CARBON COMPLIANCE

Setting an appropriate limit for zero carbon new homes

Report Carbon emission factors for fuels – Methodology and values for 2013 & 2016

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Background

A new methodology for calculating carbon emission factors for fuels and electricity was recommended in the report 'Carbon Compliance for Tomorrow's New Homes'[1] (CC4TNH) for use with future Building Regulations compliance tools. The methodology recommended for grid electricity emission factor calculations was to:

- Use a combined marginal emission factor, based on the UNFCCC[2] approach
- Include upstream emissions
- Include the effects of other greenhouse gases (CO_2 equivalent)
- Be calculated on a 15 year rolling average, fixed at a set level for the 3-year periods of Building Regulations
- Be updated annually for information to give the earliest possible indication of future trends

The Zero Carbon Hub has been commissioned by CLG to carry out work on the future Carbon Compliance level for new zero carbon homes from 2016. In order to provide the most appropriate advice, the likely CO_2(e) emission factor for grid electricity and other fuels according to the recommended methodology above is required for the Building Regulations periods 2013-2015 and 2016-2018.

AECOM were commissioned by the Zero Carbon Hub to provide, according to the recommended methodology outlined above, a best estimate of CO2(e) emission factors for the following fuels for the periods 2013-2015 and 2016-1018: Grid electricity; Mains gas; Community heating from boilers – biomass; Wood pellets and; Wood chips. Emission factors were required to be generated within a three week period, a necessarily short timescale to enable follow on work to be carried out to consider solutions available to meet a 2016 carbon compliance target.

A number of key documents and regulatory changes have occurred in the 6 months since the initial working group investigated methodologies for emission factors and produced initial estimates for the CC4TNH report. These include:

- Updated projections from the Interdepartmental Advisory Group (IAG) (June 2010)
- Updated DEFRA/DECC company guidelines for greenhouse gas reporting (August 2010)
- The EU agreement to the extension to Large Combustion Plant Directive(LCPD)/ Industrial Emissions Directive (IED) extending life of coal burning power stations from 2015/16 to 2023

[1] Zero Carbon Hub, Carbon Compliance for Tomorrow's New Homes A review of the modelling tool and assumptions, An Overview of Findings and Recommendations (July 2010)

[2] United Nations Framework Convention on Climate Change Committee

Methodology

The methodology proposed is as detailed in the CC4TNH report from Topic Work Group 2 - *Carbon intensity of fuels*[3]. This methodology was based on that set out by the Clean Development Mechanism (CDM) Executive Board of the United Nations Framework Convention on Climate Change Committee (UNFCCC)4which is used when assessing projects put forward under the CDM (as operated under the Kyoto protocol).

This methodology defines two marginal emission factors:

- 'Operating' marginal – this refers to the cohort of power stations that would reduce or increase their operation in response to changes in demand.
- 'Build' marginal – this refers to the cohort of power stations whose construction would be affected by changes in demand from a given project.

The UNFCCC methodology then proposes four approaches to calculating an operational marginal emissions factor

a) **Simple operating marginal (OM)**
Generation weighted averaged of all power plants serving the system not including low cost must run (e.g. nuclear and wind)

b) **Simple adjusted operating marginal**
Variation of the simple OM for systems where low cost/ must run plant operates for a proportion of the year at the margin.

c) **Dispatch data analysis operating marginal**
Based on the grid power units that are actually dispatched at the margin

d) **Average operating marginal**
Generation weighted average emission rate of all power plants serving the grid including low-cost/must-run power plants.

The build marginal is then calculated as the generation weighted average emission factor of the set of five power units that have been built most recently.

Finally the combined marginal emissions factor is calculated, combined the operating and built marginals. The default assumption for the weighting of these two factors is a 50:50 average. An alternative weighting can be applied if this can be justified by the type of project.

[3] Zero Carbon Hub, Carbon Compliance for Tomorrow's New Homes: A review of the modelling tool and assumptions, Topic 2, Carbon intensity of fuels (August 2010) www.zerocarbonhub.org/resourcefiles/TOPIC2_PURPLE_23August.pdf

[4] UNFCCC/CCNUCC CDM Executive Board EB 50 Report Annex 14 Methodological Tool (Version 02) Tool to calculate the emission factor for an electricity system http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-07-v2.pdf

Source of carbon emission factor data

A key aspect of the original works was a recommendation that there should be consistency in the use of emission factors by government. In carrying out this piece of work the authors were mindful of this and that emission factors can be used for a number of different functions including but not limited to:

- Informing decision making
- Individual carbon accounting
- Nationwide carbon accounting to measure progress against Kyoto targets

Subsequent to the completion of the CC4TNH Topic 2 Report[5] DEFRA published updated Guidelines for GHG Conversion Factors for company reporting[6] which for the first time included both other greenhouse gases (N_2O and CH_4) and upstream emissions (emissions from extraction up to but not including use). To enable a designer to choose the lowest carbon design solution the full impact of the choice of fuel on climate change from the emission of greenhouse gases should be considered.

The 2010 Guidelines to DEFRA / DECC's GHG Conversion Factors for Company Reporting were used as the primary source for emission factor information to ensure consistency across the source material used to generate emission factors.

[5] Zero Carbon Hub, Carbon Compliance for Tomorrow's New Homes A review of the modelling tool and assumptions, Topic 2, Carbon intensity of fuels (August 2010) www.zerocarbonhub.org/resourcefiles/TOPIC2_PURPLE_23August.pdf

[6] 2010 Guidelines to DEFRA / DECC's GHG Conversion Factors for Company Reporting August 2010 www.defra.gov.uk/environment/business/reporting/conversion-factors.htm

Carbon Emission Factors

Each fuel is considered in turn below

Biomass

Biomass is considered a carbon neutral fuel in that the emissions associated with its combustion were previously fixed in the material as it grew and will once more be fixed as replacement planted forests grow. Consequently the carbon emissions associated with the use of biomass are solely due to the transport and processing of the fuel prior to use.

In September 2010 the AECB published a discussion paper, that argued that it is fundamentally wrong to define biomass burning as low-carbon. The reasoning proposed is that burning biomass leads to similar carbon dioxide emissions per unit of heat as burning coal. Whilst trees do take up carbon as they grow, a better use for timber could be in construction when the carbon is sequestered for a greater period of time, and lower carbon fuels could be used for heat. This debate is noted but is outside of the scope of this study.

DEFRA use emission factors derived for SAP 2009 (consultation draft) including upstream and other greenhouse gas emissions. Factors are detailed in Table 1 below. 'Scopes' are defined in Appendix 2.

Table 9c	Scope 3	
Life-Cycle Conversion Factors for biomass and biogas	**Total Indirect GHG**	
Fuel used	kg $CO_{2(eq)}$ per kWh NCV	kg $CO_{2(eq)}$ per kWh GCV
Wood Chips	0.0158	0.015
Wood Pellets	0.0390	0.037

Table 1 *DEFRA biomass emission factors*

Emission factors used by DEFRA are consistent with those calculated by the BRE and published as part of the consultation for SAP 2009 (the scope of emission factors used in the final SAP 2009 includes upstream emissions but not other greenhouse gases). The breakdown of the sources of upstream emissions of $CO_{2(eq)}$ is detailed in Table 2 below.

Of the sources of greenhouse gases associated with the use of biomass as a fuel, 0.0056 $kgCO_2/kWh$ or between 15% and 38% is due to transport emissions. Over the time period 2013- 2032 the UK plans to decarbonise its transport sector through the increased electrification of passenger vehicles and Light Goods Vehicles and the increased use of biofuels in Heavy Goods Vehicles.

