Wood Mackenzie

Scottish Council for Development & Industry

The Future of Electricity Generation in Scotland

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Table of Contents

Scope of Report

This Report is intended to provide an independent assessment of the development of electricity demand and generation in Scotland over the period to 2020 and the country's ability to realise a target of 50% of its power demand from renewable sources in that time.

Section 1 provides an overview of the existing Scottish electricity market and its integration with the broader UK system. The structure of network ownership and operation is summarised, and issues of network capacity, connection constraints and network charging are discussed.

Section 2 sets out the key drivers of Scottish energy policy, including the frameworks of European Union (EU) and UK energy and climate regulation. Proposed changes to the UK Renewables Obligation and the Scottish government's role in determining energy policy are also discussed.

Section 3 describes the current situation with respect to power generation and demand in Scotland and discusses historical developments in the country's renewable generation base. The chapter then presents Wood Mackenzie's power demand and generation Base Case forecast to 2020, examining in particular changes in renewable energy capacity. An Alternative Case, in which wind generation expansion occurs at a slower rate and other low-carbon technologies play a larger role, is also explored.

Section 4 contrasts the Base Case and Alternative forecast of generation, examining variations in capital investment, carbon intensity, the costs of power production and base-load power prices.

Executive Summary

Background

Scotland currently benefits from a well supplied power generation market with a broad mix of generation technologies and fuel sources. Power is supplied by a combination of large base-load plants, including nuclear, coal and gas-fired units, hydro generation, both conventional hydro and pumped storage, and a number of other renewable sources. The country's high voltage power transmission network is connected to systems in England and Northern Ireland, and since 2005, Scotland has been integrated into the wider GB electricity trading market. The margin of generation available in excess of demand in Scotland is higher than elsewhere in the UK due to the presence of a number of large base-load power stations and recent strong growth in renewable power generation capacity. As a result, Scotland is generally an exporter of power to neighbouring networks.

Scottish energy policy is generally set at the UK level, which in turn is influenced by European Union legislative developments. However, the Scottish government has established its own ambitious target to meet 50% of electricity supply from renewable sources by 2020. There is significant potential for growth in Scotland's renewable generation capacity, particularly due to the scope for continued development of onshore wind power and, potentially, offshore wind in the longer term. However, protracted planning processes, equipment and infrastructure constraints, and increasing costs raise uncertainties about the scale and pace of development in the sector. Whilst Scotland's geography lends itself well to the exploitation of renewable energy, the remoteness of its resources and distance from market increase the cost and difficulty of bringing renewable power to market, meaning achievement of the country's renewable energy target remains less than certain.

Key Findings

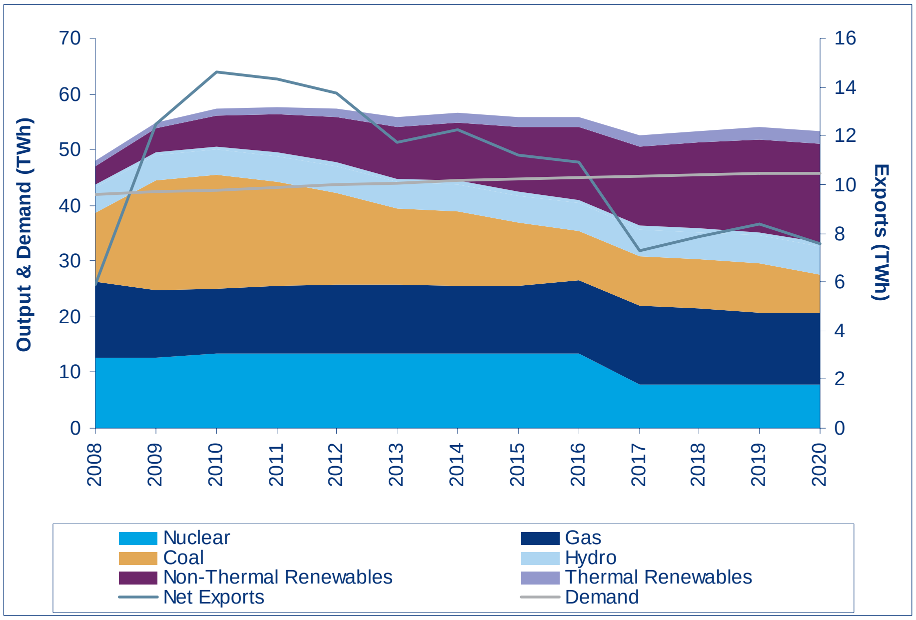
In order to develop an understanding of the future of power generation in Scotland, and the likely level of progress toward national renewable energy targets, Wood Mackenzie has formed a central scenario for the development of the Scottish power sector. This Base Case forecast is characterised by a marked loss of existing base-load capacity (notably the closure of the Cockenzie coal-fired plant and the Hunterston nuclear plant in 2016) and continued strong development of renewable generation capacity, in particular onshore wind (onshore wind capacity is predicted to increase by 5.4GW, while offshore wind developments account for a further 500MW and other renewables around 650MW). Although continued research and development funding will be put into alternative renewable sources, such as wave and tidal generation, the Base Case forecast reflects our view that growth of wind generation will play a vital role in progress towards Scotland's 2020 renewable energy target.

The results of our dispatch modelling of the Base Case generation view suggests that the system is likely to contain sufficient renewable capacity to meet the 50% in 2020 target, with the renewable share of Scottish demand standing at 55% in that year. In terms of total power produced, the renewable power share is 48%. Our analysis also reveals that the Scottish generation sector remains sufficiently competitive and well supplied to maintain the level of power transfers to neighbouring networks at similar level to that recorded in recent years, around 10TWh per annum.

In order to consider the sensitivities of the Scottish generation mix and the potential for different outcomes to arise from the uncertainties facing the market, Wood Mackenzie has also compiled an alternative view of developments over the study period. The Alternative Case assumes a lower rate of wind capacity expansion, earlier closure of the Cockenzie coal-fired power plant, and greater investment in new CCGT installations, as well as the replanting of the Longannet coal-fired station and the phased introduction of carbon capture equipment at that site.

As a result, the Alternative Case is characterised by a higher proportion of base-load output from gas and coal plants and a higher level of exports. By 2020, output from gas and CCS coal plants accounts for nearly 55% of total generation. Due to our assumption of lower build rates, renewable energy supplies fall to 40% of Scottish demand and 32% of total generation.

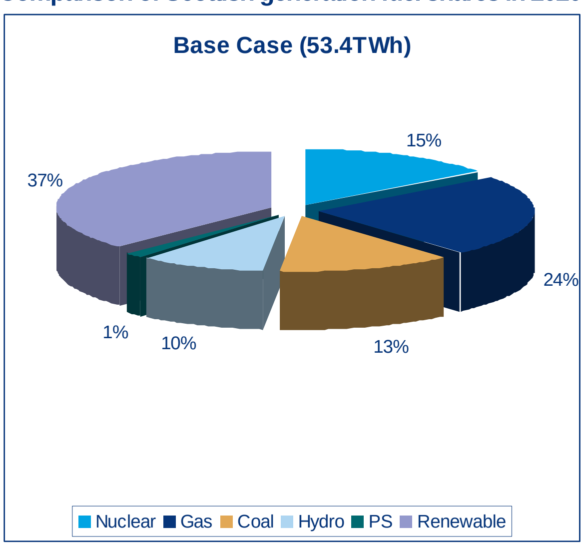
Generation Output by Source – Base Case



Source: Wood Mackenzie

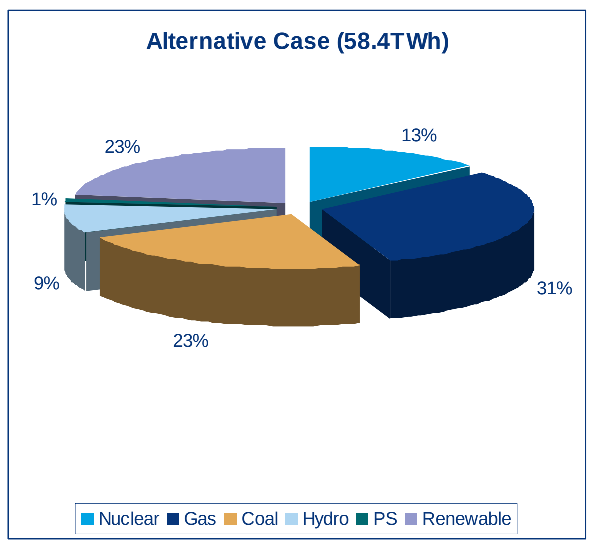
Because of the different mix and quantity of new generation in our Base and Alternative Cases the two forecasts have very different investment profiles. Based upon our plant cost assumptions, as outlined in Appendix 2, in the Base Case there is a required spend of £9.5bn between 2008 and 2020. In the Alternative Case this investment requirement, including the cost of carbon capture equipment, increases to £10.2bn. In the Base Case, over 95% of the total investment is made in renewable capacity, while in the Alternative Case this share drops to 48%. Both cases, present a picture of declining carbon intensity from the Scottish power sector, with the Base Case seeing renewable generation displacing output from fossil fuelled plants, while the Alternative Case sees additional gas replacing coal generation and the emergence of carbon-capture equipped coal generation.

Comparison of Scottish generation fuel shares in 2020



Source: Wood Mackenzie

Note: Shares expressed in terms of total generation output



Source: Wood Mackenzie

It is Wood Mackenzie's view that both cases represent plausible evolutions of the Scottish power sector. The realisation of either case will be dependent on the development and success of government policies, the ultimate influence of challenges such as system constraints and local planning issues, and developments in fuel costs and the relative costs of new build.

In the Base Case, there is still sufficient conventional plant connected to the system to ensure an adequate reserve margin at all times and maintain transfers to neighbouring systems. However, conventional generation, specifically fossil fuelled plants, will tend to see its load factor eroded by growth in renewable output. In the course of the study period we would not anticipate the provision of back-up capacity, required to provide adequate levels of support to intermittent sources of power, to present a problem in Scotland. However, it would be reasonable to assume that, as the renewable share of the market increases, the costs of system balancing will rise.

The Alternative Case, based around the extensive development of more efficient, low carbon, fossil-fuelled power sources, provides a second view of the long term development of the Scottish generation mix. It is worth note however that CCS technologies are yet to be proven at a commercial scale in the power sector and the feasibility of such additions will rely much upon the research and development activities of those companies currently active in the field. The UK's own CCS aspirations, and related Government sponsored competition, are well timed in respect to our assumptions in the Alternative Case.

Both forecast cases suggest a far greater financial commitment to new power generation in Scotland than has been made in recent years. It is also important to note that both cases will incur costs in addition to the necessary investment in new capacity, such as investments in network upgrades or carbon transport and storage facilities. From a broader economic and policy perspective, other factors, including the impacts on employment, local business opportunities and energy security, may also be relevant considerations.

Of the two views presented in this study, it is the Alternative Case that emits less CO2 and puts Scottish generation on a more competitive footing in the wider GB power market. The value that we attribute to this emissions saving and increased output, more than offsets the greater up-front costs. Over the study period the estimated benefit of the Alternative Case amounts to £1.35bn.

Although, as a result of this cost benefit, the Alternative Case seems the more attractive, in reality it is likely that a balanced combination of renewable technologies and less carbon intensive fossil-fuelled sources would provide the optimum mix of Scottish generation, in terms of the cost, competitiveness, security and diversity of energy supply. A broad-based mix of new generation technologies would also seem to offer Scotland a more attractive opportunity to develop the specialist skills, experience and capabilities that will be very much in demand as first European and then global power markets move increasingly towards lower carbon sources. Although it is not a feature of the forecast cases presented here, it is our view that nuclear power should be considered as a potential part of the longer term generation base in Scotland. However, it seems very unlikely that any development of nuclear generation in Scotland would deliver new capacity before 2020.

Although this study is limited to the period up to 2020, there are certain key issues beyond that time that are likely to have a significant impact on Scottish power generation. Of particular relevance to the material we present here is the potential further loss of base load generation, specifically nuclear and coal-fired plant closures that may occur in the period between 2020 and 2030, and the possibility that this could give rise to a generation shortfall. The timing of such losses is likely to be influenced by the performance, condition and economics of the plants concerned and is therefore subject to a number of uncertainties. However, the seemingly inevitable retirement of at least one large plant will give rise to a significant change in the Scottish market, triggering the addition of new base load generation or a much increased reliance upon supplies imported from neighbouring systems. If Scottish demand is to continue to be served by Scottish generation, it is highly likely that new base load capacity will be needed and, in addition to the technologies we consider in the forecasts presented in this report, new nuclear generation could represent a viable option at this time.

1 Overview of Scotland's Electricity Sector

Scotland and the Broader UK Electricity Market

The Scottish electricity market comprises around 10% of the total UK market and contains two vertically integrated utilities, Scottish Power (SP) and Scottish & Southern Energy (SSE), as well as two nuclear plants, both owned by British Energy. SP and SSE own the transmission and distribution systems in their respective areas, as well as the coal, gas, wind and hydro plants in Scotland. There is also one small gas-fired power producer and numerous wind generation projects in the hands of other companies.

As part of the changes in UK governmental and regulatory policy which took place in 1998, the existing Pool system operating in the electricity market in England & Wales was replaced from April 2001 by a new market, known as the New Electricity Trading Arrangements (NETA). In April 2005, NETA, which originally only covered England & Wales, was extended to cover Scotland and renamed BETTA.

Before it became part of BETTA, there was no explicit wholesale market in Scotland and trading took place via bilateral contracts. The England & Wales Pool price was effectively used as a proxy market price, replaced since the introduction of NETA by a composite of various England & Wales forward market indices. SP and SSE were obliged to make power available to competing suppliers at no more than the defined wholesale price. Similarly, they were obliged to offer reasonable terms to independent generators.

This arrangement was criticised for discouraging new entry into generation and supply, as had use of the England & Wales Pool price as a marker for failing to take account of the differing supply / demand balance in the two markets. After a regulatory review of the Scottish market it was originally proposed to implement a revised structure with an independent transmission system operator and a wholesale market and balancing mechanism along similar lines to the NETA arrangement in England & Wales. Market participants raised concerns that introducing a second trading system into the market (similar, but not identical to NETA) would harm competition by reducing liquidity. The proposal was accordingly withdrawn and replaced with the introduction of BETTA.

The introduction of BETTA has meant that Great Britain now operates a single transmission network, covering England, Scotland, and Wales, under the control of National Grid. The England-Scotland interconnector has been absorbed into the wider GB transmission infrastructure. As such, the Scottish power market is now closely integrated with the broader UK market.

Transmission Network Characteristics

The UK transmission system effectively consists of three synchronously connected transmission networks on the mainland, plus a smaller network in Northern Ireland (connected via a DC link to Scotland).

The England & Wales transmission grid operates at 400kV and 275kV. It is owned and operated by National Grid. The system is centred on a ring around London, with a number of lines stretching north and west toward concentrations of coal- and gas-fired power production. Additional rings are centred on the Birmingham, Leeds-Bradford, Manchester-Liverpool and Tyneside-Teesside industrial areas, and lines stretch along the south coast, into North and South Wales and northwards along the east and west coasts into Scotland.

Much of the Scottish transmission grid consists of 400kV and 275kV lines connecting the major nuclear and coal plants in the central belt area between Glasgow and Edinburgh, as well as the Peterhead gas-fired plant in the north-east. Ownership of the networks in Scotland remains with SSE (Northern Scotland) and Scottish Power (Southern Scotland), although the networks are operated by National Grid. The English and Scottish transmission grids are connected by four transmission lines forming two double circuits. On the east coast, both halves of the circuit operate at 400kV, while in the west one half runs at 400kV with the other at 275kV.

The Northern Ireland transmission system operates at 275kV and is owned by Northern Ireland Electricity, now part of the Viridian Group, and operated by SONI (System Operator Northern Ireland). The UK mainland is connected to Northern Ireland via the 500MW Moyle interconnector, between Ballantrae in Scotland and Ballylumford in Northern Ireland.

A 2GW HVDC interconnection between England and France began operation in 1986. Since April 2001, the interconnector, jointly owned by National Grid and its French counterpart RTE, has been made available to third parties through a competitive bidding process. While the original purpose of the line was to enable bi-directional electricity interchanges between the UK and France (exploiting, for example, the one-hour time differential between the two countries), for most of the 1990s the line operated as a base-load exporter to the UK, delivering 16-17 TWh annually. This was due to a number of factors, including the signature of one-way bulk contracts during and after the 1984-85 UK miners' strike, liberalisation of the UK industry and the fact that exports from France initially qualified as "non-fossil" under the original UK environmental subsidy regime. However, since the introduction of NETA in 2001 the interconnector has begun to operate in a more flexible mode, with exports from the UK being commonplace.

UK Electricity System

Source: Wood Mackenzie

Transmission Network Issues

While Scotland's existing transmission network continues to operate effectively under current loads, its ability to provide sufficient capacity to accommodate a continuation of recent rapid growth in renewable generation has been a much debated issue. To this end, several studies have pointed to the network's limited capacity to accommodate new generation. The Renewable Energy Transmission Study (RETS), produced in 2002 by National Grid, SP and SSE for the Department of Trade and Industry (DTI), considered a number of options for accommodating significant increases in renewable generation in Scotland and identified various infrastructure reinforcements that might be required.

Ofgem responded to the RETS report in December 2004 by proposing a mechanism to fund a number of the key upgrades identified, including:

- Beauly - Denny (primarily upgrade along existing route);
- Sloy (primarily upgrades to the substation);
- South-West Scotland (primarily new network); and
- The Scotland-England interconnector (upgrade from 2.2GW to 2.8GW by 2010).

A subsequent study by the Forum for Renewable Energy Development in Scotland (FREDS) found that these key upgrades, along with further local reinforcements, could allow the connection of up to 6.3GW of new projects. However, the study noted that additional upgrades could also be required, depending on the location of consented generation or to reduce constraint costs. These further upgrades were identified as:

- Beauly-Blackhillock (primarily upgrade to existing infrastructure);
- Beauly – Keith (primarily upgrade along existing route);
- SSE 400kV ring (primarily upgrade to existing infrastructure);
- South West Scotland 400kV extension (primarily new network);
- SP upgrades in North Ayrshire (combination of upgrade and new network); and
- Beauly-Dounreay (primarily upgrade to existing infrastructure).

Together, these further upgrades were estimated to provide for the connection of an additional 3.8GW of new generation in Scotland (although it was noted that if all the upgrades went ahead, consideration would need to be given for a further upgrade of the Scotland-England interconnector).

However, progress on upgrade work has been variable: the key Beauly-Denny project, originally scheduled for completion in 2008, is yet to be started with the planning application now subject to a public enquiry which is expected to continue for the remainder of the current year.

