UK Electricity Generation Costs Update

June 2010

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Content

Tables

Figures

Executive Summary

Mott MacDonald

This report provides a summary and supporting documentation for Mott MacDonald's assessment of current and forward power generation costs for the main large scale technologies applicable in the UK. The work was commissioned by the Department of Energy and Climate Change and undertaken during October 2009 to March 2010.

One theme of this report is that determining the costs of generation is not an easy matter. So much depends on the scope of the project (exact technology and scale, numbers ordered, suppliers selected, bundled warranties, etc), the ruling market conditions (commodity prices, supply chain bottlenecks, etc) and the ability of the developer to manage costs. This is especially so for the less proven technologies such as (third generation) nuclear, offshore wind and coal/gas plants fitted with carbon capture and storage (CCS). The main challenge for these less mature technologies is to understand the extent of the first of a kind (FOAK) premium and a large part of this depends on the responsiveness of the supply chains. More generally, uncertainty derives from the commodity prices for fuels and carbon, while performance variations play a secondary role. All this means that any assessment of levelised costs is subject to large bands of uncertainty, which implies that the relative ranking of different technologies can also shift markedly.

Levelised cost of generation is the lifetime discounted cost of an asset expressed in cost per unit energy produced

Levelised cost of generation is the lifetime discounted cost of ownership of using a generation asset converted into an equivalent unit cost of generation in £/MWh or p/kWh. This is sometimes called a life cycle cost, which emphasises the cradle to grave aspect of the definition.

In our definition here, we are considering the boundary for the costing as being the generation assets and transmission interconnection to the nearest land based substation, with the energy being defined at the transmission system side of the main transformer (often called the busbar cost or station gate cost). We consider the costs borne only by the owner in relation to its operation of the asset. It does not take account of impacts on the wider electricity system (such as reserve and balancing requirements, nor does it consider special revenue support measures (ROCs or capital grants etc). Lastly it also excludes any externalities related to the activity (from the plant itself or from the fuel supply chain impacts) except to the extent that these are internalised through the price of carbon.

Generating plant can be broadly categorised either as being expensive machines for converting free or low cost energy into electrical energy or else lower cost machines for converting expensive fuels into electrical energy. The former group comprises most renewable generation and nuclear plant, while the later group comprises plant running on fossil fuels or else biomass.

For the capital intensive plant the major drivers of levelised costs are clearly the EPC (engineering, procurement and construction) costs and outturn capex costs, the build time and the average annual plant capacity factor (ACF): the higher the ACF the greater the fixed cost dilution. Hence the focus on finding locations for wind farms that maximise the wind yield and reducing outage time at nuclear stations and for that matter wind.

Generation plant can have very different costs structures – balance between fixed and variable, front and operations loaded

For the expensive fuel converters, the primary drivers of costs are the efficiency of fuel conversion, the price of fuel and the extent of carbon penalty. That said, for coal plant, capital efficiency is also an issue, given coal is priced well below gas on a burner tip[1] basis and also given the much higher capital requirements of fired-boiler-steam turbine combinations versus GT-based technologies[2] (such as open cycle GT, CCGTs and CCGT based CHP). Indeed the capital costs of coal plant are typically a larger element of levelised costs than fuel and carbon combined. Of course, adding carbon capture and storage to a coal (or CCGT) plant, further shifts the balance towards capital costs, due to the increased capital burden, especially measured in net output terms. Fuel costs also go up though, because of the decrease in conversion efficiency from running CCS.

Excluding CCS, the hierarchy of capital costs runs as follows: nuclear is more expensive than coal (due to the much greater cost of a "reactor island" versus a "coal boiler island" and the more substantial and complex civil works (foundations and buildings); coal is more expensive than oil fired plant given higher fuel handling costs. Fired boiler-steam plant is more expensive than CCGTs as the GT and associated heat recovery steam generator is much lower cost than a fired boiler, even without adding the mandatory "bolt-on" clean-up equipment of flue gas desulphurisation (FGD) and selective catalytic reduction (SCR). In turn CCGT costs some 50% more than an equivalent open cycle GT given the lower cost of GT than HRSG and steam turbines.

[1] Burner tip basis means all costs incurred in delivering to the combustion installation and typically measured on an energy unit basis, eg £/GJ

[2] There are some exceptions, such as integrated gasification combined cycle plant which involve effectively adding a complex coal gasifier and gas treatment plant in front of a CCGT.

Looking at renewable plant capital costs, biomass combustion based plant can be seen as an expensive (smaller scale) version of a coal plant with more demanding fuel handling requirements. This also increases its auxiliary power use. For wind plant, going offshore increases the capital costs due to the more complicated foundations, offshore assembly and also the electrical cable connection to shore, while maintenance and servicing is more challenging.

Levelised costs likely to be much higher than generation costs and prices prior to 2006

In a world with carbon constraints and rising real fuel prices we must expect the levelised costs of generation to be somewhat higher than we have seen in recent decades. In the first few years of the new millennium, the spike in commodities prices, combined with insufficient investment in supply chains has meant that equipment prices for most power generation equipment and construction services are at historically high levels. This means that a plant ordered today would be expensive. EPC prices are expected to fall in the near to medium term, as the supply chain bottlenecks are addressed.

Another feature of the next decade is likely to be the mobilisation of investment in new technologies, particularly CCS and third generation nuclear, both of which are likely to incur significant learning premiums in their early deployment. These FOAK premiums on capital costs can reasonably be expected to be in the 20%-40% range.

In terms of running costs, fuel and carbon are the main drivers, but the former are subject to the balance of supply and demand, while the latter depends on the complex mix of regulatory interventions and market fundamentals. The range between the plausible low and high scenarios for these variables is of the same order of magnitude as the levelised costs of new capital intensive zero carbon generation.

All this means that there is huge uncertainty in any estimates of levelised costs, even for the mature technologies of CCGT and coal.

With this in mind, our analysis draws the following conclusions for a central case.

CCGTs running on gas have both a lower capex and lower levelised cost than the main baseload generation alternatives with a levelised generation cost (LGC) around £80/MWh in our base case, which adopts DECC's central projections for fuel and carbon[3]. Gas prices

[3] In these central case, according to DECC projections, gas prices are projected to

have to exceed the DECC high case for CCGT to look unattractive, and/or coal EPC prices would have to return to levels seen in 2006, which we are not projecting even in 2020. This levelised cost projection for CCGT compares with consensus estimates of about £25/MWh (about £33/MWh in 2009 money) made a decade ago.

Given the projected increase in carbon prices, the LGC of advanced super critical coal is significantly above that for CCGTs, at £104.5/MWh for a 2009 project start. In the medium to long term, escalating carbon prices more than offsets the projected reduction in coal's EPC premium and its increased fuel cost advantage. Moreover, this excludes the current requirement for large coal plant to fit 300MW of CCS capacity from the outset.

Integrating CCS into coal or gas fired plant would substantially raise capital and operating costs. Under DECC's central carbon price projection, the premium for CCS versus un-scrubbed plants is £32-38/MWh, although the carbon costs on the un-scrubbed coal and gas plants is £40/MWh and £15/MWh, respectively. In the longer term, as these technologies move to NOAK status, the levelised costs of CCS equipped plant will undercut those for the un-scrubbed plant. Even then, the CCS equipped plants still see levelised costs of £105-115/MWh with gas at the lower end, and coal at the upper end of the range. Adopting DECC's low carbon price projection would see the CCS equipped plant retaining a cost premium versus non equipped plant through the 2020s.

Gas fired CCGT expected to be least cost main technology option in near term

Integrated gasification combined cycle (IGCC) is shown to have a significant cost premium versus advanced super critical coal plant, which reflects the still largely demonstration status of this technology. In the longer run, especially once CCS is incorporated its costs move broadly in line with advanced supercritical coal (ASC) with CCS.

The leading 3rd generation nuclear designs, although projected to incur a significant FOAK premium have a lower levelised cost at £99/MWh than an ASC coal plant without CCS, but still significantly higher than CCGT. In the longer term as nuclear moves to NOAK status, and as carbon and fuel prices rise, nuclear is projected to become the least cost main generation option with costs around £67/MWh, some £35-45/MWh below the least cost fossil fuel options. This substantial

increase to 74 pence a therm by 2030, while CO2 increases to £70/t CO2e in the same year.

advantage is partially eroded if much lower fuel and carbon prices are assumed and is only overturned if we apply our higher capital cost profile.

Nuclear projected to be least cost option in longer term, assuming DECC's central fuel and carbon assumptions

Onshore wind is the least cost zero carbon option in the near to medium term, with central cost estimate of £94/MWh some £5/MWh less than nuclear on a FOAK basis. Offshore wind is much more expensive, with costs of £157-186/MWh (depending on wind farm location). While offshore is projected to see a large reduction in costs, compared with onshore wind, it will still face much higher costs at £110-125/MWh for projects commissioned from 2020.

Of the minor generation technologies, the CHP options considered here offer the lowest cost power, once the steam revenues are factored in. This assumes that the projects are able to secure a 100% off-take for their steam over the whole plant life. The biomass fired schemes, which have much higher heat-to-power ratios, have the lowest net costs, even seeing negative costs in the medium to long term. This latter result is largely the result of the escalation in carbon prices assumed here. In practice, given there are limited ideal steam off-takers, steam revenues will probably be significantly less, and hence net costs will consequently be higher. However, even if the biomass CHP schemes can capture half of the projected steam credit, the costs would still be less than £70/MWh in 2020.

Power only biomass fired steam turbine based plant are projected to have levelised costs which straddle those for ASC coal. The largest biomass plant (300MW) has costs of £102/MWh based on current EPC prices for projects started in 2009. High capital, fuel and non fuel operating costs versus coal are offset by avoided carbon cost for biomass. Over time, as carbon prices increase, biomass plant's position is projected to improve such that it undercuts CCGTs and even onshore wind, so that its cost in 2023 is just over £84/MWh. Learning effects for biomass combustion technology are likely to be of second order importance versus these commodity price movements.

Of the three bio-methane based gas engine options – only landfill gas and sewage gas provide levelised costs well below the projected CCGT cost with costs in the £50-60/MWh range. Anaerobic digestion of agricultural wastes, is somewhat higher, given the higher burden of capital and fixed costs assumed to be carried by the generator rather than the gas provider.

Projected levelised costs and rankings are sensitive to assumptions regarding, discount rates, fuel and carbon prices and exclude considerations of grid support, balancing requirements, embedded benefits, environmental impacts; and are not the same as bankability

The above general findings should be interpreted with care. The relative ranking and changes through time are heavily influenced by the fuel and carbon prices adopted. In our base case we are using DECC's latest central projections. The position would be very different if we had assumed current fuel and carbon prices were maintained: essentially, the relative ranking of the fossil fuel based options would be improved, though nuclear, onshore wind, CHP and the lower cost bio-methane options would still be the lower cost options.

There are a number of other important caveats that must be attached to these figures.

- The cost estimates are generally for base-load energy on common assumptions of load factor (though wind is constrained by energy availability), and as such we are ignoring the issue of dispatch risk which depends on the plant's expected merit position over its life.
- No consideration is provided here for differences between technologies for the requirements for reserve and balancing services, or in terms of transmission network reinforcement impacts.
- We have not commented on (or quantified) the vulnerability of particular technologies to fuel supply and other interruptions, which varies considerably between technologies.
- Embedded benefits for smaller scale generators connected to the distribution networks are not considered.
- Externalities relating to environmental and social impacts of construction, operation and fuel supply chains are excluded, except to the extent that they are internalised through the carbon price.

The relative ranking of LGCs does not necessarily closely relate to the ability to finance technologies in the real world. Developers in practice factor in risk premiums, the appetite of lenders and the broader impacts on their own corporate financial positions. Once these factors are considered CCGTs and onshore wind projects are often easier to finance than most other technologies.

1. Introduction

This report provides a summary and supporting documentation for Mott MacDonald's assessment of current and forward power generation costs for the main large scale technologies applicable in the UK. The work was commissioned by the Department of Energy and Climate Change and undertaken mainly between October 2009 and March 2010. The report accompanies a spreadsheet model that generates levelised costs under different scenarios of underlying assumptions.

One theme of this report is that determining the costs of generation is not an easy matter. So much depends on the scope of the project (exact technology and scale, numbers ordered, suppliers selected, bundled warranties, etc), the ruling market conditions (commodity prices, supply chain bottlenecks, etc) and the ability of the developer to manage costs. This is especially so for the less proven technologies such as nuclear (third generation pressurised water reactors), offshore wind and coal/gas plants fitted with carbon capture and storage. The main challenge for these less mature technologies is to understand the extent of the first of a kind premium and a large part of this depends on the responsiveness of the supply chains. More generally, uncertainty derives from the commodity prices for fuels and carbon, while performance variations play a secondary role. All this means that any assessment of levelised costs is subject to large bands of uncertainty which implies that the relative ranking of different technologies can shift markedly.

This report is structured in seven sections:

Section 2: outlines our definition of levelised costs, the main building blocks, data sources and our assessment process

Section 3: outlines the key drivers of power generation costs at a generic level

Section 4: shows how levelised costs are built up

Section 5: reviews the key issues affecting costs and performance for the main technologies

Section 6: outlines the main global assumptions and presents the key assumptions on plant costs and performance

Section 7: presents the key results of the study, including some sensitivity tests

Section 8: provides a number of high level concluding comments with some critical caveats

2. Definitions, building blocks and data sources

2.1 Definition of a levelised cost

Levelised cost of generation is the discounted lifetime cost of ownership of using a generation asset converted into an equivalent unit cost of generation in £/MWh or p/kWh. This is sometimes called a life cycle cost, which emphasises the cradle to grave aspect of the definition.

There are three aspects for defining this further. What assets are included? Whose costs are we considering? And what is relevant time period?[4]

Levelised cost of generation is the discounted lifetime cost of owning and operating a power plant expressed on a per unit of output basis

In our definition here, we are considering the boundary for the costing as being the generation assets and transmission interconnection to the nearest land based substation, with the energy being defined at the transmission system side of the main transformer (often called the busbar cost or station gate cost). Costs of using networks beyond the station are only counted to the extent that this is a charge upon the owners that is required to get energy to the station gate. This would apply for the appropriate use of system charges for the main interconnected transmission system, exit charges for gas networks and charges for using a CO2 transport and storage network. A full levelised cost of electricity (as opposed to generation) would include the remaining costs of the transmission network and all the costs of building and running the distribution network and supply administration, and would also correct for network losses. These non-generation costs of electricity supply are typically the same order of magnitude as the levelised costs of generation.

The definition of levelised costs considered here considers only the costs borne by the owner in relation to its operation of the asset. It does not take account of impacts on the wider electricity system (such as reserve and balancing requirements, nor does it consider special revenue support measures (ROCs or capital grants etc). Lastly it also excludes any externalities related to the activity (from the plant itself or from the fuel supply chain impacts) except to the extent that these are internalised through the price of carbon.

Timing is the last dimension and it is important for three reasons:

- the date of ordering the plant will normally lock in a large part of the capital cost, which is important in a world where equipment prices vary by market condition and through learning effects;
- the assumed operational life time of the plant determines the period over which costs are smeared;

[4] There are other issues that are important in defining the levelised cost, such as the choice of discount rate, which are mentioned in section 4 of this report.

- the discount rate will determine the balance of weight given to near and distant cash flows.

2.2 Main components of levelised cost

There are three main components of levelised costs:
- The investment (or capital) costs of bringing the asset to a point of operation;
- On-going fixed costs of keeping the plant available to generate;
- And the variable of costs of operation.

The first two items effectively determine the cost of capacity, while adding the last and dividing by the running hours, gives us a unit cost of generation.

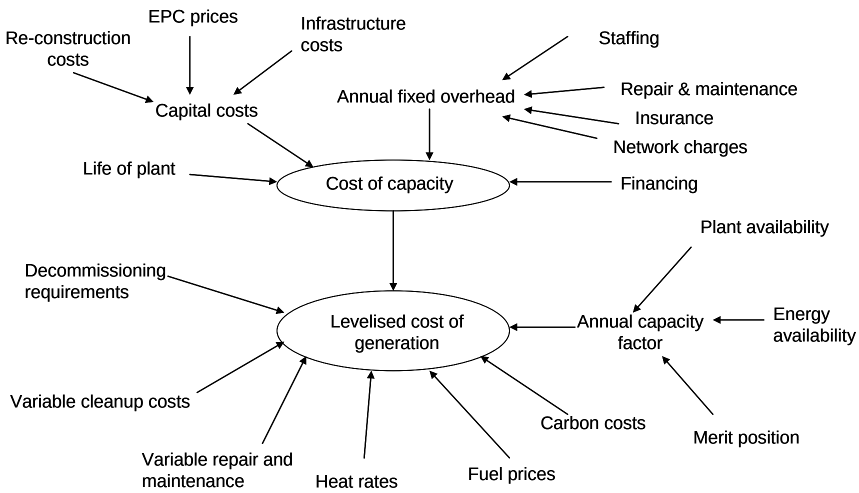
Main components of levelised costs comprise:

Investment costs

Fixed operating costs

Variable operating costs (including fuel and carbon)

Figure 2.1: Drivers of levelised costs of generation



The capital cost comprises four main items:
- The main plant and equipment package, typically called the engineering, procurement and construction (EPC) price, although this can be multiple packages. Key issues are the scope of these packages and the risk premiums to be added on.
- Infrastructure / connection costs including power, fuel and cooling system if necessary. The extent of these components will depend on whether the EPC wrap includes or excludes these items.
- Development costs including permitting, advisory services, land options / purchase. The levelised cost analysis here excludes land costs.
- Interest and funding cost during construction (- our default approach here is to apply a single discount rate to all cash-flows including the schedule of capital expenditures).

A commonly used term to describe capital costs excluding the financing terms is the overnight cost. The problem is that there is no generally recognised definition, although it is supposed to capture the investment costs at the time the project goes ahead. One problem with this definition is how to handle cost escalation and contingencies for the period during the construction period. The approach adopted in this report is to define the overnight cost as the projected outturn EPC cost, excluding financing charges. We also exclude owners' predevelopment costs (approvals, site preparation, etc) and infrastructure costs, outside of the EPC wrap.

The main fixed operating costs comprise the following:
- Operating labour
- Planned and unplanned maintenance (additional labour, spares and consumables)
- Through life (time dependent) capital maintenance
- Property taxes (rates), insurance and network use of system charges

Variable costs of operation include fuel, carbon, output related repair and maintenance and residue disposal and treatment. Fuel and carbon costs are determined by the type of fuel, heat rate, and fuel and carbon prices. Repair and maintenance costs tend to be influenced by the plant type, fuel used and operating regime. Residue disposal and treatment are largely determined by the fuel used and compliance requirement regarding residues.

One area which is difficult to categorise is decommissioning costs. These are often treated as an additional capital cost, which is incurred after the operating life of asset. The alternative is to make a provisioning allowance in either annual fixed costs or variable costs which would lead to the accumulation of funds over the operating life of the asset, such that it equals the projected decommissioning liability.

As recommended by DECC this study assumes a fixed decommissioning charge per MWh for nuclear plant that is incurred over the operating life. For all the remaining technologies we have assumed that the decommissioning liabilities are offset by the residual value of the assets. This is a reasonable assumption given the scrap value of assets is generally close to the decommissioning liabilities, furthermore due to discounting these values tend to be very small.

2.3 Data sources

The first challenge in estimating the cost of electricity generation is finding appropriate data and interpreting it. There are a number of key questions to address in examining data:
- How reliable is it?
- What is included in the scope?
- How current is it?

- Is it representative?

Cost data is not readily available – and when it is, it requires careful interpretation

Reliability: The most reliable data is likely to be the detailed prices and terms from commercially confidential contracts between vendors and purchasers. The issue is most straight forward where there exists a single turnkey or Engineering Construction and Procurement (EPC) contract with a fixed price. However, this is rare nowadays for most large power generation projects. Even where there is a single EPC contractor, the contract is likely to include elements that are subject to revision, depending on modifications in scope, market conditions etc. Where there are multiple contracting parties, this becomes even more complicated.

Vendors' tender price offers may provide another reasonably reliable estimate of EPC prices, especially if they are the final prices (often called the best and final offer (BAFO) and the project goes ahead. There is a question as to the validity of tender prices, and for that matter, EPC prices for projects which do not eventually go ahead. One could argue that we should not consider a proposed project if the developers couldn't bring it to fruition. However, if there is no other better data, then tender prices (for unrealised projects) provide the best snapshot of what costs would have been. They provide some shape to a real cost trend, although the transaction volume is lacking.

Press releases from original equipment manufacturers (OEMs) and/or developers can provide a high level price, however often in this case it is difficult to ascertain the scope and terms. The same applies to most press reports.

Studies and surveys by international agencies, academic and industry institutes can provide useful insight in terms of comparative levels across jurisdictions and technologies, although they are rarely based on real projects.

Scope and terms: the scope of works and the price terms for which the headline price relates can vary hugely. Typically EPC contract prices will provide a base price to which adjustments need to be made for material and sub-component price movements or variations for design changes called for by the developer. These EPC bases prices also tend to exclude grid connection (except in the case of wind), off-site fuel supply facilities (ports, gas connections, etc) and decommissioning. They also exclude owners development costs (design and feasibility studies, planning and licensing, etc) and financing costs (interest during construction and other financing charges).

Another aspect of scope is the technical definition of the plant in terms of its technology, associated facilities and any particular issues or constraints arising from its location. Non-UK experience needs to be adjusted for different project management and working practices, local materials and labour cost differences. Also, there is an issue of the appropriateness of technology to UK situation (- for instance, experience in Chinese supercritical coal and Korean nuclear technology is of limited relevance to the UK in the near to medium term). One also needs to take into account unit scale issues, impacts of multiple unit installations and series ordering in making price comparisons.

Terms of pricing also needs to be defined in terms of currency and the date to which the price refers and any agreed indexation, beyond the subcomponent indexation arrangements.

Timeliness: This is the most straight forward question as all that is required is to define the date to which the data refers. The more time that has passed since the date, the greater is the prospect that changes will have made the prices unrepresentative of current levels. This is especially so for the EPC market conditions, though much less so for technology improvements, which tend to advance at a slower rate. These issues are discussed in the next chapter.

Cost estimates often have to be based on potential projects

Fair representation: How representative the cost data is will depend largely on whether the scope and the timing can be easily adjusted to our chosen representative plant technology and size. There are a number of examples where overnight prices have hugely underestimated the outturn costs and so cannot be considered representative. This may reflect vendor optimism or a strategic choice to get the technology into market, or special financing terms, or a variety of mishaps. It is well known that a bundled financing package that may come with a particular vendor's offer, for instance, a soft loan offered by export credit agencies, can increase the attractiveness of a quoted overnight price.

Another aspect of how representative the data is the number of deals that are done at the price. It is often the case that when prices spike in a market, then the level of completed transactions falls as buyers hold back waiting for prices to fall or else cancel plans where the project is discretionary. Similarly, at times of price slumps in the market, less business may be done, as buyers may be financially stressed or else take a pessimistic view of the market outlook.

Cost data also needs to be viewed in the context of its relationship with cost data/estimates for related technologies. There are many shared components between technologies and so technology costs should broadly move together. A CCGT typically costs some 50% more than a comparable sized OCGT. A nuclear station will cost 30-50% more than a coal station, given the complexity of its foundations and buildings, and the higher cost of the reactor and cooling system versus a supercritical boiler.

Faced with these challenges, we are unavoidably forced to make informed judgements as to the capital costs of the different technologies. In most cases these have been anchored on confidential tender submissions or actual EPC awards. In a few cases where we lack such information, our estimates are built upon engineering cost estimates and OEM/EPC contractor's estimates for new projects starting in the pipeline today (late 2009/early 2010). For some cost elements, such as CO2 transport and storage, we have taken a view based on published estimates, while for fuel and carbon prices we have used projections provided by DECC.

3. Drivers of costs

3.1 Cost structures

Generating plant can be broadly categorised either as being expensive machines for converting free or low cost energy into electrical energy or else lower cost machines for converting expensive fuels into electrical energy. The former group comprises most renewable generation and nuclear plant, while the later group comprises plant running on fossil fuels or else expensive biomass.

For the capital intensive plant the major drivers of levelised costs are clearly the overnight and outturn capex costs, the build time and the average annual plant capacity factor (ACF): the higher the ACF the greater the fixed cost dilution. Hence the focus on finding locations for wind farms that maximise the wind yield and reducing outage time at nuclear stations and wind.

Cost structures vary from capital intensive machines with low running costs to lower cost machines with high running costs

For the expensive fuel converters, the primary drivers of costs are the efficiency of fuel conversion, the price of fuel and the extent of carbon penalty. That said, for coal plant, plant utilisation is also an issue, given coal is priced well below gas on a burner tip[5] basis and also given the much higher capital requirements of fired-boiler-steam turbine combinations versus GT-based technologies[6] (such as open cycle GT, CCGTs and CCGT based CHP). Indeed the capital costs of coal plant are typically a larger element of levelised costs than fuel and carbon combined. Of course, adding carbon capture and storage to a coal (or CCGT) plant, further shifts the balance towards capital costs, due to the increased capital burden, especially measured in net output terms. Fuel costs also go up though, because of the decrease in conversion efficiency from running CCS.

Excluding CCS, the hierarchy of capital costs runs as follows: nuclear is more expensive than coal (due to the much greater cost of a “reactor island” versus a “coal boiler island” and the more substantial and complex civil works [foundations and buildings]); coal is more expensive than oil fired plant given higher fuel handling costs. Fired boiler-steam plant is more expensive that CCGTs as the GT and associated heat recovery steam generator is much lower cost than a fired boiler, even without adding the mandatory “bolt-on” clean-up equipment of flue gas desulphurisation (FGD) and selective catalytic reduction (SCR). In turn, CCGT costs some 50% more than an equivalent open cycle GT given the lower cost of GT than HRSG and steam turbines.

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[6] There are some exceptions, such as integrated gasification combined cycle plant which involve effectively adding a complex coal gasifier and gas treatment plant in front of a CCGT.

Looking at renewable plant capital costs, biomass combustion based plant can be seen as an expensive (smaller scale) version of a coal plant with more demanding fuel handling requirements. This also increases its auxiliary power use. For wind plant, going offshore increases the capital costs due to the more complicated foundations, offshore assembly and also the electrical cable connection to shore, while maintenance and servicing is more challenging.

3.2 Commodity drivers

Commodity prices are an input into both the capital costs and ongoing running costs. For capital goods the main commodities are the non-energy commodities, particular metals and to a lesser extent chemicals and rubber (for tyres), with energy playing both a direct and indirect role (via diesel and electricity driven construction plant and indirectly via increasing commodity costs [metals, chemicals and cement]). Projected shortages of rare earth materials have been cited as another possible driver of future prices, however this is unlikely to be a significant impact as for power generation there is normally alternative material and or design options to bypass the scarcity.

The fuel and carbon price projections used in this report have been provided by DECC

For ongoing costs of thermal plant, fuel commodity prices play a key role in determining variable operating costs. This is especially so for oil and gas fired plant, and to a lesser extent for coal plant. EU allowance prices have become a significant commodity price driver influencing variable generation costs since 2005. At a €40/t CO2e carbon price – a level projected by PointCarbon and some equity analysts - a new advanced super critical coal plant would incur a variable cost penalty of over £25/MWh.

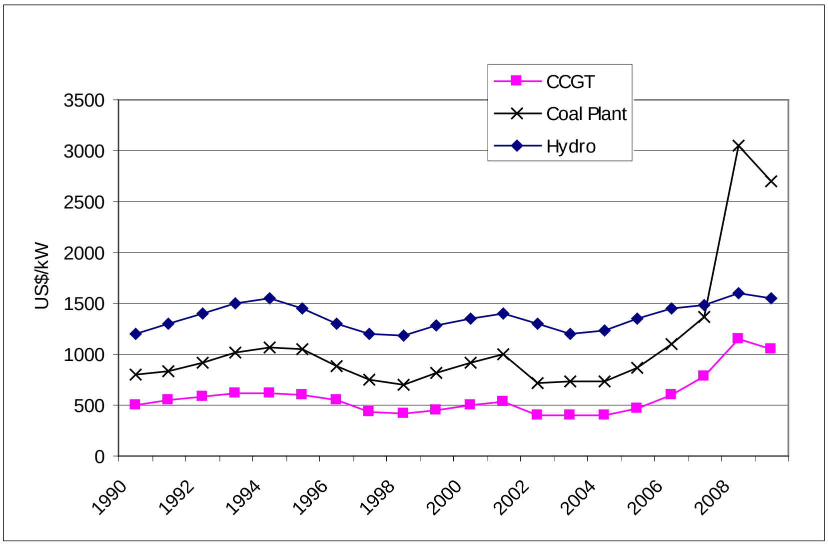
3.3 Market conditions

That current and expected market conditions can have a major impact on capital costs of plant is evident by the movements in EPC prices for the main mature technologies. Figure 3.1 and Figure 3.2 show Mott MacDonald's own assessment of international EPC prices for CCGTs and coal plant since 1990 in nominal and real $/kW terms, respectively. Both charts show that prices followed a cyclical pattern until 2006, when prices increased markedly to peak in 2008 before softening slightly in 2009. This trend is broadly consistent with that PCCI[7] power station construction cost index reported by IHS-CERA – see Figure 3.3. However, the PCCI index has seen a less marked increase than observed in EPC tender prices and quotes. This probably reflects the PCCI focus on component costs which may miss an element of margin taken by EPC contractors.

[7] PCCI stands for the Power Capital Costs Index. This index tracks the costs associated with the construction of a portfolio of 30 different power generation plants in North America. Technologies include coal, gas, wind and nuclear power plants. Values are indexed to year 2000.

