. Where possible, we have linked our CCS estimates to our estimates elsewhere in the report, as follows:

- CCGT/*IGCC* are new build H Class 1,200 MW CCGT*, or retrofitted to 1,200 MW CCGT*
- *OCGT is new build 400 MW OCGT*
- *ASC is new build 800 MW ASC boiler, or retrofitted to 500 MW coal boiler with additional capital expenditure for life extension works*
- *Biomass is a new build, post combustion CCS 300 MW boiler using dry biomass which is not dehydrated or pyralised*

For partial CCS plants, we have considered CCS on 300 MW of the plant.

8.1.1 Biomass considerations

There is considerable uncertainty about costs and practicality of large-scale biomass CCS. It may require further work to clarify this uncertainty

To ensure consistency across DECC's LCOE work, we have used the technical and cost parameters developed by Arup for small scale biomass as a starting point. This is a 22.9 MW dedicated biomass plant with a medium case capital cost of £2,595/kW. We note that there are other approaches to biomass CCS that potentially offer the opportunity to be more efficient than a post-combustion approach. Without further concrete evidence, we have assumed that technical parameters – efficiency, availability and capture rates – are similar across small scale and large scale biomass plant due to the technical similarities of the plant. However, we have applied a cost saving of 40% generated through economies of scale to the reference plant for larger scale 300 MW biomass plant. The ultimate output would be lower than 300 MW because of parasitic load. We discuss this in more detail in section 8.3.1(a). It may be that commercial scale biomass plants operate at above this level of output.

For consistency with DECC's historical LCOE work, we have considered a post-combustion approach to CCS for biomass. We note that there are other approaches to biomass CCS that potentially offer the opportunity to be more efficient than a post-combustion approach.

Because of this uncertainty, our analysis of biomass CCS is indicative and there may be some change in these numbers as the technology is further developed. The cost ranges we have proposed could vary further should other technologies and approaches be considered. We have not considered any potential carbon benefits of biomass CCS. We therefore recommend that DECC regularly reviews biomass costs as the technology develops.

We also note the potential benefits of biomass for negative emissions through removal of CO2 from the atmosphere should the fuel be grown sustainably. These potential benefits are not included in our analysis.

For the purposes of this study we assume a commissioning date of 2025 for FOAK plants.

8.2 Key timings

We have assumed commissioning dates for 2025 for FOAK.

The previous estimates for development and construction periods are summarised in Table 32.

Table 32 – CCS FOAK construction times (years)

Technology type	Case	Pre development	Construction
CCGT (post/precomb)	Low	4	3.9
	Medium	5	4.5
	High	6	5.5
CCGT (oxyfuel)	Low	4.5	4
	Medium	5.75	4.5
	High	7	5.5
CCGT (retro)	Low	3	3.5
	Medium	4	4
	High	5.5	5.5
ASC (post comb)	Low	4	4.5
	Medium	5.25	5
	High	7	6
ASC (partial)	Low	4	4.5
	Medium	5	5
	High	7	6
ASC (retro)	Low	3.5	3.5
	Medium	4.5	4
	High	6	5.5
ASC (ammonia)	Low	4	4.5
	Medium	5	5
	High	7	6
ASC (oxyfuel)	Low	4.5	5
	Medium	6	5.5
	High	7	6
IGCC (partial)	Low	4	4
	Medium	5	5
	High	6	6

Technology type	Case	Pre development	Construction
IGCC (full)	Low	4	4.5
	Medium	5.3	5
	High	7	6
IGCC (retro)	Low	3.5	3.5
	Medium	4.5	4
	High	6	5.5
Biomass	Low	3.5	3
	Medium	4.5	3.5
	High	5.5	4
OCGT	Low	4	3.9
	Medium	5	4.5
	High	6	5.5

8.2.1 Pre-development

There is significant uncertainty in CCS plants. There is limited standardisation in design and this will lead to longer predevelopment periods than for standard plants. The best recent transactional benchmark we have for similar projects is CCGT developments. The previous FOAK pre-development timings include around an additional year on CCGT estimates of two to five years. This is appropriate for an uncertain technology. The previous estimates also include provision for additional development times for the currently less well understood plants. As such we consider them appropriate.

8.2.2 Construction

As with pre-development, the best recent transactional benchmark we have for similar projects is CCGT developments. Construction timings should include additional time on the reference plant for construction and commissioning of the CCS unit, and an element of uncertainty. Experience in nuclear, outlined in section 7.2, demonstrates that uncertain power generation technologies can experience significant delays. The previous FOAK estimates are roughly twice as long as our CCGT construction times of two to three years. We consider that this adequately reflects the additional complexity and uncertainty.

8.2.3 Operating period

The operating periods are linked to the generation technology. We consider this appropriate.

8.2.4 NOAK

As understanding builds, we expect development and construction timings to shorten. For pre-development, we consider an appropriate assumption to be an additional year on our CCGT estimates: 3 years (low), 3.3 years (medium) and 6 years (high). For construction, there will likely be requirements for work on the CCS unit following construction. We consider an additional 12 months (low and medium) or 18 months (high) on our CCGT ranges to be appropriate to account for this work and potential difficulties with the work. This results in NOAK construction times of 3 years (low), 3.5 years (medium) and 4.5 years (high).

8.3 Technical parameters

8.3.1 Power output

We have derived CCS power output by applying a parasitic load to the capacity of the base generation technology outlined in 8.1. Parasitic load is the power used by the reference plant in running the CCS equipment. This includes the efficiency loss and compression of captured CO2 for transport and storage. We have considered a broad range of published and internal data for each of our estimates. While some published and internal data suggest parasitic loads above or below our calculations, we consider our calculations are the best available estimate given the current state of technology and the data available. We have presented our analysis in Table 33, Table 34, Table 35 and Table 36.

Table 33 – gas CCS parasitic load estimates (percentage reduction)

	Technology type	Previous	Our estimate
A	CCGT – post combustion	12 – 18%	20%
B	CCGT – retro post combustion	12 – 19%	23%
C	CCGT – pre combustion	c. 2%	9.6%
D	CCGT – oxyfuel combustion	11 – 17%	13%
E	OCGT – post combustion	Not considered	20%

Table 34 – ASC CCS parasitic load estimates (percentage reduction)

	Technology type	Our estimate
F	ASC – partial post combustion	8%
G	ASC – full post combustion	22%
H	ASC – ammonia	11.6%
I	ASC – retro post combustion	22%
J	ASC – oxyfuel combustion	na

Table 35 – IGCC CCS parasitic load estimates (percentage reduction)

	Technology type	Our estimate
K	IGCC – CCS	20%
L	IGCC – CCS retro	22%
M	IGCC – partial CCS	7%

Table 36 – biomass parasitic load estimates (percentage reduction)

	Technology type	Our estimate
N	Biomass – CCS	51%

It is not possible to provide a direct comparison with the previous numbers as we do not have access to the reference data for the base plants for each technology type. It is not clear what the reference plant for ASC and IGCC is and we have not presented comparisons in these cases. We have made estimates of the previous parasitic load by considering likely reference plants where possible. It is not possible to directly compare the two as we are considering different reference plant capacities.

We have estimated a parasitic load reduction for biomass that is higher than the parasitic load estimates for other technology types, and higher than the previous estimate. This is due to the general differences between biomass and coal fired boilers, and additional considerations relating to parasitic energy consumption.

(a) General efficiency considerations for biomass

The efficiency of biomass fired boilers is generally lower than that coal or coke fired boilers for a number of reasons.

There are no advanced supercritical 100% biomass fired boilers, so the efficiency of heat transfer from hot flue gas to steam is lower in an archetypal biomass fired boiler than in a coal fired boiler. The biomass fuel ash is generally more slagging (melts at lower temperature) and typically has a higher alkali content, resulting in fouling and corrosion issues. Thus, in this case the biomass boilers cannot be fired at temperatures high enough for supercritical technology. We note that there are other options for biomass CCS such as gasification, pre-combustion and supercritical fluidised bed boilers. These technologies may have the potential to deliver superior efficiencies to the approach we have considered.

The energy of a solid fuel (be it biomass, coal or coke) is released as the carbon and hydrogen contained within the solid fuel react with free oxygen (supplied via combustion air intake) to form CO2 and H2O. That is a carbon atoms reacts with two oxygen atoms, and two hydrogen atoms react with an oxygen atom. Biomass fuel generally has larger oxygen content than that found in coal or coke. The high oxygen content of biomass fuel means that some of the carbon atoms and hydrogen atoms already have C-O and H-O bonds in place. Therefore the high oxygen content of biomass fuel directly reduces the efficiency of a biomass fired boiler.

Biomass fuel generally has a higher moisture content than that found in coals (with exceptions of lignite or brown coals) or coke. The moisture soaks up energy released from combustion when it is first vaporised. This energy cannot be usefully recovered when the vapour condenses.

(b) Parasitic energy consumption for Biomass Carbon Capture

As the efficiency of biomass fired boilers is lower than that of coal or coke fired boilers, the number of carbon atoms reacted/combusted to CO2 per MWe generated is higher for biomass fired power plants than it is for coal fired plants. Thus, emissions of CO2 per MWe are higher for biomass power plant than they are for a coal fired power plant.

The capture plant parasitic energy consumption is mainly a factor of CO2 captured, as well as partial pressure of CO2 in the flue gas fed to the capture unit.

Assuming the same capture rate as for coal fired plant cases (~90%), it follows that the energy required to abate 90% of incurred CO2 emissions is greater than that of coal fired plant cases per MWe generated.

8.3.2 Efficiency

We have considered a broad range of published and internal data for each of our efficiency estimates. We have presented our analysis in Table 37, Table 38, Table 39 and Table 40. We have presented a comparison with the previous numbers below. While some published and internal data suggest parasitic efficiency above or below our calculations, we consider our calculations are the best available estimate given the current state of technology and the data available. The base efficiencies are 59.8% (our CCGT H Class medium case) for CCGT, 39.8% for IGCC, 43.5% for ASC and 29.5% for biomass.

Table 37 – gas CCS efficiency (percentage point reduction)

	Technology type	Previous	Our estimate
A	CCGT – post combustion	8.2% – 9.4%	10.9%

	Technology type	Previous	Our estimate
B	CCGT – retro post combustion	8% – 9.4%	10.9%
C	CCGT – pre combustion	12% – 17.1%	17%
D	CCGT – oxyfuel combustion	15% – 23.4%	13%
E	OCGT – post combustion	na	10.9%

Table 38 – ASC CCS efficiency (percentage point reduction)

	Technology type	Our estimate
F	ASC – partial post combustion	3.6%
G	ASC – full post combustion	9.6%
H	ASC – ammonia	11.6%
I	ASC – retro post combustion	9.2%
J	ASC – oxyfuel combustion	9.6%

Table 39 – IGCC CCS efficiency estimates (percentage point reduction)

	Technology type	Our estimate
K	IGCC – CCS	8%
L	IGCC – CCS retro	24%
M	IGCC – partial CCS	3%

Table 40 – biomass CCS efficiency estimates (percentage point reduction)

	Technology type	Our estimate
N	Biomass CCS	15%

8.3.3 Availability

The previous assumptions do not appear to include any reduction in availability through CCS installation. To reflect outages on the wider equipment for which there are less likely to be spares, such as the CO2 compressor, it is appropriate to consider a 7.5% (low), 5% (medium) and 2.5% (high) reductions in availability relative to the availability assumptions for non-CCS configurations of CCGT/OCGT/Biomass (as applicable).

8.3.4 Capture rates

We have considered a broad range of published and internal data for each of capture rates. While some published and internal data suggests capture rates above or below our calculations, we consider our calculations are the best available estimate given the current state of technology and the data available. We have presented a comparison with the previous numbers in Table 41. Our calculations are broadly in line with the previous estimates, likely because they are based on similar data. The significant differences are in ASC partial and IGCC partial. This is explained by the difference in overall power output, where a 300 MW capture unit will have different relative impacts on capture rate.

Table 41 – CCS capture rates (%)

	Technology type	Previous	Our estimate
A	CCGT – post combustion	85% - 90%	90%
B	CCGT – retro	85% - 90%	90%
C	CCGT – pre combustion	82% - 95%	93%
D	CCGT – oxyfuel combustion	90% - 98%	100%
E	OCGT – post combustion	na	90%
F	ASC – post combustion	85% - 92%	89%
G	ASC – partial post combustion	21% - 22%	33%
H	ASC – with ammonia	85% - 90%	89%
I	ASC - retrofit	85% - 92%	89%
J	ASC – oxyfuel combustion	90% - 98%	91%
K	IGCC – partial CCS (300 MW/800 MW)	36%	30%
L	IGCC – CCS	85% - 95%	89%
M	IGCC – retro CCS	84% - 89%	89%
N	Biomass – CCS	93% - 98%	89%

8.4 Capital costs

The costs stated below are for FOAK plants commissioning in 2025. The scope includes the reference plant, capture units, booster pumps and transport and storage infrastructure.

These costs do not reflect the costs of construction for a demonstration plant which is a plant constructed with the aim of testing the commercial viability of a technology. The costs represent the cost of a commercial CCS plant constructed following successful demonstration projects. These are plants constructed with the aim of generating revenue from electricity sales and other services.

We have considered the following three elements in developing our capital cost estimates:

- *Reference plant – the capital costs of the generation plant, as listed under section 8.1.*
- *Capture plant – the capital costs of the equipment installed to capture the CO2 emitted as a result of the reference plant's power generation. We developed these using a range of public and internal benchmarks for each technology type.*
- *Transport and storage – the capital cost of the pipeline and aquifer infrastructure required to transport and store the CO2. We calculated this based on a benchmark case for the transport and storage of c.3.2m tonnes of CO2 per annum. Our benchmark is around £110m for storage and £275m for transport. Other plant types capture different levels of CO2, so would require different levels of infrastructure. However, doubling capacity does not necessarily double costs as there is an opportunity for economies of scale, and halving capacity does not necessarily halve costs as there would likely be lost economies of scale. Therefore we have adjusted our benchmark case to take account of economies of scale. The table below shows the output of using our technical parameters in DECC's Levelised Cost Model for the amount of CO2 captured per year, and our estimated transport FOAK transport cost in the medium case.*

Table 42 – CCS transport and storage cost estimates

Technology type	CO2 captured mT/year	Medium case transport cost (£/kW)
CCGT – post combustion	2.9	401
CCGT – retro	1.9	430
CCGT – pre combustion	4.0	405
CCGT – oxyfuel combustion	3.7	427
OCGT – post combustion	1.5	916
ASC – post combustion	4.4	762
ASC – partial post combustion	1.5	233
ASC – with ammonia	4.2	739
ASC - retrofit	2.9	908
ASC – oxyfuel combustion	3.8	861
IGCC – partial CCS (300 MW/800 MW)	1.5	324
IGCC – CCS	4.7	760
IGCC – retro CCS	5.1	841
Biomass – CCS	1.4	1,546

8.4.1 Uncertainty

As no commercial CCS plants have been constructed in the UK there is uncertainty over the capital costs of CCS. We have reflected the following uncertainties in our analysis:

(a) Learning from demonstration plants to FOAK

We have adjusted our base FOAK capture plant cost estimate by -15% (low), -10% (medium) and 0% (high) to reflect the opportunities for learning from the construction processes of demonstration plants, which are plants constructed with the aim of testing the commercial viability of a technology. We have not considered cost reductions from learning for the reference and transport elements of the plant, as these are better established technologies.

How much learning will be derived from the construction of a demonstration plant is uncertain. Therefore we have provided a range of potential learning benefits. The number of demonstration plants that need to be constructed to generate and embed this learning is also uncertain. It is likely that some learning will derive from the construction of just one plant, as in the case we have described for nuclear in section 7. Further learning may derive from subsequent demonstration plants.

(b) Shared transport costs

There may be opportunities to reduce the costs of the transport and storage infrastructure by using existing infrastructure developed by the oil and gas industry that is no longer in use, such as pipelines. Multiple CCS plants could also share a pipeline or storage facility to benefit from economies of scale. To reflect this, we have adjusted our base transport and storage capex by -25% in the low case to reflect the opportunities for CCS plants to leverage economies of scale by sharing transport and storage infrastructure. We have only applied this in the low case for NOAK as there will be fewer plants to leverage sharing impacts.

(c) FOAK to NOAK

We have adjusted our FOAK costs for capture technologies in line with paragraph 8.4.6. We have applied an additional 20% cost reduction to transport and storage infrastructure to reflect the increased opportunities to share infrastructure as more plants are developed in the move from FOAK to NOAK. We have not considered cost reductions from learning for the reference plants as these are established technologies.

(d) Optimism bias

We consider it prudent to include optimism bias in our assessment. This reflects that no commercial scale CCS plants have yet been built in the UK and that unforeseen issues may arise during the construction process, although we note that all elements of the CCS supply chain have been technically proven elsewhere. Likely issues on major infrastructure projects include poor management and engineering, regulatory issues, site and design issues and complexity of commissioning.

The low case represents a situation in which there are no issues. Therefore we do not include any additional optimism bias.

For the other cases, we have considered the HMT Green Book guidance on optimism bias. Based on this, we have applied optimism bias of 0% (low), 6% (medium) and 25% (high). This is not the upper bound for non-standard civil engineering projects optimism bias, a large proportion of the project is standard – for example the reference plant and pipeline construction. We have applied the optimism bias to all capital costs as the elements of each section of the plant have interfaces and issues, for example related to delay, could affect all of the construction process, particularly for a FOAK plant.

We have not included optimism bias for non-CCS technology types. This is because these technology types are well understood and examples have been constructed across the world and in the UK. While carbon capture, transport and storage technologies are well understood separately, the integration of all parts with commercial scale power generation is uncertain.

Including the contingency already included in our FID capital cost estimates outlined in Appendix A, this is a total additional cost uncertainty of 7.5% (low), 16% (medium) and 40% (high).

8.4.2 Pre-licencing costs, technical and design

On average across all technologies, the previous pre-licencing, technical and design cost estimates are between 0.5% and 3% of capital costs, with the majority of medium cases being around 1%. There are no available benchmarks to test these, and estimates are based on engineering judgement and experience of other power projects. The range presented is in line with our experience of project developments. We are not aware of any changes to pre-licensing or design requirements since the previous report that would change this and there is limited available data to challenge the original assumptions. Therefore we consider them appropriate.

In our assessment, we have applied these costs to just the CCS element of the plant, and included the reference plant costs on top of these.

Table 43 – FOAK gas CCS unit pre-licensing cost estimates (£/kW)

	Technology type	Case	Previous Pre-licensing 2012 prices	LF estimate Pre-licensing 2014 prices
A	CCGT – post combustion	Low	25.0	32.5
		Medium	30.0	46.4
		High	40.0	66.6
B	CCGT – retro post combustion	Low	14.0	19.4
		Medium	22.1	31.4
		High	30.1	47.6
C	CCGT – pre combustion	Low	23.5	32.1
		Medium	29.6	45.2
		High	47.9	64.7
D	CCGT – oxyfuel combustion	Low	26.3	30.7
		Medium	32.3	44.4
		High	44.0	67.0
E	OCGT – post combustion	Low	na	61.6
		Medium		77.1
		High		109.4

Table 44 – FOAK ASC CCS pre-licensing cost estimates (£/kW)

	Technology type	Case	Previous Pre-licensing 2012 prices	LF estimate Pre-licensing 2014 prices
F	ASC – post combustion	Low	15.6	39.3
		Medium	20.2	50.7
		High	33.3	75.3
G	ASC – partial post combustion	Low	20.0	28.0
		Medium	25.0	35.8
		High	40.0	51.5
H	ASC – with ammonia	Low	20.0	39.6
		Medium	25.0	50.5
		High	40.0	74.2
I	ASC – retro post combustion	Low	11.2	15.3
		Medium	18.4	26.0
		High	30.0	45.0
J	ASC – oxyfuel combustion	Low	21.0	30.7
		Medium	26.9	41.4
		High	44.0	77.8

Table 45 – FOAK IGCC CCS pre- licensing cost estimates (£/kW)

	Technology type	Case	Previous Pre-licensing 2012 prices	LF estimate Pre-licensing 2014 prices
K	IGCC – partial CCS	Low	36.3	36.9
		Medium	43.0	42.5
		High	50.2	54.9
L	IGCC – CCS	Low	42.7	50.2
		Medium	50.6	58.9
		High	59.1	75.5
M	IGCC – retro CCS	Low	21.2	53.9
		Medium	24.4	63.3
		High	28.0	81.1

Table 46 – FOAK biomass CCS pre- licensing cost estimates (£/kW)

	Technology type	Case	Previous Pre-licensing 2012 prices	LF estimate Pre-licensing 2014 prices
N	Biomass - CCS	Low	48.2	184.2
		Medium	61.6	233.3
		High	80.3	335.2

8.4.3 Regulatory, licencing and public enquiry

On average across all technologies, the previous regulatory, licencing and public enquiry cost estimates range between 0.01% up to 0.64% for certain technologies. As for pre-licensing costs, there are no transactional benchmarks to test these; estimates need to be based on engineering judgement and experience of other power projects. The wide range is appropriate given the uncertainty involved in CCS, and we consider it appropriate that the higher costs relate to less certain technologies such as oxyfuel. We are not aware of any changes to pre-licensing or design requirements since the previous assessment that would change this. Therefore we consider them appropriate.

In our assessment, we have applied these costs to just the CCS element of the plant, and included the reference plant costs on top of these.

Table 47 – FOAK gas CCS unit regulatory cost estimates (£/kW)

	Technology type	Case	Previous Regulatory 2012 prices	LF estimate Regulatory 2014 prices
A	CCGT – post combustion	Low	0.5	0.9
		Medium	0.5	1.0
		High	5.0	11.2
B	CCGT – retro post combustion	Low	0.1	0.1
		Medium	0.1	0.1
		High	0.5	0.8
C	CCGT – pre combustion	Low	0.4	0.8
		Medium	0.5	1.0
		High	5.0	10.6
D	CCGT – oxyfuel combustion	Low	1.0	1.3
		Medium	1.4	0.8
		High	9.9	15.8
E	OCGT – post combustion	Low	na	3.3
		Medium		4.0
		High		12.8

Table 48 – FOAK ASC CCS regulatory cost estimates (£/kW)

	Technology type	Case	Previous Regulatory 2012 prices	LF estimate Regulatory 2014 prices
F	ASC – post combustion	Low	0.2	19.0
		Medium	0.2	23.6
		High	1.4	33.1
G	ASC – partial post combustion	Low	0.2	16.1
		Medium	0.2	20.0
		High	1.7	27.5
H	ASC – with ammonia	Low	0.2	19.0
		Medium	0.2	23.6
		High	1.7	33.0
I	ASC – retro post combustion	Low	0.0	2.5
		Medium	0.0	3.2
		High	0.2	4.5
J	ASC – oxyfuel combustion	Low	0.4	0.6
		Medium	0.4	0.8
		High	3.4	6.1

Table 49 – FOAK IGCC CCS regulatory cost estimates (£/kW)

	Technology type	Case	Previous Regulatory 2012 prices	LF estimate Regulatory 2014 prices
K	IGCC – partial CCS	Low	0.4	0.1
		Medium	0.4	0.1
		High	3.0	1.6
L	IGCC – CCS	Low	0.4	0.5
		Medium	0.5	0.6
		High	3.4	4.6
M	IGCC – retro CCS	Low	0.0	1.5
		Medium	0.0	1.7
		High	0.4	17.0

Table 50 – FOAK biomass CCS regulatory cost estimates (£/kW)

	Technology type	Case	Previous Regulatory 2012 prices	LF estimate Regulatory 2014 prices
N	Biomass - CCS	Low	1.0	31.6
		Medium	1.1	39.4
		High	8.3	56.1

8.4.4 Construction cost

CCS construction costs are highly uncertain. No transactional evidence for CCS costs exists. In our analysis we have considered a range of public and in-house estimates. Where possible, we have isolated the CCS infrastructure and associated extra scope in each public and in-house benchmarks. We have considered the value of each benchmark by looking at the detail of the underlying estimates and how recent the estimate. Using these benchmarks and our engineering judgement we have identified a range of costs for the CCS unit and associated extra scope. We have applied these benchmarks to the reference plants stated in 8.1.

The costs stated cover the full CCS chain, including capture plant elements, transportation and storage.

We have presented our analysis in the tables below. We have presented a comparison with the previous numbers below. Our costs are generally higher than the previous costs. Without seeing the methodology behind the previous numbers it is not possible to explain the specifics of the differences. Possible reasons include:

- *New data on capital costs, particularly from new developments in the UK, may show higher capital costs than previous data.*
- *The range of equipment captured under our estimates (see section 8.4) may be broader than in the previous estimates.*
- *We may have taken a different approach to assessing uncertainty (see section 8.4.1).*

Table 51 – FOAK gas CCS unit construction cost estimates (£/kW)

	Technology type	Case	Previous 2012 prices	LF estimate 2014 prices
A	CCGT – post combustion	Low	1,138	1,710
		Medium	1,321	2,069
		High	1,505	2,689
B	CCGT – retro post combustion	Low	842	1,167
		Medium	978	1,407
		High	1,114	1,782
C	CCGT – pre combustion	Low	1,296	1,687
		Medium	1,506	2,043
		High	1,715	2,647
D	CCGT – oxyfuel combustion	Low	1,303	1,711
		Medium	1,513	2,072
		High	2,119	2,687
E	OCGT – post combustion	Low	Na	1,907
		Medium		2,347
		High		2,969

Table 52 – FOAK ASC CCS construction cost estimates (£/kW)

	Technology type	Case	Previous 2012 prices	LF estimate 2014 prices
F	ASC – post combustion	Low	1,788	3,362
		Medium	1,932	4,175
		High	2,179	5,472
G	ASC – partial post combustion	Low	2,674	2,055
		Medium	2,950	2,557
		High	3,319	3,409
H	ASC – with ammonia	Low	2,674	3,405
		Medium	3,053	4,217
		High	3,557	5,531
I	ASC – retro post combustion	Low	1,591	1,901
		Medium	1,755	2,368
		High	1,975	2,988
J	ASC – oxyfuel combustion	Low	2,031	2,907
		Medium	2,285	3,433
		High	2,538	4,389

Table 53 – FOAK IGCC CCS construction cost estimates (£/kW)

	Technology type	Case	Previous 2012 prices	LF estimate 2014 prices
K	IGCC – partial CCS	Low	1,788	2,449
		Medium	1,932	2,816
		High	2,179	3,647
L	IGCC – CCS	Low	2,674	3,347
		Medium	2,950	3,923
		High	3,319	5,034
M	IGCC – retro CCS	Low	2,674	3,592
		Medium	3,053	4,215
		High	3,557	5,406

Table 54 – FOAK biomass CCS construction cost estimates (£/kW)

	Technology type	Case	Previous 2012 prices	LF estimate 2014 prices
N	Biomass - CCS	Low	3,512	7,154
		Medium	4,055	8,743
		High	6,357	11,414

8.4.5 Infrastructure cost

We have estimated the infrastructure costs in line with the gas assumptions explained earlier in this report (section 1.2.7). We also consider this appropriate for new build coal and biomass, less the pipeline costs.

8.4.6 Nth of a Kind

There have been numerous studies on cost reductions in CCS. This is a highly uncertain area, as CCS plants are still largely in demonstration phases. The previous report assumes a 10% capital cost reduction for gas plants, 3%–6% for ASC plants and 3%–8% for IGCC plants. Other publications consider similar and more significant savings, up to 25% by 2030. The CCS cost reduction task force[22] identifies the following potential savings on capture construction cost:

Table 55 – cost reductions

Technology type	Case	2020 FID	2028 FID
Coal[23]	Low	11%	25%
	Mid-point	8%	18%
	High	5%	11%
Gas	Low	11%	23%
	Mid-point	6.5%	15.5%
	High	2%	8%
Oxyfuel	Low	12%	28%
	Mid-point	9%	20.5%
	High	6%	13%

[22] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/201021/CCS_Cost_Reduction_Taskforce_-_Final_Report_-_May_2013.pdf

[23] We have also applied the coal cost reduction to biomass as they are similar capture technologies

We consider these savings achievable through the development of more advanced and cheaper equipment for CCS, and learning through the construction process itself. We have estimated the NOAK figure based on the 2028 FID figures in Table 55. We have estimated the NOAK costs by applying the mid-point cost reduction scenarios to our low, high and medium capture plant cases respectively. We have not made adjustments for the reference plants or transport and storage. For the purposes of this report, we have treated IGCC as coal following discussions with DECC.

Note that this cost reduction is only applied to the CCS element of the plant. We have also applied a 20% reduction to transport and storage costs to reflect the increased opportunities for sharing. We have not applied any saving to the reference plant. As stated in the gas section of the report, we consider gas technologies to be well understood and there will be limited opportunities for further savings. We consider the same to be the case for coal plants.

8.5 Cost reduction profiles for capital costs

We have considered a cost reduction profile based on a FOAK plant achieving these NOAK figures by 2028 FID. Thereafter we have applied a 0.5% per annum increase in the high case, flat costs in the medium case and a 0.5% per annum reduction in the low case, up to a maximum of ±5%. This matches the cost profile for gas plants.

This is a more conservative cost reduction profile than the previous estimates, which estimate variances of up to ±40% between the low/high cases and the base case in the base year, and increase by an additional ±0.5% in each subsequent year. This adds additional variance to the base capital cost ranges.

Our approach is linked to the scale and timings of the findings of the CCS cost reduction taskforce and the findings of our cost estimates, and we consider this appropriate.

Following the switch from FOAK to NOAK, we have applied the same ±0.5% per annum cost reduction profile that we applied for gas plants, explained in Section 2.5.

8.6 Operating costs

We have considered a broad range of published and internal data for our operating cost estimates. We have also compared these to bottom up estimates of consumables, staffing, and O&M costs. We have presented a comparison with the previous numbers below. We have considered ranges based on different staffing and O&M profiles and compared these to the variances in the benchmarks. We have generally considered annual maintenance to be 1.5% of capex, but have included higher figures for IGCC (2%), ASC oxyfuel (2.5%) and CCGT oxyfuel (6.5%) based on our benchmarks and professional judgement. Our staffing build ups vary by technology types, between 24 and 40 Full Time Equivalents for the capture unit.

We developed our estimates by comparing public benchmarks to bottom up estimates of staff costs, overheads, maintenance and consumables. These numbers are broadly in line with the previous estimates. The main difference is with IGCC plants. Part of the difference can be explained as the previous estimates do not include any variable costs and part of the difference can be explained by the difference between our estimates of the costs of the reference plants. Without seeing the previous methodology it is not possible to explain the differences between the two sets of estimates.