The UK's draft 2008 Renewable Energy Strategy (RES) reiterated the issues first covered in the RETS report, noting that network capacity was still a key constraint to the development of further renewable generation. The RES found that, in many areas of the UK (including Scotland and northern England), the transmission system had very limited potential to accommodate new generation without further system reinforcement. It noted that this limited network capacity had contributed to a considerable backlog of generation projects awaiting connection, with up to 10GW of projects estimated to be awaiting connection in Scotland alone. The RES claimed that developers in some parts of the country had been told that projects could not be connected to the grid until close to 2020.

However, the RES stated that the scale of network reinforcement needed for onshore projects, over and above current investment plans, may be relatively modest. In this sense, eventual completion of the network upgrades already planned or underway should make a substantial contribution to alleviating existing onshore grid constraints. But the RES also noted that the prospect of significant new offshore wind farm developments introduced a new challenge - the development of an offshore electricity grid - with over 6,000km of DC and around 1,900km of AC submarine cable estimated to be required to meet future offshore expansion.

In addition to physical constraints, the current framework governing grid connections presents a further limiting factor in the installation of new generation, particularly renewables. The current grid connection system was established to allow for the connection of a relatively small number of very large generation projects, often with long lead times available. The recent trend towards renewable generation has seen a much larger number of small projects seek access to the grid, which has contributed to the current project backlog (the so called GB Queue) and the excessive connection timeframes noted above. A joint study between BERR and Ofgem (Transmission Access Review 2008) found that "fundamental changes to the codes that govern access to the grid" are required to allow for greater renewable generation to be installed. Reforms in this area are now being investigated, including amending the system planning standard – the GB Security and Quality of Supply Standards (SQSS) – to allow for the connection of a greater amount of generation to a given network. BERR and Ofgem are also looking into interim arrangements to allow for the immediate connection of new capacity, while more permanent adjustments are made to the grid access framework, an approach known as "connect and manage".

Transmission Network Charging Arrangements

In April 2005, following the formation of the BETTA market, National Grid extended its system of calculating transmission network charges in England & Wales to the Scottish market. The system is based on a principle of reflecting the incremental cost of providing transmission services to a particular generator or supplier. As such, it includes a variable charge to reflect the different cost of delivering power from different areas within the UK.

Due to Scotland's location on the periphery of the UK electricity system some distance from the centre of demand, generators in Scotland are required to pay a higher charge to transport power through the transmission network. As a result, the current system of transmission network charging has drawn criticism from both the Scottish government and Scottish generators. Amongst the arguments against the current system are that it discriminates against renewable energy generation, much of which will be located in remote areas with high transmission charges.

An amendment to the Energy Act 2004, made via the Climate Change and Sustainable Energy Act 2006, provided the UK government with the power to adjust transmission charges should they be considered likely to hinder renewable energy development. However, the government is yet to draw on such powers. Following an investigation in 2007, the government announced it would postpone any decision to draw on these powers with respect to transmission charging in the north of Scotland until after the publication of a final UK Renewable Energy Strategy, when potential amendments to renewable energy support schemes would be agreed. It argued that the economic viability of renewable energy projects in the north of Scotland was sufficiently strong so as not to be affected by a higher transmission usage fee.

However, the issue continues to attract debate. In September 2008, the Scottish government - backed by Scottish Power, Scottish and Southern Energy and the Scottish Renewables Forum - submitted a proposal for a new transmission charging model to Ofgem and National Grid which would impose a uniform charge for each unit of energy that enters the system, regardless of location or capacity of the generating facility. Discussions on the issue are presently ongoing.

2 The Energy-Climate Background

Scottish energy policy is influenced by developments at the European and UK level. The following section provides an overview of these broader policy contexts before describing the current Scottish energy policy environment.

European Energy-Climate Policy

Regulatory and energy policy developments in European gas and power markets are primarily driven by legislation at the EU level. The European Commission (EC), as the principal architect of EU energy policy, has developed ambitions in three key policy areas in response to the energy challenges faced by the region:

- Market Competition: The EC has set the goal of creating a single, integrated EU market in gas and power with the intention of improving competition and driving down prices for energy consumers. A series of directives over the last decade have sought to progress this goal, leading to the full opening of gas and power markets in most jurisdictions and the gradual separation of monopoly transmission networks from competitive production and supply activities. As part of its drive to create an integrated regional market, the EC is encouraging the development of infrastructure interconnections between neighbouring countries.

- Security of Supply: Indigenous European oil and gas production is in decline (with the exception of Norwegian gas) as North Sea fields reach maturity. In addition, the installation of gas-fired power plants across Europe is driving a growing overall reliance on gas in the energy supply mix. As a result, the region is becoming increasingly dependent on energy imports, most notably Russian gas. Recent disruptions in oil and gas deliveries to Europe as a result of conflicts between Russia and former-Soviet transit states have highlighted the issue of Europe's energy security, and prompted the EC to push for a diversification in energy suppliers and supply routes. The EC has also sought to encourage the bloc to speak with "one voice" in its dealings with Russia in order to better leverage its negotiating power.

- Environment: The EC has made combating climate change a key focus of its energy policies, driven by its responsibilities under the Kyoto Protocol and its desire to be a global leader on the issue. Its key policies to reduce carbon emissions include the Emissions Trading Scheme (ETS), and the promotion of renewable energy and energy efficiency. In addition, the EC has sought to reduce the local environmental impacts of electricity generation via the Large Combustion Plant Directive (LCPD), which caps the release of nitrous oxides and sulphur dioxide into the atmosphere.

Recent Developments

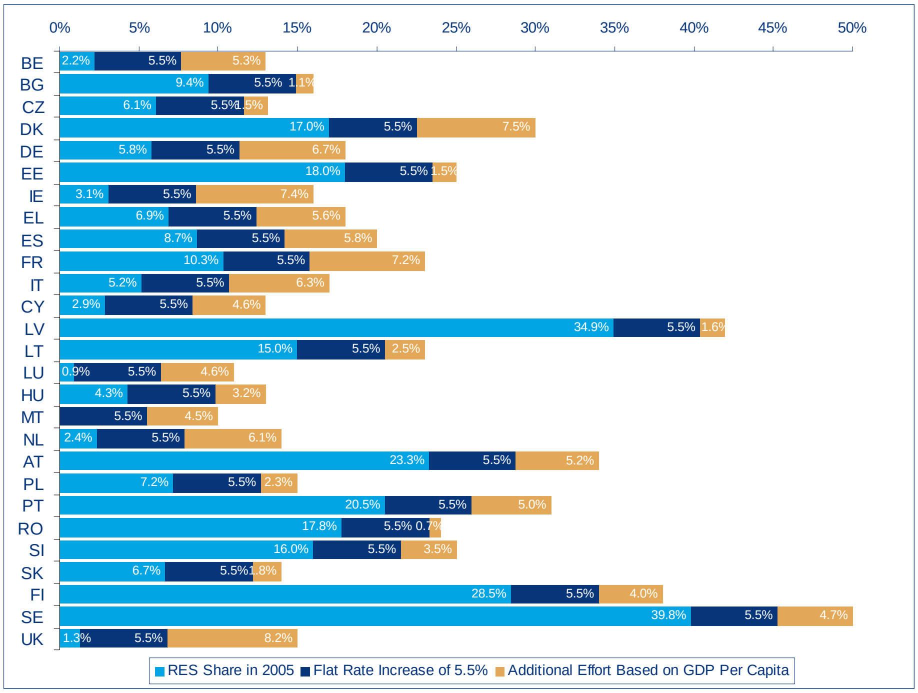
The EC is continuing to propose new measures to achieve its goals in each of these areas. In September 2007, the EC outlined its third package of legislative proposals aimed at liberalising the bloc's gas and power markets, building on the packages of 1999 and 2003. Central to the third package was a proposal to require the full separation of monopoly gas and power transmission networks from competitive production and supply activities to ensure fair access to the networks for new entrants and other market players. The package also aimed to strengthen and improve coordination between national energy regulators, proposed the formation of a regional body to oversee cross-border energy issues, and aimed to strengthen co-operation between national transmission operators.

In January 2008, in addition to the third package, the Commission also proposed a package of energy and environmental measures to place Europe on course towards a lower carbon future. The primary targets supporting this package were:

- A reduction of at least 20% in greenhouse gas emissions by 2020. This target is to increase to 30% in the event that there is international agreement to implement comparable targets in other developed nations and adequate levels of activity in developing countries. In order to meet this target the EC proposed to strengthen the ETS by expanding it to cover more greenhouse gases and more sectors and by introducing permit auctioning from 2013 (Appendix 1 provides more detailed information on the ETS, future amendments, and details of Wood Mackenzie's carbon market assumptions). The EC also announced it would seek to enable the development of carbon capture and storage (CCS) technologies by creating a legal framework to govern the practice and by supporting CCS demonstration projects.

- A 20% share of renewable energy in EU final energy consumption by 2020 (from 8.5% in 2005). The headline target was subsequently allocated among the 27 individual member states based on a calculation incorporating a country's GDP per capita. The resulting allocations are displayed below.

Allocation of EU Renewable Energy Targets



Source: European Commission

At the 2008 Spring Council of the European Union it was agreed that the climate-energy package of measures provided a good basis for agreement to be reached before the end of 2008 and consequently allow for their adoption, before the end of the current legislative term, in the early months of 2009. The climate-energy package (or the 20-20 package as it has been called) clearly demonstrates a strong, long-term commitment on the part of the EU to successfully deliver its' energy and environmental policy targets and maintain the momentum of negotiations on the United Nations Framework Convention on Climate Change (UNFCCC). This position will allow the EU to assume a central role in the next UNFCCC Conference of the Parties in Poznan, Poland in December 2008 and from there strive to secure a comprehensive post-2012 agreement on climate change in Copenhagen during 2009.

UK Energy Policy & Legislation

While UK energy policy is bound by developments at the EU level, in many areas the UK has moved more quickly to implement energy market changes than European requirements have dictated. The UK completed the opening of its power and gas markets in 1999, with all consumers becoming free to choose their energy supplier. Network ownership was subsequently split off from competitive market activities (with the exception of Scotland, which adopted an independent system operator regime) and a new market regulator was established. Since that time the UK's gas and power markets have evolved into arguably the most competitive in Europe.

More recently, the UK government's focus has turned to the overarching issues of energy security and climate change. In its 2007 White Paper, the government set out its strategy to respond to these two challenges. The White Paper reiterated the government's goal to cut the UK's carbon dioxide emissions by 60% by 2050 and proposed the creation of legally binding interim carbon targets. It sought to encourage energy savings through better information, incentives and regulation, and it proposed greater support for the development of low carbon technologies, including through the development of a regulatory framework and supporting a CCS demonstration project. Finally, it set out to create a clear and stable regulatory regime to reduce uncertainty for business and help to ensure sufficient, timely investment. The importance of the last point was emphasised by the White Paper's calculation that the UK will need around 30-35 GW of new electricity generation capacity over the next two decades and around two thirds of this capacity by 2020 as existing coal and nuclear power stations close.

As part of its efforts to ensure timely investment, the government proposed in a parallel White Paper a series of changes to the local planning system which, among other things, would streamline the process for nationally significant energy projects. As planning remains a devolved responsibility in Scotland and Wales, not all changes proposed in the White Paper will be applicable to these countries, although the UK government stated its intention to work with the devolved administrations in implementing the reforms to ensure that the planning systems in the UK operate effectively alongside each other.

The proposals in the Energy and Planning White Papers have been translated into draft legislation – including the Energy Bill, the Climate Change Bill, and the Planning Bill – and are progressing through the legislative process.

In October, the UK government underscored its focus on addressing the substantial challenges faced in the energy sector with the establishment of a new dedicated Department of Energy and Climate Change (DECC). Soon after the creation of DECC, newly appointed energy and climate change secretary Ed Miliband announced that the government would further raise its long-term climate change ambitions, committing to cutting the country's greenhouse gas emissions by 80% (against 1990 levels) by 2050. The move responded to a recommendation by the government-appointed advisory group the Climate Change Committee. In addition the government indicated that aviation and shipping sectors would be included within the scope of the target (the two sectors had been excluded under the 60% emissions reduction goal proposed in the 2007 White Paper). The government is now moving towards making the new goal binding in law through incorporating it as an amendment in the Climate Change Bill.

UK Nuclear Energy Policy

In a follow up to the White Paper, in January 2008 the government confirmed it would allow a new generation of nuclear power stations to be constructed in the country, and began the process to establish the regulatory environment and to make the necessary technical decisions to allow such plants to be built. Recent statements suggest the government is looking to encourage up to eight new nuclear plants to be built in the country. Processes to identify appropriate locations for nuclear plants and to select reactor designs are now underway.

UK Renewable Energy Policy

Consistent with addressing the high-level challenges of energy security and climate change, the UK government has also placed a strong emphasis on the development of renewable energy. In 2003, the government established goals for renewable energy to supply 10% of electricity generation by 2010, rising to 20% by 2020. However, these goals have now been superseded by the UK's target under the EU's climate-energy proposals, which would require the country to source 15% of all energy from renewable sources by 2020, with some scenarios suggesting the achievement of such a goal would require 30-35% of all UK electricity to be provided by renewable energy.

The primary mechanism for promoting renewable energy development in the UK is the Renewables Obligation (RO). Established in 2002, the RO places a requirement on electricity suppliers to source a steadily increasing proportion of the power they provide from selected renewable sources, or to pay a buy-out fee. At present, eligible sources under the RO include onshore and offshore wind, hydro (for hydro stations >20MW, only those commissioned after April 2002 or plants subject to refurbishment are eligible), biomass (although a maximum of 10% of a company's obligation can be met through biomass co-firing), landfill gas, sewage gas, geothermal, tidal and wave, photovoltaics and energy crops.

RO targets are set separately for England & Wales, Scotland and Northern Ireland, although RO Certificates (ROC) earned by electricity generators are redeemable against any of the three separate obligations, effectively creating a UK-wide market in renewable energy generation. The current pathways for the RO in England & Wales, Scotland and Northern Ireland are displayed below.

UK Renewables Obligation Pathways

Plant Name	England & Wales	Scotland	Northern Ireland
1st April 2007 to 31st March 2008	7.9	7.9	2.8
1st April 2008 to 31st March 2009	9.1	9.1	3.0
1st April 2009 to 31st March 2010	9.7	9.7	3.5
1st April 2010 to 31st March 2011	10.4	10.4	4.0
1st April 2011 to 31st March 2012	11.4	11.4	5.0
1st April 2012 to 31st March 2013	12.4	12.4	6.3
1st April 2013 to 31st March 2014	13.4	13.4	6.3
1st April 2014 to 31st March 2015	14.4	14.4	6.3
1st April 2015 to 31st March 2016	15.4	15.4	6.3
Each subsequent period of twelve months ending with the period of twelve months ending on 31st March 2027	15.4	15.4	6.3

Source: DBERR

Following the launch of the Energy White Paper in 2007, the government carried out a consultation on proposed changes to the RO. A key aspect of the proposals was a move to introduce varying support levels for different renewable energy technologies, an approach known as "banding". The use of banding is designed to encourage emerging technologies such as offshore wind, wave and tidal energy while potentially reducing support to more mature or already economic technology types. It is expected to increase the overall level of renewable energy generation driven by the RO. The government's favoured approach to banding was to offer selected technologies more than one ROC for each unit of renewable energy generated to encourage their development while other more mature technologies would receive less than one ROC.

Proposed Renewable Obligation Banding Levels

Banding Category	Technology	Level of Support (ROCs/MWh)
Established	Sewage gas; landfill gas; co-firing of non-energy crop (regular) biomass	0.25
Reference	Onshore wind; hydro-electric; co-firing of energy crops; energy from waste with combined heat and power; other not specified	1.0
Post-demonstration	Offshore wind; dedicated regular biomass	1.5
Emerging technologies	Wave; tidal stream; advanced conversion technologies (anaerobic digestion, gasification and pyrolysis); dedicated biomass burning energy crops (with or without CHP), dedicated regular biomass with CHP; solar photovoltaics; geothermal	2.0

The government also proposed operating the RO pathway on a “headroom” basis, meaning in order to avoid the risk of over-compliance and a consequent collapse in the ROC price, the RO could be increased year-to-year to ensure it stays ahead of the predicted number of ROCs. The government proposed maintaining RO levels 6% above the expected level of renewable generation up to an overall renewable contribution of 20%. The intention was to introduce the headroom approach at the same time as banding, currently targeted for April 2009. These proposed changes have been incorporated in the Energy Bill currently negotiating the legislative process. In order to ensure that changes to the RO can be adopted promptly, the government launched a statutory consultation on the details of how it intended to introduce banding on 26 June 2008. This consultation closed on 30 September.

Furthermore, in June 2008, in light of confirmation of the UK’s 15%-by-2020 renewable energy goal under the EU’s climate-energy package, the UK government opened a consultation round on a draft Renewable Energy Strategy (RES). The RES included further discussions on the RO as well as a number of separate issues. While the strategy concluded that the RO should continue to be the preferred instrument for encouraging renewable energy, it also called for a its strengthening, by extending its end-date from 2027 to 2035 or beyond, and raising or removing the 20% cap. The RES also noted that a reconsideration of the headroom approach may be warranted given the stringent new EU targets. The consultation period on the RES closes on 26 September, with the publication of a final RES due in spring 2009.

Scottish Energy Policy

Energy policy in the UK remains largely the responsibility of the UK government, although the Scottish government retains authority over certain policy areas in its own jurisdiction. Most notably, Scottish Ministers control the local planning process and have to give consent under the Electricity Act to the construction of new power stations above a certain size (50MW for onshore, 1MW for offshore). As such, the Scottish government has the ability to shape the make-up of power generation in the country by approving or refusing new projects, including in cases where this may conflict with overall UK policy.

New Nuclear Generation in Scotland

Following the UK government's announcement in January 2008 that it would allow a new generation of nuclear power plants to be built in the UK, the Scottish government declared that it would reject any applications to construct new nuclear power plants in Scotland. The Scottish government's stance was backed by the Scottish Parliament which voted 63-58 to oppose any new nuclear power stations.

Renewable Energy and Climate Change Targets

In addition to having authority over planning consents, the Scottish government has established its own ambitions in relation to renewable energy and climate change. In 2003, the Scottish government set a target to provide 40% of the country's electricity from renewable sources by 2020. The goal was subsequently raised to 50% in 2007, with an interim target of 31% set for 2011. The Scottish target clearly exceeds the overall target set by the UK government for renewable energy to supply 10% of electricity generation by 2010 and 20% by 2020.

In October 2008, the Scottish government released its draft Framework for the Development and Deployment of Renewables in Scotland (FDDRS), produced in co-operation with the FREDS. The document, which complements the parallel UK consultation on the RES, set out the Scottish government's plans for bolstering the growth of renewable energy in order to meet the broader UK renewable targets as well as Scotland's own target for 50% of gross electricity consumption to come from renewable generation by 2020. In addition, the document proposed a new target for Scotland to produce 20% of its energy - taking into account heat and transport as well as electricity - from renewable sources by 2020. Consultation on the document will close on 1 December, with feedback to be incorporated into a new renewable energy strategy for Scotland in Spring 2009.