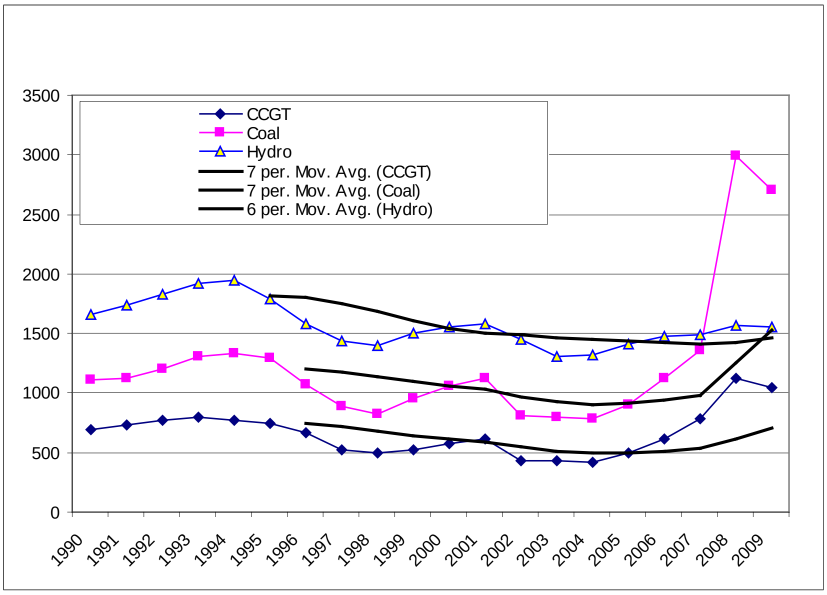
EPC prices spiked in 2007-2008 and remain well above the long term average

Figure 3.1: EPC prices in nominal $/kW



Source: Mott MacDonald

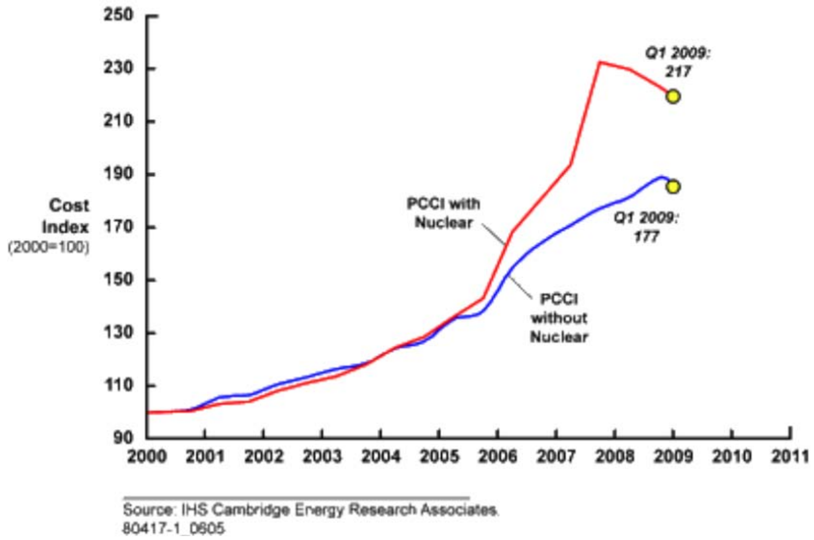
Figure 3.2: EPC prices in constant 2009 $/kW



Source: Mott MacDonald

EPC price trend mirrored by component cost index

Figure 3.3: CERA's Index (PCCI) of Power Plant Capex



Source: IHS Cambridge Energy Research Associates

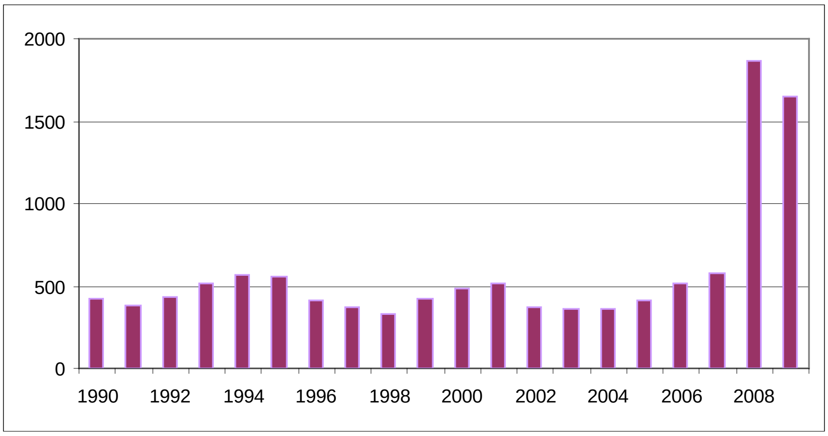
The 2007/08 spike in EPC prices and construction costs is thought to have been caused by a combination of factors:

- A spike in commodity prices;
- Bottlenecks in the supply chain, which led to vendors pricing for risk in all layers of the supply chain
- Full order books for the main OEMs and EPC contractors – both of which have seen serious shortages of skilled managers
- Vendors and EPC contractors taking margins through limited competition
- A depreciation of the US dollar versus the Yen and Euro.

Coal EPC premium versus CCGT, which has traditional been around $500/kW, is now about $1600/kW

Equipment prices for all the main plant and equipment remain elevated compared to the levels in 2006. What is interesting to note is that the price for large coal and nuclear plant saw a disproportionate rise versus GT based plant, such as CCGTs. For coal plant the premium versus CCGT rose from about $500/kW to peak at $1900/kW before coming back down to about $1600/kW (- see Figure 3.4). This capex disadvantage has had the impact of offsetting the increase in the gas-to-coal price differential at the burner tip.

Figure 3.4: Coal's EPC premium versus CCGT in $/kW



Source: Mott MacDonald

One of the major uncertainties for the relative position of coal versus gas fired CCGTs is the extent and timing of the decline in coal's capex premium versus CCGT. It is likely that that investment in the supply chain, particularly for the larger forgings and thick rolled plate will ease the bottlenecks for some of the specialist components and so lower prices. Simultaneously, it is likely that the Chinese OEMs of coal plant will address the issue of design certification and so provide competition for the Japanese and Western vendors in a wider range of markets, thus depressing prices globally.

3.4 Economies of scale

There are significant economies of scale in generation technology, especially for steam turbine based plant using either reactor or coal boilers as prime mover[8]. The main OEMs for supercritical coal plant are looking at units of 600-900MW. The nuclear vendors have pushed the current standard up to 1000-1600MW. In both cases we are probably reaching a practical limit as few buyers want to add increments of over 1000MW. It is easier to add multiples and so phase expansion and spread the burden of financing.

The benefits of scaling up GT based plant are much less as F class machines currently set the maximum size at around 300MW for a standalone machine and 450MW for a single shaft 1+1 CCGT configuration.

Multiple unit configurations can provide significant savings through allowing sharing of balance of plant equipment and support infrastructure, including civil works, grid connections, fuel facilities etc.

[8] In the context here, a prime mover is the core physical processing plant converting chemical or fissionable fuel energy to useful heat.

Typically, we would expect about a 15% saving in overnight costs per kW for CCGT and big steam power plant from a twin unit arrangement versus a single unit.

There may be potential savings for a developer that is able to place orders for a number of units for forward delivery over a significant time frame. This might apply for coal and nuclear units. The rationale is that a major OEM would be able to invest in its supply chain and provide contracts to underwrite its suppliers to do the same, and so reduce the costs of supply. The challenge would be how to capture those reductions as the OEM could equally well supply other developers buying a unit or two at a time on the same basis. There is an element of public good in such a forward order.

3.5 Complexity and energy density

The relative differentials between the capital costs of different generation technologies are driven by a combination of the complexity of the technology and its energy density. Energy technologies that can exploit more kWh of energy per square metre tend to generally use less material inputs (steel and concrete, etc) than those with lower energy densities. Technologies which employ complex designs and/or very demanding production processes tend to have higher capital costs per kW than less sophisticated technologies (that are typically more amenable to mass production techniques).

The nature of the prime mover (ie the key devices or processes which provide and harness the chemical or fissionable energy of fuel or physical motion of air or water) plays a key role in influencing costs. Where the prime mover is both very complex and large scale, and is not amenable to off-site mass production, or easy on-site fabrication, then the capital costs are likely to be high. This is the case for nuclear reactors and large super critical coal boilers. Gas turbines, although having a high degree of sophistication, are much more compact than coal boilers, and are largely built off site.

Capex costs reflect plant mass and complexity, with nuclear more expensive than coal and coal more expensive than gas fired CCGTs

The extent and complexity of civil works in terms of its mass, design complexity, requirement for specialist materials/ skills can also have a major impact on the capital costs. Nuclear plant, with their requirement for high design tolerances, complex and fortified building structures tend to have a very large civil work requirement, while open cycle gas turbine plant at the other end of the scale have more modest requirements. At issue is not just the nature of the civil structure, but also the complexity of constructing it. An offshore wind turbine generator (WTG) can often use a similar monopole structure to an onshore device; however extra material is required due to the added height of structure and there exists the added challenge of installing it in several tens of metres of water depth.

Fuel and residue handling requirements, which are largely related to the nature of the fuel rather than the conversion processes, can also have a significant impact on plant complexity and capital costs. For instance, a coal station will require a large number of fairly bulky mechanical appliances – conveyors, (often covered) coal stockyards with stacker-reclaimers, pulveriser mills, etc at the front end and then the acid gas and ash treatment equipment at the back end. This fuel cycle equipment typically accounts for 15-20% of a coal plant's EPC cost. The equivalent fuel cycle systems on a gas plant are 5% at most.

One last area which clearly affects the capital costs is the complexity of control systems and requirements for safety systems. Here, nuclear plant sit in their own special category, given the particular requirements for mitigating releases of radioactive materials, either as a result of an accident or some kind of malicious attack.

3.6 Technology progress and First of a Kind (FOAK) Premiums

For most mature technologies the main drivers of costs are market conditions and commodity prices, with some discounting for installations with multiple units. For these technologies, the main scope for technical progress is in the application of best practice construction management. Even though the UK has yet to build an advanced supercritical coal plant, there is likely to be comparatively little difference (less than 10%) between the first of a kind (FOAK) and the nth of a kind (NOAK) plant. CCGT technology is already at the NOAK level, as is onshore wind. Offshore wind still has some significant learning, especially in the area on cost effective foundations/anchoring and in reducing maintenance and servicing costs. Moving to deeper water and further offshore means wind faces a moving target as this tends to require new untried technical solutions.

Third generation nuclear plants and especially CCS are at an earlier stage, although for the former there are probably easier wins to be had in terms of improved project management than in technology changes.

Mostly, technological change progresses in an evolutionary manner, as OEMs and component manufacturers modify existing designs and try new materials and production techniques. There will from time to time be bigger step changes. Most of these still require a lengthy period of testing prototypes, however there may also be significant step improvements in some subcomponents. Possible breakthroughs under development include the application of advanced membranes which have application in hot gas clean-up for IGCC, post combustion carbon capture and air separation for oxy-fuel firing.

3.7 FOAK Premiums and Contingencies

Less mature, first-of-a-kind projects necessarily include a greater contingency element and premiums from undeveloped supply chains versus Nth-of-a-kind projects

Applying new technologies, new construction techniques and supply chain management necessarily involves additional risks compared with mature technologies. These risks are carried by the OEM and EPC contractor (or sponsor/developer where there is no EPC wrap) and the developer. It is these risks, often called contingencies that provide much of the difference between FOAK and NOAK prices.

As an illustration, Table Figure 3.1 shows the indicative build-up of FOAK and NOAK overnight EPC costs for a new nuclear station. The same issues apply for any new technology, such as conventional thermal plant with CCS, IGCC and offshore wind.

Table 3.1: Indicative build up of FOAK and NOAK overnight EPC costs for a nuclear plant in $/kW

FOAK build up		
Cost to build	3500	
FOAK premium	700	
Contractor's normal profit	300	
OEM's risk premium	250	
Headline EPC price		**4750**
Owners allowed contingency		750
Unallocated over-runs		500
Total overnight EPC cost		**6000**
NOAK build up		
Cost to build	3500	
Bulk discount/ supply chain upgrade	-300	
FOAK premium	0	
Contractor's normal profit	100	
OEM's risk premium	100	
Headline EPC price		**3400**
Owners allowed contingency		200
Unallocated over-runs		0
Total overnight EPC cost		**3600**

Source: Mott MacDonald

Both OEM and developers factor in contingencies

Overnight prices include the engineering, procurement and construction (EPC) price, costs incurred by the developer in acquiring and preparing the site for construction, any major infrastructure costs and any contingencies that parties will factor in.

The main features to note are:

The FOAK EPC price will comprise four elements:

1. the base cost of build, which is the underlying cost of equipment and construction;

2. A FOAK premium, which reflects the OEM and contractor's expectations of additional costs of undertaking the first projects;
3. The OEM and contractors' risk premium, which provides a contingency;
4. The OEM's and contractor's profit[9].

For a new technology, where OEMs and contractors have little track record the FOAK premium can be high. They may also apply a high risk premium and/or profit to reflect the risks they are bearing. This normally provides them some protection, however, it does not always outturn this was way, as cost overruns may erode profits and sometimes OEMs and/or contractors will incur losses on FOAK projects.

EPC prices are now rarely fixed, so developers need to allow for cost escalation

The headline EPC price normally forms the largest element of the overnight price. However, the EPC price may not be fixed, as now days it is common for various components to be indexed to some market indicator. As a result, developers will typically add a contingency allowance for any major capital project to allow for cost escalation of input materials and services, delays and re-working, etc. Normally, the contractual arrangements will define the arrangements by which the OEM/contractor and the developer will share these risks, however, in the end the developer tends to carry the residual cost overrun risk.

The implication of all this is that the FOAK overnight price can be substantially above the cost of build.

For a NOAK project, the situation is very different largely as the contingencies are substantially reduced.

EPC prices for mature technologies will by definition have no FOAK premium and minimal if any OEM/Contractor's contingency. Profit levels are likely to be low, given that OEM/Contractors are not seeking profit as a reward for risk.

Under a mature technology, it is possible that investments in the supply chain will have brought significant reductions in the cost of build, while bulk orders may also cut unit costs. The implication is that the EPC price will be close to the underlying cost to build for the FOAK project: in fact depending on the extent of investment in the supply chain, the headline EPC price may be less than the FOAK cost of build.

Developers' contingencies and unallocated cost overruns on mature technologies are likely to be small, such that the overnight price will be close to the headline EPC price. This situation may be complicated by the fact that even for mature technologies, there will be an element of pass through on some key material and component items which reflect

[9] This may depend on perceived risk.

volatile commodity pricing of some inputs. But even here, it is possible that a developer that commits to buy a large number of units over a number of years may be able to lock in a fixed price.

But the overall conclusion is that for NOAK projects the combination of learning from previous schemes and upgrading the supply chain capability can largely de-risk projects so as to produce a much lower overnight cost, which may outturn substantially below the FOAK levels.

Across all areas, most notably with nuclear and CCS technologies, the government is seeking to reduce the FOAK premium through measures designed to reduce the risks faced by contractors and developers. These are mainly aimed at reducing jurisdictional risks, and relate to streamlining the consenting processes in both planning and design certification.

4. Levelised cost model

4.1 Introduction

MML have developed an Excel spreadsheet model (henceforth called the Model) to allow the calculation and comparison of the levelised cost of electricity generation for each of the technology options. The Model is sufficiently flexible to allow the introduction of a number of sensitivity scenarios, in which the impact of variation in key assumptions on the cost of generation can be examined.

The Model uses input data in a standard template form for each technology, and for a number of global inputs, such as fuel and carbon prices. The Model then generates a cash flow forecast for the capital and operating costs of the project over the assumed lifetime of each technology reference plant. Net generation is calculated from gross generation minus auxiliary use. The projected cash-flows and net generation figures are then discounted (scaled) by a discount factor which gives a declining weight to distant values over near term values in the process called discounting. The levelised cost is the sum of discounted values of costs over the sum of discounted values of net generation.

4.2 Levelised Cost of Electricity Generation

Levelised unit costs divides total lifetime discounted costs by total discounted output (generation)

The levelised cost of electricity generation (LCG) is defined as the ratio of the net present value of total capital and operating costs of a particular plant to the net present value of the net electricity generated by that plant over its operating life, ie:

$$\textbf{LCG = TOTC / NPVEG}$$

LCG	=	Levelised Cost of Generation (£/MWh)
TOTC	=	Net Present Value (NPV) of total costs (capital and operating) (£)
NPVG	=	NPV of net electricity generation (MWh)

$$\mathbf{TOTC = \sum_{n=1} (TC_n / (1 + r)^n)}$$

$TOTC_P$	=	Net Present Value (NPV) of total costs (capital and operating) (£)
TC_n	=	Total costs for Power in operating year n (capital and operating costs) (£)

G_n = Net generation in operating year n

n = Operating year

r = Annual discount rate (10% real)

l = Operating life of plant

$$\textbf{NPVG} = \sum_{n=1} (G_n / (1 + r)^n)$$

The LCG therefore represents a minimum breakeven tariff expressed in £/MWh for each plant, based on the assumptions in the Model and the discount rate chosen.

The LCG is broken down in the Model into the contribution from capital costs, fixed operating costs, fuel and carbon costs and non-fuel operating costs.

Levelised costs can be seen as equivalent to the minimum break-even tariff

Table 4.1 provides an example of a levelised cost build-up for a hypothetical 1GW power station costing £1000m and running near baseload for much of its life. The values on the left half of the table are the undiscounted cash-flows, while those on the right are discounted values based on a 10% discount rate (as advised by DECC). The levelised cost result is shown at the bottom right. Figure 4.1 and Figure 4.2 show the cost breakdown and time profile of output in undiscounted and discounted terms, respectively, using the figure from the table.

Table 4.1: Example of levelised cost build-up for hypothetical power plant

	Un-discounted values						Discounted values				
	Capex: £m	Opex: £m	Fuel: £m	Total costs: £m	TWh output	Discount factor (based on a 10% d.r.)	Capex : £m	Opex: £m	Fuel: £m	Total costs: £m	TWh output
2009						1.000					0
2010						0.909					0
2011	50			50.0		0.826	41.3	0	0	41.3	0
2012	200			200.0		0.751	150.3	0	0	150.3	0

	Un-discounted values						Discounted values				
2013	400			400.0		0.683	273.2	0	0	273.2	0
2014	250			250.0		0.621	155.2	0	0	155.2	0
2015	100			100.0		0.564	56.4	0	0	56.4	0
2016		25	175.2	200.2	4.4	0.513	0	12.8	89.9	102.7	2.2
2017		25	297.8	322.8	7.4	0.467	0	11.7	138.9	150.6	3.5
2018		25	297.8	322.8	7.4	0.424	0	10.6	126.3	136.9	3.2
2019		25	297.8	322.8	7.4	0.386	0	9.6	114.8	124.5	2.9
2020		25	297.8	322.8	7.4	0.350	0	8.8	104.4	113.2	2.6
2021		25	297.8	322.8	7.4	0.319	0	8.0	94.9	102.9	2.4
2022		25	297.8	322.8	7.4	0.290	0	7.2	86.3	93.5	2.2
2023		25	297.8	322.8	7.4	0.263	0	6.6	78.4	85.0	2.0
2024		25	297.8	322.8	7.4	0.239	0	6.0	71.3	77.3	1.8
2025		25	297.8	322.8	7.4	0.218	0	5.4	64.8	70.3	1.6
2026		25	297.8	322.8	7.4	0.198	0	4.9	58.9	63.9	1.5
2027		25	297.8	322.8	7.4	0.180	0	4.5	53.6	58.1	1.3
2028		25	297.8	322.8	7.4	0.164	0	4.1	48.7	52.8	1.2
2029		25	297.8	322.8	7.4	0.149	0	3.7	44.3	48.0	1.1
2030		25	297.8	322.8	7.4	0.135	0	3.4	40.2	43.6	1.0
2031		25	280.3	305.3	7.0	0.123	0	3.1	34.4	37.5	0.9
2032		25	262.8	287.8	6.6	0.112	0	2.8	29.3	32.1	0.7
2033		25	245.3	270.3	6.1	0.102	0	2.5	24.9	27.4	0.6
2034		25	227.8	252.8	5.7	0.092	0	2.3	21.0	23.3	0.5
2035		25	210.2	235.2	5.3	0.084	0	2.1	17.6	19.7	0.4
Totals	1000	500	5571.4	7071.4	139.3		676.5	120.1	1343.2	2140	33.6
Levelised cost in £/MWh											63.7

Figure 4.1: Undiscounted costs and output profile for a hypothetical power plant

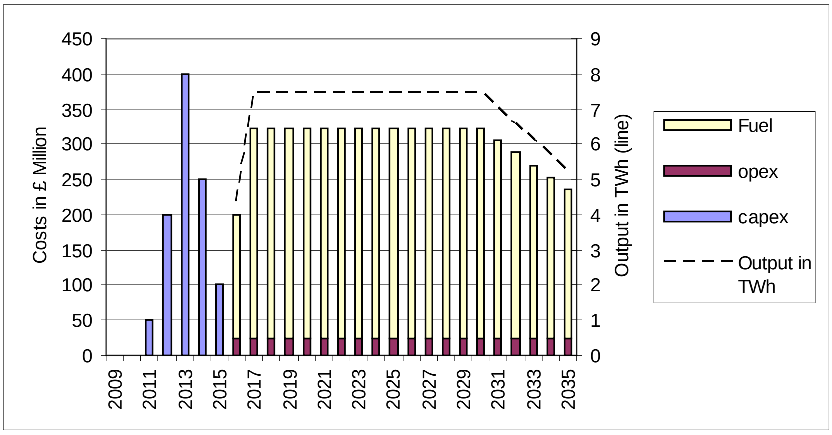
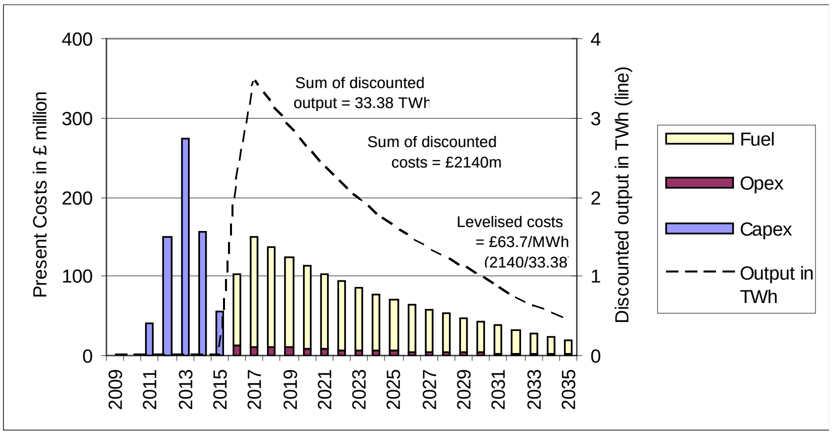


Figure 4.2: Discounted costs and output for hypothetical power plant



Source: Mott MacDonald

4.3 Model Assumptions

The Model contains assumptions with respect to the following areas for each technology:

- Project timings
  - Pre-development period
  - Construction period
  - Plant operating period

The input template also allows for decommissioning periods where decommissioning costs (capital spend at some point in the future) can be factored in. However, this facility has been overridden through applying an additional cash-flow charge, a so-called "provisioning fund" that is treated as an operational cost applied on output generated. The assumption is that the provisioning payments will accumulate over time to provide a fund that will be the appropriate size to meet the future waste and decommissioning liabilities.

- Technical data
  - Gross power output
  - Gross efficiency
  - Gross to net efficiency conversion
  - Efficiency profile on a yearly basis, to show degradation over the lifetime of each plant where appropriate
  - Availability profile on a yearly basis, to reflect the typical maintenance schedule and resulting outages
  - Load factor profile on a yearly basis.
  - Auxiliary power deduction on a yearly basis, to allow these to vary, such as would be the case for retro-fitted CCS
- Capital costs
  - Pre-licensing, technical and design costs
  - Regulatory, licensing and public enquiry costs
  - Construction costs

- Infrastructure costs

Levelised costs are built up from 13 cost items most of which are specified on a annual basis

These costs are phased annually in the Model, according to a typical payment profile and the project timing assumptions.

- Operating costs
  - Fixed operations and maintenance (O&M) costs (per MW capacity)
  - Variable O&M costs (per MWh gross generation)
  - Insurance
  - Connection and transmission network use of system (TNUoS) charges
  - CO2 transport and storage costs, where applicable

The input template also includes waste disposal and start-up costs, but these are not explicitly entered in the current analysis since these costs are typically small. Where waste disposal costs are significant, they are added into variable operating costs. Start-up costs are assumed to be zero since the comparisons here are for baseload or near baseload operation.

In addition, the Model contains a number of assumptions that apply across all technology options:

- Exchange rates (€1.10/£, $1.60/£)
- Discount rate (10% real)
- Fuel calorific values
- Fuel CO2 emissions factors for coal and gas
- Annual fuel price forecasts
- Annual carbon price forecasts

All price assumptions in the Model are in 2009 prices, although there are provisions for inflation to be included in the template.

The detailed assumptions for each technology and global assumptions are discussed in section 6, while the results are presented in Section 7.

4.4 Sensitivity Cases

The Model has the facility to include sensitivity cases for a number of the assumptions. Low, medium and high values are included in the Model for:

- All project timings
- Technical data:
  - Power output
  - Gross efficiency
  - Efficiency profile
  - Load factor profile
  - Auxiliary power profile
- All capital costs
- All operating costs

- CO_2 transport & storage costs
- Fuel prices
- Carbon price

Any combination of the low, medium and high sensitivity cases can be combined into a sensitivity scenario, to examine the impact on the levelised costs of each technology option. Note that the terms “low”, “medium” and “high” refer to the range for each cost and/or performance characteristic and so it may not make sense to combine across all the highs, or lows, but rather pick a meaningful combination.

5. Technology overview

5.1 Introduction

We focus on the proven and commercial (utility scale) technologies applicable to the UK

This chapter reviews the key features of the technology as they affect costs of development and operation for the main categories of generation technology and CCS:

- Gas fired GT based plant – OCGTs and CCGTs
- Advanced coal generation
- Carbon capture and storage (applied to gas and coal)
- Nuclear
- Renewables
- Combined heat and power

As mentioned above, all prices are quoted in 2009 money terms, unless otherwise stated.

Also it is assumed that all new orders of fossil fuel fired technology are designed in a way as to ensure they are capture-ready. This tends to have significant design and layout implications however the impacts on costs are minimal, with an uplift of capex of 1-2%. The assumptions outlining this are outlined below in the CCS section.

5.2 Gas-fired Gas Turbine Based Plant

5.2.1 Choice of representative technology

There are wide range of GTs that can be employed in open cycle operation ranging from modern aero-derivatives with high efficiency and rating up to about 100 MW, through less efficient (lower cost per kW) industrial machines, like the E class (rated around 130 MW) to the larger F class machines rated at 280 MW. For this study we have selected a single 100 MW aero-derivative machine for our open cycle plant.

For combined cycle the industry has almost universally used the F class industrial machine as its workhorse, though there are many configurations. In a UK context the industry seems to now favour building multiple units of single shaft blocks (1 gas turbine [GT] coupled on the same shaft to 1 steam turbine [ST]). These are now based on F class machines with a block capacity of up to 440 MW – although the ratings vary between OEMs.

Our chosen configuration here is a twin block installation with a gross capacity of 830 MW.

5.2.2 New-build Price levels in recent years

After a decade of cycling between $400 and $600 a kW installed EPC prices for CCGT increased sharply in 2007 and 2008 to peak at around $1250/kW in Q3:2008. This peak reflected tender prices: no actual transactions were done at these prices. Prices have since fallen, with current prices now around $1050/kW.

There have been a number of transactions in recent years, most of which we understand have been done at around the current US dollar level, however they benefited from a stronger pound. The devaluation of the dollar has meant that prices in sterling have seen a more modest softening.

5.2.3 Cost structures

Gas turbine technologies have virtue of having low investment costs, but the disadvantage of being reliant on premium fuels

The main components of CCGT are the GT, heat recovery steam generator (HRSG), steam turbine and condenser and cooling system. The main rotating parts (the GT, ST and the generator) tend to account for around 45-50% of the EPC price, the HRSG, condenser and cooling system around 20%, the balance of plant and electricals around 15%, the civil works around 15% and the remainder being miscellaneous other items.

The modest footprint of a CCGT power island (compressor-GT-HRSG and ST), the moderate cooling requirement and minimal fuel handling facilities mean the civil works element is small.

Fixed operating costs for CCGTs are low in comparison to most thermal generation technologies, given the low staffing required. Variable non-fuel operating costs however are more significant, as GTs require considerable ongoing maintenance in order to ensure availability. These costs are often incurred as part of a long term service agreement (LTSA), typically with the OEM, that is set up when the GT is procured. GT servicing and maintenance costs are typically much greater than those for steam turbines.

Clearly, though the largest variable cost component is fuel, which is determined by the running hours, heat rate and the average fuel price. Fuel costs can reasonably be expected to be more than half the total levelised costs of generation. Carbon is typically a much smaller component: given emission factors are about 40% of coal's and gas is higher price fuel, carbon is unlikely to add more than 5% to CCGT's levelised costs.

5.2.4 Drivers of costs

5.2.4.1 Local conditions

The small impact footprint of CCGTs generally means local conditions have modest impacts on costs. The main issue is likely to be proximity to the high pressure gas network (NTS), and any underground cable connections to the National Grid.

5.2.4.2 Material and component costs

Global OEMs have established efficient GT supply chains but the GT market is still subject to commodity cycles

CCGT technology is largely factory built (capital and labour intensive) rather than materials intensive. The OEM also tend to control the supply chains for their key components so are less dependent on third party vendors. These two factors probably explain why CCGT prices have not spiked as much as coal or nuclear plant.

5.2.4.3 Manufacturers order books

There are only four significant manufacturers of 50 Hz F class GTs (General Electric [GE], Siemens, Alsthom and Mitsubishi Heavy Industries [MHI]). These OEMs have a combined capability to assemble some 100 machines at any one time, implying an annual capacity of 60-80 machines, given a 15-20 month construction time. Once one or two of these OEMs have full order books, then the market moves to a suppliers' market and prices tend to rise. This has been the situation since about 2007. The slowdown in orders during 2008/09 (prompted by high asking prices and the economic slowdown promises to clear the current backlog and so is likely to ease GT prices in the near term.

5.2.4.4 Economies of scale

There are no significant economies of scale at the unit level for GTs. The industry has consolidated on F class technology, after experiments with larger G and H class.

5.2.4.5 Technology breakthroughs

All the OEMs are seeking to improve the performance of their machines - efficiency, operating flexibility and maintenance requirements – however this is likely to be seen in incremental progress. There is no major technological breakthrough anticipated in the next decade.

5.2.5 Short term outlook - 2010/11

GTs approaching maturity – so little change expected – also no obvious challenges to big four OEMs

As mentioned above, current prices are still significantly elevated versus the levels prior to 2007. There is a significant prospect that dollar EPC prices could fall during the next year or two as the economic slowdown shifts negotiating power back towards buyers. Even so, the persistence of bottlenecks and higher than long run historical material prices should keep prices above the levels seen in 2006 through 2011.