8.6.1 Operations and maintenance – fixed fee

Table 56 – FOAK gas CCS fixed O&M cost estimates (£/MW/year)

	Technology type	Case	Previous 2012 prices	LF estimate 2014 prices
A	CCGT – post combustion	Low	21,762	25,698
		Medium	25,045	30,979
		High	29,046	36,220
B	CCGT – retro	Low	21,762	25,658
		Medium	25,045	30,932
		High	29,046	36,166
C	CCGT – pre combustion	Low	20,809	25,325
		Medium	31,682	30,540
		High	45,030	35,715
D	CCGT – oxyfuel combustion	Low	18,697	70,593
		Medium	78,908	83,797
		High	139,119	96,960
E	OCGT – post combustion	Low	na	26,584
		Medium		31,752
		High		36,894

Table 57 – ASC CCS fixed O&M cost estimates (£/MW/year)

	Technology type	Case	Previous 2012 prices	LF estimate 2014 prices
F	ASC – post combustion	Low	43,231	66,743
		Medium	71,639	78,521
		High	100,047	90,299
G	ASC – partial post combustion	Low	27,158	47,919
		Medium	45,671	56,376
		High	63,360	64,832
H	ASC – with ammonia	Low	35,105	67,625
		Medium	70,668	79,558
		High	106,232	91,492
I	ASC - retrofit	Low	43,231	68,590
		Medium	71,639	80,694
		High	100,047	92,798
J	ASC – oxyfuel combustion	Low	21,297	57,995
		Medium	56,906	68,229
		High	92,515	78,464

Table 58 – IGCC CCS fixed O&M cost estimates (£/MW/year)

	Technology type	Case	Previous 2012 prices	LF estimate 2014 prices
K	IGCC – partial CCS	Low	96,734	44,315
		Medium	114,592	52,135
		High	133,937	59,956
L	IGCC – CCS	Low	113,803	55,536
		Medium	134,814	65,337
		High	157,574	75,137
M	IGCC – retro CCS	Low	113,803	69,001
		Medium	134,814	81,924
		High	157,574	94,807

Table 59 – biomass CCS fixed O&M cost estimates (£/MW/year)

	Technology type	Case	Previous 2012 prices	LF estimate 2014 prices
N	Biomass - CCS	Low	94,794	118,269
		Medium	94,815	139,139
		High	94,833	160,010

8.6.2 Operations and maintenance – variable fee

Table 60 – gas CCS variable O&M cost estimates (£/MWh)

	Technology type	Case	Previous 2012 prices	LF estimate 2014 prices
A	CCGT – post combustion	Low	1.37	2.89
		Medium	1.67	3.36
		High	2.09	4.01
B	CCGT – retro	Low	1.37	2.89
		Medium	1.67	3.36
		High	2.09	4.01
C	CCGT – pre combustion	Low	1.05	3.28
		Medium	1.35	3.81
		High	1.35	4.53
D	CCGT – oxyfuel combustion	Low	0.00	3.11
		Medium	0.53	3.62
		High	1.05	4.31
E	OCGT – post combustion	Low	na	2.48
		Medium		2.97
		High		3.38

Table 61 – ASC CCS variable O&M cost estimates (£/MWh)

	Technology type	Case	Previous 2012 prices	LF estimate 2014 prices
F	ASC – post combustion	Low	2.16	2.62
		Medium	2.35	3.04
		High	2.54	3.46
G	ASC – partial post combustion	Low	1.22	2.61
		Medium	1.38	3.03
		High	1.53	3.49
H	ASC – with ammonia	Low	0.00	2.62
		Medium	0.00	3.04
		High	0.00	3.46
I	ASC - retrofit	Low	2.16	2.64
		Medium	2.35	3.06
		High	2.54	3.49
J	ASC – oxyfuel combustion	Low	1.88	4.88
		Medium	2.41	5.70
		High	2.93	6.52

Table 62 - IGCC CCS variable O&M cost estimates (£/MWh)

	Technology type	Case	Previous 2012 prices	LF estimate 2014 prices
K	IGCC – partial CCS	Low	0	4.29
		Medium	0	5.00
		High	0	5.72
L	IGCC – CCS	Low	0	4.29
		Medium	0	5.00
		High	0	5.72
M	IGCC – retro CCS	Low	0	5.51
		Medium	0	6.43
		High	0	7.55

Table 63 – biomass CCS variable O&M cost estimates (£/MWh)

	Technology type	Case	Previous 2012 prices	LF estimate 2014 prices
N	Biomass - CCS	Low	4	6.71
		Medium	4	7.86
		High	4	9.00

8.6.3 Operations and maintenance – transport and storage

In addition, there is a transport and storage element. This is shown as the line "transport and storage" in DECC's levelised cost model, which is calculated on a cost per tonne of CO2 basis, and as such is considered a variable cost. However, it is likely there would be a fixed element to cover the operators and supervisors. We estimate the fixed element to be around 20% of the total costs. Our internal benchmarks fall in the range of the previous numbers and as such we consider them appropriate.

Table 64 –CCS transport and storage cost (£/tonne CO2)

Technology type	Case	LF estimate 2014 prices
All	Low	8.03
	Medium	19.09
	High	31.35

8.6.4 Nth of a kind

The previous estimate is a 7% reduction in operating costs from FOAK to NOAK, based on information from the CCS cost reduction task force.

The majority of operating costs relate to staffing, consumables and maintenance. As such we consider there to be more limited opportunity for cost savings compared to capital costs, where there is scope for technological development. However, we expect some opportunity for efficiency in operation through learning by doing; a 7% reduction appears possible and we have applied this to the CCS element of operating costs. We have not assumed any savings in the transport and storage or reference plant.

8.6.5 Insurance

The previous insurance cost estimate assumes costs as a percentage of construction cost per kW.

Table 65 – previous CCS insurance cost (£/kW/year) as proportion of construction cost (£/kW)

Technology type	Low	Medium	High
CCGT	0.2%	0.35%	0.5%
ASC	0.1%	0.15%	0.35%
IGCC	0.1%	0.15%	0.35%

These are slightly less than the proportion estimated for gas plants in sections 3.4 and 4.4. There are uncertainties around CCS plants. However, these uncertainties are likely to be reflected in the capital cost ranges rather than the insurance. We are unaware of additional insurance requirements on CCS plants. As such, we consider the gas ranges appropriate and have applied this proportion to the total capex including CCS, reference plant and transport and storage elements.

Table 66 – CCS insurance cost (£/kW/year) as proportion of construction cost (£/kW)

Technology type	Low	Medium	High
All	0.3%	0.4%	0.5%

8.6.6 Connection and use of system charges

The connection charges are based on the same approach as the coal and gas assumptions set out earlier in this report. Further details of the applicable tariffs are provided in Appendix C of this report.

9 Pumped storage

9.1 Technology types

There are currently four major pumped storage schemes operating in the UK, with a total installed capacity of 2,800 MW:

- *Foyers – 300 MW operated by Scottish and Southern Energy*
- *Cruachan – 440 MW operated by Scottish Power*
- *Ffestiniog – 360 MW operated by First Hydro*
- *Dinorwig – 1700 MW operated by First Hydro*

All these plants generally operate on a diurnal basis, pumping for approximately 7 to 8 hours each night during off-peak periods and generating for 5 to 14 hours each day during peak/intermediate periods. In this assessment we have assumed that future pumped storage generating capacity would operate in a similar way, utilising the difference between off-peak and peak energy spot prices.

We have also investigated the use of pumped storage for longer term seasonal regulation of wind generation as an alternative to CCGT backup generation during periods of light wind conditions.

We have considered three types of pumped storage plant:

- *new build pumped storage facilities*
- *conversion of existing conventional hydropower plants to pumped storage*
- *application of pumped storage to existing reservoir site*

For the purposes of this analysis, we have assumed all plants would be of a nominal capacity of 600 MW (though it is noted that potential pumped storage projects of lower capacity are currently under consideration by developers). (e.g., 100 MW Glyn Ronwy and 60 MW Sloy).

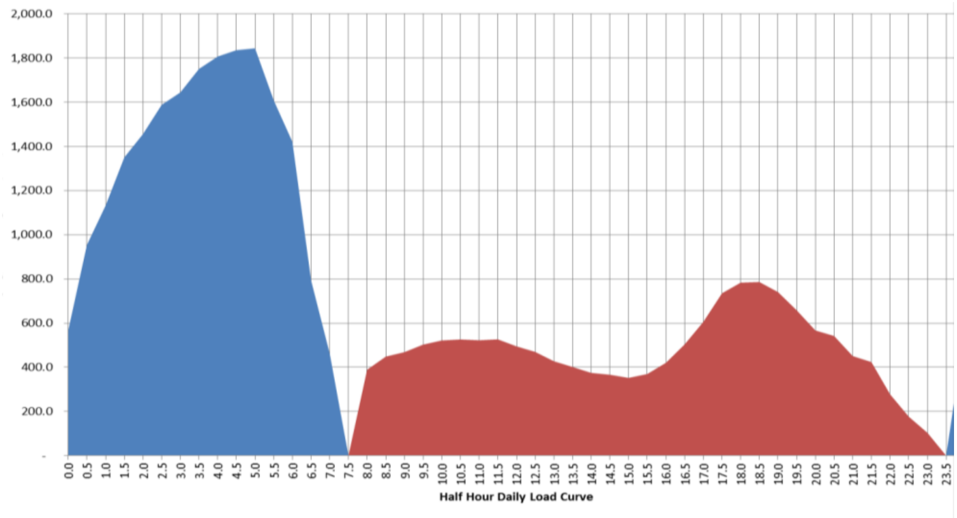
9.2 Operating regimes

We have investigated the following three pumped storage operational scenarios:

9.2.1 Daily operation for peak/off-peak regulation

The current pumped storage operating regime is shown in the figure below. This shows that of the 2,800 MW current pumped storage capacity, only about 1,800 MW is used for pumping and 800 MW is used for generation on average each day, which means that the remaining capacity is currently likely to be used as system standby reserve. This results in the load factor of the existing plant being very low at about 15.9% for pumping and about 11.6% for generation, at an overall "round-trip" efficiency (i.e., the electricity generated expressed as a percentage of the electricity used in the pumping process) of 73%.

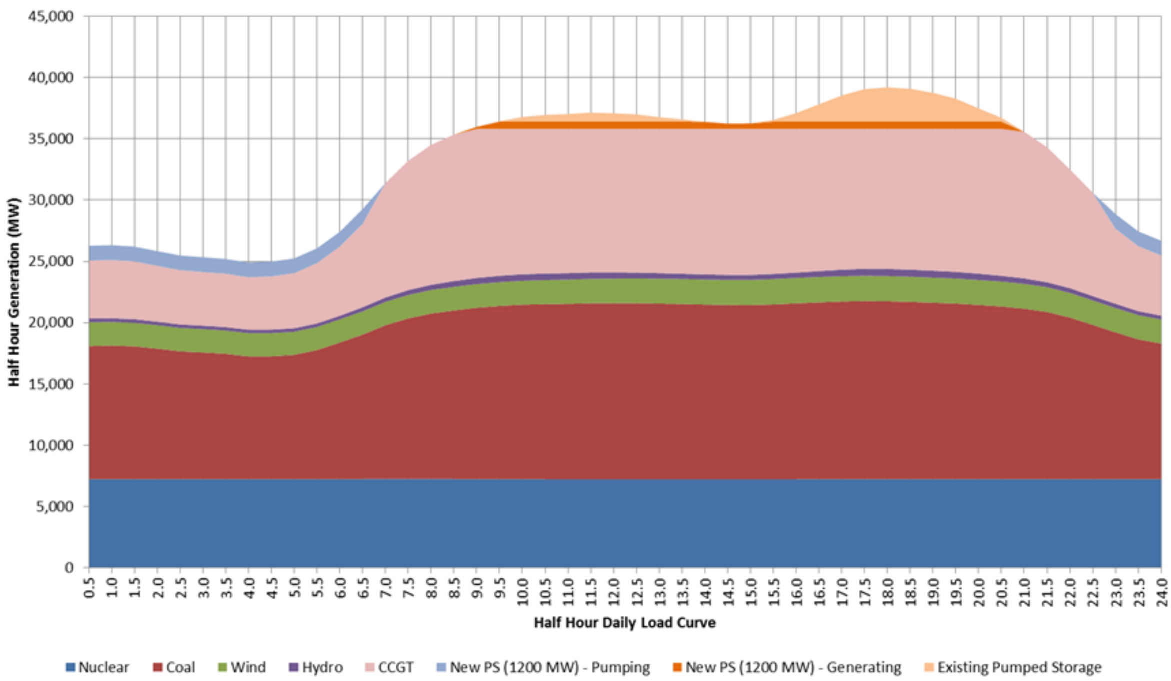
Figure 3 – pumped storage cycle



This figure also shows that the current off-peak pumping period extends to some eight hours from 23:30 to 07:30 on average each day, with pumping increased by about 10% at weekends. This means that for any future pumped storage plants it can be expected that these could operate at full pumping output for up to eight hours per day. A 600 MW plant would require 4.8 GWh off-peak pumping per day and store about 3.6 GWh for peak generation, assuming an improved “round-trip” efficiency of 75% for such new plants. Given that the larger of the new plants have a planned energy storage capacity of 30 GWh, this would represent approximately 8 days generation storage.

Operating in this way would result in a maximum pumping load factor of 33% and a maximum generating load factor of 25% for any proposed new plants, although on average it would likely be less than this.

Figure 4 – pumped storage potential



This shows how two 600 MW plants could operate, pumping at 1,200 MW over eight hours at night and generating at 600 MW for 12 hours during each day, assuming a “round-trip” efficiency of 75%.

9.2.2 Weekly operation for short term management of intermittency

We have investigated the proposed new pumped storage plants for the managing intermittency on a weekly basis, based on data the current level of wind deployment.

The same regime above could be utilised for weekly management of intermittency, by pumping for eight hours each night during a week with surplus wind and then generating the stored energy for each day during a week with no wind. This would require approximately 30 GWh of storage for each 600 MW plant, as is currently proposed for the larger of the proposed new plants.

9.2.3 Seasonal operation for long term management of intermittency

We have also investigated the use of the proposed new pumped storage plants for the seasonal regulation of intermittency based on data for the current level of wind deployment. However, based on the available wind generation records we estimate that about 7 x 600 MW plants (total 4.2 GW) would be required to achieve this, each with a storage capacity of approximately 200 GWh (total 1,400 GWh) which is almost 7 times the storage capacity (30 GWh) currently being provided for each of the proposed new plants.

This indicates that pumped storage may not be a cost effective solution for the full seasonal management of intermittency. Figures showing the simulation of the seasonal regulation of intermittency and the required storage to achieve this are presented overleaf.

Figure 5 – pumped storage operation for intermittency

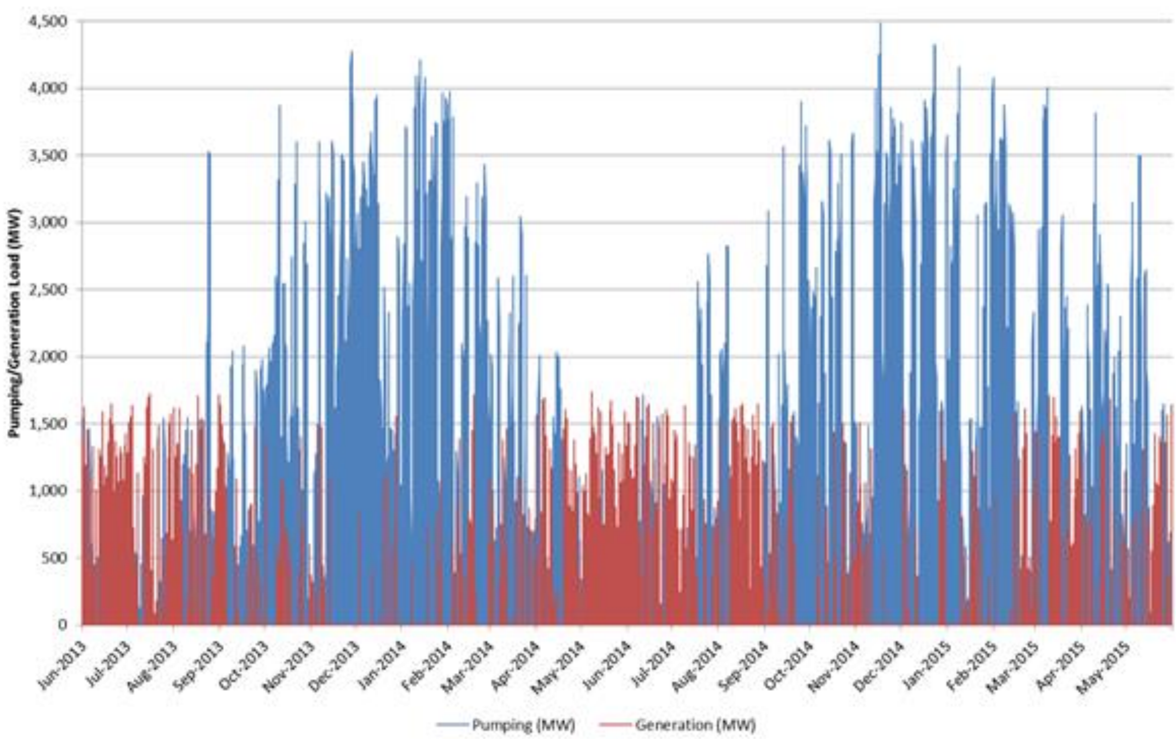
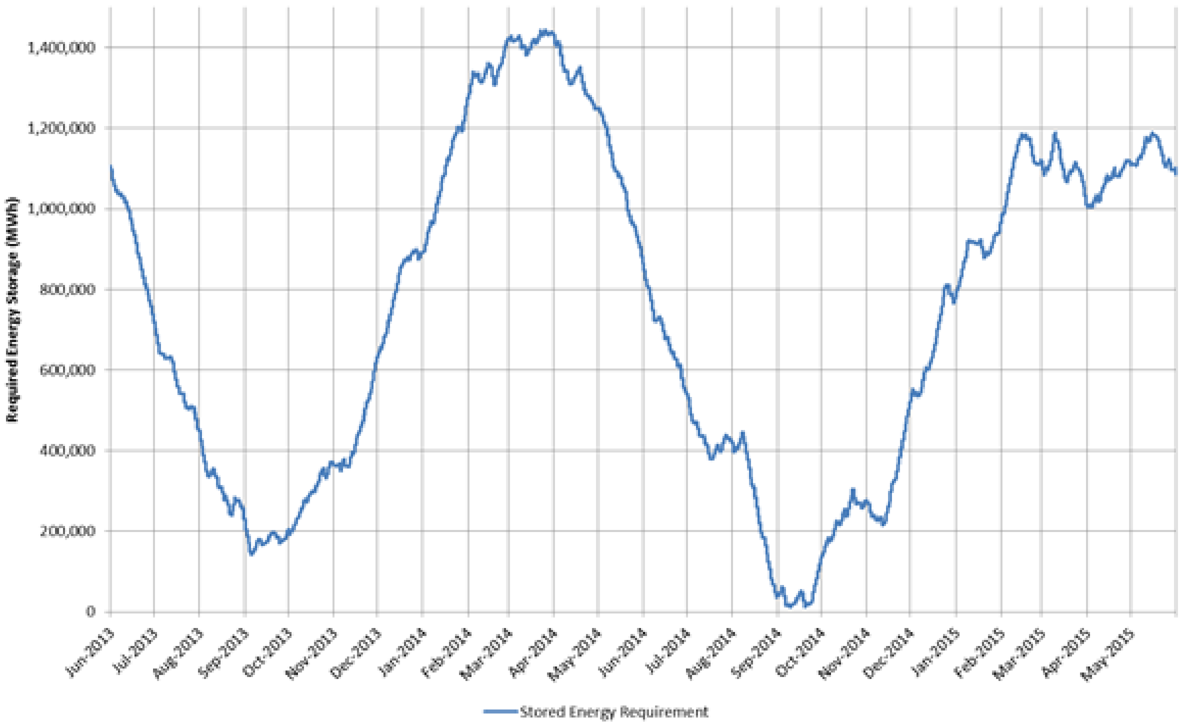


Figure 6 – pumped storage capacity for wind regulation



9.3 Key timings

We have assumed commissioning dates of 2025.

Our assessment of timings for pumped plant is based on relevant project experience across all stages of power project development, execution, construction and operation. We have summarised these in Table 67.

Table 67 – pumped storage key timings

Parameter	Low	Med	High
Pre-development period (years)	4.0	5.0	6.0
Construction period (years)	3.5	4.5	5.0
Operating period (years)	40.0	50.0	60.0

9.3.1 Pre-development

The total pre-development period (lead time) for each proposed pumped storage development is estimated to be in the range of four to six years, based on experience of similar projects, with a medium case of about five years. Smaller projects would likely be shorter with larger projects longer.

9.3.2 Construction

The total construction period for each proposed pumped storage development is estimated to be in the range of 3.5 to 5 years, based on experience of similar projects, with a medium of about 4.5 years. Smaller projects would likely be shorter with larger projects longer.

9.3.3 Operating period

Hydropower projects, including pumped storage projects, usually have a very long life expectancy due to the nature of their components that comprise dams, tunnels, power caverns and large robust hydro mechanical and electrical machinery. All of the existing pumped storage plants in the UK are still in operation and some are already over 50 years old. Provided the electrical and mechanical plant is regularly maintained and overhauled there is no reason why these plants cannot be operated indefinitely. We have assumed in our costing that the electromechanical plant would be overhauled/replaced every 30 years and that such plants would not require decommissioning over the time horizon being considered.

We have assumed a minimum operating period of between 40 and 60 years with a mean of 50 years, as is usual for major civil engineering structures, but the actual operating life could be much longer than this.

We consider the above timings would apply to all types of pumped storage given the similarity in technical characteristics.

9.4 Technical parameters

We have summarised our assessment of pumped storage technical parameters in Table 68Table 67.

Table 68 – pumped technical parameters

Parameter	Low	Med	High
Power output (MW)	600	600	600
Availability (%)	95.3	96.0	96.3

9.4.1 Power output

Most of the proposed pumped storage plants currently under consideration have an installed capacity of about 600 MW, which is a useful economic size for such plants. At a head of 500m this would require one power tunnel of about 7m in diameter, which is an optimum size. Also such plants would typically have four units of 150 MW each. This is a standard size for such plants, given the difficulty of access in mountainous areas and size limits on access tunnels etc.

Of the pumped storage options investigated most are 600 MW. One is 100 MW (Glyn Ronwy) and the smaller alternative for Sloy is 60 MW, but for the purposes of this analysis we have assumed all plants would be of a nominal capacity of 600 MW.

9.4.2 Efficiency

The current efficiency of the existing pumped storage plants is about 73%. This is the “round-trip” efficiency, which is the electricity generated as a percentage of the Electricity used in the pumping process. This is the combination of turbo-generator efficiency, reversible pump efficiency & hydraulic losses and reflects the state of the plant technology at the time these plants were constructed. However in recent years the plant efficiency that can now be achieved has improved and 75% should now be achievable. It is reported that some plants in the USA claim up to 80% overall efficiency, although this cannot be verified based on available information.
For the purposes of this assessment we have assumed a range of “round-trip” efficiencies of between 73% and 79%, with a medium case of 75% for the 1st of a kind and 77% for Nth of a kind.

This means that for an efficiency of 75%, only three quarters of the energy input during the pumping period can be recovered during the generating period.

9.4.3 Availability

The availability profile for the pumped storage plant is likely to be similar to other forms of heavy generation plant (e.g. steam turbine) and thus has been assumed to be in the range of 96.5% and 97.5% with a mean of about 97%.

9.4.4 Load Factor Profile

The predicted load factor profile is more difficult to estimate and is dependent predominantly on the length of the daily off-peak pumping window. As described above, we have assumed that any future pumped storage plants could be expected to pump for up to 8 hours per day, on average, during off-peak periods. This means the maximum pumping load factor would be up to 33%, with a maximum generating load factor of up to 25%, after applying the "round-trip" efficiency.

This means that the maximum theoretical load factor (for generation) is limited to 25%, but in practice would unlikely exceed 24%. The current generating load factor for the existing plants is around 12%. Increasing load-factor would result in purchase costs becoming marginally greater and sales costs marginally lower.

Thus for the purposes of this assessment we have assumed a range of generation load factors of 12% (low), 20% (medium) and 22% (high) based on the above analysis.

We consider the above parameters would apply to all types of pumped storage given the similarity in technical characteristics, other than as noted under availability.

9.5 Capital costs

We have summarised our assessment of pumped storage capital costs in Table 69.

Table 69 – pumped storage capital costs

Parameter	Low	Med	High
Pre-licensing (£/kW)	18.7	25.8	37.9
Regulatory (£/kW)	7.5	10.3	15.2
Capital cost (£/kW)	747	1,032	1,517
Infrastructure (£m)	10.0	25.0	50.0

9.5.1 Pre-licencing costs, technical and design

Pre-licencing costs, including feasibility designs and studies up to FEED level have been taken as 2.5% of the total capital construction cost, based on our experience of similar projects.

Note that detailed design and project supervision costs are included in the construction costs.

We consider these costs would apply to all types of pumped storage given the similarity in technical characteristics

9.5.2 Regulatory, licencing and public enquiry

We have estimated regulatory, licencing and public enquiry costs as 1% of the total capital construction cost, based on our experience of similar projects.

We consider these costs would apply to all types of pumped storage given the similarity in technical characteristics.

9.5.3 Capital costs

We have estimated capital costs in two ways:

- *a top-down evaluation of an approximate cost per MW installed, based on the actual as-constructed cost of the existing UK pumped storage plants, escalated to current prices;*
- *a bottom-up costing of proposed new pumped storage plants using pre-feasibility designs and using cost functions and manufactures prices for the E&M plant.*

Our top down evaluation uses information on the operational pumped storage sites as well as feasibility studies on a range of other 600 MW pumped storage plants that were not taken forward as pumped storage projects.

Capital costs for the proposed new pumped storage plants have been built up from the following components:

- *upper/lower reservoirs and hydraulic structures*
- *tunnels and underground caverns*
- *power station civil works*
- *power station E&M plant*
- *engineering & administration*

Our estimates for capital costs are £747 (low), £1,032 (medium) and £1,517 (high) per kW. Given the well understood nature of the civil engineering and mechanical plant, we do not anticipate any savings from moving to NOAK. Of these, the low scenario represents a conversion to pumped hydro and the medium and high scenarios represent new build schemes.

We have also considered application of pumped storage to existing reservoir sites in our analysis. These schemes have not been undertaken in the UK and there is uncertainty over the cost. Based on the information available, we consider the costs would fall between £1,276 and £1,507 per kW, which is within the range of new build traditional pumped storage scheme. Further information on such “non-traditional” pumped storage schemes is required to fully validate this estimate.

9.5.4 Infrastructure cost

We have estimated infrastructure costs in line with the approaches for gas and CCS. However, given the potential remoteness of the sites we have chosen ranges of 10km, 25km and 50km.

9.6 Cost reduction profile for capital costs

For pumped storage, the previous cost reduction profile showed 0.5% p.a. reduction in capital costs, down to a maximum decrease of 9% in the low case, a 0.5% increase in capital costs, up to a maximum increase of 9% in the high case and flat costs in the medium case. This is similar to gas plants. While the civil works element is more significant for pumped storage plants than gas plants, our indicative analysis of historical trends (allowing for inflation effects), suggests ±0.5% cited in previous studies provides a reasonable representation of the potential range of cost adjustments.

9.7 Operating costs

We have summarised our assessment of pumped storage capital costs in Table 70.

Table 70 – pumped storage operating costs

Parameter	Low	Med	High
Fixed fee (£/MW/yr)	7,982	11,192	16,012
Variable fee (£/MWh) excluding BSUoS	38.96	40.00	41.10
Insurance (% capex/yr)	0.3%	0.4%	0.5%
Connection (£/MW/yr)	14,260	15,800	16,220

9.7.1 Operations and maintenance – fixed fee

The O&M fixed fee will comprise staff, maintenance and overheads. Our estimate of fixed costs is based on internal benchmarking information and our experience of maintaining similar assets. Our estimates are £7,982 (low), £11,192 (medium) and £16,102 (high).

9.7.2 Operations and maintenance – variable fee

The O&M variable fee is the pumping cost. We have calculated this by considering the MWh pumping required per MWh generation at an estimated off peak cost of energy of £30/MWh based on an analysis of spot off peak prices for the applicable periods of pumping implied by the stated load-factors. This may not represent opportunities for forward buying or other procurement strategies. As noted in section 9.4.4, increasing load-factor would result in purchase costs becoming marginally greater and sales costs marginally lower.

9.7.3 Insurance

Our internal insurance benchmark is in the same range as the ratio of construction cost proposed for gas and CCS. Based on this we consider the same range appropriate.

9.7.4 Connection and use of system charges

We have applied an unweighted average of TNUoS tariffs for all zones where there is potential for pumped storage development. For non-conventional pumped storage, we anticipate TNUoS charges would be lower, at £8.98 per kW. Further details of the applicable tariffs are provided in Appendix C of this report.

10 Coal NOx Abatement

10.1 Technology types

This chapter considers the technical and cost parameters of the options to reduce NOx emissions on the existing UK coal fired power plants. The objective of the retrofits is to reliably meet the emission requirements of the EU Industrial Emissions Directive (IED) (200 mg/Nm3 at 6% O2). The requirements of the EU Large Combustion Plant Directive mean that after 1st January 2016 the UK coal fired power plants will all be operating with Flue Gas Desulphurisation (FGD). These options involve upgrading equipment or adding equipment at existing coal plants.

Apart from the last three units at Drax, the entire UK coal fleet is between 40 to 50 years old. If further retrofits were to be undertaken most of the plants would be of the order of 50 years old when the retrofits become operational. In addition, boiler designs vary significantly and there is no "one size fits all" retrofit. This results in a wide variance in technical characteristics. Therefore in our analysis we have considered options that could cover the range of possibilities open to the UK coal fleet.

We have considered the application of the following technologies to the upgrade of 500MW coal units:

- *low NOx combustion*
- *selective non-catalytic reduction (SNCR)*
- *selective catalytic reduction (SCR)*
- *hybrid combinations of the above*

10.2 NOx reduction technologies

There are a number of options available for reducing NOx emissions.

10.2.1 Low NOx Combustion

All coal fired units were fitted with low NOx burners in the 1990s. This technology relied on staged air burners. Further upgrades were undertaken around 10 years ago using over fire air (OFA) and boosted over fire air (BOFA) technology to provide emissions in the 400–500 mg/Nm^3 range. Burners have been developed further and it is possible to improve the current emissions performance. Currently a typical low NOx burner installation with OFA and Selective Non Catalytic Reduction (described below) may reduce NOx emissions to around 250–300 mg/Nm^3, but to our knowledge it is not able to achieve further reductions at acceptable cost.