The Scottish government has also sought to establish itself as a leader in efforts to cut greenhouse gas emissions. In October 2008, the government set out the key components of the Scottish Climate Change Bill, proposing an overall ambition to cut emissions by 80% by 2050 against 1990 levels. As with the proposed UK-level 80% emissions target, the Scottish target includes emissions in the aviation and shipping sectors, and is applicable to a basket of six greenhouse gases. The Bill also proposed an interim target to reduce emissions by 50% by 2030, as well as a framework including annual targets and regular reporting to ensure consistent progress. It is intended that the Bill will be introduced to the Scottish Parliament by the end of 2008.

Renewables Obligation (Scotland)

The key mechanism driving renewable energy development in Scotland's power sector is the Renewables Obligation (Scotland), or ROS. While the Scottish government maintains authority over the ROS, legislation establishing the mechanism has been deliberately drafted to mirror equivalent Obligations covering England & Wales and Northern Ireland, allowing for the functioning of a UK-wide market in renewable energy. At present, Scotland's RO pathway is identical to that of England & Wales, as displayed in the table above.

However, the Scottish Government made an independent change to the ROS in April 2007 by introducing an associated Marine Supply Obligation (MSO). The MSO was introduced to provide support for wave and tidal generation located in Scottish waters, and requires suppliers to meet a fixed proportion of their Obligation by securing energy from wave and tidal devices or by paying a suitably higher buy-out price. However, in introducing the MSO, the Scottish government committed not to activate the measure unless there was eligible capacity available which would enable suppliers to meet their MSO obligation. With no such capacity currently online, the MSO is currently set at zero.

As already noted, amendments to the RO for England & Wales are currently being progressed under the Energy Bill, including the introduction of banding to raise the level of support provided to less mature technologies. While these changes won't be binding on the ROS, the Scottish government has already agreed in principle on the parallel introduction of banding and has held a consultation round (closing in July 2008) on adopting such a change. In its consultation document, the government acknowledged that the introduction of banding would largely eliminate the need for a separate MSO, and therefore proposed that the MSO should be discontinued with effect from April 2009. The Scottish government is now forming a final position on the issues covered in the consultation document. This will lead to a formal consultation later in the year and a draft Order, containing any proposed amendments to the ROS, which would require approval from the Scottish Parliament. The Order is expected to be brought into force on 1 April 2009.

As with the UK's proposed introduction of banding, the proposal to increase the RO to 20% on a headroom basis does not directly apply to Scotland. However, the UK government has expressed its desire to maintain a consistent RO market across the UK. When proposing the adoption of the headroom approach, it indicated it would work with the devolved administrations of Scotland and Northern Ireland in a bid to have such an approach apply in all three jurisdictions covered by the RO. Nevertheless, as noted above, the UK's draft Renewable Energy Strategy has raised questions over whether the headroom approach is the most suitable in light of the UK's new 2020 renewable energy target, leaving some doubt over whether Scotland would also need to adopt this change.

Other Support for Renewable Technologies

Scotland's considerable prospective wave and tidal resource has seen the Scottish government give particular backing to progressing the development of marine energy technologies. Aside from the MSO, the government has contributed to the construction of the European Marine Energy Centre (EMEC), opened in Orkney in 2004 to progress the development, testing and accreditation of marine energy generation. Following the EMEC's launch, funding of £13 million was made available under the Scottish Ministers' Wave and Tidal Energy Support Scheme to support the installation and deployment of pre-commercial wave and tidal electricity generating devices at the facility.

The government has also supported the use of biomass, developing a Biomass Action Plan in 2007 and providing funding of £7.5 million over the financial years 2006/07 and 2007/08 to support the use of biomass in heat and CHP installations.

3 The Development of Generation & Demand

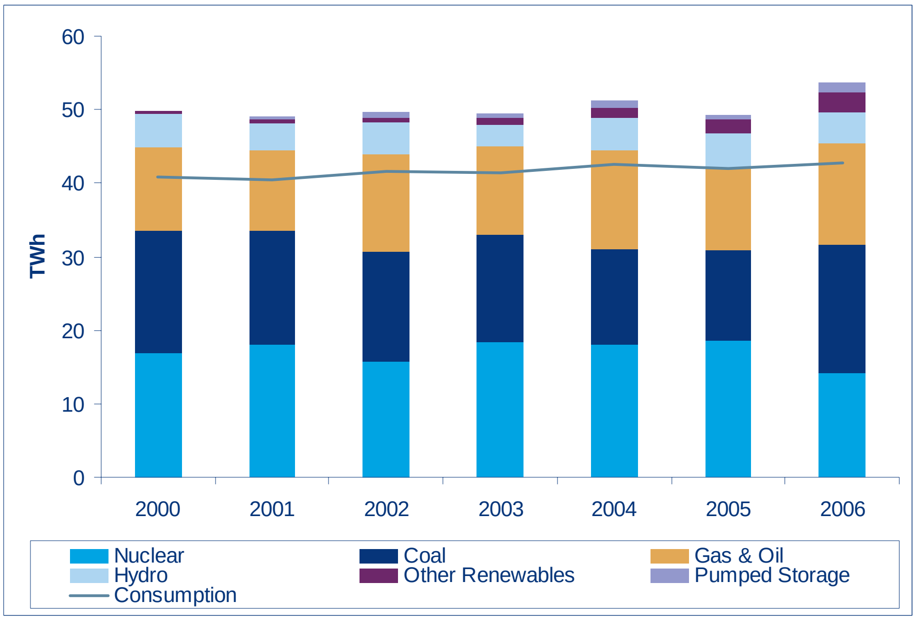
The Generation & Demand Background

Scotland's Existing Generation Mix

At present the Scotland's installed generation base consists of a broad mix of generation technologies and fuel types. Power is supplied by a combination of large base-load plants, including nuclear, coal and gas-fired units, hydro generation, both conventional hydro and pumped storage, and a number of other renewable sources. Both fossil fuelled and nuclear plants rely upon steam based generation processes, while renewable sources take advantage of more sustainable natural resources.

There is typically a surplus of generation output in the Scottish market and this power flows into the wider high voltage system in Great Britain to England and Wales, and, via the Moyle interconnector, to Northern Ireland. Of these two export flows, it is the one to the south that accounts for the large majority of excess supply. The interaction of the Scottish and English networks also plays an important role in system balancing and supply security north of the border. Although power flows are predominantly north to south, flows in the opposite direction are commonplace.

Scottish Electricity Generation by Source



Source: Scottish Government & DBERR
Note: Other Renewables includes wind, wave, solar power and thermal renewables.

Generation by Fuel & Source

Key sources of generation in the Scottish market and the significant influences affecting long-term operation may be outlined as follows:

Nuclear

Scotland currently has two operational nuclear reactors, namely Hunterston and Torness, both plants are owned by British Energy (BE). The total capacity of these plants is 2.4GW and they represent around 21% of current installed capacity, however, due to their base-load operation, they have typically made a contribution of over 35% to total Scottish generation output.

Due to limitations imposed by the condition of its boilers, the capacity of Hunterston is currently restricted to a maximum of 70% of the plant's nominal capacity. To allow the plant to operate at this level a programme of major works was completed at the site in the second and third quarters of 2008 and prior to this output had been capped at around 60%. Further works are to be carried out by BE to ascertain whether plant output can be raised above the current limit.

The UK was one of the earliest pioneers of nuclear power generation. However, the country's ageing fleet of nuclear power stations, including those located in Scotland, is now at a stage where end-of-life closures at some sites - particularly the older Magnox stations - and the potential extension of the operating lives of the Advanced Gas-cooled Reactors (AGRs), is a significant and imminent issue. The Magnox plants were the first large-scale reactors to be introduced and their age, having already received lifetime extensions, is such that imminent closure now seems undisputable.

The AGR plants, which include Hunterston and Torness, were commissioned later than the Magnox stations and still offer some scope for lifetime extensions, such as in the case of Dungeness B which received a ten-year extension to its operating lifespan in 2005.

In December 2007, it was confirmed that, having successfully completed all necessary technical and economic evaluations and received relevant external consents, the operation of Hunterston would be extended by five years to 2016. At this time, Hunterston will have reached 39 years of age. Further studies will be conducted by 2013 to assess the potential for additional extensions beyond the new limit. The current accounting lifetime of Torness ends in 2023, at which time the plant will have been in operation for 34 years.

It is our view that, where technically and economically feasible, British Energy will continue to pursue life extensions across their fleet of operational sites in the UK, although, taking into account previous operational constraints, the maximum age of AGR plants is likely to be capped at 40 years. Therefore, In the view presented here we assume that Hunterston will close in 2016, after 40 years operation, and Torness will have its lifetime extended to 2028.

Coal

There are two operational coal-fired generation plants in Scotland with a combined installed capacity of some 3.6GW. The plants, namely Longannet and Cockenzie, are owned by Scottish Power and account for just under one third of overall installed capacity in the country. Both plants are of the sub-critical pulverised fuel type.

The continued operation of Longannet and Cockenzie has been significantly influenced by the revised Large Combustion Plant Directive (LCPD) which was introduced at the beginning of 2008. The LCPD introduced new, stricter limits on atmospheric emissions of oxides of nitrogen and sulphur, and particulates (i.e. dust). All existing eligible plants (i.e. those with a rated thermal input >50MW) were required to either 'opt-in' to the control of the Directive, therefore becoming subject to its emissions limits, or to 'opt-out' and be limited to generating for only 20,000 hours over the period 1 January 2008 to 31 December 2015. LCPD opted-out plants must be closed at the expiration of their limited hour derogation or at the end of 2015, whichever occurs first. Once opted-out, it is not possible for a plant to opt back into the Directive, unless it is subject to the more onerous emissions constraints that the LCPD imposes on new build plants.

Opting in to the LCPD all but obligates coal fired generators to fit Flue Gas Desulphurisation (FGD) and the scale of such an investment has proved to be a major factor in persuading the operators of around 30% of the UK's ageing coal fired fleet to opt out of the Directive. In addition, opted in plants must reduce Nitrous Oxide emissions from 500 mg/Nm3 to 200 mg/Nm3 by 1 January 2016. This will most likely entail fitting selective catalytic reduction (SCR) equipment.

In Scotland, Longannet (2.4GW) has opted-in to the LCPD and is in the process of installing a sea-water based FGD system while Cockenzie (1.2GW) has opted-out.

In our analysis of Scottish generation, the operation of Cockenzie over the period between 2008 and 2015 has been capped to recognise the operational limitations imposed by the derogation clause, which averages out at around a 30% load factor (or 2,750 hours per year) over eight years. In our Base Case we assume that Cockenzie will remain in operation until the end of 2015 and then close. In practice the operation of Cockenzie could exceed our assumed cap in any given year due to prevailing market conditions and the relative economics of coal-fired generation in the GB power market.

Although, in our Base Case view, we assume that Longannet will remain in operation until 2020, the plant will have reached its 50th anniversary by this time and this is towards the upper age limit that we would normally assume for such technologies. However, it must be appreciated that the installation of FGD and SCR represents a significant capital investment in that generation and for this reason we would assume that Longannet will continue to operate beyond 2020.

Scottish Power is currently leading a consortium, consisting of Marathon Oil Corporation, Aker Clean Carbon and Aker Solutions, which is challenging to win the UK government's competition to develop the country's first commercial scale Carbon Capture and Storage (CCS) project. It is the consortium's aim to develop CCS at Longannet, with engineers working on plans to retrofit two of the site's existing four units with the technology. Storage of captured gasses could initially be stored in depleted gas fields in the Central North Sea or, potentially, in a much larger offshore saline aquifer. It has been suggested that the second of these two options could lend itself well to the development of an integrated storage hub, accommodating captured carbon dioxide from across Scotland and the North of England.

Gas

Total gas-fired capacity in Scotland currently stands at 1.8GW (15% of total installed) and the majority of this generation is accounted for by the 1.5GW Peterhead Combined Cycle Gas Turbine (CCGT) plant. In comparison to conventional coal plants, CCGT plants offer higher efficiency generation with a low carbon intensity.

Power generation at Peterhead was originally established in the 1980's when a large oil-burning plant was constructed at the site. The plant was subsequently converted to oil-gas dual firing to burn sour gas produced from BP's Miller Field. In 2000, a major re-powering exercise was undertaken to establish the plant in its current configuration. More recently, plant enhancements have added to the capacity of Peterhead, although the amount of power that can be exported from the station is limited by transmission infrastructure. As previously noted, there is the expectation that a series of significant investments will be made in power transmission capacity in Scotland, although this work is primarily to accommodate new renewable generation capacity and there would appear to be no current plans to increase the output of Peterhead.

In 2006, plans to develop a 350MW hydrogen fuelled plant at Peterhead were announced. The hydrogen was to be produced from natural gas, with resulting carbon dioxide being piped offshore into the Miller Field to support enhanced oil recovery from that asset. However, in the absence of an acceptable level of government support, the project was abandoned in May 2007.

In our Base Case forecast we assume that Peterhead will continue to operate beyond 2020.

Pumped Storage

Pumped storage generation is a form of energy storage that takes advantage of relatively low cost off-peak electricity to pump water into a high-level reservoir and subsequently release that water to flow through turbines into a lower reservoir at times of peak load. Due to the efficiency of the pumping process, pumped storage installations are net consumers of power. However, the advantage of pumped storage lies in its ability to provide significant quantities of power at very short notice and the resultant system balancing and peaking capabilities this provides.

Scotland has two pumped storage installations, Foyers and Cruachan, totalling some 0.7GW of capacity or 5% of the installed plant base. In our Base Case we assume that both plants remain in operation beyond 2020.

Renewables

Renewable generation capacity in Scotland has developed significantly in recent years, current capacity may be divided into three significant categories:

Hydro - the development of Scotland's existing 1.3GW of installed hydro generation capacity was driven by the North of Scotland Hydro-Electric Board, with much work taking place in the 1950's. Hydro capacity in Scotland currently accounts for 90% of all such generation in the UK and work is currently progressing to introduce a further 100MW of capacity at a new plant in Glendoe, near Loch Ness. Until recently, Glendoe had a transmission connection agreement with National Grid for the addition of 100MW of new capacity in 2012, although this has now been amended to 51.5MW from August 2008. Scottish & Southern Energy, the developer of Glendoe, predicts that first generation will take place in March 2009. In our forecast we assume that plant output will initially be limited to the lower capacity before being raised to full capacity as additional transmission system capacity becomes available. We would anticipate this subsequent change to occur no later than 2012.

In August 2008, a study carried out by the Forum for Renewable Energy Development in Scotland (FREDS), suggested that there are still 1,019 financially viable sites for the development of new hydro generation projects in Scotland, with the potential to providing a total of 657MW of new generation. This is not the first such study to be carried out in Scotland, with previous works suggesting the potential scope for additional generation to be between 270 and 1,000MW.

It is our view that any further increase in hydro generation capacity will be fairly gradual and, over the course of our study period, significantly lower than the potential outlined in recent studies. Many of the areas with greatest potential for new capacity are located towards the North West of the country and, as a result, are subject to many of the system capacity constraints placed upon incremental wind generation in Scotland. Hydro generation resources must also compete with wind for the attention of potential investors and developers, in a market where the latter technology is strongly positioned as the first choice for new renewable generation projects and both receive the same level of incentive from existing Renewables Obligation arrangements. Wind generation projects would also seem to offer certain advantages of scale not available in most situations where the potential for additional hydro generation exists.

Wind - Scotland's wind capacity has developed rapidly in recent years, supported by government energy policy and the UK's Renewables Obligation arrangements, and in terms of capacity will soon become the single largest source of renewable generation in the country. Scotland provides significant opportunities for wind farm developers, having both a good wind resource and large number of attractive sites.

However, suitable locations for wind farm developments tend to be located remote from centres of demand and as such future rates of development are likely to be, in part, determined by the availability of sufficient transmission network capacity and the ability of the grid system to provide physical connections to a large number of relatively small, isolated developments. The growth of on-shore wind capacity, as perhaps the cheapest and most accessible form of renewable power, is likely to represent a large majority of the Scottish generation sector's response to current renewable energy targets.

However, there is also scope for the development of offshore wind capacity and, in May 2008, the Crown Estate requested initial expressions of interest from companies wishing to be considered for developing offshore wind generation within Scottish territorial waters. Following an initial registration process, the Crown Estate invited interested parties to submit proposals for assessment. This process resulted in the receipt of 23 site applications from 14 organisations.

Prompted by such a high level of interest, the Scottish Government announced in October 2008 that they would conduct a Strategic Environmental Assessment (SEA) for offshore wind. It is intended that this assessment will ensure that Scotland's offshore resource is developed in a strategic and coordinated manner. The government has announced that it will prioritise completion of the process within one year.

Once it has completed its evaluation of submissions, the Crown Estate will grant successful applicants exclusive development rights to a given area, subject to a favourable SEA outcome, site specific environmental impact assessment (EIA) and statutory consents. The allocation of development rights is expected to occur in December 2008.

Biomass - Scotland's biomass capacity may be further divided into waste-derived landfill gas and dedicated biomass installations. In 2006, landfill gas accounted for around 78MW of installed capacity, with dedicated biomass making up the remainder. However, the balance was shifted somewhat in 2007 with the commissioning of a 44MW biomass plant at Stevens Croft. Biomass combustion is a recognised low/zero carbon technology and as such receives support under the Renewables Obligation.

In our Base Case forecast we predict some modest development of Scottish biomass capacity, with a tendency towards fairly small scale projects situated to take advantage of local fuel resources and by-products. We do not foresee any significant scope for large, i.e. >100MW, biomass developments with their likely dependence upon imported fuel supplies.

Marine - although the current level of generation from such sources is negligible, Scotland has also been identified as having significant potential for marine energy developments. The Scottish government has lent its support to the development of such marine energy technologies through the Marine Supply Obligation (MSO) and the foundation of the European Marine Energy Centre (EMEC). Furthermore, a framework for developing such resources has now been established: in September 2008, the Crown Estate outlined the application and consent procedure for wave and tidal energy projects in the Pentland Firth off Scotland's northern coast – the first UK marine power site to be opened up for commercial-scale development – and announced a goal of generating more than 700MW from marine developments in this area by 2020.

Nevertheless, it is Wood Mackenzie's view that wave and tidal energy remain very much in the pre-commercial stage of technology development. We anticipate that some small marine energy developments will begin generating electricity within the study period – such generation is incorporated within the "Other Renewables" category of our generation forecasts. In particular, the proposed banding of the RO and ROS are likely to drive forward marine energy investment earlier than would otherwise have been the case. However, the nascent nature of wave and tidal technologies, challenges associated with connecting offshore generating capacity to the grid, and expectations of high capital costs (roughly double those of onshore wind) suggest it is unlikely that a significant volume of marine generation will be connected to the system by 2020.