Any forward projection of emissions from biomass was considered linked to the rate of decarbonisation of transport emissions. There is some uncertainty about how sustainable biofuels currently are:

> *'There are currently significant issues relating to the true carbon efficiency of some biofuels and concerns about their impact on other aspects of environmental sustainability and food supply'*[7].

The Gallagher Review recommended a range for use of sustainable biofuels in the UK from 5%-10% of total fuel consumption (4-8% of total energy for road transport) in 2020.

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[7] Committee on Climate Change, Building a low-carbon economy – the UK's contribution to tackling climate change, (2008) http://www.theccc.org.uk/reports/building-a-low-carbon-economy

The Committee has treated recommended targets in the review for biofuel penetration as a reasonable basis for carbon budget setting. EU and UK policies, which have set targets above that recommended by the Gallagher review are currently being reconsidered. (Building a low-carbon economy – the UK's contribution to tackling climate change)

A 6% reduction in the carbon content of transport fuel would lead to a marginal reduction in carbon emissions (0.0003kgCO_2eq, 0.8%-1.4%) which when compared to the difference in carbon emissions factors of the fuels to be compared in the ZCH study was considered negligible.

	Chips	Pellets
	kg $CO_{2(eq)}$/kWh GCV	kg $CO_{2(eq)}$/kWh GCV
Regeneration	0.0001	0.0002
Harvesting	0.0011	0.0011
Extraction	0.0001	0.0001
Transport to chipping plant	**0.0018**	**0.0019**
Chipping of branchwood	0.0008	0.0008
Transport to drying and storage	**0.0016**	**0.0017**
Transport to chipping plant	**0.0005**	**0.0005**
Chipping of waste wood chunks	0.0002	0.0002
Drying, storing and cooling		0.0151
Milling		0.0007
Pelletising		0.0047
Transport to heating plant	**0.0017**	**0.0014**
Combustion and heat generation	0.007	0.0089
Total	0.0149	0.0373
Total transport	0.0056	0.0055
	37.6%	14.7%

Table 2 *Breakdown of biomass upstream emissions from SAP 2009 consultation technical documentation*

Community boilers

The emission factor for Biomass community heating used in SAP2009 are stated to be '*an average emission factor based on the mix of biomass heat sources from DUKES 2008 Table 7.6 using the emission factors above and an additional emission factor for straw* (0.044 kg$CO_{2(eq)}$/kWh)' [8]. It is unclear the exact mix of fuels used to generate this emission factor and it is not clear why, being able to specify biomass fuel source for individual boilers (Pellets or chips), the same options are not available for community heating systems. These differences, when comparing emission factors for biomass to gas and electricity are marginal. Consequently this study concluded that for the purposes of the proposed study the ZCH should use the emission factors for biomass published by DEFRA/DECC with no allowance for decarbonisation of transport.

The emission factors are thus 0.015 kg$CO_{2(eq)}$/kWh for wood chip, 0.037 kg$CO_{2(eq)}$/kWh for wood pellets and 0.013 kg$CO_{2(eq)}$/kWh for heat from community boilers fuelled by biomass.

[8] BRE, Technical Document STP09/CO203

Electricity

A methodology for calculating carbon emission factors for electricity was recommended in the report 'Carbon Compliance for Tomorrow's New Homes'[9] (CC4TNH). Specifically, that for grid electricity the factor should:

- Use a combined marginal emission factor, based on the UNFCCC approach
- Include upstream emissions
- Include the effects of other greenhouse gases (carbon equivalent)
- Be calculated on a 15 year rolling average, fixed at a set level for the 3-year periods of Building Regulations
- Be updated annually for information

As detailed in the CC4TNH report the calculation of a marginal emissions factor is sensitive to the date the operational marginal is understood to change from coal to gas and the date the build marginal changes from gas to low carbon (renewable/nuclear/fossil fuel CCS)

AECOM have undertaken further research to identify the most up to date likely projections for the retirement of existing plant and the completion of new build plant. There are a number of sources of projections of future energy supply from the following organisations:

Source	**Date**	
DECC – Interdepartmental Analysts Group (updated from January 2010)	June	2010
DECC – Updated Energy and emissions projections (updated from July 2009)	June	2010
National Grid Transmitting Britain's Energy 2010	July	2010
Committee on Climate Change	December	2008

Electricity Build Marginal

The C4TNH report used the Interdepartmental Analysts Group's (IAG) *Valuation of energy use and greenhouse gas emissions for appraisal and evaluation data* updated in January 2010 for the forecasts for the date gas was no longer expected to be the plant build marginal. This was predicted to be 2030. The IAG definition of marginal plant is understood to represent build marginal not operating marginal and is equivalent to new gas-fired Combined Cycle Gas Turbine plant. The IAG released an updated report in June 2010 which moved this date forwards to 2025. In the June 2010 IAG report DECC note that their energy model predicts that CCGT will remain the marginal plant built until 'around 2025' and confirm that their marginal which is a build marginal will be assumed to be CCGT gas to 2025. On this basis the date the build marginal moves from gas to a low carbon mix was taken as 2025.

DECC express uncertainty as to what the built marginal will be after 2025 until 2040 when a lower average emissions factor of 0.04kgCO_2/kWh is predicted by their MARKAL modelling (falling to 0.02kgCO_2/kWh by 2050). After 2025 DECC assume the (build?) marginal plant will consist of a mix of low carbon generation technologies and CCGT plant, with the relative share of low carbon

[9] Zero Carbon Hub, Carbon Compliance for Tomorrow's New Homes: A review of the modelling tool and assumptions, An Overview of Findings and Recommendations (July 2010)

technologies in this mix increasing over time and the share of CCGT decreasing and then assume that from 2040, marginal electricity emissions will be the same as average electricity emissions.

The two sets of projections are shown in Figure 1.

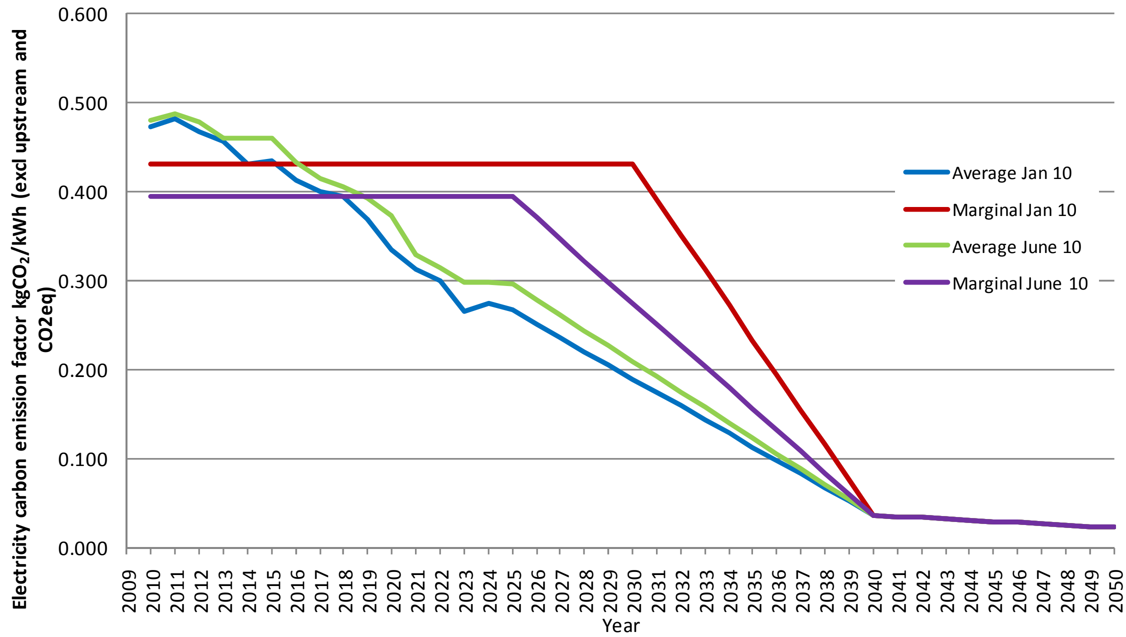

Figure 1 *Published emissions factor projections from DECC Intergovernmental Advisory Group comparison of Jan 2010 and June 2010 projections*

There is considerable uncertainty in the projecting of future energy generation and major power producer plant construction. For example the DECC Updated Energy and Emissions projections seem to indicate that no further New Gas new build CCGT is expected after 2018 (**Figure 2**).