Re-burn is the final stage of combustion modification and could meet IED emissions limits. Unfortunately, this is not likely to be adopted as it is impractical. It would be expensive, as it would require the use of gas as the re-burn fuel. In addition, the secondary combustion breaks down some of the NOx. This cannot generally be fitted to existing boilers because the space above the burners in the exiting boilers is insufficient.

Burners have been developed further and it is possible to improve current emissions performance. However, the performance of the combustion management options is unlikely to achieve the IED emission limit and we consider combustion options may need to be used in combination with other abatement technologies as outlined below.

10.2.2 Selective Non-catalytic Reduction (SNCR)

SNCR is the injection of ammonia or urea into the flue gas between 870°C–1150°C. The ammonia reacts with the oxides of nitrogen to form Nitrogen and Water. SNCR can reduce NOx emissions by around 30% to 50%. The design of the boiler and the extent to which flue gas mixes effectively limits SNCR performance.

SNCR is likely to be a component in a NOx reduction package which can reduce emissions to close to the IED emission standard.

10.2.3 Selective Catalytic Reduction (SCR)

SCR uses a catalyst to enhance the performance of the reaction between NOx and ammonia using layers of catalyst elements in a containment box. The ammonia is mixed with the inlet gas and allowed to react as the gas passes over the layers of catalyst. SCR can provide NOx emission levels which are very much lower than the IED emission limit.

It is possible to fit an SCR before the air pre-heater where the gas temperature is around with flue gas temperature of 350°C–400°C. The SCR can also be installed after precipitators at around 130°C. Unfortunately, in the UK plants there is limited space in either of the potential SCR locations and so there need to be considerable modifications to accommodate the new box containing the SCR. An SCR using a separate containment mounted over the precipitator inlet ducts has been installed on three 500 MWe units at Ratcliffe-on-Soar power station. Fiddler's Ferry power station applied for consent to fit an SCR on three units but this has not taken place.

10.2.4 Hybrid

It may be possible to use a combination of measures to control NOx emissions. For example, this could include:

- *low NOx burners with over fire air to reduce NOx concentrations to 450–500 mg/Nm3; then*
- *SNCR to reduce concentrations to 270 – 300 mg/Nm3; then*
- *a small SCR designed to reduce emissions to less than 200 mg/Nm3.*

This would reduce the size of the SCR that can be accommodated in a modified economiser casing or gas ducts, avoiding the need for a separate SCR box. This option still requires all the additional costs of SCR except the major cost of developing a separate box to contain the SCR. Whether this modification is feasible and will achieve the required emission concentrations depends completely on the characteristics of the boiler. The option is likely to just meet the IED emission standard which may restrict fuel choice.

In all cases we have made our calculations based on upgrading a 500 MW coal fired unit.

10.2.5 Our cases

In our study we have considered combinations of the above that would be applicable to the circumstances of the different UK plants. We have assumed that all the units have existing low-NOx combustion systems. These burners will be updated and other modifications such as dynamic classifiers on the coal mills may be undertaken. We have also assumed that at least two units are to be converted at the same station and the ammonia storage is shared.

(a) High case

This would comprise a SCR retrofit in a new SCR containment and upgrades of low NOx burners, air heaters and ignition burners. The installation would have a new free-standing SCR box which can be large enough to be designed to achieve full compliance with IED under all conditions. It would include space for additional catalyst to make the installation capable of achieving lower emission limits. This will be similar to the installation at Ratcliffe and those considered for Fiddlers Ferry, Longannet and Drax. This could be achieved at any of the older coal fired stations.

(b) Medium case

This would use a combination of SNCR and SCR technologies which can be accommodated within the existing boiler house structure. This would either be a smaller, lower cost SCR unit than the high case or an SNCR/SCR hybrid. This will depend on the configuration of the boiler. It may offer some small margin for further improving emission standards. This installation would not be possible at all coal fired plants.

(c) Low case

The low cost is based on the most advantageous arrangement possible with a low NOx combustion system and assumes that an SNCR/SCR hybrid which meets the IED limits is practical with the SCR accommodated within the existing plant. The SCR unit in this case would be smaller than that in the medium case. This modification would only be appropriate where the cost of fitting a sufficient SCR catalyst is relatively low. This would probably require some remodelling of the economizer. As the SCR is smaller, the installation would not provide a significant margin of compliance and would not be capable of achieving any future improvement of NOx emission standards. This option would only suit a minority of plants.

10.3 Key timings

While each of our cases involves different types of work, the overall range of equipment is similar and the overall construction times are likely to be similar.

10.3.1 Pre-development

The previous pre-development period estimate is 0.8 years (low), 1.4 years (medium) and 2 years (high).

The pre-development period would likely be around one year to conduct the FEED study and obtain necessary consents to modify the plant. Given the different circumstances of different plants, this is likely to vary, and we consider the range proposed previously to be appropriate.

10.3.2 Construction

The previous construction period estimate is 0.8 years (low), 1 year (medium) and 2 years (high).

The most likely approach would be to undertake as much work as possible during planned maintenance, with additional short shutdowns to make connections. We consider an 18 month programme to be an appropriate medium case as this will allow two summer shutdowns.

The work could reasonably be done within a year for a typical two unit plant so we consider a one year low case to be appropriate.

Should construction activity be aligned entirely with major maintenance shutdowns, the project could take up to four years. This is our high case.

For all cases, we propose construction periods of 1 year (low), 1.5 years (medium) and 4 years (high).

The plant would not be shut down for the whole construction period. The support structure for the SCR retrofit will likely be independent from the boiler structure, allowing construction even when the boiler is online. A period of four weeks will be required to connect the SCR chamber to boiler ductwork. This could be longer should the air heater and economiser need significant work, or if bypass is required. There will then need to be trial and commissioning of between 15 and 30 days. Based on this, we estimate a total shutdown time of 45 to 80 days, with a central estimate of 60 days.

10.3.3 Operating period

The previous operating period estimate is 10 years (low), 15 years (medium) and 20 years (high). The SCR unit will be designed to match the life of the boiler. Following a period of ten years the original plants will be at over twice their originally designed operating life and it is likely operators will start to consider decommissioning at this stage.

10.4 Technical parameters

In this report we have only considered the marginal change in technical parameters compared to the base plant.

10.4.1 Power output

The previous estimates assume a reduction in power output of 4.8 MW (low), 4 MW (medium) and 0 MW (high) from a 1,000 MW plant.

The SCR will reduce the output of the unit by increasing the power used in induced draught fans to overcome the increased pressure drop produced by the SCR, and there is power consumed by the ammonia injection equipment. There will also be some loss of efficiency due to evaporating the ammonia solution. The loss will vary with the complexity of the SCR installation and pressure drop across the catalyst. The environmental statement for Fiddler's Ferry states the following:

Operating the SCR Project will have a power demand above and beyond that for existing equipment, referred to as the 'parasitic load'. In total this amounts to approximately 3.5 MW per unit, or 0.7% of the power stations full load.

Fiddler's Ferry involved complex modifications, which would have incurred greater losses than anticipated under normal circumstances. We consider that 2 MW per 500 MW unit is an appropriate high and medium case, in line with the previous assumptions. We consider that 3.5 MW per 500 MW unit is an appropriate low case.

This would result in a reduction in efficiency of the same scale.

10.4.2 Availability

We do not anticipate a change in availability through environmental compliance measures.

10.5 Capital costs

We have developed our capital cost estimates using reported costs of projects in the UK and overseas. While the specifics of the projects we have considered are not identical to those considered in previous reports in this series, our assessment is broadly in line with them. These costs are approximates as there may be differences in potential modifications that may have to be carried out to the boiler, which would not be known without detailed assessment. In our assessment we have made the following assumptions:

Table 71 – coal capital cost benchmarks (£ per kW of installed capacity)

Source	High (full SCR)	Medium (full SCR or hybrid)	Low (minimum hybrid)
Reported costs, Ratcliffe-on-Soar	£165	£110	-
Published estimates, Fiddler's Ferry	£146	-	-
SCR cost survey, USA	£157	£104	-
PB 2012*	£144	-	£55
PB 2014*	£200	£100	£86.70

**LF assumption is that the lower cost estimates are forms of hybrid plants as costs do not appear sufficient to achieve full SCR*

As stated above, our analysis is based on a similar but different set of assumptions. We have presented these in the table below.

Table 72 – coal capital cost estimates (£ per kW of installed capacity)

Source	High (full SCR)	Medium (full SCR or hybrid)	Low (minimum hybrid)
Description	Full SCR and Upgrade of LNB, classifiers etc	Full SCR or SNCR SCR hybrid plus upgrade of LNB classifiers etc	Minimum cost SNCR/SCR Hybrid plus upgrade of LNB classifiers etc
LeighFisher estimate	£185	£125	£95

10.5.1 Pre-licensing, technical design, regulatory, licensing and public enquiry costs

The previous pre licensing and technical design costs estimates are £0.025/kW (low), £1/kW (medium) and £2/kW (high). It estimated regulatory, licensing and public enquiry costs at £0.02/kW (low), £0.025/kW (medium) and £0.03/kW (high).

There is limited information available on these costs given the limited developments in the UK. We estimate that around 5% of the above costs will relate to the initial FEED study and process to gain consent for altering the power station, evenly split between the two elements. This is significantly higher than the previous estimates. This reflects comments made by peer-reviewers that the previous assumptions for these costs were low. However, when combined with construction costs the overall cost remains in the same range. Therefore the difference may be because the previous estimate considered a smaller scope in its pre-construction costs, including elements of the FEED and consents process in the construction cost.

We have summarised our capital cost estimates below. A full summary of individual components is available in Appendix D.

Table 73 – summary of coal capital costs (£ per kW of installed capacity)

Source	Low (Minimum hybrid)	Medium (Full SCR or hybrid)	High (full SCR)
Pre-licencing costs, technical and design	£2.38	£3.13	£4.63
Regulatory, licencing and public enquiry	£2.38	£3.13	£4.63
Construction	£90.24	£118.74	£175.74
LeighFisher total	£95	£125	£185
Previous total	£86.75	£101.02	£202.30

10.5.2 Infrastructure cost

We do not anticipate any additional infrastructure cost, in line with the previous estimate.

10.6 Operating costs

10.6.1 Operations and maintenance – fixed fee

The previous fixed fee estimate is £1,345/MW/year (low and medium) and £8,517/MW/year (high) for catalyst replacement. Note that the high fee is for an SNCR/SCR hybrid, and includes variable costs.

We consider the cost of replacing catalysts to be a variable fee as the efficiency of catalysts reduces over time through use and the catalyst layers requires replacement. This is discussed further in the next section. We do not anticipate any increase in the fixed O&M.

10.6.2 Operations and maintenance – variable fee

The previous variable fee estimate is £0.20/MWh (low), £0.50/MWh (medium) and £0/MWh (high) for ammonia in 2012 prices. Note that the high case variable costs are included in the fixed fee.

(a) Ammonia

The major variable fee is the ammonia reagent. This fee will be applicable to all cases.

The least expensive form of ammonia is the anhydrous product, which is concentrated ammonia. This source results in the lowest equipment and operating costs, but introduces safety concerns. Ammonia is highly toxic and thus stringent safety and monitoring guidelines must be followed. Transporting anhydrous ammonia via UK highways and residential areas would be potentially hazardous.

A safer alternative is aqueous ammonia, which is a mixture of ammonia with water, usually around 25% ammonia by weight. This reduces transportation, storage and handling risk but results in higher equipment and operating costs than anhydrous. However, using such high dilution results in high cost of transport since about 75% of a road tanker load will constitute water.

Ammonia can be derived from urea. This lessens transportation and permitting risk but results in the highest equipment and operating costs. Urea for industrial use is predominantly utilised as a fertiliser.

Note that the environmental benefits of using SCR to reduce NOx emissions need to consider the emissions created during production of ammonia and during its transportation, and consumption of water.

We have assumed the use of 25% ammonia solution in this report with an assumed cost of £125 per tonne. We assume a NOx reduction of 350mg/Nm3 24 from the concentrations after an effective low-NOx combustion system to the discharge to the chimney at less than the Industrial Emissions Directive limit of 200 mg/Nm3. The 25% ammonia solution is assumed to cost £125/t which amounts to £0.30/MWh.

[24] This NOx concentration is expressed as NO_2 because the emission standards are expressed as NO_2. Around 95% of the NOx in the boiler flue gas is actually NO and the remainder is mainly NO_2. 25% Ammonia consumption is around 1.2t/hr for a 500MW unit to remove around 444 kg/h of NOx.

(b) Catalyst

Catalyst costs are difficult to quantify accurately as regular starting and stopping can damage the catalyst. A smaller, hybrid SCR will have less catalyst, but will also have less reserve capacity so will require more frequent replacement. Therefore we do not estimate a hybrid to have significantly different catalyst costs to full SCR.

Our estimate for catalyst replacement is £0.40/MWh based on replacement every five years. This is slightly higher than to the previous estimate. We consider this appropriate to take in to account some damage to the catalyst by oil burner carry over, which is caused by flexible plant operation.

(c) Operation

In addition there will be an ongoing cost for maintenance of the ammonia storage and injection systems and the SCR control and instrumentation which we estimate at £0.10/MWh.

(d) Total

In total, for all three scenarios, we estimate a variable O&M fee of £0.80/MWh.

10.6.3 Insurance

We do not anticipate any additional insurance costs, in line with the previous estimate.

10.6.4 Connection and use of system charges

We do not anticipate any additional use of system costs, in line with the previous estimate.

11 CCGT NOx Abatement

11.1 Technology types

This section considers the options available to reduce NOx emissions from existing and new build UK combined cycle gas turbine (CCGT) power plants.

A CCGT power plant uses gas turbine generators. Heat is recovered from their hot exhaust gasses to produce steam that is fed to a steam turbine plant to generate further electricity. CCGT power plants were introduced for power generation within the UK from the early 1990s. Few of these early power plants are still in operation, either being mothballed or decommissioned.

The combination of the gas turbines and steam turbine plant can result in high efficiency power generation. Modern CCGT power plants can operate at thermal efficiencies of around 60%. CCGT power plants in the UK use natural gas as their primary fuel. During operation it is only the emissions of oxides of nitrogen and carbon monoxide that have the potential to have a significant impact on local air quality.

The combustion of natural gas does not result in significant emissions of sulphur dioxide, as natural gas from the National Transmission System is considered to be a sulphur free fuel, and there are no significant emissions of particulates.

11.2 Scenarios

11.2.1 Low NOx combustion

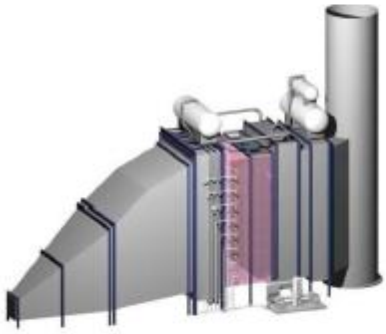
Modern gas turbines for power generation are equipped with dry low NOx combustion systems, which typically limit NOx emissions to less than 50 mg/Nm3 at loads above 60-70%. The efficiency of CCGT power plants degrades markedly below 60-70% load and thus operators endeavour to dispatch CCGT plant at high loads. The Large Combustion Plant Directive (LCPD) placed a limit for gas firing for oxides of nitrogen of 50 mg/Nm^3 on CCGT plant with an efficiency of 55% or less and a limit of 75 mg/Nm^3 for CCGT plant with higher efficiency. Note that this part-loading is a separate issue from two shifting. When two-shifting, a CCGT will operate at full load, but not at all times. Part-loading relates to backing turbines down from 100% load to part-load. In theory a turbine could run 100% of the time at part-load. However, in practice, such operation would only occur for short intervals when market prices are low but not out-of-merit for sufficient duration to justify two-shifting.

Alternative forms of mitigation to reduce emissions of NOx include Selective Catalytic Reduction (SCR) and Selective Non-catalytic Reduction (SNCR). These are post-combustion techniques involving the chemical reaction of NOx in the flue gases with a reactant such as ammonia/urea. These systems are rarely used on gas turbine plants due to their relatively low NOx emission rates compared to other plant types, such as coal. SCR equipment would also reduce the net plant output and efficiency, thereby increasing emissions of other pollutants and CO2 per unit of electricity generated. The process also results in emissions of ammonia which would otherwise not occur.

11.2.2 SCR

As described previously, SCR employs a catalyst to promote the reaction between ammonia and the NOx contained within the gas turbine exhaust gas. The catalyst is typically vanadium pentoxide. The optimum operating temperature for the reaction dictates that the catalyst and ammonia injection equipment must be located within the Heat Recovery Steam Generator (HRSG) where the temperature range is around 350-450°C.

Figure 7 – SCR located within HRSG of CCGT plant



(Source: Peerless Europe Limited).

SCR systems are capable of reducing NOx emissions by around 95%, and thus NOx emissions to atmosphere from CCGTs can be reduced to around 5 mg/Nm^3. The consequences of greater NOx reductions are:

- *increased quantity of catalyst required, with corresponding increased costs*
- *increased pressure drop within the HRSG, which reduces electricity generation and degrades CCGT plant efficiency*
- *increased quantity of ammonia consumption, which increases transportation and operating costs; and*
- *increased ammonia slip to atmosphere.*

11.2.3 Selective non-catalytic reduction (SNCR)

The SNCR process is described previously. Since gas turbine combustion systems can achieve relatively low NOx emission rates the additional reduction capability of SNCR of 30%-40% is unlikely to be effective compared to the additional cost and complexity. A hybrid SCR/SNCR combination is technically feasible but we are not aware of any such systems that have been implemented on CCGT power plant.

11.3 Key timings

11.3.1 Pre-development

As with coal environmental compliance measures, the pre-development period would likely be around one year to conduct the front-end engineering design(FEED) study and obtain necessary consents to modify the plant, but this can be variable.

We estimate a pre-development period of 0.8 (low), 1.4 (medium) and 2 (high) years.

11.3.2 Construction

Unlike coal, it would not be possible to undertake the work during planned maintenance. As explained below, installing SCR will require movement of the HRSG. A CCGT plant cannot operate without the HRSG. Installing an HRSG during a CCGT project usually takes around a year on site for larger plants, but the range of timing is dependent on specifics of the site layout.

We estimate construction periods of 0.8 years (low), 1 year (medium) and 1.5 years (high). We would anticipate this to be aligned such that it is over summer as much as possible.

11.4 Technical parameters

11.4.1 Power output

Electrical power consumption of the SCR equipment would reduce the electricity available for export to the grid. For a typical 450 MW CCGT power plant the total reduction in power output will be approximately 1 MW (0.2%). We have applied this reduction to our medium case F class plant for the medium and high cases, as they are the most likely cases for retrofit. We have applied this reduction to our medium H class plant for the low case, as this is the most likely new build.

11.4.2 Efficiency

Installation of the SCR catalyst and ammonia distribution grid within the exhaust gas stream will increase the back-pressure of the gas turbine. Gas turbine generator performance is sensitive to exhaust backpressure. The increase in exhaust pressure loss will be about 3-5 mbar. This pressure loss will decrease the power output and degrade the thermal efficiency of the CCGT. For a typical 450MW CCGT power plant the total efficiency loss will be approximately 0.1 percentage points. We have applied this reduction to our medium case F class plant for the medium and high cases, as they are the most likely cases for retrofit. We have applied this reduction to out medium H class plant for the low case, as this is the most likely new build.

11.4.3 Availability

We do not anticipate a reduction in availability other than the loss of availability during construction.

11.5 Capital costs

Retrofitting a CCGT plant to install SCR will require the catalyst and ammonia distribution equipment to be located in the middle of the HRSG. We are not aware of any CCGT plant in the UK that was designed with space to accommodate future modification for the retrofitting of a SCR system. We understand Peterhead Power Station is currently planning to fit a SCR system as part of a carbon capture demonstration plant construction.

Most of the existing UK CCGT power generation fleet is either of the double or triple-pressure Heat Recovery Steam Generator (HRSG) system. Double-pressure HRSGs tend to be used for smaller gas turbine installations, and do not produce as high efficiency as the larger triple pressure HRSG applications.

11.5.1 Double pressure HRSG

Installing SCR at double-pressure HRSGs would require modifications to the HRSG to ensure the ammonia grid and catalyst element is inserted in the correct flue gas temperature zone for optimum performance. The HRSGs tend to be smaller, which may make it easier to carry out SCR retrofit. However, double-pressure HRSGs are generally installed to older, first generation CCGT installations that are likely to have limited remaining lives and therefore SCR is unlikely to be considered.

11.5.2 Triple pressure HRSG

Modern F class and H class gas turbines will utilise large triple-pressure HRSGs in order to achieve highest thermal efficiencies. These HRSGs are very large, heavy and complex. Any work to insert a

SCR system within an existing HRSG will involve substantial mechanical and civil work, relocation of large structures and may not be practical at many power station sites due to lack of available space.

In general, it is not practical to retrofit an SCR unless the HRSG was first designed for it. Typically it would require space for the catalyst of two to three metres with additional space required for the ammonia injection grid. Retrofit of a SCR system to a horizontal HRSG would require:

- *cutting the HRSG in half,*
- *moving the back-half of the HRSG backwards,*
- *inserting the SCR system; and*
- *relocating the exhaust stack.*

This approach is uncommon in the EU and there are few cost benchmarks. An impact assessment carried out by DEFRA[25] in 2012 estimated that SCR would cost £113/kW to install for a CCGT. We have supported this assessment with PEACE modelling of the costs of adjusting the HRSG and stack and the installation of SCR equipment. This results in a total cost of £109/kW. As such we consider £110/kW to be an appropriate base case.

Cost estimates can be only very approximate since each power station will have site specific factors that could vary retrofit costs.

Retrofits that involve impeded access for construction, extensive relocation of equipment and difficult ductworks rearrangement will have higher capital costs, potentially by the order of 30%. In some cases it may even be technically impractical to carry out any such retrofit.

Therefore our high estimate for the capital cost of SCR is £140/kW.

For new build we anticipate one scenario, as there will likely be space in the economiser. There is unlikely to be a great deal of variability in design. Costs would include the SCR equipment and corresponding civil works. We estimate this to be £20/kW based on our PEACE modelling.

11.5.3 Pre-licensing, technical design, regulatory, licensing and public enquiry costs

There is limited information available on these costs given the limited developments in the UK. However, we consider requirements to be similar to coal SCR. Therefore we estimate that around 5% of the above costs will relate to the initial FEED study and process to gain consent for altering the power station, evenly split between the two elements.

We have summarised our capital cost estimates below.

Table 74 – summary of coal capital costs (£ per kW of installed capacity)

Source	Low (new build)	Medium (base case)	High (high complexity)
Pre-licencing costs, technical and design	0.50	2.75	3.75
Regulatory, licencing and public enquiry	0.50	2.75	3.75
Construction	19	104.50	132.50
LeighFisher total	20	110	140

[25] Defra – Multi pollutant measures database: extension to 2030 dated 2012

11.5.4 Infrastructure cost

We do not anticipate any additional infrastructure cost.

11.6 Operating costs

11.6.1 Operations and maintenance – fixed fee

As with coal SCR, we do not foresee any fixed operating costs. NOx abatement systems are retrofits of components to existing plants and as such the fixed costs of operation would be covered by the operating costs of the existing station.

11.6.2 Operations and maintenance – variable fee

(a) Ammonia

As with coal we have assumed use of a 25% ammonia solution. Current 25% ammonia solution prices are around £125/tonne. Achieving a NOx reduction of 45mg/Nm^3 from the gas turbines exhaust assumed to have a NOx concentration of 50 mg/ Nm^3 is estimated to cost around £0.03 per MWh.

Note the reaction of ammonia with NOx to produce water and nitrogen is not completely stoichiometric. Unreacted ammonia escapes to atmosphere (ammonia slip). Ammonia is a pollutant. Ammonia slip is mainly due to non-homogenous distribution of ammonia across the HRSG flow duct. Improved design and control systems have reduced ammonia slip to low levels of concentration, of the order of emission rates around 2mg/Nm^3. However, with time, the ammonia slip increases due to catalyst degradation. One manufacturer's data indicates a doubling of ammonia slip rate after about six years of operation.

(b) Catalyst

Over time, the SCR catalyst degrades in effectiveness. Ammonia feed consumption and ammonia slip rate increases. In a coal plant, this is caused by fouling, thermal degradation and poisoning by metals in the exhaust stream originating in the gas turbine fuel, such a sodium, potassium and vanadium. Gas turbines combusting natural gas contain no significant fouling products or metals so catalyst life can be long compared to SCR systems associated with coal-fired power stations. Experience in the USA, where SCR is more common, indicates life of a catalyst within a natural gas-fired CCGT plant would be expected to be ten years or more.

We estimate the replacement cost will be around £0.07/MWh to 0.10/MWh based on replacement every ten years.

(c) Operation

In addition there will be an ongoing cost for maintenance of the ammonia storage and injection systems and the SCR control and instrumentation. We estimate this at £0.05/MWh.

(d) Total

In total, for all three scenarios, we estimate a variable O&M fee of £0.15/MWh (low and medium) to £0.18/MWh (high).

11.6.3 Insurance

We do not anticipate any additional insurance costs, in line with our coal estimate.

11.6.4 Connection and use of system charges

We do not anticipate any additional insurance costs, in line with our coal estimate.

12 Levelised Costs

The Levelised Cost of Electricity (LCOE) provides an indication of the average overall cost of electricity generation per MWh over the expected lifetime of the asset. This allows comparison of the costs of generation across technology types. This analysis is based on the technical and cost parameters stated in this report and various financial and technical assumptions provided by DECC, including hurdle rates.

We have provided LCOE ranges for individual plants. Our assessment provides uncertainty ranges based on the parameters we have developed. In this analysis, we do not consider the following:

- *"supply curve" impacts from the concurrent development of multiple power plants of a similar technology*
- *variations in input parameters provided by DECC*
- *site specific conditions*

We explained in each technology specific chapter how we have correlated the high, medium and low scenarios for each parameter to develop an appropriate overall LCOE range for different technology types. These descriptions are under the sections "technology scenarios" for each technology. In general, we have varied pre-development and capital costs to calculate the overall LCOE range as these parameters drive the largest change in LCOE in most cases. Although current market sentiment is considered by some to be depressed, our analysis has compared costs derived from bottom-up modelling and analysis against actual historic projects over an extended period and calibrated values accordingly. Such adjustment means that our costs are likely to be representative of longer-term averages over the business cycle.

We did not consider there to be a strong correlation between these two costs and other parameters so did not correlate further parameters except in the following cases:

- *For CCGT plants, we have also considered the supply curve impact of multiple CCGT plants being in development at the same time. We discuss this in full in 12.1.1.*
- *For nuclear plant, we have also considered the impact of a major delay to construction, as we consider this a leading cause in cost overruns for nuclear power plants. We discuss this in full in 12.1.5.*

A full summary of our assumptions is in Appendix M and full tables of results in Appendix P. We have also explained the differences between our results and DECC's previous LCOE analysis from 2013 in Appendix N.

Table 75 summarises our assessment of appropriate LCOE ranges for the technologies considered in this report.