Development of Scottish Renewable Capacity

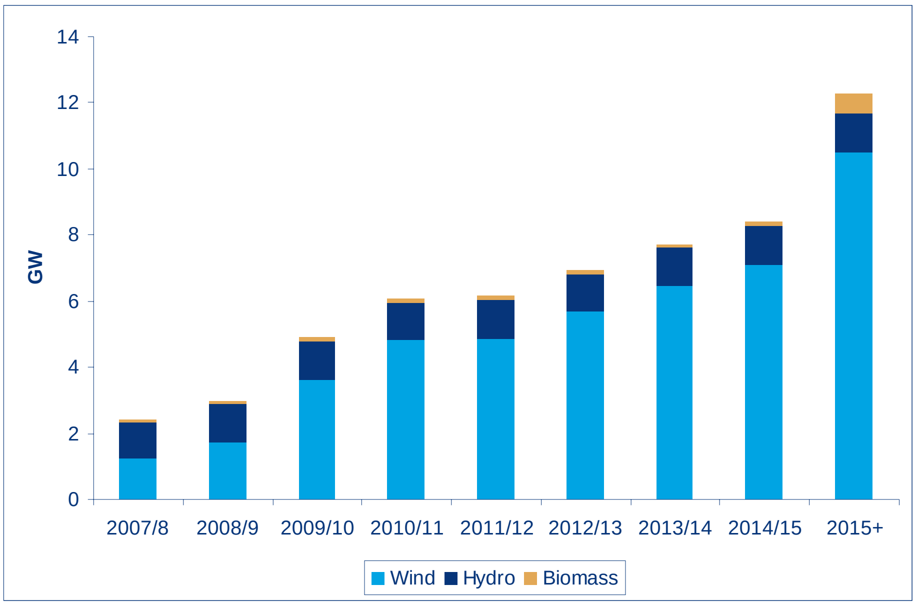
(MW)	2000	2001	2002	2003	2004	2005	2006	2008
Hydro	1320	1340	1354	1299	1307	1311	1330	1347
Wind	39	44	186	308	412	765	946	1208
Biomass & Others	32	39	55	69	91	101	120	181
Total	1391	1423	1595	1676	1810	2177	2396	2736

Source: Scottish Government & Wood Mackenzie

Current Developments in Scotland's Renewable Generation Base

Given the country's recent track record and distinct potential for growth in renewable energy sources, it seems undeniable that Scotland will play a significant role in the development of the UK's low-carbon generation fleet. To evaluate the possible extent of Scotland's role in the on-going development of the sector, the following data provides an overview of new capacity that is currently under construction, planned or proposed by developers. Whilst such data can be regarded as a snapshot of current market activity, the progression of individual projects cannot be guaranteed. However, it is felt that it does provide a reasonably good indication of the potential scale and scope of future developments.

Scottish Renewable Capacity with Grid Connection Agreements



(MW)	2007/8	2008/9	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015+
Wind	1231	1721	3635	4808	4885	5666	6453	7124	10500
Hydro	1116	1158	1158	1158	1158	1158	1158	1166	1172
Biomass	45	97	97	97	97	97	97	97	597
Total	2393	2976	4890	6063	6140	6920	7707	8386	12269

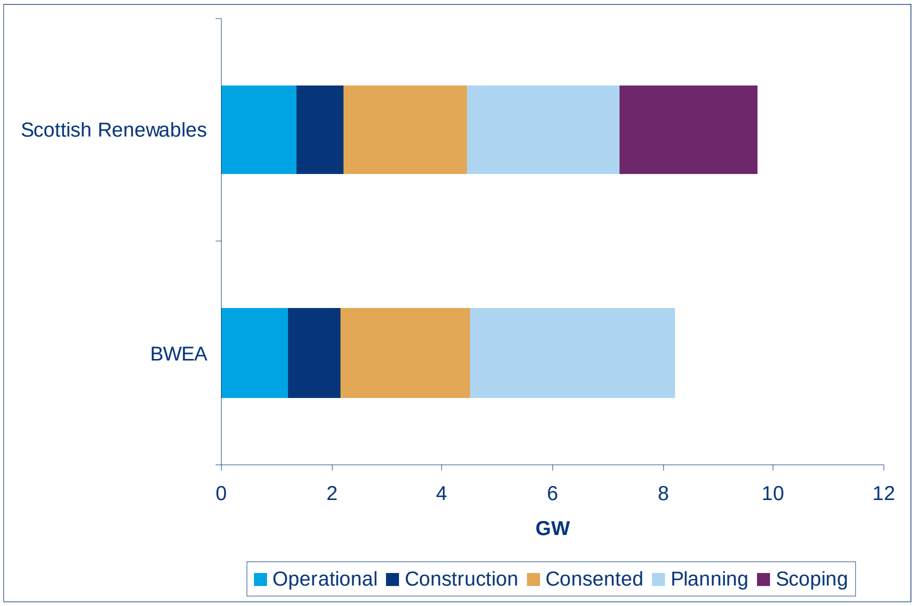
Source: National Grid, 2008 GB SYS (with May & August updates)
Note: Includes existing capacity

National Grid's 2008 GB Seven Year Statement (SYS) provides details of new generation capacity with contracts to connect to the high voltage transmission system. It reveals an expectation that Scottish renewable capacity will reach almost 8.8GW in 2014 and that connections occurring in 2015 and beyond (outside of the detailed scope of the current document) will increase this to over 12.6GW. Over 90% of the additional capacity in this view is wind generation, accounting for 9.6GW of the 10.2GW change. Of this prospective Scottish wind capacity all but 1GW is located onshore.

When considering transmission contracted generation capacity it should be remembered that there is no guarantee that the related projects will progress to the extent or within the timescales indicated. The investment plans of developers are subject to review from time to time and revisions of the plant data contained within the Seven Year Statement are made on a regular basis. However, the source remains a good general indicator of the level of prevailing market interest in particular technologies and locations.

Another means of examining the current appetite for renewable capacity build in Scotland, and the potential of wind capacity in particular, is to examine the quantity of new plant currently under development. The following chart, providing data from two different sources, provides an assessment of the amount of wind generation in Scotland that is currently operational or in the process of being developed. This information reveals that there is currently sufficient new plant in construction to raise wind capacity to over 2GW. This capacity increases to around 4.5GW if projects with planning consents are counted, between 7 and 8GW counting those at the planning stage, and potentially over 10GW including those in scoping. Scottish Renewables also refer to 1.2GW of projects currently under appeal, although that capacity has not been counted here.

Existing & Proposed Scottish Wind Generation - Capacity by Status



Source: Scottish Renewables & British Wind Energy Association

New Build Generation Economics

The relative economics of different generation technologies are influenced by raw material prices, operation and maintenance costs, fuel prices and, in the case of fossil-fuelled plants, emission costs. There is at present no clear choice between replacement base-load technologies on a cost basis alone; although in the wider European market we expect gas-fired CCGT to retain an advantage over coal due to the availability and maturity of the technology concerned, relatively low capital costs and lower carbon intensity. At lower carbon prices CCGTs begin to lose their advantage as coal technologies become more competitive.

The breakeven cost of new generation, as presented in the following data, plays an important role in determining the level of wholesale power prices. For instance, in a market which is capacity constrained the price of power will tend to rise to a level at which the addition of new generation becomes economic and hence provide developers with an incentive to invest. Differentials between wholesale market prices and the breakeven cost of alternative or emerging technologies (which in most cases are likely to be significantly more expensive than more commonly deployed sources), may also indicate the level of additional incentive or subsidy required to encourage the proliferation of certain preferred technologies.

New Build Economics by Technology

Currently a number of different new build technologies are competing in the market place. These can be broadly divided into proven technologies, such as thermal plant and nuclear, and emerging low carbon technologies, such as wind power and thermal (usually coal) plant with associated carbon capture and storage.

The economics of plant types vary as with the usual factors such as capital cost, fuel costs, operations and maintenance etc, but critically also with the future forecast price of CO2 in the ETS or successor schemes. Indeed, at present, the price of carbon is one of the major factors determining which technology is the least cost option. Although the European Commission has committed its support to the development to Carbon Capture and Storage (CCS) technologies and demonstration plants, and the UK Government has launched its own competition for the construction of a large (at least 300MW by 2014) scale post-combustion capture plant, the majority of European market interest in new coal developments remains focussed on plants which would be 'capture ready'. The timing and scale of any subsequent uptake of CCS technologies will be determined by the pace and success of technology development over the next 5 to 10 years, suitably strong price signals from the carbon market and sustained government support.

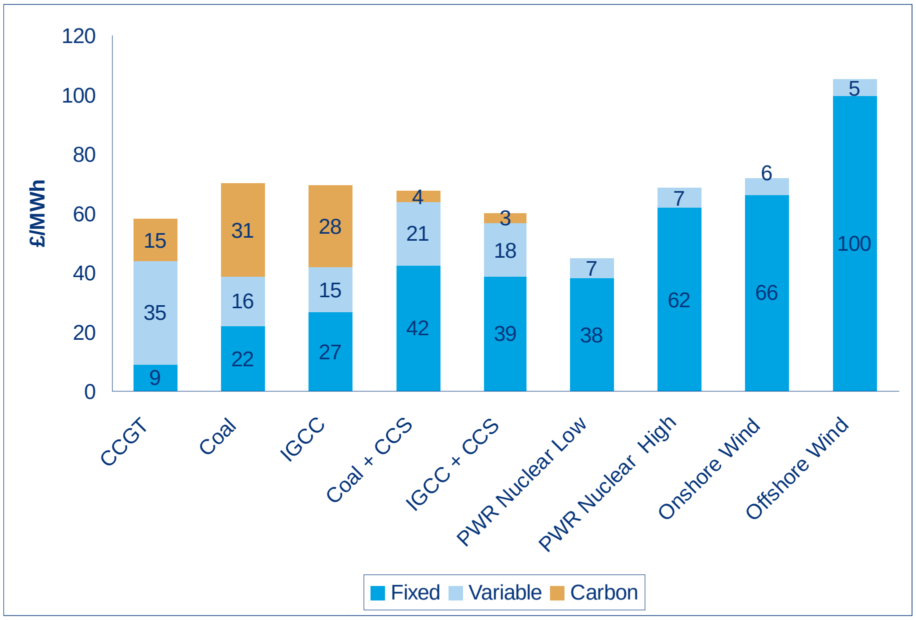
Although current policy rules out such developments in Scotland, we have presented high and low case views of the cost of new nuclear generation, based upon our estimate of the economics of the latest generation of Pressurise Water Reactor (PWR) technologies. The former estimate is intended to be indicative of the cost of projects likely to be delivered into the European market in the period to 2020, whilst the latter would be more representative of the lower cost and greater economies that could arise from a well established series of developments beyond that time.

Based upon our fuel and carbon price assumptions, as detailed in Appendix 2, the current least-cost source of applicable generation is gas-fired CCGT, followed by CCS equipped coal plants and then conventional (non-capture) coal. However, until CCS can be proven at a commercial scale in the power sector, we would remain cautious about the attractiveness of the technology as a solution to new build requirements.

Wind generation remains a relatively high cost generation source, although it should be remembered that its output is made more appealing by the additional value created by the Renewable Obligation Certificates that the source attracts.

In the particular case of generation new-build in Scotland, it is the country's location, support mechanisms and availability of natural resources that does much to determine the make-up of capacity additions, rather than the marginal cost of the generation being constructed.

LRMC of New Build Generation



Source: Wood Mackenzie

Breakdown of New Build Generation Costs

	Units	CCGT	Coal PF	IGCC	Coal PF + CCS	IGCC + CCS	PWR Nuclear Low	PWR Nuclear High	Onshore Wind	Offshore Wind
Fixed	£/MWh	9	22	27	42	39	38	62	66	100
Carbon	£/MWh	15	31	28	4	3	0	0	0	0
Variable	£/MWh	35	16	15	21	18	7	7	6	5
Total	£/MWh	58	70	70	68	60	45	69	72	105

Source: Wood Mackenzie

Power Demand - Historical and Forecast

The annual demand for electricity in Scotland currently totals around 42TWh with a peak load of 6.1GW, this compares to an overall UK demand of 404TWh and 65GW respectively. On an historical annual average basis Scotland accounts for around 10% of total UK demand. The within-year profile of Scottish power demand is largely determined by the relatively dark, cold days of winter and warmer, brighter days of summer.

A detailed breakdown of Scottish electricity consumption is not readily available although some high level statistics are published by the Department for Business, Enterprise and Regulatory Reform (BERR). In 2006, BERR data reveals that the Scottish domestic market consumed 12.1TWh of electricity, while demand from the commercial and industrial sectors totalled 17.5TWh. These demands represent around 10% and 9% of total GB demand in the respective sectors.

Average electricity consumption in the Scottish domestic sector was 4,494kWh per meter point, slightly above the GB average (4,457kWh) and 76,212kWh in the industrial and commercial sectors, below the GB average of 81,876kWh.

Wood Mackenzie's forecast of electricity demand is derived from overall UK consumption prorated to the Scottish market in line with historical demands. The following commentary provides a background to demand in each main sector of the UK market.

Domestic

The domestic sector in the UK has shown steady growth in electricity demand over the last twenty years. As the sector has matured there has been a marked switch away from primary fuels (with the notable exception of gas) to electricity. This trend is forecast to continue in the foreseeable future, supported by continued growth in the number of electrical appliances in the home. Although electricity does not compete favourably for space heating when compared to natural gas, other measurements of comfort such as lighting and use of electrical equipment have supported the growth of electricity demand.

We forecast that the use of electricity in the domestic sector will continue to grow steadily (averaging around 0.8% per annum) until 2015 and then slow slightly towards the end of our study period. This declining rate of growth will be driven by the continuing focus on climate-energy policy, including the role that end-user attitudes and behaviour can play in delivering improved energy efficiency. To further the achievement of its policy goals, the UK is committed to implementing EU energy policy relating to energy efficiency and consumer information, such as building and appliance energy labelling schemes. The advent of new technologies and practices, such as smart metering, may contribute towards easing demand growth rates, although in general, Wood Mackenzie does not anticipate any breakthrough technologies having a substantive impact on power demand during the study period.

Industrial

Power use in the Industrial sector has grown steadily over the last twenty years as the economy has matured, although year-on-year growth has fluctuated - much of this pattern may be related to the performance of the economy. In our view, demand for electricity in the sector will continue to grow, although an ongoing reduction in energy intensive industry will cause growth rates to be markedly lower than in the domestic or commercial/other sectors. Over the forecast period, we expect to see a gradual reduction in the use of other fuels (particularly more carbon intensive fossil fuels) in this sector, with this loss being replaced by electricity.

Industrial electricity demand current totals some 115TWh and we forecast that this will increase at an average rate of 0.6% per annum between 2008 and 2020, although this rate will decrease through time to an annual level of around 0.4% by 2020.

Commercial/Other

Over the last twenty years, as the UK has become increasingly de-industrialised, a greater part of the country's wealth has been generated in the commercial sector. This sector has relied heavily on electricity to provide its energy, and we forecast this trend to continue over the study period. The commercial sector is also a heavy user of air conditioning, leading to increased demand for electricity in the summer months and a flattening of the UK's seasonal demand shape. We forecast that demand in this sector will grow by an average 1% per annum between 2008 and 2020.

Energy Industries

Demand for power within the energy industries currently accounts for around 8% of gross UK electricity demand. This is expected to decrease slightly in the period to 2020. In absolute terms power demand within the energy industries sector is expected to be around 34TWh.

Losses

Losses currently account for around 8% of gross UK electricity demand and we do not expect this share to change materially during the study period.

Having considered the influences outlined above, and based on our expectations of future economic growth and incremental improvements in energy efficiency, our modelling of the demand for power in Scotland points towards a gradual slowing of growth over the study period. We forecast annual consumption to increase to 45.9TWh by 2020, a 9% increase on current levels of demand.

Forecast Annual Consumption of Electricity in Scotland

TWh	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Annual Consumption	42.0	42.4	42.8	43.2	43.6	44.0	44.4	44.7	44.9	45.2	45.4	45.6	45.9
Annual Growth (%)		0.8%	0.9%	0.9%	0.9%	0.9%	0.9%	0.8%	0.5%	0.5%	0.5%	0.5%	0.5%

Forecast Peak Demand for Electricity in Scotland

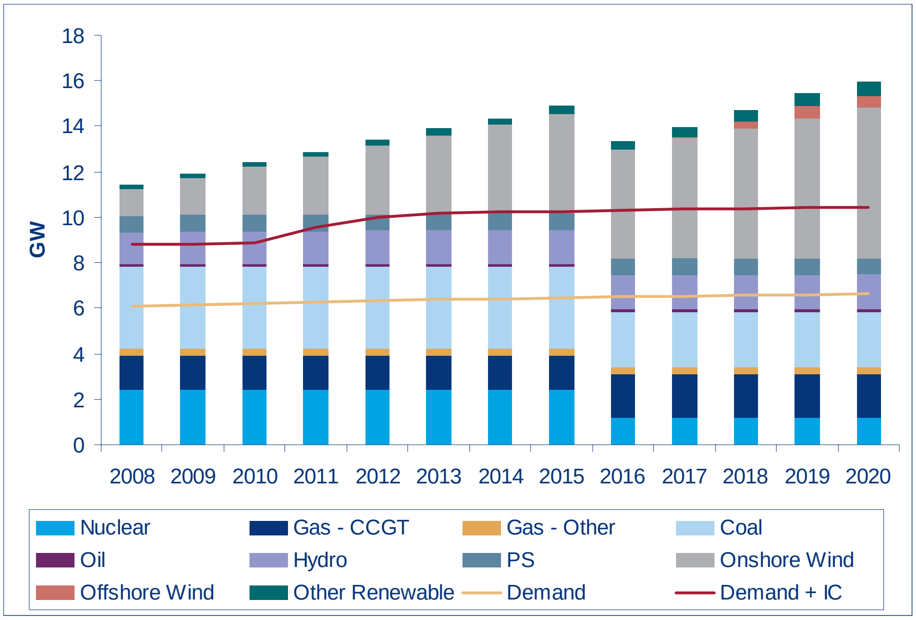
MW	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Peak Demand	6084	6134	6193	6250	6309	6366	6421	6470	6503	6537	6570	6603	6637
Annual Growth (%)		0.8%	0.9%	0.9%	0.9%	0.9%	0.9%	0.8%	0.5%	0.5%	0.5%	0.5%	0.5%

Source: Wood Mackenzie

Base Case Generation Forecast

Installed Generation Capacity

Forecast of Scottish Generation Capacity



Source: Wood Mackenzie
Note: IC refers to interconnector capacity with English and Northern Irish transmission networks

Our Base Case forecast of Scottish generation is defined by a marked loss of existing base-load capacity and strong development of onshore wind capacity. Onshore wind generation is predicted to increase by 5.4GW over the period, while offshore wind developments account for a further 500MW and other renewables, combining biomass, marine and hydro sources, around 650MW of additional capacity. In 2016, corresponding with the closure of Cockenzie and Hunterston, we also model the addition of a further 400MW of CCGT capacity.