5.2.6 Long run outlook – 2020 and beyond

There is nothing to suggest that CCGT prices will not continue to move according to a cyclical pattern driven by the altering balance of supply and demand. There has been some speculation that the emergence of new large scale GTs from Russia, China, Korea or others could undercut the prices from the big four Japanese/Western players, however, given the technical demands of the technology and owners concerns about reliability, this must be considered a slim chance. New entrants may emerge (or acquire existing players) but these are unlikely to lead to very significant cost reductions.

5.3 Advanced Coal Generation

5.3.1 Choice of representative technology

Four advanced coal generation options but advanced supercritical is currently favoured choice

In this study we consider the main utility scale mature and close-to-market advanced coal generation technologies. The technologies and the representative plant (taken for reference costing) are as follows:

- Advanced Super-Critical (ASC) pulverised coal – steam condensing cycle (2 x 600 MW), with flue gas desulphurisation (FGD) and selective catalytic reduction (SCR), with and without post-combustion CCS. The CCS options include 300 MW of CCS from start of operations with a retrofit of the remaining capacity (900 MW) to start after eight years of operation and a third case of full CCS from day one of operations.
- IGCC – assumed to be a single gasifier driving a 2+1 (830 MW gross) CCGT, with and without pre-combustion CCS (with full CCS assumed to start from start of operations);
- Oxyfuel firing of coal with full CCS from start of operations (2 x 600 MW);
- And Circulating Fluidised Bed Combustion (CFBC) with post-combustion CCS (2 x 400 MW).

Only the ASC and CFBC technology can be counted as a mature technology, although both have yet to be deployed in the UK at utility scale[10]. IGCC has been around for several decades however, it has yet to move into genuine commercial deployment, while oxy-fuel is only currently at the small-scale (10-30MWe) prototype testing stage.

5.3.2 Cost levels in recent years

There have been very few coal stations ordered in recent years in Europe and the US so there is much less transaction volume than for CCGTs, however Mott MacDonald's monitoring of tender prices and a few projects indicates a huge spike in EPC price in 2007 and 2008, with prices peaking at just over $3000/kW for western super critical plant with FGD and SCR. We believe the price has now softened to around $2700/kW, which is still well over double the level in 2006.

[10] The CEGB did experiment with super critical steam cycles and built and operated Drakelow C power station, though with was at smaller scale, and much lower temperatures and pressures than modern SC.

As mentioned above, large super critical coal units have seen among the most rampant cost escalation due to bottlenecks in supply of specialist forgings, high pressure pipes and thick rolled flat plate.

5.3.3 Cost structures

Coal plant EPC costs almost trebled in dollar terms since 2006

Coal plant's levelised costs are on balance more influenced by capex cost than opex, due to the much higher capital cost than a CCGT and comparatively lower fuel costs. The biggest capital items of a coal plant are boiler, steam turbine and generator, with the boiler alone accounting for over 25% of costs. The civil works component falls somewhere between that required for a CCGT and a nuclear station, while the fuel handling is larger item than for most other technologies, except solid fuel biomass. FGD, which once accounted for some 15-20% of capex has fallen over time such that FGD and SCR together typically account for some 10-15% of capex.

The fixed operating costs are considerably more than for CCGTs as boiler plant, fuel and ash handling and FGD all require more hands-on operation than largely automated gas fired plant. Variable non-fuel operating costs also tend to be high, largely because of the more demanding nature of the fuel. Fuel costs are likely to be the largest opex item for any normal operating coal plant, however carbon allowance costs could become a close ranked second given that even a ASC plant would emit some 0.8tCO_2e/MWh before CCS. At a €40/t EUA price this would cost about £27/MWh, equivalent to a delivered coal cost of £3/GJ.

5.3.4 Drivers of costs

5.3.4.1 Local conditions

Chinese OEMs have managed to contain cost escalation – however Chinese plant has not yet been deployed in Western or Japanese jurisdictions

The specific site conditions can be important in influencing both the capital costs and delivered fuel costs as coal transport infrastructure can be expensive. Given this, most developers will seek a site for their station which is close to an existing coal handling facility or at least provides for a low cost discharging option. The assumption here is that it will be rare to site a station primarily for access to UK-mined coal. Having good access to seawater for cooling and running a sea-water FGD can also reduce capex cost and improve plant performance.

5.3.4.2 Material and component costs

A large super critical coal boiler and its associated high pressure steam parts require some 10,000 tonnes of specialist steels and alloys. There are a number of key components where there are just two to three suppliers of materials or components (such as specialist forgings, and thick rolled flat plate).

Chinese OEMs appears to have bypassed these bottlenecks and high premiums on materials and specialised components, since their super critical technology is able to use more widely available materials and components, though this does come at the cost of lower performance. So far, no western OEM or EPC contractor is offering a “cut price” option, and anyway it is unclear whether the regulatory authorities would accept this as best available technology under the European Union’s environmental regulations.

5.3.4.3 Manufacturers order books

Coal plant developers have roughly double the number of potential vendors compared to their CCGT compatriots. However, in practice, the choice is somewhat less given that these will in turn rely upon two to three critical component manufacturers, while several packagers/builders have limited experience operating in Western Europe.

As mentioned above, the leading Western/Japanese OEMs have being running close to capacity for several years, although capacity has been constrained by bottlenecks in a number of critical components. In these circumstances it is no surprise that we have seen a seller’s market.

5.3.4.4 Economies of scale

There are economies of scale in super critical pulverised coal and a few countries (led by Germany and Japan) are now deploying 800 and 1000 MW units[11]. The main economies are in savings in the boiler costs, balance of plant and civil works – there is little difference in plant performance. While these large unit sizes could be built in the UK we believe that 600-800 MW units are more likely as these are easier to phase in and could be more easily integrated at some existing coal station sites. The fact that twin unit stations will bring similar savings than just scaling up, suggests that developers are more likely to pursue this option, or even three or four units on a site. In practice, their choice will depend on the track record for construction and operation of the different unit sizes.

5.3.4.5 Technology breakthroughs

IGCC has shown modest progress since 1990 but holds considerable promise if hot gas clean-up can be improved

Conventional super critical coal technology is fairly well established and so there appear to be no major breakthroughs ahead. There is very limited scope to improve the cycle thermodynamically. It is more likely that the application of new materials will allow higher efficiencies, though this is unlikely to come at a significantly lower cost. No one is talking of constructing a boiler from low cost, high temperature / pressure resistant plastics or ceramics.

[11] Various developers have proposed 800 MW units for the UK.

There is a greater prospect of breakthroughs in IGCC technology and in CCS. IGCC performance and costs would be significantly improved if a low cost hot-gas clean-up process could be developed. However, this has been a recognised need for a quarter of century and with little progress to date. In practice, the likelihood is that IGCC will only be employed where CCS is required and this shifts the focus to one of finding a low cost route to get hydrogen out of coal-gas (or even just raw coal).

CCS technologies and economics are discussed in section 5.4.

5.3.5 Short term outlook - 2010/11

Coal EPC prices only likely to fall gradually in near term

The short term outlook for prices of advanced coal plant is almost certainly one of declining dollar prices as the overheated market of 2008 cools. The decline is unlikely to be as anything like as marked as the ascent given that it will take some time (3-4 years) to invest in facilities to de-bottleneck the supply chain. Also in the short term there is little prospect that the Chinese OEMs will improve their quality offering to the point that they compete into the Europe and the US.

5.3.6 Long run outlook – 2020 and beyond

By 2020, there is much more uncertainty, however there is a real prospect that China's leading OEMs will be able to offer a sufficiently high quality offering into Europe. There is also the likelihood that the major bottlenecks in supply will have been addressed – perhaps by Chinese suppliers. The implication is that the underlying cost and price of advanced coal plant will probably be much less than today. Offsetting this, it is likely that by this time coal plant in Europe will need to be equipped for CCS, so overall costs of coal generation will be much higher.

In longer term, investment in supply chain and competition from Chinese OEMs will bring deep reductions in coal EPC costs

There are several emergent technologies that could potentially offer a better route for coal generation than the current favoured options of combustion and gasification. Given the need to capture the carbon in coal, the favoured options are likely to be biotech processes to extract hydrogen from coal (which would then be fed into fuel cells or GTs) or chemical looping processes, which offer 70% coal-to-electricity conversion efficiency with full carbon capture. Neither of these technologies are beyond the bench-scale and so are unlikely to be deployed even as prototypes before 2025.

5.4 Carbon Capture and Storage

5.4.1 Choice of representative technology

This study considers three carbon capture technologies:

- Post-combustion capture fitted to ASC coal and gas fired CCGT;

- Pre-combustion capture for gas fired CCGT and coal- fuelled IGCC;
- Oxy-fuel combustion of ASC coal.

In all cases it is assumed that compressed CO2 is then fed into a pipeline network for transport to an underground sequestration site. Costs of transport and storage are factored in based on a user charge per tonne of CO2 captured. No benefit is assumed from enhanced oil recovery (EOR).

We have assumed that all new plant orders from 2010 will be required to be designed to be capture-ready in accordance with the EU directive implemented in April 2009. Making plant capture ready means changing the plant layout, for instance include setting aside space for capture plant, and identification of outline routes for evacuating CO2 as well as design changes in some items. It is unlikely that these modifications, except possibly securing extra land, would significantly increase capital costs, if factored in at the initial design stage.

5.4.2 Cost levels in recent years

Early CCS is likely to be expensive adding 40-60% to plant capex

There are no existing utility-scale carbon capture installations on working power plants, so all the estimates have been made from scaling up from prototypes, detailed bottom-up engineering estimates or vendors preliminary estimates. It is important to distinguish between estimates of the incremental capex of CCS equipment and the all-in cost impacts on the levelised cost of electricity. Also, often the cost figures are expressed in cost per tonne of CO2e captured. What counts for commercial purposes is the impact on the cost of electricity and here the effect is as much through indirect impacts on the host plant.

Table 5.1 provides a summary of carbon capture (CC) capital cost estimates from a number of public sources, which was compiled by a recent review of CC studies by Mohammed Al-Juaied and Adam Whitmore. This provides a very wide range of costs from $550/kW to $1350/kW, with costs for CCGTs and ASC averaging $637 and $1024/kW, respectively. Given that the inputs into this plant are subject to many of the same drivers as other utility and process plant it is clear that these prices will have been through a similar price profile as CCGT and coal plant prices. We have assumed that the current (early 2010) price for a FOAK CCS would be $700-1000/kW for a CCGT and $1600-1800/kW for an ASC coal plant. On a NOAK basis we are projecting costs of $450-650/kW for CCGTs and $1000-1100/kW for ASC coal. These costs are per kW of gross output so include the impact of extracted steam, but not the extra auxiliary load of the CC processes.

Table 5.1: CCS capital costs estimates for PC coal and CCGT in $/kW

	Studies by:					
	MIT	Rubin	NETL	EPRI	SFA	Average
Super critical pulverised coal						
Post CCS net MW	500	493	550	550	548	528
Pre-CSS specific capex: $/kW	1330	1442	1549	1763	1703	1557
Post CCS specific capex: $/kW	2140	2345	2895	2930	2595	2581
Implied capex for CCS: $/kW	810	903	1346	1167	892	1024
Ratio of CCS capex to base plant: %	61%	63%	87%	66%	52%	66%
Natural gas CCGT						
Post CCS net MW	-	432	482	478	482	469
Pre-CSS specific capex: $/kW	-	671	554	600	723	637
Post CCS specific capex: $/kW	-	1091	1172	1027	1266	1139
Implied capex for CCS: $/kW	-	420	618	427	543	502
Ratio of CCS capex to base plant: %	-	63%	112%	71%	75%	80%

Source: M. Al-Juaied and A Whitmore, Harvard Kennedy School, 2009

5.4.3 Cost structures

CCS also substantially increases plant running costs through reducing plant efficiency, increased fixed costs and consumables

The impact of CCS on levelised costs of electricity generation comes through the following components:

- CCS plant and equipment capex (for the basic scrubbing plant or pre-combustion gas treatment works, often including a small stand alone steam generator);
- Increased auxiliary electricity load (for driving all the equipment, including the absorbers, oxygen production and CO2 compression);
- A loss of overall system conversion efficiency, which arises from stealing steam from the host ST/condenser or more likely via adding a standalone GT and steam generator alongside the host plant for meeting the CC steam and power needs;
- Increased plant fixed costs (staffing, materials and spares, insurance, etc) from the additional on-site and off-site process works;
- Increased variable operating and maintenance costs (repair and maintenance staff/services, absorber chemicals; transit and storage fees for CO2 transport and storage);
- Reduced availability for the host plant (the additional CCS plant may increase unplanned outages for the host plant).

All the above items, excepting the last one have significant impacts on levelised costs, with the CCS capex being the single largest element, and broadly comparable in size with the combined indirect plant impacts.

5.4.4 Drivers of costs

5.4.4.1 Local conditions

Access to CO2 network and storage facilities may become a critical siting issue for new plant – here we assume a simple cost per tonne fee for CO2 disposal

Other than the usual conditions of UK construction working practices, versus those in Europe and the US, the main locational factor influencing CCS costs will be its proximity to the UK's planned CCS network and the potential to share transport facilities with other users. For the purpose of this generic analysis here we have simply assumed a flat per tonne fee for disposal of captured CO2.

5.4.4.2 Material and component costs

The main materials and components of a CCS plant are rather similar to power plant, as they comprise civil structures (reinforced concrete), large steel (or concrete) vessels (for the absorber and stripper, etc), coated pipes, absorption panels, large numbers of pumps, valves and fans. While many of the components will need to withstand the corrosive properties of amines, the materials are not as specialist as those required for high pressure/ high temperatures employed in super critical coal and nuclear.

5.4.4.3 Manufacturers order books

Given the early stage of development of the technology and hence the small scale there have been no critical bottlenecks in the supply chain for CCS plant and equipment. There are at least half a dozen major players (Fluor, Aker, MHI, BASF, HTC Pure Energy and Alstom) poised to develop post-combustion systems and similar numbers for other CCS options (GE-Texaco, Conoco-Philips and Shell for IGCC and Doosan-Babcock, Air Liquide, Total, and BOC for oxy-fuel coal/ gas). There could also be possible new players from China and India.

Given this number of players and the view that CCS will be a massive new market, we see little risk that a suppliers' market will develop in the near term. The market needs to consolidate around favoured technological options with a few dominant players first.

5.4.4.4 Economies of scale

It is too early in the technology development to assess the extent of economies of scale with much confidence, however it is likely that there will be engineering limits to the size of major components (such as the absorber for post-combustion CC). This suggests that CC for larger installations will follow a multi-train single site approach: which could allow some savings on civil works and sharing of non-critical facilities.

5.4.4.5 Technology breakthroughs

Substantial potential for technical breakthroughs in carbon capture

CCS is clearly an immature technology and as such there should be considerable scope for learning over the next decade. There are a number of areas where the industry has set targets, such as reducing energy penalties and reducing the cost of transport and storage.

5.4.5 Short term outlook - 2010/11

It is clear that any developers of CCS facilities will face a considerable FOAK premium in the near to medium term. Our assessment is that this FOAK premium is likely to be of the order of 35%. In practice the premium is likely to be higher as initially developers will build smaller scale plants. This allows for a certain amount of strategic entry pricing by at least some of the competing OEMs and EPC contractors seeking to win business and prove-up their technologies.

5.4.6 Long run outlook – 2020 and beyond

If pushed vigorously by regulatory authorities, then industry could move toward NOAK level by 2025

By 2020, there should be a number of CCS installations of each of the main technologies that will have operated for a number of years, with some UK experience also. Some countries may have also signalled that CCS should become mandatory on certain installations and/or have put in place arrangements for funding investment in CCS. Most likely, public support will come in the form of provision of the CO2 transport and storage infrastructure and a minimum guarantee on the value for avoided carbon emissions. The learning on the early demonstration projects and construction of the second generation projects will allow the OEMs and EPC contractors to improve designs and construction techniques. At the same time the prospect of significant forward orders will allow OEMs to expand capacity and invest in their supply chains, so offering production scale savings. This should see prices settling down towards the NOAK level sometime by 2025.

5.5 Nuclear Generation

5.5.1 Choice of representative technology

The main nuclear generation technologies that the UK authorities are currently assessing are Areva's EPR and Westinghouse's AP1000[12]. Both these reactors are counted as third generation plus reactors with high levels of safety based on 1000 MW or above reactors. Neither of these two designs has begun operation, though both are now under construction.

[12] [12] It is reported that GE-Hitachi is reconsidering UK licensing of its design, but it is now several years behind and would therefore be unlikely to be among the first wave of projects.

There are several other third generation technologies, such as GE-Hitachi's ESBWR and also Toshiba's ABWR, both of which are being developed in US and Japan. There are also various Russian designs such as VVER and the Korean KSNP (another boiling water reactor [BWR]).

Medium term UK reactor choice is realistically constrained to Westinghouse AP1000 and Areva's EPR

The approvals and regulatory regimes overseas differ from the route established for new nuclear in the UK. Specifically, the UK regulators are running the Generic Design Assessment (GDA) process which demands a high level of design completion and justification prior to commencement of construction. The GDA process, due to conclude in mid 2011, predates the start of any major nuclear construction planned in the UK. Now moving into its third phase, there are unlikely to be any deal breakers, although some issues still need to be resolved regarding control systems for both the EPR and AP1000 designs. The government is confident that the GDA and HSE working closely with overseas nuclear regulators will be able to largely mitigate FOAK technical risks.

Two EPRs are under construction- Olkilouto-3 (OL3) in Finland and Flamanville 3 in France. OL3 is now expected on line in 2011 with Flamanville two years later. Meanwhile two twin AP1000 stations are being built in China, with the first unit due on line in 2013.

The EPR is rated at 1600 MW compared to the AP1000's 1000 MW[13]. Both are classed as pressurised water reactors (PWR). The AP1000 has more passive safety features, and so substantially cuts down on the number of components, such as pumps and valves. The EPR adopts the more traditional multiple layering of active safety systems; and double-wall reactor containment (in order to protect from impacts such as a direct aircraft impact in addition to containment). Both reactors use the same fuel and both promise high efficiency conversion from uranium to energy generated, compared with early generation PWRs. In both cases the design plant lives are 60 years.

5.5.2 Cost levels in recent years

5.5.2.1 Introduction

EPC prices uncertain, but our best estimate is $4750/kW

As mentioned in the introduction, new-build nuclear costs appear to have escalated more than any other generation technology. The EPC costs of OL3 agreed in 2004 was about $2450/kW, however a combination of design changes, equipment and material costs escalation has increased the cost to over $4200/kW. This excludes financing charges arising for a two-year extension to the build time. Confidential tenders for EPR and AP1000 tenders in 2008 seen by Mott

[13] The exact rating can vary, for example the gross capacity of the AP1000 is often listed at over 1100 MW.

MacDonald included EPC prices of $4000 to $5500/kW. While there is lots of speculation and gossip, we are aware of no firm cost estimates for the UK projects currently under consideration by EdF and Horizon. However, we believe current (early 2010) realistic EPC prices for a new build in the US or Western Europe are in the region of $3750 to 5750/kW, with a central case of $4750/kW.

Recent figures from UAE's 2009 award to a Korean consortium for four 1.2 GW BWRs indicate a lower price of about $3,600. Press reports (including the Economist) say that the upper offers were around $5000/kW. The winning price is not applicable to European and US markets, since West European and North American jurisdictions are unlikely to accept Korean designs, at least in the near term. It is also likely that Korean OEM's price offer was supported by low cost finance from the Korean export credit agency (Korea Ex-Im) and by the long term service agreement which had almost the same headline value as the EPC package (at $20bn). Even so, this deal indicates the potential scope for competitive pressures in the European and US markets should the designs from Korean and potentially other low cost OEMs become accepted.

These quoted EPC figures typically exclude grid connection, first fuelling or decommissioning. More importantly, they are rarely agreed on a fixed price basis. Even the UAE deal mentioned above is thought to include a significant portion that is subject to indexation, and we believe does not include the cost of land for the plants. Over the last decade, prices have become subject to various escalation arrangements for materials and specialist services or else they include target pricing arrangements for various components where vendors pass much of the price risk through to developers.

Given that no 3rd generation PWR have yet been completed, these prices must also include a significant FOAK premium, although this may be partly offset through multiple orders.

Allowing for cost escalation and contingencies, our central estimate of overnight cost for a FOAK project is $5750/kW

There are four main reasons for this cost premium:

- modifications in the design (often required by the overseeing regulatory authority);
- the inefficiencies in time and materials from the unavoidable learning by trial and error of the best way to undertake construction;
- price premiums on material, equipment and services from vendors who have yet to set up series production;
- to cover these price risks, OEMs, EPC contractors and sponsors tend to factor in contingencies into their price offers and cost estimates.

Allowing for some price escalation and owner contingencies, our view is that current overnight prices for plant ordered in early 2010, are in the range of $4500 to $6750/kW, with a best estimate of $5750/kW.

As the technologies are demonstrated in operation and as OEMs fine tune their designs and contractors improve their construction techniques, EPC costs will fall. In parallel, this learning will lead to substantial de-risking of projects so that contingencies will be largely eliminated. Furthermore, the prospect of steady orders will allow OEMs to invest in their supply chains, so further stripping out costs.

NOAK costs should be much less – our central estimate is $4500/kW, but not applicable this decade

All this will take some time, and the bulk of the cost reductions are unlikely to be captured until 2025. On this basis, although assuming current EPC market context, we consider a reasonable range for NOAK overnight costs to be $3800 to $5000/kW, with $4500 as our best estimate. This is on the basis of twin unit station but excluding owners' pre-development and site acquisition costs.

5.5.3 Cost structures

5.5.3.1 Key components of capex and opex

Nuclear plants are hugely capital intensive with a high front end cost and a distant lower capital cost of decommissioning and comparatively little in terms of on-going operating cost in between. Of course, in conventional discounted terms the decommissioning costs shrink to a small level.

The main components of the capital costs are the civil works (foundations and buildings), and reactor, cooling system and steam generator (SG).

Nuclear island and civils account for bulk of EPC costs

The so-called "nuclear island" components (reactor, cooling system and SG), are significantly more expensive than a coal boiler and generator. The evidence to date is that 3rd generation nuclear plants also require more complex and sophisticated foundations and building structures than a coal plant. The civil costs alone can cost up to $1500/kW. Hitachi-Westinghouse claim that the AP1000's compact design and steel pressure vessel, mean that it substantially reduces the civil works requirements, such that it has similar amount of cement as a comparable sized coal plant.

Given the scale of the latest nuclear units and extent of on-site labour required, at the peak of construction there can be up to 5000 workers employed at site and a general need to build a temporary community including beds for up to 2000 construction workers.

Once built, nuclear plants have comparatively low operational costs. A single unit EPR or AP1000 would have a total staff of 200-250, comparable with a modern coal station. Materials and spares consumption is modest. Fuel costs are likely to be about $5-6/MWh, on current Uranium prices and typical enrichment, fabrication and assembly prices for PWR fuel. This is some 20% below best current generation PWRs and reflects the improved fuel burn-up of the latest designs (62-65GWd/t of enriched Uranium versus mid 40s GWd/tU for second generation PWRs). This cost excludes any allowance for back-end storage and disposal. Allowing for spent fuel to be taken to an off-site temporary storage adds another $1-2/MWh. This means that substantial costs for waste treatment and storage, can be deferred at least until the plant shuts down.

Decommissioning costs, including waste disposal are significant but are projected to occur perhaps some 100 years after operations start. In present value terms these costs become comparatively small. Setting aside a provision paid during the operating life of the station is generally considered a prudent approach to covering these back end liabilities.

5.5.3.2 Build times

Build times have varied hugely in past, with a few stations in the UK and USA taking well over a decade to complete.

Build times, despite OEM efforts, are likely to be more than 4 years excluding often lengthy site preparation works

The French have achieved an average build time of 6.7 years, while globally since 1993 build time has shortened to around 5.3 years. This improvement probably reflects the increased importance of Chinese and East Asian projects. The vendors of the AP1000 claim build times of less than 4 years, while Areva says it should be less than 4.5 years for the EPR. In practice, in the medium term these timelines are unlikely to be achieved, not least because of material and component lead times. A reactor nozzle ring order placed today has a lead time of 5 years, though it is worth pointing out that most OEMs will have already booked their orders for the current round of projects being considered. In the long term such bottlenecks should ease and our assumption is that the build times for a NOAK plant could get close to 4 years, though a more prudent estimate would be 5 years, while a worst case could easily be 6 years.

It is worth bearing in mind that build times as quoted by OEMs are from the point at which the site is handed over to them by the developer. However there can be considerable site preparation work required ahead of this. For example, it is estimated that site preparation works for Hinkley C could take 30-36 months to complete.

5.5.4 Drivers of costs

5.5.4.1 Regulatory context

The regulatory framework can play a key role in influencing nuclear new build costs. Where national regulators require departures from the standards offered by the OEM or else those required by the US's NRC, this can add to costs. These costs are likely to be seen in higher EPC prices quoted into jurisdictions applying non standard requirements. More importantly, where regulatory scrutiny is ongoing and intrusive, this can further add to costs. The UK is seen as being particularly rigorous in its application of safety and quality standards, such as the CDM (construction design and management) regulations, which although in theory should allow safety to be built into the design, can often in practice lead to re-doing tasks.

In addition, in the UK the licensing process itself may actually act to reduce competition and therefore raise prices. For good reasons of managing the time to gain planning consent a gateway has been introduced through which vendors have to pass to be able to work in the UK[14]. Effectively the market will, for the foreseeable future be a duopoly of AREVA and Westinghouse[15]. This will present challenges to getting strongly competitive pricing as both suppliers are likely to see this as an opportunity to price to recover development costs. This problem is compounded by the need for preferred supplier relationships to be established early – between EDF and AREVA, and between Horizon and Westinghouse, for example, though Horizon has yet to confirm its preferred supplier. There are good industrial reasons for doing this, not least the need to build supply chains and skills, but it does make it very difficult for fully competitive deals to be struck.

Regulatory context may play a significant role in de-risking nuclear construction projects and in reducing delays

We would thus expect UK pricing to be somewhat higher than in more open market structures, especially markets where Asian bidders will have forced the pace in pricing. Predicting this premium is difficult: we might estimate it at 5-10% based on general power sector experience worldwide.

Another significant issue in the UK context is the perception of poor industrial relations. There have been a number of incidents where there have been disputes arising from what has been seen by some stakeholders as excessive reliance on imported labour.

5.5.4.2 Local conditions

The substantial civil works component in new third generation nuclear stations implies a certain amount of ground risk, though given the expectation of a level site and adequate site explorations this should not be a major risk.

5.5.4.3 Market conditions, material costs, manufacturers order books and supply chain issues

There are a number of ways in which the market conditions can affect newbuild costs, ranging from commodity price effects on materials, the length of manufacturers order books and number of alternative

[14] The "Generic Design Assessment" process of the HSE.

[15] It is reported that GE-Hitachi is reconsidering UK licensing of its design, but it is now several years behind and would therefore be unlikely to be among the first wave of projects.

suppliers of components and services which can affect component delivery times and prices. In this regard, Areva, which has a high degree of vertical integration in its supply chain, especially the heavy components claims to have the advantage. However, Westinghouse, which lacks such integration, counters that its ability to pick and choose its suppliers as conditions change gives it the advantage.

In recent years it has been noticed that each tier of suppliers to the reactor manufacturers has tended to build in risk margins for uncertain input prices (whether this is materials, sub-components, equipment and/or services) in a way that has multiplied the risk premium. This has perhaps been exacerbated by the fact that there has been little confidence in the industry of the timing and extent of forward orders, such that suppliers have been reluctant to invest in production facilities or make long term commitments with their own suppliers.

5.5.4.4 Economies of scale, multiples and bulk ordering

Considerable scope for economies from multiple orders, though biggest reductions will come from OEM investment in supply chains

Increasing reactor size has traditionally led to reduced per kW overnight costs. Studies on US, Canadian and French fleets over the last three decades have shown that costs increase according to the ratio of the larger unit to the smaller one, raised to the power of 0.55. This means moving from a 600 MW to 1000 MW unit increases total cost by 32%, which in turn implies a saving in $/kW cost of almost 25%. This relates to reactor cost only and what is less clear is the extent to which these savings may have been offset by more challenging engineering and also more substantial civil works.

Building multiples units in one station has also shown to reduce per unit EPC costs. Based on experience in Japan, US, France and Germany, building twin units typically cuts unit costs by 15%. These savings arise mainly through savings in sharing civil costs and in balance of plant equipment. It is important here to note that all the proposed developments in the UK are based on two to three units per site.

Where a dominant buyer can order a series of reactors, there is also the prospect of significant cost reductions. This might reflect a reduced supplier's margin for the bulk order, but should also derive from reductions in the supply chain costs coming from the industry being able to lock in benefits of investing in new facilities to increase output. An industry that sees the prospect of multiple firm orders is much more likely to invest in upgrading its supply chain. As mentioned earlier, these supply chain effects, are a major driver of the FOAK premium.

5.5.4.5 Technology breakthroughs

Technology breakthroughs unlikely to influence plant choice before 2025, however great scope for improving construction techniques and supply chain capabilities

The long development and construction lead times, the need for safety case approvals and huge size of nuclear facilities suggest that nuclear technology will tend to evolve somewhat slowly. While there are clearly a number of different technology development avenues being considered from fusion proper, proton fusion, fast reactors, pebble bed reactors and small scale packaged reactors, none of these are likely to be viable within the next decade. The small packaged reactors could technically be made available within this period, however, there is little chance that the international community will accept application of this technology beyond existing military facilities.

Probably of more importance than applying new technologies will be the increased focus on improving construction management. This is likely to involve more detailed control of logistics using best practice construction monitoring, and lessons learned in delivery of mega projects globally in the last 20 years. These is likely to include smarter procurement and detailed requirements management, focussed through up-to-date computer applications including those that utilise augmented reality techniques.

One possible development on the fuelling side, could be the introduction of thorium-uranium blended fuel, which is currently being developed by a Russian led consortium.

5.5.5 Short term outlook - 2010/11

EPC prices unlikely to fall significantly in near term as will take time to relieve supply chain bottlenecks

The short term outlook for nuclear overnight prices is likely to be one of continued elevated prices, although they may decrease slightly from the peak levels in 2008-09. There is little chance that the bottlenecks in the supply chain will be eased dramatically in the next couple of years, as the investment lead times are likely to be 3-4 years.