Table 75 – LCOE ranges at new DECC hurdle rates

Category	Technology	Commissioning date	Low LCOE (£/MWh)	High LCOE (£/MWh)	LCOE Range (£/MWh)
Gas	CCGT	2020	82	85	3
	CHP (CHP mode)		96	102	6
	OCGT[26] (peaking)		129	178	49
	OCGT (critical peak)		186	371	185
	Reciprocating engine[27] (peaking)		113	272	159
	Reciprocating engine (critical peak)		145	903	758
Nuclear	FOAK	2025	85	123	38
	NOAK	2030	69	99	30
CCGT CCS	Post-combustion	2025	112	133	21
	Pre-combustion		121	141	21
	Oxyfuel		119	140	21
	Retrofit post-combustion		99	112	12
IGCC CCS	Full pre-combustion		142	176	35
	Partial pre-combustion		154	178	25
	Retrofit pre-combustion		154	189	35
ASC CCS	Full post-combustion		135	178	43
	Partial post-combustion		137	164	27
	Retrofit post-combustion		109	133	24
	Oxyfuel		128	162	33
	Ammonia		135	178	43
Other CCS	Biomass		372	459	87
	OCGT post-combustion		173	198	25
Pumped storage	Pumped storage		120	195	75

[26] The OCGT range is the maximum and minimum of LCOE for all OCGT capacities (100 MW, 299 MW, 300 MW, 400 MW, 600 MW)
[27] The Reciprocating engine range is the maximum and minimum of LCOE for diesel and gas engines

Figure 8 – baseload LCOE

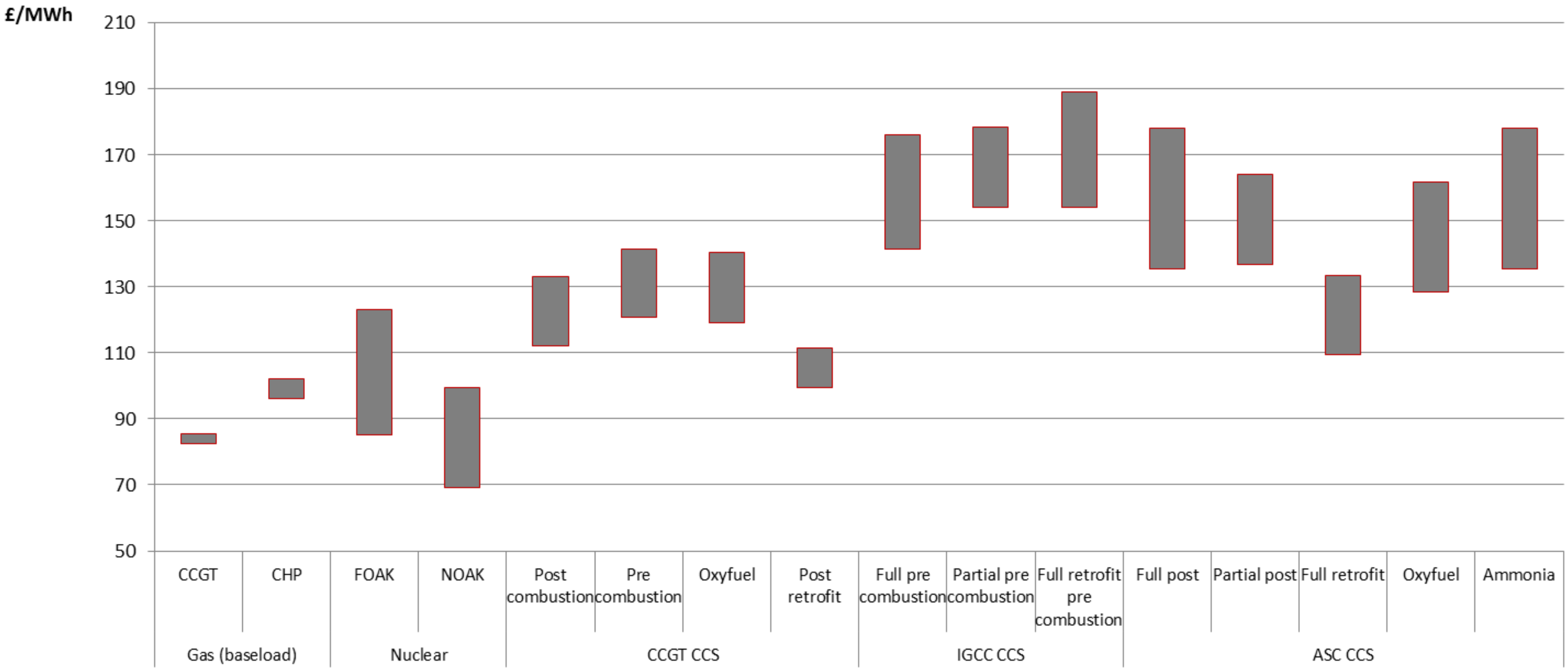
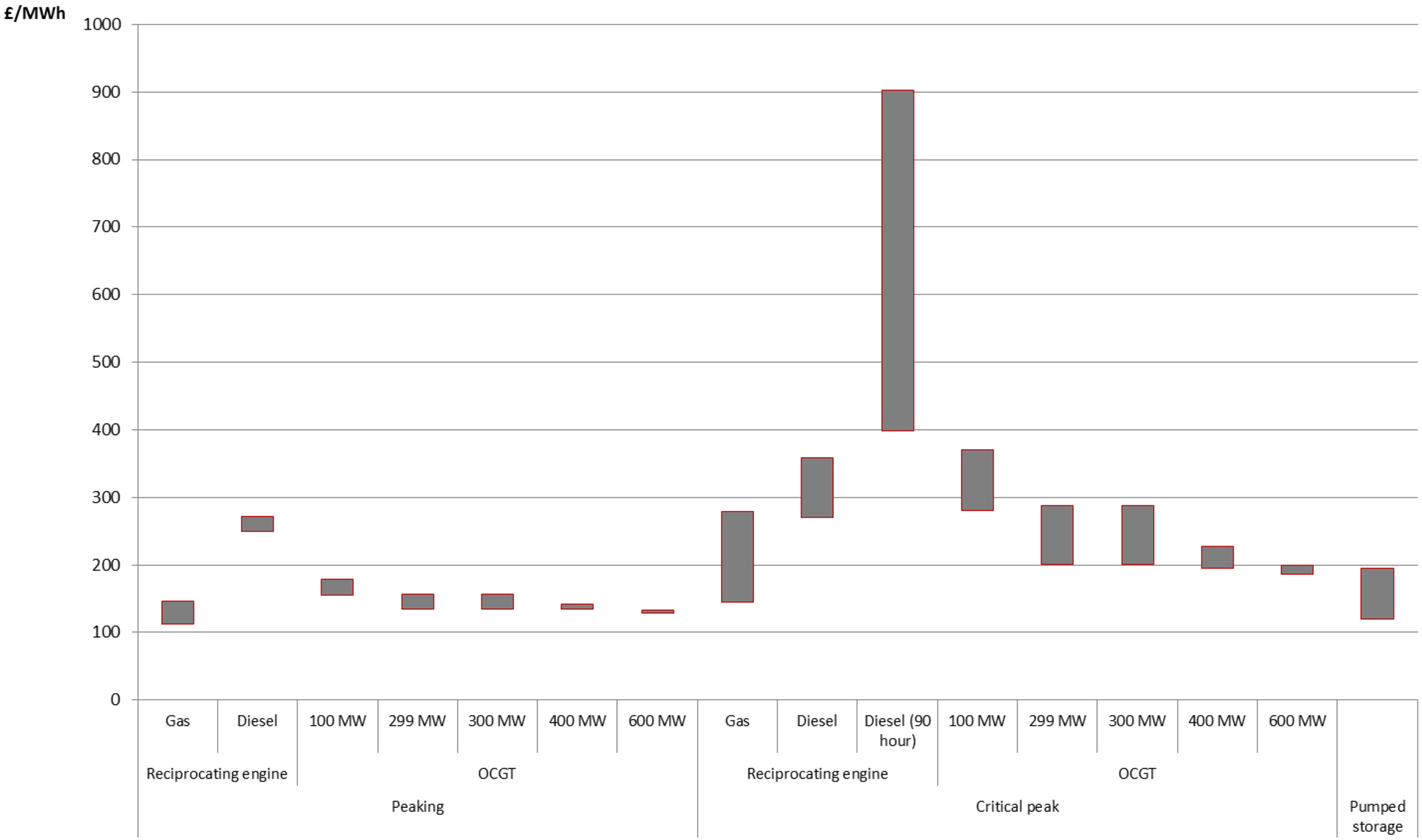


Figure 9 – peaking LCOE



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12.1 Our results

We estimated LCOE for all technologies using DECC's LCM. We used the parameters summarised in Appendix F to Appendix K and the assumptions summarised in Appendix M. All costs are in 2014 prices unless otherwise stated. All costs are stated to the nearest integer, so numbers may not add due to rounding.

12.1.1 CCGT

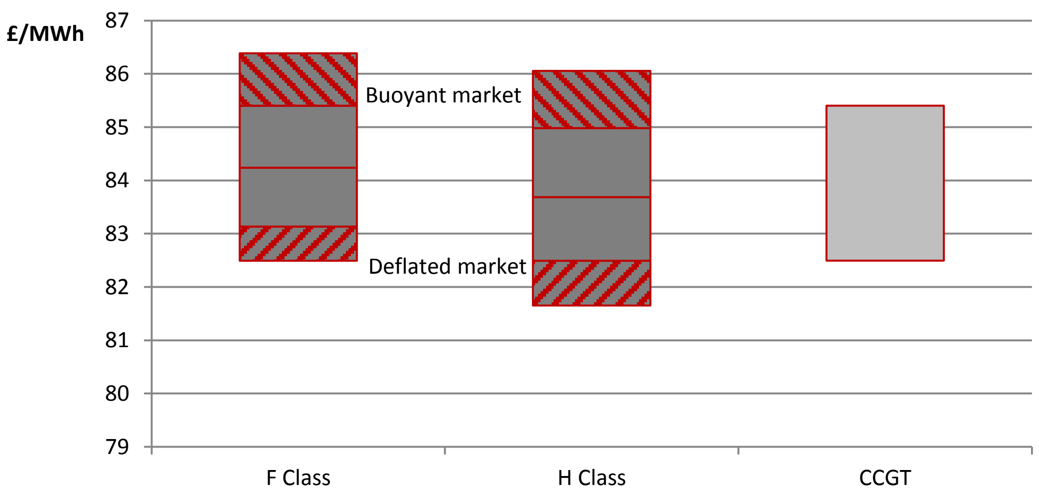
Table 76 – CCGT medium case LCOE

Cost category	£/MWh	
	F Class	H Class
Pre-development	0	0
Construction	6	7
Fixed O+M	2	2
Variable O+M	3	3
Fuel	45	44
Carbon	28	27
Total	**84**	**84**

Figure 10 below shows the overall levelised cost range based on the above analysis. We consider this an appropriate uncertainty range for levelised costs for CCGT plants commissioning in 2020. Table 76 Table 76 shows that around 90% of the levelised cost for CCGT plants is attributable to fuel and carbon prices based on the forecast price levels provided for this study. Any movement in gas and carbon prices relative to such assumptions may therefore result in further variance in levelised costs beyond the levels indicated by this analysis.

A further consideration is the extent to which market factors could possibly affect CCGT development if multiple CCGT projects were to be progressed at the same time. To understand the potential impact on LCOE, we have considered potential variations in construction costs of 30% trough-to-peak (i.e., +/-15% around the average) across the business cycle, with our high, medium and low cases assuming the mid-point of the business cycle.. These are used as illustrative indications of limited market activity or where market conditions are buoyant and potential demand may be greater than supply chain capacity. Any such additional variations on this basis could result in changes to LCOE of ±1% over or below the high and low LCOE respectively.

Figure 10 – CCGT LCOE



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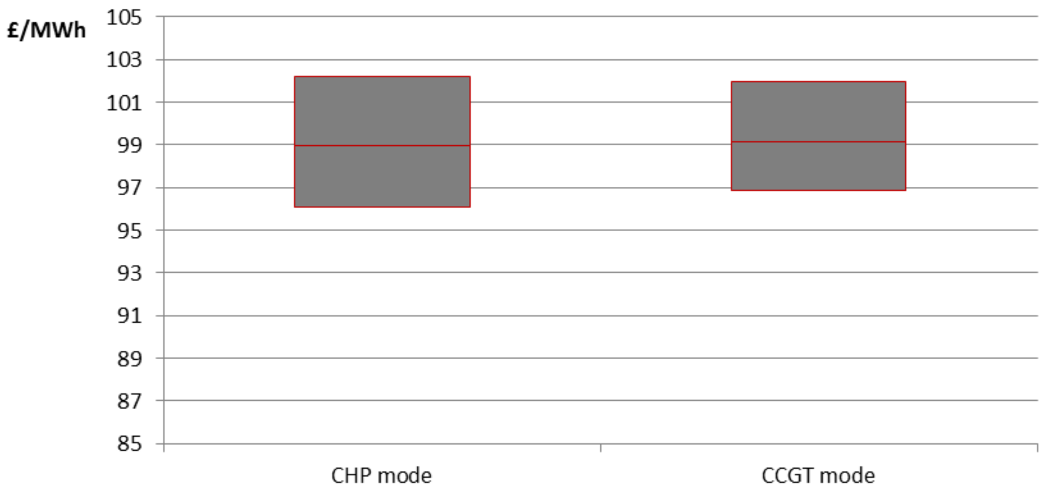
12.1.2 CCGT CHP

Table 77 – CCGT CHP medium case LCOE

Cost category	£/MWh	
	CHP	CHP (Power only)
Pre-development	1	1
Construction	12	9
Fixed O+M	4	4
Variable O+M	5	5
Fuel	69	51
Carbon	40	30
Heat revenue	-32	0
Total	**99**	**99**

Figure 11 below shows the overall levelised cost range based on the above analysis. We consider this an appropriate uncertainty range for levelised costs for CHP plants commissioning in 2020. Table 77 shows that around 80 to 85% of the levelised cost, excluding heat revenues, for CHP plants is attributable to fuel and carbon prices based on the forecast price levels provided for this study. As such there may be further variance in levelised costs beyond the levels indicated by this analysis.

Figure 11 – CCGT CHP LCOE



12.1.3 OCGT

(a) Peaking OCGT (2,000 hours)

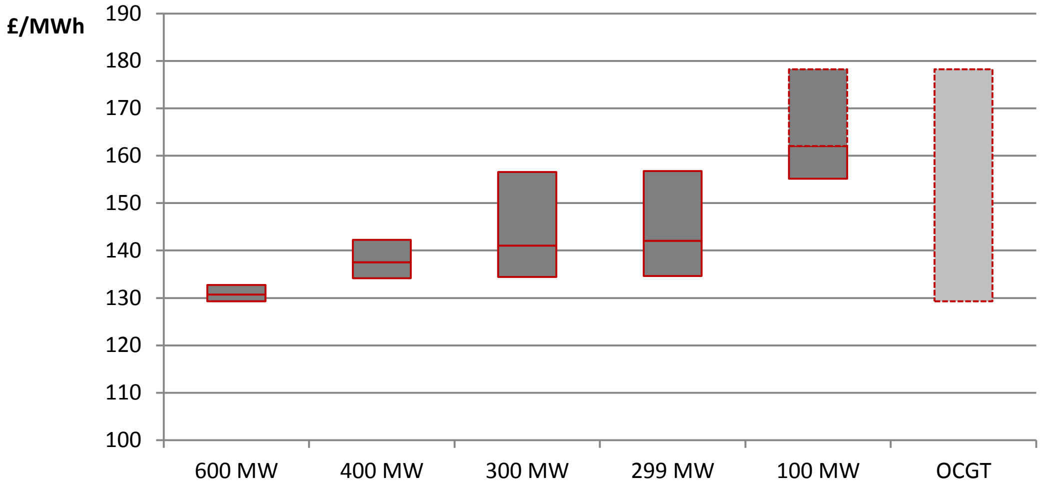
Table 78 – peaking OCGT medium case LCOE

Cost category	£/MWh				
	600 MW	400 MW	300 MW	299 MW	100 MW
Pre-development	1	2	2	2	4
Construction	16	19	22	23	38
Fixed O+M	6	6	7	7	10
Variable O+M	3	3	3	3	4
Fuel	65	67	66	66	65
Carbon	40	41	41	41	40
Total	**131**	**138**	**141**	**142**	**162**

Figure 12 below shows our overall levelised cost range based on the above analysis. We consider this an appropriate uncertainty range for levelised costs for OCGT plants commissioning in 2020.

Table 78 shows that around 60% of the levelised cost for high load factor OCGT plants is attributable to fuel and carbon prices based on the forecast price levels provided for this study. As such there may be further variance in levelised costs beyond the levels indicated by this analysis.

Figure 12 – peaking OCGT LCOE



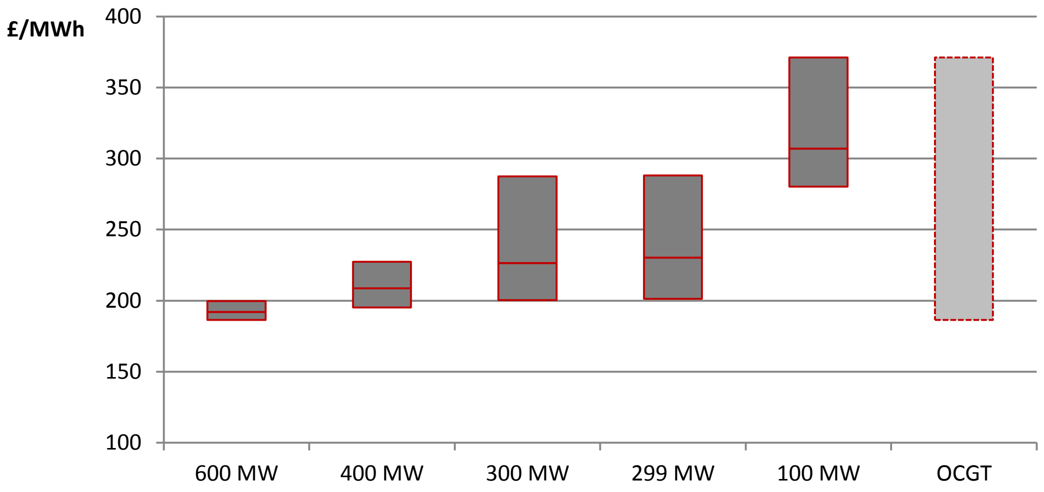
(b) Critical peak OCGT (500 hours)

Table 79 – critical peak OCGT medium case LCOE

Cost category	£/MWh				
	600 MW	400 MW	300 MW	299 MW	100 MW
Pre-development	5	6	7	7	18
Construction	63	73	88	92	150
Fixed O+M	17	18	21	21	31
Variable O+M	3	3	3	3	4
Fuel	65	67	66	66	65
Carbon	40	41	41	41	40
Total	**192**	**209**	**226**	**230**	**307**

Figure 13 below shows our overall levelised cost range based on the above analysis. We consider this an appropriate uncertainty range for levelised costs for low load factor OCGT plants commissioning in 2020. Table 79 shows that around 60% of the levelised cost for high load factor OCGT plants is attributable to fuel and carbon prices based on the forecast price levels provided for this study. As such there may be further variance in levelised costs beyond the levels indicated by this analysis.

Figure 13 – critical peak OCGT LCOE



12.1.4 Reciprocating engines

(a) Peaking reciprocating engines (2,000 hours)

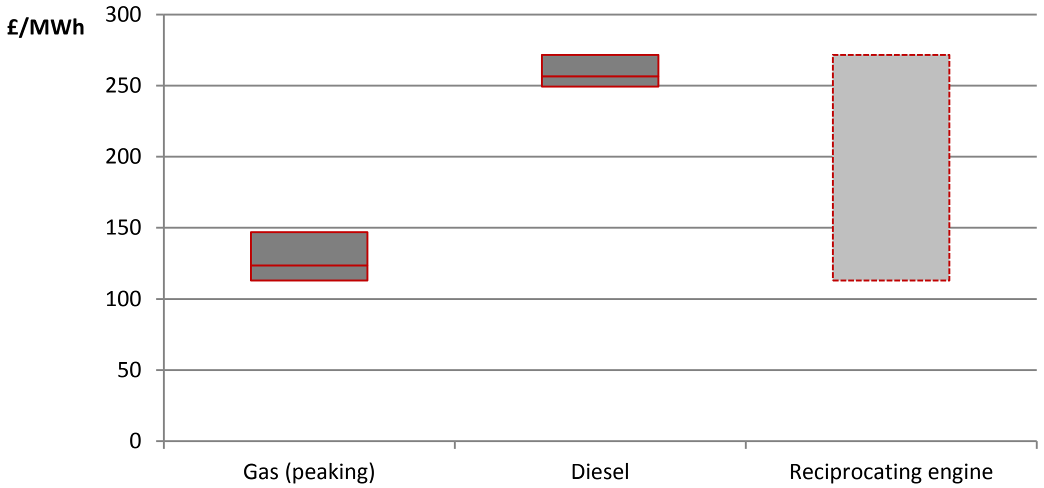
Table 80 – peaking reciprocating engines medium case LCOE

Cost category	£/MWh (2014 prices)	
	Gas	Diesel
Pre-development	1	1
Construction	29	22
Fixed O+M	-11	-11
Variable O+M	2	2
Fuel	69	199
Carbon	33	44
Total	**124**	**256**

Figure 14 below shows our overall levelised cost range based on the above analysis. Note that the negative fixed operations and maintenance cost is caused by a negative DUoS charge. We consider this an appropriate uncertainty range for levelised costs for reciprocating engine plants commissioning in 2020.

Table 80 shows that around 60% of the levelised cost for high load factor reciprocating engine plants is attributable to fuel and carbon prices based on the forecast price levels provided for this study. As such there may be further variance in levelised costs beyond the levels indicated by this analysis.

Figure 14 – peaking reciprocating engines LCOE



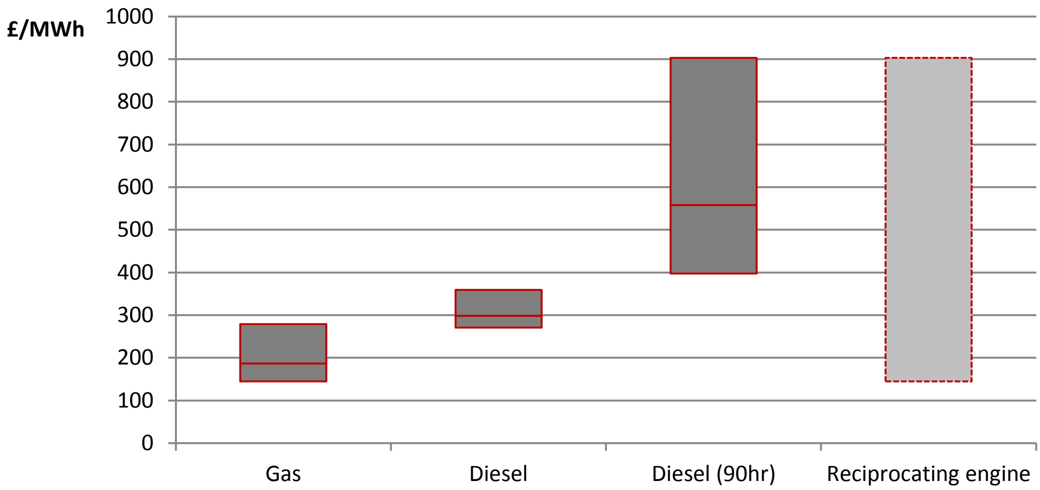
(b) Critical peak reciprocating engines (90 and 500 hours)

Table 81 – critical peak reciprocating engines medium case LCOE

Cost category	£/MWh (2014 prices)		
	Gas (500 hr)	Diesel (500 hr)	Diesel (90 hr)
Pre-development	4	4	20
Construction	115	87	498
Fixed O+M	-37	-37	-205
Variable O+M	2	2	2
Fuel	69	199	199
Carbon	33	44	44
Total	**186**	**299**	**558**

Figure 15 below shows the overall levelised cost range based on the above analysis. Note that the negative fixed operations and maintenance cost is caused by a negative DUoS charge. The DUoS charge is 2% higher in the critical peak case in £/MW/year terms than the peaking case . However, this translates to a lower Fixed O&M in LCOE terms as there are fewer hours for the cost to be spread over. The DUoS charge is around 55% higher in £/MW/year terms than the peaking case. However, given there are even fewer hours for the costs to be spread over, this translates to a significantly lower Fixed O&M in LCOE terms. We consider this an appropriate uncertainty range for levelised costs for reciprocating engine plants. Table 81 shows that around 60% of the levelised cost for high load factor reciprocating engine plants is attributable to fuel and carbon prices. As such there may be further variance in levelised costs beyond the range indicated by this analysis based on DECC's fuel price inputs.

Figure 15 – critical peak reciprocating engines LCOE



Note that for comparison, the 90hr p.a. case is also shown. The overall range reflects this as well as the 500hr p.a. base cases.

12.1.5 Nuclear

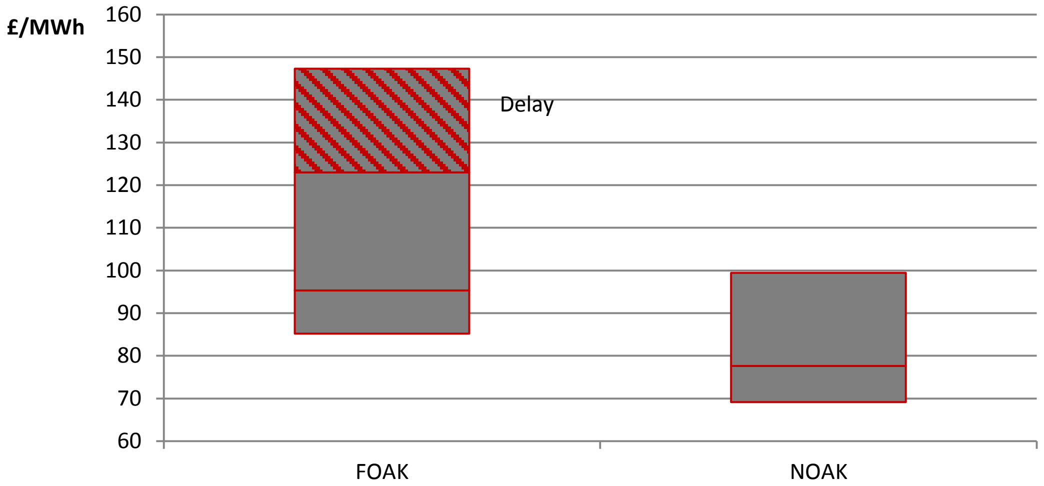
Table 82 – nuclear medium case LCOE

Cost category	£/MWh		
	FOAK	FOAK delay	NOAK
Pre-development	7	27	3
Construction	66	97	52
Fixed O+M	11	11	11
Variable O+M	5	5	5
Fuel	5	5	5
Carbon	0	0	0
Decommissioning and waste*	2	2	2
Total	**95**	**147**	**78**

*Values for decommissioning and waste provided by DECC

Figure 16 below shows the overall levelised cost range based on the above analysis. For FOAK, the red shaded area shows the difference between the high FOAK LCOE and the high FOAK LCOE that includes delay. This reflects the fact that a significant cause of cost increases in nuclear projects is delay to the programme, as described in section 7.7. We consider this an appropriate uncertainty range for levelised costs for FOAK nuclear plants commissioning in 2025 and NOAK nuclear plants commissioning in 2030. Table 82 shows that around 6% of the levelised cost for nuclear plants is attributable to fuel prices based on the forecast price levels provided for this study. As such there may be further variance in levelised costs beyond the range indicated by this analysis, but more limited than for gas plants.

Figure 16 – nuclear LCOE



12.1.6 CCS

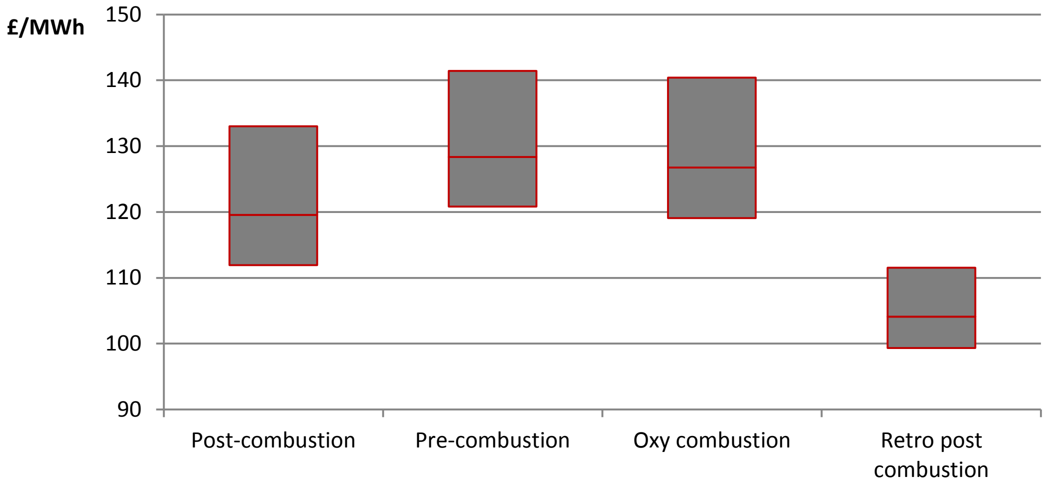
(a) CCGT CCS

Table 83 – CCGT CCS FOAK medium case LCOE

Cost category	£/MWh			
	Post	Pre	Oxy	Post retro
Pre-development	2	2	2	1
Construction	41	40	41	26
Fixed O+M	5	5	12	5
Variable O+M	3	4	4	3
Fuel	57	65	60	57
Carbon	4	3	0	4
Capture and storage	7	9	9	7
Total	**120**	**128**	**127**	**104**

Figure 17 below shows the overall levelised cost range based on the above analysis. We consider this an appropriate uncertainty range for levelised costs for FOAK CCGT CCS plants commissioning in 2025. Table 83 shows that in the medium case around 50% to 60% of the levelised cost for CCGT CCS plants is attributable to fuel and carbon prices based on the forecast price levels provided for this study. As such there may be further variance in levelised costs beyond the levels indicated by this analysis.

Figure 17 – CCGT CCS FOAK LCOE



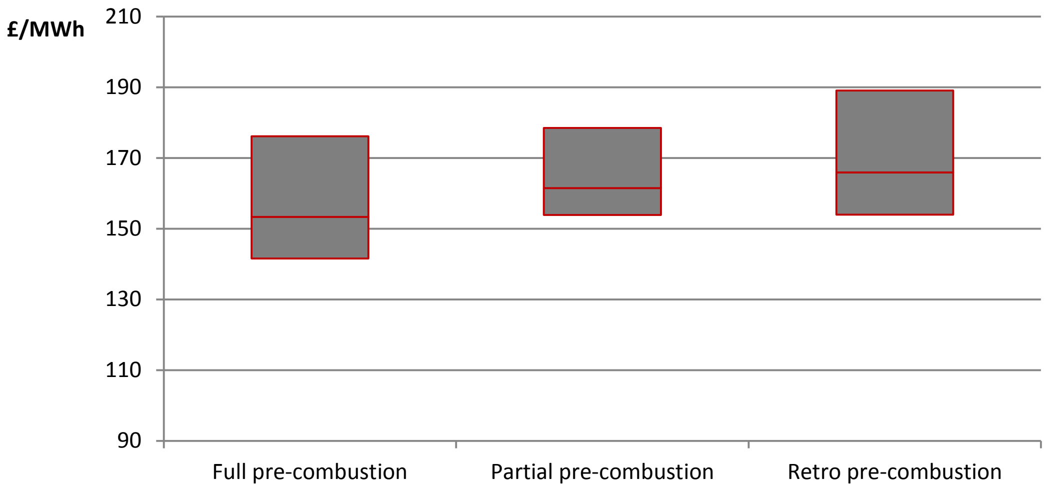
(b) IGCC CCS

Table 84 – IGCC CCS FOAK medium case LCOE

Cost category	£/MWh		
	Full	Partial	Retro
Pre-development	2	1	2
Construction	78	56	79
Fixed O+M	12	9	15
Variable O+M	5	5	6
Fuel	28	24	31
Carbon	11	61	13
Capture and storage	18	5	20
Total	**153**	**161**	**166**

Figure 18 below shows the overall levelised cost range based on the above analysis. We consider this an appropriate uncertainty range for levelised costs for FOAK IGCC CCS plants commissioning in 2025. Table 84 shows that in the medium case around 25% to 55% of the levelised cost for IGCC CCS plants is attributable to fuel and carbon prices based on the forecast price levels provided for this study. As such there may be further variance in levelised costs beyond the levels indicated by this analysis.