This latter addition is assumed to provide a degree of flexible and responsive generation support to the system at around the time that a large quantity of older conventional plant (nuclear and coal) is to be withdrawn. There exists a degree of uncertainty around this addition because, at present, it has been some time since any potential developer has expressed an interest in developing such capacity in Scotland. In part, this may be down to the high cost of system charges levied upon Scottish generators and the existence of more attractive opportunities elsewhere in Great Britain. However, given the comparatively minor nature of the addition involved, we have chosen to reflect the possible development of such capacity as part of our Base Case view.

Capacity Margins

The capacity margin (or plant margin as it is also commonly referred to) is the amount by which the installed generation capacity connected to a system exceeds the peak demand placed upon it. Capacity margins are usually defined in terms of the amount of excess capacity available as a percentage of the prevailing peak demand.

A margin of spare capacity is required in all power systems to accommodate the inherent uncertainties of balancing the supply and demand of an energy source that is instantaneous in nature and lacks any appropriate means of storage. Therefore additional generation capacity must be available to accommodate unexpected supply interruptions (plant trips), forecast errors and rapid deviations in system load. When changes occur that influence the balance of generation and demand, the system operator, National Grid in the case of Scotland, will take steps to re-establish equilibrium and maintain supply security. The majority of routine short-term balancing actions taken by the system operator will lead to an increase or reduction in generation output.

A margin of spare capacity is also required to accommodate the general availability, maintenance and repair of generating plants and the transmission system.

The appropriate level of margin is dependent upon the characteristics of the power system concerned. The higher levels of certainty associated with short term forecasts of generation and demand means that, in most cases, security of electricity supply can be achieved with a lower plant margin. For example, an acceptable margin for real time operation may typically be of the order of 10%. Accordingly, an acceptable level margin employed for the purposes of longer term planning is likely to be significantly higher than the short term requirement.

In the liberalised electricity market of Great Britain there is no set standard for longer term margins, as the need for new plant is determined by market forces. If levels of margin are deemed to be too low, the market will place a greater value upon the output of available generation, until market prices rise to a point at which it becomes economic for new plants to be constructed. Alternatively, if the margin is too high, this will tend to depress market prices and may lead to the withdrawal of some capacity (on either a temporary or permanent basis).

In it's Seven Year Statement, National Grid provides an example calculation of planning margin, based upon an assumption of an 85% level of generation availability at the time of winter peak demands several years ahead. Under these circumstances, they point out that it would be necessary to plan to meet that peak demand with only 85% of installed generation. This would mean that an installed generating capacity equivalent to about 118% of the peak demand, i.e. 1/0.85, would be needed in order to meet system load. It is further mentioned that an additional allowance would be required for other factors, such as the risk that actual weather is more severe than the conditions assumed in the demand forecasting process.

National Grid also state that, in the past, large integrated power system utilities, e.g. the Central Electricity Generating Board in England and Wales, sought to achieve a plant margin of some 24% for long term planning purposes. At present, the overall GB plant margin is around this level.

The following chart provides a view of capacity margins in Scotland. The coloured areas represent the range of margin arising from installed generation with and without the contribution of intermittent wind generation (wind generation being counted at its full installed capacity at the top of the range and at zero at the bottom). Due to the interconnected nature of the Scottish system, with its ability to transfer power to England and Northern Ireland, margin has been calculated on the basis of Scottish demand alone (the higher or the two ranges shown) and Scottish demand plus maximum export capacity. Although, in the period beyond 2015, the second of these two measures predicts a range which becomes negative at lower levels of contribution from intermittent sources this does not give cause for concern, as in reality exports would be reduced to maintain local system security.

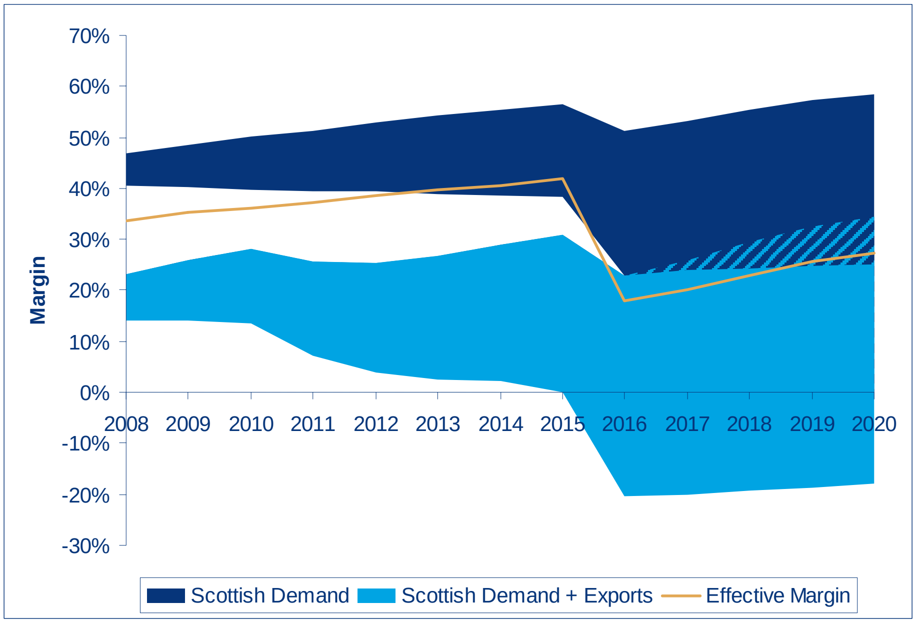
The influence of the anticipated loss of coal (Cockenzie) and nuclear (Hunterston) capacity in 2016 is quite clearly reflected in a marked reduction in the margin at that time.

It should be noted that the interconnector between Scotland and England is an integrated part of the wider GB transmission system and will routinely flow power in both directions, supplying power to the Scottish system as well as facilitating exports. Due to its configuration, the capability of the system to transmit power South to North is not as significant as in the opposite direction.

We have also calculated the Effective Margin arising from our Base Case forecast, taking into account the likely level of availability of each generation technology. For instance, the availability of large conventional thermal generation, coal or gas fired, may be assumed to be around 80 to 85% at times of peak demand, while renewable sources might typically contribute between 30 and 40%. For this assessment of margin we have assumed that onshore wind has a 30% availability and hydro 40%. For the margin shown here we also assume that there is a zero cross-border flow under peak demand conditions. Such an assessment of the predicted balance between supply and demand provides a more specific and insightful indication of the adequacy of the forecast plant mix and level of connected generation. Once again anticipated loss of capacity around 2015 is clearly marked.

Based upon these measures, and the level of integration with other networks, it is our assessment that the predicted level of generation capacity is more than sufficient to provide an adequate level of security of supply to Scottish consumers.

Installed Capacity Margin & Range of Intermittency

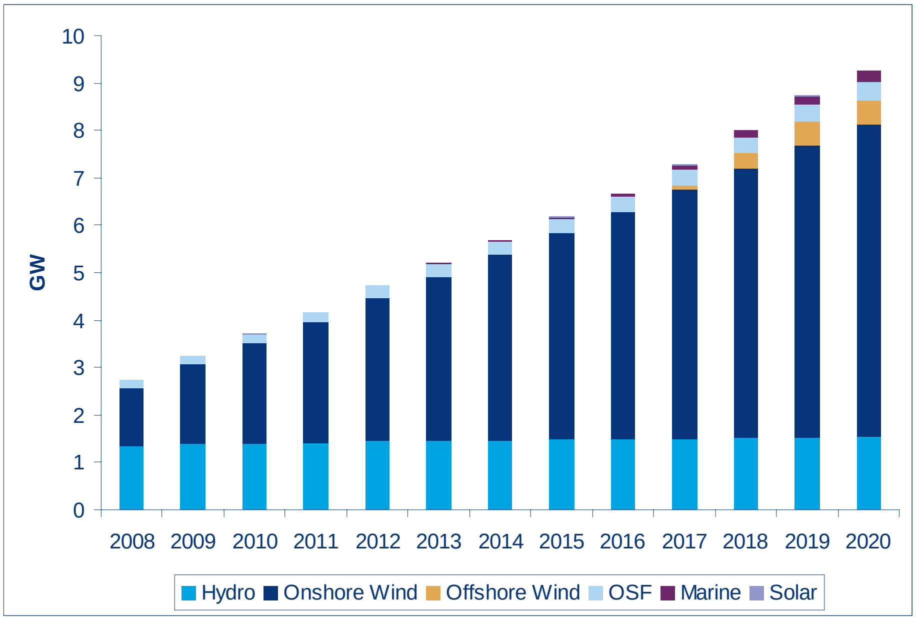


Source: Wood Mackenzie

Development of Renewable Generation Capacity

The Base Case assumes that onshore wind will form the major part of renewable capacity build in Scotland over the study period and that only limited quantities of other renewable sources will emerge in the country over this time. Although continued research and development funding will be put into alternative renewable sources, such as wave and tidal, it is our view that wind will play a very significant role in energy industry's response to Scotland's ambitious renewable energy targets.

Forecast of Renewable Generation Capacity in Scotland



Source: Wood Mackenzie
Note: OSF denotes Other Solid Fuels, including Biomass

The following table provides a comparison of our forecast of renewable generation capacity growth and the views put forward in the government's recent Renewable Energy Framework consultation document. As it can be seen, our Base Case forecast of onshore wind capacity development is consistent with the projection put forward by the government, as is our view of the growth of biomass, however we take a more cautious view of the potential for hydro, offshore wind and wave & tidal technologies.

In the Framework consultation document, it is noted that a level of uncertainty remains around the projection of renewable capacity whilst banding arrangements to vary the scale of incentives offered to particular technologies, under the proposed revision of the Renewables Obligation, are yet to be finalized. The following estimates from the Framework document are based upon an assumption that:

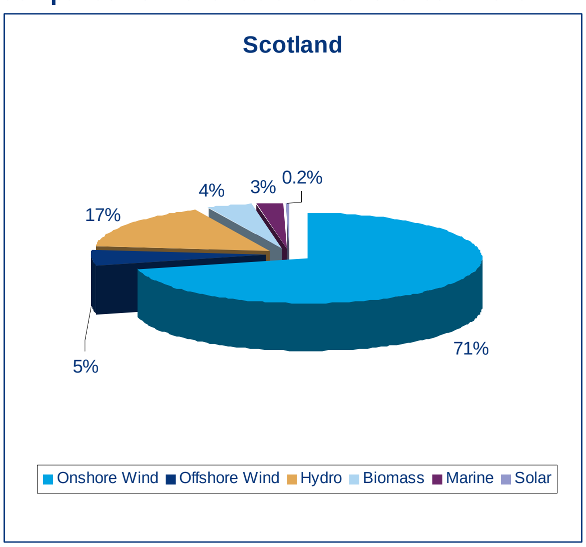
- appropriate financial incentives are in place;
- research and development is successful;
- grid access and availability improves; and
- projects move with reasonable speed through the planning system.

Comparison of Renewable Generation Capacity Forecasts

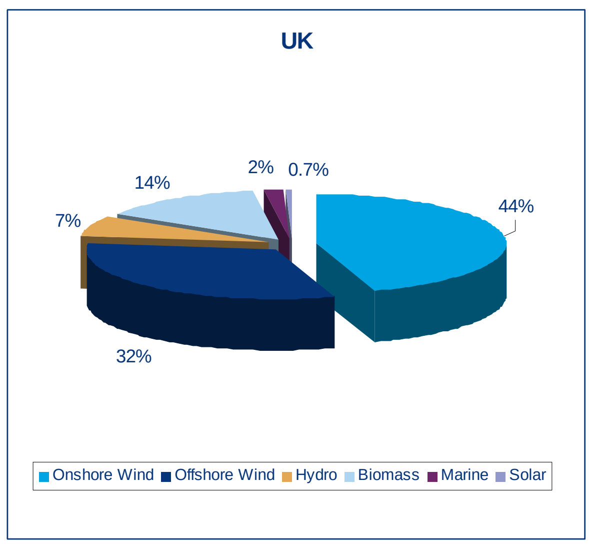
Technology	Current	Renewable Energy Framework 2020 Estimate	Wood Mackenzie 2020 Forecast
Hydro	1.4	2.1 to 2.4	1.7
Onshore Wind	1.3	5 to 7	6.6
Offshore Wind	0	1 to 4	0.5
Wave & Tidal	0	0.5 to 1.0	0.2
Biomass	0.04	0.2 to 0.4	0.4
Total	2.8	8.8 to 14.8	9.3

Source: Scottish Government & Wood Mackenzie

Comparison of Renewable Market Shares in 2020



Source: Wood Mackenzie



Source: Wood Mackenzie

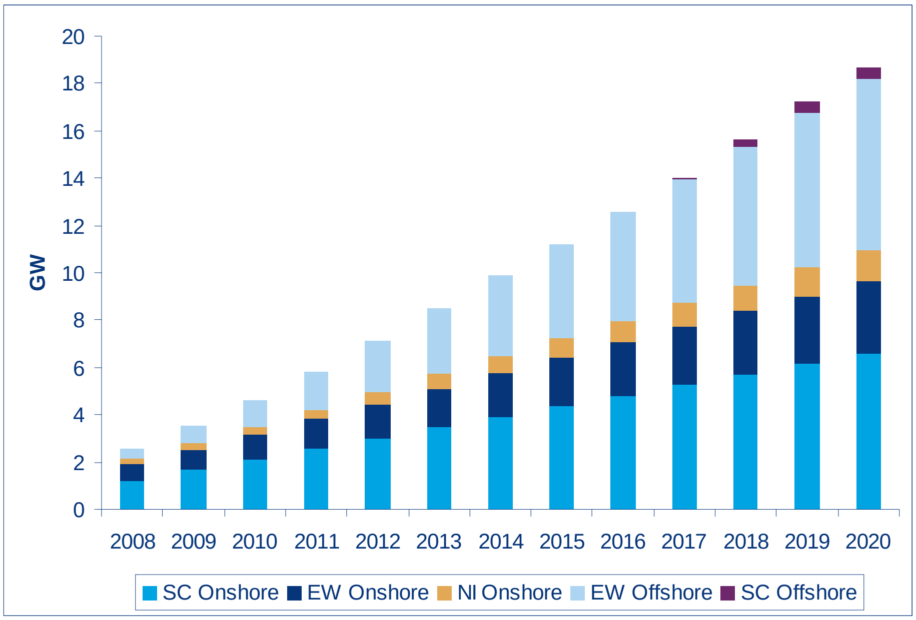
In our Base Case, onshore wind will form a far larger part of Scotland's renewable capacity build than elsewhere in the UK, with 2.3GW added in England & Wales and around 1GW in Northern Ireland. However growth in Scottish offshore wind, totalling 500MW during the study period, is relatively low in comparison to England & Wales where we foresee some 6.8GW of development. By 2020, capacity in Scotland accounts for around 60% of the total onshore wind installed in the UK and just over 35% of total wind (onshore and offshore) in the UK.

During our study period we assume that wind capacity additions in Scotland reach a peak rate of around 450MW per annum. Some slowing of this rate at the very end of the period is assumed as desirable sites become more difficult to acquire and the sector finds itself competing for equipment and investment in an increasingly active international market.

It is also our view that there will be a noticeable shift from onshore to offshore wind development in the UK during the period, as developers circumvent the planning issues associated with onshore wind projects by going offshore and take advantage of the greater flexibility this also provides to locate generation closer to demand centres in the southern part of England. Unfortunately, without the introduction of significant offshore transmission networks, offshore wind in Scotland will rely upon much of the infrastructure being used by onshore projects, and seems set to remain less attractive than developments further south as a result.

Total UK wind generation capacity is expected to reach 16.1GW in 2020.

Forecast of Wind Generation Capacity in the UK

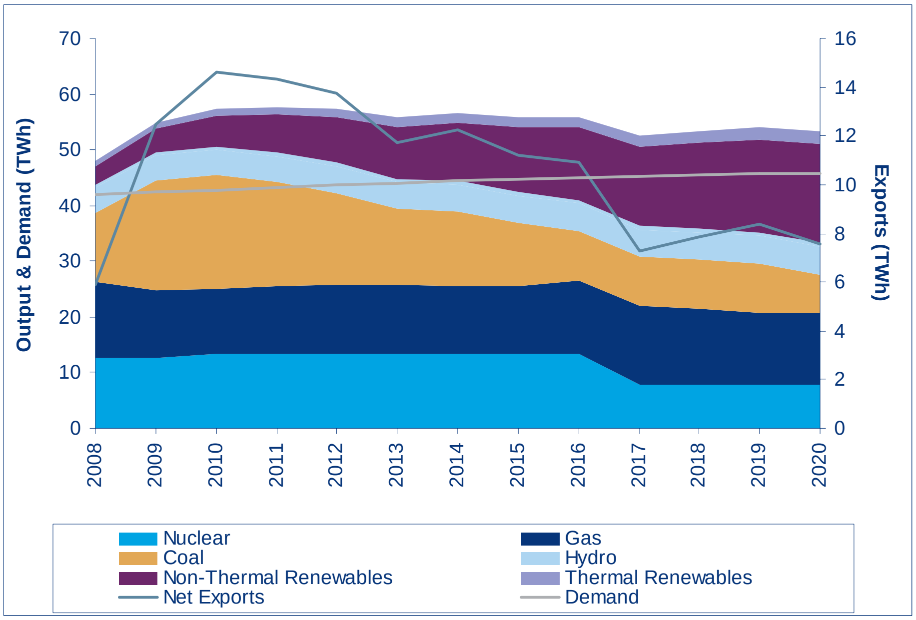


Source: Wood Mackenzie

The results of our dispatch modelling of the Base Case generation view suggests than the system would contain sufficient renewable capacity to meet the 50% in 2020 target, with the renewable share of Scottish demand standing at 55% in that year. In terms of total power produced, the renewable power share is 48%. Our analysis also reveals that the Scottish generation sector remains sufficiently competitive and well supplied to maintain the level of power transfers at a similar level to that recorded in recent years, around 10TWh per annum.

Generation Output & Exports

Generation Output by Source – Base Case



Source: Wood Mackenzie

With the exception of 2008, total generation remains in a range between 54TWh and 57TWh per annum. This relatively minor change, and overall slight reduction over time, occurs despite a 35% increase in total installed capacity and is testimony to the changing nature of the installed plant mix. As the share of intermittent renewable sources increases and plant closures occur, the overall load factor of the generation base is reduced. In the latter years of the forecast period the utilisation of conventional capacity begins to be impacted by the non-dispatched nature of renewable output, that is to say renewables provide power to the system whenever there is a sufficient resource, i.e. when the wind blows, at a variable cost close which is close to zero, and this displaces more expensive coal and gas plants.