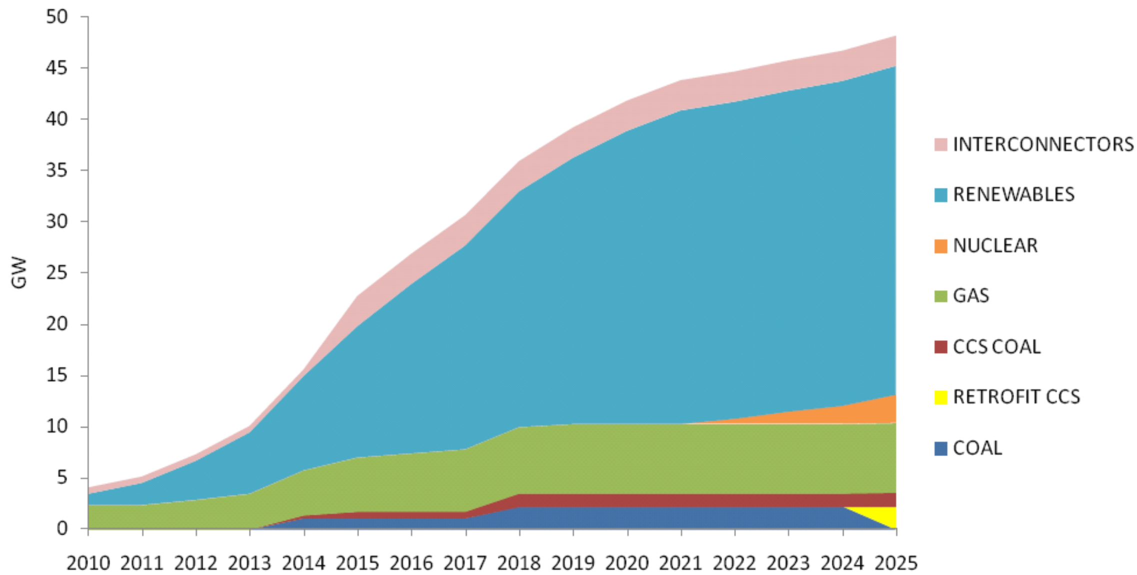

Figure 2 *Projected cumulative new build by plant type for MPPs 2010 to 2025*

The IAD June 2010 report states: *Marginal emission … factors will be kept under review and updated as necessary as they are subject to considerable uncertainty in the long-term, particularly in the electricity sector where it is unclear what type/mix of generation will constitute the marginal source of electricity supply.*

Electricity Operational Marginal

For the CC4TNH report AECOM reviewed the dispatch data from Electron to understand what fuel was dispatched at the marginal of demand. This was found to be coal (Figure 3)

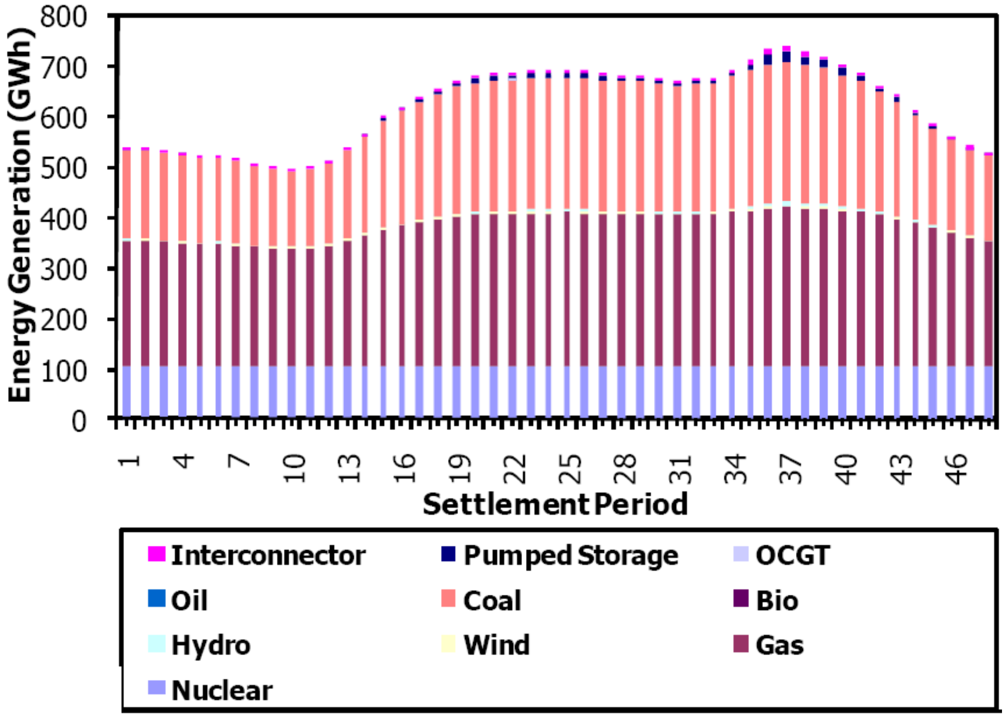

Figure 3 *Average fuel contributions to grid generation February 2010, Elexon trading operations report.*

Historically the operational marginal has fluctuated between coal and gas depending on the relative fuel costs. For the past two winters the National Grid have predicted that gas would be the operating marginal and then have found that the historic dispatch data indicates that coal was the marginal operating plant. Lower gas prices lead to its use as base load generating plant.

The National Grid Winter Consultation Report 2010/11 predicts that gas will be the operating marginal with coal operating as base load generator for the next winter:

> ***Winter 2010/11 Outlook – Gas***
> *Fuel price futures show an increase in the oil and coal price with gas also increasing albeit retaining a seasonal profile. The current mid winter price of gas suggests coal may be the winter base load plant with gas fired generation as the marginal plant. However, as we have observed changes in the fuel prices for the past two winters which has lead to gas being used for base load generation, our current forecast assumes this will happen again and gas, rather than coal, is forecast to be base load.*

Review of the May 2010 Elexon trading operations report indicates that coal is currently operating as the summer marginal plant (Figure 4)