Figure 18 – IGCC CCS FOAK LCOE



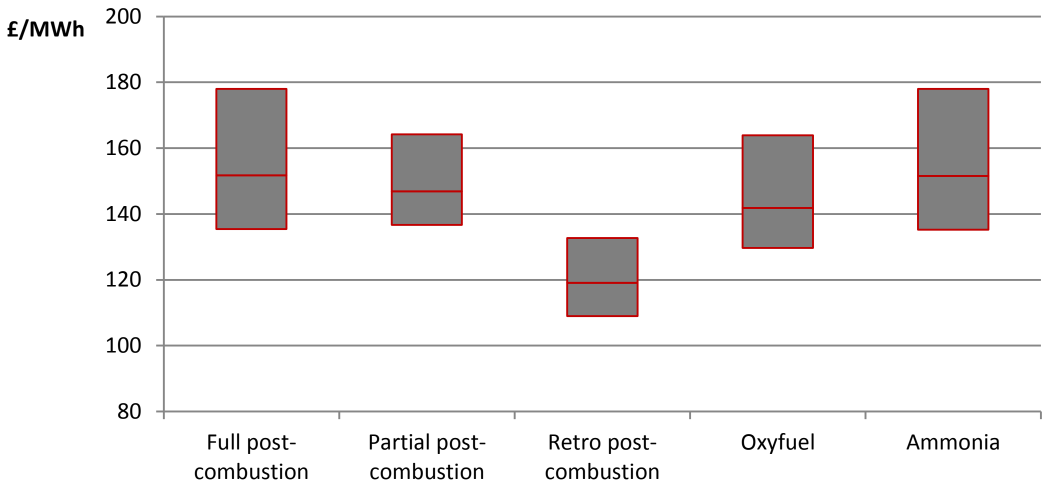
(c) ASC CCS

Table 85 – ASC CCS FOAK medium case LCOE

Cost category	£/MWh				
	Full post	**Partial post**	**Retro post**	**Oxy**	**Ammonia**
Pre-development	2	2	1	2	2
Construction	81	49	50	72	81
Fixed O+M	12	9	12	11	13
Variable O+M	3	3	3	6	3
Fuel	26	22	27	25	25
Carbon	11	57	9	8	10
Capture and storage	17	5	17	17	16
Total	**152**	**147**	**120**	**140**	**152**

Figure 19 below shows the overall levelised cost range based on the above analysis. We consider this an appropriate uncertainty range for levelised costs for FOAK ASC CCS plants commissioning in 2025. Table 85 shows that in the medium case around 25% to 55% of the levelised cost for ASC CCS plants is attributable to fuel and carbon prices based on the forecast price levels provided for this study. As such there may be further variance in levelised costs beyond the levels indicated by this analysis.

Figure 19 – ASC CCS FOAK LCOE



(d) Other CCS

Table 86 – other CCS FOAK medium case LCOE

Cost category	£/MWh	
	Biomass	OCGT
Pre-development	8	3
Construction	165	49
Fixed O+M	21	6
Variable O+M	8	3
Fuel	202	102
Carbon	0*	8
Capture and storage	42	13
Total	**447**	**183**

*Note that a biomass CCS plant would produce some carbon emissions that are not captured and stored. This follows DECC's modelling approach of treating non-biomass electricity generation technologies as carbon neutral. The potential benefits of biomass for negative emissions are not included in our analysis.

Figure 20 below shows the overall levelised cost range for biomass CCS on the above analysis. We consider this an appropriate uncertainty range for levelised costs for FOAK Biomass CCS plants commissioning in 2025. Table 86 shows that around 50% to 55% of the levelised cost for Biomass CCS plants is attributable to fuel and carbon prices based on the forecast price levels provided for this study. As such there may be further variance in levelised costs beyond the levels indicated by this analysis.

Figure 20 – biomass CCS FOAK LCOE

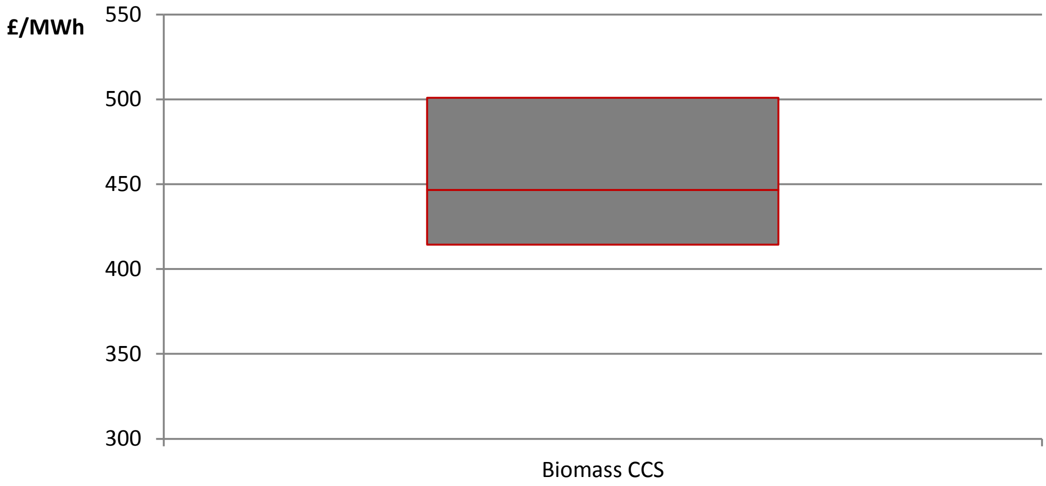


Figure 22 below shows the overall levelised cost range for OCGT CCS on the above analysis. We consider this an appropriate uncertainty range for levelised costs for FOAK OCGT CCS plants commissioning in 2025. Table 86 shows that around 55% to 65% of the levelised cost for OCGT CCS plants is attributable to fuel and carbon prices based on the forecast price levels provided for this study. As such there may be further variance in levelised costs beyond the levels indicated by this analysis.

Our LCOE analysis of biomass CCS results in significant from the previous DECC results. As this is larger than other changes in LCOE from previous DECC results, we have considered the drivers of change in more detail. The chart below shows the difference in LCOE from the previous biomass parameters, run at the same hurdle rate and same fuel cost assumptions, to the current biomass LCOE.

Figure 21 – drivers of change in biomass LCOE

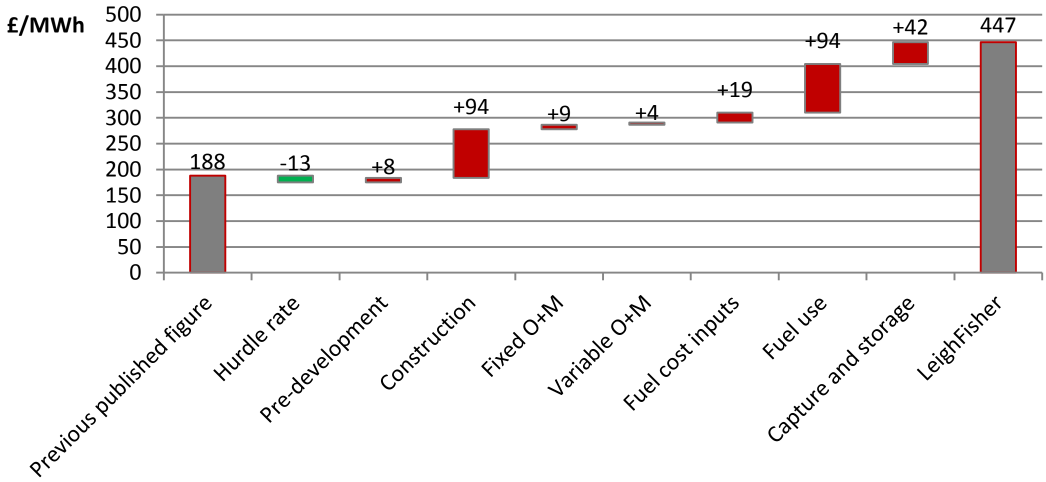
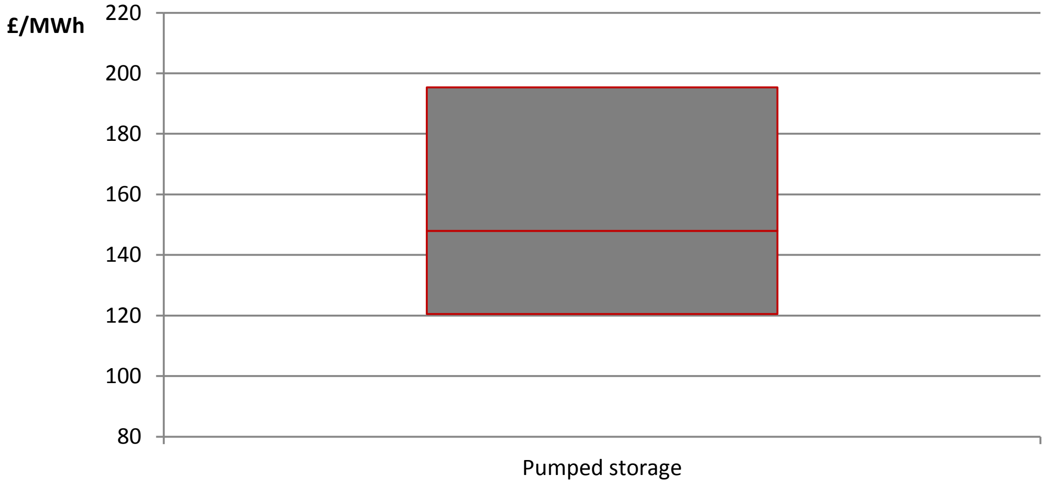


Table 87 – drivers of change in biomass LCOE

Cost category	Impact on LCOE and reasons for change
Hurdle rate	The previous numbers were at a different hurdle rate. Updating the hurdle rates reduces the costs.
Pre-development costs	The previous numbers did not allow for pre-development costs. We consider it appropriate to include a pre-development cost allowance in line with the proportion of construction costs under other CCS technologies
Construction	We developed our construction costs for the reference plant using Arup's cost numbers for a small scale biomass CHP unit with a cost reduction of 40% to represent the economies of scale of moving to a larger scale unit. We developed a bottom up estimate for the costs of the CCS units. We have calculated the £/kW by dividing this sum by the estimated power output of the plant. As discussed in 8.3.1, the power output is lower than previous estimates because of the higher parasitic load. If the parasitic load was the same level as previous estimates, the capital cost would be around £6,000 per kW. This would result in an increase in LCOE owing to an increase in construction costs of around £44/MWh rather than £94/MWh.
Fixed O+M	As with construction, the lower power output drives a higher £/kW for fixed O&M. If the parasitic load was the same level as previous estimates, the fixed cost would be around £120,000 per MW. This would result in an increase in LCOE owing to an increase in fixed operating costs of around £4/MWh rather than £9/MWh. The remainder is inclusion of insurance costs and connection costs, which were not allowed for in the previous LCOE.
Variable O+M	The majority of the difference in variable O&M is the inclusion of BSUoS, which was not allowed for in the previous LCOE.
Fuel cost inputs	DECC has provided updated fuel cost inputs for biomass. These lead to an increase in fuel costs.
Fuel use	The efficiency is lower than the previous estimates because of the higher parasitic load. The previous estimates did not appear to include any reduction in efficiency. This drives higher fuel use and hence higher fuel costs. If the efficiency was the same as previous estimates, the fuel use would be unchanged.
Capture and storage	The previous numbers did not allow for capture and storage operating costs.

Figure 22 – OCGT CCS FOAK LCOE



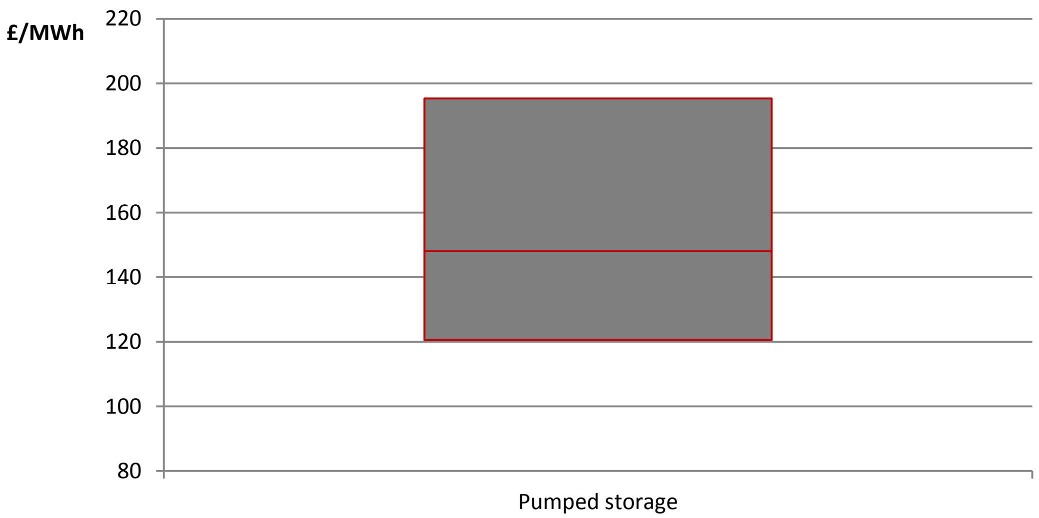
12.1.7 Pumped storage

Table 88 – pumped storage medium case LCOE

Cost category	£/MWh
	LF 2014 prices
Pre-development	5
Construction	85
Fixed O+M	17
Variable O+M	42
Fuel	0
Carbon	0
Total	**148**

Figure 23 below shows the overall levelised cost range based on the above analysis. We consider this an appropriate uncertainty range for levelised costs for a pumped storage plant commissioning in 2025. Table 88 shows that none of the levelised cost for pumped storage plants is attributable to fuel and carbon price based on the forecast price levels provided for this study. However, around 40% is variable O&M, which is linked to the wholesale electricity price, which could vary over the forecasts provided by DECC for the next 20 years. As such there may be further variance in levelised costs beyond the range indicated by this analysis.

Figure 23 – pumped storage LCOE



Appendix A Other cost data

A.1 Additional costs

We have also considered a range of other costs that are not included in the levelised cost analysis: land costs, business rates and contingency.

A.1.1 Land

We have taken the current average value for consented industrial land in England from "Land value estimates for policy appraisal"[28], £482,000 per hectare, as our low estimate. We have taken a medium case of two times the low case and a high case of four times the low case based on in house data.

Table 89 – land cost per hectare

Estimate (£/Ha)	Low	Med	High
Land cost	482,000	964,000	1,928,000

We then apply these land costs to our land area estimates for the cost per plant. For illustration of a potential range we have aligned low land area with low land cost, medium with medium and high with high. In practice there may be no correlation.

Table 90 – land cost per plant

Power plant	Land area (Ha)			Land cost (£/plant)		
	Low	Med	High	Low	Med	High
CCGT F Class	10	10	10	4,820,000	9,640,000	19,280,000
CCGT H Class	10	10	10	4,820,000	9,640,000	19,280,000
OCGT 600 MW	3	5	6	1,446,000	4,820,000	11,568,000
OCGT 400 MW	3	5	6	1,446,000	4,820,000	11,568,000
OCGT 299 MW	3	5	6	1,446,000	4,820,000	11,568,000
OCGT 100 MW	3	5	6	1,446,000	4,820,000	11,568,000
Gas reciprocating engine	1	1	1	482,000	964,000	1,928,000
Diesel reciprocating engine	1	1	1	482,000	964,000	1,928,000
CHP	3	5	6	1,446,000	4,820,000	11,568,000
CHP power only	3	5	6	1,446,000	4,820,000	11,568,000
Nuclear	60	70	80	28,920,000	67,480,000	154,240,000
CCGT – post combustion	13	14	15	6,266,000	13,496,000	28,920,000
CCGT – pre combustion	12	13	14	5,784,000	12,532,000	26,992,000
CCGT – oxyfuel	11	12	13	5,302,000	11,568,000	25,064,000
CCGT – retro post combustion	13	14	15	6,266,000	13,496,000	28,920,000
ASC CCS	20	22	24	9,640,000	21,208,000	46,272,000
IGCC CCS	13	14	15	6,266,000	13,496,000	28,920,000
Pumped storage	80	100	120	38,560,000	96,400,000	231,360,000

[28] Land value estimates for policy appraisal 2014, Department for Communities and Local Government

A.1.2 Business Rates

We have reviewed business rates from the Valuation Office Agency for recently constructed plants and in house data. This data suggests that business rates (£/MW/year) are 8.5 (low), 9 (medium) and 9.5 (high) times the construction cost (£/kW). For illustration of a potential range we have aligned low construction cost with a low business rates multiplier, medium with medium and high with high. In practice there may be no correlation.

Table 91 – business rates estimates

Power plant	Business rates (£/MW/year)		
	Low	Med	High
CCGT F Class	3,426	4,275	5,187
CCGT H Class	3,732	4,644	5,634
OCGT 600 MW	2,407	2,617	2,793
OCGT 400 MW	2,467	2,967	3,518
OCGT 299 MW	2,565	3,612	6,109
OCGT 100 MW	4,901	5,622	7,396
Gas reciprocating engine	2,346	2,700	3,078
Diesel reciprocating engine	1,955	2,250	2,565
CHP	5,219	6,498	7,885
CHP power only	4,191	5,220	6,337
Nuclear (FOAK)	31,297	36,891	48,583
Nuclear (NOAK)	28,491	33,887	44,921
CCGT – post combustion	14,692	18,856	25,841
CCGT – pre combustion	14,294	18,323	25,066
CCGT – oxyfuel	14,661	18,827	25,745
CCGT – retro post combustion	9,824	12,518	16,747
ASC – post combustion	28,451	35,304	47,824
ASC – partial post combustion	20,900	25,473	34,803
ASC – with ammonia	30,532	37,935	51,357
ASC - retrofit	28,578	37,572	51,984
ASC – oxyfuel combustion	17,466	23,011	32,389
IGCC – partial CCS	16,025	21,109	28,133
IGCC – CCS	25,204	31,642	42,628
IGCC – retro CCS	28,940	37,956	52,544
Pumped storage	6,350	9,288	14,412

A.2 Contingency

We have also considered contingency that a developer may include in its budget at FID. This is not an additional cost, as it is likely to be included in the original project budget. Whether contingency is used or not will partly define where a project sits in the low, medium and high range.

Our estimates of contingency represent the proportion of a project budget that may be set aside as contingency at FID. This contingency may or may not be used over the construction period. It is not additional to the construction costs provided elsewhere in the report. Our contingency estimates are based on our experience of power construction projects, taking in to account the likely range of project specific uncertainties. Nuclear and CCS have greater technology uncertainty, and pumped storage and nuclear are of larger scale and longer timelines, so we have proposed higher for these projects.

Table 92 – Contingency estimates

Power plant	Contingency (% of budget at FID)		
	Low	Med	High
Gas	5%	7.5%	10%
Nuclear	7.5%	10%	15%
CCS	7.5%	10%	15%
Pumped storage	7.5%	10%	10%

Appendix B Cost estimate classification

As stated in 1.2.2, our cost estimates are stated to Class 4 level of accuracy in the AACE International Recommended Practice No. 18R-97: Cost Estimate Classification System shown in Table 93below.

Table 93 – cost estimate classification system

Primary Characteristics		Secondary Characteristics			
Estimate Class	**Level of project definition Expressed as % of complete definition**	**End Usage Typical purpose of estimate**	**Methodology Typical estimating method**	**AACE expected accuracy range Typical variation in low and high ranges (see Note below)**	**Jacobs expected overall accuracy range**
Class 5 (Order of Magnitude)	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgement or Analogy	L: -20% to -50% H: +30% to +100%	- 50% to +50%
Class 4 (Preliminary)	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	- 30% to + 40%
Class 3 (Early Budget)	10% to 40%	Budget, Authorisation, or Control	Semi-detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	- 20% to + 30%
Class 2 (Budget/ Control)	30% to 70%	Control or Bid/Tender	Detailed Unit Cost with Forced Detailed Take-off	L: -5% to -15% H: +5% to +20%	- 10% to + 15%
Class 1 (Definitive/ Construction)	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-off	L: -3% to -10% H: +3% to +15%	- 5% to + 5%

Note: The Expected Accuracy Ranges stated in the above matrix reflect those included in the Cost Estimate Classification Matrix for the Process Industries, incorporated in AACE International Recommended Practice No. 18R-97: Cost Estimate Classification System – as applied in Engineering, Procurement and Construction for the Process Industries, dated February 02, 2005. They reflect data from a wide variety of companies and estimating/data-gathering procedures.

The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of AFU typically at a 50% probability of under-run/overrun for given scope.

Appendix C Use of System costs

The following categories of Use of System charges are included in our analysis:

- *Transmission Network Use of System charges (TNUoS) – these are ex-ante published tariffs levied by the Transmission System Operator under the terms of the Connection and Use of System Code (CUSC) for use of the transmission system. Such charges are levied on a £/kW basis.*
- *Distribution Use of System charges (DUoS) - these are ex-ante published tariffs levied by each of the fourteen Distribution Network Operators under the terms of the Distribution Connection and Use of System Agreement (DCUSA) for use of their DNO system. Such charges comprise p/kWh, p/kVA and p/kVA/day tariffs.*
- *Balancing Services Use of System charges (BSUoS) – ex-post charges charged at £/MWh rate to all generators and off-takers which reflects the actual balancing costs incurred by the System Operator in each half-hour settlement period.*

The following sections provide further details on the assumptions we have made in calculating appropriate use-of-system charges for each sector.

C.1 Transmission Network Use of System Charges

Transmission Network Use of System Charges (TNUoS) for transmission-connected generators are charged on a locational basis with 27 separate geographical zones in the GB mainland. The charges are levied on a £/kW basis. National Grid publishes forecast tariffs for each zone for 4yrs ahead and provides a tool on its web-site to enable users to determine TNUoS costs on a site specific basis under the new charging regime following approval of CMP213. We have used National Grid's tool for the purposes of calculating tariffs for this study and, for consistency, have used the assumptions for load factor values as stated elsewhere in this report (rather than the generic values included within that tool's data set).

For TNUoS charging purposes, embedded generators (i.e., generators connected to the distribution network rather than the transmission network) are treated as negative demand and TNUoS charges are effectively payments to the generators based on actual output during the three Triad periods in any year. For demand charges there are 14 separate geographical zones (corresponding to the 14 DNO areas). For the purposes of this study, reciprocating engines are assumed to be embedded generators and Triad avoidance charges calculated accordingly. An average performance during Triad periods of 90% of capacity is assumed in all cases irrespective of load factor[29].

C.2 Distribution Use of System Charges

Embedded generators (i.e., generators connected to the distribution network rather than the transmission network), would be subject to Distribution Use of System Charges (DUoS) applicable to the Distribution Network Operator (DNO) zone in which they were connected. All 14 DNOs use charging models based on the same methodologies (EHV Distribution Charging Methodology (EDCM) for EHV-connected customers and Common Distribution Charging Methodology (CDCM) for all other customers). For this study we have used an average for all DNOs of EHV tariffs published in the

[29] As an indication, a generator running 2hrs per weekday from December to February, excluding the 2 week Christmas break, would account for around 100hrs operation. Thus the 90hr pa scenario considered in this study would reasonably be expected to capture the three Triad periods under such an operating strategy.

current Charging Statements. Such charges comprise p/kWh, p/kVA/day and p/day tariffs which we have converted to equivalent £/kW based on the load factor assumptions described herein. (A summary of the published tariffs is also provided for information). If a generator were to connect at 11kV or 33kV, different tariffs would apply.

C.3 Zonal TNUoS plus DUoS charges

We have calculated aggregate TNUoS and DUoS costs for each zone.

For the purposes of our report, we make various assumptions about the likely locations of new developments in each sector based on existing plants or consented future developments. This ensures that the values are not unduly skewed by high tariffs for certain zones, for example in the north of Scotland, since non-renewable deployment (other than pumped storage) is unlikely in those zones

C.3.1 Central case assumptions

We have calculated aggregate TNUoS and DUoS costs for expected deployment on the following basis for the central case assessment:

- *CCGT and OCGT – unweighted average of TNUoS tariffs for all zones for which there is consented development with capacity on the Transmission Entry Capacity Register and/or existing sites (given the possibility that such sites may be re-planted)*
- *Reciprocating engines - average DUoS tariffs plus embedded benefits (TNUoS triad avoidance) on average basis for same zones as CCGT and OCGT*
- *Coal (retro-fit) – unweighted average of TNUoS tariffs for all zones with existing coal-fired capacity*
- *CCS – as for CCGT or coal above as appropriate*
- *Nuclear – unweighted average of TNUoS tariffs for all zones where development is planned (EdF, Horizon and NuGen sites)*
- *We have applied an unweighted average of TNUoS tariffs for all zones where there is potential for pumped storage development. For the planned Glyn Ronwy scheme, we anticipate TNUoS charges would be lower, at £8.98 per kW.*

C.3.2 Low and high case assumptions

The data at individual zone level has also been used to guide the selection of appropriate values for low and high cases. The low case is based on the rate for the second lowest cost zone and the high case is based on the rate for the second highest cost zone applicable to each sector. Using the second lowest/highest rates in this manner would give a reasonable indication of the range of potential rates without making an assumption of all prospective developments achieving the lowest/highest possible rates.

C.4 Balancing Services Use of System charges (BSUoS)

Unlike TNUoS and DUoS which are published ex-ante tariffs, BSUoS is calculated ex-post at half-hourly granularity on a £/MWh basis and chargeable at the same rate for all generation sectors and demand offtake. It is therefore recommended that this is treated as £/MWh opex cost for the purposes of DECC's LCM model. Accordingly the £/kW values for connection and UoS stated in the summary tables herein do not include BSUoS.

A forecast value of £1.90/MWh for the central case has been proposed which is consistent with recent values taken from the long-term trend of rolling annual average data. Low and high cases of £1.65/MWh and £2.15/MWh are proposed.

C.5 NTS and LDZ Charges

We do not include National Transmission System (NTS) charges or Local Distribution Zone (LDZ) charges in our analysis. It is assumed that such costs would be included within the "as delivered" fuel prices that are used as inputs to DECC's models and we have therefore not included them in costs.

The values of the use of system charges on this basis are set out below, broken down separately by TNUoS, DUoS and BSUoS.

C.6 Charging values

Table 94 – CMP213 methodology including circuit specific element

Technology	TNUoS tariff (£/kW p.a.)		
	Low	Central	High
CCGT, CHP	-9.00	3.28	23.01
Coal	-2.76	3.82	9.82
Nuclear	-3.54	0.49	3.06
OCGT 5.7%	-5.10	2.35	12.37
OCGT 22.8%	-4.79	2.53	14.45
Reciprocating engines (embedded) (all load factors)	-34.87	-28.58	-16.44
Pumped Storage	14.26	15.80	16.22

Table 95 – DUoS values

Technology	TNUoS tariff (£/kW p.a.)		
	Low	Central	High
Reciprocating engines (90hr p.a.)	0.12	0.59	1.03
Reciprocating engines 5.7%	--0.59	0.05	2.11
Reciprocating engines 22.8%-	-5.12	-3.36	0.65

Table 96 – aggregate TNUoS plus DUoS values

Technology	TUoS + DUoS tariff (£/kW p.a.)		
	Low	Central	High
CCGT, CHP	-9.00	3.28	23.01
Coal	-2.76	3.82	9.82
Nuclear	-3.54	0.49	3.06
OCGT 5.7%	-5.10	2.35	12.37
OCGT 22.8%	-4.79	2.53	14.45
Reciprocating engines (90hr p.a.)	-34.75	-27.99	-14.17
Reciprocating engines 5.7%	--35.46	-28.53	-14.33
Reciprocating engines 22.8%%	-39.99	-31.94	-15.83
Pumped Storage	14.26	15.80	16.22

Table 97 – BSUoS values

BSUoS tariff (£/MWh)		
Low	Central	High
1.65	1.90	2.15

C.7 Tariff information used to calculate Use of System Charges

The following tables provide the underlying tariff forecasts used to calculate the Use-of-System Charges set out in this Appendix (relevant zones for each technology have been identified as per the principles set out in section 1.2.6 and published forecast tariffs for the next four years have been averaged for these zones).

Table 98 – TNUoS zonal generation tariffs under CMP213 methodology plus circuit specific element (£/kW)

Zone		CCGT,CHP Average	Coal Average	Nuclear Average	OCGT 5.7%	OCGT 22.8%
1	North Scotland					
2	East Aberdeenshire	£25.09			£17.56	£19.03
3	Western Highlands					
4	Skye and Lochalsh					
5	Eastern Grampian and Tayside					
6	Central Grampian					
7	Argyll					
8	The Trossachs					
9	Stirlingshrie and Fife		£21.89			
10	South West Scotland	£23.01			£12.37	£14.45
11	Lothian and Borders	£18.29			£7.64	£9.73
12	Solway and Cheviot					
13	North East England	£9.89	£9.82	£10.37	£6.85	£7.44
14	North Lancashire and The Lakes	£5.97			£2.93	£3.53
15	South Lancashire, Yorkshire and Humber	£4.56	£4.28		£4.33	£4.37
16	North Midlands and North Wales	£1.97	£1.99		£2.92	£2.74
17	South Lincolnshire and North Norfolk	£0.65			£1.50	£1.33
18	Mid Wales and The Midlands	-£0.23	-£0.21	-£0.22	£0.54	£0.39
19	Anglesey and Snowdon			£3.06		
20	Pembrokeshire	£3.22			£7.47	£6.64
21	South Wales	£0.49	£0.52		£4.81	£3.96
22	Cotswold	-£3.51		-£3.54	-£5.10	-£4.79
23	Central London	-£9.61			-£11.19	-£10.89
24	Essex and Kent	-£2.71	-£2.76		-£4.30	-£3.99
25	Oxfordshire, Surrey and Sussex	-£5.14	-£5.01		-£2.45	-£2.98
26	Somerset and Wessex	-£7.19		-£7.23	-£3.22	-£4.00
27	West Devon and Cornwall	-£9.00			-£2.74	-£3.97

Table 99 – TNUoS zonal generation tariffs (£/kW) (applicable to Triad avoidance)

Zone	DNO	TNUoS DEMAND £/kW
1	SHEPD	15.21
2	SP	16.44
3	Northern	24.57
4	ENW	27.15
5	Yorkshire	27.61
6	Manweb	27.29
7	East Midlands	30.11
8	West Midlands	30.78
9	Eastern	31.71
10	South Wales	29.24
11	South Eastern	34.27
12	London	35.66
13	Southern	35.20
14	SWEB	34.87
AVERAGE		**28.58**

Table 100 – DUoS values

Zone	DNO	Export Super Red unit rate (p/kWh)	Export fixed charge (p/day)	Export capacity rate (p/kVA/day)
1	SHEPD	0.00	4,291	0.07
2	SP	-0.09	12,319	0.05
3	Northern	-0.07	3,490	0.07
4	ENW	-0.47	2,822	0.07
5	Yorkshire	-0.12	2,571	0.05
6	Manweb	-0.59	1,752	0.04
7	East Midlands	0.00	1,196	0.06
8	West Midlands	-0.02	1,100	0.07
9	Eastern	-0.38	1,249	0.05
10	South Wales	-0.20	864	0.05
11	South Eastern	-0.63	1,319	0.04
12	London	0.00	8,623	0.05
13	Southern	-0.04	1,383	0.05
14	SWEB	-0.27	832	0.06
AVERAGE		**-0.21**	**3,130**	**0.06**

For a 20 MW generator, this would result in a variable charge of -£2.07[30] and a fixed charge of £15,488 p.a.[31].