It is possible that one or two large players – EdF and Horizon – will seek to place a bulk order of reactors that would be delivered to more than one site over a number of years. As mentioned, Horizon has talked of ordering some 6-6.5 GW at two to three sites. EDF has said that it is looking at ordering 6-8 EPRs that would be allocated across three countries. This should reduce the per kW overnight price and would allow the FOAK premium to spread over more units, although as mentioned earlier there is still a significant element of FOAK learning specific to each country where the technology is applied.

5.5.6 Long run outlook – 2020 and beyond

In the long run nuclear EPC costs even from Western OEM should fall under pressure from competition from Korean and Chinese OEMs

By 2020 the supply chain bottlenecks should have been addressed and the main nuclear OEMs will have commissioned at least a handful of reactors in at least three and maybe five jurisdictions. The industry is likely to have several tens of reactors in the construction pipeline. OEM and EPC contractors will have the benefit of learning from this experience and should have been able to reduce their overnight prices and mitigate outturn costs through modifying designs and the construction process. All this assumes that the various national regulatory authorities do not require design and construction changes that add significantly to cost.

We do not anticipate any major technological innovations, at least in terms of commercially viable projects before 2025. One promising technology is small-scale packaged nuclear modules – based on those used in submarines – which could be mass produced, and provided to utilities on a 10-20 year lease basis. In practice, disseminating nuclear materials (even in small quantities in sealed units) may be considered too risky for the IAEA.

5.6 Renewable Generation

5.6.1 Choice of representative technology

Renewable generation technologies covered include wind and hydro and various biomass/bio-methane and waste options – solar, wave and tidal are not covered

The study considers the following renewable generation technologies, all of which could realistically be applied at above the 5 MW scale.

- Onshore wind (100 MW) located 10 km from a MV substation;
- Offshore wind (200 MW located 25 km from shore in 20 metres of water, using monopole foundations);
- Round 3 offshore wind (400 MW located 75 km from shore in 50 metres of water);
- Hydro reservoir plant – 100 MW
- Hydro pumped storage[16] – 100 MW, at a coastal location
- Biomass combustion – 50 MW and 300 MW wood pellet fired plant
- Biomass fired combined heat and power (32MWe and 110MWe)
- Biomass gasification/ pyrolysis
- Anaerobic digestion (agricultural wastes)
- Energy-from-waste (combustion)
- Landfill and sewage gas

This list does not include all viable technologies, for instance, tidal barrages are certainly proven and can be deployed at large scale, but these have not been included in our terms of reference. Tidal stream and wave power devices were considered at too early stage for any sizeable deployment within the next five years.

[16] It should be noted that hydro pumped storage is not a true renewable technology as it uses grid electricity

5.6.2 Cost levels in recent years

EPC prices for many renewables have also risen in recent years, most notably for wind

EPC costs for almost all the renewable technologies have risen in the last five years, although nothing like as much as much as big coal and nuclear. Wind has seen probably the greatest increase, as there have been serious bottlenecks in the supply of wind turbine generators (WTG) and in some of the construction support services (vessels and cranes). Hydro has been the main exception, as prices of the main electrical and mechanical equipment and civil works have increased "only" 20-30%. This low rate of price increase probably reflects the relatively modest level of orders for this technology versus some of the other technologies and the lack of any significant bottlenecks. Capital costs for most of the biomass based technologies, whether based on steam generators, reciprocating engines or gasifiers have increased more than hydro but much less than wind. This has reflected modest demand side pressure to date.

5.6.3 Cost structures

As mentioned in Section 5.6 most renewable energies are highly capital intensive and have low variable costs. Wind and hydro are the most capital intensive technologies as there is no fuel (or carbon) or variable costs and fixed costs are modest (although not for offshore wind).

Most renewable generation technologies are dominated by capital, however offshore wind, energy-from-waste and biomass waste plants have high operating costs

Biomass (and EfW and landfill gas) plant costs are also dominated by capital costs, although this will depend on whether there is a significantly positive gate fee (purchase price) for the fuel. Plants using higher grade (high CV and comparatively clean) fuels, such as wood fuels will tend to have to pay high prices per GJ compared with plants taking biomass wastes and so will have high running costs. In some cases, biomass plant may also have high ash handling and disposal costs, especially where a significant portion of their residues is classed as hazardous. Renewable plants, with the exception of most existing hydro, tend to be commercially viable only because of financial support through the sale of ROCs and their exemption from the climate change levy.

5.6.4 Drivers of costs

5.6.4.1 Locational Impact

Location has a huge impact on the costing of most renewable technologies. This is especially important for wind farms, where the location will affect the wind yield, the construction costs and the repair and maintenance costs. While going offshore will tend to increase annual capacity factors, capital costs and operating costs both increase substantially, versus onshore locations. Hydro is similarly dependent on site conditions and the local hydrology. While capital costs of biomass plant will be largely unaffected by the location, the running costs will affect the ability and costs of sourcing the feedstock. And of course, viable biomass CHP is contingent on a suitable steady heat load.

5.6.4.2 Material and component costs

In crude tonnes of steel or cement per MWh generated over the lifetime, most renewable energy technologies require more materials than a modern coal fired plant. However, the cost impacts of materials and critical components has been less of an issue than for large coal and nuclear plant. Part of the reason for this is that the smaller scale of facilities allows more off-site assembly, which reduces production costs. There have, however been some areas, especially for WTG, where there have been bottlenecks in component supplies.

5.6.4.3 Manufacturers' order books

Except in the case of wind, developers of most of the renewable technologies have to date not had any significant delay in getting equipment vendors to start production. This has not been the case for WTG, where there was a significant waiting list, especially during 2007 and 2008. These have now receded.

5.6.4.4 Economies of scale

Economies of scale are not typically substantial for renewables

Compared with fossil fuel and nuclear generation there are limited economies of scale in renewable generation. Larger WTG require more demanding support structures, while adding more generators provides only modest savings in shared infrastructure (substations and cable to shore). The (modest) saving from bulk order discounts may be as large as these economies.

The opportunities for most biomass generation options to exploit economies of scale are limited by the costs and impracticalities of transporting, handling and storing biomass fuels. A number of the technologies (such as gas engines, anaerobic digesters, and gasifiers, etc) are considered scalable beyond 5 MW only on a multiple module basis. Landfill gas, EfW and AD of liquid biomass wastes are all limited by both these technological limits and resource constraints. Biomass fired boilers, given a suitable imported source of high CV (wood-fuel) feedstock, could be sized at several 100 MW, however the largest size is effectively capped at 300 MW because of the requirement that all new boiler plant) is designed to be "capture ready" above this threshold.

5.6.4.5 Technology breakthroughs

A number of the renewable generation technologies appear to have reached maturity. Hydro schemes, LFG, sewage gas, AD and EFW are all at a stage where only incremental advances are expected.

Pyrolysis and biomass gasification could make more of a step increase, although achieving a significant jump in scale as well may prove more challenging, if past progress is an indicator. Biomass boilers and onshore wind are also unlikely to yield any big surprises. This leaves the main scope for technological innovation in offshore wind (and other marine technologies and solar photovoltaic, neither of which is covered in this study).

While onshore wind may have converged on 3-blade horizontal axis machines there are a number of options under consideration for offshore applications. These include vertical axis designs, such as the "V" shaped Nova, a 10-20 MW WTG with the generator at the hub near the base, as well as several floating and anchored structures supporting more conventional horizontal WTGs. There also plans for pneumatic transmission, applying high temperature superconductors to reduce generator sizes (and improve efficiency) and other such devices aimed at reducing nacelle size, costs and overall WTG availabilities. None of these innovations are close to market and it is unlikely that they will be deployed before 2015 at the earliest. Even further off are plans for airborne generators that would be suspended by kites or balloons.

5.6.5 Short term outlook - 2010/11

EPC prices expected to see modest fall in near term

EPC prices for WTG and biomass generation plant are both expected to decrease in the near term. For wind, the expansion in supply capacity of WTG plant, in part due to the emergence of new players is likely to reduce delivery times and prices despite continued strong demand growth. Biomass plant costs are projected to decline somewhat slower, as prices have been less affected by supply chain bottlenecks. There is also the possibility of supply bottlenecks in the larger biomass plant sector, especially if most of the current planned projects move towards financial close.

5.6.6 Long run outlook – 2020 and beyond

Slim prospect that major technological breakthrough will lead to major cost reductions before 2025, though beyond this big improvements are possible

Over the longer term, we can expect real costs reductions in both wind and biomass generation technologies as suppliers scale up facilities and improve production techniques. There are also likely to be continuing incremental improvements in design which will lower capital costs as well as major cost reduction arising from improved construction techniques. The potential for major technical breakthrough is modest over the next 10-15 years, although there is a prospect that new biotechnology will lead to lower cost routes to convert biomass energy to electricity. It is also conceivable that one day new materials will allow wind turbine blades to be extruded or stamped out rather than built up in layers in what is still a labour intensive process.

5.6.7 Technologies in brief

This section provides a brief summary of the main renewable technologies considered in this report.

- Onshore wind; now reaching maturity, though WTG sizes are still slowly increasing. Technology has consolidated on 3-blade horizontal axis WTG, though there are variants as to drive train arrangements. Typically, wind farms will comprise anything from half a dozen to over 100 WTG.
- Offshore wind; compared to onshore this is an immature technology application. The main challenges are in constructing and servicing WTG in an offshore environment and then the additional costs of the electrical connection. WTGs proven for land need to be adapted for marine conditions, while complex foundations and subsea cables add to equipment and material costs. Offshore construction, with specialised vessels and cranes increases construction times and costs. The main advantage of offshore is the higher average wind speeds, however this does little to offset the higher capital costs, so offshore wind is currently a relatively expensive generation option.
- Hydro reservoir plant: these plants require a river with adequate water flows and suitable site for building a dam to make a reservoir. The reservoir provides a means of storing water and releasing it such that the overall capacity factor of the generating plant can be increased, and also so the plant can be despatched when energy is most needed. In practice, there are extremely few potential remaining sites left in the UK that could offer more than about 100 MW which would not be ruled out on environmental and social grounds.
- Hydro pumped storage (PS): similar issues apply for pumped storage as for reservoir hydro, although in the case of PS generally two reservoirs are required. There is an option of use of the sea or an underground aquifer as the lower reservoir, however, this presents probably an even greater challenge in finding an acceptable site. For the former, one would need to build a large reservoir near the coast and then build tunnels down to shoreline. Extensive work has been undertaken by Mott MacDonald in past decades in this area, with over 10 GW of opportunities identified.
- Biomass combustion: typically based on stoker or fluidised bed boilers and steam turbines, with typical sizes of 5 MW to 30 MW, though over 50 MW has been built and several 300 MW units are now being planned in the UK. The main limitation on size is the fuel transport, handling and storage facilities. Capital costs are significantly higher than coal, because of small scale, demanding combustion conditions and fuel handling requirements. Efficiencies on a HHV basis seldom exceed 30%.
- Gasification/ pyrolysis of municipal waste: both processes produce a combustible syngas which is then fired in a gas engine. Pilot scale units of a few MW are still in testing, however, at least one developer is planning to role out of 1 MW units for energy from waste facilities in the UK and Turkey. These could be installed on a

modular basis and could in principle displace the current MSW combustion boiler (or staged gasifier) and steam turbine technology, once sufficiently proven. Capital costs are likely to comparable with AD systems, but again the application in waste treatment, means that a portion of the cost can be assumed to be covered by the waste disposal operation.

- Anaerobic Digestion: already a mature technology, though at a small scale. This is because AD is most suited to wet biomass wastes which generally have low heat contents so are unlikely to be transported very far, so capacity is limited by available feedstock. Even so, where feedstock is available at a negative or low positive gate fee then AD can be commercially attractive, especially if the digestion process yields solid residues that can be sold as a viable fertiliser or fish meal.
- Energy-from-waste: typically based on combustion-boiler-steam turbine, with most facilities having moving (or vibrating) grate boilers with sent out ratings generally less than 10 MW. Some plants exceed 10 MW but transport and storage logistics tend to limits capacity to well below the 50 MW limit. Plant costs are in £4000-£5000/kW range, depending on size.
- Landfill (LFG) and sewage gas (SG): typically sub 5 MW installations, although there are a few 10-25 MW sites. Both technologies are based on gas engine generators, but with very different front end feed requirements. Sewage gas, at least in advanced form, requires substantial processing plant (to ensure that solid residues are safe for use as fertiliser, otherwise it requires expensive landfill). In contrast, LFG plants require relatively simple gas treatment, although it does require significant ongoing spend on drilling and developing gas gathering network. Otherwise for both technologies opex is low and fuel is zero. Build time is short – 1-1.5 years, with project life typically 20 years, though this can be as short as 10 years or more than 40 years. There is some potential for expanding UK's SG capacity, but practically none for LFG.

5.7 Biomass Co-firing and CHP

5.7.1 Background

This section includes a general introduction to CHP, an overview of biomass applications and then finally a comment on gas fired CHP modes.

By definition, Combined Heat and Power plants supply a combination of power and heat as simultaneous outputs from the same fuel input. Traditionally, CHP has been seen as a power generation system that produces "free" (or cheap) steam or other heat as a by product. This is in line with the traditional, technical definition of CHP:

CHP is the use of a necessary heat load to allow cost effective power generation

"CHP is the generation of electric power and beneficial use of the by product heat."

While this is technically true, it is not very informative and the following, more commercially oriented definition is suggested:

"CHP is the use of a necessary heat load to allow cost effective power generation."

This definition is more helpful as it points to the significance of the heat load in achieving thermal efficiency.

5.7.2 Technology Options

Different technologies have different heat-to-power ratios in their outputs and the heat outputs have different qualities. The base case characteristics (assuming full heat recovery) of the main technologies are summarised below in Table 5.2.

Table 5.2: Characteristics of CHP technologies

Technology	Fuel	Power Yield % (of fuel input)	Heat Yield % (of fuel input)			Overall Efficiency %	Heat to Power Ratio
			High Temp	Med Temp	Low Temp		
Gas turbine	Gas or distillate	28	54	0	0	82	1.9
Gas turbine + Steam turbine		39	0	0	42	81	1.1
Reciprocating Engine	Gas	33	25	0	22	80	1.4
Reciprocating Engine	Heavy Fuel Oil	40	18	0	22	80	1.0
Steam Turbine	Any	29*	0	0	0	29*	0
Steam Turbine	Any	19	0	0	62	81	3.3
Steam Turbine	Any	12.5	0	69	0	81	5.5

Source: Mott MacDonald - * Power Only – no heat supply

As can be seen from the table, the heat-to-power ratios and grade of heat available from different configurations vary quite widely. In particular, the power efficiency of a steam turbine based scheme is controlled by the quality of heat supplied. This makes defining efficiency potentially complex.

For applications using biomass it must be noted that solid fuels cannot be fired directly in either a gas turbine or reciprocating engine. These prime movers can only be used indirectly with biomass fuels via gasification or anaerobic digestion. This in turn means that only plant using fired boilers and steam turbines can be used with solid fuels and the CHP configurations correspondingly are limited.

5.7.3 Thermal Efficiency

A common method of defining the thermal efficiency of a CHP system is to add the electrical output to the heat output and compare the result with the total fuel use. While simple, this method does not take account of the different values of the different types of output – where electric power is more valuable than even the highest grade of heat and high grade heat is more valuable than lower grade heat etc (because of the greater volumes of power that could have been generated from a given quantity of higher quality steam).

An alternative method of defining CHP system efficiency, focusing on the efficiency of the power generation component is presented below:

$$\text{CHP Power Efficiency} = \frac{\text{Net Power Generated}}{\text{(Total Fuel Used – Avoided Fuel for Heat)}}$$

CHP power efficiency can be seen as net power generated divided by the incremental fuel use

This is effectively the incremental fuel use (compared to heat only supply) compared to the net power generated and allows direct evaluation of the power generation efficiency. It automatically takes account of the different amounts of fuel that would be required for the supply of different grades of heat (eg different pressure and temperature steam) and the effects on power generation that the supply of such different steam qualities can have (usually most significant with steam turbine systems).

5.7.4 Selected Configurations

For the purposes of this levelised cost modelling analysis, and to highlight the variations in power yield depending on quality and quantity of heat supplied, we have selected the following representative plant configurations. For consistency, we have maintained a constant boiler header steam flow in each case.

1. Base Case – Power generation only using moderate steam cycle efficiency and moderate economy of scale. Main characteristics: power output 28 MWe, main steam pressure 100 bara, non re heat, 0.08 bara condenser vacuum and 85% steam turbine isentropic efficiency. Assuming woodchip fuel this offers an overall generation efficiency (HHV to net power) of 25.8%.
2. Maximum power generation compatible with maintaining maximum thermodynamic efficiency results in the selection of a back-pressure steam turbine supplying low pressure steam (3 bara) / hot water. This gives main characteristics: 94.4 MWf fuel input, net power yield (after allowing for avoided auxiliary loads in alternate plant) 18.1 MWe / 19.2% and thermal output of 57.7 MWth / 61.1%. Combined efficiency 80%.

3. Higher grade heat supply option with reduced power generation from high back pressure (12.5 bara) steam turbine. The main characteristics are: 86.4 MWf fuel input, net power output (after allowing for avoided auxiliary loads in alternate plant) 11.8 MWe / 13.6% and thermal output of 57.9 MWth / 67.0%. Combined efficiency 81%.

5.7.5 Biomass co-firing

Several biomass co-firing options, which differ on capital requirements, but all entail additional fuel handling facilities

Each of the plants (power only and CHP) can be supplied with steam raised from the firing of biomass. There are three basic configurations when considering adding biomass firing capability to an existing plant:

- Co-firing in an existing (usually coal fired) boiler
- Co-firing in a new, free standing boiler but supplying steam to an existing or shared steam turbine system
- Free standing system with no co-firing

5.7.5.1 Co-firing in existing boilers

In a utility scale plant, the option of using biomass in an existing boiler is usually preferred because of the high steam pressures and temperatures used in utility steam power plant mean that unless very large steam additions are foreseen, matching the existing steam conditions in a biomass boiler will not be cost effective. Even where large biomass plants are considered, it is likely to be technically difficult to combine new and existing steam flows and a new, free-standing plant is usually preferred.

The capital scope of this option is based around the new fuel handling facilities (receipt, storage and preparation), modifying or adding to the fuel feed system and modifications to mills and burners systems to allow for the different characteristics of the chosen range of biomass fuels.

5.7.5.2 Co firing with a new boiler

In industrial scale plant, where the primary fuel consumption is limited, co firing in an existing boiler (on similar lines to the process used in utility boilers) offers very limited scope in terms of biomass volume addition. In this case, the possibility of installing a new, free standing biomass fired boiler is the next step. This offers the benefits of fuel specific design, independent operation of the traditional and biomass boilers and maximum re use of existing steam turbine generation plant (including condenser if installed). In this case, the technical issues associated with connecting a new steam supply to an existing system are much reduced.

The capital cost of this option is substantially greater than the option of co firing in an existing boiler. This is because the main element of cost in a biomass fired scheme is the boiler (and associated equipment) itself.

5.7.5.3 Free standing new plant

This option offers the greatest flexibility, the greatest opportunity for fuel specific design, eliminates common mode failure risk and maximises the improvements in process supply reliability. However, it comes at the greatest capital cost and complexity.

5.7.6 Capital Cost Comparison

Capital costs of co-firing dominated by boiler requirements

The capital costs of adding biomass co-firing to utility boilers is well established although this is rarely in connection with a CHP scheme on the same scale as the original power utility plant. This is because there are no utility scale coal fired CHP schemes in the UK. In practice, the two main options for adding biomass firing to existing CHP schemes are adding a new boiler or the full new plant option. **Error! Reference source not found.** Table 5.3 shows the estimated capital investment for the two routes are surprisingly close, largely due to the dominance of the boiler plant within the total costs. The power only specific capex works out at over £3,500/kW, which is much higher than utility scale generation plant. For the back pressure LP configuration the specific capex works out at over £5,100/kW also expressed per electrical capacity.

Table 5.3: Capital costs of small biomass CHP

Scheme	Configuration	Capital Cost: £m	Capital Cost: £/kWe
1	New, free-standing biomass fired 28 MW power only plant	99	3536
2	New, free-standing LP CHP plant, net output 18.1 MW	89	5115
3	New, free-standing MP CHP plant, net output 11.8 MW	87	7500
4	New boiler and fuel system to feed steam to pre-existing plant of types 1, 2 or 3.	76	2714-6552

Source: Mott MacDonald

Lack of economies of scale mean capital costs per kW well above utility scale coal plant

Each of the above configurations is based on a similar nominal steam flow rate and boiler steam conditions so as to make the main boiler price comparable (there are minor differences in economiser design and capacity due to assumed return temperatures but these variations are not dominant).

For comparison, a semi utility scaled biomass unit (power output of around 100 MW) would show economies of scale at around £263m (equivalent to about £2,600/kW). All the indicative costs listed cover

EPC, grid connection, planning and other owner's costs but exclude interest during construction.

5.7.7 Operating costs and Steam credits

The operating costs of biomass CHP plant are likely to be a little higher than a comparable steam turbine based power only plant, rated at the same fuel energy input level and certainly much higher than large scale utility plant. Expressed in operating costs per kW of electrical capacity, the opex levels for biomass fired CHP plant will be much higher. However, these higher operating costs (and capex) levels are likely to be largely offset by the steam credits.

The small scale of biomass CHP schemes generally means that they will have higher annual fixed costs per MW than larger utility scale plant, especially when expressed in £/MW of electrical capacity.

There is likely to be a modest uplift in the operational, repair and maintenance costs for the CHP configurations versus power only of the same fuel input, which reflects the need to manage steam supplies. However the additional costs for biomass fuel handling will be significantly more than the CHP uplift. This will also be seen in terms of a significantly higher level of auxiliary power consumption.

Variable non-fuel costs are unlikely to be significantly different than for conventional steam plant.

Fuel costs will clearly depend on the delivered biomass price, however, these would normally be significantly more than the costs for a comparable coal fired plant. Except for biomass wastes, biomass prices expressed per GJ are generally at a premium to coal prices, and are more likely to be close to those for gas. The low electrical efficiencies of CHP plant mean that per MWh of electricity produced biomass fuel costs will be much higher than for power only plant.

On operating cost account, high fixed costs and fuel costs more than offset by potential revenues from steam sales

Offsetting these higher fixed operating costs and fuel costs will be a substantial steam credit. On the basis that this credit should reflect the avoided costs of producing heat using a gas fired boiler, and all the steam output is sold, then this steam credit could be broadly as much as the overall levelised cost on power for a baseload operation.

Assuming a 65ppt gas price (broadly in line with DECC's central projection) and an 80% efficient boiler the steam credit is worth £31.5/MWh of thermal energy. Given the high heat:power ratios (3.2:1 to 4.9:1) this implies a steam credit of £100-150/MWh(e). This demonstrates the huge value of the steam load in driving CHP economics.

5.7.8 Gas fired CHP modes

This section reviews at a high level the main technical and commercial issues impacting the deployment of conventional gas fired CHP.

5.7.8.1 Typical Configurations

There are several possible configurations of gas fired (gas turbine based) CHP plant of an industrial scale. The configuration is dependent on the quantity and quality of heat required by the host process. A representative selection of options (not optimised designs) might be:

Large LP steam demand (typical of a large paper mill)

- 40 MW gas turbine
- HP HRSG
- Back pressure steam turbine (approx 12 MW)
- LP steam export of approximately 60 MWth.
- Heat to power ratio around 1.2 (ref net power output)

Large MP steam demand (typical of a large middle range chemical plant)

- 40 MW gas turbine
- MP HRSG
- No steam turbine
- MP steam export of approximately 68 MWth.
- Heat to power ratio around 1.7 (ref net power output)
- Same fuel consumption as previous scheme

Very Large MP / LP steam demand (typical of a large refinery)

- 292 MW gas turbine
- HP HRSG
- Extraction / Back pressure steam turbine (approx 56 MW)
- MP steam output of approximately 126 MWth
- LP steam export of approximately 154 MWth.
- All steam used by heat off-taker – no LP/Vacuum steam turbine stage
- Heat to power ratio around 0.8 (ref net power output)

5.7.8.2 Non-availability of Heat Load

Continued availability of heat load is critical to project viability

Each of the above configurations assumes that the heat off-take is reliable and approximately continuous. If this is not the case, additional plant items such as turbine exhaust by-pass stacks (to allow reduced or zero steam raising while GT continues to operate) or dump condensers (to allow GT and steam turbines to operate in the absence of heat load) will be required or the GT will have to be shut down when heat loads reduce. In cases where condenser capacity is chosen, all the corresponding costs of condenser cooling will be incurred.

In the case of the CCGT configuration (large scheme) the option of including a full LP/Vacuum section in the steam turbine configuration should be considered. This would allow unused process steam to be used in the CCGT plant to generate extra power for export.

In each case where precautions are taken for loss or interruption of heat load, extra capital costs and maintenance costs will be incurred and some alternate operational constraints may be imposed (such as maintaining a minimum steam flow through the LP/Vacuum stage of the steam turbine in the large CCGT case).

5.7.8.3 Power Output Effects

Extracting steam (or other forms of heat) from what would otherwise be a CCGT power generation configuration will reduce the power output and reduce the corresponding power generation efficiency.

However, beneficial use of the heat extracted from the CCGT cycle replaces the need for fuel combustion in alternate plant. If power generation efficiency is measured as the net power generated compared to the net increase in fuel use (ie total fuel use less the fuel that would have been used by traditional means), a power generation efficiency of more than 75% HHV basis) can be demonstrated. In contrast, running a gas turbine without the planned heat load (and without precautionary capital investment) would result in a power generation efficiency in the range 28 – 38%.

5.7.8.4 Operational and Construction Impacts

A well designed, operated and maintained CHP plant should be able to achieve reliabilities and availabilities similar to those of the corresponding CCGT configurations.

It should be possible to construct a well designed CHP plant in the same time as the corresponding CCGT configurations. Commissioning and testing of the plant, in particular the control and supply quality to the heat off-taker may take a little longer than the core CCGT plant but this impact should be small.

5.7.8.5 Commercial Complexity

CHP developers face challenge in finding appropriate heat loads and then in structuring (necessarily) complex off-take arrangements

The discussion above demonstrates that continuity of heat off-take is core to both the plant design and operational efficiencies. The ability to strike a robust heat off-take contract is critical to viability of a CHP investment. Any potential heat off-taker must be financially robust and willing to sign an off-take contract which will substantially protect the CHP plant developer against the economic and commercial impacts of loss of heat load. The terms necessary for such protection are likely to be onerous on the heat off-taker.

5.7.8.6 Available Heat Loads

For large CHP schemes to be commercially viable, there must be correspondingly large, financially robust heat off-takers. The larger the proposed scheme, the larger the corresponding heat load requirement.

The number of such heat loads in the UK that do not already have such CHP schemes is limited. Many paper mills already have such schemes. Several large refinery or chemical plant complexes already have such schemes and it should be remembered that not all the heat load represented by refineries is accessible to a potential CHP scheme as part of the heat is necessarily provided by the combustion of non-commercial by-product fuels. These non-commercial fuels arise as by-products from the refinery processes and must have a disposal route. Substituting these fuels with heat from a CHP plant would result in a cost increase to the refinery rather than a cost saving.

Large industrial processes tend to offer base load, non seasonal heat loads. Seasonal heat loads such as space heating offer many fewer base load operating hours and therefore capital costs have to be recovered over a smaller number of hours per year. The use of thermal source chilling loads to fill in the summer heat demand trough is of limited use in improving the overall economics of a seasonal heat load.

6. Main levelised cost assumptions

6.1 Introduction

This section outlines the main assumptions used in the levelised cost modelling. This covers the issue of discount rates, plant lives, fuel prices, carbon prices, the general level of EPC prices and a summary of the key plant level capex and opex and performance parameters.

6.2 Discounting and plant lives

Base case assumes 10% real discount rate and economic plant lives

In the base case, a 10% real discount rate has been applied across all cash-flows and energy production over all years. We have also run sensitivities on a 7.5% discount rate. Discounting is applied over the economic life of the plants, which are assumed to be somewhat longer than the typical financing terms. Table 6.1 shows the plant life assumptions used. For the purposes of this study we have assumed that oxy-fuel coal generation costs (including CCS) are the same as ASC coal with CCS, while CFBC is the same as ASC coal.

Table 6.1: Plant life assumptions

Technology	Economic Life
Open cycle GT	30
CCGT	35
CCGT with CCS	35
ASC coal	45
IGCC	35
ASC coal with CCS	40
Nuclear	60
Wind	25
Biomass combustion	30
Gas engines	20

Source: Mott MacDonald

6.3 Fuel prices

The fuel price assumptions, which have been taken from DECCs own analysis, are shown in Table 6.2. This shows that real coal, gas and oil prices are expected to be higher than the pre-2004 long term average. This reflects the prevailing assumption among governments and international agencies that the world now needs to develop higher cost fossil energy reserves than those accessed in previous decades. We have added a delivery charge of £6/tonne for coal and 2p/therm for gas to give a “burner tip” price. Expressed in £/GJ these scenarios all indicate a substantial cost advantage for coal at the burner tip (as shown in Table 6.3), though of course this is partly offset by the relatively low efficiency of coal fired plant versus gas fired CCGTs.