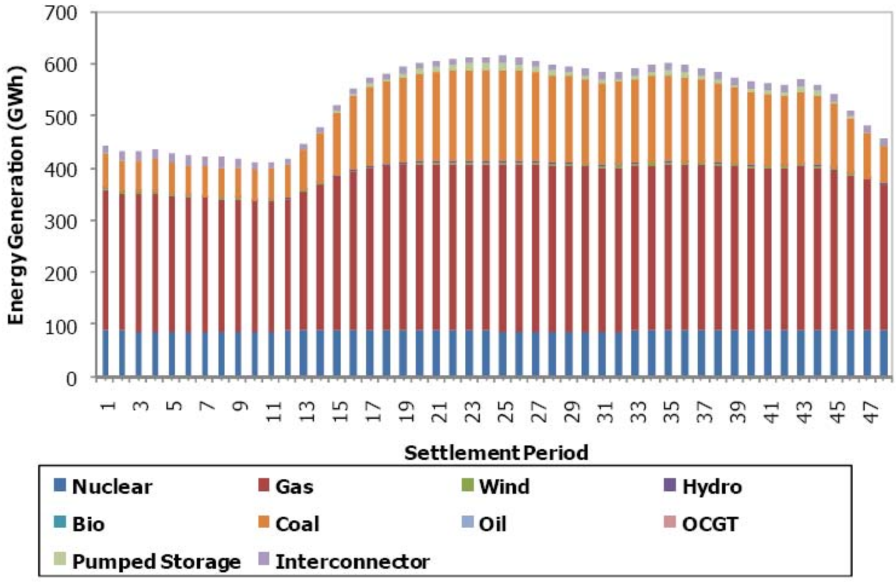

Figure 4 *Average fuel contributions to grid generation May 2010, Elexon trading operations report.*

Projecting into the future, the availability of coal-fired power generation is set to decrease due to the increasing impact of the Large Combustion Plant Directive (LCPD) and the Industrial Emissions Directive (IED). The higher carbon emissions associated with the generation of electricity from coal has also reduced the price competitiveness of coal due to the European Union Emissions Trading Scheme (EU ETS). New build coal fitted with demonstration Carbon Capture and Storage (CCS) is expected to be operated as base load producer whilst plant affected by the emissions directives will run for reduced hours driving this plant to continue to operate at the marginal.

In predicting a best estimate of electricity emissions factors for 2013-2016 and 2016-2019 we have taken a simple dispatch data approach to determining the marginal plant. Based on the dispatch reporting from the Elexon trading operations report a simple dispatch data methodology was used assuming that the operational marginal will remain coal until the last unabated coal plant is retired.

In February-April 2010 when the CC4TNH work was undertaken the LCPD was predicted to force the closure of the oldest coal burning power stations by 2015. The LCPD is one of the seven existing EU directives, including the IPPC that was recast under the Industrial Emissions Directive (IED). Prior to the endorsement by the European Parliament of the IED (7th July 2010) the requirements of LCPD were the subject of hard negotiating by those member states (including the UK) with significant coal generating capacity. As a result, the text of the endorsement states that member states can put in place "transitional national plans" to give LCPs until July 2020 to meet the requirements. Older plants can continue to operate beyond this date if their operating hours do not exceed 17,500 hours after 2016 and if they close by the end of 2023.

The latest (June2010) projections for the decommissioning of unabated coal stations were provided by DECC (Figure 5) indicating that DECC have largely updated their projections to take account of a transitional plan for plant decommissioning that runs up to 2023. The DECC projections include one plant closing in 2024.

The availability of this plant from 2016 to 2024 is of considerable uncertainty. How plant is operated will likely depend on factors including the rate of commissioning of new gas and nuclear plant; the relative price of coal and gas, the cost of carbon within the EU ETS, the need for intermittent availability to support periods of low renewable generation etc. If the older coal plants were to run for 17,500 hours with 80% availability then they would be required to close 2.5 years after 2016 - mid 2019.It is considered unlikely that coal would remain the summer and winter marginal as is currently the case right up until 2023 or 2024. There will be a period of tail off where coal at the margin of operation would contribute less than 10% of the annual UK power generation. For this study the assumption was taken that coal will no longer be the operating marginal from 2022.Further work is recommended to understand the range of likely operating scenarios for the projected mix after 2018.

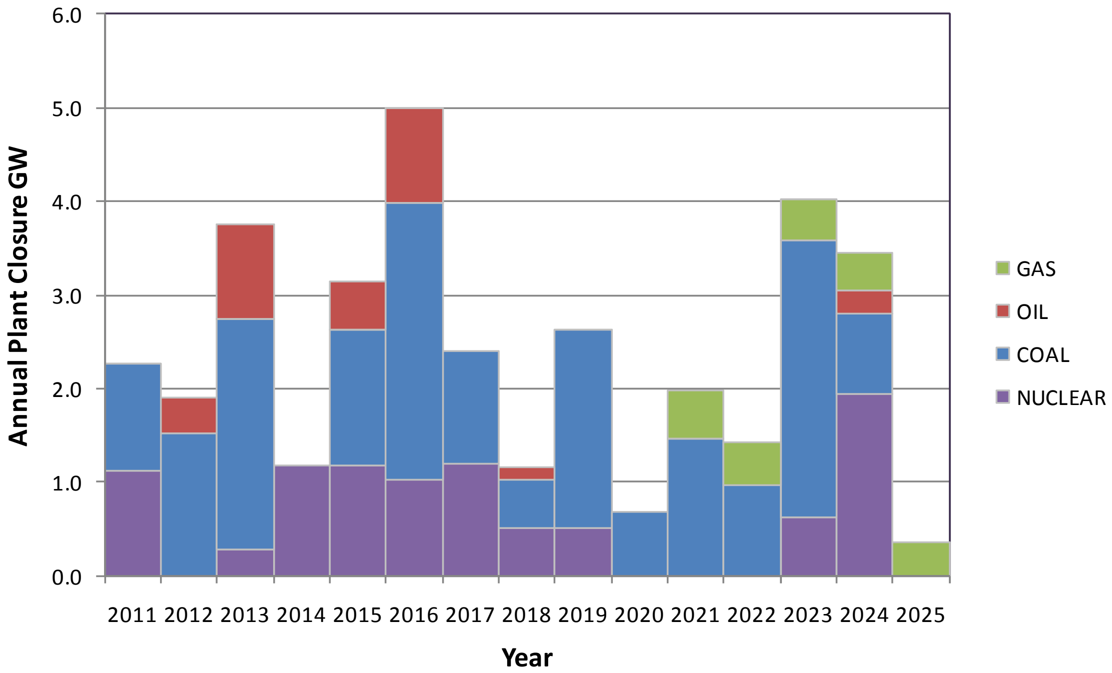

Figure 5 *DECC planned Plant Closure 2011-2025*

The combined marginal emission factor is represented in Figure 6 below together with the IAG marginal and average projections. The key points that define the combined marginal are:

- The date at which coal-fired power stations cease to operate and the operating marginal drops to a level reflecting older gas-fired CCGT plant.
- The date at which new build power stations are solely very low carbon i.e. nuclear, renewable and fossil fuel plants with carbon capture and storage (CCS).
- The date at which gas-fired CCGT plant ceases to be the operating marginal plant and coal-fired CCS is assumed to become marginal (assumed to be post 2035 and not plotted below).