[30] average charge of -0.21 x 1000 (convert to p/MWh) / 100 (convert to £/MWh)
[31] Export charge of 3,130 x 365 (convert to p/year) / 100 (convert to £/year) = £11,423
Export capacity rate of 0.06 x 20,000 (convert to 20 MW generator) / 365 (convert to £/year) / 100 (convert to £/year) = 4065

Appendix D Coal cost assumptions

NOx Control Technique	Description	Indicative Performance (mg/Nm3 @ 6% O2)	Indicative Cost for a 500 MW unit (£m)	NOx Control Technique
Low NOx Burners (LNB)	First burners fitted intended to stage combustion by controlling air addition. Latest burners can stage fuel as well as air and improve performance.	600 mg/Nm^3 for the 1990's LNBs	Already fitted	Will not meet IED 200 mg/Nm^3 requirement.
Low NOx Burners with Over Fire Air (OFA) and Boosted Over Fire Air (BOFA)	Addition of last 15% of combustion air above the primary combustion zone. This is an addition to a low NOx burner system	400 – 500 mg/Nm^3	£10 - £12	Will not meet IED 200 mg/Nm^3 requirement. Upgrade of existing systems will be less
Re-burn	Injection of low nitrogen fuel such as gas above low NOx burners and below over fire air. UK existing boilers do not have sufficient furnace height.	200 - 250 mg/Nm^3	Not Applicable, cannot be fitted	Could approach IED limits but the option is not practical for retrofitting.
Selective Non Catalytic Reduction **SNCR**	Would be fitted after burners and OFA system. Inject ammonia or urea into flue gas at around 870 - 1150ºC. Reagent converts NOx to nitrogen & water.	30 - 50% reduction of LNB emissions 200 - 350 mg/Nm^3	£15	Require multiple injection points to be operable over a range of output. Cost includes the ammonia storage system.
Selective Catalytic Reduction **SCR**	Injecting ammonia or urea into flue gas and reacting over a catalyst. Reagent converts NOx into nitrogen and water. Usually installed before air preheater with flue gas temperature of 350-400ºC. The SCR can also be installed after precipitators at around 130ºC.	80 - 95% reduction of LNB emissions 50 - 100 mg/Nm^3	£70 - £90*	Requires major modifications to extract and return flue gas and then a separate containment for the catalyst. Needs upgrade of the induced draught fans
Hybrid SNCR and SCR	Combination of Low NOx burners, OFA, SNCR and SCR. The SCR does not have to be full scale because the inlet NOx has been reduced by burners and SNCR. Will only be possible if the boiler can be adapted to allow space for the SCR.	Overall performance adjusted to meet IED, 200 mg/Nm^3	£45 - £65*	May be possible to avoid the need for an additional SCR containment. Fitting in existing gas passes would be cheaper.

*Includes allowance for improving combustion including LNB upgrades, mill classifiers, ignition burners etc to improve NOx performance of combustion systems to save ammonia injection in the SNCR/SCR and to avoid combustion deposits on catalyst.

Appendix E Gas turbine references

Manufacturer	Model	CCGT H class	CCGT F class	100MW OCGT	300MW OCGT	400MW OCGT	600MW OCGT	CHP
Siemens	SGT5-8000H	×				×		
	SGT5-4000F		×		×		×	
	SGT5-2000E				×			
	SGT 800			×				×
	Trent 60 DLE			×				
General Electric	9HA.01	×				×		
	93741 FB		×					
	9F.05				×		×	
	9E.03					×		×
	6F.03			×				
	LMS100-PB			×	×			
Alstom Power	GT13E2 2012					×		
	GT 26		×					
Mitsubishi Heavy Industries	701F4		×				×	

Appendix F CCGT parameter summary

CCGT 1,200 MW H class		1st OF A KIND Low	Medium	High	Nth OF A KIND Low	Medium	High
Key Timings							
Total Pre-development Period	years	2.0	2.3	5.0	2.0	2.3	5.0
Construction Period	years	2.0	2.5	3.0	2.0	2.5	3.0
Plant Operating Period	years	20.0	25.0	35.0	20.0	25.0	35.0
Technical data							
NET Power Output	MW	1,190	1,200	1,210	1,190	1,200	1,210
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	58.8%	59.8%	60.7%	58.8%	59.8%	60.7%
Average availability	%	92.3%	93.0%	93.6%	92.3%	93.0%	93.6%
Average load factor	%	100%	100%	100%	100%	100%	100%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	5.3	10.8	13.6	5.3	10.8	13.6
Regulatory + licensing + public enquiry	£/kW	0.3	0.4	3.6	0.3	0.4	3.6
Construction costs							
Capital cost (excluding interest during construction)	£/kW	439	516	593	439	516	593
Infrastructure cost	£'000	7,553	15,105	30,210	7,553	15,105	30,210
Operating costs							
O&M fixed fee	£ / MW / Year	9,770	12,240	14,670	9,770	12,240	14,670
O&M variable fee (excl BSUoS)	£ / MWh	1.22	1.43	1.83	1.22	1.43	1.83
Insurance	£ / MW / Year	1,317	2,064	2,965	1,317	2,064	2,965
Connection and UoS charges	£ / MW / Year	(9,000)	3,280	23,010	(9,000)	3,280	23,010

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CCGT 1,400 MW F class		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	2.0	2.3	5.0	2.0	2.3	5.0
Construction Period	years	2.0	2.5	3.0	2.0	2.5	3.0
Plant Operating Period	years	20.0	25.0	35.0	20.0	25.0	35.0
Technical data							
NET Power Output	MW	1,340	1,471	1,370	1,340	1,471	1,370
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	57.4%	58.8%	60.0%	57.4%	58.8%	60.0%
Average availability	%	91.7%	92.6%	93.6%	91.7%	92.6%	93.6%
Average load factor	%	100%	100%	100%	100%	100%	100%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	4.8	10.0	11.5	4.8	10.0	11.5
Regulatory + licensing + public enquiry	£/kW	0.3	0.3	3.3	0.3	0.3	3.3
Construction costs							
Capital cost (excluding interest during construction)	£/kW	403	475	546	403	475	546
Infrastructure cost	£'000	7,553	15,105	30,210	7,553	15,105	30,210
Operating costs							
O&M fixed fee	£ / MW / Year	9,131	11,440	13,710	9,131	11,440	13,710
O&M variable fee (excl BSUoS)	£ / MWh	1.14	1.43	1.71	1.14	1.43	1.71
Insurance	£ / MW / Year	1,209	1,900	2,730	1,209	1,900	2,730
Connection and UoS charges	£ / MW / Year	(9,000)	3,280	23,010	(9,000)	3,280	23,010

CHP (in Power only mode)		1st OF A KIND Low	Medium	High	Nth OF A KIND Low	Medium	High
Key Timings							
Total Pre-development Period	years	2.0	2.3	5.0	2.0	2.3	5.0
Construction Period	years	2.0	2.5	3.0	2.0	2.5	3.0
Plant Operating Period	years	20.0	25.0	35.0	20.0	25.0	35.0
Technical data							
NET Power Output	MW	198	227	255	198	227	255
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	51.6%	51.7%	51.7%	51.6%	51.7%	51.7%
Average availability	%	92.3%	93.0%	93.6%	92.3%	93.0%	93.6%
Average load factor	%	100%	100%	100%	100%	100%	100%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	26.6	51.6	62.7	26.6	51.6	62.7
Regulatory + licensing + public enquiry	£/kW	0.1	0.2	16.7	0.1	0.2	16.7
Construction costs							
Capital cost (excluding interest during construction)	£/kW	493	580	667	493	580	667
Infrastructure cost	£'000	6,785	13,570	27,140	6,785	13,570	27,140
Operating costs							
O&M fixed fee	£ / MW / Year	11,650	23,565	35,670	11,650	23,565	35,670
O&M variable fee (excl BSUoS)	£ / MWh	1.46	2.95	4.45	1.46	2.95	4.45
Insurance	£ / MW / Year	1,479	2,320	3,335	1,479	2,320	3,335
Connection and UoS charges	£ / MW / Year	(9,000)	3,280	23,010	(9,000)	3,280	23,010

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CHP (in CHP mode)		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	2.0	2.3	5.0	2.0	2.3	5.0
Construction Period	years	2.0	2.5	3.0	2.0	2.5	3.0
Plant Operating Period	years	20.0	25.0	35.0	20.0	25.0	35.0
Technical data							
NET Power Output	MW	146	168	190	146	168	190
Average Steam Output	MW (thermal)	163	182	200	163	182	200
Steam take up	%	100%	100%	100%	100%	100%	100%
Net Efficiency (LHV)	%	37.9%	38.2%	38.5%	37.9%	38.2%	38.5%
Average availability	%	92.3%	93.0%	93.6%	92.3%	93.0%	93.6%
Average load factor	%	100%	100%	100%	100%	100%	100%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	33.2	64.3	78.0	33.2	64.3	78.0
Regulatory + licensing + public enquiry	£/kW	0.2	0.2	0.2	0.2	0.2	0.2
Construction costs							
Capital cost (excluding interest during construction)	£/kW	614	722	830	614	722	830
Infrastructure cost	£'000	6,785	13,570	27,140	6,785	13,570	27,140
Operating costs							
O&M fixed fee	£ / MW / Year	12,459	28,222	42,719	12,459	28,222	42,719
O&M variable fee (excl BSUoS)	£ / MWh	1.87	3.53	5.34	1.87	3.53	5.34
Insurance	£ / MW / Year	2,022	2,888	4,150	2,022	2,888	4,150
Connection and UoS charges	£ / MW / Year	(9,000)	3,280	23,010	(9,000)	3,280	23,010

Appendix G OCGT parameter summary

OCGT 600 MW (critical peak, 500 hours p.a.)		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	1.5	1.8	4.5	1.5	1.8	4.5
Construction Period	years	1.5	2.0	2.5	1.5	2.0	2.5
Plant Operating Period	years	20.0	25.0	35.0	20.0	25.0	35.0
Technical data							
NET Power Output	MW	602	625	664	602	625	664
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	38.3%	39.2%	39.9%	38.3%	39.2%	39.9%
Average availability	%	92.9%	96.4%	97.7%	92.9%	96.4%	97.7%
Average load factor	%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	15.4	17.5	21.8	15.4	17.5	21.8
Regulatory + licensing + public enquiry	£/kW	2.1	2.4	3.1	2.1	2.4	3.1
Construction costs							
Capital cost (excluding interest during construction)	£/kW	283	291	294	283	291	294
Infrastructure cost	£'000	7,553	15,105	30,210	7,553	15,105	30,210
Operating costs							
O&M fixed fee	£ / MW / Year	3,643	4,564	5,470	3,643	4,564	5,470
O&M variable fee (excl BSUoS)	£ / MWh	0.68	0.88	1.02	0.68	0.88	1.02
Insurance	£ / MW / Year	850	1,163	1,470	850	1,163	1,470
Connection and UoS charges	£ / MW / Year	(5,100)	2,350	12,370	(5,100)	2,350	12,370

OCGT 600 MW (peaking, 2,000 hours p.a.)		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	1.5	1.8	4.5	1.5	1.8	4.5
Construction Period	years	1.5	2.0	2.5	1.5	2.0	2.5
Plant Operating Period	years	20.0	25.0	35.0	20.0	25.0	35.0
Technical data							
NET Power Output	MW	602	625	664	602	625	664
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	38.3%	39.2%	39.9%	38.3%	39.2%	39.9%
Average availability	%	91.4%	94.9%	96.2%	91.4%	94.9%	96.2%
Average load factor	%	22.8%	22.8%	22.8%	22.8%	22.8%	22.8%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	15.4	17.5	21.8	15.4	17.5	21.8
Regulatory + licensing + public enquiry	£/kW	2.1	2.4	3.1	2.1	2.4	3.1
Construction costs							
Capital cost (excluding interest during construction)	£/kW	283	291	294	283	291	294
Infrastructure cost	£'000	7,553	15,105	30,210	7,553	15,105	30,210
Operating costs							
O&M fixed fee	£ / MW / Year	5,465	6,846	8,205	5,465	6,846	8,205
O&M variable fee (excl BSUoS)	£ / MWh	0.68	0.88	1.02	0.68	0.88	1.02
Insurance	£ / MW / Year	850	1,163	1,470	850	1,163	1,470
Connection and UoS charges	£ / MW / Year	(4,790)	2,530	14,450	(4,790)	2,530	14,450

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OCGT 400 MW (critical peak, 500 hours p.a.)		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	1.5	1.8	4.5	1.5	1.8	4.5
Construction Period	years	1.5	2.0	2.5	1.5	2.0	2.5
Plant Operating Period	years	20.0	25.0	35.0	20.0	25.0	35.0
Technical data							
NET Power Output	MW	399	400	400	399	400	400
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	34.6%	38.1%	40.8%	34.6%	38.1%	40.8%
Average availability	%	92.9%	96.4%	97.7%	92.9%	96.4%	97.7%
Average load factor	%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	20.8	23.6	29.4	20.8	23.6	29.4
Regulatory + licensing + public enquiry	£/kW	2.1	2.4	3.1	2.1	2.4	3.1
Construction costs							
Capital cost (excluding interest during construction)	£/kW	290	330	370	290	330	370
Infrastructure cost	£'000	7,553	15,105	30,210	7,553	15,105	30,210
Operating costs							
O&M fixed fee	£ / MW / Year	4,161	5,213	6,248	4,161	5,213	6,248
O&M variable fee (excl BSUoS)	£ / MWh	0.78	1.01	1.17	0.78	1.01	1.17
Insurance	£ / MW / Year	871	1,319	1,852	871	1,319	1,852
Connection and UoS charges	£ / MW / Year	(5,100)	2,350	12,370	(5,100)	2,350	12,370

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OCGT 400 MW (peaking, 2,000 hours p.a.)		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	1.5	1.8	4.5	1.5	1.8	4.5
Construction Period	years	1.5	2.0	2.5	1.5	2.0	2.5
Plant Operating Period	years	20.0	25.0	35.0	20.0	25.0	35.0
Technical data							
NET Power Output	MW	399	400	400	399	400	400
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	34.6%	38.1%	40.8%	34.6%	38.1%	40.8%
Average availability	%	91.4%	94.9%	96.2%	91.4%	94.9%	96.2%
Average load factor	%	22.8%	22.8%	22.8%	22.8%	22.8%	22.8%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	20.8	23.6	29.4	20.8	23.6	29.4
Regulatory + licensing + public enquiry	£/kW	2.1	2.4	3.1	2.1	2.4	3.1
Construction costs							
Capital cost (excluding interest during construction)	£/kW	290	330	370	290	330	370
Infrastructure cost	£'000	7,553	15,105	30,210	7,553	15,105	30,210
Operating costs							
O&M fixed fee	£ / MW / Year	6,242	7,820	9,372	6,242	7,820	9,372
O&M variable fee (excl BSUoS)	£ / MWh	0.78	1.01	1.17	0.78	1.01	1.17
Insurance	£ / MW / Year	871	1,319	1,852	871	1,319	1,852
Connection and UoS charges	£ / MW / Year	(4,790)	2,530	14,450	(4,790)	2,530	14,450

OCGT 300 MW (critical peak, 500 hours p.a.)		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	1.5	1.8	4.5	1.5	1.8	4.5
Construction Period	years	1.5	2.0	2.5	1.5	2.0	2.5
Plant Operating Period	years	20.0	25.0	35.0	20.0	25.0	35.0
Technical data							
NET Power Output	MW	292	311	302	292	311	302
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	38.3%	38.7%	42.2%	38.3%	38.7%	42.2%
Average availability	%	92.9%	96.4%	97.7%	92.9%	96.4%	97.7%
Average load factor	%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	24.7	28.0	34.9	24.7	28.0	34.9
Regulatory + licensing + public enquiry	£/kW	2.1	2.4	3.1	2.1	2.4	3.1
Construction costs							
Capital cost (excluding interest during construction)	£/kW	302	401	643	302	401	643
Infrastructure cost	£'000	6,785	13,570	27,140	6,785	13,570	27,140
Operating costs							
O&M fixed fee	£ / MW / Year	5,066	6,347	7,607	5,066	6,347	7,607
O&M variable fee (excl BSUoS)	£ / MWh	0.95	1.23	1.42	0.95	1.23	1.42
Insurance	£ / MW / Year	905	1,606	3,215	905	1,606	3,215
Connection and UoS charges	£ / MW / Year	(5,100)	2,350	12,370	(5,100)	2,350	12,370

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OCGT 300 MW (peaking, 2,000 hours p.a.)		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	1.5	1.8	4.5	1.5	1.8	4.5
Construction Period	years	1.5	2.0	2.5	1.5	2.0	2.5
Plant Operating Period	years	20.0	25.0	35.0	20.0	25.0	35.0
Technical data							
NET Power Output	MW	292	311	302	292	311	302
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	38.3%	38.7%	42.2%	38.3%	38.7%	42.2%
Average availability	%	91.4%	94.9%	96.2%	91.4%	94.9%	96.2%
Average load factor	%	22.8%	22.8%	22.8%	22.8%	22.8%	22.8%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	24.7	28.0	34.9	24.7	28.0	34.9
Regulatory + licensing + public enquiry	£/kW	2.1	2.4	3.1	2.1	2.4	3.1
Construction costs							
Capital cost (excluding interest during construction)	£/kW	302	401	643	302	401	643
Infrastructure cost	£'000	6,785	13,570	27,140	6,785	13,570	27,140
Operating costs							
O&M fixed fee	£ / MW / Year	7,600	9,521	11,411	7,600	9,521	11,411
O&M variable fee (excl BSUoS)	£ / MWh	0.95	1.23	1.42	0.95	1.23	1.42
Insurance	£ / MW / Year	905	1,606	3,215	905	1,606	3,215
Connection and UoS charges	£ / MW / Year	(4,790)	2,530	14,450	(4,790)	2,530	14,450

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OCGT 299 MW (critical peak, 500 hours p.a.)		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	1.5	1.8	4.5	1.5	1.8	4.5
Construction Period	years	1.5	2.0	2.5	1.5	2.0	2.5
Plant Operating Period	years	20.0	25.0	35.0	20.0	25.0	35.0
Technical data							
NET Power Output	MW	292	299	299	292	299	299
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	38.3%	38.7%	42.2%	38.3%	38.7%	42.2%
Average availability	%	92.9%	96.4%	97.6%	92.9%	96.4%	97.6%
Average load factor	%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	25.0	29.2	34.9	25.0	29.2	34.9
Regulatory + licensing + public enquiry	£/kW	2.1	2.5	3.1	2.1	2.5	3.1
Construction costs							
Capital cost (excluding interest during construction)	£/kW	305	418	643	305	418	643
Infrastructure cost	£'000	6,785	13,570	27,140	6,785	13,570	27,140
Operating costs							
O&M fixed fee	£ / MW / Year	5,083	6,368	7,633	5,083	6,368	7,633
O&M variable fee (excl BSUoS)	£ / MWh	0.95	1.23	1.42	0.95	1.23	1.42
Insurance	£ / MW / Year	905	1,606	3,215	905	1,606	3,215
Connection and UoS charges	£ / MW / Year	(5,100)	2,350	12,370	(5,100)	2,350	12,370

OCGT 299 MW (peaking, 2,000 hours p.a.)		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	1.5	1.8	4.5	1.5	1.8	4.5
Construction Period	years	1.5	2.0	2.5	1.5	2.0	2.5
Plant Operating Period	years	20.0	25.0	35.0	20.0	25.0	35.0
Technical data							
NET Power Output	MW	292	299	299	292	299	299
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	38.3%	38.7%	42.2%	38.3%	38.7%	42.2%
Average availability	%	91.4%	94.9%	96.2%	91.4%	94.9%	96.2%
Average load factor	%	22.8%	22.8%	22.8%	22.8%	22.8%	22.8%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
		25.0					
Pre-licensing costs, Technical and design	£/kW		29.2	34.9	25.0	29.2	34.9
Regulatory + licensing + public enquiry	£/kW	2.1	2.5	3.1	2.1	2.5	3.1
Construction costs							
Capital cost (excluding interest during construction)	£/kW	305	418	643	305	418	643
Infrastructure cost	£'000	6,785	13,570	27,140	6,785	13,570	27,140
Operating costs							
O&M fixed fee	£ / MW / Year	7,625	9,553	11,449	7,625	9,553	11,449
O&M variable fee (excl BSUoS)	£ / MWh	0.95	1.23	1.42	0.95	1.23	1.42
Insurance	£ / MW / Year	905	1,606	3,215	905	1,606	3,215
Connection and UoS charges	£ / MW / Year	(4,790)	2,530	14,450	(4,790)	2,530	14,450

OCGT 100 MW (critical peak, 500 hours p.a.)		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	1.5	1.8	4.5	1.5	1.8	4.5
Construction Period	years	1.5	2.0	2.5	1.5	2.0	2.5
Plant Operating Period	years	20.0	25.0	35.0	20.0	25.0	35.0
Technical data							
NET Power Output	MW	80	96	97	80	96	97
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	35.6%	39.2%	42.1%	35.6%	39.2%	42.1%
Average availability	%	92.9%	96.4%	97.7%	92.9%	96.4%	97.7%
Average load factor	%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	64.8	73.5	91.6	64.8	73.5	91.6
Regulatory + licensing + public enquiry	£/kW	2.1	2.4	3.1	2.1	2.4	3.1
Construction costs							
Capital cost (excluding interest during construction)	£/kW	577	625	779	577	625	779
Infrastructure cost	£'000	6,279	12,559	25,117	6,279	12,559	25,117
Operating costs							
O&M fixed fee	£ / MW / Year	7,885	9,879	11,840	7,885	9,879	11,840
O&M variable fee (excl BSUoS)	£ / MWh	1.48	1.91	2.22	1.48	1.91	2.22
Insurance	£ / MW / Year	1,730	2,499	3,893	1,730	2,499	3,893
Connection and UoS charges	£ / MW / Year	(5,100)	2,350	12,370	(5,100)	2,350	12,370

OCGT 100 MW (peaking, 2,000 hours p.a.)		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	1.5	1.8	4.5	1.5	1.8	4.5
Construction Period	years	1.5	2.0	2.5	1.5	2.0	2.5
Plant Operating Period	years	20.0	25.0	35.0	20.0	25.0	35.0
Technical data							
NET Power Output	MW	80	96	97	80	96	97
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	35.6%	39.2%	42.1%	35.6%	39.2%	42.1%
Average availability	%	91.4%	94.9%	96.2%	91.4%	94.9%	96.2%
Average load factor	%	22.8%	22.8%	22.8%	22.8%	22.8%	22.8%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	64.8	73.5	91.6	64.8	73.5	91.6
Regulatory + licensing + public enquiry	£/kW	2.1	2.4	3.1	2.1	2.4	3.1
Construction costs							
Capital cost (excluding interest during construction)	£/kW	577	625	779	577	625	779
Infrastructure cost	£'000	6,279	12,559	25,117	6,279	12,559	25,117
Operating costs							
O&M fixed fee	£ / MW / Year	11,828	14,818	17,760	11,828	14,818	17,760
O&M variable fee (excl BSUoS)	£ / MWh	1.48	1.91	2.22	1.48	1.91	2.22
Insurance	£ / MW / Year	1,730	2,499	3,893	1,730	2,499	3,893
Connection and UoS charges	£ / MW / Year	(4,790)	2,530	14,450	(4,790)	2,530	14,450

Appendix H Reciprocating engine parameter summary

Reciprocating Engine (diesel, critical peak, 90 hours p.a.)		1st OF A KIND Low	1st OF A KIND Medium	1st OF A KIND High	Nth OF A KIND Low	Nth OF A KIND Medium	Nth OF A KIND High
Key Timings							
Total Pre-development Period	years	1.0	2.0	3.0	1.0	2.0	3.0
Construction Period	years	0.3	0.5	0.7	0.3	0.5	0.7
Plant Operating Period	years	10.0	15.0	20.0	10.0	15.0	20.0
Technical data							
NET Power Output	MW	18	20	22	18	20	22
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	35.0%	36.0%	37.0%	35.0%	36.0%	37.0%
Average availability	%	92.6%	94.7%	96.4%	92.60%	94.7 %	96.4%
Average load factor	%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	8.1	10.0	13.5	8.1	10.0	13.5
Regulatory + licensing + public enquiry	£/kW	2.0	3.0	4.0	2.0	3.0	4.0
Construction costs							
Capital cost (excluding interest during construction)	£/kW	230	250	270	230	250	270
Infrastructure cost	£'000	432	2,160	6,480	432	2,160	6,480
Operating costs							
O&M fixed fee	£ / MW / Year	8,000	10,000	12,000	8,000	10,000	12,000
O&M variable fee (excl BSUoS)	£ / MWh	0.07	0.09	0.11	0.07	0.09	0.11
Insurance	£ / MW / Year	690	1,000	1,350	690	1,000	1,350
Connection and UoS charges	£ / MW / Year	(34,470)	(27,990)	(14,170)	(34,750)	(27,990)	(14,170)

Reciprocating Engine (diesel, critical peak, 500 hours p.a.)		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	1.0	2.0	3.0	1.0	2.0	3.0
Construction Period	years	0.3	0.5	0.7	0.3	0.5	0.7
Plant Operating Period	years	10.0	15.0	20.0	10.0	15.0	20.0
Technical data							
NET Power Output	MW	18	20	22	18	20	22
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	35.0%	36.0%	37.0%	35.0%	36.0%	37.0%
Average availability	%	92.6%	94.7%	97.0%	92.6%	94.7%	97.0%
Average load factor	%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	8.1	10.0	13.5	8.1	10.0	13.5
Regulatory + licensing + public enquiry	£/kW	2.0	3.0	4.0	2.0	3.0	4.0
Construction costs							
Capital cost (excluding interest during construction)	£/kW	230	250	270	230	250	270
Infrastructure cost	£'000	432	2,160	6,480	432	2,160	6,480
Operating costs							
O&M fixed fee	£ / MW / Year	8,000	10,000	12,000	8,000	10,000	12,000
O&M variable fee (excl BSUoS)	£ / MWh	0.07	0.09	0.11	0.07	0.09	0.11
Insurance	£ / MW / Year	690	1,000	1,350	690	1,000	1,350
Connection and UoS charges	£ / MW / Year	(35,460)	(28,530)	(14,330)	(35,460)	(28,530)	(14,330)

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Reciprocating Engine (diesel, peak, 2,000 hours p.a.)		1st OF A KIND Low	Medium	High	Nth OF A KIND Low	Medium	High
Key Timings							
Total Pre-development Period	years	1.0	2.0	3.0	1.0	2.0	3.0
Construction Period	years	0.3	0.5	0.7	0.3	0.5	0.7
Plant Operating Period	years	10.0	15.0	17.0	10.0	15.0	17.0
Technical data							
NET Power Output	MW	18	20	22	18	20	22
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	35.0%	36.0%	37.0%	35.0%	36.0%	37.0%
Average availability	%	92.2%	94.3%	95.7%	92.2%	94.3%	95.7%
Average load factor	%	23%	23%	23%	23%	23%	23%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	8.1	10.0	13.5	8.1	10.0	13.5
Regulatory + licensing + public enquiry	£/kW	2.0	3.0	4.0	2.0	3.0	4.0
Construction costs							
Capital cost (excluding interest during construction)	£/kW	230	250	270	230	250	270
Infrastructure cost	£'000	432	2,160	6,480	432	2,160	6,480
Operating costs							
O&M fixed fee	£ / MW / Year	8,000	10,000	12,000	8,000	10,000	12,000
O&M variable fee (excl BSUoS)	£ / MWh	0.07	0.09	0.11	0.07	0.09	0.11
Insurance	£ / MW / Year	690	1,000	1,350	690	1,000	1,350
Connection and UoS charges	£ / MW / Year	(39,990)	(31,940)	(15,830)	(39,990)	(31,940)	(15,830)

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Reciprocating Engine (gas, critical peak, 500 hours p.a.)		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	1.0	2.0	3.0	1.0	2.0	3.0
Construction Period	years	0.3	0.5	0.7	0.3	0.5	0.7
Plant Operating Period	years	10.0	15.0	20.0	10.0	15.0	20.0
Technical data							
NET Power Output	MW	18	20	22	18	20	22
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	35.0%	36.0%	37.0%	35.0%	36.0%	37.0%
Average availability	%	92.6%	94.7%	97%	92.6%	94.7%	97%
Average load factor	%	5.7%	5.7%	5.7%	5.7%	5.7%	5.7%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	8.1	10.0	13.5	8.1	10.0	13.5
Regulatory + licensing + public enquiry	£/kW	2.0	3.0	4.0	2.0	3.0	4.0
Construction costs							
Capital cost (excluding interest during construction)	£/kW	276	300	324	276	300	324
Infrastructure cost	£'000	688	3,439	10,318	688	3,439	10,318
Operating costs							
O&M fixed fee	£ / MW / Year	8,000	10,000	12,000	8,000	10,000	12,000
O&M variable fee (excl BSUoS)	£ / MWh	0.05	0.07	0.08	0.05	0.07	0.08
Insurance	£ / MW / Year	690	1,000	1,350	690	1,000	1,350
Connection and UoS charges	£ / MW / Year	(35,460)	(28,530)	(14,330)	(35,460)	(28,530)	(14,330)

Reciprocating Engine (gas, peak, 2,000 hours p.a.)		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	1.0	2.0	3.0	1.0	2.0	3.0
Construction Period	years	0.3	0.5	0.7	0.3	0.5	0.7
Plant Operating Period	years	10.0	15.0	17.0	10.0	15.0	17.0
Technical data							
NET Power Output	MW	18	20	22	18	20	22
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	35.0%	36.0%	37.0%	35.0%	36.0%	37.0%
Average availability	%	92.2%	94.3%	95.7%	92.2%	94.3%	95.7%
Average load factor	%	23%	23%	23%	23%	23%	23%
CO2 scrubbing	%						
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	8.1	10.0	13.5	8.1	10.0	13.5
Regulatory + licensing + public enquiry	£/kW	2.0	3.0	4.0	2.0	3.0	4.0
Construction costs							
Capital cost (excluding interest during construction)	£/kW	276	300	324	276	300	324
Infrastructure cost	£'000	688	3,439	10,318	688	3,439	10,318
Operating costs							
O&M fixed fee	£ / MW / Year	8,000	10,000	12,000	8,000	10,000	12,000
O&M variable fee (excl BSUoS)	£ / MWh	0.05	0.07	0.08	0.05	0.07	0.08
Insurance	£ / MW / Year	690	1,000	1,350	690	1,000	1,350
Connection and UoS charges	£ / MW / Year	(39,990)	(31,940)	(15,830)	(39,990)	(31,940)	(15,830)