Table 6.2: Projected fuel prices

Low Case - Low Global Energy Demand			
2009	Oil - Brent	Gas – NBP	Coal - ARA
Year	$/barrel	p/therm	$/tonne
2008	102	58	147
2010	50	34	80
2015	58	35	50
2020	60	35	50
2025	60	36	50
2030	60	36	50
Mid Case - Timely Investment, Moderate			
2009 prices	**Oil - Brent**	**Gas – NBP**	**Coal - ARA**
Year	$/barrel	p/therm	$/tonne
2008	102	58	147
2010	70	58	110
2015	75	63	80
2020	80	67	80
2025	85	71	80
2030	90	74	80
High Case – High Demand, Producers' Market Power			
2009 prices	**Oil - Brent**	**Gas - NBP**	**Coal - ARA**
Year	$/barrel	p/therm	$/tonne
2008	102	58	147
2010	84	70	120
2015	102	83	100
2020	120	97	100
2025	120	97	100
2030	120	97	100

Source: DECC

Fuel prices are taken from DECC 2009 analysis

Table 6.3: Burner tip (delivered) prices for gas and coal

	Average price 2015-2030		Converted in £/GJ net		
Scenario	**Gas in p/therm**	**Coal in $/t**	**Gas**	**Coal**	**Coal adv.**
Low	35	50	3.90	1.39	2.50
Mid	68	80	7.37	2.14	5.23
High	95	100	10.21	2.64	7.57

Source: Mott MacDonald estimates based on DECC assumptions

6.4 Carbon prices

Three carbon prices scenarios for EU Allowances (EUAs) have been tested:

- Zero price (designed to explore the underlying equipment, operations and fuel costs)
- DECC's central case: whereby the carbon price rises slowly from £14.10 a tonne CO2e in 2010 to £16.3/t in 2020, then more rapidly

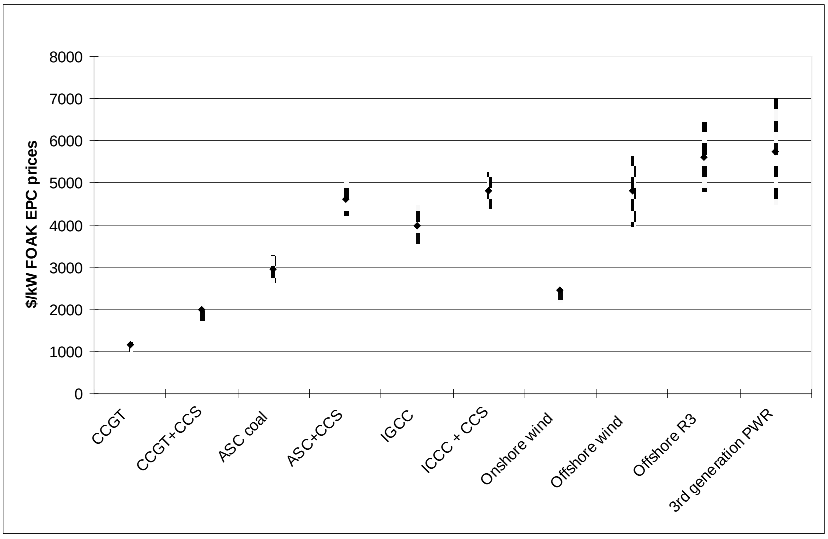
to £70/t in 2030 and £135/t in 2040. Averaged over the period to 2040 this works out at £54.3/t.

- As a third case, we have applied a flat £20/t case, which is roughly double the average level for Q1:2010.

6.5 Overnight prices in early 2010

Figure 6.1 and Figure 6.2 show the range of overnight prices assumed for plant orders assumed to be made in early 2010 on the basis of a FOAK and NOAK status respectively. For less mature technologies, all those involving CCS, offshore wind and nuclear, there is considerable divergence between the NOAK and FOAK levels. In contrast the FOAK –NOAK spread for onshore wind, CCGTs and supercritical coal plant are comparatively small. The figures in sterling equivalent are provided in Annex 1, for each technology.

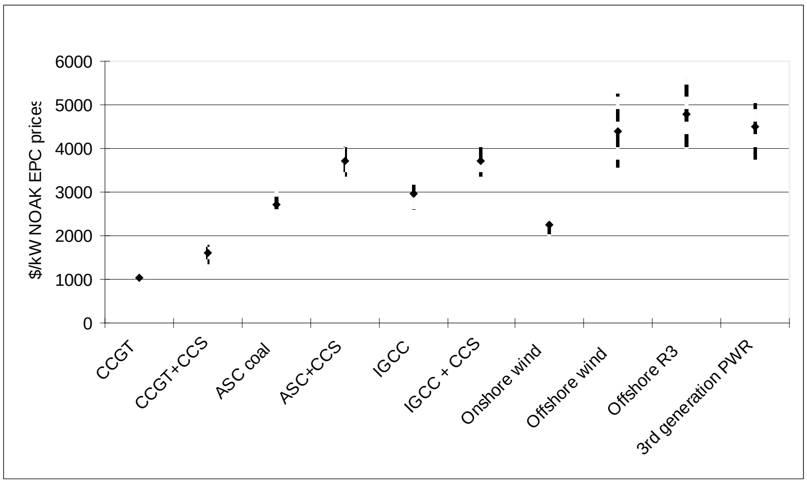
Figure 6.1: Overnight prices for FOAK plants ordered in early 2010



Source: Mott MacDonald

Most low carbon technologies come with a high capex premium

Figure 6.2: Overnight prices for NOAK plants ordered in early 2010



Source: Mott MacDonald

6.6 EPC price trends

EPC prices for most technologies are projected to fall significantly by 2020

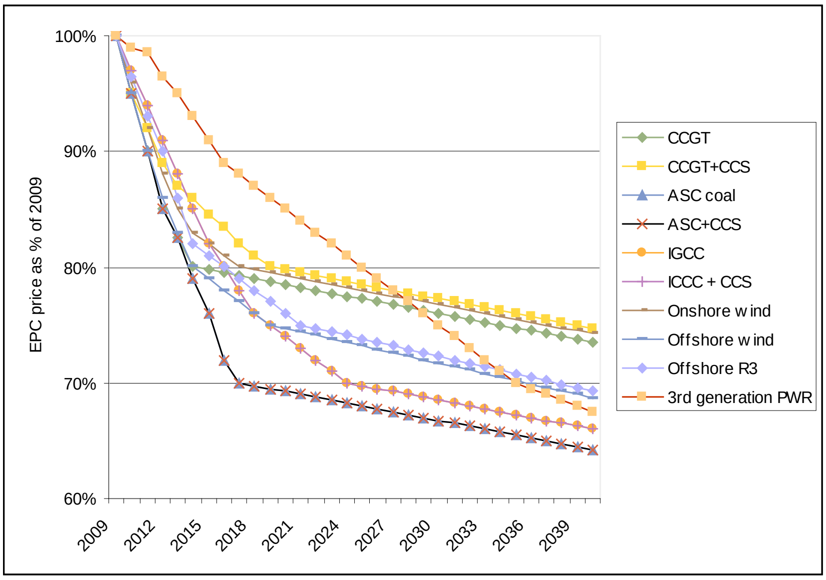
Our general assumption is that EPC prices for most technologies will fall in the near to medium term as bottlenecks are eased and manufacturers invest in their supply chains. There are also likely to be on-going innovations in design, production and construction which will bring steady incremental "learning" through time at least until a technology reaches maturity. This learning process is different to more accelerated learning that arises from deployment of early commercial scale installations for each particular technology as it moves from a first of kind (FOAK) to the Nth of a kind (NOAK) status. A major driver in reducing prices is likely to be increased competition from Chinese and other low cost manufacturers (compared with European North American and Japanese OEMs). These downward pressures are expected to be partially offset by scarcity effects as prices of commodities, energy and some specialist services increase. Overall, however, the expectation is for real EPC prices to fall. The pessimistic scenario is that prices would remain at current levels.

Figure 6.3 presents our most aggressive EPC price reduction scenario for the main technologies expressed as an index of 2009 levels. This shows a real reduction by 2020 of between 15% and 30%, with marked deceleration after this, such that prices in 2040 are 25% to 37% below the 2009 level. Coal plant costs are expected to see the fastest decline, with nuclear seeing the slowest decline in the first decade but catching up later as the European and US developers increasingly buy from Korean and other low cost suppliers.

Our central case projection takes the average of this aggressive scenario and the no change case, such that real prices fall 13% to 18% below current levels by 2040 – see Figure 6.4.

If these cost escalators are applied to the 2010 prices we can generate a set of overnight capital prices for plant ordered in 2020. This is shown for the main technologies in US$/kW in Table 6.4.

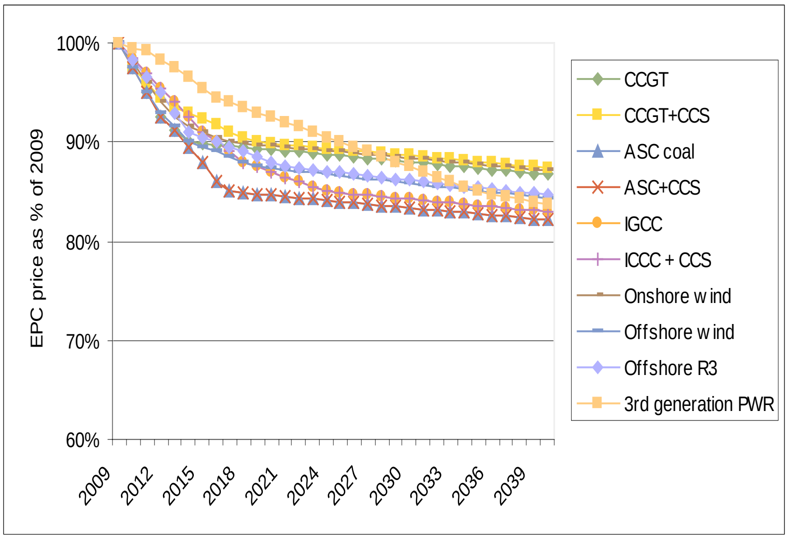
Figure 6.3: Real EPC price trends under aggressive price reduction case



Source: Mott MacDonald

Supercritical coal and nuclear plant projected to see greatest capex cost reductions

Figure 6.4: Real EPC price trends under central case scenario



Source: Mott MacDonald

Table 6.4: Overnight NOAK prices in 2020 in $/kW

	Low	central	high
CCGT	848	937	982

	Low	central	high
CCGT+CCS	1,258	1,438	1,573
ASC coal	2,031	2,285	2,496
ASC+CCS	2,877	3,131	3,385
IGCC	2,306	2,567	2,871
ICCC + CCS	2,958	3,219	3,480
Onshore wind	1,793	2,008	2,151
Offshore wind	3,145	3,843	4,542
Offshore R3	3,520	4,224	4,928
3rd generation PWR	3,515	4,163	4,625

Source: Mott MacDonald

6.7 Station fixed costs

Station annual fixed costs are 1% to 3% of total EPC cost

The main fixed costs for most stations relate to operation and maintenance, which comprises the operational workforce, and materials, spares and specialist services bought in. These costs tend to comprise a certain steady state minimum with periodic increases for scheduled serving, and overlaying this an intermittent occurrence of unplanned expenses. Averaging these major repairs over all the years, can provide a significant uplift on normal ongoing maintenance costs.

The other key fixed cost components are insurance, business rates and grid charges. In total, these items amount to much less than the engineering O&M costs. Table 6.5 shows the total fixed costs for the main technologies.

Table 6.5: Station fixed costs for main technologies

	FOAK		NOAK	
	Fixed costs: £/kW/yr	% of EPC cost	Fixed costs: £/kW/yr	% of EPC cost
CCGT	28,750	2.3%	26,000	2.3%
CCGT+CCS	47,000	2.6%	38,000	2.5%
ASC coal	71,000	2.7%	56,000	2.3%
ASC coal+CCS	100,000	2.7%	79,000	2.5%
IGCC	60,000	1.7%	51,500	1.9%
ICCC + CCS	98,000	2.5%	71,000	2.2%
Onshore wind	37,537	1.0%	34,203	1.0%
Offshore wind	114,000	2.7%	76,243	1.8%
Offshore R3	141,750	2.8%	102,514	2.3%
3rd generation PWR	85,000	1.5%	71,000	1.6%

Source: Mott MacDonald

Other fixed costs items like grid charges and insurance typically much less than operational and maintenance spend

Business rates vary by technology group and between England and Wales and Scotland. Rates are set in relation to installed capacity and typically work out at about £4-6/kW a year.

Insurance costs, on the other hand, vary largely in relation to the owners' circumstances rather than the location of plant. In general the major electricity companies with large portfolios of plant, who often finance on balance sheet, tend to insure only for the main obligatory risks. This is in marked contrast to independent generation business, which seek (often under lenders' direction) to insure against a broader range of risks (including business interruption). Even on a mature thermal technology this difference can easily be £5/kW a year.

There are a number of fixed cost items which can vary substantially even for the same technology depending on where the plant is located and the requirements of owner. The key location dependent item is grid charges for use of the transmission system. This varies according to which generation zone the plant connection is in. Under the 2009/10 charges, the difference between the most favourable and unfavourable zones is almost £30/kW a year, with plants connected in the southwest peninsula of England receiving close to £7/kW a year versus those in the north of Scotland paying almost £23/kW a year. We have assumed for the central case that most technologies would face a £6/kW a year charge, with onshore wind subject to a charge of £10/kW a year.

6.8 Key Plant characteristics and Performance Parameters

Plant availabilities tend to be similar, however build time, and auxiliary loads vary considerably

Table 6.6 provides a summary of the lead times and key technical parameters for NOAK plants assumed in this study. A fuller listing is presented in Appendix 1.

Table 6.6: Lead-times and key technical parameters for NOAK plants

	Pre-dev. period: years	Construction period	Gross effic.	Plant availability	Aux. load %
CCGT	2.0	2.5	59.0%	91.2%	2.3%
CCGT+CCS	2.0	3.5	50.0%	89.5%	10.8%
ASC coal	3.0	4.0	45.0%	90.2%	6.5%
ASC+CCS	4.0	4.5	36.0%	89.0%	15.5%
IGCC	4.0	4.0	45.0%	87.5%	4.5%
ICCC + CCS	4.0	4.0	36.0%	87.4%	13.5%
Onshore wind	5.0	2.0	100.0%	97.9%	1.8%
Offshore wind	5.0	2.0	100.0%	95.9%	2.0%
Offshore R3	5.0	2.0	100.0%	95.9%	2.0%
3rd generation PWR	4.0	5.0	100.0%	90.8%	4.5%

Source: Mott MacDonald

6.9 Money terms and currency rates

All prices are expressed in 2009 money, while the sterling exchange rate versus the US dollar and Euro are assumed fixed at 1.60 and 1.10, respectively.

7. Main results

7.1 Introduction

This chapter outlines the main results of the analysis of levelised electricity generation cost (LGC). It focuses primarily on the main technologies likely to be deployed in the UK over the next decade and a half.

Near to medium term comparisons done on basis of readiness of technologies today – longer term use NOAK costs

The comparisons have been run in a number of ways. Our near to medium term comparisons are done on the basis of the readiness of the technologies today. This means that all the CCS options, IGCC, third generation nuclear PWRs and offshore wind would be expected to incur a significant FOAK premium for projects initiated in the next five to ten years. CCGTs and super critical coal are assumed to be NOAK as are onshore wind projects.

It is worth emphasising that given the lead times in project development, the first dates at which new projects, not currently under development, could be ordered would be 2012-13 as they would have to go through a pre-development stage. This suggests that capital costs should be somewhat lower than current quotes in the market, on the basis that we expect most power EPC prices should fall.

Our long term comparison, which assumes projects are ordered in 2023 (so plant are brought into operation in 2025-28), assumes that all the main technologies have reached a NOAK status.

10 cases run: 6 with DECC's fuel/carbon prices and 10% discount factor, but varying project timing. 2 cases using 7.5% discount rate and 2 with higher/lower fuel/carbon prices

The technologies are also compared under different fuel and carbon prices and under a 7.5% discount rate rather than the 10% rate. In all cases we have assumed that plant run baseload, or at their energy availability for wind and hydro.

The results are shown graphically, with the LGC shown by the seven main components – capital costs, fixed opex, non-fuel variable opex, fuel, carbon, CO2 transport and storage and waste processing and decommissioning for the following 10 cases:

- Case 1: 10% discount rate, with project assumed to be started in 2009, but based on current (early 2010) EPC prices, with unabated CCGT and supercritical coal and onshore wind treated as NOAK, while the remaining plant incur FOAK premiums
- Case 2: as above but using projected EPC prices
- Case 3: 10% discount rate, project start in 2013 using projected prices, with same mix of FOAK/NOAK
- Case 4: as above but with project start in 2017
- Case 5: 10% discount rate, project start in 2017, all NOAK basis
- Case 6: 10% discount rate, project start 2023, all plant treated as NOAK
- Case 7: As case 1 above but with a 7.5% discount rate
- Case 8: As case 6 above but with 7.5% discount rate

- Case 9: High fuel price case, 10% discount rate, project start 2017, all NOAK
- Case 10: Low fuel prices and flat £20/tCO2 carbon price, 10% discount rate, 2017 start and all NOAK

The first six cases all apply a 10% discount rate and DECC's central fuel and carbon price projections, with project timing being the main distinguishing feature. All the cases to 2013 assume a FOAK/NOAK mix, while for the 2017 project start, both a mixed FOAK/NOAK and all NOAK case are considered. The 2023 start case assumes all NOAK. Cases 7 and 8 consider two sensitivities using a 7.5% discount rate, while cases 9 and 10 (again using a 10% discount rate) examine variation in the fuel and carbon prices. The results are tabulated in Annex B. Figure 7.1 to Figure 7.6 present the stacked costs for the first six cases. Figure 7.7 then summarises the projected time trends for the total levelised costs for the 10 technologies, through plotting the headline costs for cases 1-6 above.

Lastly in order to aid comparison, the total costs are also shown in Table 7.1 as a £/MWh premium or discount to the CCGT levelised costs on the basis of current EPC prices and DECC's central fuel and carbon prices.

7.2 Main technologies

Un-scrubbed CCGT is least cost current option for main technologies

The level of costs and ranking between technologies is uncertain as it depends on the timing of orders, extent of EPC price movements, fuel and carbon prices, financing costs, and technological learning. Faced with this uncertainty, any conclusions are therefore tentative. With this proviso in mind we make the following observations.

CCGTs running on gas have both a lower capex and lower levelised cost than the main baseload generation alternatives with a LGC around £80/MWh in our base case. Gas prices have to exceed the DECC high case for CCGT to look unattractive, and coal prices would have to be much lower than DECC is projecting.

Advanced super critical coal is seen to be £24/MWh more expensive than CCGTs (at £104.5/MWh). What is more, under DECC's central case projections for carbon, coal plant's premium over CCGT increases over time, despite the fact that its EPC premium (over CCGT) is projected to fall and as gas prices increase relative to coal. Moreover, this excludes the requirement for a significant tranche of CCS capacity to be installed on new coal from the outset.

Integrating CCS into coal or gas fired plant would substantially raise the costs, by £32-38/MWh in the near term when they will carry a large FOAK premium. It needs to be remembered that the carbon penalty on coal and CCGT without CCS is projected to be £40/MWh and £15/MWh for projects started in 2009. Applying a 7.5% discount rate, the CCS premium of coal plant falls to just £20/MWh. In the longer term, as these technologies move to the NOAK status, and as carbon costs keep rising their cost premium versus an unabated plant disappears. This is under DECC's central case carbon price projection (which sees EUA prices rising to £70/t by 2040. Also we are assuming a fairly low CO2 transport and storage charge of about £6/tCO2e.

IGCC is shown to have a significant cost premium versus advanced super critical coal plant, which reflects the still largely demonstration status of this technology. In the longer run, especially once CCS is incorporated its costs are broadly in line with ASC with CCS.

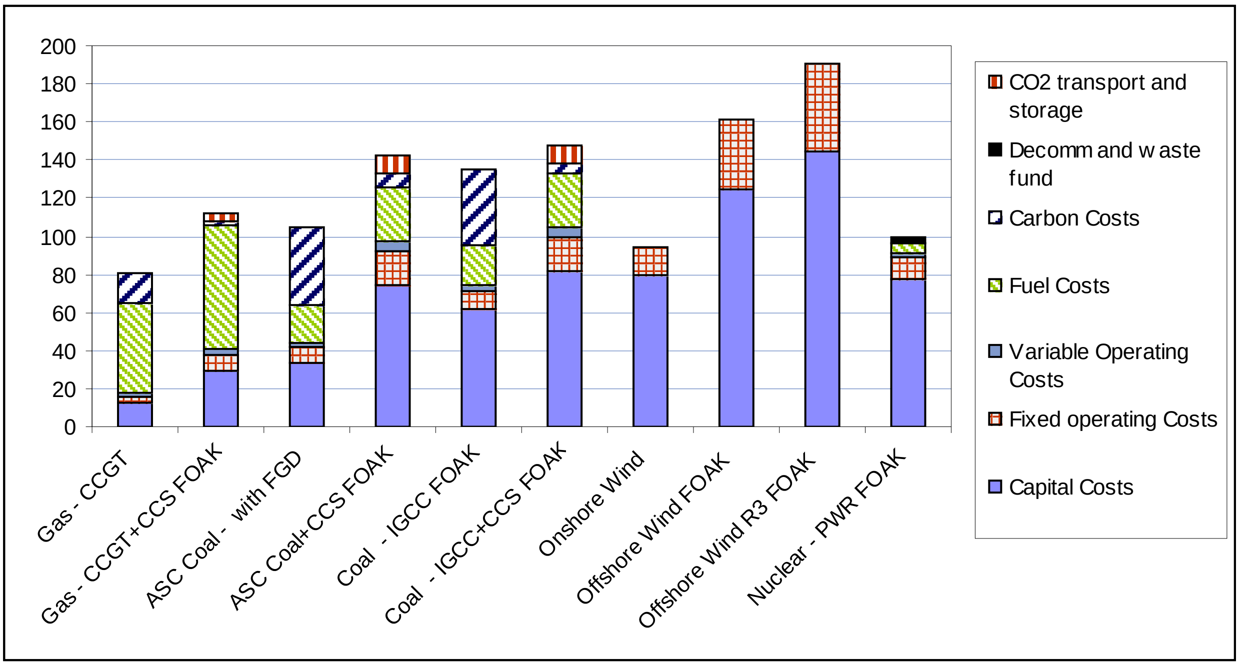
Nuclear has a current levelised cost just under £100/MWh on our central case, which means that it lies above CCGT but below coal without CCS. However, this is very much a FOAK cost, and our projection is that on a NOAK basis costs will fall to by about one third to £68/MWh, possibly for projects initiated as early as 2017. By the early 2020s, nuclear is projected to have a £35-40/MWh levelised cost advantage versus the lowest cost fossil fuel options and it would be the least cost zero carbon generation option among the main technologies.

Onshore wind is the current least cost zero carbon option with a total cost of £94/MWh, which puts it between CCGT and coal. A modest real cost reduction over the next decade means that it is projected to undercut CCGT to be the least cost substantive renewable option. Offshore wind is much more expensive at £157-186/MWh, substantially more than nuclear on a FOAK basis. On a NOAK basis, by 2025 offshore wind's costs are projected in our base case to fall to £110-125/MWh, which means that it would still be the most expensive low carbon energy of the main technologies.

7.3 Minor technologies

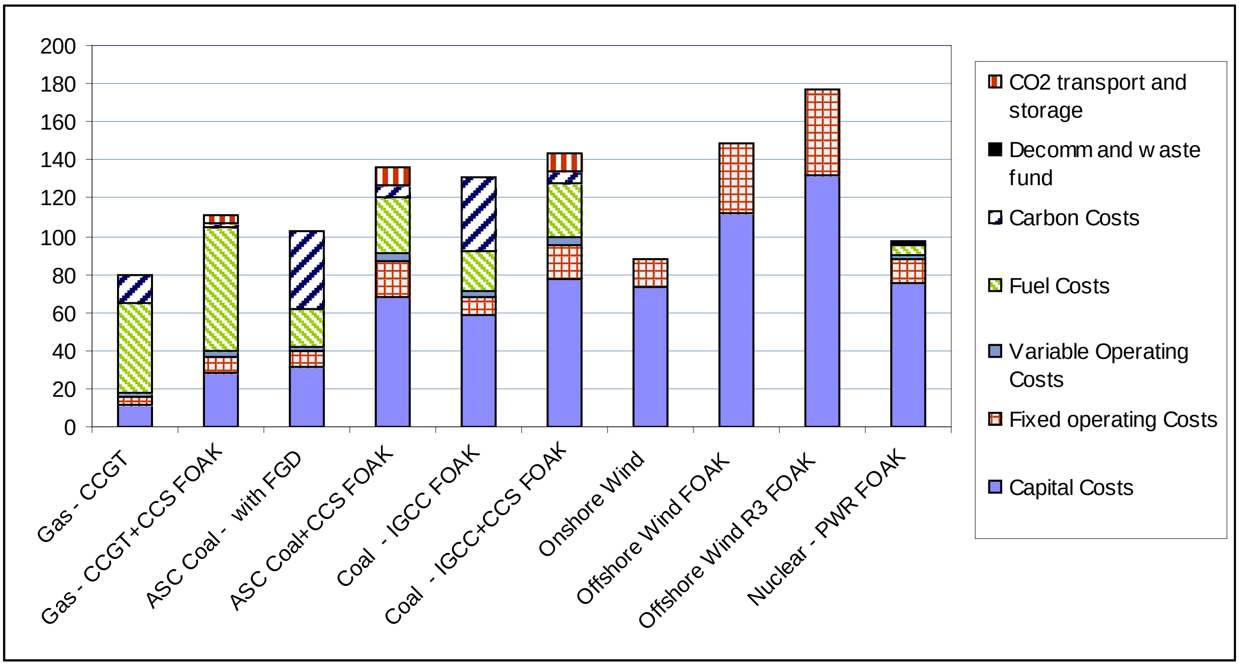
The results for minor technologies are covered in Appendix C.

Figure 7.1: Levelised costs of main technologies assuming current EPC prices with 2009 project start – mix of FOAK and NOAK: £/MWh



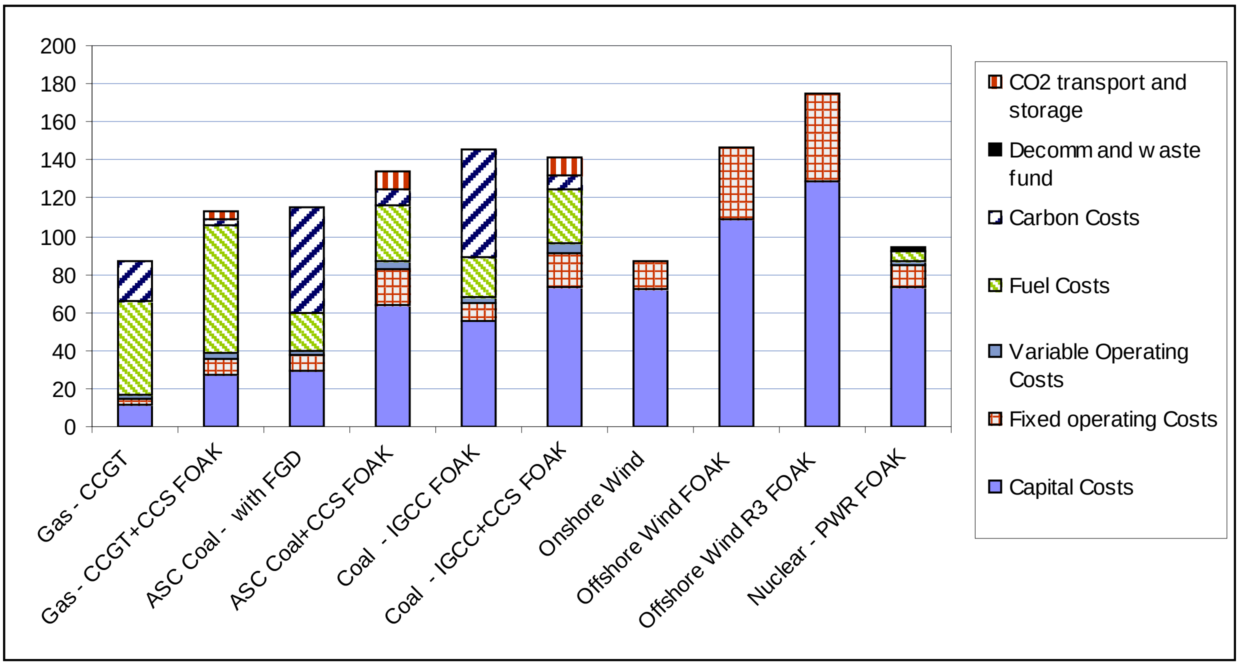
Source: Mott MacDonald

Figure 7.2: Levelised costs of main technologies for projects started in 2009 – mix of FOAK and NOAK: £/MWh



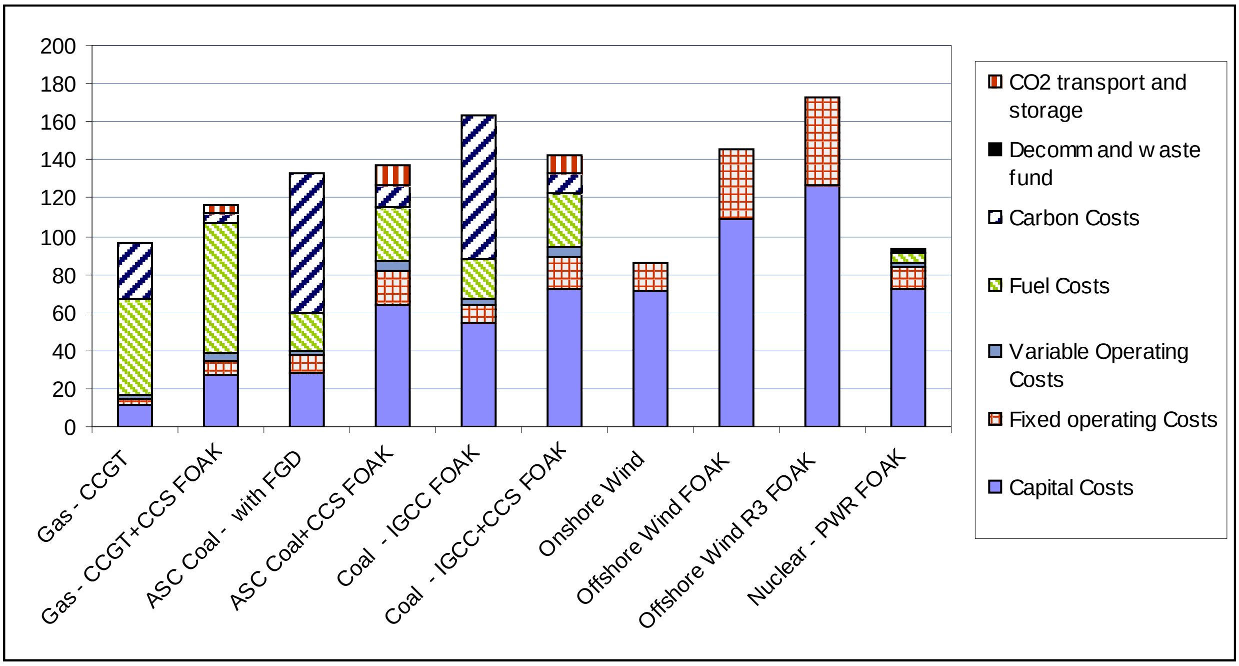
Source: Mott MacDonald

Figure 7.3: Levelised costs of main technologies for projects started in 2013 - mix of FOAK and NOAK: £/MWh