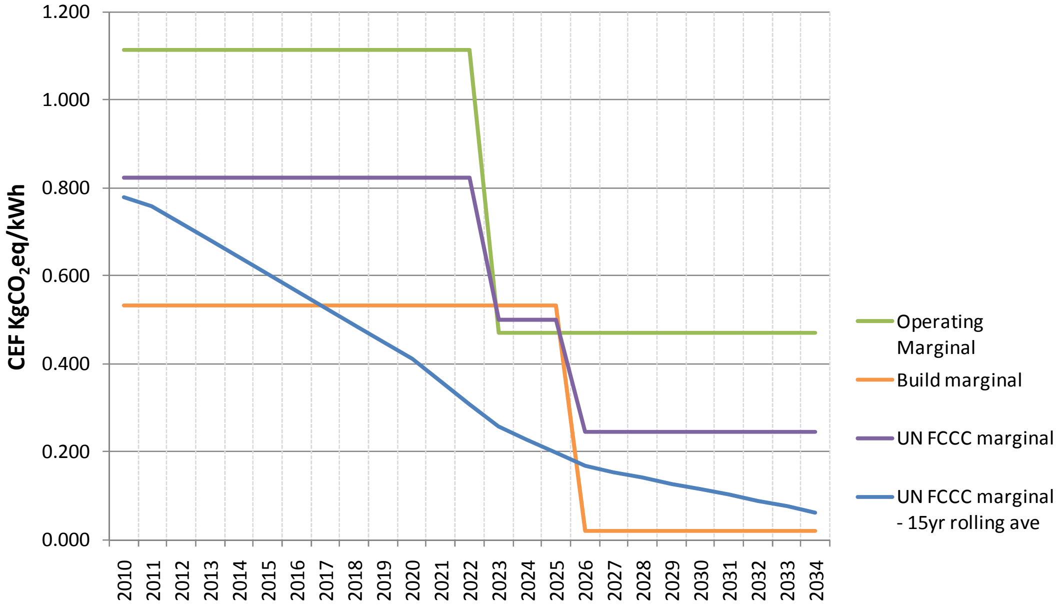

Figure 6 *Build, Operating, Average UNFCCC marginal emission factor projections and 15 year rolling average.*

In projecting emissions factors for 2013-2016 and 2016-2019, and taking a 15 year rolling average, emissions assumptions are required up to 2034. Gas CCGT is assumed to continue to be the operating marginal post 2034. The date at which new build comprises solely low carbon generation is assumed to be 2025, when gas would no longer be the build marginal. These assumptions are discussed in more detail below.

The emissions factor shown in Figure 6 above and detailed in Table 3 below for marginal new build gas plant was taken to be for New build CCGT using LNG sourced natural gas. The emission factor for operating marginal gas plant (post 2022) was taken as existing build CCGT using natural gas. Conversion efficiencies and transmission losses were sourced from the Defra/DECC emission factors for company reporting[10].

	Scope 1[11]		Scope 3		All Scopes				
	CO_2	CH_4	N_2O	Total Direct GHG	Total Indirect GHG	Grand Total GHG	conversion efficiency	transmission losses	delivered CEF
Fuel Type	kg CO_2/ kWh GCV	kg $CO_{2(eq)}$ / kWh GCV	kg $CO_{2(eq)}$ / kWh GCV	kg $CO_{2(eq)}$/ kWh GCV	kg $CO_{2(eq)}$ / kWh GCV	kg $CO_{2(eq)}$ / kWh GCV	%	%	kg $CO_{2(eq)}$ / kWh GCV
Coal (electricity generation)	0.31907	0.00006	0.00277	0.32190	0.05265	**0.375**	36.4%	8.00%	**1.11**
Natural Gas existing build	0.18485	0.00027	0.00011	0.18523	0.01799	0.203	46.7%	8.00%	**0.47**
LNG new build CCGT	0.18485	0.00027	0.00011	0.18523	0.06488	0.250	50.8%	8.00%	**0.53**

[10] Additional source: conversation with Mr David Wilson at DECC (New build Gas CCGT and transmission losses)

[11] See Appendix 2 for definition of Scopes

Table 3 *Emission factors used in determination of electricity emission factor.*

Taken as a 15 year average this methodology generates the following emission factors for marginal electricity for the periods 2013-2016 and 2016-2019 (Figure 7).

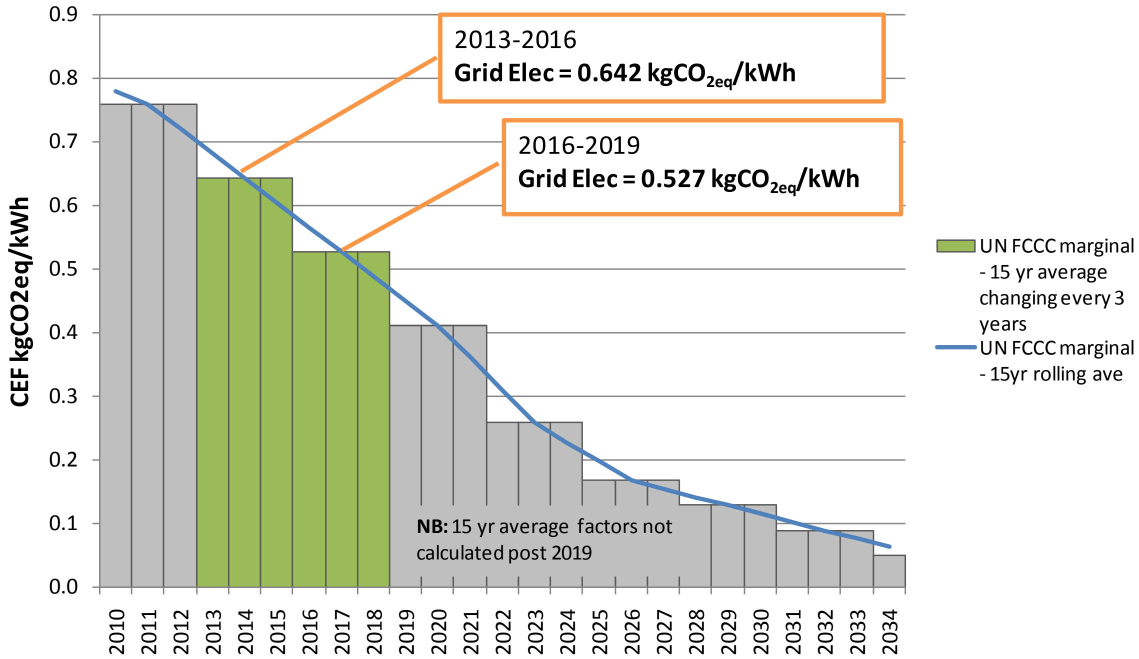

Figure 7 *Electricity emission factors 2013-2016 and 2016-2019*

Emission factors are heavily influenced by the date unabated coal is no longer considered the operational marginal. The impact of moving this date by two years is shown in Table 4 below.

Date Operating marginal changes form Coal to Gas	Emissions factor $kgCO_2eq$/kWh	
	2013-2016	**2016-2019**
2020	0.599	0.484
2022	0.642	0.527
2024	0.685	0.570

Table 4 *Sensitivity of electricity emission factor to period of time Coal operates as marginal plant.*

The UNFCCC methodology identifies that the operational marginal should comprise the last 10% of plant to be dispatched. If coal is the last fuel to be dispatched due to limited operating hours and higher carbon cost from the DECC prediction of electricity generation (Figure 8) it seems possible that coal could reasonably be considered the marginal until circa 2022, depending on the proportion of coal consumed in new demonstration CCS power plant (which is not 100% abated). Further work is required to consider likely plant operation over this period.