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Appendix I Nuclear parameter summary

Nuclear		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	5.0	5.0	7.0	5.0	5.0	7.0
Construction Period	years	5.0	8.0	12.0	5.0	5.0	8.0
Plant Operating Period	years	60.0	60.0	60.0	60.0	60.0	60.0
Technical data							
NET Power Output	MW	3,300	3,300	3,300	3,300	3,300	3,300
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	-	-	-	-	-	-
Average availability	%	83.0%	90.2%	91.1%	83.0%	90.2%	91.1%
Average load factor	%	100%	100%	100%	100%	100%	100%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	110.0	233.0	635.0	53.1	124.6	433.6
Regulatory + licensing + public enquiry	£/kW	2.2	2.9	4.1	2.0	2.6	3.7
Construction costs							
Capital cost (excluding interest during construction)	£/kW	3,682	4,099	5,114	3,352	3,765	4,729
Infrastructure cost	£'000	0	11,500	50,000	0	11,500	50,000
Operating costs							
O&M fixed fee	£ / MW / Year	60,784	72,940	85,097	60,784	72,940	85,097
O&M variable fee (excl BSUoS)	£ / MWh	2.62	2.62	2.62	2.62	2.62	2.62
Insurance	£ / MW / Year	6,000	10,000	12,000	6,000	10,000	12,000
Connection and UoS charges	£ / MW / Year	(3,540)	490	3,060	(3,540)	490	3,060

Appendix J CCS parameter summary

CCGT Post-combustion		1st OF A KIND Low	1st OF A KIND Medium	1st OF A KIND High	Nth OF A KIND Low	Nth OF A KIND Medium	Nth OF A KIND High
Key Timings							
Total Pre-development Period	years	4.0	5.0	6.0	3.0	3.3	6.0
Construction Period	years	3.9	4.5	5.5	3.0	3.5	4.5
Plant Operating Period	years	20	25	35	20	25	35
Technical data							
NET Power Output	MW	963	963	963	963	963	963
Average Steam Output	MW (thermal)						
Steam take up	%						
Net Efficiency (LHV)	%	48.9%	48.9%	48.9%	48.9%	48.9%	48.9%
Average availability	%	84.8%	88.0%	91.5%	84.8%	88.0%	91.5%
Average load factor	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CO_2 scrubbing	%	89.6%	89.6%	89.6%	89.6%	89.6%	89.6%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	32.5	46.4	66.6	28.1	38.6	49.9
Regulatory + licensing + public enquiry	£/kW	0.9	1.0	11.2	0.8	0.9	8.7
Construction costs							
Capital cost (excluding interest during construction)	£/kW	1,728	2,095	2,720	1,527	1,747	2,046
Infrastructure cost	£'000	7,553	15,105	30,210	7,553	15,105	30,210
Operating costs							
O&M fixed fee	£ / MW / Year	25,698	30,979	36,220	24,583	29,668	34,712
O&M variable fee (excl BSUoS)	£ / MWh	2.89	3.36	4.01	2.89	3.36	4.01
Insurance	£ / MW / Year	4,861	7,398	10,151	4,258	6,480	8,921
Connection and UoS charges	£ / MW / Year	(9,000)	3,280	23,010	(9,000)	3,280	23,010

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CCGT Retrofit		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	3.0	4.0	5.5	3.0	3.3	6.0
Construction Period	years	3.5	4.0	5.5	3.0	3.5	4.5
Plant Operating Period	years	20	25	35	20	25	35
Technical data							
NET Power Output	MW	618	618	618	618	618	618
Average Steam Output	MW (thermal)						
Steam take up	%						
Net Efficiency (LHV)	%	48.9%	48.9%	48.9%	48.9%	48.9%	48.9%
Average availability	%	84.8%	88.0%	91.5%	84.8%	88.0%	91.5%
Average load factor	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CO2 scrubbing	%	89.6%	89.6%	89.6%	89.6%	89.6%	89.6%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	19.4	31.4	47.6	16.0	24.5	33.4
Regulatory + licensing + public enquiry	£/kW	0.1	0.1	0.8	0.1	0.1	0.6
Construction costs							
Capital cost (excluding interest during construction)	£/kW	1,156	1,391	1,763	958	1,085	1,237
Infrastructure cost	£'000	0	0	0	0	0	0
Operating costs							
O&M fixed fee	£ / MW / Year	25,658	30,932	36,166	24,546	29,624	34,661
O&M variable fee (excl BSUoS)	£ / MWh	2.89	3.36	4.01	2.89	3.36	4.01
Insurance	£ / MW / Year	4,784	7,313	10,016	4,191	6,404	8,802
Connection and UoS charges	£ / MW / Year	(9,000)	3,280	23,010	(9,000)	3,280	23,010

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CCGT Pre-combustion		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	4.0	5.0	6.0	3.0	3.3	6.0
Construction Period	years	3.9	4.5	5.5	3.0	3.5	4.5
Plant Operating Period	years	20	25	35	20	25	35
Technical data							
NET Power Output	MW	1084	1084	1084	1084	1084	1084
Average Steam Output	MW (thermal)						
Steam take up	%						
Net Efficiency (LHV)	%	42.4%	42.4%	42.4%	42.4%	42.4%	42.4%
Average availability	%	84.8%	88.0%	91.5%	84.8%	88.0%	91.5%
Average load factor	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CO2 scrubbing	%	93.3%	93.3%	93.3%	93.3%	93.3%	93.3%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	32.1	45.2	64.7	27.6	37.4	48.2
Regulatory + licensing + public enquiry	£/kW	0.8	1.0	10.6	0.8	0.8	8.2
Construction costs							
Capital cost (excluding interest during construction)	£/kW	1,682	2,036	2,639	1,478	1,688	1,974
Infrastructure cost	£'000	7,553	15,105	30,210	7,553	15,105	30,210
Operating costs							
O&M fixed fee	£ / MW / Year	25,325	30,540	35,715	24,236	29,259	34,242
O&M variable fee (excl BSUoS)	£ / MWh	3.28	3.81	4.53	3.25	3.77	4.49
Insurance	£ / MW / Year	4,905	7,463	10,238	4,294	6,534	8,993
Connection and UoS charges	£ / MW / Year	(9,000)	3,280	23,010	(9,000)	3,280	23,010

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CCGT Oxyfuel		1st OF A KIND			Nth OF A KIND		
		Low	**Medium**	**High**	**Low**	**Medium**	**High**
Key Timings							
Total Pre-development Period	years	4.5	5.8	7.0	3.0	3.3	6.0
Construction Period	years	4.0	4.5	5.5	3.0	3.5	4.5
Plant Operating Period	years	20	25	35	20	25	35
Technical data							
NET Power Output	MW	1038	1038	1038	1038	1038	1038
Average Steam Output	MW (thermal)						
Steam take up	%						
Net Efficiency (LHV)	%	46.3%	46.3%	46.3%	46.3%	46.3%	46.3%
Average availability	%	84.8%	88.0%	91.5%	84.8%	88.0%	91.5%
Average load factor	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CO2 scrubbing	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	30.7	44.4	67.0	25.6	35.8	48.5
Regulatory + licensing + public enquiry	£/kW	1.3	0.8	15.8	1.1	0.7	11.5
Construction costs							
Capital cost (excluding interest during construction)	£/kW	1,725	2,092	2,710	1,472	1,689	1,973
Infrastructure cost	£'000	7,553	15,105	30,210	7,553	15,105	30,210
Operating costs							
O&M fixed fee	£ / MW / Year	70,593	83,797	96,960	66,336	78,788	91,200
O&M variable fee (excl BSUoS)	£ / MWh	3.11	3.62	4.31	3.10	3.60	4.29
Insurance	£ / MW / Year	4,969	7,572	10,378	4,212	6,432	8,842
Connection and UoS charges	£ / MW / Year	(9,000)	3,280	23,010	(9,000)	3,280	23,010

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OCGT Post-combustion		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	4.0	5.0	6.0	2.8	3.0	5.5
Construction Period	years	3.9	4.5	5.5	2.0	3.0	4.0
Plant Operating Period	years	20	25	35	20	25	35
Technical data							
NET Power Output	MW	290	290	290	290	290	290
Average Steam Output	MW (thermal)						
Steam take up	%						
Net Efficiency (LHV)	%	27.2%	27.2%	27.2%	27.2%	27.2%	27.2%
Average availability	%	83.9%	89.9%	93.7%	83.9%	89.9%	93.5%
Average load factor	%	90.0%	94.0%	96.0%	90.0%	94.0%	96.0%
CO2 scrubbing	%	89.6%	89.6%	89.6%	89.6%	89.6%	89.6%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	61.6	77.1	109.4	55.3	65.0	83.2
Regulatory + licensing + public enquiry	£/kW	3.3	4.0	12.8	3.1	3.6	9.6
Construction costs							
Capital cost (excluding interest during construction)	£/kW	1,984	2,456	3,097	1,697	1,975	2,245
Infrastructure cost	£'000	7,553	15,105	30,210	7,553	15,105	30,210
Operating costs							
O&M fixed fee	£ / MW / Year	26,584	31,752	36,894	25,160	30,077	34,968
O&M variable fee (excl BSUoS)	£ / MWh	2.48	2.97	3.38	2.47	2.96	3.38
Insurance	£ / MW / Year	5,737	8,943	11,932	4,876	7,577	10,136
Connection and UoS charges	£ / MW / Year	(4,790)	2,530	14,450	(4,790)	2,530	14,450

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IGCC Partial		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	4.0	5.0	6.0	3.0	3.3	6.0
Construction Period	years	4.0	5.0	6.0	3.0	3.5	4.5
Plant Operating Period	years	20	25	35	20	25	35
Technical data							
NET Power Output	MW	760	760	760	760	760	760
Average Steam Output	MW (thermal)						
Steam take up	%						
Net Efficiency (LHV)	%	37.2%	37.2%	37.2%	37.2%	37.2%	37.2%
Average availability	%	84.8%	88.0%	91.5%	84.8%	88.0%	91.5%
Average load factor	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CO_2 scrubbing	%	29.6%	29.6%	29.6%	29.6%	29.6%	29.6%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	36.9	42.5	54.9	30.2	32.8	38.1
Regulatory + licensing + public enquiry	£/kW	0.1	0.1	1.6	0.1	0.1	1.1
Construction costs							
Capital cost (excluding interest during construction)	£/kW	2,459	2,830	3,664	2,011	2,183	2,541
Infrastructure cost	£'000	5,000	10,000	15,000	5,000	10,000	15,000
Operating costs							
O&M fixed fee	£ / MW / Year	44,315	52,135	59,956	41,213	48,486	55,759
O&M variable fee (excl BSUoS)	£ / MWh	4.29	5.00	5.72	4.10	4.78	5.47
Insurance	£ / MW / Year	9,711	14,062	19,293	7,944	11,496	15,778
Connection and UoS charges	£ / MW / Year	(2,760)	3,820	9,820	(2,760)	3,820	9,820

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IGCC Full		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	4.0	5.0	7.0	3.0	3.3	6.0
Construction Period	years	4.5	5.0	6.0	3.0	3.5	4.5
Plant Operating Period	years	20	25	35	20	25	35
Technical data							
NET Power Output	MW	652	652	652	652	652	652
Average Steam Output	MW (thermal)						
Steam take up	%						
Net Efficiency (LHV)	%	31.9%	31.9%	31.9%	31.9%	31.9%	31.9%
Average availability	%	84.8%	88.0%	91.5%	84.8%	88.0%	91.5%
Average load factor	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CO_2 scrubbing	%	88.9%	88.9%	88.9%	88.9%	88.9%	88.9%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	50.2	58.9	75.5	41.0	45.3	52.2
Regulatory + licensing + public enquiry	£/kW	0.5	0.6	4.6	0.4	0.5	3.2
Construction costs							
Capital cost (excluding interest during construction)	£/kW	3,347	3,923	5,034	2,733	3,019	3,484
Infrastructure cost	£'000	5,000	10,000	15,000	5,000	10,000	15,000
Operating costs							
O&M fixed fee	£ / MW / Year	55,536	65,337	75,137	51,649	60,763	69,878
O&M variable fee (excl BSUoS)	£ / MWh	4.29	5.00	5.72	4.10	4.78	5.47
Insurance	£ / MW / Year	15,401	22,703	30,884	12,576	18,523	25,209
Connection and UoS charges	£ / MW / Year	(2,760)	3,820	9,820	(2,760)	3,820	9,820

IGCC Retrofit		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	3.5	4.5	6.0	3.0	3.3	6.0
Construction Period	years	3.5	4.0	5.5	3.0	3.5	4.5
Plant Operating Period	years	20	25	35	20	25	35
Technical data							
NET Power Output	MW	622	622	622	622	622	622
Average Steam Output	MW (thermal)						
Steam take up	%						
Net Efficiency (LHV)	%	28.1%	28.1%	28.1%	28.1%	28.1%	28.1%
Average availability	%	84.8%	88.0%	91.5%	84.8%	88.0%	91.5%
Average load factor	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CO_2 scrubbing	%	88.9%	88.9%	88.9%	88.9%	88.9%	88.9%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	53.9	63.3	81.1	44.0	48.7	56.1
Regulatory + licensing + public enquiry	£/kW	1.5	1.7	17.0	1.2	1.3	11.7
Construction costs							
Capital cost (excluding interest during construction)	£/kW	3,592	4,215	5,406	2,933	3,244	3,741
Infrastructure cost	£'000	0	0	0	0	0	0
Operating costs							
O&M fixed fee	£ / MW / Year	69,001	81,924	94,807	64,855	77,046	89,197
O&M variable fee (excl BSUoS)	£ / MWh	5.51	6.43	7.55	5.32	6.21	7.30
Insurance	£ / MW / Year	18,642	27,636	37,731	15,463	22,925	31,338
Connection and UoS charges	£ / MW / Year	(2,760)	3,820	9,820	(2,760)	3,820	9,820

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ASC Full		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	4.0	5.0	7.0	2.8	3.3	5.5
Construction Period	years	4.5	5.0	6.0	2.0	3.5	4.0
Plant Operating Period	years	20	25	35	20	25	35
Technical data							
NET Power Output	MW	624	624	624	624	624	624
Average Steam Output	MW (thermal)						
Steam take up	%						
Net Efficiency (LHV)	%	33.9%	33.9%	33.9%	33.9%	33.9%	33.9%
Average availability	%	87.6%	90.8%	94.3%	87.6%	90.8%	94.3%
Average load factor	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CO2 scrubbing	%	89.0%	89.0%	89.0%	89.0%	89.0%	89.0%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	39.3	50.7	75.3	37.2	45.1	59.5
Regulatory + licensing + public enquiry	£/kW	19.0	23.6	33.1	18.9	22.3	27.8
Construction costs							
Capital cost (excluding interest during construction)	£/kW	3,362	4,175	5,472	3,085	3,613	4,275
Infrastructure cost	£'000	5,000	10,000	15,000	5,000	10,000	15,000
Operating costs							
O&M fixed fee	£ / MW / Year	66,743	78,521	90,299	65,497	77,056	88,614
O&M variable fee (excl BSUoS)	£ / MWh	2.62	3.04	3.46	2.62	3.04	3.46
Insurance	£ / MW / Year	11,084	15,754	20,225	10,252	14,453	18,504
Connection and UoS charges	£ / MW / Year	(2,760)	3,820	9,820	(2,760)	3,820	9,820

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ASC Partial		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	4.0	5.0	7.0	2.8	3.3	5.5
Construction Period	years	4.5	5.0	6.0	2.0	3.5	4.0
Plant Operating Period	years	20	25	35	20	25	35
Technical data							
NET Power Output	MW	734	734	734	734	734	734
Average Steam Output	MW (thermal)						
Steam take up	%						
Net Efficiency (LHV)	%	39.9%	39.9%	39.9%	39.9%	39.9%	39.9%
Average availability	%	87.6%	90.8%	94.3%	87.6%	90.8%	94.3%
Average load factor	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CO2 scrubbing	%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	28.0	35.8	51.5	27.2	32.7	42.0
Regulatory + licensing + public enquiry	£/kW	16.1	20.0	27.5	16.0	18.9	23.3
Construction costs							
Capital cost (excluding interest during construction)	£/kW	2,055	2,557	3,409	1,970	2,312	2,779
Infrastructure cost	£'000	5,000	10,000	15,000	5,000	10,000	15,000
Operating costs							
O&M fixed fee	£ / MW / Year	47,919	56,376	64,832	47,477	55,855	64,233
O&M variable fee (excl BSUoS)	£ / MWh	2.61	3.03	3.49	2.61	3.03	3.45
Insurance	£ / MW / Year	7,012	9,648	12,224	6,757	9,249	11,696
Connection and UoS charges	£ / MW / Year	(2,760)	3,820	9,820	(2,760)	3,820	9,820

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ASC Retrofit		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	3.5	4.5	6.0	2.8	3.3	5.5
Construction Period	years	3.5	4.0	5.5	2.0	3.5	4.0
Plant Operating Period	years	7.5	15	22.5	20	25	35
Technical data							
NET Power Output	MW	390	390	390	390	390	390
Average Steam Output	MW (thermal)						
Steam take up	%						
Net Efficiency (LHV)	%	32.4%	32.4%	32.4%	32.4%	32.4%	32.4%
Average availability	%	87.6%	90.8%	94.3%	87.6%	90.8%	94.3%
Average load factor	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CO2 scrubbing	%	89.0%	89.0%	89.0%	89.0%	89.0%	89.0%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	15.3	26.0	45.0	13.1	20.7	32.0
Regulatory + licensing + public enquiry	£/kW	2.5	3.2	4.5	2.5	3.0	3.8
Construction costs							
Capital cost (excluding interest during construction)	£/kW	1,885	2,345	2,961	1,577	1,849	2,105
Infrastructure cost	£'000	0	0	0	0	0	0
Operating costs							
O&M fixed fee	£ / MW / Year	68,590	80,694	92,798	67,212	79,073	90,934
O&M variable fee (excl BSUoS)	£ / MWh	2.64	3.06	3.49	2.64	3.06	3.48
Insurance	£ / MW / Year	5,141	8,124	10,836	4,310	6,801	9,100
Connection and UoS charges	£ / MW / Year	(2,760)	3,820	9,820	(2,760)	3,820	9,820

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ASC Ammonia		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	4.0	5.0	7.0	2.8	3.3	5.5
Construction Period	years	4.5	5.0	6.0	2.0	3.5	4.0
Plant Operating Period	years	20	25	35	20	25	35
Technical data							
NET Power Output	MW	624	624	624	624	624	624
Average Steam Output	MW (thermal)						
Steam take up	%						
Net Efficiency (LHV)	%	33.9%	33.9%	33.9%	33.9%	33.9%	33.9%
Average availability	%	87.6%	90.8%	94.3%	87.6%	90.8%	94.3%
Average load factor	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CO2 scrubbing	%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	39.6	50.5	74.2	37.5	44.9	58.7
Regulatory + licensing + public enquiry	£/kW	19.0	23.6	33.0	18.9	22.3	27.8
Construction costs							
Capital cost (excluding interest during construction)	£/kW	3,405	4,217	5,531	3,120	3,646	4,316
Infrastructure cost	£'000	5,000	10,000	15,000	5,000	10,000	15,000
Operating costs							
O&M fixed fee	£ / MW / Year	67,625	79,558	91,492	66,315	78,017	89,720
O&M variable fee (excl BSUoS)	£ / MWh	2.62	3.04	3.46	2.62	3.04	3.46
Insurance	£ / MW / Year	13,605	19,294	25,156	12,319	17,357	22,548
Connection and UoS charges	£ / MW / Year	(2,760)	3,820	9,820	(2,760)	3,820	9,820

ASC Oxyfuel		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	4.5	6.0	7.0	2.8	3.3	5.5
Construction Period	years	5.0	5.5	6.0	2.0	3.5	4.0
Plant Operating Period	years	20	25	35	20	25	35
Technical data							
NET Power Output	MW	552	552	552	552	552	552
Average Steam Output	MW (thermal)						
Steam take up	%						
Net Efficiency (LHV)	%	33.9%	33.9%	33.9%	33.9%	33.9%	33.9%
Average availability	%	87.6%	90.8%	94.3%	87.6%	90.8%	94.3%
Average load factor	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CO2 scrubbing	%	91.2%	91.2%	91.2%	91.2%	91.2%	91.2%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	30.7	41.4	77.8	24.3	30.9	52.3
Regulatory + licensing + public enquiry	£/kW	0.6	0.8	6.1	0.5	0.6	4.1
Construction costs							
Capital cost (excluding interest during construction)	£/kW	2,965	3,516	4,487	2,349	2,629	3,015
Infrastructure cost	£'000	5,000	10,000	15,000	5,000	10,000	15,000
Operating costs							
O&M fixed fee	£ / MW / Year	57,995	68,229	78,464	53,935	63,453	72,971
O&M variable fee (excl BSUoS)	£ / MWh	4.88	5.70	6.52	3.00	3.53	4.06
Insurance	£ / MW / Year	8,896	13,267	17,949	7,047	10,516	14,222
Connection and UoS charges	£ / MW / Year	(2,760)	3,820	9,820	(2,760)	3,820	9,820

Biomass with CCS		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	3.5	4.5	5.5	2.8	3.3	5.5
Construction Period	years	3.0	3.5	4.0	2.0	3.5	4.0
Plant Operating Period	years	20	20	20	20	25	35
Technical data							
NET Power Output	MW	146	146	146	146	146	146
Average Steam Output	MW (thermal)						
Steam take up	%						
Net Efficiency (LHV)	%	14.3%	14.3%	14.3%	14.3%	14.3%	14.3%
Average availability	%	92.5%	95.0%	97.5%	92.5%	95.0%	97.5%
Average load factor	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
CO2 scrubbing	%	89.0%	89.0%	89.0%	89.0%	89.0%	89.0%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	184.2	233.3	335.2	178.4	212.7	272.2
Regulatory + licensing + public enquiry	£/kW	31.6	39.4	56.1	31.5	37.1	47.1
Construction costs							
Capital cost (excluding interest during construction)	£/kW	7,154	8,743	11,414	6,386	7,371	8,683
Infrastructure cost	£'000	5,000	10,000	15,000	5,000	10,000	15,000
Operating costs							
O&M fixed fee	£ / MW / Year	118,269	139,139	160,010	113,887	123,712	133,536
O&M variable fee (excl BSUoS)	£ / MWh	6.71	7.86	9.00	6.70	7.82	8.94
Insurance	£ / MW / Year	23,945	30,328	36,777	21,641	26,821	32,079
Connection and UoS charges	£ / MW / Year	(9,000)	3,280	23,010	(9,000)	3,280	23,010

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Appendix K Pumped storage parameter summary

Pumped storage		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	4.0	5.0	6.0	4.0	5.0	6.0
Construction Period	years	3.5	4.5	5.0	3.5	4.5	5.0
Plant Operating Period	years	40.0	50.0	60.0	40.0	50.0	60.0
Technical data							
NET Power Output	MW	600	600	600	600	600	600
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	-	-	-	-	-	-
Average availability	%	95.3%	96%	96.3%	95.3%	96%	96.3%
Average load factor	%	12.0%	22.0%	24.0%	12.0%	22.0%	24.0%
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	18.7	25.8	37.9	18.7	25.8	37.9
Regulatory + licensing + public enquiry	£/kW	7.5	10.3	15.2	7.5	10.3	15.2
Construction costs							
Capital cost (excluding interest during construction)	£/kW	747	1,032	1,517	747	1,032	1,517
Infrastructure cost	£'000	10,000	25,000	50,000	10,000	25,000	50,000
Operating costs							
O&M fixed fee	£ / MW / Year	7,982	11,192	16,012	7,982	11,192	16,012
O&M variable fee (excl BSUoS)	£ / MWh	38.96	40.00	41.10	38.96	40.00	41.10
Insurance	£ / MW / Year	2,241	4,128	7,585	2,241	4,128	7,585
Connection and UoS charges	£ / MW / Year	14,260	15,800	16,220	14,260	15,800	16,220

Appendix L NOx abatement parameter summary

Coal NOx abatement		1st OF A KIND Low	1st OF A KIND Medium	1st OF A KIND High	Nth OF A KIND Low	Nth OF A KIND Medium	Nth OF A KIND High
Key Timings							
Total Pre-development Period	years	0.8	1.4	2.0	0.8	1.4	2.0
Construction Period	years	1	1.5	4.0	0.8	1.4	2.0
Plant Operating Period	years	10.0	15.0	20.0	10.0	15.0	20.0
Technical data							
NET Power Output	MW	993.0	996.0	996.0	993.0	996.0	996.0
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	(0.7%)	(0.4%)	(0.4%)	(0.7%)	(0.4%)	(0.4%)
Average availability	%	-	-	-	-	-	-
Average load factor	%	-	-	-	-	-	-
CO2 scrubbing	%	-	-	-	-	-	-
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	2.38	3.13	4.63	2.38	3.13	4.63
Regulatory + licensing + public enquiry	£/kW	2.38	3.13	4.63	2.38	3.13	4.63
Construction costs							
Capital cost (excluding interest during construction)	£/kW	95	125	185	95	125	185
Infrastructure cost	£'000	-	-	-	-	-	-
Operating costs							
O&M fixed fee	£ / MW / Year	-	-	-	-	-	-
O&M variable fee	£ / MWh	0.8	0.8	0.8	0.8	0.8	0.8
Insurance	£ / MW / Year	-	-	-	-	-	-
Connection and UoS charges	£ / MW / Year	-	-	-	-	-	-

CCGT NOx abatement		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period	years	0.8	1.4	2.0	0.8	1.4	2.0
Construction Period	years	0.8	1.0	1.5	0.8	1.4	2.0
Plant Operating Period	years	25.0	25.0	25.0	25.0	25.0	25.0
Technical data							
NET Power Output	MW	1,176	1,377	1,377	1,176	1,377	1,377
Average Steam Output	MW (thermal)	-	-	-	-	-	-
Steam take up	%	-	-	-	-	-	-
Net Efficiency (LHV)	%	(0.1%)	(0.1%)	(0.1%)	(0.1%)	(0.1%)	(0.1%)
Average availability	%	-	-	-	-	-	-
Average load factor	%	-	-	-	-	-	-
CO2 scrubbing	%	-	-	-	-	-	-
Capital costs							
Pre-development costs							
Pre-licensing costs, Technical and design	£/kW	0.5	2.8	3.8	0.5	2.8	3.8
Regulatory + licensing + public enquiry	£/kW	0.5	2.8	3.8	0.5	2.8	3.8
Construction costs							
Capital cost (excluding interest during construction)	£/kW	20	110	140	20	110	140
Infrastructure cost	£'000	-	-	-	-	-	-
Operating costs							
O&M fixed fee	£ / MW / Year	-	-	-	-	-	-
O&M variable fee	£ / MWh	0.15	0.15	0.18	0.15	0.15	0.18
Insurance	£ / MW / Year	-	-	-	-	-	-
Connection and UoS charges	£ / MW / Year	-	-	-	-	-	-

Appendix M Levelised cost assumptions

We have undertaken analysis of the LCOE of each technology type through DECC's LCM using the following technology specific assumptions, agreed with DECC. Where a cost or technical parameter is not specifically stated to be otherwise, we have used the value corresponding to the medium case.

M.1 Our assumptions

Table 101 – assumptions for gas LCOE

Scenario	FOAK/NOAK	Commissioning year	Assumptions
Low	NOAK	2020	Low pre-development cost Low capital cost Low cost reduction profile
Medium	NOAK	2020	Medium pre-development cost Medium capital cost Medium cost reduction profile
High	NOAK	2020	High pre-development cost High capital cost High cost reduction profile

Table 102 – assumptions for nuclear LCOE

Scenario	FOAK/NOAK	Commissioning year	Assumptions
Low	FOAK	2025	Low pre-development cost Low capital cost
Medium	FOAK	2025	Medium pre-development cost Medium capital cost
High	FOAK	2025	High pre-development cost High capital cost
High (delay)	FOAK	2029	High pre-development cost High capital cost High cost reduction profile High construction period
Low	NOAK	2030	Low pre-development cost Low capital cost Low cost reduction profile
Medium	NOAK	2030	Medium pre-development cost Medium capital cost Medium cost reduction profile
High	NOAK	2030	High pre-development cost High capital cost High cost reduction profile

Table 103 – assumptions for CCS LCOE

Scenario	FOAK/NOAK	Commissioning year	Assumptions
Low FOAK	FOAK	2025	Low pre-development cost Low capital cost
Medium FOAK	FOAK	2025	Medium pre-development cost Medium capital cost
High FOAK	FOAK	2025	High pre-development cost High capital cost

Table 104 – assumptions for pumped storage LCOE

Scenario	FOAK/NOAK	Commissioning year	Assumptions
Low FOAK	NOAK	2025	Low pre-development cost Low capital cost
Medium FOAK	NOAK	2025	Medium pre-development cost Medium capital cost
High FOAK	NOAK	2025	High pre-development cost High capital cost

DECC also provided the following global assumptions:

- *Exchange rates*
- *Technology specific hurdle rates*
- *Calorific values for coal and gas*
- *Fuel emissions factors for coal, gas and biomass*
- *Fuel prices for coal, gas, uranium and biomass, including add on costs to reflect transport costs*
- *Carbon price*
- *Heat revenues*
- *Fuel to carbon conversion factors*

M.2 Other assumptions

It was not within our scope to provide forecasts of future fuel and carbon prices, so we have run our analysis using DECC's assumptions. Our analysis in this chapter does not include the potential impact of changes to fuel and carbon prices. The fuel and carbon elements of levelised costs for gas and coal plants can be significant. Recent experience shows that there can be variance in natural gas prices in particular. Our analysis for gas and coal plants assumes commissioning in 2025. Forecasts for fuel and carbon prices 10 years in advance are likely to be uncertain. This means the LCOE ranges could ultimately be wider. To aid the reader in considering the potential impact of fuel and carbon prices, we have provided the estimated proportion of levelised cost that is fuel or carbon cost in the relevant sections below based on the input assumptions for these costs as provided by DECC. For reference, Table 105 summarises the medium case cost input assumptions provided by DECC.

Table 105 – DECC cost inputs (medium case)

Cost (2014 prices)	2015	2020	2025	2030
Coal ($/tonne)	59.13	68.42	81.70	85.86
Gas (p/therm)	45.95	51.61	65.92	67.41
Uranium (£/MWh)	5.42	5.42	5.42	5.42
Diesel (£/MWh)	41.40	55.10	77.83	77.83
Biomass (£/MWh)	28.96	28.96	28.96	28.96
Carbon (£/tonne)	21.73	28.38	55.64	77.90

In addition, load factor will have an impact on actual LCOE. We have assessed the LCOE based on fixed load factor assumptions. Higher or lower load factors than those used in our analysis may also result in different LCOE.