In 2008, the expected level of generation output is somewhat reduced by lower levels of production from coal-fired generation, due to higher fuel prices and the outages necessary to complete FGD installation at Longannet. In the mid-term, output and transfers increase as new renewable sources are connected, but then fall back later in the period as nuclear and coal-fired plant is lost. Net export flows (some imports would also be expected to occur, although these are fairly minor in comparison) are a fundamental aspect of the Scottish generation-demand balance, with transfers to England and Northern Ireland acting as a spill for excess generation from the relatively well-supplied Scottish system. Variation in the volume of exports will also form an important part of the Scottish system's response to fluctuations in the level of contribution from intermittent sources, growing in importance as the capacity of such sources increases.

An Alternative Case for the Development of Scottish Generation

In order to consider the sensitivities of the Scottish generation mix and the potential for different outcomes arising from the current range of uncertainties facing the market we have compiled an alternative case for the development of generation. In this alternative view we have taken the opportunity to examine the scope for reducing emissions from the power sector in Scotland by utilising technologies to lower the carbon intensity of conventional thermal generation sources.

The key differences and drivers of change between the two cases may be summarised as follows:

- Wind capacity development does not occur at the rate predicted in the Base Case and a lower rate of capacity build occurs over the period. Onshore wind capacity additions peak at just under 250MW per annum and remain around this level throughout the period. Total installed wind capacity reaches 4GW (2.6GW less than in the Base Case) in 2020. No significant offshore wind developments occur.

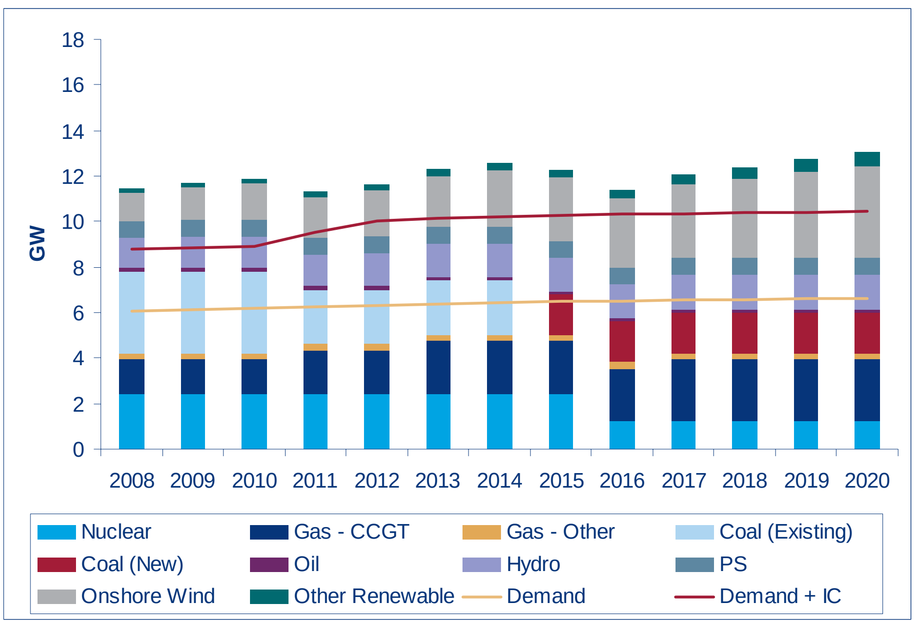
- Other renewable sources develop as in the Base Case.

- The LCPD opted-out coal plant at Cockenzie closes in 2011, in advance of the expiry of its limited hour derogation.

- The conventional coal-fired sub-critical steam plant at Longannet is replaced with a more efficient super-critical plant (higher pressure and temperature steam) in 2015, the capacity of the new plant is 1.8GW. The new plant is fitted with carbon capture equipment on a phased basis, with one 600MW unit fitted in 2015, one in 2017 and a third in 2019. This view of the adoption and development of carbon capture represents an ambitious and successful fast-track development of the technology.

- Three 400MW CCGTs are commissioned during the period, one in 2011, another in 2013 and a final one in 2017. Total CCGT capacity reaches 2.7GW.

Forecast of Scottish Generation Capacity – Sensitivity Case

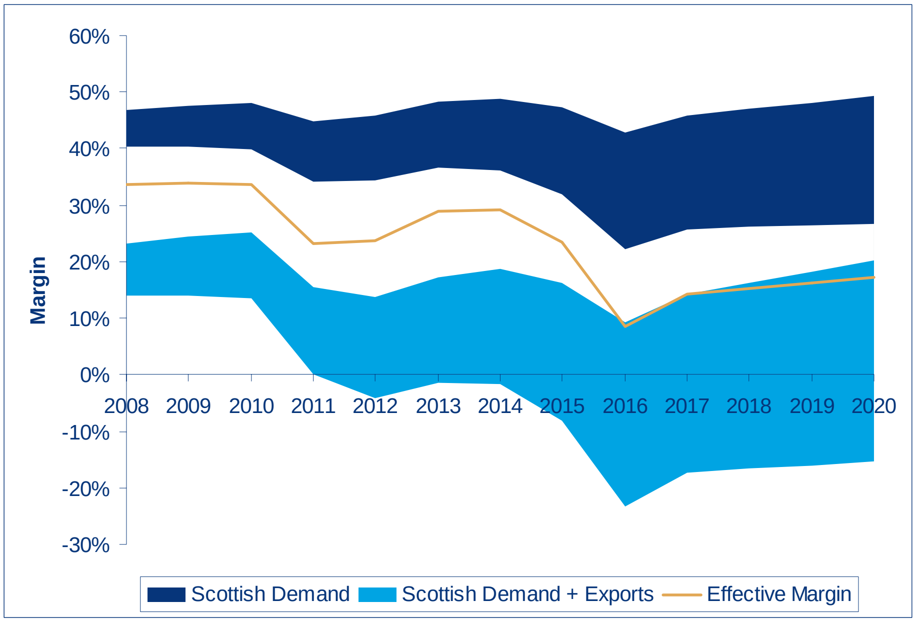


Source: Wood Mackenzie
Note: IC refers to interconnector capacity with English and Northern Irish transmission networks

Our assumptions relating to demand and transfer capacity remain the same as those made in the Base Case.

Capacity Margins

Installed Capacity Margin & Range of Intermittency

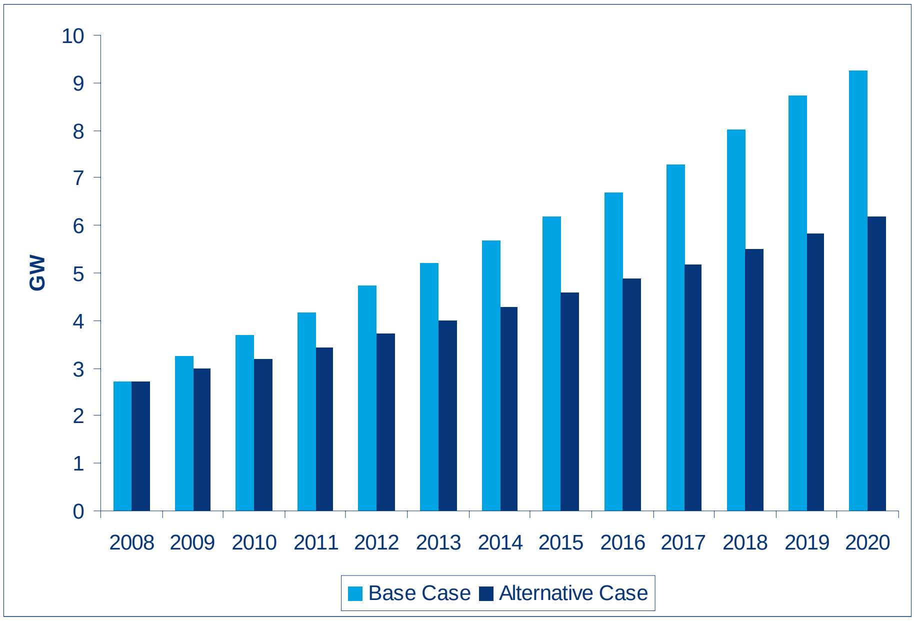


Source: Wood Mackenzie

Our Alternative Case suggests a view of margins which are generally lower than those in the Base Case. However, with less renewable capacity in the plant mix, the range of margin with and without the contribution of intermittent sources is somewhat reduced. The Effective Margin, derived using the same set of plant availability assumptions as used in the Base Case, reduces over time and tends to be more influenced by capacity losses in 2015 than the Base Case. Post-2015, after falling to below 10%, the level of the Effective Margin recovers to just below 20% as the capacity of gas-fired and renewable plants increases.

As in the Base Case, having taken into account the integrated nature of the underlying GB transmission system, it is our view that the Alternative Case provides an adequate level of security of supply to Scottish consumers. However, the level of excess generation capacity is lower than in the Base Case and, should longer term (post 2015) investments in new capacity not materialise as projected, the system would become more exposed to a potential tightening of the supply - demand balance.

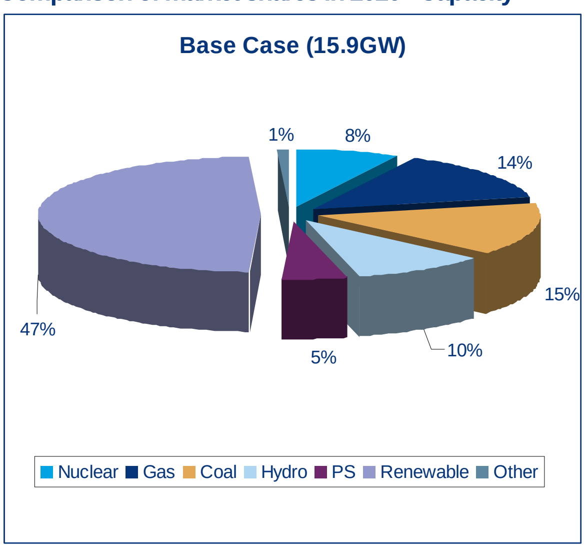
Comparison of Renewable Generation Capacity



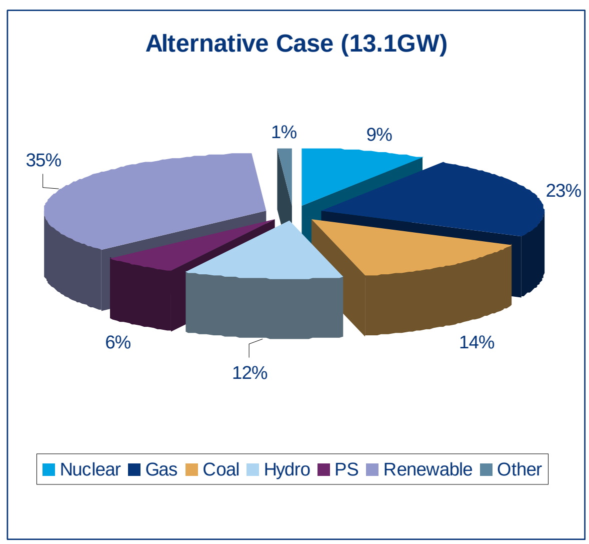
Source: Wood Mackenzie

In the Alternative Case, our revised assumptions about the development of installed wind generation deliver a total renewable capacity of around 6.2GW in 2020, about 3GW less than in the Base Case. Total installed capacity in 2020 is 2.8GW less than the Base Case, although the overall installed fuel mix is noticeably more diverse.

Comparison of market shares in 2020 - Capacity



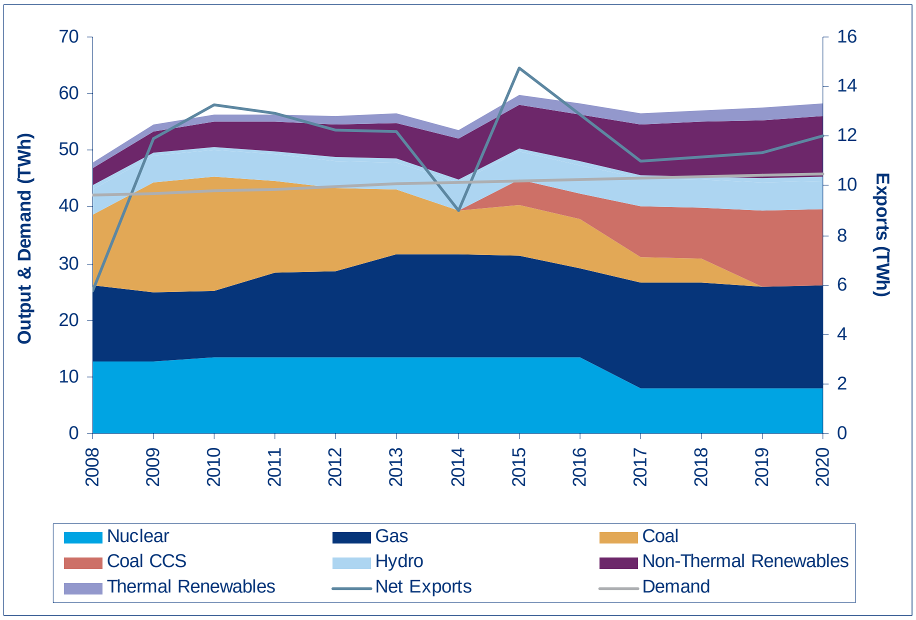
Source: Wood Mackenzie



Source: Wood Mackenzie

Generation Output & Exports

Generation Output by Source – Alternative Case



Source: Wood Mackenzie

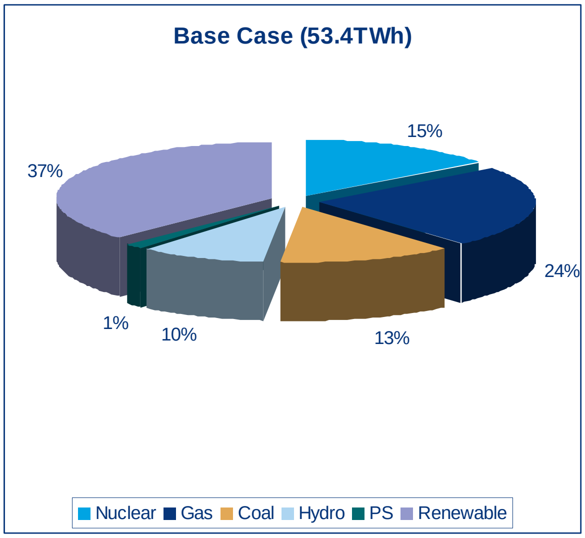
The Alternative Case is characterised by a higher proportion of base-load output from gas and coal plants, as might be expected given our assumed capacity additions over the period, and a higher level of exports.

In 2008, the forecast is influenced by the same LCPD-related constraints on the output of coal generation as detailed in the Base Case. From 2009 onwards, despite the lower level of installed capacity, exports average a little over 12TWh, 1.4TWh per annum above the average level of Base Case exports in that period. By 2020, output from gas and coal-fired plants accounts for nearly 55% of total generation. Due to our assumption of lower build rates, renewable energy supplies reach only 40% of Scottish demand and 32% of total generation in 2020 (down from 55% and 48% respectively).

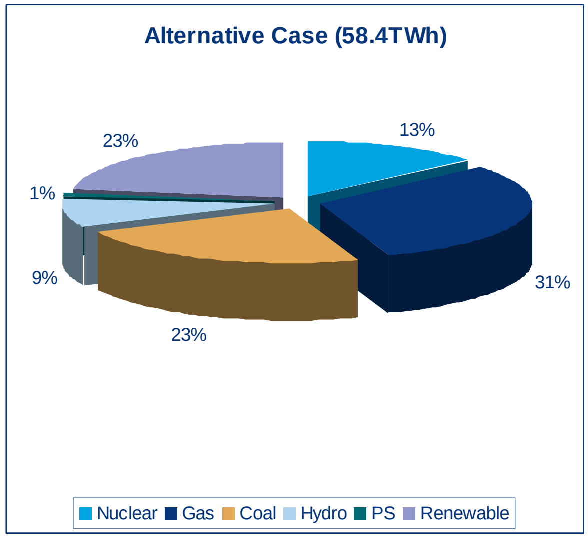
Due to our assumption of lower build rates, renewable energy supplies reach only 40% of Scottish demand and 32% of total generation in 2020 (down from 55% and 48% respectively).

The following charts provide a comparison of the fuel shares of power generation, in terms of a percentage of total output, in each of our cases in 2020.

Comparison of market shares in 2020 – Output



Source: Wood Mackenzie
Note: Shares expressed in terms of total generation output



Source: Wood Mackenzie

4 Contrasting the Generation Cases

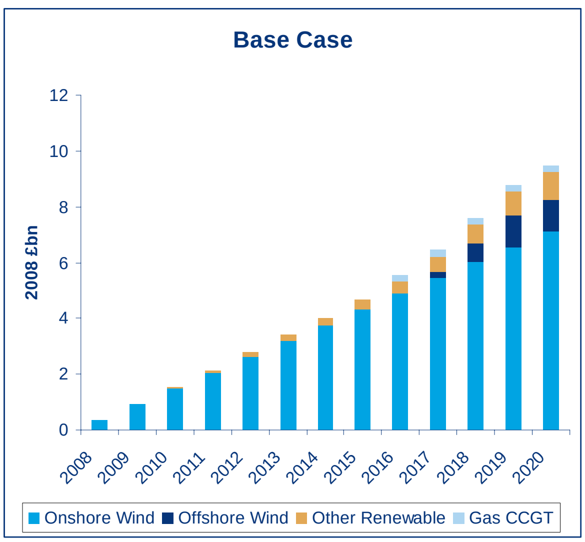
In the previous section we introduced two generation forecasts, the first a Base Case view focussed upon continued strong growth in renewable generating capacity, particularly onshore wind, with a sufficient level of development to satisfy Scotland's 2020 renewable generation target, and a second, our Alternative Case, with lower renewable build, greater take up of new gas and coal-fired generation and the introduction of carbon capture equipment. Both forecast cases provide sufficient generation to ensure continued security of supply in the Scottish market and the capability to transfer competitive surplus generation to neighbouring networks.

The following comparisons examine the investment, emissions and supply cost characteristics of each case.

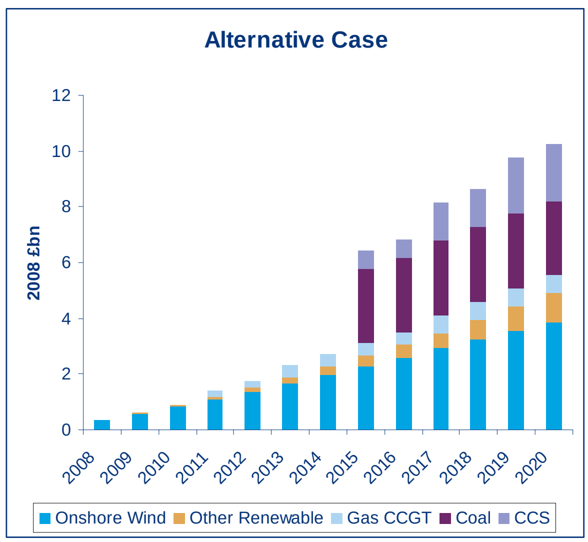
Capital Investment

Because of the different mix and quantity of new generation in our Base and Alternative Cases the two forecasts have very different investment profiles. Based upon our plant cost assumptions, as outlined in Appendix 2, in the Base Case there is a required spend of £9.5bn between 2008 and 2020. In the Alternative Case this investment requirement, including the cost of CCS equipment, increases to £10.2bn. In the Base Case, over 95% of the total investment is made in renewable capacity, while in the Alternative Case this share drops to 48%.