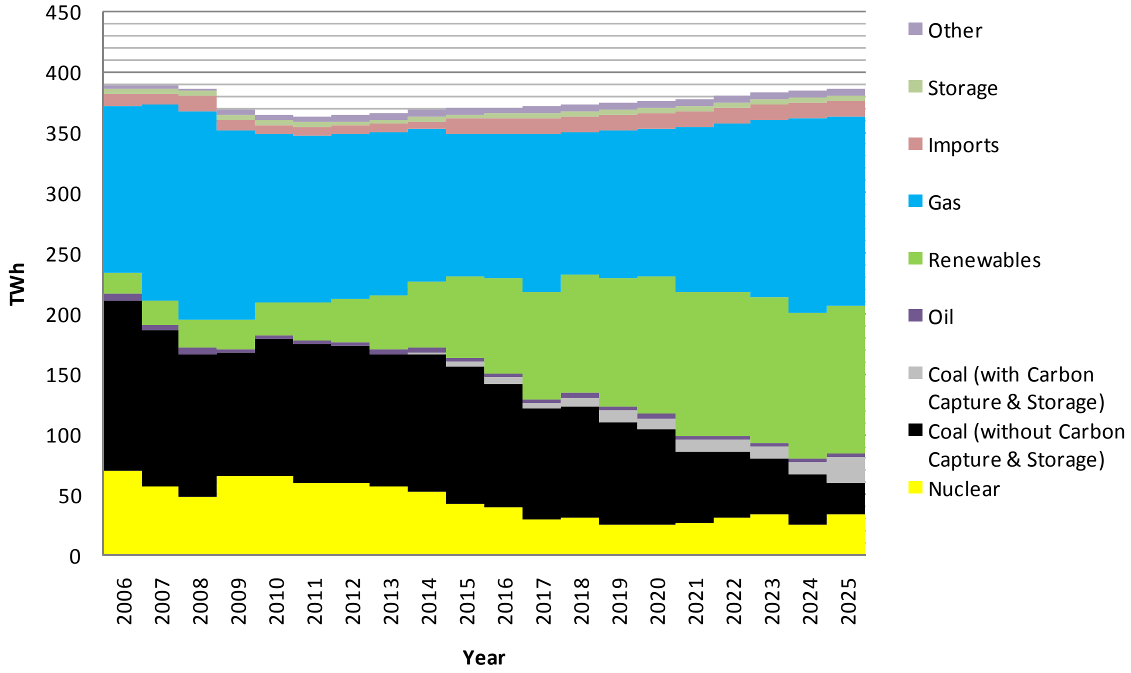

Figure 8 *Electricity generation by source -DECC updated emission projection – June 2010*

The UNFCCC calculation approach is applicable only when low cost must run plant comprises less than 50% of the generation mix. By 2025 one DECC prediction of the proportion of generation mix indicates that low cost must run will comprise approximately 45% of the generation mix (Figure 8). It is recommended that the projection for future marginal plant post 2025 and the assumption that changes in marginal plant occur as clear step changes be explored further.

Gas

Gas consumption in the UK is predicted to decline due to improvements in energy efficiency in buildings before slowly starting to rise after circa 2025 (Figure 9).

Home production of natural gas from the UK Continental shelf (UKCS) is in decline. Imports from Norway are projected to stabilise in 2014 and plateau before marginally declining. In 'Transporting Britain's Energy 2010' the National Grid predict that 'in terms of meeting the total UK import requirement, the Norwegian contribution falls from approximately 67% in 2009/10 to only 24% in 2020/21. Projections by the National Grid (Figure 10) and DECC indicate that Liquefied Natural Gas (LNG) imported from overseas and degasified for injection into the national grid is expected to make up the gap in supply and demand.

National Grid forecasts indicate 'a steady increase in LNG imports before an increased requirement post 2015 as supplies from both the UKCS and Norway are forecast to decline'. The National Grid predict LNG will make up over 40% of UK supply by 2020/21.

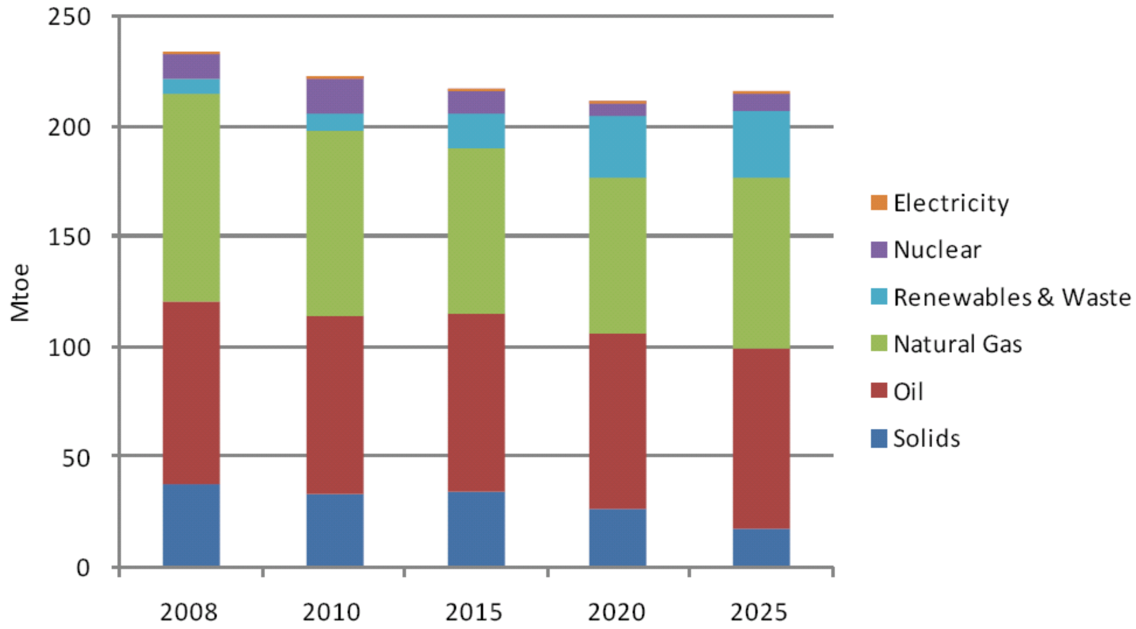

Figure 9: *DECC – Projections of Primary Energy Demand*

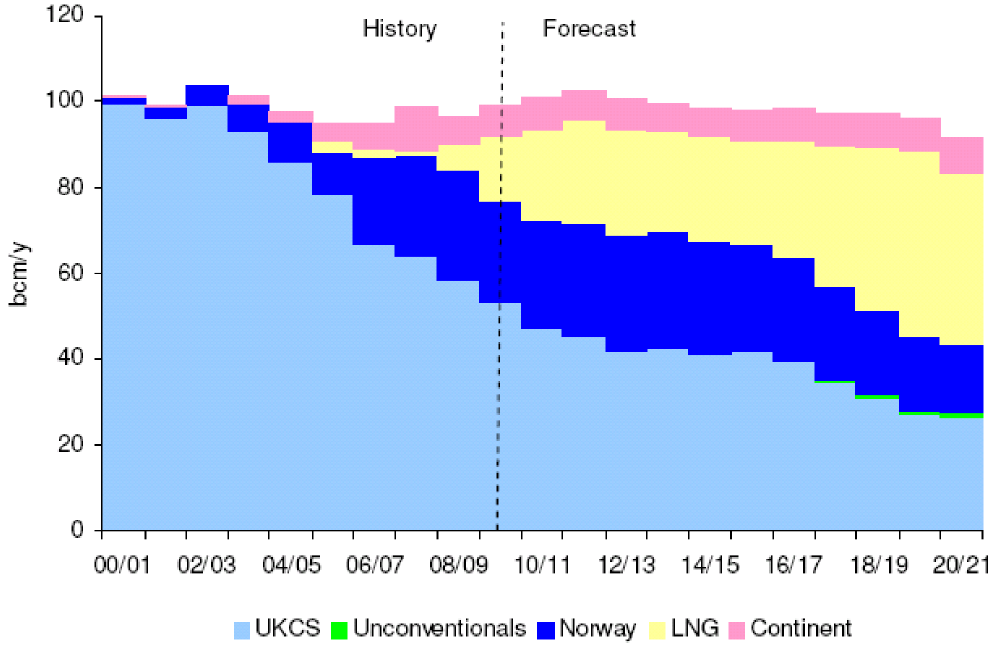

Figure 10: *National Grid - Base Case Annual Supply 10 year outlook*

Taking a marginal approach to gas consumption we have made the assumption that a 'build marginal' - the additional gas required to meet a rising demand, or the gas not required if demand is falling will be LNG.