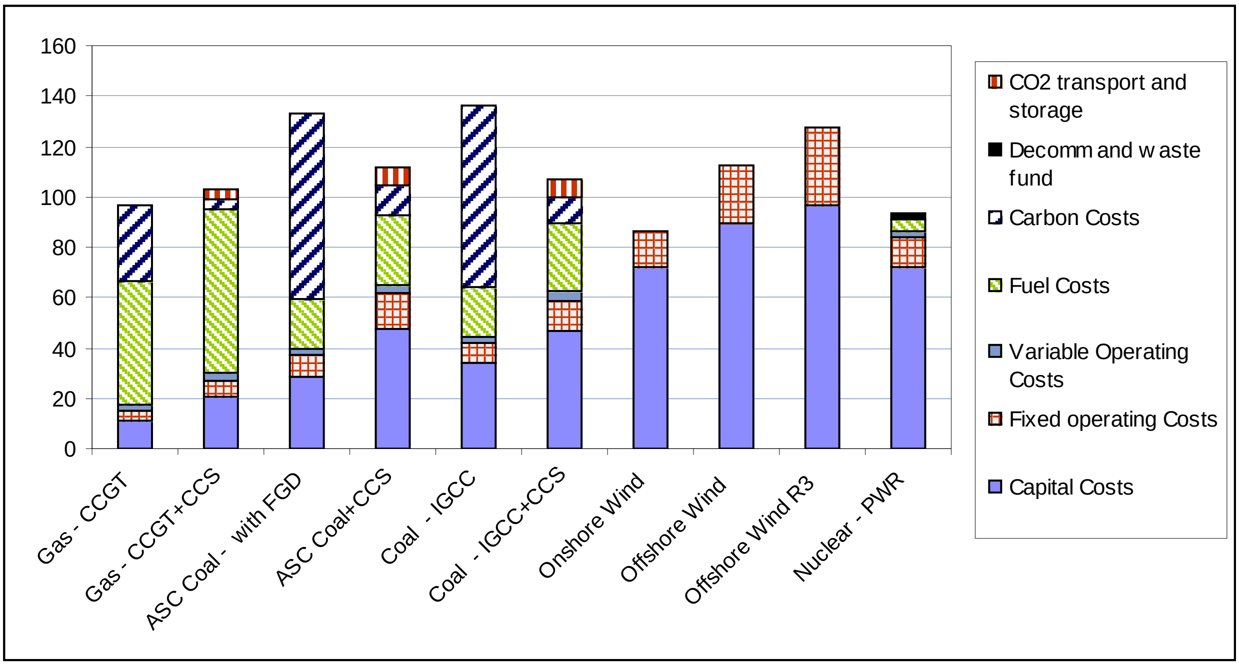
Source: Mott MacDonald

Figure 7.4: Levelised costs of main technologies for projects started in 2017 – mix of FOAK and NOAK: £/MWh



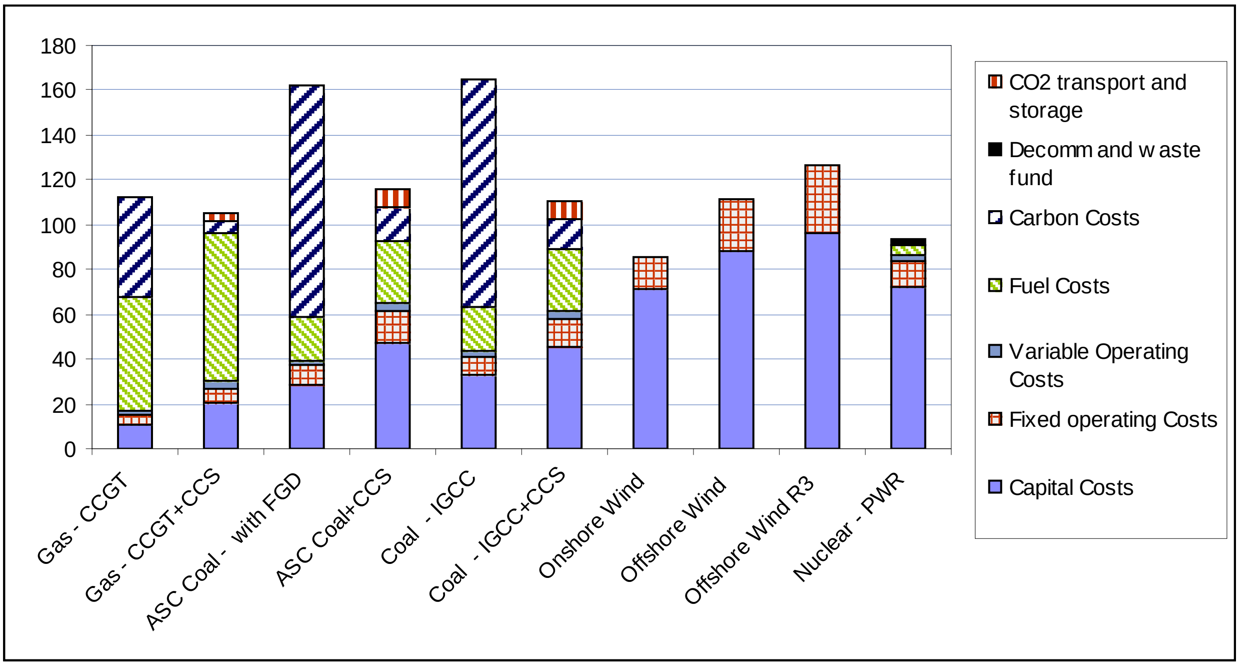
Source: Mott MacDonald

Figure 7.5: Levelised costs of main technologies on NOAK basis for project started in 2017: £/MWh



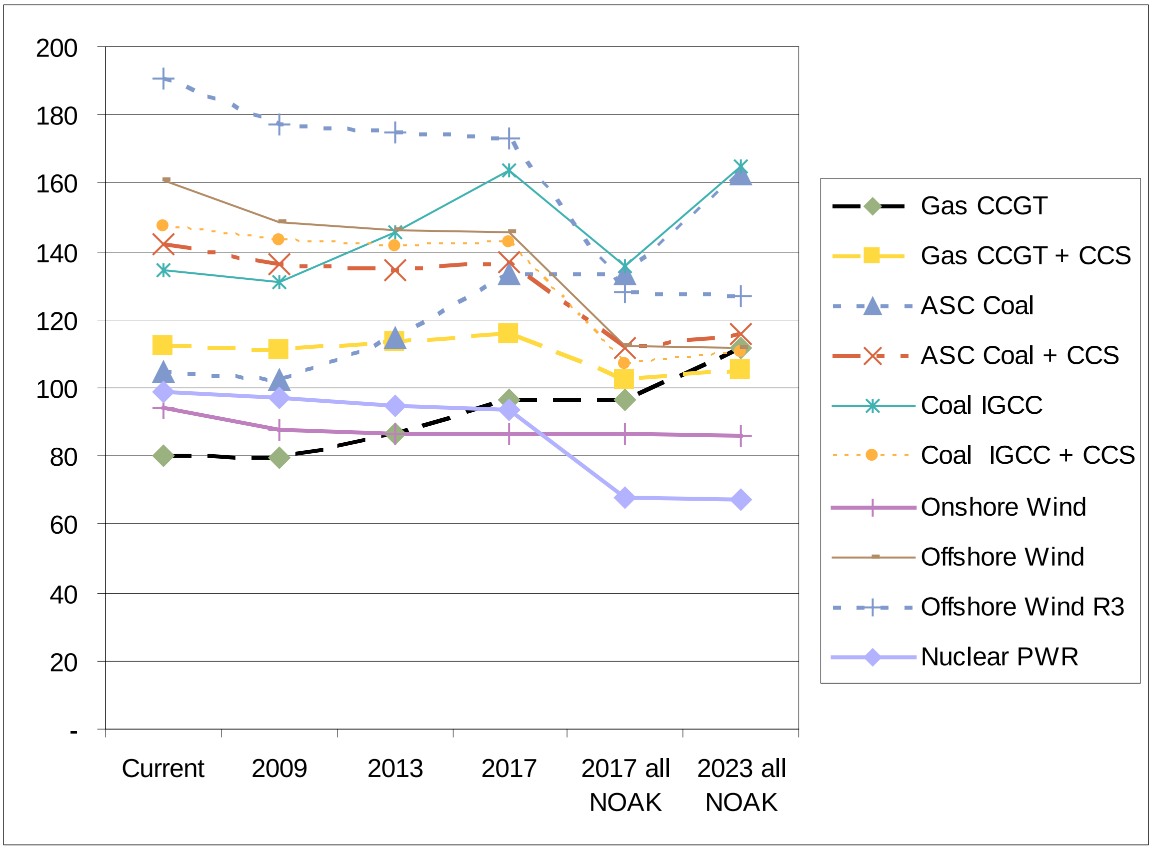
Source: Mott MacDonald

Figure 7.6: Levelised costs of main technologies on NOAK basis for projects started in 2023: £/MWh



Source: Mott MacDonald

Figure 7.7: Levelised costs for the main technologies under different project start dates and FOAK/NOAK status: £/MWh



Source: Mott MacDonald

Table 7.1: Premium versus levelised cost of CCGT based on today's price and 2009 project start:: £/MWh

	Gas - CCGT	Gas - CCGT+CCS	ASC Coal - with FGD	ASC Coal+CCS	Coal - IGCC	Coal - IGCC+CCS	Onshore Wind	Offshore Wind	Offshore Wind R3	Nuclear - PWR
Current prices	0.0	32.2	24.2	61.8	54.3	67.3	13.6	80.6	110.2	18.7
2009 start	-0.6	31.1	21.9	55.9	51.0	62.8	7.6	68.2	97.1	16.9
2013 start	6.4	33.2	34.6	54.1	65.5	61.4	6.4	65.8	94.4	14.3
2017 start	16.2	35.5	52.9	56.5	83.3	62.2	6.1	65.1	92.6	13.1
2017 start all NOAK	16.2	22.3	52.9	31.6	55.7	26.8	6.1	32.1	47.6	-12.5
2023 start all NOAK	31.6	25.2	82.1	35.2	84.4	29.9	5.5	31.2	46.7	-12.9
Average of 1-6 cases	11.7	29.9	44.7	49.2	65.7	51.7	7.5	57.2	81.4	6.3
Current prices @7.5%	0.1	26.2	24.1	43.7	44.0	48.4	-2.5	56.5	82.0	-4.2
2023 start @ 7.5%	32.6	20.8	84.7	23.7	83.4	20.2	-9.0	13.4	27.3	-26.9
High fuel price, 2017 start all NOAK	32.9	43.5	57.4	37.9	60.1	33.0	6.1	32.1	47.6	-11.4
Low fuel + flat £20/t EUA, 2017 start all NOAK	-29.8	-12.6	-11.7	13.0	-7.4	9.7	6.1	32.1	47.6	-13.5

Source: Mott MacDonald

8. Summary and Conclusions

Levelised costs will be higher than costs pre 2006 and also current forward prices

In a world with carbon constraints and rising real fuel prices we must expect the levelised costs of generation to be somewhat higher than we have seen in recent decades. In the first few years of the new millennium, the spike in commodities prices, combined with insufficient investment in supply chains has meant that equipment prices for most power generation equipment and construction services are at historically high levels. This means that a plant ordered today would be expensive. EPC prices are expected to fall in the near to medium term, as the supply chain bottlenecks are addressed.

Another feature of the next decade is likely to be the mobilisation of investment in new technologies, particularly CCS and third generation nuclear, both of which are likely to incur significant learning premiums in their early deployment. These FOAK premiums on capital costs can reasonably be expected to be in the 20%-40% range.

In terms of running costs, fuel and carbon are the main drivers, but the former are subject to the balance of supply and demand, while the latter depends on the complex mix of regulatory interventions and market fundamentals. The range between the plausible low and high scenarios for these variables is of the same order of magnitude as the levelised costs of new capital intensive zero carbon generation.

All this means that there is huge uncertainty in any estimates of levelised costs, even for the mature technologies of CCGT and coal.

With this in mind, our analysis draws the following conclusions for a central case.

CCGTs running on gas have both a lower capex and lower levelised cost than the main base-load generation alternatives with a LGC around £80/MWh in our base case, which adopts DECC's central projections for fuel and carbon[17]. Gas prices have to exceed the DECC high case for CCGT to look unattractive, and/or coal EPC prices would have to return to levels seen in 2006, which we are not projecting even in 2020. In comparison, only a decade ago the consensus was that the LGC of CCGT would be about £25/MWh (about £33/MWh in 2009 money).

Given the projected increase in carbon prices, the LGC of advanced super critical coal is significantly above that for CCGTs, at £104.5/MWh for a 2009 project start. In the medium to long term, escalating carbon prices more than offsets the projected reduction in coal's EPC premium

[17] Gas prices are projected to increase to 74p a therm In 2030, while carbon increases to £70/tCO2 in the same year.

and its increased fuel cost advantage. Moreover, this excludes the current requirement for large coal plant to fit 300MW of CCS capacity from the outset.

Integrating CCS into coal or gas fired plant would substantially raise capital and operating costs. Under DECC's central carbon price projection, the premium for CCS versus un-scrubbed plants is £32/MWh-£38/MWh, although the carbon costs on the un-scrubbed coal and gas plants is £40/MWh and £15/MWh, respectively. In the longer term, as these technologies move to NOAK status, the levelised costs of CCS equipped plant will undercut those for the un-scrubbed plant. Even then, the CCS equipped plants still see levelised costs of £105-115/MWh, with gas at the lower end and coal at the upper end of the range. Adopting DECC's low carbon price projection would see the CCS equipped plant retaining a cost premium versus non equipped plant through the 2020s.

IGCC is shown to have a significant cost premium versus advanced super critical coal plant, which reflects the still largely demonstration status of this technology. In the longer run, especially once CCS is incorporated its costs move broadly in line with ASC coal with CCS.

Nuclear and onshore wind are the least cost low carbon options today, but both above un-scrubbed CCGT

The leading 3rd generation nuclear designs, although projected to incur a significant FOAK premium have a lower levelised cost at £99/MWh than an ASC coal plant without CCS, but still significantly higher than CCGT. In the longer term as nuclear moves to NOAK status, and as carbon and fuel prices rise, nuclear is projected to become the least cost main generation option with costs around £67/MWh, some £35-45/MWh below the least cost fossil fuel options. This substantial advantage is partially eroded if much lower fuel and carbon prices are assumed and is only overturned if we apply our higher capital cost profile.

In longer term nuclear projected to least cost option of main technologies

Onshore wind is the least cost zero carbon option in the near to medium term, with a cost of £94/MWh some £5/MWh less than nuclear. Offshore wind is much more expensive, with costs of £157-186/MWh (depending on wind farm location). While offshore is projected to see a large reduction in costs, compared with onshore wind, it will still face much higher costs at £110-125/MWh for projects commissioned from 2020.

Of the minor generation technologies, the CHP options considered here offer the lowest cost power, once the steam revenues are factored in. This assumes that the projects are able to secure a 100% off-take for their steam over the whole plant life at a gas replacement cost basis. The biomass fired schemes, which have much higher heat-to-power ratios, have the lowest net costs, even seeing negative costs in the medium to long term. This latter result is largely the result of the escalation in carbon prices assumed here. In practice, given there are limited ideal steam off-takers, steam revenues will probably be significantly less, and hence net costs will consequently be higher. However, even if the biomass CHP schemes can capture half of the projected steam credit, the costs would still be less than £70/MWh in 2020.

Power-only biomass fired steam turbine based plant are projected to have levelised costs which straddle those for ASC coal. The largest biomass plant (300MW) has costs of £102/MWh based on current EPC prices for projects started in 2009. High capital, fuel and non fuel operating costs versus coal are offset by avoided carbon cost for biomass. Over time, as carbon prices increase, biomass plant's position improves such that it undercuts CCGTs and even onshore wind, so that it's cost in 2023 is just over £84/MWh.

Of the three bio-methane based gas engine options – only landfill gas and sewage gas provide levelised costs well below the projected CCGT cost with costs in the £50-60/MWh range. Anaerobic digestion of agricultural wastes, is somewhat higher, given the higher burden of capital and fixed costs assumed to be carried by generator rather than the gas provider.

Costs and relative ranking is heavily influenced by assumptions on fuel and carbon

The above general findings should be interpreted with care. The relative ranking and changes through time are heavily influenced by the fuel and carbon prices adopted. In our base case we are using DECC's latest central projections. The position would be very different if we had assumed current fuel and carbon prices were maintained: essentially, the relative ranking of the fossil fuel based options would be improved, though nuclear, onshore wind, CHP and the lower cost bio-methane options would still be the lower cost options.

There are a number of other important caveats that must be attached to these figures.

- The cost estimates are generally for base-load energy on common assumptions of load factor (though wind is constrained by energy availability), and as such we are ignoring the issue of despatch risk which depends on the plant's expected merit position over its life.
- No consideration is provided here for differences between technologies for the requirements for reserve and balancing services, or in terms of transmission network reinforcement impacts.
- We have not commented on (or quantified) the vulnerability of particular technologies to fuel supply and other interruptions, which varies considerably between technologies.
- Embedded benefits for smaller scale generators connected to the distribution networks are not considered.
- Externalities relating to environmental and social impacts of construction, operation and fuel supply chains are excluded, except to the extent that they are internalised through the carbon price.

Low levelised costs do not necessarily mean projects are bankable

The relative ranking of LGCs does not necessarily closely relate to the ability to finance technologies in the real world. Developers in the practice factor in risk premiums, the appetite of lenders and the broader impacts on their own corporate financial positions. Once these factors are considered CCGTs and onshore wind projects are often easier to finance than most other technologies.

Appendices

Mott MacDonald

Appendix A. Main technology input assumptions

Table A.1: Gas CCGT

Gas Plant - CCGT		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period (including pre-licensing, licensing & public enquiry)	years	1.6	2.0	3.0	1.4	2.0	3.0
Construction Period	years	2.5	2.8	3.2	2.0	2.5	3.0
Plant Operating Period	years	20.0	25.0	30.0	25.0	30.0	35.0
Technical data							
Gross Power Output	MW	830	830	830	830	830	830
Gross Efficiency	%	55.0%	56.0%	57.0%	58.0%	59.0%	60.0%
Average Degradation	%	3.5%	3.6%	3.6%	3.5%	3.5%	3.5%
Average Availability	%	88.7%	89.7%	91.2%	90.2%	91.2%	92.7%
Average Load Factor	%	45.0%	90.0%	100.0%	45.0%	90.0%	100.0%
Auxiliary Power	%	2.1%	2.3%	2.6%	2.0%	2.3%	2.5%
CO2 Removal	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capital costs							
Pre-licencing costs, Technical and design	£/kW	30.0	40.0	50.0	20.0	25.0	40.0
	£m	24.9	33.2	41.5	16.6	20.8	33.2
Regulatory + licencing + public enquiry	£/kW	30.0	35.0	40.0	15.0	25.0	35.0
	£m	24.9	29.1	33.2	12.5	20.8	29.1
EPC cost	£/kW	653.1	721.9	756.3	593.8	656.3	687.5
	£m	542.1	599.2	627.7	492.8	544.7	570.6
Infrastructure cost	£/kW	6.0	12.0	18.1	6.0	12.0	18.1
	£m	5.0	10.0	15.0	5.0	10.0	15.0
Dev. costs as share of EPC price		9.2%	10.4%	11.9%	5.9%	7.6%	10.9%
Total Capital Cost (excl. IDC)	**£/kW**	**719.1**	**808.9**	**864.3**	**634.8**	**718.3**	**780.6**
Operating costs							
O&M fixed fee	£/MW/yr	13,200	16,500	20,900	12,000	15,000	19,000
	£m/yr	11.0	13.7	17.3	10.0	12.5	15.8
O&M variable fee	£/MWh	1.8	2.2	2.8	1.8	2.2	2.5
	£m/yr	5.1	12.9	18.2	5.2	13.1	16.9
Total O&M costs	**£m/yr**	**16.0**	**26.6**	**35.6**	**15.1**	**25.6**	**32.6**
		2.0%	2.3%	2.8%	2.0%	2.3%	2.8%
Insurance	£/MW/yr	5,000	6,250	8,125	4,000	5,000	6,500
	£m/yr	4.2	5.2	6.7	3.3	4.2	5.4
Connection and UoS charges	£/MW/yr	2,000	6,000	10,000	2,000	6,000	10,000
	£m/yr	1.7	5.0	8.3	1.7	5.0	8.3
CO2 transport and storage costs	£/MWh	-	-	-	-	-	-
	£m/yr	-	-	-	-	-	-
Total fixed costs: £/MW/yr		*20,200*	*28,750*	*39,025*	*18,000*	*26,000*	*35,500*
Total Operating Costs	**£m/yr**	**21.8**	**36.8**	**50.6**	**20.1**	**34.7**	**46.3**
Ratio of fixed O&M to EPC price: %		2.0%	2.3%	2.8%	2.0%	2.3%	2.8%

Source: Mott MacDonald

Table A.2: CCGT with CCS

Gas Plant - CCGT with CCS

		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 (including pre-licensing, licensing & public enquiry)	years	1.8	2.4	3.6	1.5	2.0	3.0
Construction Period	years	3.6	4.2	4.8	3.0	3.5	4.0
Plant Operating Period	years	22.0	27.0	32.0	25.0	30.0	35.0
Technical data							
Gross Power Output	MW	830	830	830	830	830	830
Gross Efficiency	%	45.6%	47.5%	49.4%	48.0%	50.0%	52.0%
Average Degradation	%	3.1%	3.1%	3.1%	3.1%	3.1%	3.1%
Average Availability	%	87.0%	88.0%	89.5%	88.5%	89.5%	91.0%
Average Load Factor	%	45.0%	90.0%	100.0%	45.0%	90.0%	100.0%
Auxiliary Power	%	10.5%	11.8%	11.6%	9.5%	10.8%	10.5%
CO2 Removal	%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Capital costs							
Pre-licencing costs, Technical and design	£/kW	50.0	60.0	80.0	35.0	50.0	60.0
	£m	41.5	49.8	66.4	29.1	41.5	49.8
Regulatory + licencing + public enquiry	£/kW	40.0	50.0	60.0	25.0	30.0	40.0
	£m	33.2	41.5	49.8	20.8	24.9	33.2
EPC cost	£/kW	1,093.8	1,250.0	1,367.2	875.0	1,000.0	1,093.8
	£m	907.8	1,037.5	1,134.8	726.3	830.0	907.8
Infrastructure cost	£/kW	6.0	12.0	18.1	6.0	12.0	18.1
	£m	5.0	10.0	15.0	5.0	10.0	15.0
Dev. costs as share of EPC price		8.2%	8.8%	10.2%	6.9%	8.0%	9.1%
Total Capital Cost (excl. IDC)	**£/kW**	**1,189.8**	**1,372.0**	**1,525.3**	**941.0**	**1,092.0**	**1,211.8**
Operating costs							
O&M fixed fee	£/MW/yr	25,000	32,000	40,000	20,000	25,000	30,000
	£m/yr	20.8	26.6	33.2	16.6	20.8	24.9
O&M variable fee	£/MWh	2.8	3.2	4.1	2.8	3.2	3.8
	£m/yr	7.8	18.4	26.8	8.0	18.7	24.8
Total O&M costs	**£m/yr**	**28.6**	**45.0**	**60.0**	**24.6**	**39.5**	**49.7**
		2.3%	2.6%	2.9%	2.3%	2.5%	2.7%
Insurance	£/MW/yr	6,000	9,000	12,000	5,000	7,000	9,000
	£m/yr	5.0	7.5	10.0	4.2	5.8	7.5
Connection and UoS charges	£/MW/yr	2,000	6,000	10,000	2,000	6,000	10,000
	£m/yr	1.7	5.0	8.3	1.7	5.0	8.3
CO2 transport and storage costs	£/MWh	3.0	3.8	4.5	2.5	3.1	3.8
	£m/yr	8.5	21.6	29.3	7.2	18.3	24.8
Total fixed costs: £/MW/yr		*33,000*	*47,000*	*62,000*	*27,000*	*38,000*	*49,000*
Total Operating Costs	**£m/yr**	**43.8**	**79.0**	**107.6**	**37.6**	**68.6**	**90.3**
Ratio of fixed O&M to EPC price: %		2.3%	2.6%	2.9%	2.3%	2.5%	2.7%

Source: Mott MacDonald

Table A.3: Coal Plant

Coal Plant - Pulversied fuel, ASC with FGD

		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 (including pre-licensing, licensing & public enquiry)	years	2.8	3.3	4.4	2.5	3.0	4.0
Construction Period	years	4.2	4.8	5.4	3.5	4.0	4.5
Plant Operating Period	years	32.0	36.0	40.0	35.0	40.0	45.0
Technical data							
Gross Power Output	MW	1,600	1,600	1,600	1,600	1,600	1,600
Gross Efficiency	%	42.9%	43.9%	44.9%	44.0%	45.0%	46.0%
Average Degradation	%	2.9%	3.0%	3.0%	2.9%	2.9%	2.9%
Average Availability	%	87.0%	89.0%	90.0%	88.2%	90.2%	91.2%
Average Load Factor	%	45.0%	90.0%	100.0%	45.0%	90.0%	100.0%
Auxiliary Power	%	6.5%	7.0%	7.5%	6.0%	6.5%	7.0%
CO2 Removal	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capital costs							
Pre-licencing costs, Technical and design	£/kW	40.0	60.0	90.0	30.0	40.0	50.0
	£m	64.0	96.0	144.0	48.0	64.0	80.0
Regulatory + licencing + public enquiry	£/kW	40.0	60.0	90.0	30.0	40.0	50.0
	£m	64.0	96.0	144.0	48.0	64.0	80.0
EPC cost	£/kW	1,650.0	1,856.3	2,028.1	1,500.0	1,687.5	1,843.8
	£m	2,640.0	2,970.0	3,245.0	2,400.0	2,700.0	2,950.0
Infrastructure cost	£/kW	17.5	21.9	27.3	17.5	21.9	27.3
	£m	28.0	35.0	43.8	28.0	35.0	43.8
Dev. costs as share of EPC price		4.8%	6.5%	8.9%	4.0%	4.7%	5.4%
Total Capital Cost (excl. IDC)	**£/kW**	**1,747.5**	**1,998.1**	**2,235.5**	**1,577.5**	**1,789.4**	**1,971.1**
Operating costs							
O&M fixed fee	£/MW/yr	42,000	50,000	60,000	30,000	38,000	45,000
	£m/yr	67.2	80.0	96.0	48.0	60.8	72.0
O&M variable fee	£/MWh	2.1	2.4	3.0	1.8	2.0	2.5
	£m/yr	11.5	26.9	37.8	9.7	22.8	32.0
Total O&M costs	**£m/yr**	**78.7**	**106.9**	**133.8**	**57.7**	**83.6**	**104.0**
		2.5%	2.7%	3.0%	2.0%	2.3%	2.4%
Insurance	£/MW/yr	10,000	15,000	18,000	9,000	12,000	15,000
	£m/yr	16.0	24.0	28.8	14.4	19.2	24.0
Connection and UoS charges	£/MW/yr	2,000	6,000	10,000	2,000	6,000	10,000
	£m/yr	3.2	9.6	16.0	3.2	9.6	16.0
CO2 transport and storage costs	£/MWh	-	-	-	-	-	-
	£m/yr	-	-	-	-	-	-
Total fixed costs: £/MW/yr		*54,000*	*71,000*	*88,000*	*41,000*	*56,000*	*70,000*
Total Operating Costs	**£m/yr**	**97.9**	**140.5**	**178.6**	**75.3**	**112.4**	**144.0**
Ratio of fixed O&M to EPC price: %		2.5%	2.7%	3.0%	2.0%	2.3%	2.4%

Source: Mott MacDonald

Table A.4: Coal with CCS

Coal Plant - Pulversied fuel, ASC with FGD and CC

		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 (including pre-licensing, licensing & public enquiry)	years	3.3	4.4	5.5	3.0	4.0	5.0
Construction Period	years	4.8	5.4	6.0	4.0	4.5	5.0
Plant Operating Period	years	32.0	36.0	39.0	35.0	38.0	42.0
Technical data							
Gross Power Output	MW	1,600	1,600	1,600	1,600	1,600	1,600
Gross Efficiency	%	33.2%	35.1%	36.6%	34.0%	36.0%	37.5%
Average Degradation	%	2.4%	2.5%	2.5%	2.4%	2.4%	2.4%
Average Availability	%	80.2%	84.5%	86.0%	84.5%	89.0%	90.6%
Average Load Factor	%	45.0%	90.0%	100.0%	45.0%	90.0%	100.0%
Auxiliary Power	%	15.5%	16.5%	18.0%	14.8%	15.5%	16.5%
CO2 Removal	%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Capital costs							
Pre-licencing costs, Technical and design	£/kW	60.0	80.0	120.0	40.0	50.0	60.0
	£m	96.0	128.0	192.0	64.0	80.0	96.0
Regulatory + licencing + public enquiry	£/kW	60.0	80.0	120.0	40.0	50.0	60.0
	£m	96.0	128.0	192.0	64.0	80.0	96.0
EPC cost	£/kW	2,656.3	2,890.6	3,125.0	2,125.0	2,312.5	2,500.0
	£m	4,250.0	4,625.0	5,000.0	3,400.0	3,700.0	4,000.0
Infrastructure cost	£/kW	17.5	21.9	27.3	17.5	21.9	27.3
	£m	28.0	35.0	43.8	28.0	35.0	43.8
Dev. costs as share of EPC price		4.5%	5.5%	7.7%	3.8%	4.3%	4.8%
Total Capital Cost (excl. IDC)	**£/kW**	**2,793.8**	**3,072.5**	**3,392.3**	**2,222.5**	**2,434.4**	**2,647.3**
Operating costs							
O&M fixed fee	£/MW/yr	68,000	77,000	90,000	50,000	58,000	65,000
	£m/yr	108.8	123.2	144.0	80.0	92.8	104.0
O&M variable fee	£/MWh	3.2	3.8	4.8	2.6	3.1	3.8
	£m/yr	16.4	40.7	57.5	13.8	34.2	48.4
Total O&M costs	**£m/yr**	**125.2**	**163.9**	**201.5**	**93.8**	**127.0**	**152.4**
		2.6%	2.7%	2.9%	2.4%	2.5%	2.6%
Insurance	£/MW/yr	14,000	17,000	22,000	11,000	15,000	19,000
	£m/yr	22.4	27.2	35.2	17.6	24.0	30.4
Connection and UoS charges	£/MW/yr	2,000	6,000	10,000	2,000	6,000	10,000
	£m/yr	3.2	9.6	16.0	3.2	9.6	16.0
CO2 transport and storage costs	£/MWh	7.0	7.8	8.6	5.6	6.3	6.9
	£m/yr	35.6	83.3	103.6	30.0	70.2	87.3
Total fixed costs: £/MW/yr		*84,000*	*100,000*	*122,000*	*63,000*	*79,000*	*94,000*
Total Operating Costs	**£m/yr**	**186.4**	**284.0**	**356.3**	**144.6**	**230.8**	**286.1**
Ratio of fixed O&M to EPC price: %		2.6%	2.7%	2.9%	2.4%	2.5%	2.6%