Comparison of Capacity Investment Costs



Source: Wood Mackenzie



Source: Wood Mackenzie

The higher capital costs associated with the Alternative Case could, on first inspection, be taken to suggest that a focus on investments in renewable energy would be a less expensive means of progressing the Scottish and UK governments' ambitions to develop a low-carbon economy, particularly when compared to an alternative focus on CCS investment. However, a consideration of the required capital costs of plant investment alone do not take into account the broader costs associated with particular generation technologies, most notably the cost of upgrading grid infrastructure to accommodate increased renewable generation capacity and the volume of projects located further away from centres of demand. The cost of grid investment to connect substantial new renewable generation could detract from the cost-effectiveness of this scenario. Similarly though, our plant cost assumptions in the Alternative Case do not make any specific allowance for the wider costs of carbon transport and storage infrastructure, which would push up overall capital investment requirements and break-even costs.

Furthermore, investment requirements during the study period also need to be balanced against broader impacts, such as resulting carbon emissions (discussed below), opportunities for local businesses, employment and the acceleration of technology development leading to lower costs over the longer term. As many of these factors fall outside the scope of this study, a separate and specific assessment would be needed to determine the broader economic impacts of the two generation cases presented here.

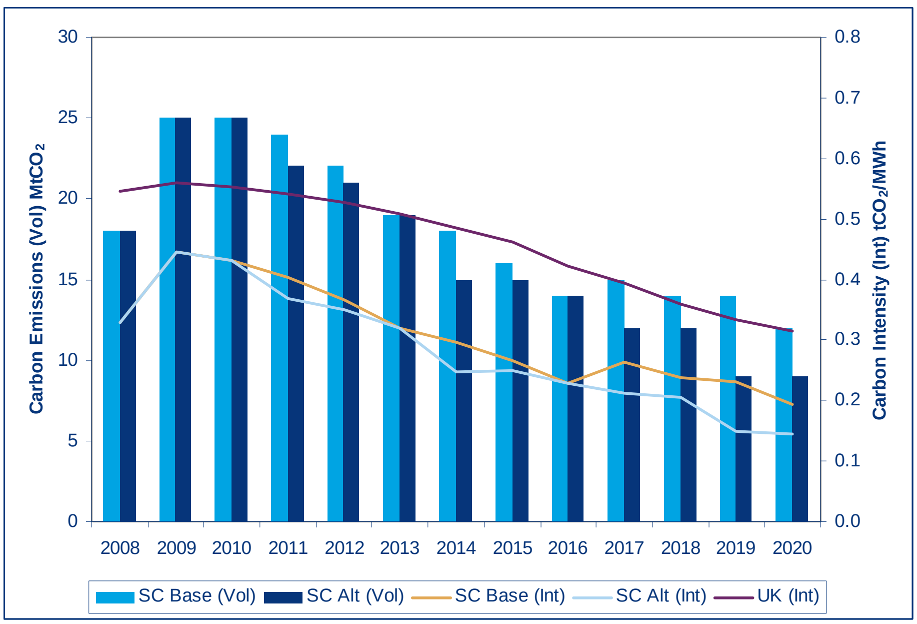
Carbon Intensity

Both forecast cases present views of Scottish generation with declining rates of carbon intensity, in the Base Case this is largely due to renewable generation displacing output from fossil fuelled plants, while in the Alternative Case emissions drop as output from existing coal plants is replaced by generation from new carbon-capture equipped coal generation and an increased utilisation of gas. In both views the carbon intensity, expressed in terms of tonnes of carbon dioxide emitted per MWh of power generated, of Scottish generation is significantly lower than that of the overall UK supply mix, around one third lower in the Base Case.

In terms of total emissions, the Base Case view is responsible for 236 MtCO2 over the study period, whilst generation in the Alternative Case emits 216 MtCO2, a reduction of 8%. Under the Base Case, annual emissions fall from 18MtCO2 in 2008 to 12MtCO2 in 2020, while under the Alternative Case annual emissions fall from 18MtCO2 in 2008 to 9MtCO2 in 2020. Although, due to the relative size of the Scottish market, the lower carbon emissions of the Alternative Case do not have a material impact upon the carbon intensity of the overall UK power mix and are therefore unlikely in themselves to have any material impact of the cost of carbon arising from the mechanisms of the EU's Emissions Trading Scheme (ETS). Further details of the ETS are provided in Appendix 1.

Applying our price forecast for emissions in Phase 3 of the ETS (€65/tCO2) suggests that the market value of the 20 million tonne reduction of carbon emissions in the Alternative case would be in the region of €1.3bn (£0.95bn).

Carbon Emissions and Carbon Intensity of Power Generation



Source: Wood Mackenzie

Power Prices and Cost of Supply Curves

So far, we have examined the installed capacity, output mix, investment requirements and carbon emissions of each of our forecast cases. However, to provide a comprehensive comparison of these alternative views of the development of Scottish generation, it is also necessary to consider the costs of power production in each case and the level of wholesale power prices that could arise as a result. On this final point, it is necessary to consider power prices in the context of the integrated GB market, which, for price setting purposes, draws no distinction between power produced in Scotland or elsewhere.

Our modelling reveals that the short run marginal cost (SRMC) of Scottish generation, that is the cost of producing the final unit of electricity necessary to meet demand (with generation being dispatched in order of ascending cost), in each of our cases is very similar. Although the installed generation mix in each case is different, the similarity between costs is not unexpected, as this reflects the level at which a balance exists between the economics of generation in Scotland and those of the wider UK system.

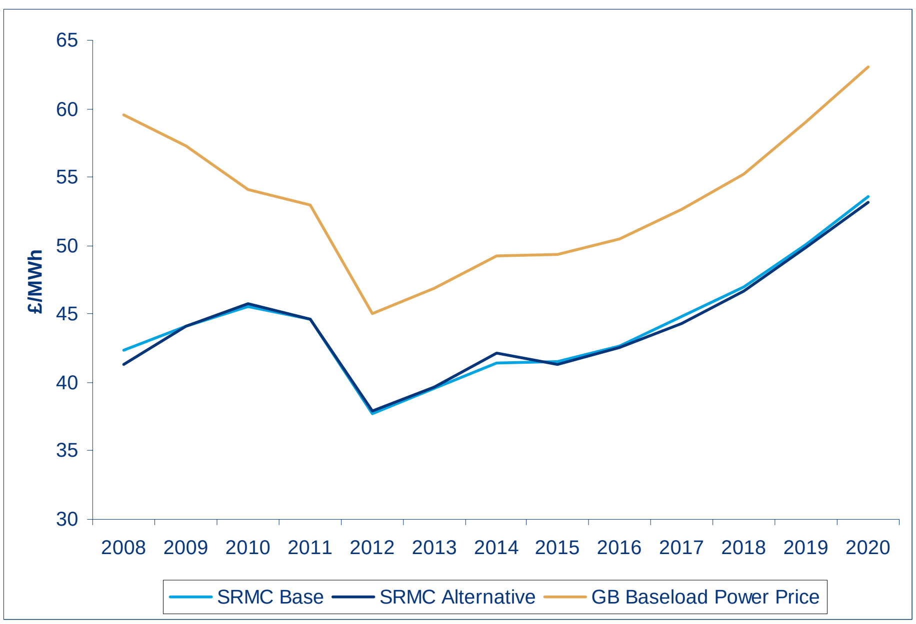
The profile of costs and price in the following chart largely reflect trends in associated fuel input costs and the degree of price uplift applied (on top of SRMCs) by the prevailing supply-demand balance of the GB market. The wider gap between the level of SRMCs and the base-load price at the beginning of the forecast period is indicative of our expectations of a premium being factored into wholesale prices to reflect capacity constraints arising from on-going works to bring opted-in coal plants into compliance with the emissions limits imposed by the LCPD and the extended outage of some nuclear capacity. As the availability of generation capacity is returned to more normal levels at the plants in question we expect this price uplift to dissipate. The low point of our price trends, occurring in 2012, reflects a point in time at which we foresee a combination of lower coal, gas and carbon prices.

What is important to bear in mind is that, although the SRMC in both cases is almost identical, the generation sector is more competitive in the Alternative Case, as the fossil fuelled element of the plant base is more efficient, leading to a total export flow during the period of 154TWh, 16TWh above the Base Case.

Although Scottish generation produces more electricity in the Alternative Case, the proportion of total GB power demand being met by output from Scottish plants is little changed, for instance in the Base Case view Scottish generation meets 12% of GB demand in 2020, while in the Alternative Case it meets 13% in that year. The influence of the larger GB market (as defined by existing electricity trading arrangements) and the Scottish generation sector's contribution to it, are factors that must be taken into account when considering the likely extent of any contrast between wholesale power prices that might arise between our two cases.

It is our conclusion that, due to the small change in generation output (in the context of overall GB demand), the wholesale electricity prices that would arise from our Base and Alternative Cases would not be materially different from one another. For this reason, in the following chart (and Appendix 2) we present only one projection of base-load power prices. Derived from this price forecast, the total value of the additional power exported to neighbouring systems in the Alternative Case during our study period is £1.1bn.

SRMCs of Generation & GB Base-Load Price Forecast (2008 real prices)

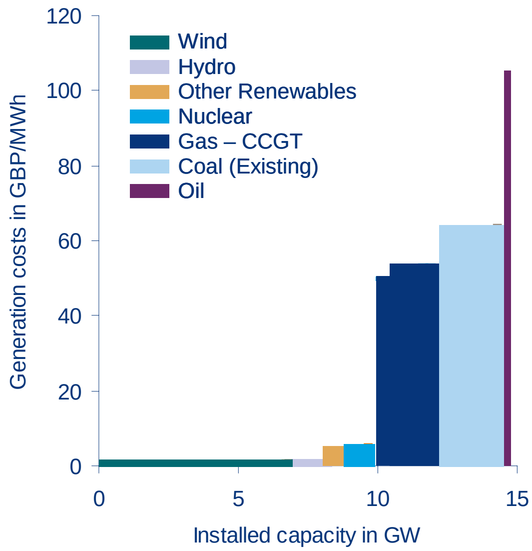


Source: Wood Mackenzie

The power supply curves in the following charts provide a view of the quantity and short-run cost of power from particular sources in each of our forecast cases. It is worth noting the large volume of low cost renewable output in the Base Case and the contrasting economics of gas and coal generation across views. In the Alternative Case, carbon capture allows coal-fired plant to take a position ahead of gas in the cost stack, our assumed cost of carbon in Phase 3 of the ETS would prevent conventional coal from doing this.

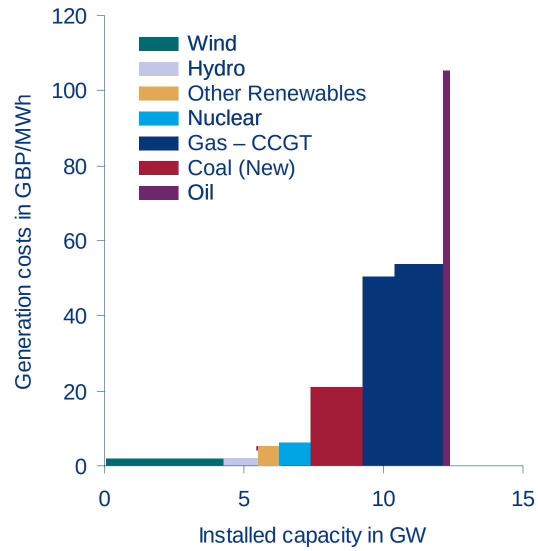
Power Supply Curves – Base & Alternative Cases

Base Case – Winter 2019/2020



Source: Wood Mackenzie

Alternative Case – Winter 2019/2020



Source: Wood Mackenzie

As with our analysis of investment costs, the above consideration of supply curves is not indicative of the broader costs that may be associated with particular generation technologies, most notably the cost of upgrading grid infrastructure to accommodate growth in renewable generation capacity and connections.

5 Conclusions

Our two forecast cases reveal that capacity changes in the Scottish power generation sector are likely to lead to a significant reduction in carbon emissions over the period to 2020. One means of achieving such a change is to increase renewable energy capacity, whilst the continued use of fossil fuels in conjunction with the installation of carbon capture and storage facilities also provides opportunities to reduce emissions.

Although Scotland's 2020 renewable energy target seems ambitious, our Base Case forecast indicates that it is achievable. However, even though our expectation of the development rate of wind capacity is well within the scope of currently consented or planned projects, the scale of the commitment required on the part of developers, grid companies and regulators should not be underestimated. Without a reliable long-term market environment, offering appropriate levels of incentive, in which developers are able to bring forward projects (through planning and connection processes) in reasonable timescales, Scotland will fail to attract the investment required to maintain the forecast level of renewable build.

The rate of renewable build in the Base Case relies upon the provision of sufficient transmission capacity, which itself will require significant capital investment, although our assumed additions can be accommodated within the expanded Scottish system (and wider GB network) as outlined in previously published investment and capacity studies (however this does require the associated capacity to be situated in suitable locations). Still, the grid upgrade requirements associated with a greater reliance on geographically dispersed renewable energy sources will add to the overall cost of the Base Case. It is also essential that a suitably flexible and responsive network connection regime is put in place and on-going work on the Transmission Access Review and GB Security and Quality of Supply Standard (SQSS) are encouraging in this respect.

The progress of transmission system expansions, such as the Beauly – Denny project, will be key to the Scottish system's ability to continue to accommodate growth in renewable generation capacity. Any delay in the realisation of such investments could temporarily sterilise the development potential of large areas of the country, which might otherwise provide suitable sites for new generation. At worst, should one or more of the current group of proposed system developments fail to develop, this could severely restrict Scotland's renewable energy potential. Although alternative, less visually intrusive system reinforcement options might exist, they remain, at present, prohibitively expensive.

In the Base Case, there is still sufficient conventional plant connected to the system to ensure an adequate reserve margin at all times and maintain transfers to neighbouring systems. However, such capacity will tend to see its load factor eroded by growth in renewable output. In the course of the study period we would not anticipate the provision of back-up capacity, required to provide adequate levels of support to intermittent sources of power, to present a problem in Scotland. However, it would be reasonable to assume that, as the renewable share of the market increases, the costs of system balancing will rise.

The Alternative Case, based around the extensive development of more efficient, low carbon, fossil-fuelled power sources, provides a second plausible view of the long term development of the Scottish generation mix. It is worth noting however that CCS technologies are yet to be proven at a commercial scale in the power sector and the feasibility of such additions will rely upon the success of on-going research and development activities. The UK's own CCS aspirations, and related Government sponsored competition, are well timed in respect to our assumptions in the Alternative Case.

Taking into account the current stage of its development, current estimates of the costs and lead times of CCS must be regarded as being subject to an unavoidable degree of uncertainty. If CCS cannot be delivered at reasonable cost, and here it also becomes necessary to consider the infrastructure required to transport and store captured gasses, then the comparison we draw between the Base and Alternative Case would require further consideration. However, given the clear potential for CCS in Scotland, it is our conclusion that the Alternative Case presents a worthwhile assessment of the scope for such technology and, even if commercial deployment were to slip to beyond 2020, the possible benefits of its introduction.

Comparison of the two forecast cases reveals that our Alternative Case presents a view of Scottish generation that would require a greater capital investment in new plant than is necessary to deliver current renewable energy targets, although both forecast cases suggest a far greater financial commitment to new power generation in Scotland than has been made in recent years. However, it is important to note that both cases will incur costs in addition to the necessary investment in new capacity, such as investments in network upgrades and carbon transport and storage facilities. From a broader economic and policy perspective, other factors, including the impacts on employment, local business opportunities, carbon emissions and energy security, may also be relevant considerations.

Nevertheless, of the two views presented, it is the Alternative Case that emits less CO2 and puts Scottish generation on a more competitive footing in the wider GB power market. The value that we attribute to this emissions saving and increased output, more than offsets the greater up-front costs. Over the study period the estimated benefit of the Alternative Case amounts to £1.35bn.

Although, as a result of this cost benefit, the Alternative Case seems the more attractive, in reality it is likely that a balanced combination of renewable technologies and less carbon intensive fossil-fuelled sources would provide the optimum mix of Scottish generation, in terms of the cost, competitiveness, security and diversity of energy supply. A broad based mix of new generation technologies would also seem to offer Scotland a more attractive opportunity to develop the specialist skills, experience and capabilities that will be very much in demand as first European and then global power markets move increasingly towards lower carbon sources. Although it is not a feature of the forecast cases presented here, it is our view that nuclear power should be considered as a potential part of the longer term generation base in Scotland. However, it seems very unlikely that any development of nuclear generation in Scotland would deliver new capacity before 2020.

Although this study is limited to the period up to 2020, there are certain key issues beyond that time that are likely to have a significant impact on Scottish power generation. Of particular relevance to the material we present here is the potential further loss of base load generation, specifically nuclear and coal-fired plant closures that may occur in the period between 2020 and 2030, and the possibility that this could give rise to a generation shortfall. The timing of such losses is likely to be influenced by the performance, condition and economics of the plants concerned and is therefore subject to a number of uncertainties. However, the seemingly inevitable retirement of at least one large plant will give rise to a significant change in the Scottish market, triggering the addition of new base load generation or a much increased reliance upon supplies imported from neighbouring systems. If Scottish demand is to continue to be served by Scottish generation, it is highly likely that new base load capacity will be needed and, in addition to the technologies we consider in the forecasts presented in this report, new nuclear generation could represent a viable option at this time.

Appendix 1: EU Emissions Trading Scheme and the Carbon Market

The modelling of carbon prices arising from the EU Emissions Trading Scheme (ETS) forms an integral part of our power dispatch modelling. The following notes provide a high-level overview of the Scheme.

The ETS is the world's largest functioning greenhouse gas trading scheme and from its introduction involved over 11,400 installations, representing around 45% of the total CO_2 emissions of the EU25. The scheme is based on a 'cap and trade' type arrangement, under which participants are obliged to surrender sufficient allowances to cover their emissions of relevant gasses, at present only CO_2, or pay a penalty at the end of each 12-month trading period.