For the purposes of the CHP analysis, DECC also provided values for heat revenues.

Appendix N Changes from previously published data

DECC last published LCOE analysis in its report Electricity Generation Costs (December 2013)[32]. There are two drivers behind changes from the numbers presented in that report to our outputs. These are:

- ***Parameters*** *– the changes to the cost and technical parameters, presented in this report, will drive changes in LCOE*
- ***Hurdle rates*** *– changes to DECC's hurdle rate assumptions change the pre-development and construction cost elements of LCOE, even if cost and technical parameters do not change*

Where comparison is possible on a like-for-like basis[33] we have provided an explanation for the differences between our results and previous results below. We first consider the impact on LCOE of changing to our proposed parameters but using the previous hurdle rates. We then consider the impact of changing the hurdle rates to DECC's new hurdle rates.

All "2013" values are stated in 2012 prices and all "LF" values are stated in 2014 prices.

N.1 Inputs

As explained throughout the report, we have recommended changes to a number of technical and cost inputs. The sections below show the impact of changing the inputs to our recommendations, but using the previous hurdle rates. We then discuss the reasons for the changes. The tables below show changes to the medium case, based on the assumptions outlined in Appendix M. Note that the previous report did not consider reciprocating engines or pumped storage, so these are not included in our analysis of the changes since 2013.

N.1.1 Gas

Table 106 – impact of changing parameters on gas technology LCOE at previous hurdle rates

Cost category	CCGT H class		CHP		OCGT	
	2013	LF	2013	LF	2013	LF
Pre-development	0	0	1	1	4	4
Construction	7	6	7	10	43	61
Fixed O+M	4	2	7	4	23	17
Variable O+M	0	3	0	5	0	3
Fuel	49	44	74	69	74	65
Carbon	21	28	32	43	32	41
Additional Costs	0	0	-32	-32	0	0
Total	**81**	**84**	**89**	**101**	**175**	**191**

Our CCGT parameters result in higher levelised costs than the previous parameters. This is due to:

- *higher O&M, including a higher allocation towards variable O&M and inclusion of BSUoS in variable O&M*

[32] https://www.gov.uk/government/publications/electricity-generation-costs-december-2013

[33] This is not always the case given the differences between the configurations considered in our scope and those previously assessed by PB

- *a greater rate of efficiency degradation leads to higher fuel use. This causes higher carbon costs per MWh. Lower fuel costs mean the fuel costs are lower overall despite the higher fuel use.*

Our CHP parameters result in overall costs comparable with previous parameters albeit with:

- *slightly higher capital cost*
- *a lower efficiency and higher efficiency degradation rate leads to higher fuel use. This causes higher fuel and carbon costs per MWh, despite the lower fuel costs per unit.*

Our OCGT parameters result in higher levelised costs than the previous parameters. This is due to:

- *a higher capital cost*
- *a lower O&M cost, largely driven by the greater proportion of variable O&M in our analysis, partly driven by including BSUoS as a variable cost rather than fixed.*
- *a lower load factor*

N.1.2 Nuclear

Table 107 – impact of changing parameters on nuclear technology LCOE at previous hurdle rates

Cost category	FOAK		NOAK	
	2013	**LF**	**2013**	**LF**
Pre-development	5	7	4	3
Construction	59	72	53	56
Fixed O+M	11	11	10	11
Variable O+M	3	5	3	5
Fuel	5	5	5	5
Carbon	0	0	0	0
Decommissioning and waste	2	2	2	2
Total	**86**	**102**	**77**	**82**

Our FOAK parameters result in higher levelised costs than the previous parameters, due to:

- *a higher capital cost, resulting from the net present value effect of a longer construction time*
- *higher use of system charges overall, with BSUoS moving in to variable O&M*

We also understand from DECC that the previous cost reduction profile may have assumed a 2020 deployment rather than 2025. This means there is an additional 5 years of cost reduction in the previous FOAK figure, which may also explain part of the difference.

Our NOAK parameters result in higher levelised costs than the previous parameters, due to:

- *a less significant FOAK to NOAK cost reduction and less significant cost reduction profile*
- *higher use of system charges*

N.1.3 CCS

Our changes drive differences in CCS LCOE across all CCS technologies. Our CCS parameters have lower availability estimates, to account for technical issues with CCS equipment. This results in higher pre-development, construction and Fixed O&M costs for all CCS LCOE. Including BSUoS as variable O&M also leads to a reallocation between fixed and variable O&M for all CCS LCOE. We also understand from DECC that there may have been an error in the previous cost reduction profiles for CCS which means they exaggerate cost increases or decreases. We have stated this difference in the tables below as “less significant cost reduction profile”.

Various other changes to parameters drive changes to CCS LCOE. These are explained in the tables below.

Table 108 – impact of changing parameters on FOAK CCGT CCS technology LCOE at previous hurdle rates

Cost category	Post combustion		Pre combustion		Oxyfuel		Post retrofit	
	2013	LF	2013	LF	2013	LF	2013	LF
Pre-development	1	2	1	2	2	2	1	1
Construction	31	51	35	50	36	51	20	32
Fixed O+M	4	5	5	5	13	12	4	5
Variable O+M	2	3	1	4	1	4	2	3
Fuel	56	56	69	65	71	60	56	56
Carbon	3	4	4	3	2	0	3	4
CO2 Capture and Storage	7	7	9	9	9	9	7	7
Total	**105**	**130**	**124**	**138**	**134**	**137**	**94**	**110**

Table 109 – CCGT CCS FOAK LCOE differences

Technology	Reasons for LF parameters leading to different levelised costs
Post-combustion	• *a higher capital cost and less significant cost reduction profile* • *lower efficiency, partially offset by lower fuel costs* • *higher capture rate, increasing the costs of CO2 capture and storage, but decreasing the volume of carbon*
Pre-combustion	• *a higher capital cost and less significant cost reduction profile* • *lower efficiency, offset by lower fuel costs* • *higher capture rate*
Oxyfuel combustion	• *a higher capital cost and less significant cost reduction profile* • *higher efficiency* • *higher capture rate*
Retrofit post-combustion	• *a higher capital cost and less significant cost reduction profile* • *lower efficiency, partially offset by lower fuel costs* • *higher capture rate*

Table 110 – impact of changing parameters on FOAK IGCC CCS technology LCOE at previous hurdle rates

Cost category	Full		Partial		Full retrofit	
	2013	LF	2013	LF	2013	LF
Pre-development	2	3	2	2	1	3
Construction	76	94	67	67	36	94
Fixed O+M	19	12	16	9	19	15
Variable O+M	0	5	0	5	0	6
Fuel	36	28	32	24	38	31
Carbon	7	11	38	58	9	12
CO2 Capture and Storage	17	18	6	5	18	20
Total	**156**	**169**	**161**	**170**	**120**	**181**

Table 111 – IGCC CCS FOAK LCOE differences

Technology	Reasons for LF parameters leading to different levelised costs
Full	• *a higher capital cost and less significant cost reduction profile* • *Lower fixed O&M, but inclusion of variable O&M* • *Lower efficiency, offset by lower fuel costs*
Partial	• *a higher capital cost and less significant cost reduction profile* • *Lower fixed O&M, but inclusion of variable O&M* • *Lower efficiency, offset by lower fuel costs* • *Lower capture rate*
Retro	• *a higher capital cost and less significant cost reduction profile* • *Lower fixed O&M, but inclusion of variable O&M* • *Lower efficiency, offset by lower fuel costs* • *Lower capture rate*

Table 112 – impact of changing parameters on FOAK ASC CCS technology LCOE at previous hurdle rates

Cost category	Full post		Partial post		Full retrofit		Oxyfuel		Ammonia	
	2013	**LF**	**2013**	**LF**	**2013**	**LF**	**2013**	**LF**	**2013**	**LF**
Pre-development	1	3	1	2	1	1	1	2	1	3
Construction	63	97	43	60	37	58	55	88	63	98
Fixed O+M	10	12	7	9	10	12	8	11	10	13
Variable O+M	2	3	1	3	2	3	2	6	0	3
Fuel	36	26	29	22	37	27	36	25	40	25
Carbon	7	10	43	54	7	9	5	8	9	10
CO2 Capture and Storage	17	17	3	5	17	17	18	17	18	16
Total	**137**	**168**	**127**	**155**	**111**	**127**	**125**	**156**	**141**	**168**

Table 113 – ASC CCS FOAK LCOE differences

Technology	Reasons for LF parameters leading to different levelised costs
Full post combustion	• *a higher capital cost and less significant cost reduction profile* • *inclusion of BSUoS in variable O&M* • *Lower efficiency, offset by lower fuel costs*
Partial post combustion	• *a higher capital cost and less significant cost reduction profile* • *higher fixed O&M and inclusion of BSUoS in variable O&M* • *higher capture rate*
Retro post combustion	• *a higher capital cost and less significant cost reduction profile* • *Lower efficiency, , offset by lower fuel costs* • *Higher capture rate*
Oxyfuel	• *a higher capital cost and less significant cost reduction profile* • *lower efficiency, offset by lower fuel costs* • *lower capture rate*
Ammonia	• *a higher capital cost and less significant cost reduction profile* • *inclusion of variable O&M element and inclusion of BSUoS in variable O&M* • *Higher efficiency* • *Higher capture rate*

Table 114 – impact of changing parameters on FOAK Biomass CCS technology LCOE at previous hurdle rates

Cost category	Biomass	
	2013	**LF**
Pre-development	0	11
Construction	84	195
Fixed O+M	12	21
Variable O+M	4	8
Fuel	108	202
Carbon	0	0
CO2 Capture and Storage	0	42
Total	**207**	**479**

*Note that a biomass CCS plant would produce some carbon emissions that are not captured and stored. This follows DECC's modelling approach of treating non-biomass electricity generation technologies as carbon neutral. The potential benefits of biomass for negative emissions are not included in our analysis.

Table 115 – biomass CCS FOAK LCOE differences

Technology	Reasons for LF parameters leading to different levelised costs
Biomass	• *Higher parasitic load driving lower efficiency and power output* • *Knock on effect of lower power output is higher £/kW for construction and O&M costs* • *Higher pre-development costs* • *a higher capital cost and less significant cost reduction profile* • *Inclusion of infrastructure costs* • *Higher fixed and variable O&M* • *Inclusion of insurance and connection costs* • *Inclusion of capture and storage opex*

N.2 Hurdle rates

DECC has changed its hurdle rate assumptions since its 2013 report. Updating hurdle rates and updated parameters results in an increase in LCOE for gas and a decrease in LCOE for all other technologies. These results are expected as they follow the movements in hurdle rates: DECC has increased hurdle rates for gas and reduced hurdle rates for all other technologies.

Table 116 – impact of changing hurdle rates on LCOE

Group	Technology	LF at old Hurdle rates (2014 prices)	LF new HR	Difference (£/MWh)	Difference (%)
Gas	CCGT H class	83.8	83.7	-0.1	-0.2%
	CHP	100.5	99.0	-1.6	-1.5%
	OCGT	190.7	192.0	1.4	0.7%
Nuclear	FOAK	102.3	95.4	-6.9	-6.8%
	NOAK	82.4	77.7	-4.7	-5.8%
CCGT CCS	Post combustion	129.7	119.6	-10.1	-7.8%
	Pre combustion	138.4	128.4	-10.0	-7.3%
	Oxyfuel	137.2	126.8	-10.4	-7.6%
	Post retrofit	109.9	104.1	-5.8	-5.3%
IGCC CCS	Full	169.2	153.3	-15.9	-9.4%
	Partial	170.3	161.4	-8.8	-5.2%
	Full retrofit	180.7	165.9	-14.8	-8.2%
ASC CCS	Full post	168.4	151.7	-16.7	-9.9%
	Partial post	154.8	146.9	-7.9	-5.1%
	Full retrofit	127.2	119.5	-7.6	-6.0%
	Oxyfuel	156.2	140.0	-16.2	-10.4%
	Ammonia	168.5	151.5	-17.0	-10.1%
Biomass	Biomass	478.8	446.6	-32.2	-6.7%

*Note that a biomass CCS plant would produce some carbon emissions that are not captured and stored. This follows DECC's modelling approach of treating non-biomass electricity generation technologies as carbon neutral. The potential benefits of biomass for negative emissions are not included in our analysis.

Appendix O CCS breakdown

The tables below provide a breakdown of LCOE between the capital expenditure for the three CCS plant elements (reference plant, capture plant and capture and storage plant). Differences in cost allocation between elements could result in different costs. Therefore we consider the most accurate approach to LCOE for CCS is to consider the aggregated costs. The tables below therefore should be considered indicative breakdowns.

Table 117 – CCS FOAK low case

FOAK low case	CCS plant (£/KW)	Transport and storage (£/KW)	Reference plant (£/kW)	Optimism bias (£/kW)	Total (£/kW)
CCGT – post combustion	881	282	547	0	1,710
CCGT – retro	833	334	0	0	1,167
CCGT – pre combustion	892	309	486	0	1,687
CCGT – oxyfuel combustion	897	307	507	0	1,711
OCGT – post combustion	935	610	362	0	1,907
ASC – post combustion	906	571	1,885	0	3,362
ASC – partial post combustion	279	175	1,601	0	2,055
ASC – with ammonia	968	554	1,883	0	3,405
ASC - retrofit*	954	697	251	0	1,901
ASC – oxyfuel combustion†	2,320	587	0	0	2,907
IGCC – partial CCS†	2,216	233	0	0	2,449
IGCC – CCS†	2,777	570	0	0	3,347
IGCC – retro CCS	2,962	630	0	0	3,592
Biomass – CCS	2,978	1,159	3,017	0	7,154

Table 118 – CCS FOAK medium case

FOAK medium case	CCS plant (£/KW)	Transport and storage (£/KW)	Reference plant (£/kW)	Optimism bias (£/kW)	Total (£/kW)
CCGT – post combustion	932	376	643	117	2,069
CCGT – retro	882	445	0	80	1,407
CCGT – pre combustion	945	412	571	116	2,043
CCGT – oxyfuel combustion	950	409	596	117	2,072
OCGT – post combustion	990	814	411	133	2,347
ASC – post combustion	959	762	2,217	236	4,175
ASC – partial post combustion	295	233	1,884	145	2,557
ASC – with ammonia	1,025	739	2,215	239	4,217
ASC - retrofit*	1,010	929	295	134	2,368
ASC – oxyfuel combustion†	2,456	782	0	194	3,433
IGCC – partial CCS†	2,346	311	0	159	2,816
IGCC – CCS†	2,940	760	0	222	3,923
IGCC – retro CCS	3,136	841	0	239	4,215
Biomass – CCS	3,153	1,546	3,550	495	8,743

Table 119 – CCS FOAK high case

FOAK high case	CCS plant (£/KW)	Transport and storage (£/KW)	Reference plant (£/kW)	Optimism bias (£/kW)	Total (£/kW)
CCGT – post combustion	1,036	376	739	538	2,689
CCGT – retro	980	445	0	356	1,782
CCGT – pre combustion	1,050	412	656	529	2,647
CCGT – oxyfuel combustion	1,055	409	685	537	2,687
OCGT – post combustion	1,100	814	461	594	2,969
ASC – post combustion	1,066	762	2,550	1,094	5,472
ASC – partial post combustion	328	233	2,166	682	3,409
ASC – with ammonia	1,138	739	2,548	1,106	5,531
ASC - retrofit*	1,122	929	339	598	2,988
ASC – oxyfuel combustion†	2,729	782	0	878	4,389
IGCC – partial CCS†	2,607	311	0	729	3,647
IGCC – CCS†	3,267	760	0	1,007	5,034
IGCC – retro CCS	3,484	841	0	1,081	5,406
Biomass – CCS	3,503	1,546	4,082	2,283	11,414

Table 120 – CCS NOAK low case

NOAK low case	CCS plant (£/KW)	Transport and storage (£/KW)	Reference plant (£/kW)	Optimism bias (£/kW)	Total (£/kW)
CCGT – post combustion	740	226	547	0	1,513
CCGT – retro	700	267	0	0	967
CCGT – pre combustion	749	247	486	0	1,482
CCGT – oxyfuel combustion	709	245	507	0	1,461
OCGT – post combustion	785	488	362	0	1,635
ASC – post combustion	743	457	1,885	0	3,085
ASC – partial post combustion	229	140	1,601	0	1,970
ASC – with ammonia	794	443	1,883	0	3,120
ASC - retrofit*	782	557	251	0	1,590
ASC – oxyfuel combustion†	1,833	469	0	0	2,302
IGCC – partial CCS†	1,817	186	0	0	2,003
IGCC – CCS†	2,277	456	0	0	2,733
IGCC – retro CCS	2,428	504	0	0	2,933
Biomass – CCS	2,442	927	3,017	0	6,386

Table 121 – CCS NOAK medium case

NOAK medium case	CCS plant (£/KW)	Transport and storage (£/KW)	Reference plant (£/kW)	Optimism bias (£/kW)	Total (£/kW)
CCGT – post combustion	783	301	643	0	1,727
CCGT – retro	741	356	0	0	1,097
CCGT – pre combustion	794	329	571	0	1,694
CCGT – oxyfuel combustion	750	327	596	0	1,674
OCGT – post combustion	831	651	411	0	1,893
ASC – post combustion	787	609	2,217	0	3,613
ASC – partial post combustion	242	186	1,884	0	2,312
ASC – with ammonia	840	591	2,215	0	3,646
ASC - retrofit*	828	743	295	0	1,866
ASC – oxyfuel combustion†	1,940	626	0	0	2,566
IGCC – partial CCS†	1,924	249	0	0	2,172
IGCC – CCS†	2,411	608	0	0	3,019
IGCC – retro CCS	2,571	673	0	0	3,244
Biomass – CCS	2,585	1,236	3,550	0	7,371

Table 122 – CCS NOAK high case

NOAK high case	CCS plant (£/KW)	Transport and storage (£/KW)	Reference plant (£/kW)	Optimism bias (£/kW)	Total (£/kW)
CCGT – post combustion	870	301	739	115	2,025
CCGT – retro	824	356	0	71	1,250
CCGT – pre combustion	882	329	656	112	1,979
CCGT – oxyfuel combustion	834	327	685	111	1,957
OCGT – post combustion	924	651	461	122	2,159
ASC – post combustion	874	609	2,550	242	4,275
ASC – partial post combustion	269	186	2,166	157	2,779
ASC – with ammonia	934	591	2,548	244	4,316
ASC - retrofit*	920	743	339	120	2,122
ASC – oxyfuel combustion†	2,156	626	0	167	2,949
IGCC – partial CCS†	2,138	249	0	143	2,529
IGCC – CCS†	2,679	608	0	197	3,484
IGCC – retro CCS	2,857	673	0	212	3,741
Biomass – CCS	2,872	1,236	4,082	491	8,683

* ASC retrofit reference plant costs include life extension works
† Because of the aggregated nature of some of our benchmark data, we have not provide detailed breakdowns between the CCS plant and reference plant for all technology types

LeighFisher

Appendix P Levelised cost results at new hurdle rates

P.1 CCGT results

CCGT F Class

Cost category	£/MWh		
	Low	Mid	High
Pre-development	0	0	0
Construction	5	6	7
Fixed O+M	2	2	2
Variable O+M	3	3	3
Fuel	45	45	45
Carbon	28	28	28
Total	**83**	**84**	**85**

CCGT H Class

Cost category	£/MWh		
	Low	Mid	High
Pre-development	0	0	0
Construction	5	7	8
Fixed O+M	2	2	2
Variable O+M	3	3	3
Fuel	44	44	44
Carbon	27	27	27
Total	**82**	**84**	**85**

P.2 CHP results

CHP

Cost category	£/MWh		
	Low	Mid	High
Pre-development	1	1	1
Construction	10	12	15
Fixed O+M	4	4	4
Variable O+M	5	5	5
Fuel	69	69	69
Carbon	40	40	40
Heat revenue	-32	-32	-32
Total	**96**	**99**	**102**

CHP power only mode

Cost category	£/MWh		
	Low	Mid	High
Pre-development	0	1	1
Construction	8	9	12
Fixed O+M	4	4	4
Variable O+M	5	5	5
Fuel	51	51	51
Carbon	30	30	30
Heat revenue	0	0	0
Total	**97**	**99**	**102**

P.3 OCGT results

600 MW peaking

Cost category	£/MWh		
	Low	Mid	High
Pre-development	1	1	1
Construction	15	16	18
Fixed O+M	6	6	6
Variable O+M	3	3	3
Fuel	65	65	65
Carbon	40	40	40
Total	**129**	**131**	**133**

600 MW critical peak

Cost category	£/MWh		
	Low	Mid	High
Pre-development	4	5	6
Construction	57	63	69
Fixed O+M	17	17	17
Variable O+M	3	3	3
Fuel	65	65	65
Carbon	40	40	40
Total	**186**	**192**	**200**

400 MW peaking

Cost category	£/MWh		
	Low	Mid	High
Pre-development	1	2	2
Construction	15	19	23
Fixed O+M	6	6	6
Variable O+M	3	3	3
Fuel	67	67	67
Carbon	41	41	41
Total	**134**	**138**	**142**

400 MW critical peak

Cost category	£/MWh		
	Low	Mid	High
Pre-development	5	6	8
Construction	60	73	90
Fixed O+M	18	18	18
Variable O+M	3	3	3
Fuel	67	67	67
Carbon	41	41	41
Total	**195**	**209**	**227**

300 MW peaking

Cost category	£/MWh		
	Low	Mid	High
Pre-development	2	2	2
Construction	16	22	37
Fixed O+M	7	7	7
Variable O+M	3	3	3
Fuel	66	66	66
Carbon	41	41	41
Total	**134**	**141**	**157**

300 MW critical peak

Cost category	£/MWh		
	Low	Mid	High
Pre-development	6	7	9
Construction	63	88	147
Fixed O+M	21	21	21
Variable O+M	3	3	3
Fuel	66	66	66
Carbon	41	41	41
Total	**200**	**226**	**287**

299 MW peaking

Cost category	£/MWh		
	Low	Mid	High
Pre-development	2	2	2
Construction	16	23	38
Fixed O+M	7	7	7
Variable O+M	3	3	3
Fuel	66	66	66
Carbon	41	41	41
Total	**135**	**142**	**157**

299 MW critical peak

Cost category	£/MWh		
	Low	Mid	High
Pre-development	6	7	9
Construction	64	92	148
Fixed O+M	21	21	21
Variable O+M	3	3	3
Fuel	66	66	66
Carbon	41	41	41
Total	**201**	**230**	**288**

100 MW peaking

Cost category	£/MWh		
	Low	Mid	High
Pre-development	4	4	6
Construction	32	38	53
Fixed O+M	10	10	10
Variable O+M	4	4	4
Fuel	65	65	65
Carbon	40	40	40
Total	**155**	**162**	**178**

100 MW critical peak

Cost category	£/MWh		
	Low	Mid	High
Pre-development	15	18	22
Construction	125	150	210
Fixed O+M	31	31	31
Variable O+M	4	4	4
Fuel	65	65	65
Carbon	40	40	40
Total	**280**	**307**	**371**

P.4 Reciprocating engines results

Gas peaking

Cost category	£/MWh		
	Low	Mid	High
Pre-development	1	1	1
Construction	19	29	52
Fixed O+M	-11	-11	-11
Variable O+M	2	2	2
Fuel	69	69	69
Carbon	33	33	33
Total	**113**	**124**	**147**

Gas critical peak

Cost category	£/MWh		
	Low	Mid	High
Pre-development	3	4	5
Construction	74	115	207
Fixed O+M	-37	-37	-37
Variable O+M	2	2	2
Fuel	69	69	69
Carbon	33	33	33
Total	**145**	**186**	**279**

Diesel peaking

Cost category	£/MWh		
	Low	Mid	High
Pre-development	1	1	1
Construction	15	22	37
Fixed O+M	-11	-11	-11
Variable O+M	2	2	2
Fuel	199	199	199
Carbon	44	44	44
Total	**249**	**256**	**272**

Diesel critical peak (500 hr)

Cost category	£/MWh		
	Low	Mid	High
Pre-development	3	4	5
Construction	60	87	146
Fixed O+M	-37	-37	-37
Variable O+M	2	2	2
Fuel	199	199	199
Carbon	44	44	44
Total	**270**	**299**	**359**

Diesel critical peak (90hr)

Cost category	£/MWh		
	Low	Mid	High
Pre-development	16	20	27
Construction	342	498	836
Fixed O+M	-205	-205	-205
Variable O+M	2	2	2
Fuel	199	199	199
Carbon	44	44	44
Total	**398**	**558**	**903**

P.5 Nuclear results

Nuclear FOAK

Cost category	£/MWh		
	Low	Mid	High
Pre-development	3	7	18
Construction	59	66	82
Fixed O+M	11	11	11
Variable O+M	5	5	5
Fuel	5	5	5
Carbon	0	0	0
Decommissioning and waste	2	2	2
Total	**85**	**95**	**123**

Nuclear NOAK

Cost category	£/MWh		
	Low	Mid	High
Pre-development	1	3	9
Construction	45	52	67
Fixed O+M	11	11	11
Variable O+M	5	5	5
Fuel	5	5	5
Carbon	0	0	0
Decommissioning and waste	2	2	2
Total	**69**	**77**	**99**

P.6 CCS results

CCGT post combustion CCS

Cost category	£/MWh		
	Low	Mid	High
Pre-development	1	2	3
Construction	34	41	53
Fixed O+M	5	5	5
Variable O+M	3	3	3
Fuel	57	57	57
Carbon	4	4	4
CO2 Capture and Storage	7	7	7
Total	**112**	**120**	**133**

CCS pre combustion CCS

Cost category	£/MWh		
	Low	Mid	High
Pre-development	1	2	3
Construction	33	40	52
Fixed O+M	5	5	5
Variable O+M	4	4	4
Fuel	65	65	65
Carbon	3	3	3
CO2 Capture and Storage	9	9	9
Total	**121**	**128**	**141**

CCGT oxyfuel CCS

Cost category	£/MWh		
	Low	Mid	High
Pre-development	1	2	3
Construction	34	41	53
Fixed O+M	12	12	12
Variable O+M	4	4	4
Fuel	60	60	60
Carbon	0	0	0
CO2 Capture and Storage	9	9	9
Total	**119**	**127**	**140**

CCGT retro CCS

Cost category	£/MWh		
	Low	Mid	High
Pre-development	1	1	1
Construction	22	26	33
Fixed O+M	5	5	5
Variable O+M	3	3	3
Fuel	57	57	57
Carbon	4	4	4
CO2 Capture and Storage	7	7	7
Total	**99**	**104**	**112**

IGCC full CCS

Cost category	£/MWh		
	Low	Mid	High
Pre-development	2	2	3
Construction	66	78	100
Fixed O+M	12	12	12
Variable O+M	5	5	5
Fuel	28	28	28
Carbon	11	11	11
CO2 Capture and Storage	18	18	18
Total	**142**	**153**	**176**

IGCC partial CCS

Cost category	£/MWh		
	Low	Mid	High
Pre-development	1	1	2
Construction	48	56	72
Fixed O+M	9	9	9
Variable O+M	5	5	5
Fuel	24	24	24
Carbon	61	61	61
CO2 Capture and Storage	5	5	5
Total	**154**	**161**	**178**

IGCC retro CCS

Cost category	£/MWh		
	Low	Mid	High
Pre-development	2	2	3
Construction	67	79	101
Fixed O+M	15	15	15
Variable O+M	6	6	6
Fuel	31	31	31
Carbon	13	13	13
CO2 Capture and Storage	20	20	20
Total	**154**	**166**	**189**

ASC full CCS

Cost category	£/MWh		
	Low	Mid	High
Pre-development	2	2	4
Construction	65	81	106
Fixed O+M	12	12	12
Variable O+M	3	3	3
Fuel	26	26	26
Carbon	11	11	11
CO2 Capture and Storage	17	17	17
Total	**135**	**152**	**178**

ASC partial CCS

Cost category	£/MWh		
	Low	Mid	High
Pre-development	1	2	3
Construction	40	49	66
Fixed O+M	9	9	9
Variable O+M	3	3	3
Fuel	22	22	22
Carbon	57	57	57
CO2 Capture and Storage	5	5	5
Total	**137**	**147**	**164**

ASC retro CCS

Cost category	£/MWh		
	Low	Mid	High
Pre-development	1	1	2
Construction	40	50	63
Fixed O+M	12	12	12
Variable O+M	3	3	3
Fuel	27	27	27
Carbon	9	9	9
CO2 Capture and Storage	17	17	17
Total	**109**	**120**	**133**

ASC oxyfuel CCS

Cost category	£/MWh		
	Low	Mid	High
Pre-development	1	2	3
Construction	61	72	92
Fixed O+M	11	11	11
Variable O+M	6	6	6
Fuel	25	25	25
Carbon	8	8	8
CO2 Capture and Storage	17	17	17
Total	**128**	**140**	**162**

ASC ammonia CCS

Cost category	£/MWh		
	Low	Mid	High
Pre-development	2	2	4
Construction	66	81	107
Fixed O+M	13	13	13
Variable O+M	3	3	3
Fuel	25	25	25
Carbon	10	10	10
CO2 Capture and Storage	16	16	16
Total	**135**	**152**	**178**

Biomass CCS

Cost category	£/MWh		
	Low	Mid	High
Pre-development	7	8	12
Construction	135	165	216
Fixed O+M	21	21	21
Variable O+M	8	8	8
Fuel	202	202	202
Carbon	0	0	0
CO2 Capture and Storage	42	42	42
Total	**414**	**447**	**501**

OCGT CCS

Cost category	£/MWh		
	Low	Mid	High
Pre-development	2	3	4
Construction	39	49	62
Fixed O+M	6	6	6
Variable O+M	3	3	3
Fuel	102	102	102
Carbon	8	8	8
CO2 Capture and Storage	13	13	13
Total	**173**	**183**	**198**

*Note that a biomass CCS plant would produce some carbon emissions that are not captured and stored. This follows DECC's modelling approach of treating non-biomass electricity generation technologies as carbon neutral. The potential benefits of biomass for negative emissions are not included in our analysis.

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P.7 Pumped storage results

Pumped storage

Cost category	£/MWh		
	Low	Mid	High
Pre-development	3	5	7
Construction	58	85	130
Fixed O+M	17	17	17
Variable O+M	42	42	42
Fuel	0	0	0
Carbon	0	0	0
CO2 Capture and Storage	0	0	0
Total	**120**	**148**	**195**