Source: Mott MacDonald

Table A.5: IGCC

Coal Plant - IGCC

		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period (including pre-licensing, licensing & public enquiry)	years	3.3	4.4	5.5	3.0	4.0	5.0
Construction Period	years	4.2	4.8	5.4	3.5	4.0	4.5
Plant Operating Period	years	20.0	25.0	30.0	25.0	30.0	35.0
Technical data							
Gross Power Output	MW	870	870	870	870	870	870
Gross Efficiency	%	42.9%	43.9%	44.9%	44.0%	45.0%	46.0%
Average Degradation	%	2.4%	2.5%	2.5%	2.4%	2.4%	2.4%
Average Availability	%	83.1%	86.3%	88.8%	84.2%	87.5%	90.0%
Average Load Factor	%	45.0%	90.0%	100.0%	45.0%	90.0%	100.0%
Auxiliary Power	%	4.4%	5.0%	5.5%	4.0%	4.5%	5.0%
CO2 Removal	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capital costs							
Pre-licencing costs, Technical and design	£/kW	50.0	70.0	90.0	30.0	40.0	50.0
	£m	43.5	60.9	78.3	26.1	34.8	43.5
Regulatory + licencing + public enquiry	£/kW	50.0	70.0	90.0	30.0	40.0	50.0
	£m	43.5	60.9	78.3	26.1	34.8	43.5
EPC cost	£/kW	2,235.9	2,489.1	2,784.4	1,656.3	1,843.8	2,062.5
	£m	1,945.3	2,165.5	2,422.4	1,440.9	1,604.1	1,794.4
Infrastructure cost	£/kW	32.2	40.2	50.3	32.2	40.2	50.3
	£m	28.0	35.0	43.8	28.0	35.0	43.8
Dev. costs as share of EPC price		4.5%	5.6%	6.5%	3.6%	4.3%	4.8%
Total Capital Cost (excl. IDC)	**£/kW**	**2,368.1**	**2,669.3**	**3,014.7**	**1,748.4**	**1,964.0**	**2,212.8**
Operating costs							
O&M fixed fee	£/MW/yr	33,600	42,000	50,400	28,000	35,000	42,000
	£m/yr	29.2	36.5	43.8	24.4	30.5	36.5
O&M variable fee	£/MWh	2.7	3.1	3.9	2.1	2.5	3.1
	£m/yr	7.6	18.5	26.4	6.1	15.0	21.4
Total O&M costs	**£m/yr**	**36.8**	**55.0**	**70.3**	**30.5**	**45.5**	**58.0**
		1.5%	1.7%	1.8%	1.7%	1.9%	2.0%
Insurance	£/MW/yr	10,000	12,000	16,000	8,500	10,500	13,000
	£m/yr	8.7	10.4	13.9	7.4	9.1	11.3
Connection and UoS charges	£/MW/yr	2,000	6,000	10,000	2,000	6,000	10,000
	£m/yr	1.7	5.2	8.7	1.7	5.2	8.7
CO2 transport and storage costs	£/MWh	-	-	-	-	-	-
	£m/yr	-	-	-	-	-	-
Total fixed costs: £/MW/yr		*45,600*	*60,000*	*76,400*	*38,500*	*51,500*	*65,000*
Total Operating Costs	**£m/yr**	**47.2**	**70.7**	**92.9**	**39.6**	**59.8**	**78.0**
Ratio of fixed O&M to EPC price: %		1.5%	1.7%	1.8%	1.7%	1.9%	2.0%

Source: Mott MacDonald

Mott MacDonald

Table A.6: IGCC with CCS

Coal Plant - IGCC with CCS

	Unit	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 (including pre-licensing, licensing & public enquiry)	years	3.3	4.4	5.5	3.0	4.0	5.0
Construction Period	years	4.2	4.8	5.4	3.5	4.0	4.5
Plant Operating Period	years	20.0	25.0	30.0	25.0	30.0	35.0
Technical data							
Gross Power Output	MW	870	870	870	870	870	870
Gross Efficiency	%	33.2%	35.1%	36.6%	34.0%	36.0%	37.5%
Average Degradation	%	2.4%	2.5%	2.5%	2.4%	2.4%	2.4%
Average Availability	%	83.0%	86.3%	88.7%	84.1%	87.4%	89.9%
Average Load Factor	%	45.0%	90.0%	100.0%	45.0%	90.0%	100.0%
Auxiliary Power	%	13.8%	14.9%	16.0%	12.5%	13.5%	14.5%
CO2 Removal	%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Capital costs							
Pre-licencing costs, Technical and design	£/kW	50.0	70.0	100.0	35.0	45.0	55.0
	£m	43.5	60.9	87.0	30.5	39.2	47.9
Regulatory + licencing + public enquiry	£/kW	50.0	70.0	100.0	35.0	45.0	55.0
	£m	43.5	60.9	87.0	30.5	39.2	47.9
EPC cost	£/kW	2,762.5	3,006.3	3,250.0	2,125.0	2,312.5	2,500.0
	£m	2,403.4	2,615.4	2,827.5	1,848.8	2,011.9	2,175.0
Infrastructure cost	£/kW	32.2	40.2	50.3	32.2	40.2	50.3
	£m	28.0	35.0	43.8	28.0	35.0	43.8
Dev. costs as share of EPC price		3.6%	4.7%	6.2%	3.3%	3.9%	4.4%
Total Capital Cost (excl. IDC)	**£/kW**	**2,894.7**	**3,186.5**	**3,500.3**	**2,227.2**	**2,442.7**	**2,660.3**
Operating costs							
O&M fixed fee	£/MW/yr	60,000	75,000	85,000	40,000	50,000	60,000
	£m/yr	52.2	65.3	74.0	34.8	43.5	52.2
O&M variable fee	£/MWh	3.2	3.8	4.8	2.6	3.1	3.8
	£m/yr	9.2	22.6	32.2	7.5	18.3	26.1
Total O&M costs	**£m/yr**	**61.4**	**87.8**	**106.2**	**42.3**	**61.8**	**78.3**
		2.2%	2.5%	2.6%	1.9%	2.2%	2.4%
Insurance	£/MW/yr	14,000	17,000	22,000	12,000	15,000	19,000
	£m/yr	12.2	14.8	19.1	10.4	13.1	16.5
Connection and UoS charges	£/MW/yr	2,000	6,000	10,000	2,000	6,000	10,000
	£m/yr	1.7	5.2	8.7	1.7	5.2	8.7
CO2 transport and storage costs	£/MWh	7.0	7.8	8.6	5.6	6.3	6.9
	£m/yr	20.0	46.2	58.1	16.2	37.5	47.1
Total fixed costs: £/MW/yr		*76,000*	*98,000*	*117,000*	*54,000*	*71,000*	*89,000*
Total Operating Costs	**£m/yr**	**95.4**	**154.0**	**192.1**	**70.7**	**117.5**	**150.7**
Ratio of fixed O&M to EPC price: %		2.2%	2.5%	2.6%	1.9%	2.2%	2.4%

Source: Mott MacDonald

Table A.7: Onshore wind

Wind - Onshore Wind

		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period (including pre-licensing, licensing & public enquiry)	years	5.0	6.0	7.0	4.0	5.0	6.0
Construction Period	years	1.5	2.0	3.0	1.5	2.0	2.5
Plant Operating Period	years	18.0	22.0	23.0	20.0	24.0	25.0
Technical data							
Gross Power Output	MW	100	100	100	100	100	100
Gross Efficiency	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Average Degradation	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Average Availability	%	94.7%	96.6%	97.2%	96.0%	97.9%	98.5%
Average Load Factor	%	25.0%	28.0%	31.0%	25.0%	28.0%	31.0%
Auxiliary Power	%	1.7%	2.0%	2.2%	1.5%	1.8%	2.0%
CO2 Removal	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capital costs							
Pre-licencing costs, Technical and design	£/kW	70.0	100.0	130.0	50.0	70.0	100.0
	£m	7.0	10.0	13.0	5.0	7.0	10.0
Regulatory + licencing + public enquiry	£/kW	50.0	70.0	100.0	35.0	50.0	80.0
	£m	5.0	7.0	10.0	3.5	5.0	8.0
EPC cost	£/kW	1,375.0	1,531.3	1,625.0	1,250.0	1,400.0	1,500.0
	£m	137.5	153.1	162.5	125.0	140.0	150.0
Infrastructure cost	£/kW	-	-	-	-	-	-
	£m	-	-	-	-	-	-
Dev. costs as share of EPC price		8.7%	11.1%	14.2%	6.8%	8.6%	12.0%
Total Capital Cost (excl. IDC)	**£/kW**	**1,495.0**	**1,701.3**	**1,855.0**	**1,335.0**	**1,520.0**	**1,680.0**
Operating costs							
O&M fixed fee	£/MW/yr	13,703	15,987	18,270	10,962	13,703	15,530
	£m/yr	1.4	1.6	1.8	1.1	1.4	1.6
O&M variable fee	£/MWh	-	-	-	-	-	-
	£m/yr	-	-	-	-	-	-
Total O&M costs	**£m/yr**	**1.4**	**1.6**	**1.8**	**1.1**	**1.4**	**1.6**
		1.0%	1.0%	1.1%	0.9%	1.0%	1.0%
Insurance	£/MW/yr	9,350	11,550	15,400	8,500	10,500	14,000
	£m/yr	0.9	1.2	1.5	0.9	1.1	1.4
Connection and UoS charges	£/MW/yr	8,000	10,000	15,000	8,000	10,000	15,000
	£m/yr	0.8	1.0	1.5	0.8	1.0	1.5
CO2 transport and storage costs	£/MWh	-	-	-	-	-	-
	£m/yr	-	-	-	-	-	-
Total fixed costs: £/MW/yr		*31,053*	*37,537*	*48,670*	*27,462*	*34,203*	*44,530*
Total Operating Costs	**£m/yr**	**3.1**	**3.8**	**4.9**	**2.7**	**3.4**	**4.5**
Ratio of fixed O&M to EPC price: %		1.0%	1.0%	1.1%	0.9%	1.0%	1.0%

Source: Mott MacDonald

Mott MacDonald

Table A.8: Offshore wind

Wind - Offshore Wind		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 (including pre-licensing, licensing & public enquiry)	years	5.0	6.0	7.0	4.0	5.0	6.0
Construction Period	years	1.5	2.0	3.0	1.5	2.0	2.5
Plant Operating Period	years	18.0	22.0	23.0	20.0	24.0	25.0
Technical data							
Gross Power Output	MW	200	200	200	200	200	200
Gross Efficiency	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Average Degradation	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Average Availability	%	93.5%	94.6%	95.6%	94.8%	95.9%	96.9%
Average Load Factor	%	35.0%	39.0%	43.0%	38.0%	41.0%	45.0%
Auxiliary Power	%	2.0%	2.2%	2.4%	1.8%	2.0%	2.2%
CO2 Removal	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capital costs							
Pre-licencing costs, Technical and design	£/kW	45.0	55.0	65.0	35.0	45.0	50.0
	£m	9.0	11.0	13.0	7.0	9.0	10.0
Regulatory + licencing + public enquiry	£/kW	45.0	55.0	65.0	35.0	45.0	50.0
	£m	9.0	11.0	13.0	7.0	9.0	10.0
EPC cost	£/kW	2,500.0	3,000.0	3,500.0	2,250.0	2,750.0	3,250.0
	£m	500.0	600.0	700.0	450.0	550.0	650.0
Infrastructure cost	£/kW	-	-	-	-	-	-
	£m	-	-	-	-	-	-
Dev. costs as share of EPC price		3.6%	3.7%	3.7%	3.1%	3.3%	3.1%
Total Capital Cost (excl. IDC)	**£/kW**	**2,590.0**	**3,110.0**	**3,630.0**	**2,320.0**	**2,840.0**	**3,350.0**
Operating costs							
O&M fixed fee	£/MW/yr	70,000	80,000	90,000	45,676	50,243	54,811
	£m/yr	14.0	16.0	18.0	9.1	10.0	11.0
O&M variable fee	£/MWh	-	-	-	-	-	-
	£m/yr	-	-	-	-	-	-
Total O&M costs	**£m/yr**	**14.0**	**16.0**	**18.0**	**9.1**	**10.0**	**11.0**
		2.8%	2.7%	2.6%	2.0%	1.8%	1.7%
Insurance	£/MW/yr	22,000	25,000	27,000	15,000	17,000	20,000
	£m/yr	4.4	5.0	5.4	3.0	3.4	4.0
Connection and UoS charges	£/MW/yr	5,000	9,000	12,000	5,000	9,000	12,000
	£m/yr	1.0	1.8	2.4	1.0	1.8	2.4
CO2 transport and storage costs	£/MWh	-	-	-	-	-	-
	£m/yr	-	-	-	-	-	-
Total fixed costs: £/MW/yr		*97,000*	*114,000*	*129,000*	*65,676*	*76,243*	*86,811*
Total Operating Costs	**£m/yr**	**19.4**	**22.8**	**25.8**	**13.1**	**15.2**	**17.4**
Ratio of fixed O&M to EPC price: %		2.8%	2.7%	2.6%	2.0%	1.8%	1.7%

Source: Mott MacDonald

Table A.9: Offshore wind Round 3

Wind - Offshore Wind R3		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period (including pre-licensing, licensing & public enquiry)	years	5.0	6.0	7.0	4.0	5.0	6.0
Construction Period	years	1.5	2.0	3.0	1.5	2.0	2.5
Plant Operating Period	years	18.0	22.0	23.0	20.0	24.0	25.0
Technical data							
Gross Power Output	MW	400	400	400	400	400	400
Gross Efficiency	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Average Degradation	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Average Availability	%	93.5%	94.6%	95.6%	94.8%	95.9%	96.9%
Average Load Factor	%	35.0%	39.0%	43.0%	38.0%	41.0%	45.0%
Auxiliary Power	%	2.0%	2.2%	2.4%	1.8%	2.0%	2.2%
CO2 Removal	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capital costs							
Pre-licencing costs, Technical and design	£/kW	50.0	65.0	85.0	35.0	45.0	55.0
	£m	20.0	26.0	34.0	14.0	18.0	22.0
Regulatory + licencing + public enquiry	£/kW	50.0	60.0	70.0	35.0	42.0	50.0
	£m	20.0	24.0	28.0	14.0	16.8	20.0
EPC cost	£/kW	3,000.0	3,500.0	4,000.0	2,500.0	3,000.0	3,500.0
	£m	1,200.0	1,400.0	1,600.0	1,000.0	1,200.0	1,400.0
Infrastructure cost	£/kW	-	-	-	-	-	-
	£m	-	-	-	-	-	-
Dev. costs as share of EPC price		3.3%	3.6%	3.9%	2.8%	2.9%	3.0%
Total Capital Cost (excl. IDC)	**£/kW**	**3,100.0**	**3,625.0**	**4,155.0**	**2,570.0**	**3,087.0**	**3,605.0**
Operating costs							
O&M fixed fee	£/MW/yr	87,750	97,750	107,750	59,379	68,514	77,649
	£m/yr	35.1	39.1	43.1	23.8	27.4	31.1
O&M variable fee	£/MWh	-	-	-	-	-	-
	£m/yr	-	-	-	-	-	-
Total O&M costs	**£m/yr**	**35.1**	**39.1**	**43.1**	**23.8**	**27.4**	**31.1**
		2.9%	2.8%	2.7%	2.4%	2.3%	2.2%
Insurance	£/MW/yr	30,000	35,000	40,000	20,000	25,000	30,000
	£m/yr	12.0	14.0	16.0	8.0	10.0	12.0
Connection and UoS charges	£/MW/yr	5,000	9,000	12,000	5,000	9,000	12,000
	£m/yr	2.0	3.6	4.8	2.0	3.6	4.8
CO2 transport and storage costs	£/MWh	-	-	-	-	-	-
	£m/yr	-	-	-	-	-	-
Total fixed costs: £/MW/yr		*122,750*	*141,750*	*159,750*	*84,379*	*102,514*	*119,649*
Total Operating Costs	**£m/yr**	**49.1**	**56.7**	**63.9**	**33.8**	**41.0**	**47.9**
Ratio of fixed O&M to EPC price: %		2.9%	2.8%	2.7%	2.4%	2.3%	2.2%

Source: Mott MacDonald

Table A.10: Nuclear 3rd generation PWR

Nuclear - PWR

		1st OF A KIND			Nth OF A KIND		
		Low	Medium	High	Low	Medium	High
Key Timings							
Total Pre-development Period (including pre-licensing, licensing & public enquiry)	years	3.3	4.4	5.5	3.0	4.0	5.0
Construction Period	years	5.0	6.0	7.0	4.0	5.0	6.0
Plant Operating Period	years	55.0	60.0	60.0	60.0	60.0	65.0
Technical data							
Gross Power Output	MW	1,600	1,600	1,600	1,600	1,600	1,600
Gross Efficiency	%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Average Degradation	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Average Availability	%	82.0%	86.3%	88.2%	86.3%	90.8%	92.8%
Average Load Factor	%	80.0%	90.0%	100.0%	80.0%	90.0%	100.0%
Auxiliary Power	%	4.4%	5.0%	5.5%	4.0%	4.5%	5.0%
CO2 Removal	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capital costs							
Pre-licencing costs, Technical and design	£/kW	50.0	75.0	100.0	35.0	50.0	75.0
	£m	80.0	120.0	160.0	56.0	80.0	120.0
Regulatory + licencing + public enquiry	£/kW	50.0	75.0	100.0	35.0	50.0	75.0
	£m	80.0	120.0	160.0	56.0	80.0	120.0
EPC cost	£/kW	2,812.5	3,593.8	4,218.8	2,375.0	2,812.5	3,125.0
	£m	4,500.0	5,750.0	6,750.0	3,800.0	4,500.0	5,000.0
Infrastructure cost	£/kW	-	-	-	-	-	-
	£m	-	-	-	-	-	-
Owners' predevelopment costs as % of EPC price		3.6%	4.2%	4.7%	2.9%	3.6%	4.8%
Total Capital Cost (excl. IDC)	**£/kW**	**2,912.5**	**3,743.8**	**4,418.8**	**2,445.0**	**2,912.5**	**3,275.0**
Operating costs							
O&M fixed fee	£/MW/yr	45,000	50,000	60,000	30,000	37,500	45,000
	£m/yr	72.0	80.0	96.0	48.0	60.0	72.0
O&M variable fee	£/MWh	1.8	2.0	2.5	1.5	1.8	2.0
	£m/yr	16.1	21.8	30.9	14.5	20.1	26.0
Total O&M costs	**£m/yr**	**88.1**	**101.8**	**126.9**	**62.5**	**80.1**	**98.0**
		1.6%	1.4%	1.4%	1.3%	1.3%	1.4%
Insurance	£/MW/yr	17,000	22,000	27,000	14,000	18,000	22,000
	£m/yr	27.2	35.2	43.2	22.4	28.8	35.2
Connection and UoS charges	£/MW/yr	2,000	6,000	10,000	2,000	6,000	10,000
	£m/yr	3.2	9.6	16.0	3.2	9.6	16.0
CO2 transport and storage costs	£/MWh	-	-	-	-	-	-
	£m/yr	-	-	-	-	-	-
Total fixed costs: £/MW/yr		*64,000*	*78,000*	*97,000*	*46,000*	*61,500*	*77,000*
Total Operating Costs	**£m/yr**	**118.5**	**146.6**	**186.1**	**88.1**	**118.5**	**149.2**
Ratio of fixed O&M to EPC price: %		1.6%	1.4%	1.4%	1.3%	1.3%	1.4%

Source: Mott MacDonald

Mott MacDonald

Appendix B. Levelised cost results for main technologies

Table B.1: Levelised costs of main technologies: £/MWh

Case 1
10% discount rate, 2009 project start at today's EPC prices, with mixed FOAK/NOAK

Levelised Cost	Gas CCGT	Gas CCGT with CCS - FOAK	ASC coal	ASC coal with CCS - FOAK	Coal IGCC - FOAK	Coal IGCC with CCS - FOAK	Onshore Wind	Offshore Wind - FOAK	Offshore Wind R3 - FOAK	Nuclear PWR - FOAK
Capital Costs	12.4	29.8	33.4	74.1	61.7	82.0	79.2	124.1	144.6	77.3
Fixed operating Costs	3.7	7.7	8.6	18.6	9.7	17.7	14.6	36.7	45.8	12.2
Variable Operating Costs	2.3	3.6	2.2	4.7	3.4	4.6	-	-	-	2.1
Fuel Costs	46.9	65.0	19.9	28.7	20.3	28.3	-	-	-	5.3
Carbon Costs	15.1	2.1	40.3	6.5	39.6	5.5	-	-	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	2.1
CO2 transport and storage	-	4.3	-	9.6	-	9.5	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-	-	-	-
Total Levelised Cost	80.3	112.5	104.5	142.1	134.6	147.6	93.9	160.9	190.5	99.0

Case 2
10% discount rate, 2009 project start at projected EPC prices, with mixed FOAK/NOAK

Levelised Cost	Gas CCGT	Gas CCGT with CCS - FOAK	ASC coal	ASC coal with CCS - FOAK	Coal IGCC - FOAK	Coal IGCC with CCS - FOAK	Onshore Wind	Offshore Wind - FOAK	Offshore Wind R3 - FOAK	Nuclear PWR - FOAK
Capital Costs	11.8	28.7	31.1	68.1	58.3	77.4	73.2	111.7	131.6	75.5
Fixed operating Costs	3.7	7.7	8.6	18.6	9.7	17.7	14.6	36.7	45.8	12.2
Variable Operating Costs	2.3	3.6	2.2	4.7	3.4	4.6	-	-	-	2.1
Fuel Costs	46.9	65.0	19.9	28.7	20.3	28.3	-	-	-	5.3
Carbon Costs	15.1	2.1	40.3	6.5	39.6	5.5	-	-	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	2.1
CO2 transport and storage	-	4.3	-	9.6	-	9.5	-	-	-	0
Steam Revenue	-	-	-	-	-	-	-	-	-	0
Total Levelised Cost	79.7	111.4	102.2	136.2	131.2	143.0	87.8	148.5	177.4	97.1

Case 3

10% discount rate, 2013 project start at projected EPC prices, with mixed FOAK/NOAK

Levelised Cost	Gas CCGT	Gas CCGT with CCS - FOAK	ASC coal	ASC coal with CCS - FOAK	Coal IGCC - FOAK	Coal IGCC with CCS - FOAK	Onshore Wind	Offshore Wind - FOAK	Offshore Wind R3 - FOAK	Nuclear PWR - FOAK
Capital Costs	11.2	27.7	29.1	63.9	55.5	73.6	72.1	109.4	128.8	72.9
Fixed operating Costs	3.7	7.7	8.6	18.6	9.7	17.7	14.6	36.7	45.8	12.2
Variable Operating Costs	2.3	3.6	2.2	4.7	3.4	4.6	-	-	-	2.1
Fuel Costs	48.5	67.2	19.9	28.7	20.3	28.3	-	-	-	5.3
Carbon Costs	21.0	3.0	55.1	9.0	56.9	7.9	-	-	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	2.1
CO2 transport and storage	-	4.3	-	9.6	-	9.5	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-	-	-	-
Total Levelised Cost	86.7	113.5	114.9	134.4	145.8	141.7	86.7	146.1	174.6	94.6

Case 4
10% discount rate, 2017 project start at projected EPC prices, with mixed FOAK/NOAK

Levelised Cost	Gas CCGT	Gas CCGT with CCS - FOAK	ASC coal	ASC coal with CCS - FOAK	Coal IGCC - FOAK	Coal IGCC with CCS - FOAK	Onshore Wind	Offshore Wind - FOAK	Offshore Wind R3 - FOAK	Nuclear PWR - FOAK
Capital Costs	11.2	27.1	28.7	63.6	54.1	71.8	71.7	108.7	127.0	71.8
Fixed operating Costs	3.7	7.7	8.6	18.6	9.7	17.7	14.6	36.7	45.8	12.2
Variable Operating Costs	2.3	3.6	2.2	4.7	3.4	4.6	-	-	-	2.1
Fuel Costs	49.8	68.9	19.9	28.7	20.3	28.3	-	-	-	5.3
Carbon Costs	29.6	4.3	73.8	11.7	76.1	10.6	-	-	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	2.1
CO2 transport and storage	-	4.3	-	9.6	-	9.5	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-	-	-	-
Total Levelised Cost	96.5	115.8	133.2	136.8	163.6	142.4	86.3	145.4	172.9	93.4

Case 5
10% discount rate, 2017 project start at projected EPC prices, all NOAK

Levelised Cost	Gas - CCGT	Gas - CCGT with CCS	ASC Coal	ASC Coal+CCS	Coal IGCC	Coal - IGCC with CCS	Onshore Wind	Offshore Wind	Offshore Wind R3	Nuclear - PWR
Capital Costs	11.2	20.7	28.7	47.8	33.7	46.5	71.7	89.4	97.0	49.6
Fixed operating Costs	3.7	6.0	8.6	13.8	8.0	12.3	14.6	23.0	30.9	9.1
Variable Operating Costs	2.3	3.6	2.2	3.7	2.7	3.6	-	-	-	1.8
Fuel Costs	49.8	64.7	19.9	27.6	19.6	27.2	-	-	-	5.2
Carbon Costs	29.6	4.1	73.8	11.4	72.0	10.0	-	-	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	2.1
CO2 transport and storage	-	3.5	-	7.6	-	7.5	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-	-	-	-
Total Levelised Cost	96.5	102.6	133.2	111.9	136.0	107.1	86.3	112.4	127.9	67.8

Source: Mott MacDonald

Table B.2: Levelised costs on main technologies (continued): £/MWh

Case 6

10% discount rate, 2023 project start at projected EPC prices, all NOAK

Levelised Cost	Gas - CCGT	Gas - CCGT with CCS	ASC Coal	ASC Coal+CCS	Coal IGCC	Coal - IGCC with CCS	Onshore Wind	Offshore Wind	Offshore Wind R3	Nuclear - PWR
Capital Costs	11.1	20.5	28.4	47.4	33.0	45.5	71.2	88.5	96.0	49.2
Fixed operating Costs	3.7	6.0	8.6	13.8	8.0	12.3	14.6	23.0	30.9	9.1
Variable Operating Costs	2.3	3.6	2.2	3.7	2.7	3.6	-	-	-	1.8
Fuel Costs	50.9	65.9	19.9	27.6	19.6	27.2	-	-	-	5.2
Carbon Costs	44.0	6.0	103.2	15.6	101.4	14.1	-	-	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	2.1
CO2 transport and storage	-	3.5	-	7.4	-	7.5	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-	-	-	-
Total Levelised Cost	111.9	105.5	162.3	115.5	164.7	110.2	85.8	111.5	126.9	67.4

case 7

7.5% discount rate, 2009 project start at today's EPC prices, with mixed FOAK/NOAK

Levelised Cost	Gas CCGT	Gas CCGT with CCS - FOAK	ASC coal	ASC coal with CCS - FOAK	Coal IGCC - FOAK	Coal IGCC with CCS - FOAK	Onshore Wind	Offshore Wind - FOAK	Offshore Wind R3 - FOAK	Nuclear PWR - FOAK
Capital Costs	9.6	22.9	24.9	54.8	47.0	62.5	63.2	100.1	116.7	54.5
Fixed operating Costs	3.7	7.7	8.6	18.5	9.7	17.6	14.6	36.6	45.6	12.2
Variable Operating Costs	2.3	3.6	2.2	4.7	3.4	4.6	-	-	-	2.1
Fuel Costs	47.4	65.6	20.0	28.7	20.3	28.3	-	-	-	5.3
Carbon Costs	17.5	2.4	48.8	7.7	44.0	6.1	-	-	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	2.1
CO2 transport and storage	-	4.3	-	9.6	-	9.5	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-	-	-	-
Total Levelised Cost	80.4	106.5	104.4	124.0	124.3	128.7	77.8	136.8	162.3	76.1

Case 8

7.5% discount rate, 2023 project start at projected EPC prices, all NOAK

Levelised Cost	Gas - CCGT	Gas - CCGT with CCS	ASC Coal - with FGD	ASC Coal - with FGD and CCS	Coal - IGCC	Coal - IGCC with CCS	Onshore Wind	Offshore Wind	Offshore Wind R3	Nuclear - PWR
Capital Costs	8.6	15.6	21.1	34.7	25.2	34.8	56.7	70.9	76.9	35.2
Fixed operating Costs	3.7	6.0	8.6	13.7	8.0	12.3	14.6	22.9	30.7	9.1
Variable Operating Costs	2.3	3.6	2.2	3.7	2.7	3.6	-	-	-	1.8
Fuel Costs	51.0	66.0	20.0	27.7	19.6	27.2	-	-	-	5.2
Carbon Costs	47.4	6.5	113.1	16.9	108.1	15.0	-	-	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	2.1
CO2 transport and storage	-	3.5	-	7.3	-	7.5	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-	-	-	-
Total Levelised Cost	112.9	101.1	165.0	104.0	163.7	100.5	71.3	93.7	107.6	53.4

Case 9

10% discount rate, 2017 project start at projected EPC prices, all NOAK, high fuel price and DECC central carbon price

Levelised Cost	Gas - CCGT	Gas - CCGT with CCS	ASC Coal	ASC Coal+CCS	Coal - IGCC	Coal - IGCC with CCS	Onshore Wind	Offshore Wind	Offshore Wind R3	Nuclear - PWR
Capital Costs	11.2	20.7	28.7	47.8	33.7	46.5	71.7	89.4	97.0	49.6
Fixed operating Costs	3.7	6.0	8.6	13.8	8.0	12.3	14.6	23.0	30.9	9.1
Variable Operating Costs	2.3	3.6	2.2	3.7	2.7	3.6	-	-	-	1.8
Fuel Costs	66.4	85.9	24.4	33.9	24.1	33.4	-	-	-	6.3
Carbon Costs	29.6	4.1	73.8	11.4	72.0	10.0	-	-	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	2.1
CO2 transport and storage	-	3.5	-	7.6	-	7.5	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-	-	-	-
Total Levelised Cost	113.2	123.8	137.7	118.2	140.4	113.3	86.3	112.4	127.9	68.9

Case 10

10% discount rate, 2017 project start at projected EPC prices, all NOAK, low fuel price and flt £20/tCO2 carbon price

Levelised Cost	Gas - CCGT	Gas - CCGT with CCS	ASC Coal	ASC Coal+CCS	Coal - IGCC	Coal - IGCC with CCS	Onshore Wind	Offshore Wind	Offshore Wind R3	Nuclear - PWR
Capital Costs	11.2	20.7	28.7	47.8	33.7	46.5	71.7	89.4	97.0	49.6
Fixed operating Costs	3.7	6.0	8.6	13.8	8.0	12.3	14.6	23.0	30.9	9.1
Variable Operating Costs	2.3	3.6	2.2	3.7	2.7	3.6	-	-	-	1.8
Fuel Costs	25.4	32.9	13.2	18.3	13.0	18.0	-	-	-	4.2
Carbon Costs	8.0	1.0	16.0	2.2	15.6	2.2	-	-	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	2.1
CO2 transport and storage	-	3.5	-	7.6	-	7.5	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-	-	-	-
Total Levelised Cost	50.5	67.7	68.6	93.3	72.9	90.0	86.3	112.4	127.9	66.8

Source: Mott MacDonald

Appendix C. Costs of minor technologies

This annex outlines the high level results and main input assumptions regarding the minor generation technologies; which for this analysis include:

- Biomass combustion for electricity only based on 50MW and 300MW plants fired by wood pellets
- Biomass fired CHP plants rated at 32/105 MWe and MWth and 110/330 MWe and MWth
- AD plant fired on agricultural wastes rated at 2MW
- Landfill gas fired engines rated at 4MW
- Sewage gas fired engines rated at 5MW
- Open cycle gas turbine (OCGT) based on LM100 machine
- Medium size gas fired GT based CHP rated at 50/60 MWe/MWth
- Large scale gas fired CHP based on F class CCGT rated at 340/235 MWe and MWth
- Reservoir hydro scheme rated at 100MW and a hydro pumped storage scheme rated at 100MW.