The DEFRA emission factors for gas are detailed in Table 5 below. The breakdown of emission factors highlights the carbon emissions associated with the liquefaction, transport and re-gasification of LNG prior to injection into the National Grid. Indirect greenhouse gas emissions result in a 35% increase in the CO_2eq emissions factor for LNG. This compares to a 10% increase for natural gas where the primary source of upstream emissions is understood to be due to methane leakage in extraction and transport.

	Scope 1				Scope 3	All Scopes
	CO_2	CH_4	N_2O	Total Direct GHG	Total Indirect GHG	Grand Total GHG
Fuel Type	kg CO_2 per kWh	kg CO_2eq per kWh	kg CO_2eq per kWh	kg CO_2eq per kWh	kg CO_2eq per kWh	kg CO_2eq per kWh
LNG	0.185	0.00027	0.00011	0.185	0.065	0.250
Natural Gas	0.185	0.00027	0.00011	0.185	0.018	0.203

Table 5 *DEFRA/DECC emission factors for gas used in the UK*

The 'operational marginal' is taken as the top 10% of the operating supply (UNFCCC methodology). Discussions with Mr Mike Earp at DECC identified that UK gas marginal supply is sourced from a storage resource comprising short, medium and long range storage. From Figure 11 below the majority of marginal supply can be seen to be sourced from medium and long range storage – predominantly existing exhausted gas fields (e.g. Rough in the North Sea) and salt caverns.

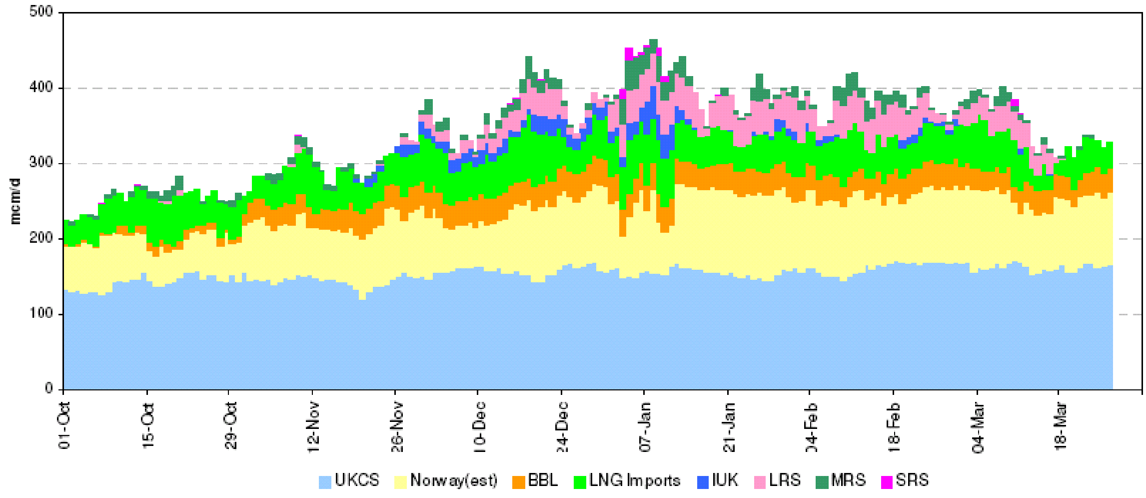

Figure 11: *National Grid – Gas Supply build up – 1st October 2009 to 31st March 2010*

UK Gas storage locations are filled over summer months when there is lower demand for heat. Gas is compressed to 200 bar and stored in locations such as Rough for release into the system at times of winter peak demand.

The latest sourced summer data was from 2008. For that year summer gas demand was sourced from UKCS, Norway and imports from the continent with a small proportion of gas imported as LNG. It was therefore assumed that gas stored in long and medium range storage would principally have an emissions factor associated with natural gas not LNG. The assumption was made that operational marginal is natural gas that is stored over summer months and discharged over the heating season.

This initial analysis would benefit from a more in depth approach to consider the future UK gas mix in summer months when storage is recharged. From the profile in Figure 11 the autumn and spring months might comprise a proportion of LNG and/or Interconnector import (BBL). As such there may be a case for the operational marginal to be a combination of LNG and natural gas. Furthermore it is likely that over time the summer import of LNG will increase and that the operational marginal would tend further towards LNG.

By nature of the short time frame of this work the gas emissions factor has taken a simplistic interpretation of the complex operating arrangements employed by the national grid and all the suppliers to ensure constant supply of gas is maintained. This does not take account of the use of short term 'bullet' LNG storage of natural gas to manage peak loads. The assumption was taken that as this is the most expensive form of short range storage it would be unlikely to be required to provide significant capacity in the summer when there is generally excess capacity on the network.

Energy associated with gas compression for storage

Natural gas is compressed to around 200 bar for storage at the Rough gas field. The energy cost of compression of methane from 85bar (assumed pressure of grid) to 200bar storage pressure was calculated to be less than 0.7% of the calorific content of the fuel and so was assumed negligible for the purpose of this study.

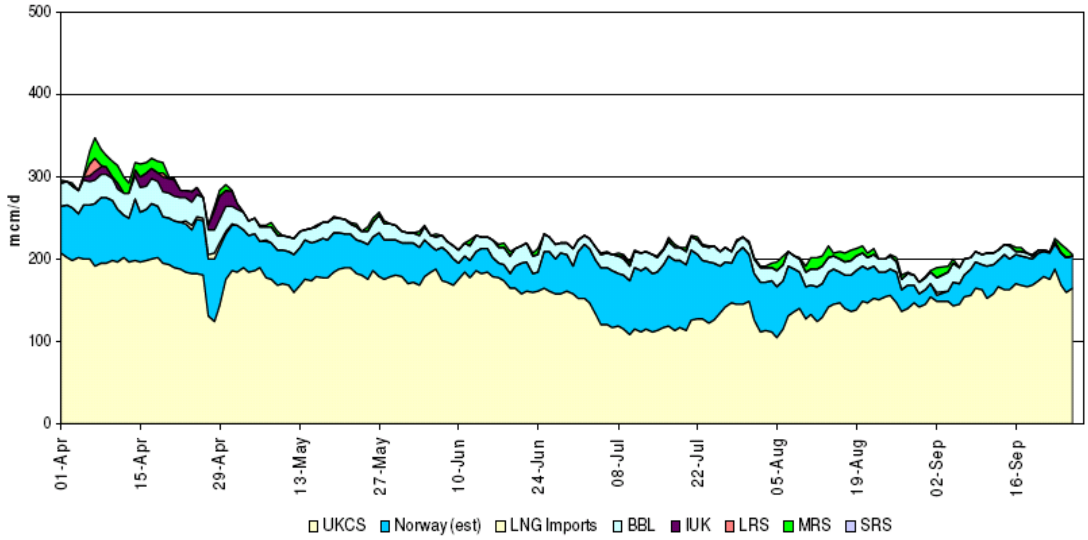

Figure 12 *Gas Demand Build up Summer 2008* [12]

Reviewing the national grid 2010 summer projections (Figure 13) LNG is the only source of gas supply predicted to increase in the summer months supporting the assumption that LNG is the build marginal.