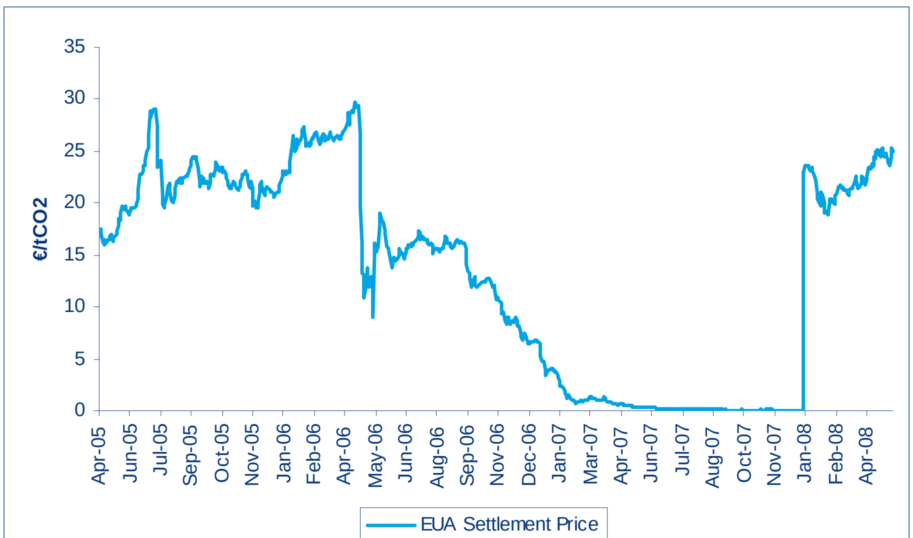
The ETS comprises of three distinctive phases, covering the following periods:

- Phase 1: 2005 to 2008 (inclusive calendar years)
- Phase 2: 2008 to 2012
- Phase 3: 2013 to 2020

The behaviour of EU Emissions Allowance (EUA) prices under ETS has been and is likely to continue to be, a source of considerable uncertainty. During Phase 1 prices opened at very low levels in January 2005, although there followed an extended period when carbon prices appeared to be fairly logically driven by the price differential between coal-fired and gas-fired power generation (and thus providing a measure of the carbon abatement cost within the power generation sector).

However, carbon prices collapsed in late April 2006, following the announcement that emissions in 2005 had out-turned at a level significantly below the expectations established by the National Allocation Plans (NAPs) of the nations participating in the scheme. Significant movements in price also occurred during 2007, with carbon trading at below €1/tCO2 for much of the final year of Phase I. The commencement of Phase II saw carbon prices increasing to the range €20-€25/tCO2, with forward prices for EUAs currently trading at around €23-€27/tCO2 (2012).

Historical Carbon Prices



Source: ECX, Historical Data 2008

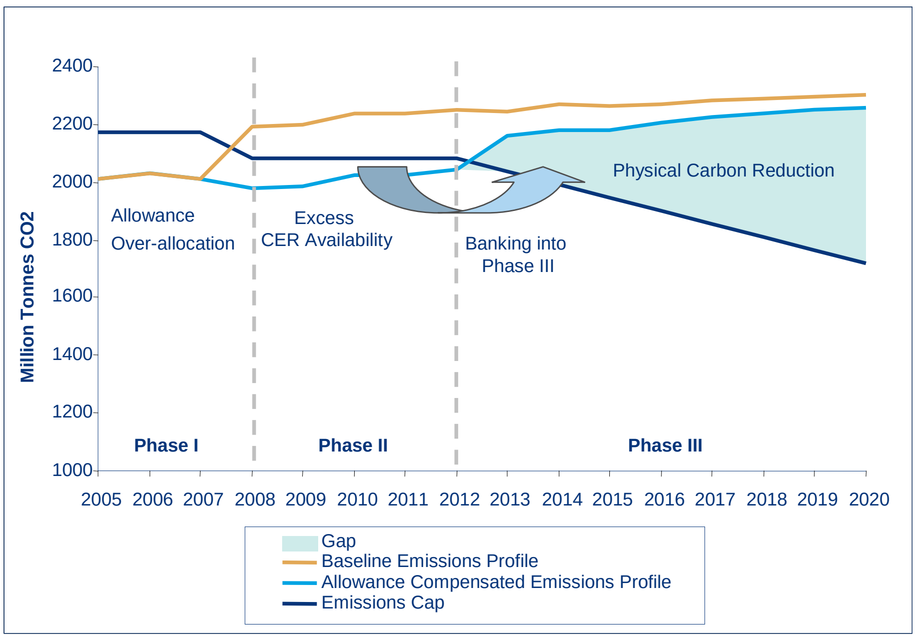
The carbon price change between Phase I and II has been driven partly by European Commission actions to ensure that member states deliver tighter NAPs and also by the proposed Phase III regime which will provide the capability to bank EUAs during Phase II for subsequent use in Phase III of the scheme. Overall use of alternative carbon credits in Phase III, specifically Certified Emissions Reductions (CERs), is expected to be far more limited than in Phase II, this is in part due to the anticipated carryover of banked EUAs from the earlier phase.

In contrast to Phases I and II, the proposed Phase III regime will not feature country specific emissions targets. These targets, previously detailed in the NAP for each member state, will be replaced by an EU-wide emissions reduction target. Exactly how the emissions reduction burden will be shared among the member states is not yet clear, although the EU Commission expects that emissions allowances will be allocated on the basis of fully harmonised rules.

The proposed Phase III regime will also introduce a significant change to the methodology by which emissions allowances are allocated. Whilst free allocation of the majority of emissions allowances has been a feature of Phase I and II, the European Commission believes that auctioning should be the basic principle for allocation of allowances from Phase III onwards. The power generation sector could face full auctioning of emissions allowances from 2013, while other industrial sectors, including aviation, will ramp up to full auctioning by 2020, with some probable exceptions.

In addition to the fact that Phase III is likely to see a move to emissions allowance auctioning, another key factor is the reduction in the EU ETS CO2 emissions target. The EU ETS target is to achieve a 20% reduction of CO2 emissions, relative to 1990 levels, by 2020. Phase I and Phase II will have a minimal impact on actual CO2 emission reductions due mainly to over-allocation of allowances (Phase I) and increased usage of alternatives such as CERs in Phase II. However, the combination of emissions allowance auctioning, restricted use of alternatives such as CERs and a much tighter emissions cap is likely to ensure that a physical reduction of CO2 emissions will be achieved during Phase III. Wood Mackenzie's forecast of emissions levels in the period to 2020 are set out below.

EU ETS CO2 Emissions Target



Appendix 2: Base Case Fuel Price & Power Generation Cost Assumptions

Fuel & Carbon Price Assumptions (2008 Real Terms)

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Oil	$/bbl	107.0	90.7	94.0	83.5	78.5	73.5	70.0	70.0	70.0	71.0	71.5	72.5	73.5
Coal	$/mmbtu	4.86	4.17	3.39	3.09	2.86	2.70	2.58	2.56	2.57	2.59	2.60	2.58	2.73
Gas	$/mmbtu	10.7	10.4	10.1	9.5	8.2	8.2	8.2	8.0	7.9	8.1	8.3	8.7	9.0
	p/therm	54.5	53.3	51.8	48.7	42.3	42.0	42.2	41.2	40.6	41.6	42.6	44.5	46.0
Electricity (Base-load)	£/MWh	59.4	57.7	58.5	58.4	50.6	51.3	53.1	54.0	55.1	57.8	61.9	68.3	78.0
Carbon	€/tCO2	33.0					65.0							

Source: Wood Mackenzie

New Build Economics by Technology (2008 Real Terms)

Plant Details	**Gas CCGT**	**Coal PF**	**Coal IGCC**	**Coal PF with CCS**	**Coal IGCC with CCS**
Gross Capacity (MW)	450	600	450	500	500
Gross Efficiency (HHV)	50%	40%	45%	30%	37%
Load Factor	85%	85%	85%	85%	85%
Economic Life (years)	25	40	40	40	40
Discount Rate (WACC)	10%	10%	10%	11%	11%
Overnight Capital Cost (£/kW)	500	1275	1550	2150	1925
Construction Time (years)	3	4	4	4.5	4.5
Total Cost (£m)	248	888	809	1302	1166
Total Fixed Costs (£/MWh)	**9.0**	**22.1**	**26.6**	**42.3**	**38.7**
Gross Fuel Price (HHV) ($/mmbtu)	8.6	2.9	2.9	2.9	2.9
Gross Fuel Cost (£/MWh)	31.7	13.4	11.9	17.8	14.5
Total Variable Costs (£/MWh)	**34.8**	**16.4**	**15.2**	**21.4**	**18.0**
Carbon Price (€/tCO2)	50	50	50	50	50
Emission Factor - Fuel Input (tCO2/MWh)	0.2	0.3	0.3	0.3	0.3
Emission Factor - Power Output (tCO2/MWh)	0.4	0.9	0.8	0.1	0.1
Carbon Cost (£/MWh)	**14.5**	**31.3**	**27.8**	**4.2**	**3.4**
Break Even (£/MWh)	**58.3**	**69.8**	**69.6**	**67.8**	**60.1**

Source: Wood Mackenzie

Plant Details	**Nuclear PWR Low**	**Nuclear PWR High**	**Onshore Wind**	**Offshore Wind**
Gross Capacity (MW)	1600	1600	80	250
Gross Efficiency (HHV)	33%	33%	100%	100%
Load Factor	85%	85%	30%	33%
Economic Life (years)	50	50	30	25
Discount Rate (WACC)	11%	11%	10%	10%
Overnight Capital Cost (£/kW)	1600	2500	1200	2000
Construction Time (years)	6	8	2	3
Total Cost (£m)	3376	5929	101	552
Total Fixed Costs (£/MWh)	**38.1**	**61.8**	**66.1**	**99.7**
Gross Fuel Price (HHV) ($/mmbtu)	0.8	0.8	0.0	0.0
Gross Fuel Cost (£/MWh)	4.5	4.5	0.0	0.0

Plant Details	Nuclear PWR Low	Nuclear PWR High	Onshore Wind	Offshore Wind
Total Variable Costs (£/MWh)	**6.7**	**6.7**	**5.8**	**5.3**
Carbon Price (€/tCO2)	50	50	50	50
Emission Factor - Fuel Input (tCO2/MWh)	0.0	0.0	0.0	0.0
Emission Factor - Power Output (tCO2/MWh)	0.0	0.0	0.0	0.0
Carbon Cost (£/MWh)	**0.0**	**0.0**	**0.0**	**0.0**
Break Even (£/MWh)	**44.8**	**68.5**	**71.9**	**105.0**

Source: Wood Mackenzie
Note: Fuel & carbon costs based upon average forecast values over the 2010 to 2020 period, calculations assume a currency conversion rate of US$1.95 to £1

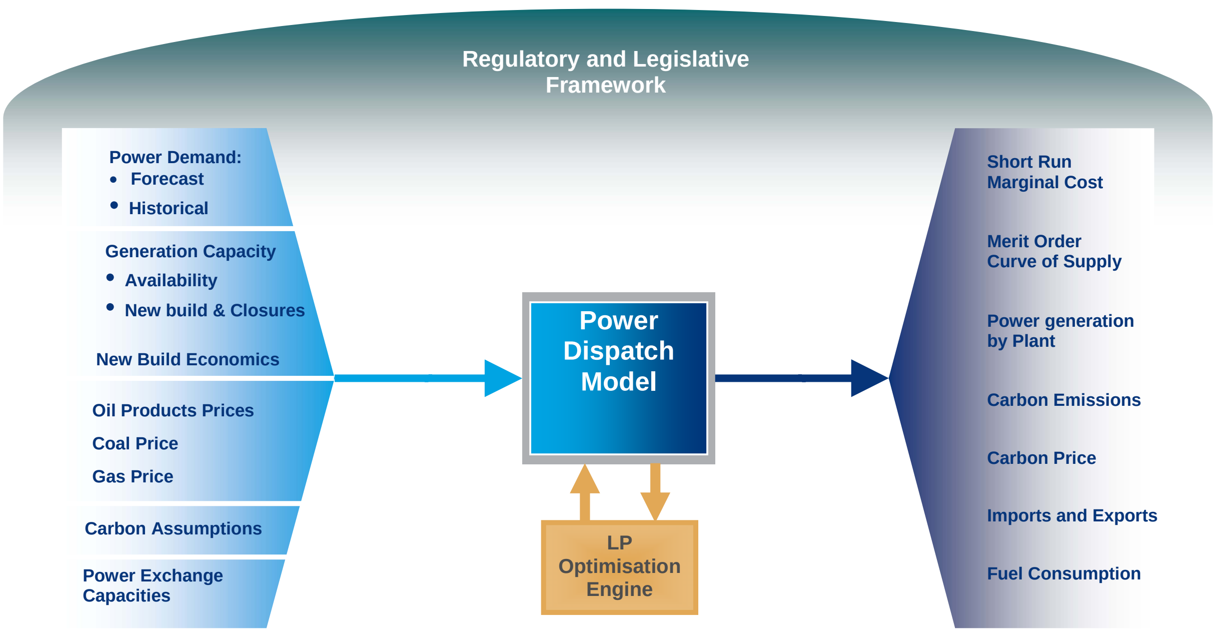
Appendix 3: Overview of European Power Model

Wood Mackenzie's integrated analysis of European electricity markets, from which the analysis presented in this report has been taken, is based upon our proprietary European Power Model (EPM), which uses linear programming to analyse the power market on a minimum cost optimised basis.

For each year of an analysis the EPM compiles a monthly merit order of generation plant by country, taking into account such factors as fuel cost, conversion efficiency, operational constraints and carbon emissions. The calculated cost of supplying power includes not only fuel prices and other plant specific items, but also the cost of complying with the emissions constraints imposed by the European Emissions Trading Scheme.

Whilst the main objective of the model is to meet prevailing power demand at minimum price, it is also capable of incorporating constraints due to; monthly/within day availability of single/multi-fuelled generators, monthly/within day availability of interconnectors; annual emissions limits; and monthly/annual fuel-type limits.

The diagram below provides an overview of the inputs and outputs of the EPM.



Glossary

Alternating current (AC): An electric current whose direction reverses cyclically, as opposed to direct current (DC), whose direction remains constant.

Barrel (bbl): A unit equivalent to 159 litres used to measure volumes of oil.

Base-load generation/supply: Power that is generated/supplied at a constant rate throughout the day.

British Electricity Trading and Transmission Arrangements (BETTA): The framework governing the operation of the UK wholesale power market. BETTA replaced the New Electricity Trading Arrangements (NETA) after the integration of Scotland into the England & Wales electricity system.

Biomass: Plant materials and animal waste used as fuel.

British thermal units (btu): A measurement of energy. 100,000 btu is known as a therm. One million btu (mmbtu) is equivalent to approximately $28m^3$ of natural gas, depending on temperature and pressure.

Capacity/reserve margin: The difference between expected demand and the available generation capacity. The capacity margin gives a valid indication within the operational timeframe of the ability of the system to meet demand. A narrow capacity margin indicates an unacceptable level of risk that supply will be interrupted because of a shortage of generation, while an excessive capacity margin (indicating too much generating capacity on the system) adds to the cost of electricity.

Carbon Capture and Storage (CCS): Capturing carbon dioxide (CO2) from large point sources such as fossil fuel power plants and storing it instead of releasing it into the atmosphere. The "capturing" can be done both pre- and post-combustion. In post-combustion, CO2 is captured from flue gases emitted by fossil fuel-fired power stations. In pre-combustion, fossil fuel is partially oxidized before being burned, for instance in a gasifier. The resulting syngas (carbon monoxide and hydrogen) is shifted into CO2 and more hydrogen, and the resultant CO2 can then be captured from a relatively pure exhaust stream.

Combined Cycle Gas Turbine (CCGT): A technology to improve the thermal efficiency of a gas turbine. Hot gases from the gas turbine are used to turn a power turbine which generates electricity in the normal way. The exhaust gases are then passed through a heat recovery boiler (or heat exchanger), producing steam which can then be used to generate more electricity in a steam turbine. The name derives from the fact that the technology combines the Brayton (gas turbine) and Rankine (steam turbine) thermodynamic cycles.

Flue Gas Desulphurisation (FGD): A technology that employs a sorbent, usually lime or limestone, to remove sulphur dioxide from the gases produced by burning fossil fuels. Flue gas desulphurisation is current state-of-the art technology for major SO2 emitters, like power plants.

High voltage direct current (HVDC): A system of electricity transmission. The advantage of HVDC is the ability to transmit large amounts of power over long distances with lower capital costs and with lower losses than AC. High-voltage direct current transmission allows efficient use of energy sources remote from load centers.

Independent Power Producer (IPP): An electric power generator who is separate from the major national or regional companies.

Independent System Operator (ISO): An independent organisation set up to run transmission systems owned by two or more entities. The transmission owners retain title to their assets and the ISO runs the systems as a joint operation to ensure fair access and competition.

Installed capacity: Production capacity of a power plant based either on its rated (nameplate) capacity or actual (practically determined) capacity.

Integrated Gasification Combined Cycle (IGCC): a type of generation technology that burns a synthetic gas (syngas), created from coal, to produce power. To maximise efficiency, IGCC plants employ a combined cycle (gas and steam) turbine configuration (see CCGT entry above for more details).

Kilovolt (kV): The unit of electrical potential equivalent to 1,000 volts.

Load factor: A measure of the output of a power plant compared to the maximum output it could produce.

Long run marginal cost (LRMC): The cost of meeting an increase in electricity demand over an extended period of time. The LRMC includes all short run costs as well as the capital cost of adjusting system capacity.

Megawatt (MW): Unit of electrical power equal to 1 million watts or 1,000 kilowatts. One MW is enough to power ~500 homes. 1,000 MW equals 1 gigawatt (GW).

Megawatt-hours (MWh): Unit of energy commonly used to measure electricity production or consumption. 1 MWh is the amount of energy produced by a 1MW power plant operating for a period of 1 hour. 1,000MWh equals 1 gigawatt-hour (GWh). 1,000GWh equals 1 terawatt-hour (TWh).

Overnight capital cost: The capital cost of a project if it could be constructed overnight. This cost does not include the interest cost of funds used during construction.

Peak demand/load: Maximum power used (instantaneously) within a given time period (in MW/GW).

Pulverised Fuel (PF): A method of burning coal where the fuel is ground into a fine powder prior to combustion

Pump storage hydro electric plant: An electricity generation system which pumps water into a storage reservoir that is released to drive power turbines at times of peak demand.

Pressurised Water Reactor (PWR): A design of nuclear reactor using pressurised water as its primary coolant.

Selective Catalytic Reduction (SCR): A means of converting nitrogen oxides, also referred to as NO_x with the aid of a catalyst into diatomic nitrogen, N_2, and water, H_2O. SCR can be used to substantially reduce NOx emissions from large power plants.

Short run marginal cost (SRMC): The cost of producing one additional unit of electricity i.e. the variable cost. In the European context, the SRMC includes the cost of fuel, the cost of required emission permits, and the cost of plant operations and maintenance.

Transmission system/grid/network: The system of high-voltage power lines, transformers and switches that move large volumes of power across long distances.

Wholesale market: The point at which generators offer their electricity output to retailers.