For most renewable technologies it is difficult to generalise on technical configurations and hence costs

For all the options above, with the exception of the OCGT, there are huge difficulties in defining a generic cost since there are multiple options regarding technologies, configurations, feedstock and residue treatment and disposal requirements and contractual arrangements. This means that great care should be made in generalising from these figures and it is important that the input assumptions are borne in mind when comparing these costs.

The main input assumptions are outlined below.

CHP plants: In all cases here, it is assumed that 100% of steam output over the life of the project is valued at the avoided cost of natural gas used in a large industrial boiler with a HHV efficiency of 81% with gas priced at the same level as that provided to large generators. No capacity costs are assumed to be avoided, however, the avoided carbon is counted. The capacity benefit is comparatively small compared with avoided fuel and carbon costs. The assumption of a continuous firm and high value off-take for heat is contrasts with the real situation in the UK, where there are few obvious off-takers, which have not already secured supply via CHP and there is minimal prospect of such new loads. In practice, available heat load are typically more variable, required at different qualities, and/or have limited long term security, because of exposure to competitive forces. The high heat to power ratios of steam turbine based CHP (necessary for **biomass**) further limits the applicability of this type of CHP versus gas turbine based (**gas** fired) CHP plants. District heating loads are particularly difficult to rely on due to seasonality, peaky daily load profiles and limited economies of scale.

AD on agricultural wastes: here we assumes a favourable feedstock, as typified by straw silage, which has a high gas yield per tonne and also modest requirements for pre-treatment of feedstocks and residues. It is assumed that residues can be returned to the fields. No feedstock price is assumed, although the operations and maintenance includes an allowance of about a £1/GJ for feedstock delivery and handling. In practice, for uncontaminated feedstocks, the gate fee[18] could be more than the -£1/GJ allowed here.

Landfill gas: we have assumed that the generator is a separate entity from the landfill operator and that the capital costs of generation include a up front capacity fee paid to the landfill developer. The ongoing costs of managing the gas wells and gas treatment and in developing new wells and gas gathering network, is split between fixed and variable operation and maintenance. A royalty allowance, which is in practice paid as a negotiated percentage of income, is also added to the variable opex. These arrangements mean that no positive or negative gate fee is specified.

Sewage gas: the facility assumed here is an advanced AD digester, gas treatment facility and power island. However, we have not included the full capital or operating costs of the advanced biological processing of solid waste (the advanced pressure cooking and pasteurisation) which are compliance requirements for disposal of the sewage treatment facilities' effluents and solid residues, since these costs would be incurred anyway. Also, the gas is assumed to be provided at a zero gate fee, while the solid residues are also assumed to have a zero net exit fee.

Reservoir hydro and pumped storage hydro: given the site specific nature of hydro schemes, the varying construction types and the combinations of energy and power capability, any such generic estimates must be treated with great caution. Our estimated overnight EPC figures for 100MW rated schemes are lower per kW of capacity than large coal plant, which is reflective of assumed favourable site. We have also assumed the site is close to existing transmission system so no major interconnection costs are included. The assumed capacity factor for the reservoir scheme is 40%, while the maximum ACF for the pumped storage scheme is 25% based on its pumping/generation cycle. LEC are calculated using these ACF. No allowance has been made for cost of pumping energy for the PS scheme, as this is assumed to be taken into account in income side (which not considered here).

[18] The gate fee is normally the charge that a supplier of low grade feedstock will pay to a processer to take its supplies away and is measured at the processors' gate. A negative gate fee means that the processor pays for the feedstock including delivery costs.

The levelised cost build up is shown for three cases, all of which are based on DECC's central fuel and carbon price, namely:

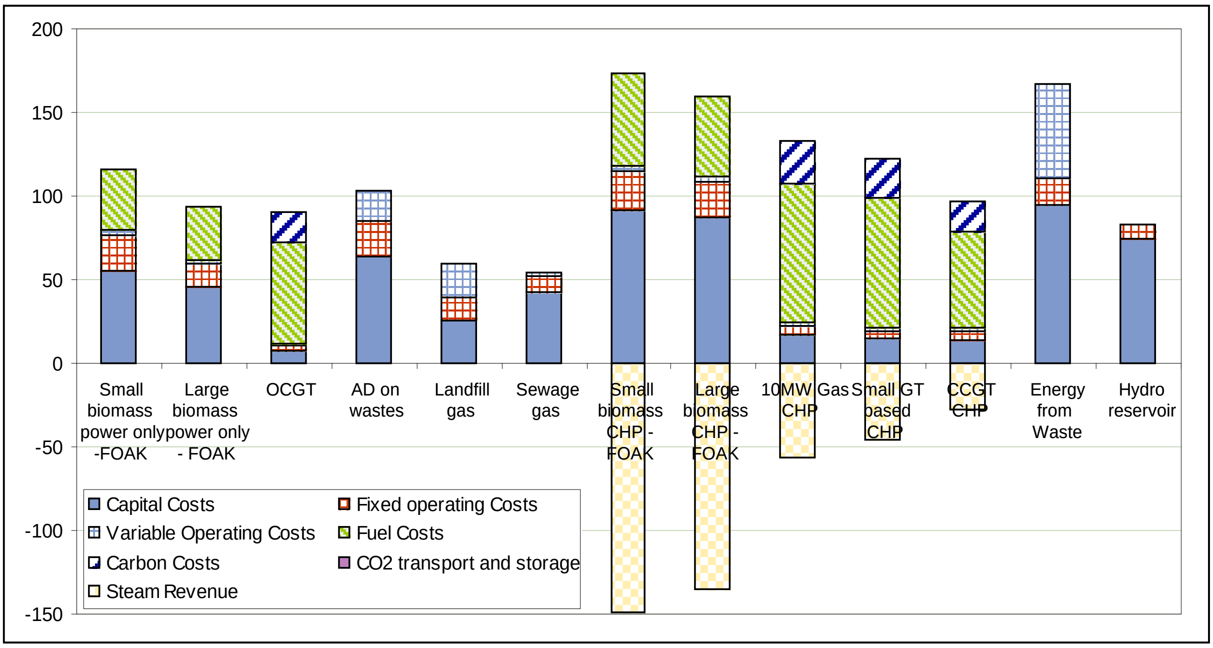
- Case 1: 10% discount rate, with project assumed to be started in 2009, but based on current (early 2010) EPC prices, with all plants treated as NOAK except the biomass combustion plant (electricity only and CHP);
- Case 2: 10% discount rate, project start 2023, all plant treated as NOAK
- Case 3: As 1 above but with a 7.5% discount rate;
- Case 4: As 2 above but with 7.5% discount rate;
- Case 5: High fuel price case, 10% discount rate, project start 2017, all NOAK
- Case 6: Low fuel prices and flat £20/tCO2 carbon price, 10% discount rate, 2017 start and all NOAK.

Landfill gas and sewage gas are easily the least cost options among the renewables, at least until steam sales credit is taken into account

The main features to note regarding the levelised costs of these technologies are:

Most of the minor technologies considered have levelised costs well above the current level for CCGT for a project assumed to be started in 2009. The two exceptions are landfill gas and sewage gas, which cost £60 and £55/MWh, respectively. Reservoir hydro's costs come in at £83/MWh, although there are just a handful of sites where such low costs could be achieved in the UK. The other technologies costs generally come in at around £100/MWh or more (AD on agricultural wastes, and large biomass combustion all come in around £100/MWh, while smaller biomass combustion and small gas fired CHP costs around £125/MWh, with biomass CHP costing £170-200/MWh). Figure C.1 shows the levelised cost build up for the base case assumptions, at current EPC prices for a projected started in 2009. All of these technologies, except for biomass combustion can probably be considered at the NOAK level, so there is modest scope for costs reduction deriving from technology improvements.

Figure C.1: Levelised costs of minor technologies assuming current EPC prices for project started in 2009: £/MWh



Source: Mott MacDonald

Steam revenues for CHP, especially schemes with high H:P ratios are huge

However, for the CHP technologies, taking steam revenues into account substantially changes the picture, especially for the options which have a high heat-to-power ratio (such biomass driven steam turbines). The net levelised cost of the two biomass CHP options (which both have HP ratios over 3) are £43 and £30/MWh for the large and small installation, respectively. The small and large gas fired CHP options cost £79 and £71/MWh, so just undercutting conventional CCGTs.

In terms of cost structure, the gas turbine options (whether open cycle of CHP based) all have low capital costs, but high fuel and carbon costs. Non fuel variable and fixed costs tend to be moderate. In contrast, the biomass combustion options tend to have very high capex and fixed operating costs, but somewhat lower fuel costs than gas fired plant and zero carbon. The three bio-methane options (AD of agricultural wastes, landfill gas and sewage gas) are all shown to have zero fuel costs (though for the AD options feedstock delivery is included within variable cost), but otherwise the costs are quite different. The AD option has the highest capital and fixed operating cost, while landfill gas has the lowest, which reflects the high degree of feedstock treatment for the agricultural wastes compared with the minimal requirement for the landfill gas. Sewage gas falls between the two, largely because the most of the expensive feedstock treatment is assumed to be borne by the host sewage works.

The two hydro options' levelised costs are both dominated by capital cost, and the key driver here is extent of fixed cost dilution through increasing the capacity factor. The higher costs for the pumped storage plant (£118/MWh versus £83/MWh) largely reflect the 25% capacity factor versus the 40% for the reservoir hydro scheme. In practice, the pumped storage plant will also incur a pumping cost (equal to the average cost of power bought to fill the upper reservoir multiplied by the loss factor in the pumping-generation cycle), which will need to be deducted from the income from generation.[19]

All the above costs are based on 10% discount rate. Discounting at 7.5% reduces the costs, especially for the capital intensive options, such as biomass combustion and hydro power. Assuming today's EPC prices, the net levelised cost of biomass CHP is reduced to just £13 and £5/MWh.

Ranking of levelised costs of these minor technologies is subject to realisable steam value, biomass prices and gate fees – no obvious technological breakthroughs in prospect

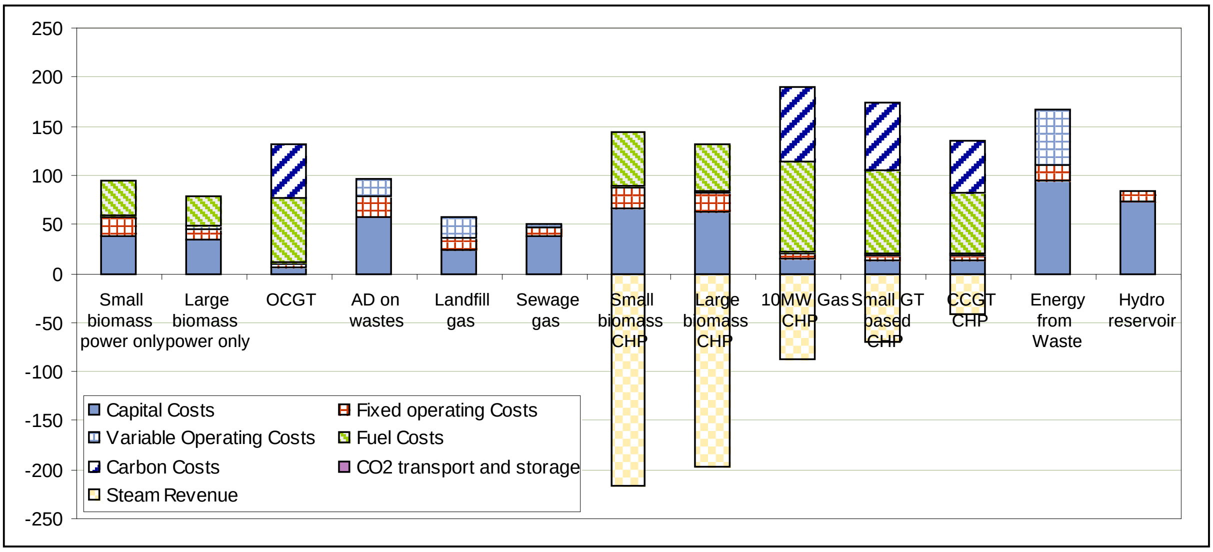
The cost level and structures changes as the assumed start date for projects are altered. As the project start dates are delayed, the capital costs of projects are seen to fall. This reflects the assumed reduction in general EPC prices as well as movement toward NOAK costings. This is especially noticeable for the capital intensive projects, such as biomass combustion, but much less for gas fired GT based options. Offsetting this for the gas fired options is the escalating fuel and carbon costs, which based on DECC's assumptions sees a significant increase in the fuel and carbon component of costs. This is especially noticeable for the gas fired open cycle GT.

These fuel and carbon price drivers do not affect the biomass or bio-methane costs, as these fuels and feedstocks are assumed to unaffected by fossil fuel prices. However, the increase in gas and carbon prices also leads to a big increase in the steam values, which improves the economics of CHP, particularly biomass fired. Indeed in 2023, under our base case assumptions, biomass CHP would have negative net cost, assuming all of the plant's steam was sold at the steam value calculated on displaced gas in an industrial boiler.

Comparison of Figure C.3 and Figure C.4 shows the projected improvement in the position of biomass combustion, and especially its CHP variants, versus other technologies, and the relative deterioration of gas fired OCGTs.

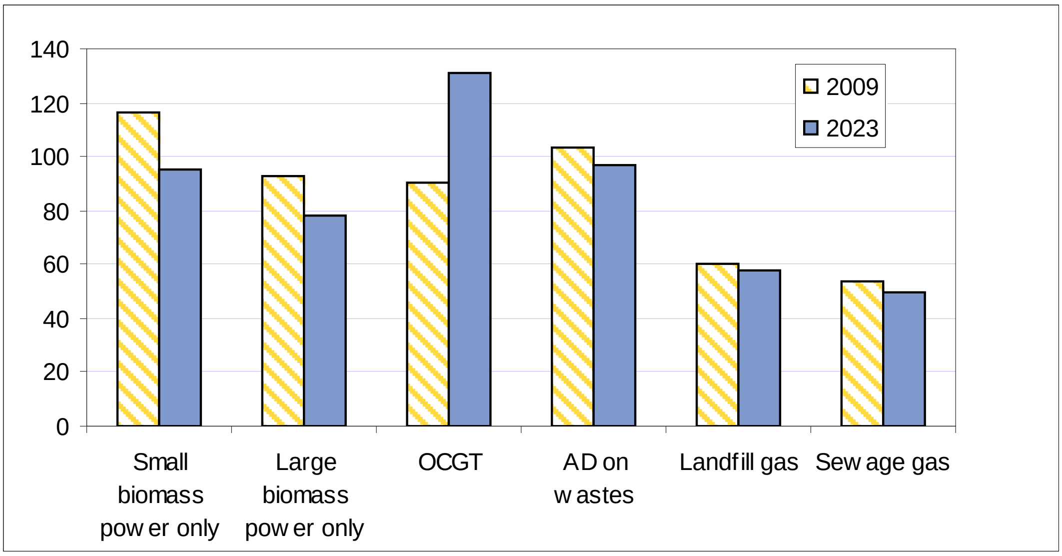
[19] Of course, pumped storage plants are also well placed to offer balancing services to the system operators and can extra trading income from participating in the balancing mechanism.

Figure C.2: Levelised costs of minor technologies for 2023 project start, 10% discount rate, all NOAK: £/MWh



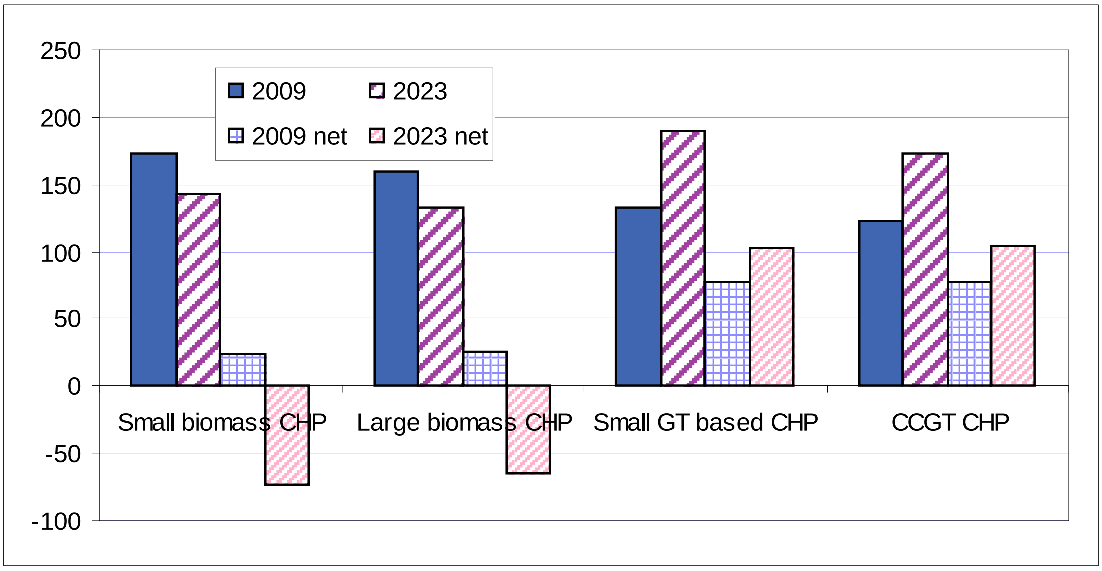
Source: Mott MacDonald

Figure C.3: Levelised costs of minor renewable power only options in 2009 and 2023: £/MWh



Source: Mott MacDonald

Figure C.4: Levelised cost of CHP options in 2009 and 2023



Source: Mott MacDonald

Table C.1: Levelised costs of minor technologies under different cases: £/MWh

Case 1

10% discount rate, 2009 project start at today's EPC prices, with mixed FOAK/NOAK

Levelised Cost	Small biomass power only - FOAK	Large biomass power only - FOAK	OCGT	AD on wastes	Landfill gas	Sewage gas	Small biomass CHP - FOAK	Large biomass CHP - FOAK	10MW Gas CHP	Small GT based CHP	CCGT CHP	Energy from Waste	Hydro reservoir
Capital Costs	55.8	46.1	7.1	63.8	25.8	42.9	91.3	86.8	17.2	15.1	14.3	94.9	74.2
Fixed operating Costs	21.0	13.4	3.0	21.0	13.1	8.9	23.9	22.0	4.8	4.3	5.0	15.2	9.0
Variable Operating Costs	2.5	2.5	1.5	18.6	21.1	2.1	2.8	2.4	2.4	2.4	1.9	56.7	-
Fuel Costs	36.7	31.2	60.6	-	-	-	54.9	48.7	83.4	76.8	57.1	-	-
Carbon Costs	-	-	18.2	-	-	-	-	-	25.5	23.5	18.5	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	-	-	-	-
CO2 transport and storage	-	-	-	-	-	-	-	-	-	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-148.5	-135.0	-56.6	-45.2	-27.2	-	-
Total Levelised Cost	116.0	93.2	90.5	103.4	60.0	54.0	172.9	160.0	133.4	122.1	96.7	166.8	83.2
Net Levelised Cost							24.4	24.9	76.8	76.8	69.4		

Case 2

10% discount rate, 2023 project start at projected EPC prices, all NOAK

Levelised Cost	Small biomass power only	Large biomass power only	OCGT	AD on wastes	Landfill gas	Sewage gas	Small biomass CHP	Large biomass CHP	10MW Gas CHP	Small GT based CHP	CCGT CHP	Energy from Waste	Hydro reservoir
Capital Costs	38.8	33.7	6.4	57.2	23.4	38.5	65.9	62.7	15.5	13.6	12.8	94.9	74.2
Fixed operating Costs	18.4	12.0	3.0	21.0	13.1	8.9	21.1	19.3	4.8	4.3	5.0	15.2	9.0
Variable Operating Costs	2.2	2.2	1.5	18.6	21.1	2.1	2.2	2.2	2.4	2.4	1.9	56.7	-
Fuel Costs	35.7	30.6	66.3	-	-	-	54.3	48.2	91.1	83.9	62.0	-	-
Carbon Costs	-	-	54.2	-	-	-	-	-	75.4	69.4	53.6	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	-	-	-	-
CO2 transport and storage	-	-	-	-	-	-	-	-	-	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-216.6	-196.9	-87.2	-69.8	-42.1	-	-
Total Levelised Cost	95.2	78.4	131.4	96.8	57.6	49.6	143.6	132.3	189.3	173.7	135.2	166.8	83.2
Net Levelised Cost							-73.0	-64.6	102.0	103.9	93.2		

Case 3

7.5% discount rate, 2009 project start at today's EPC prices, with mixed FOAK/NOAK

Levelised Cost	Small biomass power only - FOAK	Large biomass power only - FOAK	OCGT	AD on wastes	Landfill gas	Sewage gas	Small biomass CHP - FOAK	Large biomass CHP - FOAK	10MW Gas CHP	Small GT based CHP	CCGT CHP	Energy from Waste	Hydro reservoir
Capital Costs	44.1	34.8	5.6	51.8	20.9	34.9	71.1	67.7	13.5	11.8	11.0	75.3	53.2
Fixed operating Costs	21.0	13.4	3.0	21.0	13.1	8.9	23.8	21.9	4.8	4.3	5.0	15.2	9.0
Variable Operating Costs	2.5	2.5	1.5	18.6	21.1	2.1	2.8	2.4	2.4	2.4	1.9	56.7	-
Fuel Costs	36.7	31.3	61.3	-	-	-	55.0	48.7	84.8	78.0	57.7	-	-
Carbon Costs	-	-	21.2	-	-	-	-	-	29.7	27.3	21.4	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	-	-	-	-
CO2 transport and storage	-	-	-	-	-	-	-	-	-	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-154.0	-140.0	-59.2	-47.3	-28.5	-	-
Total Levelised Cost	104.3	82.0	92.6	91.5	55.1	45.9	152.7	140.8	135.2	123.9	97.0	147.2	62.2
Net Levelised Cost							-1.2	0.8	76.0	76.6	68.5		

Case 4

7.5% discount rate, 2023 project start at projected EPC prices, all NOAK

Levelised Cost	Small biomass power only	Large biomass power only	OCGT	AD on wastes	Landfill gas	Sewage gas	Small biomass CHP	Large biomass CHP	10MW Gas CHP	Small GT based CHP	CCGT CHP	Energy from Waste	Hydro reservoir
Capital Costs	30.7	25.2	5.0	46.5	19.0	31.3	51.7	49.2	12.1	10.6	9.9	75.3	53.2
Fixed operating Costs	18.5	11.9	3.0	21.0	13.1	8.9	21.1	19.2	4.8	4.3	5.0	15.2	9.0
Variable Operating Costs	2.2	2.2	1.5	18.6	21.1	2.1	2.2	2.2	2.4	2.4	1.9	56.7	-
Fuel Costs	35.8	30.7	66.4	-	-	-	54.4	48.2	91.7	84.4	62.1	-	-
Carbon Costs	-	-	58.6	-	-	-	-	-	81.9	75.3	57.8	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	-	-	-	-
CO2 transport and storage	-	-	-	-	-	-	-	-	-	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-223.1	-202.9	-90.5	-72.3	-43.6	-	-
Total Levelised Cost	87.2	70.0	134.6	86.1	53.2	42.3	129.4	118.8	192.9	177.1	136.6	147.2	62.2
Net Levelised Cost							-93.7	-84.0	102.4	104.8	93.0		

Source: Mott MacDonald

Table C.2: Levelised costs of minor technologies (continued): £/MWh

Case 5

10% discount rate, 2017 project start at projected EPC prices, all NOAK, high fuel prices

Levelised Cost	Small biomass power only	Large biomass power only	OCGT	AD on wastes	Landfill gas	Sewage gas	Small biomass CHP	Large biomass CHP	10MW Gas CHP	Small GT based CHP	CCGT CHP	Energy from Waste	Hydro reservoir
Capital Costs	39.1	33.9	6.4	57.7	23.5	38.8	66.5	63.2	15.6	13.7	12.9	94.9	74.2
Fixed operating Costs	18.4	12.0	3.0	21.0	13.1	8.9	21.1	19.3	4.8	4.3	5.0	15.2	9.0
Variable Operating Costs	2.2	2.2	1.5	18.6	21.1	2.1	2.2	2.2	2.4	2.4	1.9	56.7	-
Fuel Costs	46.5	39.8	86.7	-	-	-	70.6	62.6	119.2	109.7	80.9	-	-
Carbon Costs	-	-	35.7	-	-	-	-	-	49.9	45.9	36.1	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	-	-	-	-
CO2 transport and storage	-	-	-	-	-	-	-	-	-	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-218.7	-198.8	-88.6	-70.8	-42.6	-	-
Total Levelised Cost	106.2	87.9	133.3	97.3	57.7	49.9	160.4	147.3	191.8	176.0	136.7	166.8	83.2
Net Levelised Cost							-58.3	-51.5	103.3	105.2	94.2		

Case 6

10% discount rate, 2017 project start at projected EPC prices, all NOAK, low fuel prices and flat carbon price of £20/tCO2

Levelised Cost	Small biomass power only	Large biomass power only	OCGT	AD on wastes	Landfill gas	Sewage gas	Small biomass CHP	Large biomass CHP	10MW Gas CHP	Small GT based CHP	CCGT CHP	Energy from Waste	Hydro reservoir
Capital Costs	39.1	33.9	6.4	57.7	23.5	38.8	66.5	63.2	15.6	13.7	12.9	94.9	74.2
Fixed operating Costs	18.4	12.0	3.0	21.0	13.1	8.9	21.1	19.3	4.8	4.3	5.0	15.2	9.0
Variable Operating Costs	2.2	2.2	1.5	18.6	21.1	2.1	2.2	2.2	2.4	2.4	1.9	56.7	-
Fuel Costs	21.4	18.4	33.1	-	-	-	32.6	28.9	45.5	41.9	31.0	-	-
Carbon Costs	-	-	10.4	-	-	-	-	-	14.3	13.1	9.7	-	-
Decomm and waste fund	-	-	-	-	-	-	-	-	-	-	-	-	-
CO2 transport and storage	-	-	-	-	-	-	-	-	-	-	-	-	-
Steam Revenue	-	-	-	-	-	-	-73.0	-66.4	-30.7	-24.5	-14.4	-	-
Total Levelised Cost	81.2	66.4	54.5	97.3	57.7	49.9	122.4	113.6	82.6	75.5	60.4	166.8	83.2
Net Levelised Cost							49.3	47.2	51.9	51.0	46.0		

Source: Mott MacDonald

Acronyms

AD	Anaerobic Digestion
ASC	Advanced Super Critical (coal)
BAFO	Best And Final Offer
bara	Bar -atmosphere
Capex	Capital expenditure
CC	Carbon Capture
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CFBC	Circulating fluidised bed combustion
CHP	Combined Heat and Power
CO2	Carbon dioxide
DECC	Department of Energy and Climate Change
EfW	Energy from waste
EPC	Engineering Procurement and Construction
EPR	European Power Reactor (from Areva)
FGD	Flue Gas Desulphurisation
FOAK	First Of A Kind
GT	Gas Turbine
HHV	High heating value (excludes energy in evaporating moisture in fuel)
HRSG	Heat recovery steam generator
HSE	Health, Safety and Environment
IAEA	International Atomic Energy Agency
IGCC	Integrated Gasification Combined Cycle
LFG	Landfill gas
LP	Low pressure (relating to steam)
MP	Medium pressure (relating to steam)
MSW	Municipal solid waste
NOAK	Nth Of A Kind (as opposed to first)
NPV	Net Present Value
NTS	National Transmission System (gas)
O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbine
OEM	Original Equipment Manufacturer
Opex	Operating expenditure
PC	Pulverised Coal
PWR	Pressurised Water Reactor
ROC	Renewable Obligation Certificate

SCR	Selective Catalytic Reduction
SG	Sewage gas
TNUoS	Transmission network use of system
WTG	Wind Turbine Generator