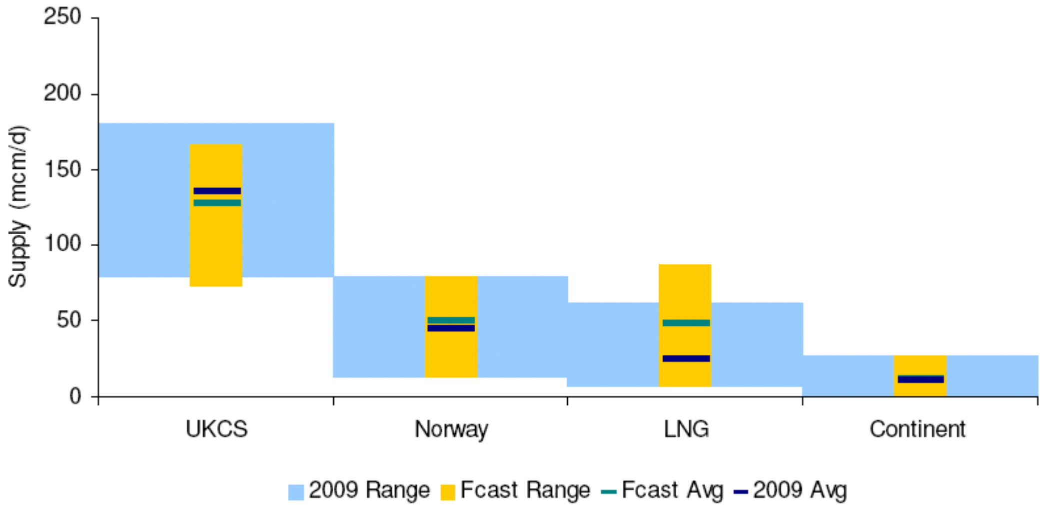

Figure 13 *2010 Summer forecast of Gas supply by source*

The Marginal emissions factor for gas was calculated as a 50:50 split between LNG and natural gas to be 0.227 kg$CO_{2(eq)}$/kWh

To maintain a consistent approach to the choice of fuels a 15 year rolling average of emissions from gas should be calculated to enable the designer to make an informed decision on the lifetime carbon emissions of their heating fuel choice. Over time it is predicted that LNG might comprise an increasing proportion of summer gas consumption, increasing the emissions factor of stored gas and leading to a higher combined marginal tending towards a maximum emissions factor of 0.25 kgCO_2/kWh. It was not possible to source projections of summer UK gas consumptions in order to be able to sensibly project the summer mix and the impact on our assumptions of the operational marginal. Without further detailed work an assumption of a 50:50 split between LNG and natural gas was considered sufficiently robust for the ZCH work.

[12] UK National Grid Gas Monthly Summer Update - October 2008

Conclusions - Emissions factors for Zero Carbon Hub modelling

Based on the work described above the following interim emissions factors are recommended for use in the Zero carbon hub carbon compliance work.

	Emission factor $kgCO_{2eq}$/kWh GCV	
	2013-2016	**2016-2019**
Grid electricity	0.642	0.527
Mains Gas	0.227	0.227
Biomass chip	0.015	0.015
Biomass pellet	0.037	0.037
Biomass community heating	0.019	0.019

Table 6 *2013-2016 and 2016-2019 emission factors*

Emission factors for 2013-2016 and 2016-2019 are higher than those currently in use in Part L 2010. This is in part due to the use of CO_2 equivalent emission factors but most significantly due to taking a marginal approach to the impact of changes in demand on electricity supply rather than a grid average approach.

Recommendations for further work

- The UNFCCC calculation approach is applicable only when low cost must run plant comprises less than 50% of the generation mix. By 2025 one DECC prediction of the proportion of generation mix indicates (Figure 8) that low cost must run will comprise approximately 45% of the generation mix. It is recommended that the projection for future marginal plant post 2025 and the assumption that changes in marginal plant occur as clear step changes be explored further.
- Further work is required to consider likely plant operation over the period 2016-2023.
- For this study the assumption was taken that coal will no longer be the operating marginal from 2022.Further work is recommended to understand the range of likely operating scenarios for the projected mix after 2018.
- It is recommended that the calculation of the emissions factor for electricity be considered using the gas marginal emissions factor in the calculation of the built and operating gas CCGT emissions factors instead of separate UKCS natural gas and LNG emissions factors.

Annex 1: Main sources of information

The main sources of information used by AECOM to inform this work are as follows:

Emission factors

2010 Guidelines to DEFRA / DECC's GHG Conversion Factors for Company Reporting	August 2010
Well-to-Tank Report Version 3.0, APPENDIX 2 Description and detailed energy and GHG balance of individual pathways	November 2008
BRE, Technical Document STP09/CO202 – Methodology for the Generation of UK Emission Factors for use in the NCM (Mar 2009)	March 2009
BRE, Technical Document STP09/CO203 – Revised Emission Factors for use in the NCM: Data sources and assumptions	March 2009
Digest of UK Energy Statistics 2010 (DUKES)	July 2010
The Greenhouse Gas Protocol a corporate accounting and reporting standard	September 2001

Projected plant build out

DECC, Valuation of energy use and greenhouse gases (GHG) emissions for appraisal and evaluation: background documentation (June 2010)	June 2010
DECC, Updated Energy and Emissions Projections (June 2010)	June 2010
DECC, Energy Markets Outlook (Dec 2009)	December 2009
National Grid, Transporting Britain's Energy 2010: Development of Energy Scenarios (July 2010)	July 2010
National Grid, The potential for Renewable Gas in the UK (Jan 2009)	January 2009

Methodology

UNFCCC Annex 14 Methodological Tool (V02) Tool to calculate the emission factor for an electricity system.	October 2009

Annex 2: Definition of Scopes

Excerpt from 2010 Guidelines to DEFRA / DECC's GHG Conversion Factors for Company Reporting (page 5)

What is the difference between direct and indirect emissions?

The definition used in used in the **GHG Protocol** for direct and indirect emissions is slightly different than for these **Annexes** (which are consistent also with the Government's Act on CO_2 Calculator and Carbon Offsetting Accreditation Scheme). In these **Annexes** direct and indirect emissions are defined as follows:

Direct GHG emissions are those emissions emitted at the point of use of a fuel/energy carrier (or in the case of electricity, at the point of generation).

Indirect GHG emissions are those emissions emitted prior to the use of a fuel/energy carrier (or in the case of electricity, prior to the point of generation), i.e. as a result of extracting and transforming the primary energy source (e.g. crude oil) into the energy carrier (e.g. petrol). Emissions from the production of vehicles or infrastructure are not considered.

The **GHG Protocol** defines direct and indirect emissions slightly differently as follows:

Direct GHG emissions are emissions from sources that are owned or controlled by the reporting entity.

Indirect GHG emissions are emissions that are a consequence of the activities of the reporting entity, but occur at sources owned or controlled by another entity.

What are the GHG Protocol Scopes 1, 2 and 3

The GHG Protocol further categorizes direct and indirect emissions into three broad scopes:

Scope 1: Direct GHG emissions emitted at the point of combustion of fuels.

Scope 2: Indirect GHG emissions from consumption of purchased electricity, heat or steam. (= Direct GHG emissions from the production of electricity, heat or steam.)

Scope 3: Indirect emissions, such as the extraction and production of purchased materials and fuels, transport-related activities in vehicles not owned or controlled by the reporting entity, electricity- related activities (e.g. T&D losses) not covered in Scope 2, outsourced activities, waste disposal, etc.

Outside of Scopes: Emissions data for direct CO_2 emissions from biologically sequestered carbon (e.g. CO2 from burning biomass/biofuels) are reported separately from the scopes.